SUSPLAN

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Abstract
This study analyses the transnational infrastructure developments in Europe until 2050 in four different storyline backgrounds. For both the electricity and gas market the main market developments are described after which conclusions are drawn with respect to joint market developments. The study provides a number of key conclusions and recommendations for policy-makers.

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LIST OF ABREVIATIONS

AC	Alternating current
ACER	Agency for the cooperation of energy regulators
CAES	Compressed air energy storage
CCGT	Closed cycle gas turbine
CCS	Carbon capture and storage (of CO_2)
CDM	Clean development mechanism
CHP	Combined heat and power production
CSP	Concentrated solar power
DC	Direct current
DOE	Department of energy
EC	European Commission
ECN	Energy research Centre of the Netherlands (ECN)
EIA	Energy information administration
EIE	Energy in excess
ENTSO	European network of transmission system operators
ENTSO-E	European network of transmission system operators for electricity
ENTSO-G	European network of transmission system operators for gas
ETS	European emission trading scheme
ETSO	European transmission system operators
EU	European Union
EWEA	European Wind Energy Association
FACTS	Flexible alternating current transmission systems
GJ	Gigajoule
GRI	Gas regional initiative
GSE	Gas storage Europe
GTE	Gas Transmission Europe
HV	High voltage
IAEA	International Atomic Energy Agency
IEA	International Energy Agency
ITGI	Interconnection Turkey, Greece, Italy
JI	Joint implementation
kV	Kilovolt
kWh	Kilowatt hour
LNG	Liquefied Natural Gas
MS	Member state of the European Union
MT	Megaton
MTSIM	Red
MW	Megawatt
MWh	Megawatt hour
NIMBY	Not in my backyard
NTC	Net transfer capacity
OCGT	Open cycle gas turbine
ppm	Parts per million
PST	Phase shifting transformer
PTDF	Power transfer distribution factor
R&D	Research and development

RES	Renewable energy sources
RES-E	Renewable energy sources for electricity
RES-G	Renewable energy sources for gas
SSO	Storage system operator
ST	Steam turbine
TAP	Trans-Adriatic Pipeline
t	Ton
TSO	Transmission system operator
TWh	Terawatt hour
TYNDP	Ten year network development plan
UCTE	Union for the Coordination of Transmission of Electricity
UK	United Kingdom
VOLL	Volume of lost load
VSC	Voltage Source Converter
WEO	World Energy Outlook
WEPP	World electric power plants (database)
WGV	Working gas volume

Country abbreviations in electricity model MTSIM:

AT	Austria
BG	Bulgaria
BL	Belgium and Luxembourg
BX	Balkan countries (Albania, Bosnia and Herzegovina, Kosovo, Montenegro, Republic of Macedonia, Serbia)
CH	Switzerland
CZ	Czech Republic
DE	Germany and Denmark West
ES	Spain
FR	France
GR	Greece
HR	Croatia
HU	Hungary
IT	Italy
NL	The Netherlands
PL	Poland
PT	Portugal
RO	Romania
SI	Slovenia
SK	Slovak Republic
UA_W	Ukraine West
KA	Kaliningrad Region of Russia
RU	Russia
BY	Belarus and Moldova
TR	Turkey
MT	Malta
TU	Tunisia
DZ	Algeria
MA	Morocco

LY	Libya
IS	Iceland

Country abbreviations in gas model GASTALE:

AL	Algeria
AT	Austria
BALKAN	Balkan region, covering Croatia, Bosnia-Herzegovina, Serbia, Montenegro, Macedonia, Albania, Slovenia, Greece, Bulgaria and Romania.
BALTIC	Baltic region, covering Sweden, Finland, Norway, Estonia, Latvia and Lithuania
BELUX	Belgium and Luxembourg
BG	Bulgaria
CENTRAL	Central European region, covering Czech Republic, Slovakia and Hungary
DE	Germany
DEDK	Germany and Denmark
DK	Denmark
FR	France
GR	Greece
HU	Hungary
IBERIA	Iberian Peninsula, covering Spain and Portugal
IT	Italy
ITALP	Italy and the Alps, covering Italy, Malta, Austria and Switzerland
PL	Poland
RO	Romania
RU	Russia
SL	Slovenia
TN	Tunisia
TR	Turkey
UKIE	UK and Ireland

EXECUTIVE SUMMARY

This report summarises the results from the transnational scenario analysis (WP3) of the SUSPLAN project *(Planning for Sustainability)*, addressing both the gas and electricity infrastructure needs in EU27+ under different scenarios/storylines with high penetrations of renewable energy sources. The storylines reflect four different futures which differ along two dimensions; firstly, the public attitude towards a sustainable energy system transition, and secondly, the degree and speed in which sustainable energy technologies are developed. The project has several unique features compared to other infrastructure studies; it not only addresses the longer time frame to 2050, but also has a multi energy-multi infrastructure perspective. Unique to many other studies, this report highlights the interaction between the electricity and gas sector infrastructure requirements.

Key findings from an electricity infrastructure perspective show that several expansions needs are common to all four storylines. This expansion seems to be fundamental for a better exploitation of the network and RES integration irrespective of the future energy system characteristics. In particular, the corridors that connect Central Europe with the Iberian Peninsula (ES-FR, FR-DE, FR-BL, FR-IT, DE-PL) are expanded in order to exploit and transfer all the potential RES generation to consumption centres, e.g. those placed in central Europe, at minimum marginal cost. Some corridors placed in Eastern and South-Eastern Europe (AL-GR, RO-UA_W and SK-UA) are also significantly expanded in all storylines.

In general, similar trends in electricity infrastructure reinforcements can be observed with respect to the ongoing/expected developments in the period up to 2030. This is particularly the case for some crucial regions and corridors of the pan-European transmission system, like the France-Spain links, the interconnections along the axis Germany-Poland-Baltic countries as well as the Central European region and the North Sea offshore grids concerning the British Islands, the Scandinavian countries and North-Western Europe. These regions and corridors are in fact to be considered crucial ones for the fulfilment of RES targets both in 2020 and in the 2030 storylines.

From a gas infrastructure perspective, results show that, within EU, some cross-border investments are robust across the different storylines, whereas other cross-border investments are storyline dependent. Cross-border investment in the gas corridor from Turkey to Central Europe and relatively smaller investment in the Northwest European pipeline system are constant across storylines. The South-East European corridor is an important supply corridor in all storylines. Upgrades in the Northwest European region are, despite of possible changes in gas flow patterns, rather limited due to the already quite well-developed infrastructure in this part of Europe. The infrastructure in this part of Europe will be increasingly used to accommodate import flows whereas it used to accommodate Dutch and UK export flows previously. This observation is in line with industry views on future gas pipeline investment requirements for particularly this region.

Important storyline differences can be observed especially in the Southwest and South of Europe where additional EU internal pipeline investments are required to facilitate for mostly pipeline imports from Algeria (to Italy and Spain) and LNG imports (via Italy). Since the need for additional imports from Algeria and LNG exporting countries is different across storylines, also infrastructure investments are storyline-dependent.

By jointly addressing the implications of future renewable energy futures on different aspects of the electricity and gas markets, a paradox can be observed, namely, that the electricity infrastructure cost of integrating renewable electricity are higher in especially low energy demand storylines. This is caused by an increasing need to transfer large volumes of electricity through Europe so to match favourable electricity generation regions with existing load centres. In a high energy demand storyline it is easier to match demand and electricity production locally. However, gas infrastructure developments need to be taken into account as well. A high energy demand storyline also causes a larger penetration of gas in the energy mix, although the actual penetration rate varies across the storylines.

The study has also looked at the impact of high RES penetration and accompanying need for infrastructure on electricity generation costs, CO_2 emissions and security of supply. As the share of RES increases so will the capital cost per unit of electricity production, however, the negative impact of an increasing capital cost is expected to overcompensate by the positive impact on fuel and CO_2 emission costs per unit production. From a security of supply perspective, it should be noted that the gas import dependency of the EU in relative terms remains high, 85-95%, especially since EUs own gas production is small and will decrease over the period. However, a combination of a RES penetration and reduction in energy consumption will result in a significant decrease in the import of gas from outside Europe in absolute terms, from 815 billion m^3 in the **Red** storyline to 290 billion m^3 in the **Green** storyline in 2050.

This report provides an important input to the overall policy recommendations which will be presented in Work Package 5 of the project. Key recommendations from this study can be summarised as follows:

- A strong support is needed in particular for the realisation of a number of critical energy corridors on both the gas and electricity market, especially infrastructure expansion requirements that are needed across a wider range of possible future energy market developments (as covered by identified storyline backgrounds). Measures to this purpose can be further developed under the recently launched Energy Infrastructure Package of the EC.

- Future infrastructure developments would benefit from more certainty with respect to the long-term EU climate policy. Especially, the choice of technology in the electricity generation sector in the medium to long term is prone to specific dynamics and expectations of fuel and especially CO_2 prices. The current ETS puts a price on the emission of CO_2 but is not successful in providing a long-term perspective on a credibly high CO_2 price. This especially harmful in an industry where (generation and electricity and gas infrastructure) investments are capital intensive and need to be depreciated over a time span of 40 or even 50 years. This is something to explicitly take into account in discussions on future pathways to a sustainable energy system in 2050. The current EU preparations for a 2050 energy vision are an example.

- There is a strong need to take into account the fact that electricity and gas markets are strongly intertwined, both in the short term (on operational issues), as well as the long-term, in for example infrastructure development. Focussing on single strategies for either market, for example electricity market policy, whether from a market integration, security of supply or sustainability perspective is bound to give rise to inadequate policies and regulations and undesirable developments elsewhere. The risk of such happening obviously is limited in a 2040 / 2050 future energy system where gas only has a limited role to play in the overall energy system (as for example would be the case in a green storyline).

1 INTRODUCTION

1.1 Context

The SUSPLAN *(Planning for Sustainability)* project addresses the need for infrastructure investments to accommodate the integration of a large share of renewable energy system in the longer time frame 2030-2050 in EU27+. A key objective of the project is to present a set of guidelines, consisting of strategies, recommendations, criteria and benchmarks, for more efficient integration of renewable energies in this time frame, with special emphasis on Pan-European harmonization.

Infrastructure and integration of renewable energies into the European energy markets is a key topic on the political agendas of the European Commission and the Member States. The Energy Infrastructure Package, recently adopted by the European Council, highlights that Europe is still lacking the grid infrastructure to enable renewable energies to develop and compete on an equal footing with traditional sources in both the short and longer term. Large scale wind parks in Northern Europe and solar facilities in Southern Europe need corresponding power lines capable of transmitting this renewable power to the areas of high consumption. A key message is that today's grid infrastructure will struggle to absorb the volumes of renewable power which the 2020 targets entail (33% of gross electricity generation).

In the longer term, European Council has given a commitment to the decarbonisation path with a target for the EU and other industrialised countries of 80 to 95% cuts in emissions by 2050. New strategies on energy infrastructure development to encourage adequate grid investments in electricity, gas, oil and other energy sectors will be needed if emission cuts are to be achieved. Provided the supply is stable, natural gas will continue to play a key role in the EU's energy mix in the coming years due to its relative low CO_2 content compared to competing fuels and because gas can gain importance as the back-up fuel for variable electricity generation.[1] This calls for diversified imports, both pipeline gas and Liquefied Natural Gas (LNG) terminals, while domestic gas networks are required to be increasingly interconnected.

Currently, the main tool for providing a pan-European planning vision for grid infrastructure in line with the long-term EU policy targets is the ten-year network development plan (TYNDP) drafted by the newly established bodies; the European TSO for electricity (ENTSO-E) and the European network of transmission system operators for gas (ENTSO-G).

In order to define the best strategies and policy recommendations for appropriate infrastructure needs in the timeframe to 2050, a separate work package within the SUSPLAN project is dedicated to study the role which transnational networks can play. Expansion of transnational infrastructures may facilitate the integration of a larger amount of regional/national supply of RES than would be possible without additional transnational energy infrastructure investments. This report presents the results from this particular analysis.

[1] Flexible gas-based electricity generation is by no means the only viable means to provide flexibility to an electricity system that experiences large deviations in the supply from for example wind-based generation units but certainly in the short to medium term it is one of the most cost-effective.

A unique feature of the SUSPLAN project compared to other EU-funded infrastructure projects is the focus on multi energy sources - multi infrastructures. At transnational level, the project deals with both the electricity and gas infrastructures, and addresses the interactions between those. It is deemed necessary to consider the interaction between electricity and gas infrastructures since the extension of electricity infrastructure may also warrant an extension of the gas infrastructure and the other way around. For example, RES supply will have an impact on power generation by gas-based power plants and consequently on gas demand and required gas infrastructure. To date, the interaction between developments in the gas networks and electricity networks is quite limited but the mutual influence and dependency between these infrastructures is expected to increase in the long run. The SUSPLAN project addresses also the interdependency between regional and transnational decisions on RES deployment and infrastructure investments, a topic highlighted also in this report.

A number of relevant studies, funded under both the European Commission's FP7 and IEE programs are addressing renewable energy infrastructure integration issues. REALISEGRID[2] and IRENE-40 are two important studies under the FP7 program. Whereas the SUSPLAN project focuses on the role of RES in the energy mix and the challenges of integrating high shares of RES from the perspective of electricity and gas infrastructures, the REALISEGRID focuses on the electricity transmission infrastructure only, and assesses how it should be optimally developed to support the achievement of a reliable, competitive and sustainable electricity supply in the EU. However, REALISEGRID models the details of the single transmission lines, whereas SUSPLAN only considers equivalent trans-national transmission corridors and neglects the details on the internal lines of each country. The IRENE-40 is focused on identifying the strategies for investors and regulators enabling a more secure, ecologically sustainable and competitive European electricity system. The three projects have important overlaps and synergies.

1.2 Objectives and approach

The overall objectives of the transnational scenario analysis section of SUSPLAN can be summarized as follows:

- Determination of transnational electricity and gas infrastructure routes and capacities needed in the future (including accompanying costs) in each of the four storylines, taking into account relevant results from the regional case studies.
- Insights in the interaction between extensions/changes of gas and electricity infrastructures.
- Cost-benefit analysis to analyse whether the costs of these new infrastructure do outweigh the benefits (including effects on CO_2 savings and security of supply in a transnational context).
- Qualitative description of the relevant barriers (economic, legal, technical and environmental) and options for removing barriers for investments in new electricity and gas infrastructure.

Within the SUSPLAN project, a consistent scenario framework [Auer et al., 2009] is defined for the regional as well as the transnational analyses of RES grid infrastructure integration in Europe up to 2050. The transnational analysis of the cross border electricity and gas infrastructure needs in

[2] FP7 project REALISEGRID: "REseArch methodoLogIes and technologieS for the effective development of pan-European key GRID infrastructures to support the achievement of a reliable, competitive and sustainable electricity supply", http://realisegrid.rse-web.it.

Europe between 2030-2050 carried out under the assumptions of four SUSPLAN storylines. A starting point for electricity and gas infrastructure in Europe in 2030 has been assumed on the basis on the ENTSO-E and ENTSO-G ten-year development plans, preliminary results from the REALISEGRID project [REALISEGRID, 2010b, 2010c] and modelling with the GASTALE model. Following this, gas and electricity market models are used within a modelling framework to determine the transnational electricity and gas infrastructure needs between 2030-2050 in each of the four storylines. In this modelling framework, GASTALE is used to simulate EU gas markets and determine the optimal transnational gas infrastructure investments whereas MTSIM is used to simulate EU electricity markets and determine the needs for electricity network expansion. Moreover, the interaction between the electricity and gas markets is also taken into account by utilizing an iterative approach with input/output interactions between MTSIM and GASTALE models.

In assessing the cost and benefits of more RES-E and RES-G supply against incremental costs of investing in electricity and gas infrastructures in Europe, security of supply and CO_2 emission reduction impacts of RES-E and RES-G *realized through higher availability and better utilization of RES through the extension of interconnection capacity* are taken into account through a simple cost-benefit analysis.

1.3 Report outline

Following this introduction chapter, the report presents the methodology and input assumptions for analysis of the transnational infrastructure needs in Chapter 2. Chapter 3 presents the results of the scenario analysis obtained with the electricity market model, MTSIM, whereas Chapter 4 presents the results of the scenario analysis obtained with the gas market model GASTALE. Both chapters present results per scenario, including market developments underlying the infrastructure developments, and conclude with a comparison of results across storylines. Chapter 5 then proceeds with an assessment of barriers for transnational infrastructure developments and includes solutions to remove or mitigate these barriers. Chapter 6 contains an integral analysis of the electricity and gas developments. There we reflect on the major energy corridors in the EU and analyse the impact of storyline drivers on energy markets and infrastructure requirements. Finally, chapter 7 presents the main conclusions and recommendations of this study.

The research performed in this study has delivered a large amount of quantitative data on both electricity and gas sector developments. This data is depicted in a range of tables and figures throughout the announced chapters but are also made available on internet. As part of the SUSPLAN project a web-based user interface is developed that collects and presents all results from the project's research activities. A link to this interface will be available at http://www.susplan.eu.

2 METHODOLOGY AND ASSUMPTIONS

Within SUSPLAN project, a consistent storyline framework [Auer et al., 2009] is defined for the regional as well as the transnational analyses of RES grid infrastructure integration in Europe up to 2050. The main focus of transnational studies is the analysis of the cross border electricity and gas infrastructure needs in Europe between 2030-2050 under the assumptions of four SUSPLAN storylines. This requires establishing a starting point for electricity and gas infrastructure in Europe up to 2030. Thus, analysis of SUSPLAN storylines is done under a two-step approach: First, a set-up of infrastructure developments until 2030 is established for both gas and electricity infrastructures. Then gas and electricity market models are used within a modelling framework to determine the transnational electricity and gas infrastructure needs between 2030-2050 in each of the four storylines. In this modelling framework, GASTALE is used to simulate EU gas markets and determine the optimal transnational gas infrastructure investments whereas MTSIM is used to simulate EU electricity markets and determine the needs for electricity network expansion. Moreover, the interaction between the electricity and gas markets is also taken into account by utilizing an iterative approach with input/output interactions between MTSIM and GASTALE models. In this section, all the steps taken for methodology from the storyline set up until obtaining the output from the modelling are described.

2.1 Storyline approach

This section briefly describes the storylines developed for SUSPLAN project, and the interpretation of the corresponding storyline assumptions for electricity and gas markets at both European and national levels. The details of the methodology for storyline framework and the assumptions can be found in the SUSPLAN guidebook [Auer et al., 2009].

2.1.1 SUSPLAN storylines

Before each of the four storylines are described more in detail, the basic assumptions and background information, including regional and transnational features, for the definition of the SUSPLAN storylines are listed below:

- There is a strong political will in Europe to promote sustainable development and security of supply in the energy sector. This leads to a significant improvement in the framework promoting increased deployment of RES generation technologies.
- The share of RES in the future European energy system will be large. The use of conventional technologies like nuclear power plants and fossil fuel technologies (also with new CCS) will follow traditional infrastructure planning and operation strategies. Therefore, this already known aspect will not be explicitly analysed in the SUSPLAN project in detail. However, in the different storylines different penetration rates and emphasis of these technologies are assumed.
- Hydrogen will not be applied as energy carrier at distribution level in the given time perspective of SUSPLAN (up to 2050). If hydrogen is applied large-scale, it will be as bulk transport of energy or large-scale storage for the power sector. Electricity (e.g. electric vehicles) will turn out to be the most cost effective alternative to fossil fuels in the transport sector, but bio-fuels may in some storylines fill also a certain amount of the energy demand in the transport sector.

- SUSPLAN focuses on stationary energy production and consumption, i.e. the transport sector itself is not a part of the SUSPLAN project. However, electric vehicles and bio fuels might influence the stationary energy balance (e.g. reduced bio-energy potentials for electricity and heat generation in case of bio fuel use and applications in the transport sector).

The SUSPLAN project comprehensively addresses the aspect of large-scale integration of different types of RES generation technologies. This creates different needs for infrastructures on different levels and dimensions:

- Transmission grid expansion needs both onshore and offshore to enable the utilization of the economies of scale of large-scale RES-Electricity generation of technologies like onshore and offshore wind, wave and tidal, CSP (concentrated solar power), etc.;
- Distribution grid modernisation needs enabling the implementation of active grid elements and smart technologies interacting with several different kinds of grid users (smart grid concepts);
- Consideration of the interdependencies (and partly contrary objectives) between the needs of centralised top-down transmission grid infrastructure planning (favouring centralised RES-Electricity generation) and decentralised bottom-up smart grid concepts (favouring distributed RES-Electricity generation like PV, etc.);
- Consideration of the interdependencies between electricity, heat and gas grid infrastructures needs in case of combined-heat and power generation (e.g. biomass), on the one hand, and also switches of energy carriers “fuelling” particular energy services, on the other hand.
- Grid infrastructure needs to get spatial access to flexible electricity generation and storage technologies being qualified to contribute to the balancing of power systems with high shares of variable and intermittent RES-Electricity generation.

The four SUSPLAN storylines are constructed to cover all these kinds of aspects. In accordance with the SUSPLAN Guidebook [Auer et al., 2009], the SUSPLAN storylines, including regional and transnational features, are described:

”Green” Storyline

There is a very high focus in Europe on environmental challenges and the need for reduction of CO_2 emissions. The positive environmental awareness applies to governments and citizens across Europe. Consumers choose environmentally friendly commodities. Public opposition is hardly visible. As a result, energy demand is low. R&D of technologies relevant for reduction of CO_2 emissions has been given high priority for many years and efforts have resulted in breakthroughs in many areas relevant for the energy sector.

Moreover, in **Green** all major technologies for RES generation are available at commercial level and large amounts of RES generation are possible at local, regional, national and trans-national level. The consumer has become a producer, and local energy production is very widespread.

In terms of grid infrastructures, in **Green l**arge-scale power grids are available to be implemented in an efficient way both onshore and offshore. On distribution level, smart grids are reality. Storage technologies for balancing variable RES generation are available in terms of (pumped-) hydro power from the Alpine region as well as the Nordic countries. Also other new technologies are available and economically competitive for storage of energy both at local (end-user) as well as at aggregated level (e.g. different battery systems and also CAES[3]).

"Yellow" Storyline

There is a very high environmental awareness among the consumers, which highly influences their demand for energy. Energy demand is low in the **Yellow** storyline. There are limited breakthroughs in new technologies for RES generation as well as for transmission and distribution, in particular smart grids. However, due to the high environmental focus among people ("bottom-up" driver), there is a market pull for technologies for local production as well as for reduction of energy consumption.

There is a lower penetration rate of new and innovative technologies compared to the *Green* storyline, and more of energy demand reduction is caused by changes in behaviour and needs among consumers. In the transport sector there is also limited deployment of electric cars outside the main city centres, as a result of few breakthroughs in battery storage technology.

In **Yellow**, new RES-Electricity generation is dominated by distributed solutions like PV. In general, RES production is mainly based on technologies that have been mature for many years.

In **Yellow**, finally, there have not been enough technological breakthroughs to make new large-scale energy efficient power grids commercially attractive. However, there is some deployment of Smart grid technologies due to the environmental focus among the consumers. Storage for balancing variable and intermittent RES generation is available in terms of (pumped-) hydro power from the Alpine region and to some degree from the Nordic countries. Also some decentralised solutions are available to contribute to balancing variable and intermittent RES production.

"Red" Storyline

The **Red** storyline represents the least sustainable energy future. There are limited breakthroughs in technology for RES production, transmission and distribution as well as for energy demand reduction. In **Red**, energy demand is relatively high due to very low awareness among consumers.

New RES generation is mainly established at municipal level. There is very limited interest for local (micro-) production. Furthermore, there have not been any necessary breakthroughs to establish significant new large-scale RES production on transnational level. RES production is to large extent based on current established technologies.

In terms of grid infrastructures, in **Red,** large-scale offshore power grids are assumed to have no significant breakthroughs. Furthermore, smart grids are barely developed due to limited interest for local production and customer participation. Storage technologies for balancing variable and intermittent RES generation are available in terms of (pumped-) hydro power from the Alpine region and the Nordic countries. Eventually, at high enough electricity price levels the demand side may adjust their consumption to some extent in **Red** to contribute to balance intermittent RES generation.

"Blue" Storyline

[3] CAES: "Compressed Air Energy Storage"

In the **Blue** storyline, the development of the energy system in Europe is mainly driven by the central governments. Public R&D funding in the energy sector lead to breakthroughs in technology for RES production, transmission and distribution as in the **Green** storyline. Investments in new capacities are mainly driven by governments. In **Blue**, energy demand is high, since energy is still mainly a low-interest product among the European public. High energy demand is a result of both low interest in environmental questions and rather low energy prices.

In terms of RES-Electricity generation, in **Blue** large-scale and centralised solutions of RES-E power plants are implemented (e.g. big offshore wind farms as well as CSP (Concentrated Solar Power) plants, etc.), supported by national and EU policy instruments.

Finally, in **Blue** large-scale power transmission grids are implemented and operated in an efficient manner both onshore as well as offshore. On the contrary, Smart grids have a very limited deployment. Storage technologies for balancing variable and intermittent RES generation is available in terms of (pumped-) hydro power from Alpine countries as well as the Nordic countries. At high enough prices, the demand side reduces its consumption and flexible demand also contributes to balancing intermittency in RES production.

Each of the four storylines represents a region on the graph in Figure 2-1:

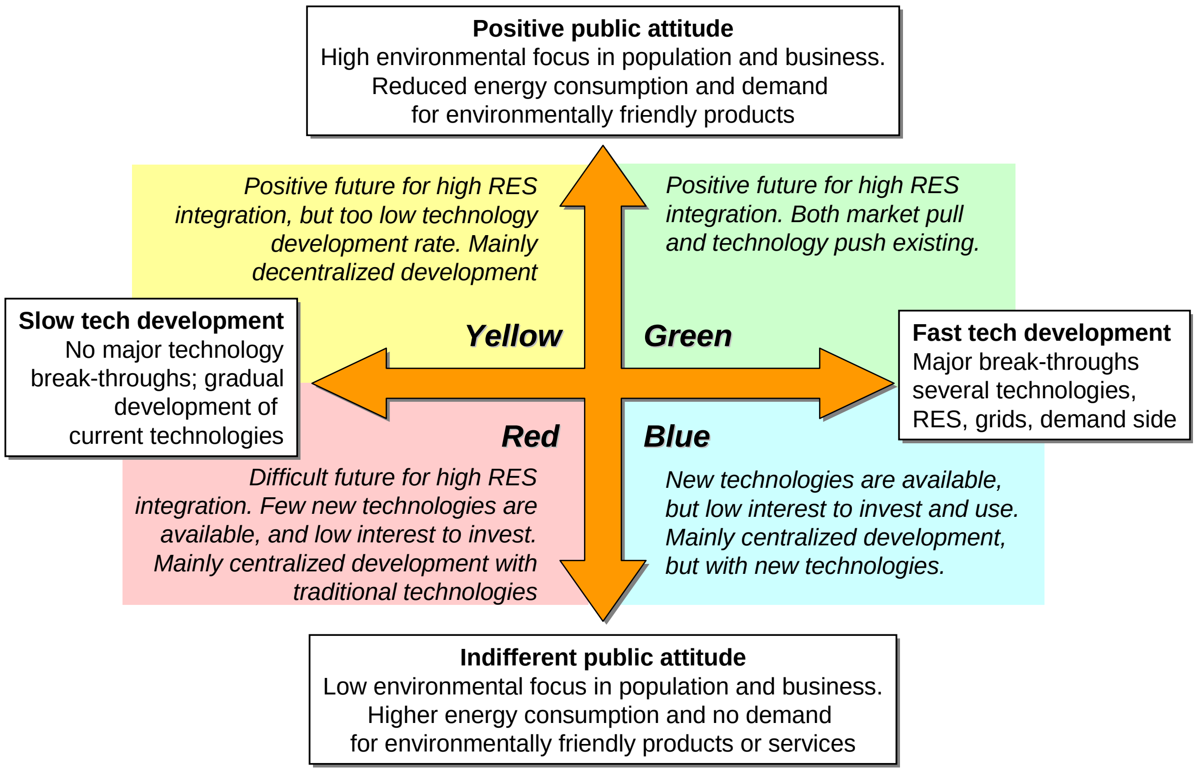

Figure 2-1 Overview of SUSPLAN storylines

According to these storylines, the location and share of RES, generation mix, connection of RES to either transmission or distribution networks, availability of offshore and smart grids, and demand developments are all factors which will impact the need for additional trans-national infrastructures for gas as well as for electricity between 2030-2050.

2.1.2 Consistent set of empirical settings for the storylines

As it becomes apparent from the storyline description, the four storylines resemble significantly diverse futures. This has implications both on the electricity and gas sectors. For example, the **Green** storyline is characterized by very high penetration of renewable energy sources across Europe, while the **Red** storyline assumes an evolution of the power supply sector similar to the one that Europe experienced in the recent past. Therefore the assumed electricity production portfolio differs substantially in the two storylines. The input assumptions for the electricity and gas sectors are described in detail below.

2.1.2.1 Storyline assumptions for electricity market

For several of the scenario studies on both regional and trans-national levels it is important to agree on consistent empirical settings of the key region-independent parameters. However, in this context it is not important to consider a high number of parameters describing the external-driven cornerstones of the energy systems in the different regions. In the SUSPLAN project, the key parameters determining the cornerstones of energy supply and demand patterns (with or also without high shares of RES generation) are limited to a handful of candidates:

- RES/RES-electricity deployment
- Final energy/electricity demand development
- RES/RES-electricity technology cost development
- Development of fossil fuel-, CO_2- and biomass prices
- Development of wholesale electricity prices

In the following, the empirical settings of several of the key region-independent parameters described above - being of core relevance for SUSPLAN scenario analyses - are visualized and, furthermore, the most relevant references/sources and own assumptions are briefly explained.

RES/RES-Electricity deployment up to 2050

For each of the four different storylines in SUSPLAN four different empirical sets of future developments for both RES generation as a share of final total energy demand and RES-electricity generation as a share of final total electricity demand are determined on aggregated European level up to 2050. Figure 2-2 and Figure 2-3 below present RES and RES-Electricity deployment in the four different SUSPLAN storylines on aggregated European level up to 2050[4].

Final Energy/Electricity Demand up to 2050

Similar to future RES/RES-electricity deployment the same sets have been established also for total final energy and total final electricity demand for each of the four storylines in SUSPLAN on aggregated European level up to 2050. Figure 2-4 below presents final energy demand (electricity demand is not shown here; but the source is the same) in the four different SUSPLAN storylines on aggregated European level up to 2050. These data is based on an extrapolation of Primes model runs up to 2030 [EC, 2007].

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[4] Source: Green-X modelling results up to 2030 extrapolated up to 2050 according to the long-term RES/RES-Electricity potentials and ambitions in energy efficiency in the different European counties (www.green-x.at, www.greennet-europe.org).

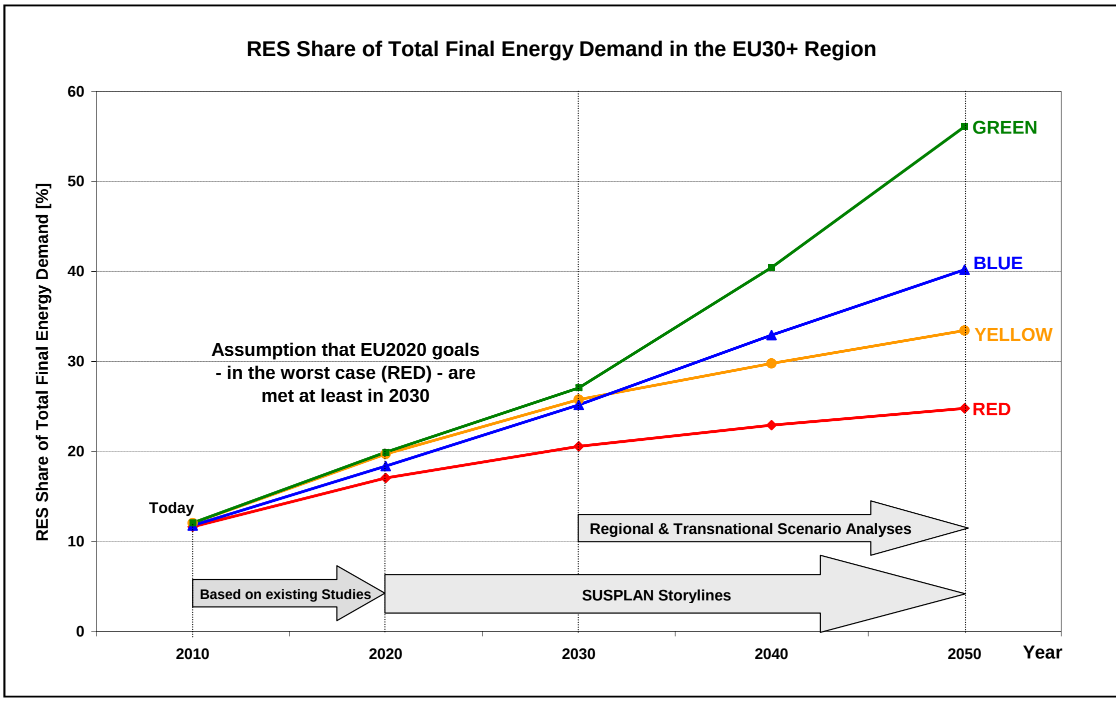

Figure 2-2 RES deployment as a share of total final energy demand on aggregated European level in the four different storylines in SUSPLAN

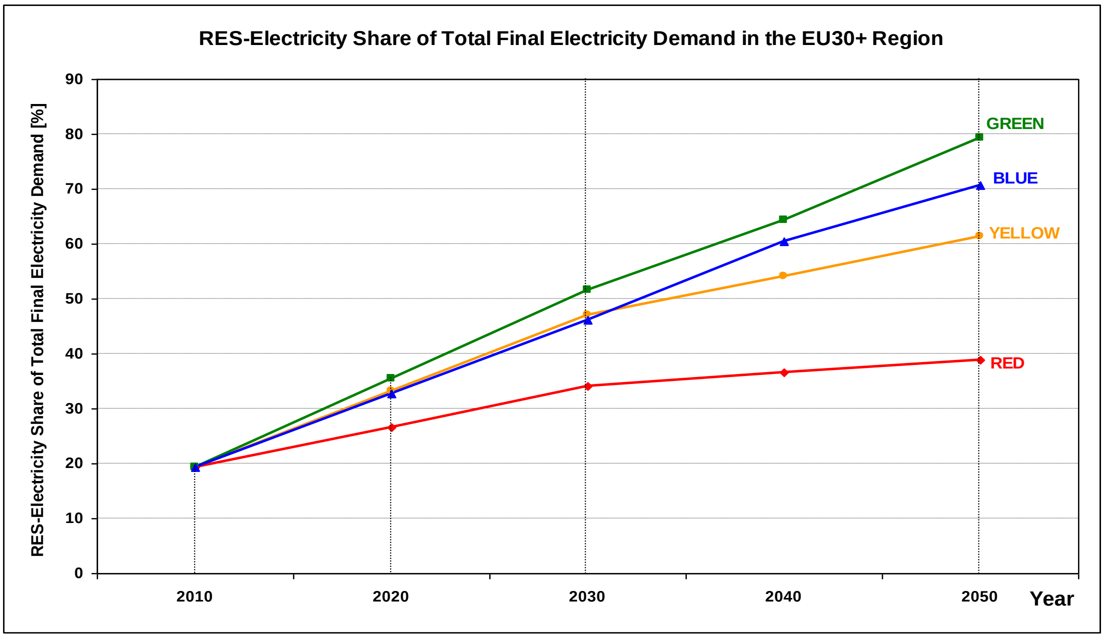

Figure 2-3 RES-Electricity deployment as a share of total final electricity demand on aggregated European level in the four different storylines in SUSPLAN

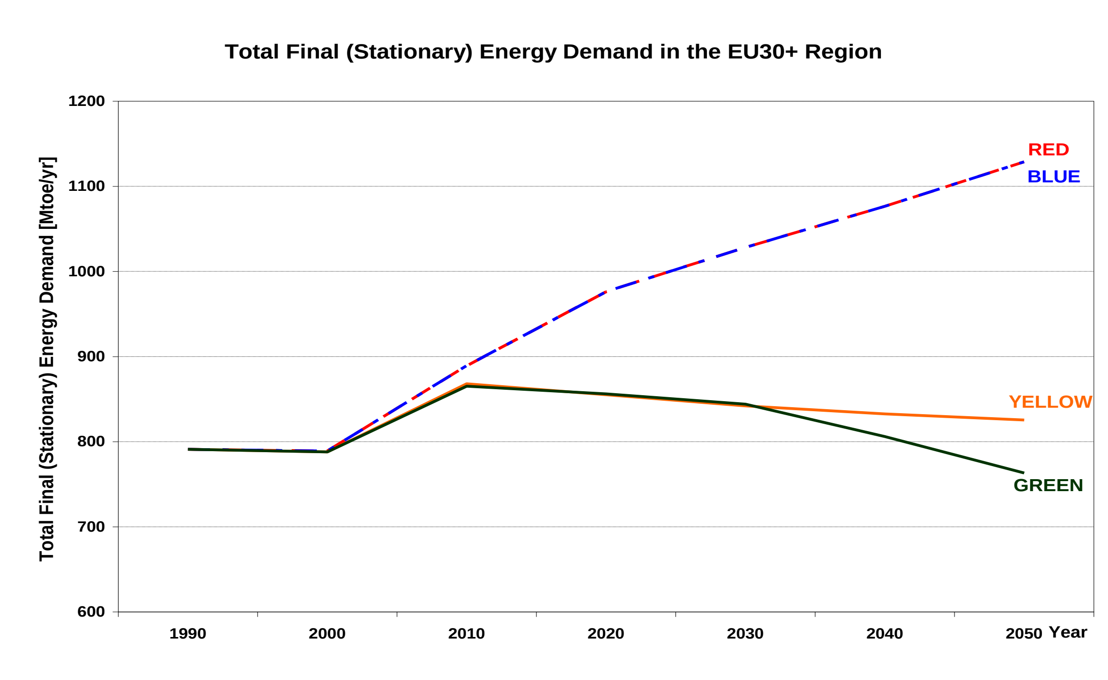

Figure 2-4 Total final stationary energy demand on aggregated European level in the four different storylines in SUSPLAN

Fossil Fuel-, CO_2- and Biomass Prices up to 2050

A consistent set of relevant prices for fossil fuels, CO_2 and biomass need to be part of the starting point for the analysis of future electricity and gas market developments. Although in particular the price of electricity and the price of gas need to be determined within an iterative analysis between the particular models deployed in this study a coherent set of initial prices and price trajectories need to be defined for each of the storylines.

After an assessment of the price developments as put forward in important international studies (e.g. European Energy and Transport Trends of

the European Commission [EC, 2007], World Energy Outlook' (WEO) of the International Energy Agency [IEA, 2009a], Annual Energy Outlook 2009 - With Projections to 2030 of the U.S. Energy Information Administration of the Department of Energy [EIA-DOE, 2009], others), we have decided to use particularly the future price trajectories of the i.e. Reference Scenario and 450 ppm Scenario of the World Energy Outlook [IEA, 2009a].The two different price scenarios of the WEO2009 are implemented in the SUSPLAN approach according to the expected demand and importance of fossil and CO_2 products in the different storylines. As the demand patterns of the storyline two couples **Red**/**Blue** and **Yellow**/**Green** are similar, the four different storylines are combined to two storyline-clusters (see Figure 2-5).

- **Yellow**/**Green**: Due to lower demand of fossil fuels and decreasing importance of CO_2 instruments, the low price path of each of the two price scenarios of the WEO [IEA, 2009a] is used.
- **Red**/**Blue**: Due to still high demand of fossil fuels and still high importance of CO_2 instruments, the high price path of each of the two price scenarios of the WEO [IEA, 2009a is used.

Positive Public Attitude

WEO2009 "450 ppm Scenario" ($2008 Prices)	2008	2015	2020	2025	2030	2035	2040	2045	2050
IEA crude oil imports ($/bbl)	**97,2**	**86,7**	**90,0**	**90,0**	**90,0**	**90,0**	**90,0**	**90,0**	**90,0**
Natural gas imports ($/Mbtu PCS)	10,3	10,5	11,0	11,0	11,0	11,4	11,4	11,4	11,4
Natural gas imports ($/Mbtu PCI)	11,5	11,6	12,3	12,3	12,3	12,3	12,3	12,3	12,3
Natural gas imports ($/MWh PCI)	**39,2**	**39,7**	**41,9**	**41,9**	**41,9**	**41,9**	**41,9**	**41,9**	**41,9**
OECD steam coal imports ($/t)	120,6	85,6	80,1	72,5	64,8	57,2	49,6	41,9	34,3
OECD steam coal imports ($/MWh)	**16,5**	**11,7**	**10,9**	**9,9**	**8,8**	**7,8**	**6,8**	**5,7**	**4,7**

Lower demand of Fossils in Yellow/Green than Red/Blue -> Lower Price Level

WEO2009 "Reference Scenario" ($2008 Prices)	2020	2030	2040	2050
CO_2 Price [$/t$CO_2$]	43	54	65	76

Public adapts production and consumption of energy themselves in a sustainable way; CO_2 market less important instrument and, therefore, prices are lower

Slow Techn. Develop.

Fast Techn. Develop.

WEO2009 "Reference Scenario" ($2008 Prices)	2008	2015	2020	2025	2030	2035	2040	2045	2050
IEA crude oil imports ($/bbl)	**97,2**	**86,7**	**100,0**	**107,5**	**115,0**	**122,5**	**130,0**	**137,5**	**145,0**
Natural gas imports ($/Mbtu PCS)	10,3	10,5	12,1	13,1	14,0	15,0	15,9	16,9	17,8
Natural gas imports ($/Mbtu PCI)	11,5	11,6	13,5	14,6	15,6	16,7	17,7	18,8	19,8
Natural gas imports ($/MWh PCI)	**39,2**	**39,7**	**45,9**	**49,7**	**53,2**	**56,8**	**60,4**	**64,0**	**67,6**
OECD steam coal imports ($/t)	120,6	91,1	104,2	107,1	109,4	112,0	114,5	117,0	119,5
OECD steam coal imports ($/MWh)	**16,5**	**12,4**	**14,2**	**14,6**	**14,9**	**15,3**	**15,6**	**16,0**	**16,3**

Higher demand of Fossils in Red/Blue than Yellow/Green -> Higher Price Level

WEO2009 "450 ppm Scenario" ($2008 Prices)	2020	2030	2040	2050
CO_2 Price [$/t$CO_2$]	50	100	125	150

High CO_2 market price is important instrument (for authorities) to influence production and consumption of energy (due to indifferent „public")

Indifferent Public Attitude

Figure 2-5 Expected development of the fossil fuel (crude oil, natural gas, coal) and CO_2 prices up to 2050 in the Red/Blue and Yellow/Green storylines in SUSPLAN

In SUSPLAN scenario analyses it is assumed that there will be a common European market for biomass in the medium- to long-term, resulting in a converging international biomass wholesale price. Derived from the RES2020 project[5], where several relevant country-specific biomass fraction and cost data are available for all EU27 Member States (incl. Norway), an average biomass price of €6 per GJ is taken as starting point for 2010 for several of the four storylines in SUSPLAN. Moreover, roughly 80% of the biomass cost values in the different countries are within a range of €2 to €9 per GJ, with a decreasing trend for moderate biomass use towards the future. In the SUSPLAN storyline context the empirical settings of the biomass wholesale prices up to 2050 have been set as follows .Due to the fact that in the **Red** storyline demand for biomass is assumed to be the lowest (compared to other storylines in SUSPLAN), a linear price decrease from €6 per GJ in 2010 to €5 per GJ until 2050 is foreseen. In the **Blue** storyline demand on biomass is somewhat higher than in **Red** and, therefore, a constant biomass price of €6 per GJ remains until 2050. In the two other storylines, **Green** and **Yellow**, demand on biomass is significantly higher and, therefore, increasing biomass wholesale prices are expected until 2050 reaching price levels of €8 per GJ and €10 per GJ for **Green** and **Yellow** respectively.

In the SUSPLAN project, the wholesale electricity market price development in the four different storylines is not set exogenously; it is modelled endogenously with a European electricity market model where – among others – the empirical settings of parameters described above (like fossil fuel-, biomass- and CO_2 prices, RES-Electricity generation per technology, electricity demand on country-level, etc.) are used accordingly. For modelling the European electricity market on an annual basis up to 2050, in seven (out of nine in total) regional scenario studies the model EMPS

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[5] www.res2020.eu

has been empirically scaled for each of the four storylines correspondingly[6].The EMPS model is a socio-economic electricity system model that can handle systems with large shares of conventional and variable/intermittent electricity generation as well as long- and short-term storage options. Basically it is a stochastic optimization model which calculates a minimum cost strategy for the operation of an electricity system. In the SUSPLAN application of the EMPS model each European country is considered as a single node (characterized by an endogenously determined internal supply and demand balance) with distinct import and export transmission capacities to the neighbouring countries, see Figure 2-6.

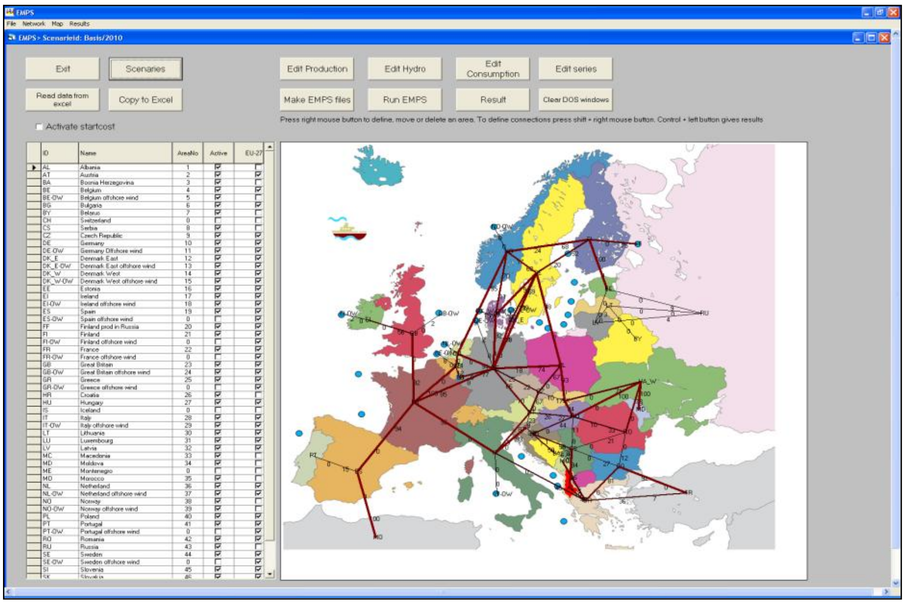

Figure 2-6 EMPS electricity market model for the regional scenario studies in SUSPLAN

Several empirical settings of the parameters in the EMPS model go in line with the overall philosophy of the different storylines in SUSPLAN. This means in particular, that e.g. several capacity settings both generation and cross-border transmission, are implemented in accordance with the overall description of the storylines.

2.1.2.2 Storyline assumptions for gas market

The four storylines are designed along two axes; a public attitude and a technology development axis. While public attitude affects directly the gas sector (e.g. a highly environmental attitude, as in the **Green** storyline, implies more efficient use of energy and therefore lower demand of energy sources including gas), technology development in the electricity sector influences the gas sector through the deployment of power generation technologies. For example, a future with high deployment of renewables can have a double effect on gas. On the one hand, renewables prevent fossil fuel power plants, including gas-fired units, from being developed. On the other hand, high penetration of intermittent sources (e.g. offshore and onshore wind) requires the development of flexible generation (e.g. hydro, gas-fired units) to enhance the balancing capability of the system.

[6] For a detailed description of this model we refer to the so-called Guidebook (D1.2) for SUSPLAN scenario analyses. The guidebook is available on the project website: www.susplan.eu.

Therefore, it is not trivial to predetermine the effect of power generation technology development on the gas sector.

In case of a positive public attitude towards sustainability, zero carbon houses are deployed, resulting in significant energy savings in the residential sector such as in the **Yellow** and **Green** storylines. In addition, heat pumps substitute to a great extent the current heating systems (e.g. gas-fired boilers) in the **Green** storyline and hence affect directly gas requirements in households. As a result, gas demand in the residential sector is lower in the **Green** storyline compared to the **Yellow**. Gas demand reduction in the industrial sector is smaller in relative terms for both storylines, but still significant, compared to the **Red** and **Blue** storylines. This reduction is explained by efficiency measures in industrial facilities and buildings in the tertiary and public sectors.

From the above description it also becomes obvious that the main effect of the storyline assumptions is related to gas demand (e.g. technology development assumptions only cover the electricity sector). In fact, apart from gas demand, the other input parameters remain constant in all four storylines. These include amongst else, gas production availability, gas infrastructure costs, future market structure, etc.

Gas demand in this study is represented by three sectors; residential, industrial including services and power sector. Gas demand for the residential and industrial sectors is defined exogenously, while demand for the power sector[7] is provided by MTSIM in the context of the parallel operation of the two models. The latter is part of the methodology employed for the assessment of the needs in new electricity and gas infrastructure developments taking into account the interactions between the two sectors which are explained in detail in Section 2.3.3. Hence, this section will focus on the gas consumption assumptions for the residential and industrial sectors.

For consistency, the sources used to generate electricity consumption storylines are also utilized to obtain the gas consumption data for the corresponding storylines. The **Red** and **Blue** storylines are characterized by the same indifferent public attitude towards environmental concerns. Deployment of heat pumps or other innovative concepts in the residential and industrial sectors is extremely limited in both storylines. The "European Energy and Transport Storylines up to 2030" baseline storyline [EC, 2007] resembles the evolution of the two sectors and thus it was selected as a source for gas demand data. It should be remarked that gas demand in the **Red** and **Blue** storylines is identical for the two sectors, as the assumptions are common in both of them.

For the **Yellow** and **Green** storylines the Second Strategic Energy Review [EC, 2008] was used as a starting point and namely the New Policy storyline that assumes a 20% RES and GHG emission reduction target in 2020, in addition to energy efficiency measures. As the information in this report is not given for the entire EU-27, further analysis was required to derive national based demand figures.

The above sources cover gas demand evolution up to 2030. For the period from 2030-2050, uniform growth rates are applied among all European countries. These rates are defined per sector and decade. For example lower growth rates are applied for the residential sector compared to the

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[7] A proportion of power sector's demand is also defined exogenously and it represents demand in the transformation sector excluding fuel inputs for power plants, which is given by MTSIM.

industrial sector in the **Green** and **Yellow** storylines. Growth rates can either be positive (increase of absolute demand) or negative (decrease of absolute demand). It is assumed that energy demand per sector changes with the same or similar rate between 2030-50 as in the preceding decade (2020-30). The same rates are applied for the development of natural gas demand.

Turkey is expected to play a key role as a transit country for European gas supplies in the coming decades. Gas supplies from the Caspian Sea and Middle East (e.g. Iran, Azerbaijan) are projected to pass through the country. The Nabucco pipeline is planned to cross the country delivering gas from the Caspian Region, Middle-East and Egypt to the Balkans and Central Europe, while more pipelines through Turkey are in the inception or more advanced stage. From the above it becomes apparent that Turkey will be a very important country for the European gas sector and hence the country is included in the GASTALE model. The situation for the electricity sector is very different on the other hand. Interconnections between Turkey and Bulgaria or Greece are relatively limited and are not expected to expand significantly, while the two regions are still operating asynchronously[8]. Hence, Turkey is not included in the MTSIM model. For this reason, it is assumed that gas demand in Turkey remains constant across all four storylines, in order to eliminate the impact in gas infrastructure requirements due to different gas demand in the country.

2.2 Establishing the starting point: infrastructure developments until 2030

2.2.1 Electricity infrastructure

Since 2030 is the starting timeframe horizon of SUSPLAN, it has been necessary to build up the cross-border transmission system evolution storyline in Europe from the current state up to 2030. This exercise was already carried out within the REALISEGRID project: the therein considered timeframe horizon has concerned the evolution of transmission years between 2005 and 2025-2030 [REALISEGRID, 2010b] [REALISEGRID, 2010c] [REALISEGRID, 2010d]. Therefore, in presence of a coordination and mutual collaboration between the two parallel FP7 projects, the assumptions and the approach used in REALISEGRID have been applied and considered also for SUSPLAN starting point setting purposes.

The aim pursued by this exercise within REALISEGRID WP2 [REALISEGRID, 2010d] has been the determination of the values of the future 'maximum allowable cross-border transmission capacity'[9] (for both flow directions at each border) in the European system, starting from the reference year 2005. The analysis has begun from the available NTC ENTSO-E values[10] for summer 2005 and winter 2005-2006, updated with the latest ETSO/ENTSO-E available NTC data (summer 2009 and winter 2009-2010)[11]. Given the difficulty of estimating, for each cross-border corridor, both a summer and a winter NTC value, it has been decided to define only a single annual value corresponding to the maximum NTC estimated value (in the vast majority of cases, the winter one).

[8] The parallel operation of the ENTSO-E and Turkish systems was initiated in 2010 and will be in full operation after a year of intense testing. For more information, please check ENTSO-E's website (news dated 07/06/2010).
[9] This definition has been meant to be more proper than the one of NTC (Net Transfer Capacity), because the (present and future) NTC estimation can be only carried out by TSOs and is officially published by ETSO/ENTSO-E. However, the two concepts are similar.
[10] Available at: https://www.entsoe.eu/resources/ntc-values/ntc-matrix/.
[11] In case of discordant NTC values between TSOs at the same border and flow direction, the choice to consider the highest value of the two possible options has been made.

To devise the future development of European cross-border interconnections from 2005-2010 up to 2025-2030 (with a five-year time step), the information and the data contained in several public sources regarding existing interconnection projects (ongoing, planned, under study, potential) in Europe have been taken into account. Among these, the main references have been the UCTE Transmission Development Plan [UCTE, 2008, 2009], the NORDEL annual statistics [NORDEL, 2006, 2007, 2008], the BALTSO Reports [BALTSO, 2005, 2006, 2007, 2008] and the ENTSO-E Ten-Year Network Development Plan (TYNDP) 2010-2020 [ENTSO-E, 2010a]. The information and the data therein contained have been also complemented by those ones available in other sources, like the EWEA report [EWEA, 2009] for offshore grids developments and the expansion plans of some TSOs (also to include in the picture additional elements related to projects of merchant lines not included in the ENTSO-E TYNDP [ENTSO-E, 2010a]).

For the estimation of future cross-border capacity of interconnections within the ENTSO-E, in absence of information about the expected net capacity increase provided by the single expansion project, opportune assumptions have been made by RSE in the framework of the REALISEGRID project, also based on the fact that, due to existing internal network constraints, only a quota of the theoretically available capacity increase can be effectively considered as net capacity increment. In this sense, the assumptions for capacity increase by new HVAC lines take account of 300 MW for 220 kV ties, 900 MW for 380 kV ties (single circuit), 1500 MW for 380 kV ties (double circuit). Exceptions to this approach have been made for the Balkan power systems, where the internal congestions very much limit the net available capacity: in those cases, in line with currently in place capacity limits, an increased capacity of 250 MW for new 380 kV lines has been conservatively assumed. For new HVDC links, the rated capacity increase has been fully taken into consideration. For the estimation of future cross-border capacity of interconnections at the edges of the ENTSO-E, the same approach as the one used for the internal cross-border projects has been followed. However, the inputs/outputs from/to outside ENTSO-E are taken as fixed yearly electricity injections: opportune (average) utilisation factors have been then assumed to convert maximum net capacity in annual net electricity exchange. These factors, in some cases, reflect the current interconnection utilisation situation projected over the years of investigation; in other cases, capacity expansion has had to take account of the enlargement of the ENTSO-E in the mid-long term horizon, to include larger injections from countries like e.g. Ukraine, Moldova, and Turkey to the European bloc under study. For the estimations of the future exchanges from/to Russia to/from ENTSO-E (Baltic Region), the storyline from 2020 onwards has taken into account the simultaneous generation contributions by both new nuclear plants projected to be developed in Russia (Kaliningrad region) and Lithuania (Visaginas). For the interconnection expansion between North Africa and ENTSO-E, conservative estimations have been carried out, shifting the realisation of the ambitious plans of solar import from Africa (e.g. DESERTEC[12] Initiative) to the post-2030 period. Thus, in the region only the interconnections between Tunisia and Italy (from 2020) and between Algeria and Spain (from 2025) have been included in the picture up to 2030. Main references for the estimations related to the interconnections at the edges of ENTSO-E have been the UCTE-IPS/UPS study [UCTE-IPS/UPS, 2008], the Medring update [MED-EMIP, 2010], the Turkey-UCTE study updates [ENTSO-E, 2010b], the Kaliningrad documents [Inter-RAO, 2010] as well as the ENTSO-E TYNDP [ENTSO-E, 2010a]. Further assumptions on the trend of net electricity flows (GWh) from extra-EU power systems have been made, also taking into account

[12] DESERTEC project: http://www.desertec.org.

corresponding load utilisation factors, which in most cases have been kept constant at the 2030 level. The profile of import/export is flat throughout the entire year.

2.2.2 Gas infrastructure

Gas infrastructure in the context of this report refers to gas transport pipelines towards the EU and within the EU, gas storage facilities in the EU, LNG re-gasification (i.e. import) terminals in the EU, and liquefaction (i.e. export) terminals in regions neighbouring the EU. For all four types of gas infrastructure an estimate needs to be made with respect to available capacity in 2030 – which is the starting year of the modelling analysis on gas market developments reported on in Chapter 4. Provision of such an estimate is done in two steps: First, publicly available information on investment plans in gas infrastructure until 2019 is used. Second, the gas market modelling tool, GASTALE, is utilized to bridge the gap between the available investment plans until 2019 and the base year 2030. Below we discuss the available data used for infrastructure capacities until 2020 together with the results of the model-based estimation of available gas infrastructure in 2030.

Gas transport pipelines until 2020

The European Ten Year Network Development Plan published by ENTSO-G at the end of 2009 [ENTSO-G, 2009], which covers expected network developments in the period 2010-2019, is used as the basis for gas infrastructure developments in the period until 2030. The 10 year network development plan as prepared by ENTSO-G combines expected and planned gas infrastructure capacity developments as anticipated by TSOs. It covers both pipeline capacity developments within Europe as well as developments in the capacity of pipelines accommodating gas supplies towards the EU. The ENTSO-G network development plan generally covers infrastructure projects for which a firm investment decision is taken.[13] This implies that actual pipeline infrastructure developments may involve larger capacity developments than indicated in the network development plan due to the presence of planned projects for which a firm investment decision is not yet taken. Thus, additional information on planned but not yet formally approved pipeline projects has been used as well [Balkaninsight, 2010; BEMIP, 2009, EC, 2010a]. Gas pipeline projects not included in the ENTSO-G data have been added. Finally, projects which are indicated by the 2009 GTE+ study [GTE+, 2009] to improve reverse flow capacity have been taken into account as well.

Table A.11 in the appendix contains the data of pipeline capacity developments until 2020 to transport gas within Europe based on the sources mentioned above. Among the project pipelines accommodating gas supplies towards the EU, the largest capacity additions are Nord Stream, South Stream and Nabucco. The main gas corridors towards the EU are presented in Table 2-1. Because it is not likely that the full capacity of the South Stream pipeline will be realized in the event that competing projects such as Nabucco are realized, we assume that only half of the intended capacity of 63 billion m^3 is actually realized. The same holds for the planned expansion of a corridor between Greece and Italy (whether or not passing Albania), in which two projects are more or less competing. These are the ITGI project, which stands for Interconnector Turkey, Greece, Italy, and the Trans-Adriatic Pipeline (TAP).

[13] Exception in this respect is Spain. The Spanish TSO gas included infrastructure projects in its infrastructure developments assessment for which no final investment decision was taken at the time of publication of the network plan.

Pipeline	Route	Capacity increase (billion m^3/year)
Nabucco	TR->BG->RO->HU->AT->DE	max. 31
ITGI Poseidon	TR->GR	4
ITGI Poseidon / TAP	GR-> IT	8
Baltic	DK<->PL	5
South stream	RU->BG->RO->RS->HU->SI->AT	31
Nord stream	RU->DE	55
GALSI	TN->IT	8
Transmediterranean	AL -> TN -> IT	3.3

Table 2-1 Main natural gas corridors to Europe in the period 2010-2020[14]

Gas storage facilities until 2020

Data on gas storage developments in the period 2010 until 2020 are largely based on the gas storage investment database published regularly by GSE[15]. The database has been described in [De Joode and Özdemir, 2009] who assess gas storage capacity projections for the region of Northwest Europe. For reasons of consistency we considered the use of gas storage investment data published in the 10 year network development [ENTSO-G, 2009] but we found that the GSE database was more complete. In our estimation of total storage capacity in the year 2030, we have assumed that all planned and projected investment projects present in the GSE storage database will be realized by 2020. As [De Joode and Özdemir, 2009] argue, this may not be the case for several reasons. Planned investment projects may have been delayed or cancelled in the aftermath of the economic crisis or simply because the proposed investment plan was only announced for strategic reasons without a solid business case. In the event of all planned storage investment projects going ahead, total working gas volume (WGV) in the whole of Europe may increase from about 89 billion m^3 at the end of 2010 to about 202 billion m^3 by 2020. Figure 2-7 shows the gas storage capacity additions until 2020.[16] As illustrated in this figure, the largest increase in gas storage capacity is anticipated in Italy, Austria, Germany, and the UK.

[14] TR: Turkey, BG: Bulgaria, RO: Romania, HU: Hungary, AT: Austria, DE: Germany, GR: Greece, IT: Italy, DK: Denmark, PL: Poland, RU: Russia, SL: Slovenia, TN: Tunisia, AL: Algeria.

[15] http://www.gie.eu.com/maps_data/GSE/database/index.html

[16] Appendix A contains a table with gas storage capacity development in Europe in the period between 2010 and 2030(Table A.12).

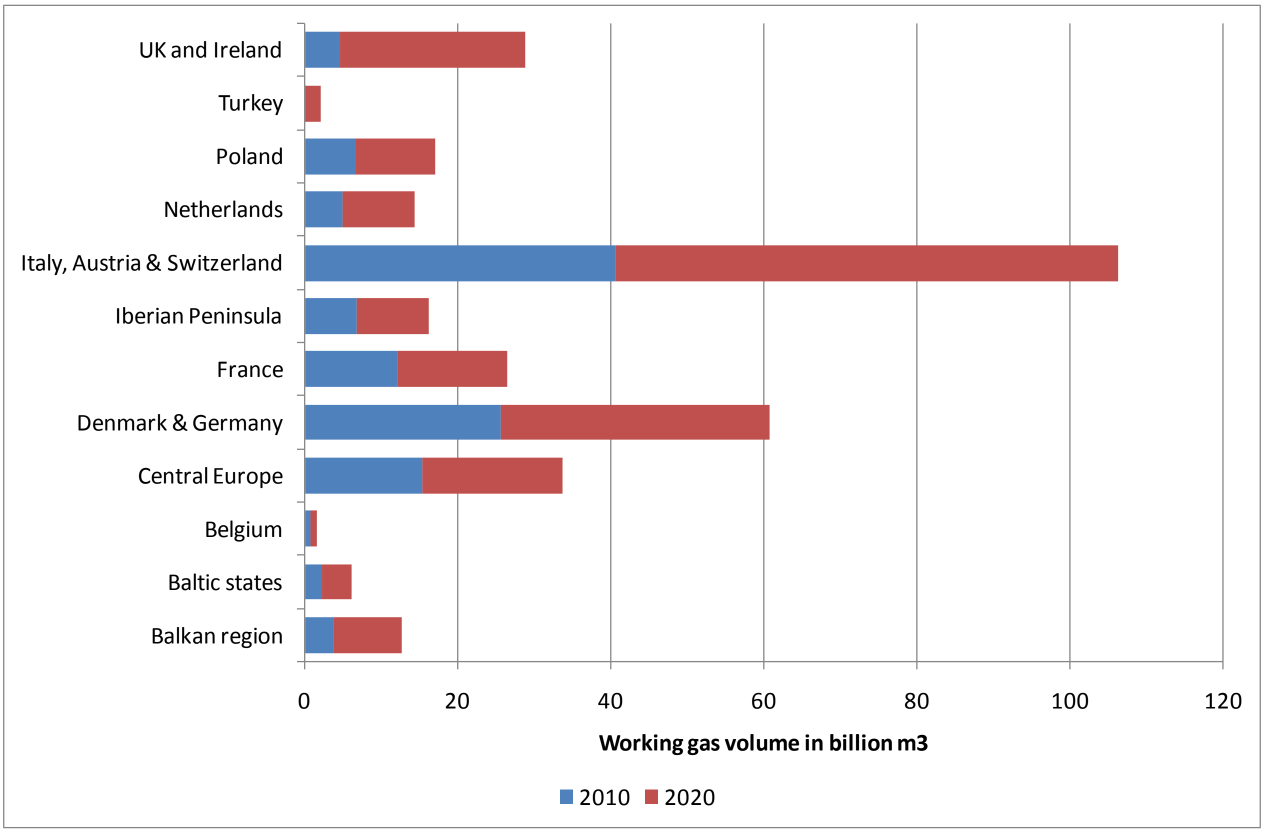

Figure 2-7 Working gas volume in gas storage facilities in Europe until 2020 (source: GSE and De Joode and Özdemir (2009)

LNG liquefaction and re-gasification terminals until 2020

The IEA provides information on the expected developments in LNG import and export capacity [IEA, 2009a, 2009b, 2010a, 2010b]. Data have been provided for 2010 and 2015. The 2015 data have been extrapolated to 2020. It is assumed that the LNG that is transported by vessels to Europe originates from Qatar and Nigeria. LNG re-gasification data are fully based on the ENTSO-G TYNDP [ENTSO-G, 2009]. Total LNG re-gasification capacity is expected to increase from 207 billion m^3 in 2010 to 261 billion m^3 in 2020. The largest LNG import capacity additions are observed on the Iberian Peninsula, the Netherlands, Poland and the UK (see Figure 2-8).

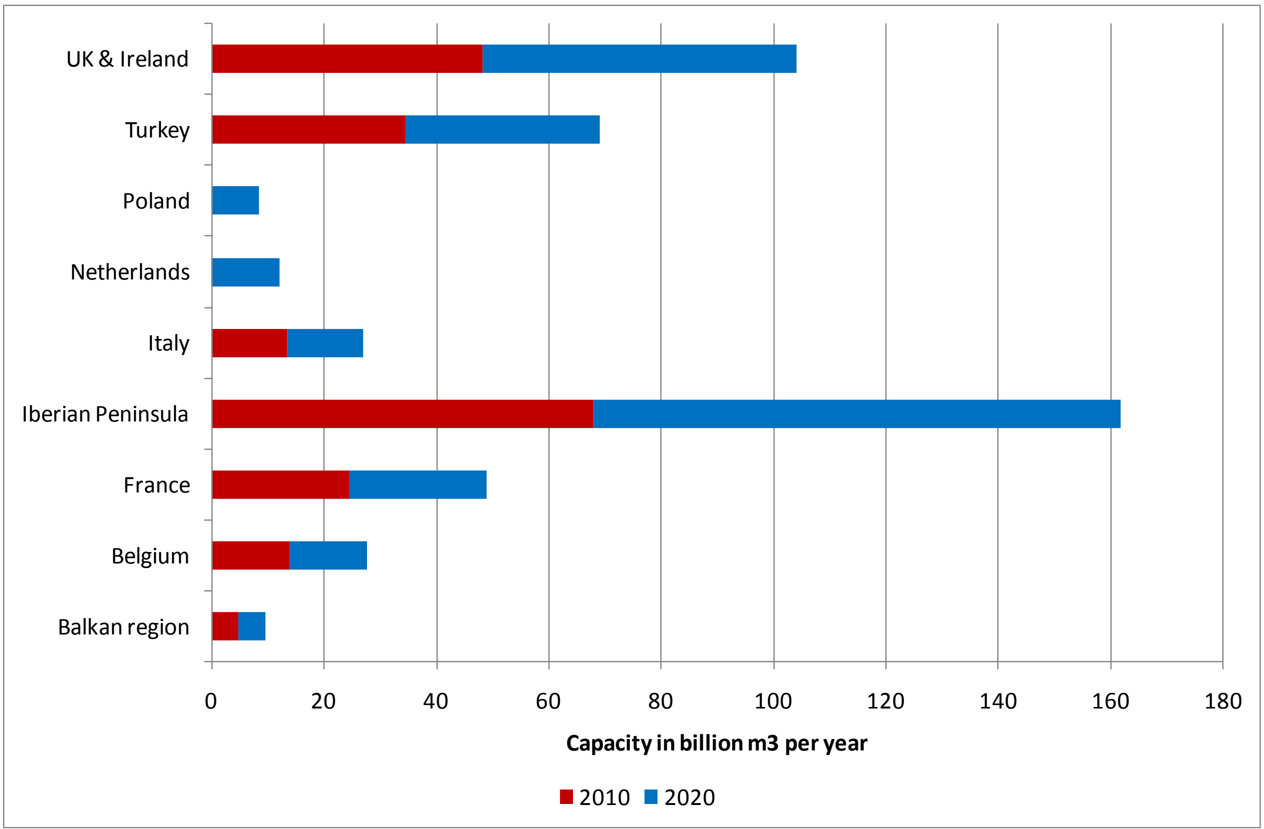

Figure 2-8 LNG re-gasification capacity development in Europe between 2010 and 2020

Identification of additional network requirements in the period 2020-2030
The additional network infrastructure requirements in the period 2020-2030 have been identified by applying the GASTALE model based on MTSIM/EMPS inputs for the four different storylines. Section 2.3.2 discusses the GASTALE modelling tool applied, whereas section 2.3.1 presents the MTSIM model. The infrastructure developments identified for the 2020-2030 period are shown in Table A.11, Table A.12, Table A.13 and Table A.14 in Appendix A.

2.3 Modelling approach

In this section we present the different modelling tools adopted in this study. Section 2.3.1 and section 2.3.2 present the electricity market model MTSIM and the gas market model GASTALE respectively.

2.3.1 Electricity market model MTSIM

MTSIM (Medium Term SIMulator) developed by RSE, is an electricity market simulator able to determine the hourly clearing of a zonal market over an annual time horizon. In calculating the zonal prices it takes into account:

- Variable fuel costs of thermal power plants;
- Other variable costs that affect power plants (such as O&M, CO_2 emissions, etc.);
- Bidding strategies by producers, in terms of price mark-ups over production costs.

The main results provided by the simulator are:

- Hourly marginal price per market zone;

- Hourly dispatching of all dispatchable power plants;
- Fuel consumption and related variable costs for each thermal power plant;
- Emissions of CO_2 (and other pollutants) and related costs relevant to the purchase of emission allowances;
- Power flows on the interconnections between market zones;
- Revenues, variable profits and market shares of the modelled generation companies.

The model can handle several types of constraints, among which:

- Power transfer capacity on the interconnections between market zones; the equivalent transmission network is modelled using the so-called *Power Transfer Distribution Factors* (PTDF[17]). MTSIM can model active power flows by calculating a DC Optimal Power Flow; in this way, transmission bottlenecks can be identified and the needs for network reinforcement can be quantified;
- Emission constraints and related trading of emission allowances at an exogenous price set in the relevant international markets (e.g. ETS, CDM, and JI).

Non-dispatchable power plants operation (typically renewable sources such as wind, photovoltaic, run-of-river hydro, etc.) is modelled exogenously: hourly generation profiles have to be provided as input to the simulator. Reservoir hydro stations are modelled by means of their typical hourly balance, which takes into account the stored amount of water, intake and off take as well as a pre-defined amount of natural precipitation, which is defined for each month of the year.
A further feature of MTSIM that has been added specifically for the SUSPLAN project is the capability to run the tool with variable line transmission limits, for assessing the AC-network expansion needs (so called "planning modality"): in this modality, MTSIM can increase inter-zonal AC transmission capacities in case the annualized costs of such expansions are lower than the consequent reduction of generation costs due to a more efficient dispatching. On the other hand, the DC network between 2030-2050 is estimated in correspondence with each storyline. The expansions of HVDC lines between 2030 and 2050 are defined exogenously; their implementation is described in 2.3.1.2. All AC and DC expansion costs resulting from the four storylines for the periods 2030-40 and 2040-2050 refer to annuities. In order to identify when MTSIM is not executing in planning modality, it will be said that MTSIM operates in "traditional modality". In this modality, MTSIM does not take into account the "network expansion" possibility, i.e. enforces a pre-defined transit limitation on each line/corridor of the network.

2.3.1.1 Representation of electricity transmission network

The European AC and DC transmission network has been modelled with an equivalent representation (see Figure 2-9) where each country (or aggregate of countries, such as in the Balkans) is represented by a node, interconnected with the neighbouring ones via equivalent lines characterized by a transmission capacity equal to the Net Transfer Capacity (NTC) of the corridor between the two countries.

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[17] Power Transfer Distribution Factors, commonly referred to as PTDFs, express the percentage of a power transfer from source A to sink B that flows on each transmission facility that is part of the interconnection between A and B.

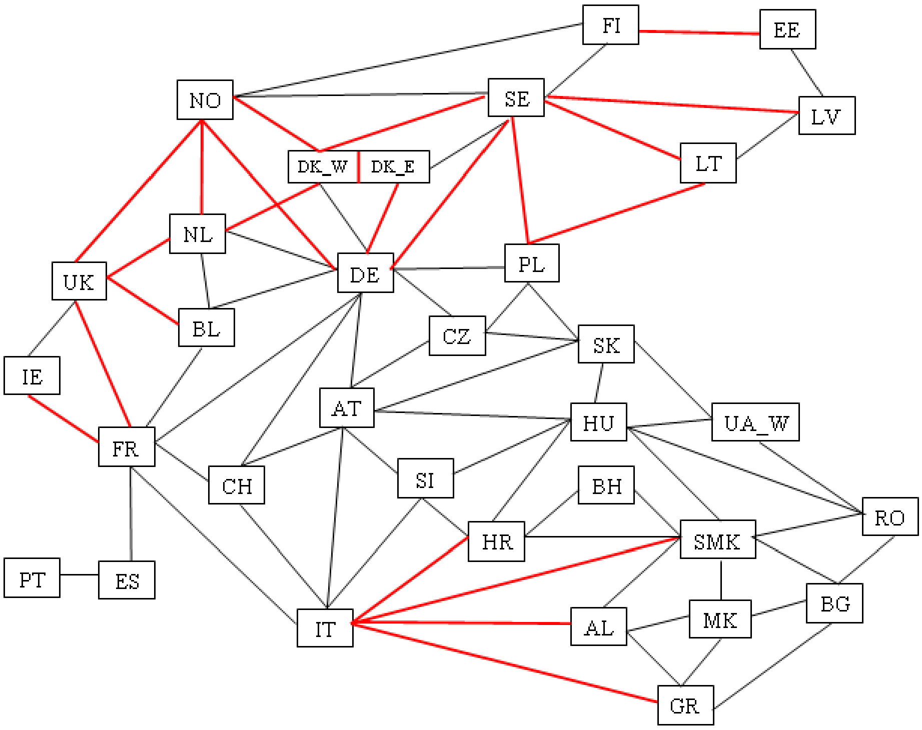


Figure 2-9 Equivalent representation of the European AC (in black) and DC (in Red) transmission network in the year 2030[18]

The PTDF[19] (*Power Transfer Distribution Factor*) matrix used in the MTSIM simulator has been calculated on the basis of a series of DC Load Flows executed on a detailed representation (about 4000 nodes) of the European AC network. As far as the NTC values (for both flow directions) are concerned, the latest ENTSO-E available data[20] (summer 2009 and winter 2008-2009) have been used. Moreover, for each cross-border interconnection and for each month, the average hourly exchanged power has been calculated, using data from the ENTSO-E Statistical Database. In case the average hourly exchanged power in a certain month was higher than the official NTC value, the former has been taken into account as the reference interconnection transmission capacity[21].

As far as the electricity exchanges via DC interconnections are concerned, they are independent from the PTDF matrix coefficients (usually DC transits are regulated by an exchange program independent from the flow in the rest of the network). This was implemented by adding two

[18] The abbreviations used in Figure 2-9 are the following: AT: Austria, BG: Bulgaria, BL: Belgium and Luxembourg, BX: Balkan countries (Albania, Bosnia and Herzegovina, Kosovo, Montenegro, Republic of Macedonia, Serbia), CH: Switzerland, CZ: Czech Republic, DE: Germany and Denmark West, ES: Spain, FR: France, GR: Greece, HR: Croatia, HU: Hungary, IT: Italy, NL: The Netherlands, PL: Poland, PT: Portugal, RO: Romania, SI: Slovenia, SK: Slovak Republic, UA_W: Ukraine West

[19] Power Transfer Distribution Factors, commonly referred to as PTDFs, express the percentage of a power transfer from source A to sink B that flows on each transmission facility that is part of the interconnection between A and B. In each of these load flows, with the slack node put in France, 100 MW of active power has been injected, in turn, into each country, while the load of all the other N-1 countries has been increased by 100/(N-1) MW. For the sake of simplicity, the presence of phase shifter transformers has been neglected. The equivalent value of the reactance of each European cross-border interconnection has been provided by ENTSO-E: https://www.entsoe.eu/index.php?id=69.

[20] Historical NTC values available at the ENTSO-E website: https://www.entsoe.eu/index.php?id=69.

[21] This is the case, for example, for the interconnection between Slovenia and Italy.

fictitious generators, both characterized by maximum and minimum generation capacity equal to the maximum and minimum transit capacity of the HVDC link, in all the two the zones that the DC line connects. An additional hourly constraint imposes that the energy generated by one generator is equal to the energy absorbed by the other one, in order to simulate the transit of energy from one node to the other. This modelling allows optimizing the usage of the HVDC link, because the program optimum algorithm will take hour by hour the decision about the optimal transit so as to minimize the overall yearly dispatching cost.

2.3.1.2 Assessment of future transmission network

In the present study, the "planning" feature has been used to determine the optimal expansion of the European AC cross-border transmission network. On the other hand, the DC transmission network until 2050 is taken exogenously in correspondence with each storyline.

Assessment of future DC network

For the years after 2030 up to 2050, in correspondence with each storyline, essentially on the basis of the two main drivers (public attitude and technological development) and also of RES progress (in particular of wind onshore and offshore installations), some assumptions on the development of the European DC transmission grid between 2030 and 2050 have been made. These estimations have been performed in terms of increase of transmission capacity (MW) at each interconnection border. They have been derived up to 2050 (for the two decades: 2030-2040 and 2040-2050) by interpreting and projecting 2030 forecast data and trend available by respectively EWEA, TSOs/ENTSO-E, calibrating them on the basis of storyline features (for specific data see ANNEX A.6). In this sense, the storyline **Green** is the most optimistic counting on both positive public attitude (with increasing RES penetration) and technology development. The intermediate storylines **Blue** (positive technology development, negative public attitude) and **Yellow** (positive public attitude, negative technology development) are characterised by the same level of DC grid capacity increase over the years, lower with respect to the **Green** storyline. On the other hand, the most pessimistic storyline **Red** features the lowest level of DC grid capacity increase over the years, since the two drivers have a negative impact and represent a barrier towards further DC grid development.

Similarly to the DC grid and for each storyline, also for estimating the increase of transmission capacity (MW) at each interconnection border with extra-EU power systems, some assumptions on the development of the pan-European AC/DC transmission grid between 2030 and 2050 have been made (for the two decades: 2030-2040 and 2040-2050). These estimations have been based on long term projections of public information available by TSOs/ENTSO-E and of specific studies/projects. In particular, updates on the studies related to interconnections Turkey-UCTE, UCTE-IPS/UPS, MedRing/MED-EMIP, DESERTEC/Transgreen[22], and Kaliningrad projects have been taken into due account. Concerning interconnections between Southern Europe and North Africa, ad hoc assumptions have been taken into account in MTSIM by considering exchanges of electricity from/to countries like Morocco, Algeria, Tunisia and Libya to/from Southern Europe in all four storylines in the years 2030-2050 (for specific data, again see ANNEX A.6).

[22] TRANSGREEN (now known as Medgrid) project: http://www.transgreen.eu.

Also in this case the most optimistic case is given by the **Green** storyline and the most pessimistic is the **Red** one, while the intermediate case is covered by the storylines **Blue** and **Yellow**, having the same level of transmission capacity increase. However, in this case the differences between storylines are less marked than in the DC grid development.

Assessment of future AC network

In order to assess the expansions needs of AC trans-national transmission corridors, the scheme described below has been implemented (as already specified, the DC network is evaluated exogenously). Due to computational problems, the calculation of the AC corridors expansion is carried out through a sequence of simulation steps, as described below. Figure 2-10 shows the general methodology applied for the study:

1. Execution of one MTSIM simulation in "traditional mode" at the reference year 2030: the aim of this simulation is to analyze (in terms of Generation mix, Energy not provided, Prices, Congestion, etc.) the situation of the pan-European transmission network at 2030 using the assumptions on AC and DC pan-European transmission network.
2. Execution of MTSIM in "planning mode"[23] in order to assess the transmission network expansion needs in the 2030-40 decade. To this aim, in order to reduce the model complexity, otherwise too high for the present average hardware, three MTSIM simulation steps; are executed in sequence as follows:
    a. In a first step MTSIM is executed using all the 2040 storyline data (including guessed HVDC expansions) except for the AC network, that remains the same as the one considered for 2030 and the gas price values resulting from the loop between GASTALE and MTSIM run for 2030. With this simulation, the hourly values of HVDC electricity flows are determined; these values will be used as an input in the next simulations in order to Reduce the problem dimension: by eliminating HVDC interconnections and imposing these DC transits as input data (as they were system injections), in fact, it is possible to define two different independent networks: one only that includes the former UCTE network and one that only includes the former Nordel network (see Figure 2-9); this split allows to drastically reduce the running time.
    b. In the **second step** two simulations are executed, one for the UCTE network and one for the Nordel network, in "planning mode": one corresponds to the former NORDEL+BALTSO+UK+IE network and one to the former UCTE network.
    In this way we calculate an "optimal" expansion value (in MW) for each interconnection corridor for the considered decade. This value is hypothetically a number lying between zero and infinite. In some cases this theoretical "optimum" value could be also unrealistically big, i.e. not comparable with the increase of capacity that can really occur along a cross-border interconnection for a single decade. For this reason, it is necessary to impose a ceiling to the MTSIM expansion program. The maximum value imposed is a function of the storyline analyzed, because it depends on both the public attitude and the technological development.
    In particular:
        - For the **Red** and the **Blue** storylines, the maximum capacity expansion has been fixed as 3000 MW, which represent a 400 kV line with double circuit;

[23] From 2030 onwards internal congestion is considered as been resolved so that the additional capacity brought by the corridors expansion is fully exploited.

- For the **Green** and **Yellow** storylines, the maximum capacity expansion has been assumed equal to 6000 MW, which represents the installation of two 400kV lines with double circuit.

Subsequently, for each interconnection a "realistic" expansion value has been estimated. This "realistic" value has been determined by associating to the expansion value calculated by MTSIM the closest entry in Table 2-2 and Table 2-3. These tables report the typical dimensioning of real commercial transmission links. In order to evaluate how the assumption of the maximum expansion constraint limits the corridor expansions in MTSIM a sensitivity run without investment limitation has been defined and executed. Results of this scenario are reported in Section 3.1.3.

3. Execution of one MTSIM simulation in "traditional mode" at the reference year 2040: the aim of this simulation is to analyze (in terms of Generation mix, Energy not provided, Prices, Congestion, etc.) the situation of the pan-European transmission network at 2040.
4. Execution of three MTSIM simulations in order to assess the transmission network expansion needs in the 2040-50 decade as described at point 2;
5. Execution of one MTSIM simulation in "traditional mode" at the reference year 2050: the aim of this simulation is to analyze (in terms of Generation mix, Energy not provided, Prices, Congestion, etc.) the situation of the pan-European transmission network at 2050.

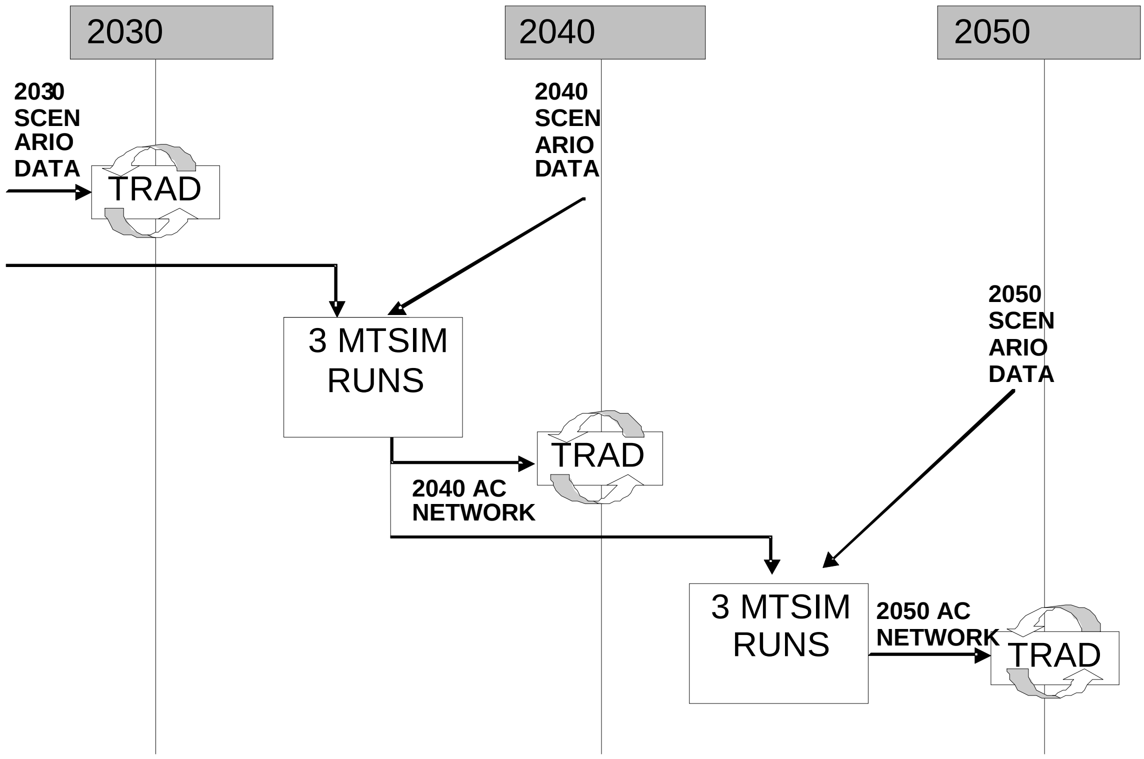


Figure 2-10 General methodology applied in SUSPLAN

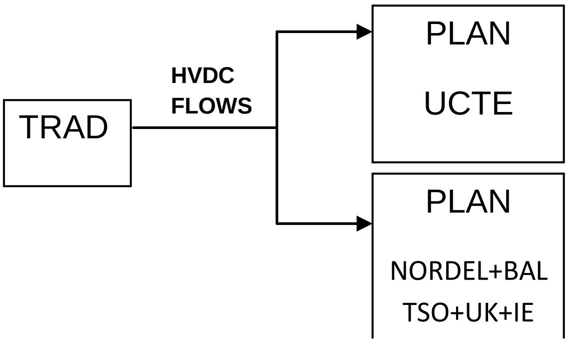


Figure 2-11 Methodology for the network expansion assessment

Capacity expansion (MW)	Type of line
300	220 kV, single circuit
600	220 kV, double circuit
1500	400 kV, single circuit
3000	400 kV, double circuit

Table 2-2 Definition of the values for capacity expansions for Red and Blue storyline

Capacity expansion (MW)	Type of line
300	220 kV, single circuit
600	220 kV, double circuit
900	1 - 220 kV, single circuit 1 - 220 kV, double circuit
1200	2 - 220 kV, double circuit
1500	400 kV, single circuit
1800	1 - 400 kV, single circuit 1- 220 kV, single circuit
2100	1 - 400 kV, single circuit 1 - 220 kV, single circuit
3000	400 kV, double circuit
3600	1 - 400 kV, double circuit 1 - 220 kV, double circuit
4500	1 - 400 kV, double circuit 1 - 400 kV, single circuit
6000	2 - 400 kV, double circuit

Table 2-3 Definition of the values for capacity expansions for Yellow and Green storyline

2.3.1.3 Data input

In the MTSIM model each country has been grouped into a node of the equivalent AC European network, therefore, for each country, an "equivalent" power plant for each main generation technology has been defined, as detailed in the following. In general, the net generation capacity and energy values have been estimated on the basis of [Lise *et al.*, 2006]. Additional information necessary for a more detailed subdivision of the UCTE data has been gathered from the results of the FP6 project ENCOURAGED[24] and of the FP7 project REALISEGRID [REALISEGRID,

[24] FP6 project ENCOURAGED: "Energy corridor optimisation, for European markets of gas, electricity and hydrogen", http://www.ecn.nl/nl/units/ps/themas/energie-infrastructuur/projects/encouraged.

2010c] [REALISEGRID, 2010d]. Additional estimates, where necessary, were done by RSE. Below we report on the main assumptions. Additional information on assumptions and input data can be founded in Appendix A.

2.3.1.4 Fuel costs

From 2030 to 2050, fuel prices from WEO 2009 have been taken into account. For green and yellow storylines we used prices referred to the"450 ppm scenario", while for red and blue ones we used prices of the "Reference scenario". As for gas prices, for each scenario, we used the WEO values only in the first iteration of the loop MTSIM-GASTALE.[25]

Fuel cost (€/GJ) Green and Yellow	2030	2040	2050
Coal	1.96	1.51	1.04
Gas	9.31	9.31	9.31
Lignite	0.88	0.68	0.47
Oil	9.54	9.54	9.54
Uranium	0.80	0.80	0.80

Table 2-4 Fuel cost assumptions for Green and Yellow storyline

Fuel cost (€/GJ) Red and Blue	2030	2040	2050
Coal	3.31	3.47	3.62
Gas	11.82	13.43	15.03
Lignite	1.49	1.56	1.63
Oil	12.19	13.77	15.36
Uranium	0.80	0.80	0.80

Table 2-5 Fuel costs for Red and Blue storyline

2.3.1.5 Network expansion costs

As described in 2.3.1.2, HVAC expansion costs are used by the model in order to evaluate the optimal corridor expansion. On the other hand, HVDC expansion is not evaluated internally by the model because HVDC expansions are assumed beforehand. As far as network expansion is concerned, average cost data (the same for all scenarios) considered within the context of the EC FP7 project REALISEGRID, based on publicly available sources and feedbacks from TSOs and from manufacturers, have been used. Average cost data reported in the Table 2-6 refer to year 2005 (starting point of the REALISEGRID analysis), assuming an operating infrastructure life of 40 years and an interest rate of 8%.

It must be taken into account that these cost values may vary depending on different parameters, such as line length, power rating and voltage level as well as on several local factors, like manpower costs, environmental constraints, geographical conditions, etc. Typical infrastructure distance has been assumed for AC overhead lines and HVDC cables.

[25] WEO energy prices assumptions were presented in Figure 2-5. The prices in Table 2-4 and Table 2-5 correspond with original WEO energy prices and are converted to € per GJ for model input purposes

	HVAC overhead lines	HVDC cables
Average line length	80 km	130 km
Investment cost (CAPEX)	50 k€/MW	cables:220 k€/MW converters:140 k€/MW
Compensation costs	15% CAPEX una tantum	-
O&M costs	5% CAPEX yearly	5% CAPEX yearly
Annualized cost	**7322 €/MW**	**48190 €/MW**

Table 2-6 Annualized AC expansion assumptions

Basing on the estimation trend described in ANNEX A-7, annualized AC and HVDC expansion costs (see Table 2-7) have been derived accordingly.
With regards to AC and HVDC expansion costs, the values used are reported in Table 2-7. The methodology applied is described in section 2.3.1.

	AC [€/MW]		**HVDC [€/MW]**	
	30-40	**40-50**	**30-40**	**40-50**
RED	6158	6158	26986	26986
YELLOW	5969	5843	26081	25175
BLUE	5948	5738	25175	23665
GREEN	5759	5424	23665	22156

Table 2-7 Annualized AC and HVDC expansion costs

2.3.1.6 Wind power plants

As for wind power plants, it was chosen to adopt a real wind profile taken from a historical wind series. Hourly wind production data [Lise et al., 2006] of the last 60 years (1948-2008), related to at least one point per country, have been used. For countries bordering the sea two separate points have been identified: one for onshore and one for offshore wind. On the basis of previous analyses[26], it has been decided to adopt, for each nation, the 2004 historic production profile. Figure 2-12 presents an exemplary wind production profile for that year. This year has been chosen because it was characterized by strong winds and a high production level, in particular in the North Sea area. For each country in which wind installations are foreseen, an hourly generation profile has been constructed. In particular, for the 2030 **Red** storyline, the hourly profiles of each country at 2030 have been calculated by multiplying hourly production profile by the forecasted installed capacity. In this way the profiles for the 2030 **Red** Storyline have been calculated. In order to obtain all other profiles, it has been chosen to add a constant value to the 2030 **Red** profiles. Adding this value allows not increasing the profile variability, because it is assumed that the variability of wind production decreases when installed wind capacity increases.

[26] As for example in the TradeWind project: TradeWind, Further Developing Europe's Power Market for Large scale Integration of Wind Power, www.tradewind.eu.

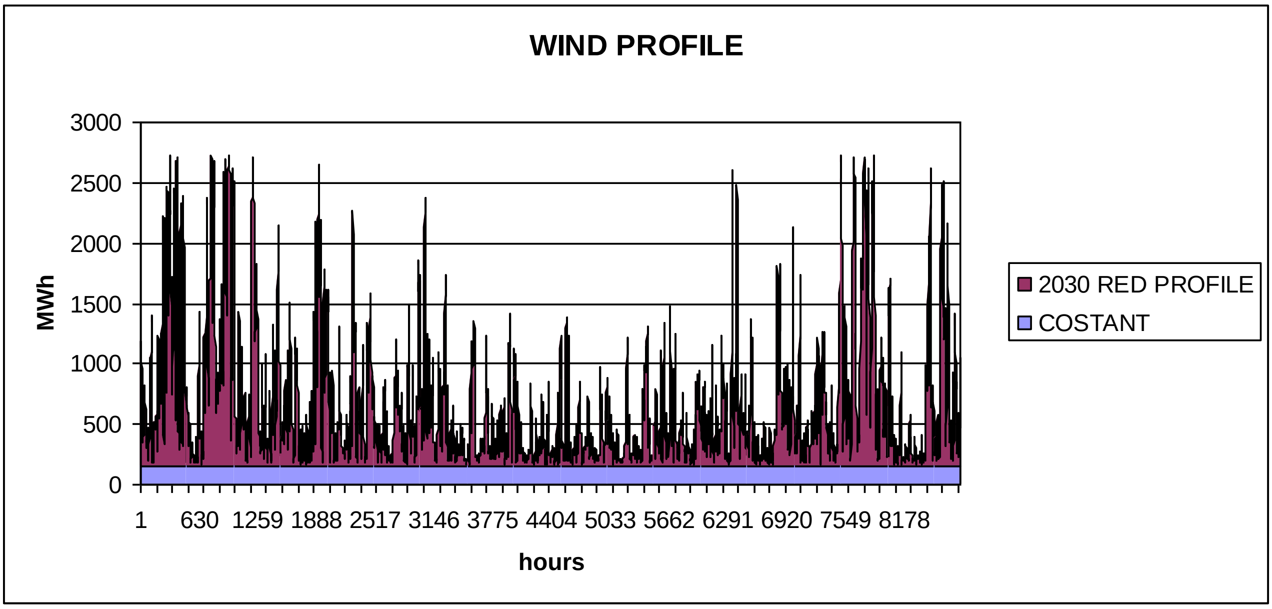


Figure 2-12 Exemplary production profile of wind

2.3.2 Gas market model GASTALE

2.3.2.1 Introduction and representation of transmission network

GASTALE is a game-theoretic equilibrium model of the European natural gas market which includes all gas producers supplying to Europe and European gas consumers while taking into account the existing gas infrastructure such as transport pipelines, LNG shipping network, and storage. In addition it is capable of simulating investment decision-making for additional gas infrastructure (i.e. expansion of pipeline capacity, expansion of storage capacity, expansion of LNG liquefaction and re-gasification capacity). The geographical coverage and the network structure of the model are given in Figure 2-13.

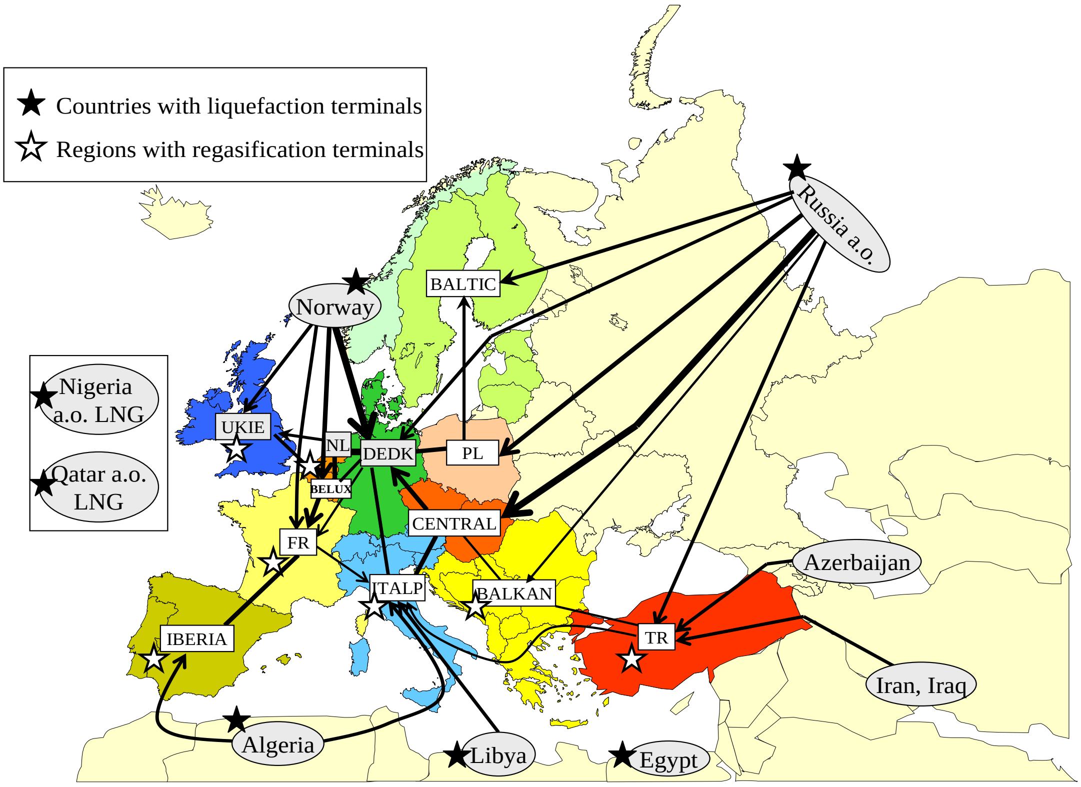


Figure 2-13 Illustration of gas infrastructure in GASTALE

GASTALE is an equilibrium model containing different gas market actors striving for different optimization goals. Below we briefly characterize the actors and their optimization problems:

- Producers decide on production and transport to the region of consumption, earning a wholesale price;
- Consumers consist of three different market sectors, namely the power generation sector, the industrial sector, and the residential sector. In addition, consumption is divided over three seasons within a year: low, shoulder, and high demand periods representing (i) April-September; (ii) February, March, October, November; and (iii) December-January of each calendar year respectively;
- TSOs provide transport through on- and offshore pipelines and LNG shipping;
- SSOs regulate injection into storage during the low-demand warm season and withdrawals for consumption during the medium- and high-demand cold season.

Producers are the only strategic players and pay TSOs and LNG shippers to transport gas to the market. Storage owners buy gas in the low demand period for sale in the other periods. As in [Gabriel *et.al*, 2005], a type of congestion pricing is assumed in transport and storage. In particular, transporters and storage operators are assumed to charge long-run variable cost (including capital costs) unless capacity constraints bind; if the latter occurs, then the price charged for transport increases until the demand for transport services equals the supply. The detailed description of the model with model input assumptions for generation and consumption can be found in Appendix A.

2.3.2.2 Modeling of gas infrastructure investment

An important feature of the GASTALE model is endogenous investment decision-making with respect to expansion of gas infrastructure. This includes gas pipelines, LNG facilities, and gas storage facilities. Investment decision-making is represented by a heuristic investment process within a recursive structure of ten-year periods rather than a perfect foresight approach for all the periods considered simultaneously. That is, it is assumed that infrastructure investors look ahead for ten years only and economically optimal expansion of gas infrastructure is determined for every decade (e.g., 2030-2040) from a short-sighted point of view. An investment decision is taken in every ten year period based on most recent information, which is assumed to be perfect indicators for equilibrium prices and volumes in the next ten-year period.

Decision for the economically optimal expansion is mainly based on the following rule: if the average yearly congestion price of an infrastructure asset (pipeline, LNG, or storage) over the next ten-year period equals or exceeds X% more of its annualized marginal cost of investment-so called "hurdle rate"- accounting for depreciation, then additional capacity will be realized. The investment rule is part of the optimality conditions of infrastructure operators and the all infrastructure capacity expansion plans based on next period's prices are determined simultaneously with gas prices and congestion fees which also include unit cost of investment (accounting for depreciation and hurdle rate). Input parameter assumptions for investment decision-making differ across different gas infrastructure assets and are given in Table 2-8.

Type of asset	**Economic lifetime [years]**	**Hurdle rate [%]**	**Interest rate [%]**
Gas pipelines	20	20	8
LNG terminals	30	20	10
Gas storage facilities	30	10	10

Table 2-8 Parameter values for investment decision-making in gas infrastructure assets

The analysis within this study does not include decision-making on the possible need for replacement investments.[27] Once an asset is at the end of its economic lifetime it is assumed that gas infrastructure services can still be delivered against marginal infrastructure costs. The reason for this approach is that data on the aging of gas infrastructure assets across the EU and reliable cost data related to replacement investments is lacking.

2.3.3 Interactions between MTSIM and GASTALE

There is a strong interaction between the electricity and gas markets. Gas prices and, in general, fossil fuels prices affect the electricity market clearing, being the dispatching solution function of a cost-driven merit order. This dependence has become stronger since the penetration of gas in electricity generation has largely increased in the last decade throughout the EU, mainly due to its environmental advantages over other fossil fuels. Consequently, the integration of large-scale RES in long term electricity network development plans will have a direct impact on the gas market. Examples of such direct impacts are the possible decrease in gas consumption in the power generation sector due to an increasing penetration of RES in the one region, and a possible increase in gas consumption due to its increasingly important role as back-up for non-available wind-based electricity in the other region. The change in gas consumption levels in the power sector will influence gas prices and gas flows to and within Europe, and consequently affect the need for expansion of the gas infrastructure. Likewise, the investments in gas infrastructure influence the

[27] Technically the model could take into account replacement investment decision-making.

availability of gas and gas prices which consequently together with CO_2 prices affect the gas powered generation in electricity markets, the level of electricity prices, and electricity exchange.

The interaction between the gas and electricity market models implies that different storyline developments with respect to the electricity generation mix (for example the penetration of RES) (as was described in Section 2.1.1) will have impact on both future electricity and gas infrastructure use and investment. Cross-border infrastructure requirements for electricity and gas are modelled using the MTSIM and GASTALE models respectively. In our approach, we simulate the interactions between electricity and gas markets for three separate key years (2030, 2040 and 2050). Investment levels determined for the year *i* are used as an initial point for the year *i* +10. For each storyline, our methodology can be summarized as follows:

1. For a given RES development and expected WEO gas price, run MTSIM in "planning" modality and determine the corresponding economically optimal electricity transmission corridors expansion.
2. By imposing the optimal grid expansion defined in Step 1, run MTSIM in "traditional modality" (no grid expansions allowed) to obtain the corresponding gas consumption level in each EU country in the year *i*.
3. Run GASTALE with the gas consumption data of power sector provided by MTSIM at Step 2 and find the economically optimal gas infrastructure in the year i with the corresponding gas prices for each region as shown in Figure 2-14.
4. The new gas prices are fed into MTSIM and Steps 2 and 3 are repeated until gas prices and consumption levels converge. If convergence is achieved, move to the next period. With the term "convergence" we intend that, in two subsequent iterations, all gas prices and consumption data exchanged between MTSIM and GASTALE differ of a negligible quantity

The current approach in terms of input/output interactions between MTSIM and GASTALE models can be summarized as illustrated in Figure 2-14. Convergence of input and output for both models was generally reached in three iterative steps.

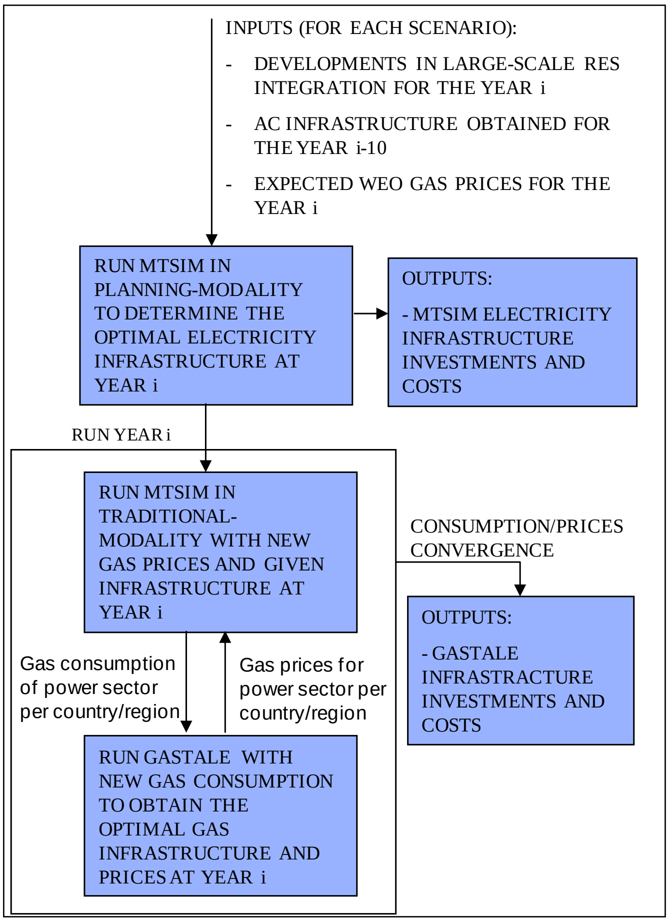


Figure 2-14 Illustrative interactions between electricity and gas market modelling tools

Convergence of gas prices

In Section 2.1.2.1 we explained that two particular price scenarios were taken from the World Energy Outlook to be used as background for the identified SUSPLAN storylines. Whereas these scenarios basically set the relevant price trajectories within the identified storylines in an exogenous manner, the price of gas is determined endogenously within the interactions between MTSIM and GASTALE, with the gas prices from the World Energy Outlook only being used as starting point for the iterative computations. This implies that the resulting gas price trajectory per storyline differs from the starting price trajectory taken from the World Energy Outlook. The difference between the ex ante price assumption and ex post result for each storyline is shown in Table 2-9.

As is apparent from the figures depicted in the table there are large differences observed in ex ante and ex post gas price levels. The MTSIM model in first instance uses the ex ante gas price from the World Energy Outlook to determine the deployment of electricity generation capacity throughout Europe. This results in an associated amount of gas consumption in the electricity sector. The calculated amount of gas consumption in the electricity sector (on a country-by-country basis) is then fed into the GASTALE model and provides a new equilibrium of gas prices and gas consumption in the electricity sector. The new gas price is then used in MTSIM to determine the associated amount of gas consumption in the electricity sector. This process continues until there is a converged gas price that gives rise to the same level of gas consumption in the electricity sector in both the MTSIM and GASTALE model.

Storyline			2030	2040	2050
Red	Gas	Ex ante (WEO)	11.82	13.43	15.03
	Gas	Ex post	5.44	5.77	6.08
	Coal	Exogenous (WEO)	3.31	3.47	3.62
Yellow	Gas	Ex ante (WEO)	9.31	9.31	9.31
	Gas	Ex post	4.72	4.68	4.72
	Coal	Exogenous (WEO)	1.96	1.51	1.04
Blue	Gas	Ex ante (WEO)	11.82	13.43	15.03
	Gas	Ex post	5.13	5.39	5.74
	Coal	Exogenous (WEO)	3.31	3.47	3.62
Green	Gas	Ex ante (WEO)	9.31	9.31	9.31
	Gas	Ex post	4.75	4.62	4.48
	Coal	Exogenous (WEO)	1.96	1.51	1.04

Table 2-9 Overview of gas and coal prices in SUSPLAN storylines (ex ante and ex post gas prices, and exogenous coal price, all in € per GJ)

The methodological set-up of the model analyses was such that although the gas price was found endogenously via several iterations between the two models deployed, other prices, notably the price of coal continued to be imposed exogenously (taken from the World Energy Outlook). The difference between fuel costs of generating electricity via coal or gas-based generation units is quite important when analyzing the deployment of installed capacity throughout Europe since it directly influences the deployment of generation units. This fact, in combination with the acquired fuel input prices for coal and gas, is to be kept in mind when analyzing the electricity sector developments in Chapter 3.

3 RESULTS ELECTRICITY MARKET ANALYSIS[28]

3.1 Results per storyline

3.1.1 Red storyline

Summary of storyline results:

- High installation costs do not allow to expand significantly the network: only 29000 MW in the 2030->40 decade, and 16000 MW in the 2040->50 decade;
- Electricity balance: from 2030 till 2050 the United Kingdom and East Europe importing into an exporting region due to the increasing amount of available RES sources;
- Germany remains an importing country with the import level constantly increasing from 2030 till 2050;
- Cross-border lines that connect Germany with the European system are most frequently congested. The same happens for the United Kingdom and in the interconnection between Italy and the Balkan Region. This is true for all three grid years, accentuated by the fact that the European AC transmission network capacity does not increase significantly (29000 MW in the 2030-40 decade, 16000 MW in the 2040-50 decade). This low network increase is due to very high expansion costs and low RES energy availability;
- The low amount of available RES energy and the low transmission network upgrade brings to a prices increase (107 €/MWh in 2030, 115 €/MWh in 2040, 124 €/MWh in 2050). Prices stay similar Europe-wide, but increase mainly in central Europe;
- High total European operative costs (i.e. CO_2 and fuel cost) in 2030 increasing of 22% in 2050;
- Main expanded interconnections: ES->FR (6000 MW), FR->DE (6000 MW) , DE->PL (6000 MW) , BL->NL (4500 MW);
- Due to under dimensioned network and high demand, there are cases of load shedding in Germany in 2030, then overcome in the next two decades thanks to the grid expansions that facilitate import from other countries.

Figure 3-1 shows the electricity generation mix for the **Red** Storyline: it can be seen that the RES/THERMAL generation ratio is constant in all the three SUSPLAN milestone years; the RES generation is characterized by a high amount of energy from wind power plants that provide 37-39% of energy. Concerning the thermal power plants, gas power plants generate the highest amount of energy (56-63 % of the total) while nuclear production is about 33%.

[28] Data acquired in the electricity market analysis is also available via the web-based user-interface developed in the SUSPLAN project. This tool may be accessed via http://www.susplan.eu.

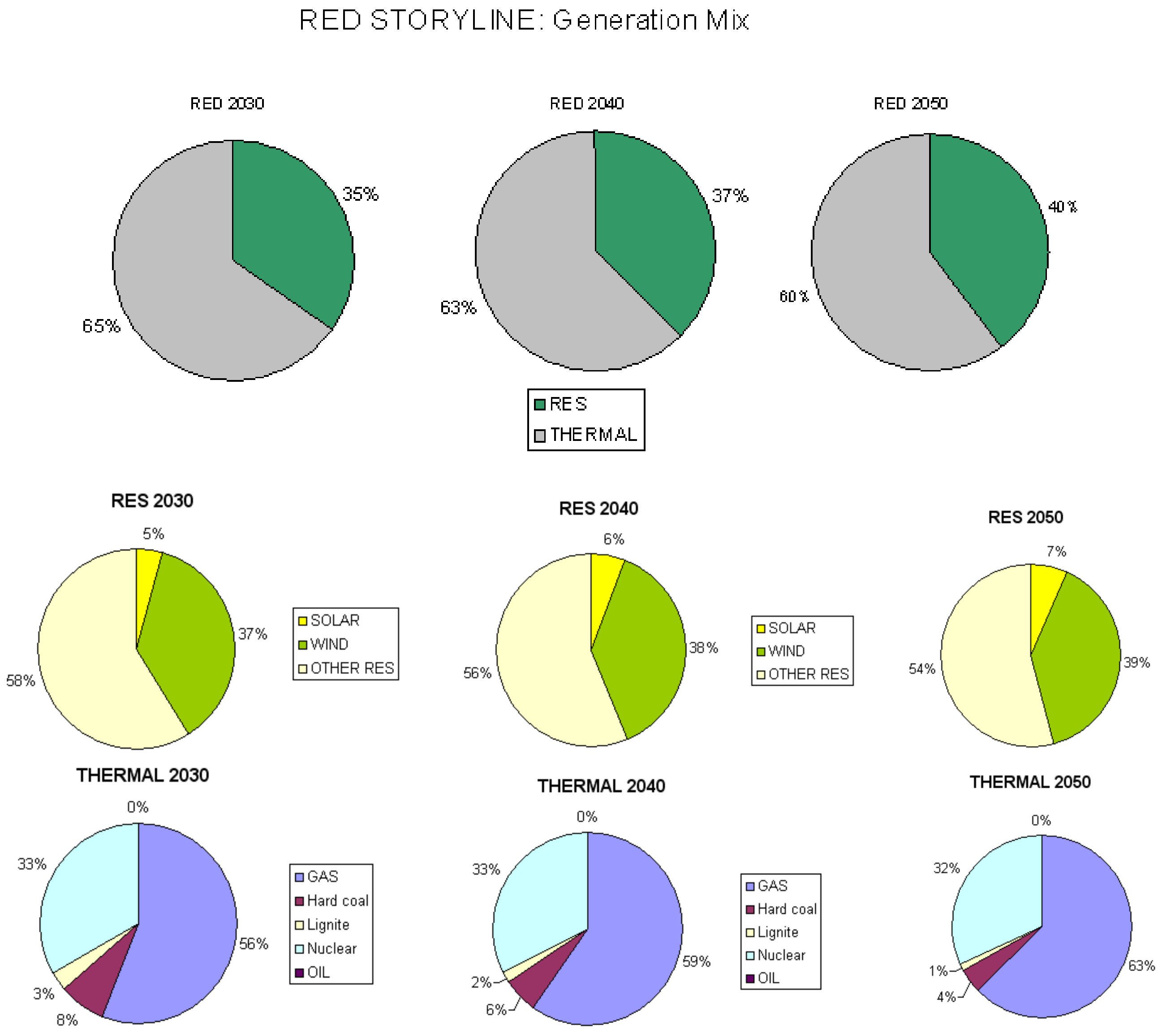


Figure 3-1 European electricity generation mix in the Red storyline

Regarding the electricity balance of countries (Figure 3-3) it can be seen that Germany is more and more an importing country; this behavior is caused by the very high forecasted demand level (640 TWh in 2030) with respect to the installed thermal capacity: the load is higher than the thermal capacity in 90% of the hours. On the other side, Spain Italy and Belgium become more and more exporter counties, due to the amount of energy available from RES power plants. This situation creates energy flows from the West Europe (mainly Spain, France, United Kingdom, Ireland, Italy and Belgium) to central Europe, mainly Germany, causing congestion on the lines that connects these two regions.

As it can be shown in Figure 3-5, the most frequently congested lines are FR->DE, BL->DE, NO->DE,DK->DE, SE->DE, SE->PL, LT->PL. These congestions create two price zones (see Figure 3-2): the south-east Europe with mean prices around 70-80 €/MWh, and the central Europe with prices around 140 € MWh.

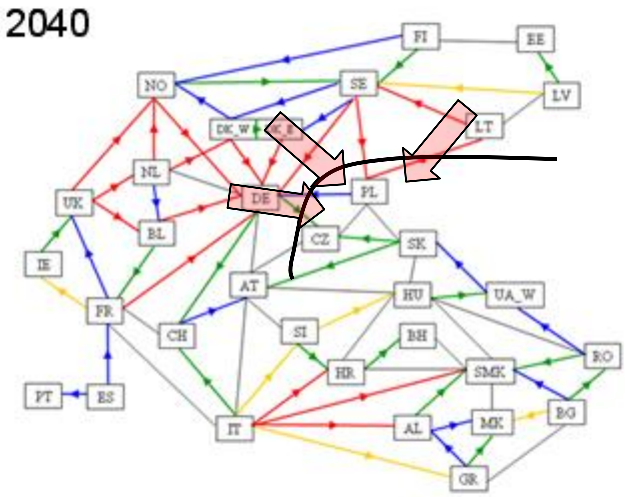


Figure 3-2 Two price zones in 2040 in the Red storyline

Notwithstanding the high expansion costs, the program decides to expand the corridors that contribute to sink the price difference between the two aforementioned price zones, since this produces a significant reduction of the dispatching costs. The ES-FR corridor is increased by 75% in the decade 2030-40, and by 43% in the decade 2040-50; FR-DE is increased by 100% in the first decade and by 50% in the second one; BL-NL is increased by 125% in the first decade and by 28% in the second one; the DE-PL corridor is increased by 97% in the first decade and by 49% in the second one. It can also be observed that also the interconnection with Ukraine is expanded: RO->UA_W is expanded by 150% in the decade 2030-40 and by 30% in the decade 2040-50, and SK-UA_W is increased by 375% in the first decade and by 80% in the second one.

Figure 3-4 presents an overview of the different electricity price levels across the EU in this storyline. When interpreting this figure one needs to keep in mind that electricity prices concern wholesale electricity prices that are based on an optimal dispatch of available electricity generation units, with the criteria for dispatch being the bids put forward by operators of electricity generation units. These bids typically reflect marginal costs of electricity generation only. Obviously operators also need to take into account the fact that investment cost need to be recovered with short-term profits. The wholesale electricity price levels depicted here may not be sufficient to recover the capital costs of investment for all generation technologies. This raises the question whether some additional mechanism needs to be put in place that assures that investment in these generation assets can be reasonably be recovered. A typical mechanism capable of doing so is the implementation of a capacity market.[29] In any case, the prices depicted in Figure 3-4 (and later figures in sections discussing the results of other storylines) only depict short-term wholesale market electricity prices and do not reflect end-user prices. The difference between the two would consist of taxes, distribution network costs, retail costs of supply and perhaps some type of fixed capacity payment.

[29] In fact, a number of EU countries already have adopted some type of capacity mechanism to deal with this issue.

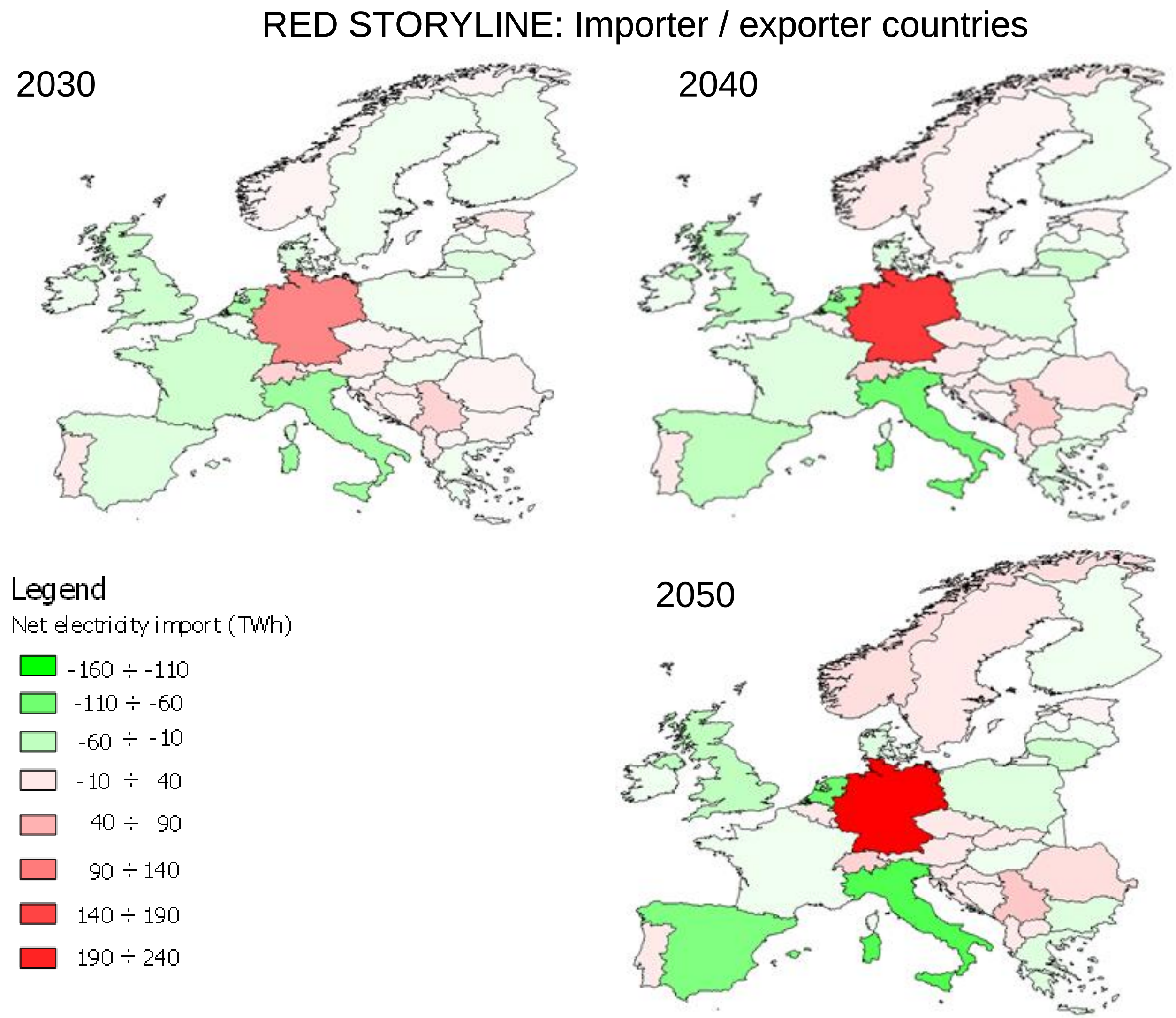


Figure 3-3 Electricity importing and exporting countries in the Red storyline

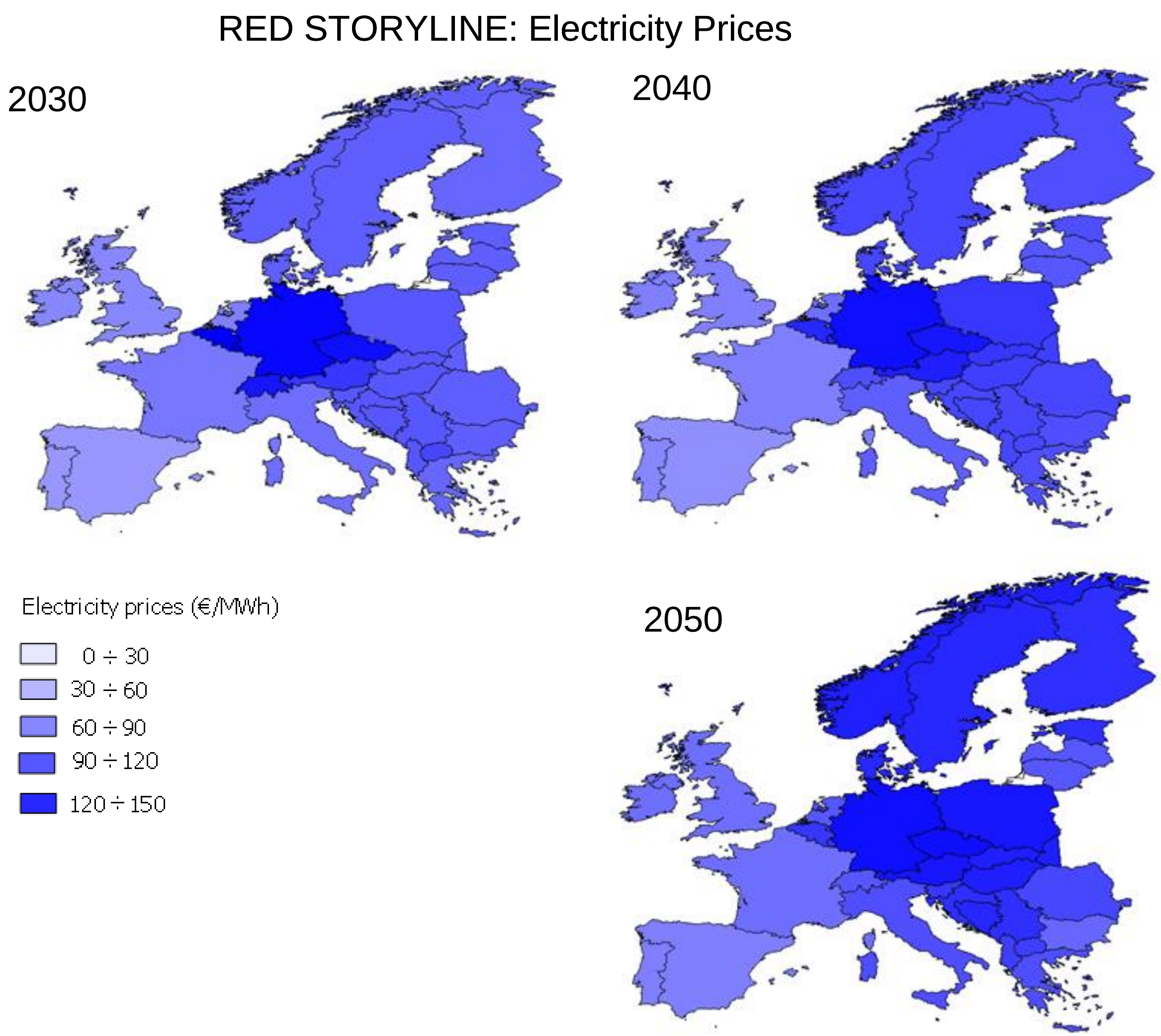


Figure 3-4 Electricity prices across Europe in the Red storyline

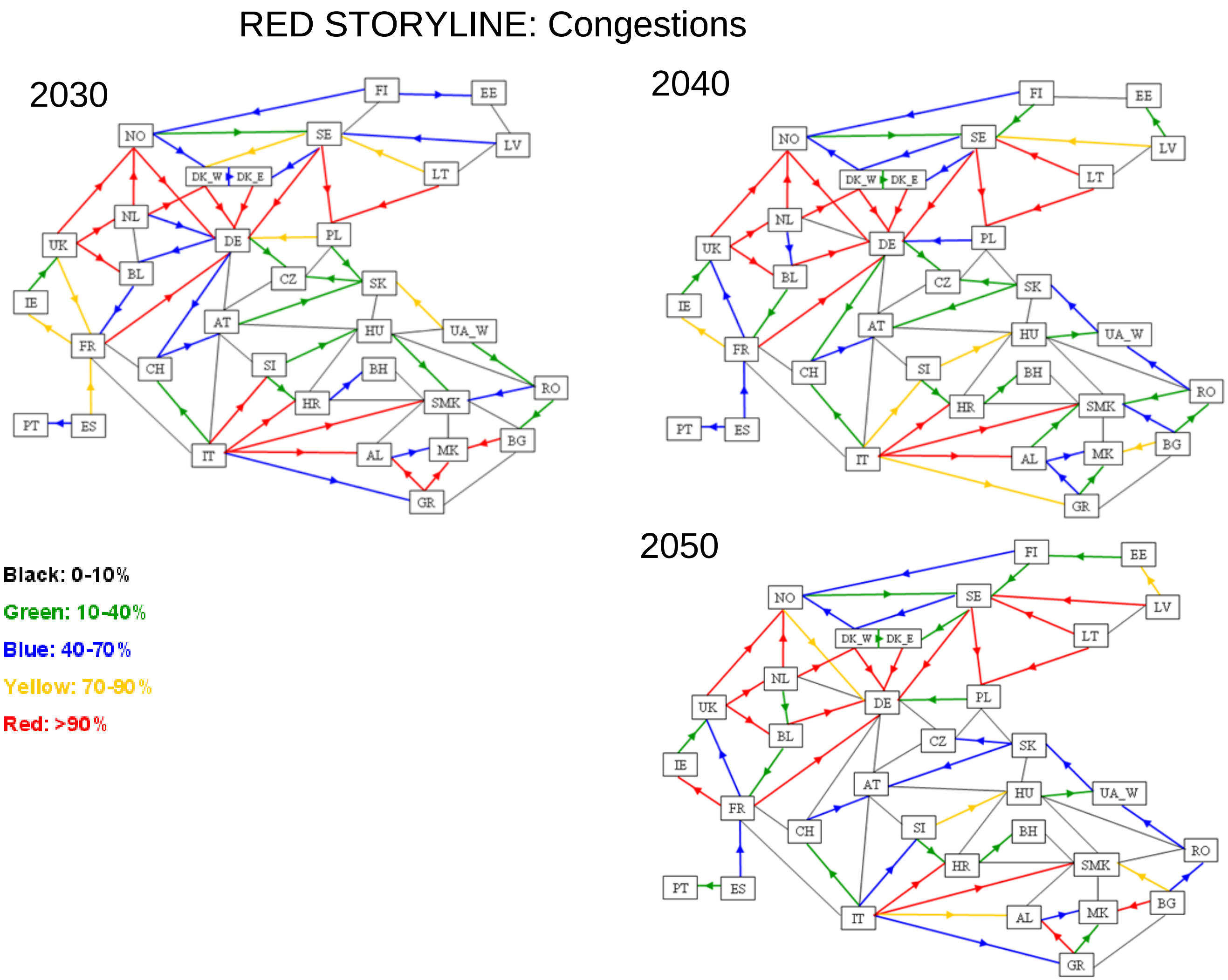


Figure 3-5 Level of congestion on electricity interconnections across Europe in the Red storyline

	Load shedding	Energy In Excess
2030	BL: 209 GWh CH: 497 GWh DE: 180 GWh	ES: 3 GWh PT: 1 GWh
2040	CH: 0,4 GWh CZ_W: 0,9 GWh DE: 210 GWh	ES: 3120 GWh PT: 1774 GWh
2050	CZ_E: 0,12 GWh CZ_W: 0,4 GWh DE: 0,9 GWh	ES: 8788 GWh PT: 13254 GWh

Table 3-1 Energy In Excess and Energy Not Produced in the Red storyline

	2030(A->B)	2030(B->A)	2030-2040	2040-2050
PT->ES	-3000	3000	0 (0%)	0 (0%)
ES->FR	-4000	4000	3000 (75%)	3000 (43%)
FR->IT	-2595	4200	300 (7%)	0 (0%)
IT->CH	-6540	3710	3000 (81%)	0 (0%)
FR->CH	-2300	3200	0 (0%)	0 (0%)
FR->DE	-3150	3000	3000 (100%)	3000 (50%)
FR->BL	-3100	4000	3000 (75%)	0 (0%)
CH->DE	-1500	3200	0 (0%)	300 (9%)
DE->BL	0	980	0 (0%)	0 (0%)
BL->NL	-2400	2400	3000 (125%)	1500 (28%)
NL->DE	-5350	4500	0 (0%)	0 (0%)
DE->DK_W	-2000	1500	0 (0%)	0 (0%)
DE->PL	-3000	3100	3000 (97%)	3000 (49%)
DE->CZ_W	-3800	2300	0 (0%)	0 (0%)
DE->AT	-6880	6880	0 (0%)	0 (0%)
CH->AT	-1400	1400	0 (0%)	0 (0%)
IT->AT	-2200	2200	600 (27%)	300 (11%)
IT->SI	-2150	2150	1500 (70%)	600 (16%)
CZ_E->PL	-2000	800	0 (0%)	600 (75%)
PL->SK	-1400	1500	0 (0%)	300 (20%)
CZ_E->SK	-1000	2000	600 (30%)	300 (12%)
AT->CZ_W	-2000	1100	0 (0%)	0 (0%)
SK->HU	-2100	3000	0 (0%)	0 (0%)
AT->HU	-1200	1500	0 (0%)	0 (0%)
AT->SI	-1200	1200	0 (0%)	0 (0%)
HU->SMK	-600	600	300 (50%)	0 (0%)
HU->RO	-1400	600	0 (0%)	0 (0%)
SMK->BG	-650	500	600 (120%)	300 (27%)
SMK->RO	-850	500	300 (60%)	0 (0%)
RO->BG	-950	950	0 (0%)	300 (32%)
BG->GR	-1400	1500	600 (40%)	0 (0%)
AL->GR	-300	150	1500 (1000%)	300 (18%)
AL->SMK	-1200	1250	1500 (120%)	0 (0%)
BH->SMK	-1900	2000	0 (0%)	0 (0%)
MK->GR	-300	350	600 (171%)	0 (0%)
MK->SMK	-600	1100	0 (0%)	0 (0%)

HR->BH	-1600	1530	0 (0%)	0 (0%)
HR->SMK	-600	680	0 (0%)	0 (0%)
HR->SI	-1900	1900	0 (0%)	0 (0%)
HR->HU	-2500	3000	0 (0%)	0 (0%)
RO->UA_W	-400	400	600 (150%)	300 (30%)
HU->UA_W	-1150	650	0 (0%)	0 (0%)
SK->UA_W	-400	400	1500 (375%)	1500 (79%)
DK_E->SE	-1300	1700	300 (18%)	0 (0%)
NO->SE	-5250	5450	0 (0%)	0 (0%)
SE->FI	-2700	2800	0 (0%)	0 (0%)
FI->NO	-1000	1000	0 (0%)	0 (0%)
LT->LV	-1900	2100	0 (0%)	0 (0%)
LV->EE	-1300	1400	0 (0%)	0 (0%)
Total [MW]			28800	15600
Annualized AC cost [€/MW]			6158	6158
Total AC costs per decade [M€]			2110,5	1144,7

Table 3-2 AC network expansions across Europe in the Red storyline

	A->B	**B->A**	**2030-2040**	**2040-2050**
GR_IT	-1000	1000	0 (0%)	0 (0%)
AL_IT	-2000	2000	0 (0%)	0 (0%)
SMK_IT	-1000	1000	0 (0%)	0 (0%)
HR_IT	-1000	1000	0 (0%)	0 (0%)
FR_IE	-1000	1000	0 (0%)	0 (0%)
FR_UK	-3000	3000	1000 (33%)	1000 (25%)
UK_BL	-1000	1000	0 (0%)	1000 (100%)
UK_NL	-1320	1320	1000 (76%)	0 (0%)
NL_NO	-1700	1700	1000 (59%)	1000 (37%)
NO_DE	-2400	2400	1000 (42%)	1000 (29%)
SE_DE	-600	600	600 (100%)	0 (0%)
SE_PL	-600	600	600 (100%)	0 (0%)
LT_PL	-1000	1000	0 (0%)	0 (0%)
LV_SE	-700	700	0 (0%)	0 (0%)
EE_FI	-1000	1000	0 (0%)	0 (0%)
SK_AT	-1500	1500	0 (0%)	0 (0%)
HU_SI	-900	900	0 (0%)	0 (0%)
BL_DE	-1000	1000	0 (0%)	0 (0%)
DE_DK_E	-1150	1150	550 (48%)	0 (0%)
NL_DK_W	-600	600	0 (0%)	0 (0%)
NO_DK_W	-1600	1600	0 (0%)	0 (0%)
DK_W_SE	-680	740	360 (49%)	0 (0%)
MK_BG	-450	250	200 (80%)	250 (56%)
AL_MK	-500	500	200 (40%)	250 (36%)
DK_W_DK_E	-600	600	600 (100%)	0 (0%)
Total [MW]	-28300	28160	7110	4500
Annualized DC cost [€/MW]			26986	26986
Total DC costs per decade [M€]			1920	1210

Table 3-3 DC network expansions across Europe in the Red storyline

3.1.2 Yellow storyline

Summary of storyline results:

- Supply and demand balance of countries: from 2030 till 2050 East Europe goes from being an importing region to an exporting region due to the increasing amount of available RES sources; this behaviour is similar to the **Green** storyline;
- Similarly to the **Green** storyline, Germany remains an importing country, the import level being constantly increasing from 2030 till 2050; in 2040 also Italy and Belgium turn into electricity importing countries;
- CO_2 emissions in this storyline are somewhat lower than in the **Green** storyline in 2030 but due to technological advancement of generation technologies CO_2 emissions in the period until 2050 will strongly decrease in the **Green** storyline, giving rise to a better emission performance compared to the **Yellow** storyline;
- Cross-border lines that connect Germany with the European system are the most frequently congested. This is true for all three grid years;
- Overall network reinforcements are low (28000 MW in the 2030->40 decade, 16000 MW in the 2040->50 decade). In 2030-40 decade are, respectively, 50% less and in 2040-50 decade are 72% less than **Green** storyline expansions. This is due to high fixed prices for installing new lines and to the significant presence of RES locally providing cheap energy;
- Due to the limited network reinforcements, the high amount of energy available from RES source is not always exploited and in some (rare) cases, there is an exceeding amount of RES that cannot be delivered to the loads:
    - In 2030 and in 2040 in ES , IE, PT, UK;
    - In 2040 in ES and PT;
- Due to low demand increase, low network development and high increase of available RES, prices remain more or less constant for all the three grid years;
- Main expanded interconnections: ES->FR (12000 MW), DE-> FR (12000 MW). Germany shows again the most appealing load concentration.

Figure 3-6 shows the generation mix for the **Yellow** Storyline: the generation ratio (RES/THERMAL) shows a small increasing from 49% in 2030 to 53% in 2050. Concerning RES generation, it can be seen that wind generation has a considerable increase, from 38% in 2030 to 49% in 2050. Also, the solar shows a considerable increase, (from 6% in 2030 to 12% in 2050). Concerning the thermal power plants, gas and nuclear power plants generate the highest amount of energy (47-54 % and 45-52% respectively) while hard coal shows a strong decrease in the 2030-40 decade, from 7% to 1% in 2040 and 2050.

Regarding the electricity balance of countries (Figure 3-7) Germany becomes more and more an importing country. This behavior is caused, like for the other Storylines, by the very high forecasted demand level (640 TWh in 2030) with respect to the installed thermal capacity: the load is higher than the thermal capacity in 90% of the hours. On the other side, Spain Italy and Belgium become more and more exporter countries, due to the amount of energy available from RES power plants, while the Scandinavian region transfers from a more or less self-reliant country into an electricity importing country, although the import dependency level remains relatively small.

Observing Figure 3-8, it can be seen that the prices are very similar all over Europe, with values around 50€/MWh.

As it can be shown in Figure 3-9, the most frequently congested lines are FR->DE, BL->DE, NO->DE,DK->DE, SE->DE, SE->PL, LT->PL. Notwithstanding the highly congested lines, prices are similar in all Europe. The ES-FR corridor is increased by 150% in the decade 2030-40, and by 60% in the decade 2040-50; FR-DE is increased by 200% in the first decade and by 67% in the second one; BL-NL is increased by 125% in the first decade and keeps constant in the second one; It can be noted that AL-GR increases by 800% in the decade 2040-50.

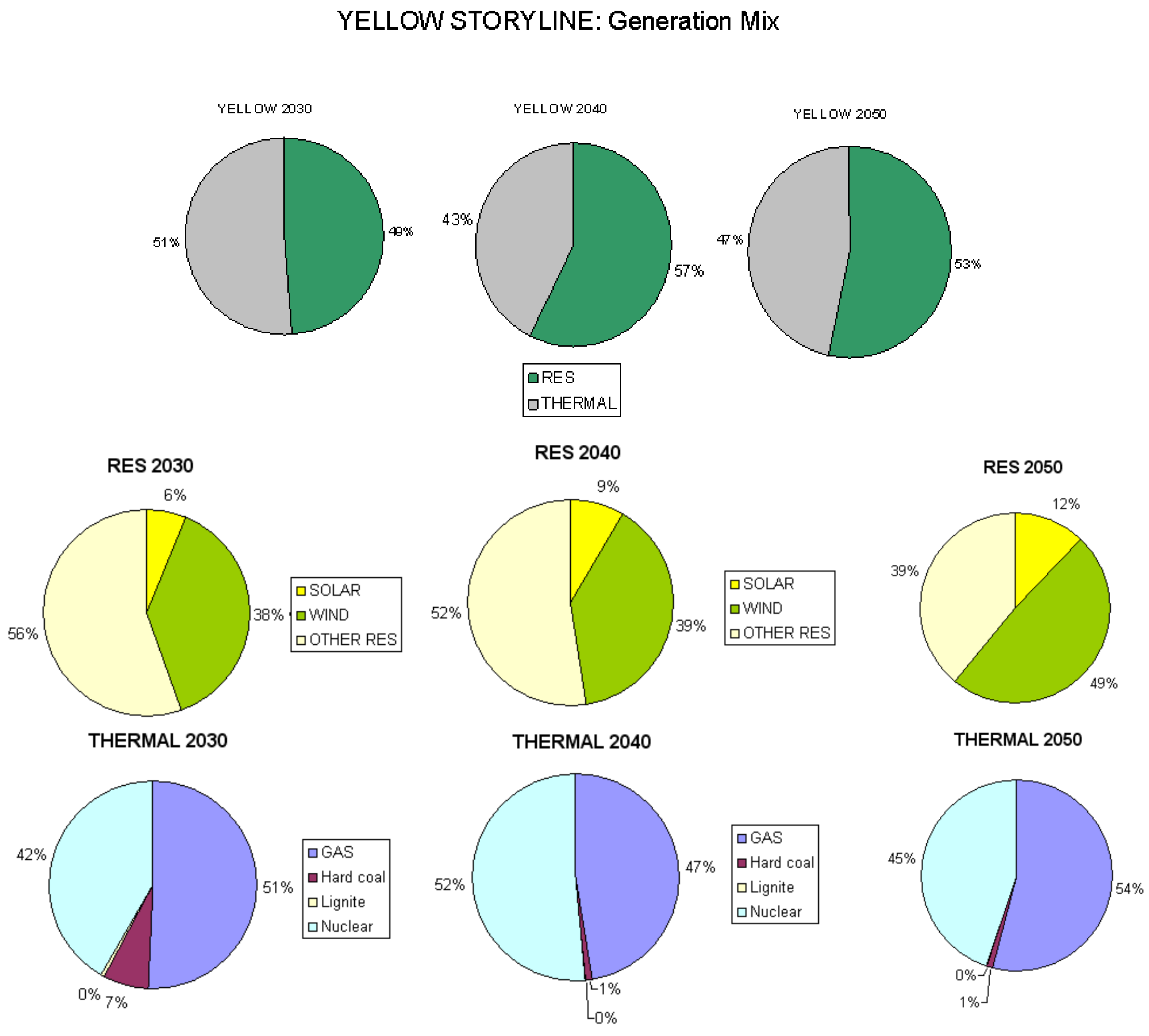


Figure 3-6 European electricity generation mix in the Yellow storyline

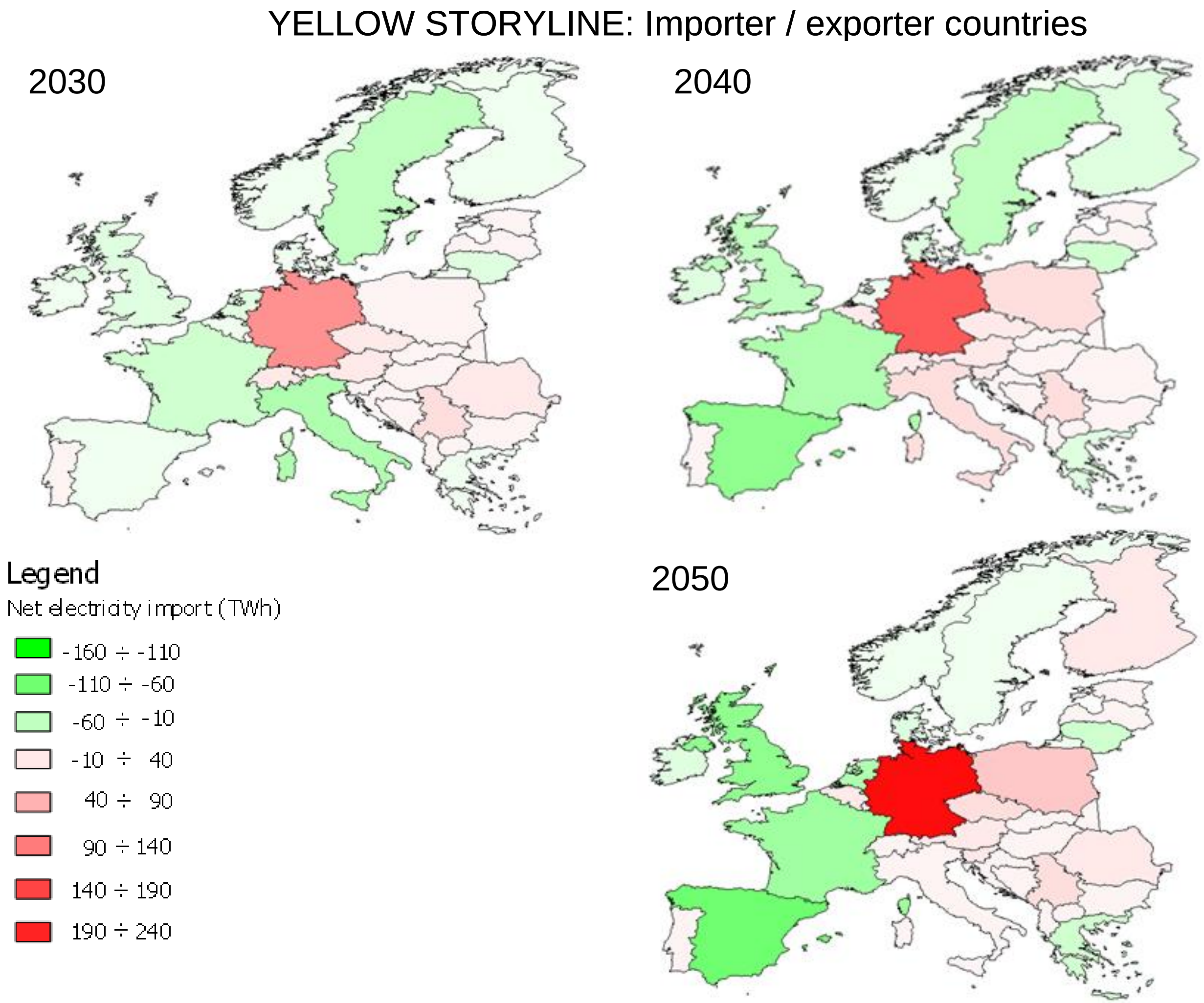


Figure 3-7 Electricity importing and exporting countries in the Yellow storyline

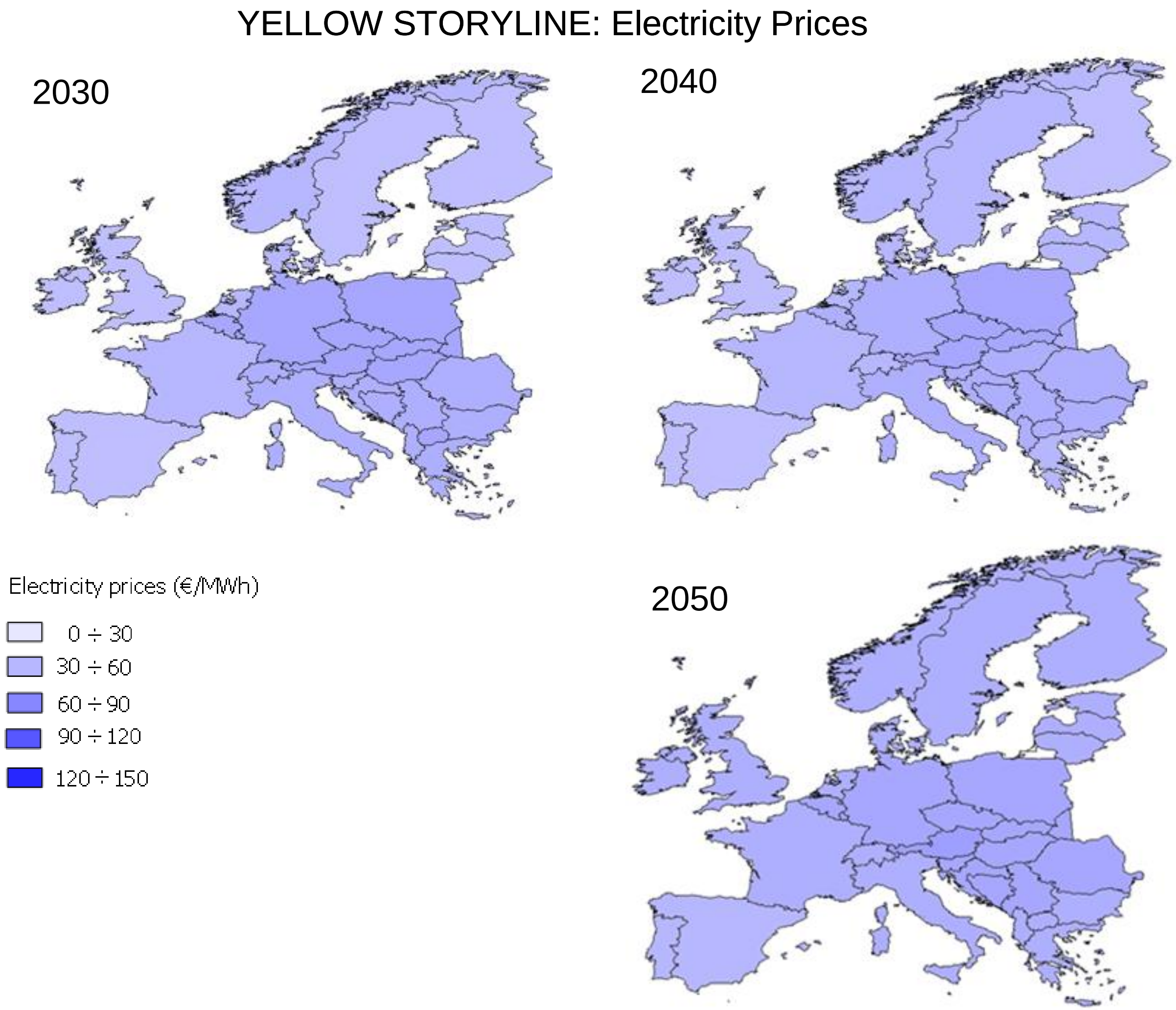


Figure 3-8 Electricity prices across Europe in the Yellow storyline

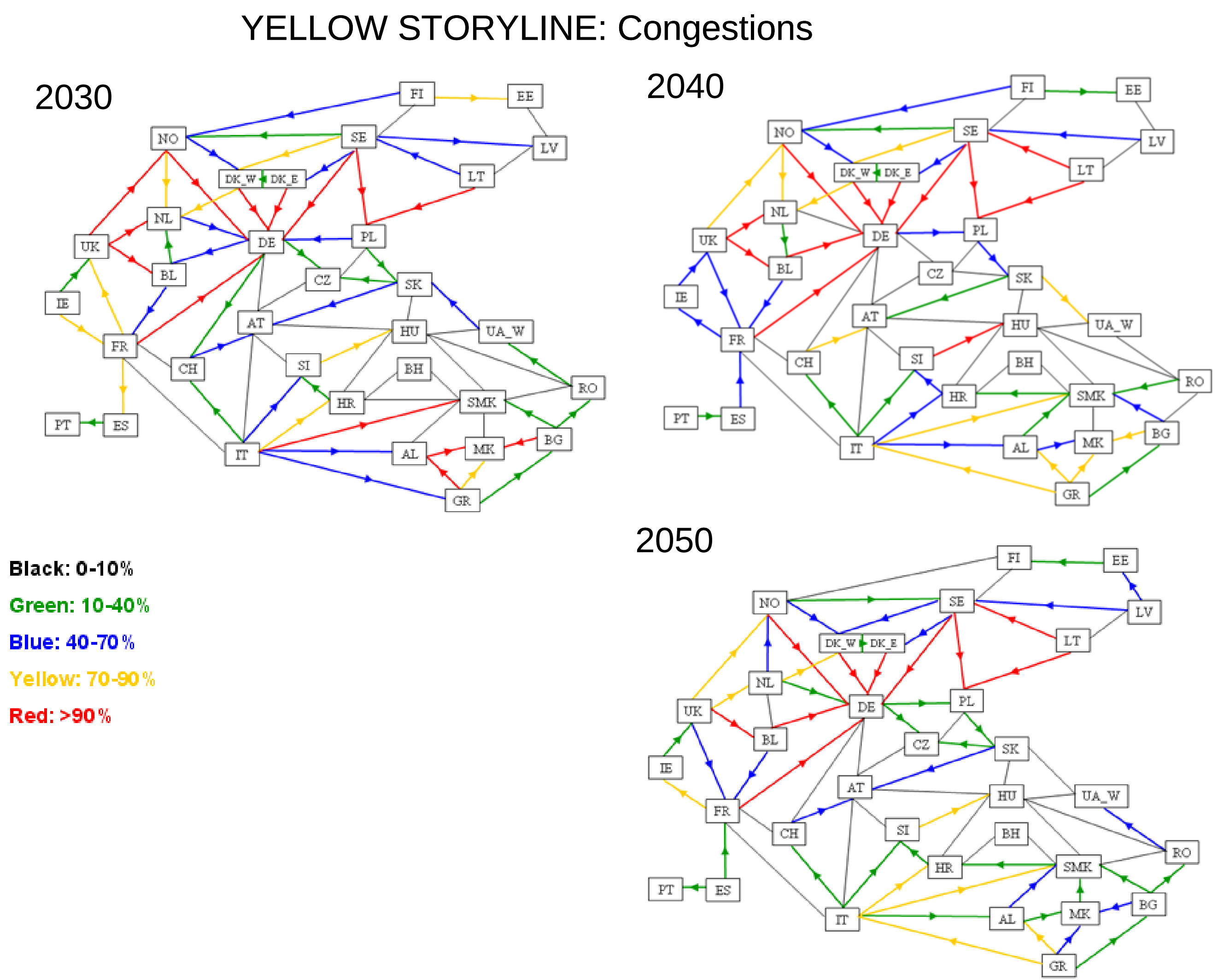


Figure 3-9 Level of congestion on electricity interconnections across Europe in the Yellow storyline

	Load shedding	Energy In Excess
2030	-	ES: 622 GWh IE: 415 GWh PT: 608 GWh UK: 902 GWh
2040	-	ES: 1708 GWh IE: 55 GWh PT: 587 GWh UK: 49 GWh
2050	-	ES: 1035 GWh PT: 267 GWh

Table 3-4 Energy In Excess and Energy Not Produced in the Yellow storyline

	2030(A->B)	2030(B->A)	2030-2040	2040-2050
PT->ES	-3000	3000	900 (30%)	0 (0%)
ES->FR	-4000	4000	6000 (150%)	6000 (60%)
FR->IT	-2595	4200	1500 (36%)	0 (0%)
IT->CH	-6540	3710	0 (0%)	0 (0%)
FR->CH	-2300	3200	1200 (38%)	0 (0%)
FR->DE	-3150	3000	6000 (200%)	6000 (67%)
FR->BL	-3100	4000	0 (0%)	0 (0%)
CH->DE	-1500	3200	1200 (38%)	0 (0%)
DE->BL	0	980	0 (0%)	0 (0%)
BL->NL	-2400	2400	3000 (125%)	0 (0%)
NL->DE	-5350	4500	0 (0%)	0 (0%)
DE->DK_W	-2000	1500	300 (20%)	0 (0%)
DE->PL	-3000	3100	3000 (97%)	0 (0%)
DE->CZ_W	-3800	2300	0 (0%)	0 (0%)
DE->AT	-6880	6880	0 (0%)	0 (0%)
CH->AT	-1400	1400	0 (0%)	0 (0%)
IT->AT	-2200	2200	300 (14%)	0 (0%)
IT->SI	-2150	2150	0 (0%)	0 (0%)
CZ_E->PL	-2000	800	600 (75%)	0 (0%)
PL->SK	-1400	1500	1200 (80%)	300 (11%)
CZ_E->SK	-1000	2000	0 (0%)	0 (0%)
AT->CZ_W	-2000	1100	300 (27%)	0 (0%)
SK->HU	-2100	3000	600 (20%)	0 (0%)
AT->HU	-1200	1500	0 (0%)	0 (0%)
AT->SI	-1200	1200	0 (0%)	0 (0%)
HU->SMK	-600	600	300 (50%)	0 (0%)
HU->RO	-1400	600	0 (0%)	0 (0%)
SMK->BG	-650	500	0 (0%)	0 (0%)
SMK->RO	-850	500	0 (0%)	0 (0%)
RO->BG	-950	950	0 (0%)	0 (0%)
BG->GR	-1400	1500	0 (0%)	600 (40%)
AL->GR	-300	150	0 (0%)	1200 (800%)
AL->SMK	-1200	1250	0 (0%)	900 (72%)
BH->SMK	-1900	2000	0 (0%)	0 (0%)
MK->GR	-300	350	0 (0%)	300 (86%)
MK->SMK	-600	1100	0 (0%)	0 (0%)

HR->BH	-1600	1530	0 (0%)	0 (0%)
HR->SMK	-600	680	0 (0%)	0 (0%)
HR->SI	-1900	1900	0 (0%)	0 (0%)
HR->HU	-2500	3000	0 (0%)	0 (0%)
RO->UA_W	-400	400	300 (75%)	0 (0%)
HU->UA_W	-1150	650	300 (46%)	0 (0%)
SK->UA_W	-400	400	0 (0%)	1200 (300%)
DK_E->SE	-1300	1700	300 (18%)	0 (0%)
NO->SE	-5250	5450	0 (0%)	0 (0%)
SE->FI	-2700	2800	300 (11%)	0 (0%)
FI->NO	-1000	1000	900 (90%)	0 (0%)
LT->LV	-1900	2100	0 (0%)	0 (0%)
LV->EE	-1300	1400	0 (0%)	0 (0%)
Total [MW]			28500	16500
Annualized AC cost [€/MW]			5969	5843
Total AC costs per decade [M€]			2027	1144,7

Table 3-5 AC network expansions across Europe in the Yellow storyline

	A->B	**B->A**	**2030-2040**	**2040-2050**
GR_IT	-1000	1000	0 (0%)	0 (0%)
AL_IT	-2000	2000	0 (0%)	0 (0%)
SMK_IT	-1000	1000	0 (0%)	0 (0%)
HR_IT	-1000	1000	0 (0%)	0 (0%)
FR_IE	-1000	1000	1000 (100%)	0 (0%)
FR_UK	-3000	3000	2000 (67%)	1000 (20%)
UK_BL	-1000	1000	1000 (100%)	1000 (50%)
UK_NL	-1320	1320	1000 (76%)	1000 (43%)
NL_NO	-1700	1700	2000 (118%)	1000 (27%)
NO_DE	-2400	2400	2000 (83%)	1000 (23%)
SE_DE	-600	600	600 (100%)	0 (0%)
SE_PL	-600	600	600 (100%)	0 (0%)
LT_PL	-1000	1000	0 (0%)	0 (0%)
LV_SE	-700	700	0 (0%)	0 (0%)
EE_FI	-1000	1000	0 (0%)	0 (0%)
SK_AT	-1500	1500	0 (0%)	0 (0%)
HU_SI	-900	900	0 (0%)	0 (0%)
BL_DE	-1000	1000	0 (0%)	0 (0%)
DE_DK_E	-1150	1150	550 (48%)	0 (0%)
NL_DK_W	-600	600	0 (0%)	0 (0%)
NO_DK_W	-1600	1600	0 (0%)	0 (0%)
DK_W_SE	-680	740	360 (49%)	0 (0%)
MK_BG	-450	250	200 (80%)	250 (56%)
AL_MK	-500	500	200 (40%)	250 (36%)
DK_W_DK_E	-600	600	600 (100%)	0 (0%)
Total [MW]	-28300	28160	12110	5500
Annualized DC cost [€/MW]			26081	25175
Total DC costs per decade [M€]			3768	1645,5

Table 3-6 DC network expansions across Europe in the Yellow storyline

3.1.3 Blue storyline

Summary of storyline results:

- Electricity balance of countries:
  - In 2030 Germany as well as the countries of the former Yugoslavia are importing countries. In 2040 the East Europe becomes a self-sufficient region (i.e. shows a balance of import and export), while Germany steadily behaves as an energy importing nation till 2050;
  - In 2050 Spain and Portugal are neutral, while Italy becomes an importing country;
- Cross-border lines that connect Germany and United Kingdom with the European system are the most frequently congested. This is true in all three grid years, despite the significant increase of the European AC transmission network capacity (44000 MW in the 2030-40 decade, 49000 MW in the 2040-50 decade). This network increase is functional to decrease European electricity prices. In 2040 the interconnections between Italy and the Balkan region are congested too;
- The high load demand level causes, despite the high RES deployment, the dispatching of less efficient more expensive thermal power generation. For this reason, prices remain high, but the transmission network upgrade allows to reduce prices from 2030 till 2050 (83 €/MWh in 2030, 70 €/MWh in 2040, 65 €/MWh in 2050 The trend is different from region to region: in particular, prices decrease in North Europe, stay similar in the South-Europe, and increase a lot in Central Europe, mainly Germany, and East Europe;
- Total European operative costs (i.e. CO_2 and fuel cost) are high in 2030 and show a small reduction till 2050 (27%);
- Main expanded interconnections: ES->FR (6000 MW), FR->IT (6000 MW), FR->DE (6000 MW), FR->BL (6000 MW), DE->PL (6000 MW), PL->SK (6000 MW), HR->SI (4500 MW) ;
- Despite the network expansion, due to the high demand level there is exceeding (not dispatched) wind energy in United Kingdom and Ireland in 2050;
- Load shedding doesn't take place.

Figure 3-10 shows the generation mix for the **Blue** Storyline: it can be seen that the generation ratio (RES/THERMAL) increases a lot from 2030 (47%) to 2050 (69%); the RES generation is characterized by an increasing amount of energy available from wind power plants (44% in 2030, 54% in 2040 and 69% in 2050). Concerning the thermal power plants, the mix stays constants all over the three milestone years: 49%-52% of energy from gas fired power plants, 44-39% from nuclear power plants and 7-8% from hard coal fired power plants.

Regarding the electricity balance of countries (Figure 3-11) it can be seen that Germany shows the same behavior as in the other storylines, becoming more and more an importing country. This behavior is caused by the very high forecast demand level with respect to the installed thermal capacity: the load is higher than the thermal capacity in 90% of the hours. On the other side, the Scandinavian Peninsula becomes more and more an exporting country, along with the United Kingdom, Ireland and France. Italy moves from a situation in which it is exporting electricity in 2030 scenario to a situation in which it is importing electricity in 2050. Concerning the prices, the situation is similar all over Europe in 2030, with prices staying around 80-100 €/MWh, while in 2050 there are four zones with quite diversified prices:

- the Scandinavian peninsula and United Kingdom with prices around 0€/MWh
- France and Iberia peninsula, with prices around 20€/MWh

- the countries placed in Center-South Europe with values around 30-40 €/MWh,
- Germany, Czech Republic, Slovakia, Poland and Ukraine with prices around 100 €/MWh.

The large differences between wholesale electricity prices across these regions can largely be explained by the strong restrictions imposed in this storyline regarding the expansion of electricity infrastructure capacity. Although significant investment does take place on numerous interconnectors (see the list of expansions below), it is not sufficient from the perspective of achieving one electricity market with comparable prices across different regions.

Due to the high amount of energy from RES sources, the program decides to significantly expand a high number of interconnections, in particular:

- ES-FR corridor by 75% in decade 2030-40 and 43% in decade 2040-50;
- FR-IT corridor by 71% in decade 2030-40 and 42% in decade 2040-50;
- IT-CH corridor by 80% in decade 2040-50;
- FR-DE corridor by 100% in decade 2030-40 and 50% in decade 2040-50;
- FR-BL corridor by 75% in decade 2030-40 and 43% in decade 2040-50;
- BL-NL corridor by 125% in decade 2030-40 and 56% in decade 2040-50;
- DE-PL corridor by 97% in decade 2030-40 and 49% in decade 2040-50;
- CH-AT corridor by 43% in decade 2030-40 and 75% in decade 2040-50;
- PL-SK corridor by 200% in decade 2030-40 and 67% in decade 2040-50;
- SMK-BG corridor by 120% in decade 2030-40 and 136% in decade 2040-50;
- SMK-RO corridor by 120% in decade 2030-40 and 55% in decade 2040-50;
- AL-GR corridor by 400% in decade 2030-40 and 80% in decade 2040-50;
- HR-SI corridor by 79% in decade 2030-40 and 88% in decade 2040-50;
- SK-UA_K corridor by 150% in decade 2030-40 and 150% in decade 2040-50.

In order to test whether the strong restrictions on infrastructure expansion are indeed the main explanation behind the considerable regional price differences a sensitivity analysis was performed. More specifically, a sensitivity run has been performed in order to assess how the adoption of a maximum expansion limit on each corridor (3000 MW per decade) is really binding and provides a constraint on the obtained solution. The scenario taken into account is the Blue 2040-50 in “planning modality”. Two simulations have been executed: one with limits on the maximum installed capacity, and one in which these limits have been disregarded. A comparison of the scenario results is reported in Table 3-7. As it can be noticed, the most significantly expanded corridors are those that connect the Iberian Peninsula with the Central-European region. This fact highlights even more the necessity of expansion for this backbone. Clearly, the expansion figures obtained in the "unconstrained case" are unrealistic: up to 53000 MW of new installed capacity added within one decade is indeed an unrealistic setup.

	NO CONSTRAINTS	WITH CONSTRAINTS
PT->ES	837,87	600
ES->FR	**32863,34**	**3000**
FR->IT	3719,01	3000
IT->CH	3570,34	3000
FR->CH	75,58	0
FR->DE	**53164,75**	**3000**
FR->BL	**5655,25**	**3000**

CH->DE	0	0
DE->BL	0	0
BL->NL	**10044,57**	**3000**
NL->DE	0	0
DE->DK_W	1052,88	1500
DE->PL	**18175,45**	**3000**
DE->CZ_W	1864,13	1500
DE->AT	0	0
CH->AT	1633,87	1500
IT->AT	0	0
IT->SI	1227,58	1500
CZ_E->PL	1492,47	1500
PL->SK	4723,74	3000
CZ_E->SK	193,54	300
AT->CZ_W	1910,53	1500
SK->HU	2457,82	3000
AT->HU	0	0
AT->SI	0	0
HU->SMK	191,96	300
HU->RO	0	0
SMK->BG	1303,94	1500
SMK->RO	1014,06	600
RO->BG	0	0
BG->GR	0	0
AL->GR	993,02	600
AL->SMK	720,91	600
BH->SMK	0	0
MK->GR	377,54	300
MK->SMK	0	0
HR->BH	338,49	300
HR->SMK	711,83	600
HR->SI	2418,94	3000
HR->HU	1772,86	1500
RO->UA_W	364,71	300
HU->UA_W	636,05	600
SK->UA_W	1474,05	1500
CZ_W->CZ_E	0	0
DK_E->SE	246,12	300
UK->IE	0	0
NO->SE	0	0
SE->FI	0	0
FI->NO	124,91	0
UK->NO	0	0
SE->LT	0	0

Table 3-7 Comparison between Blue 2040-50 with and without constraints on maximum installable capacity

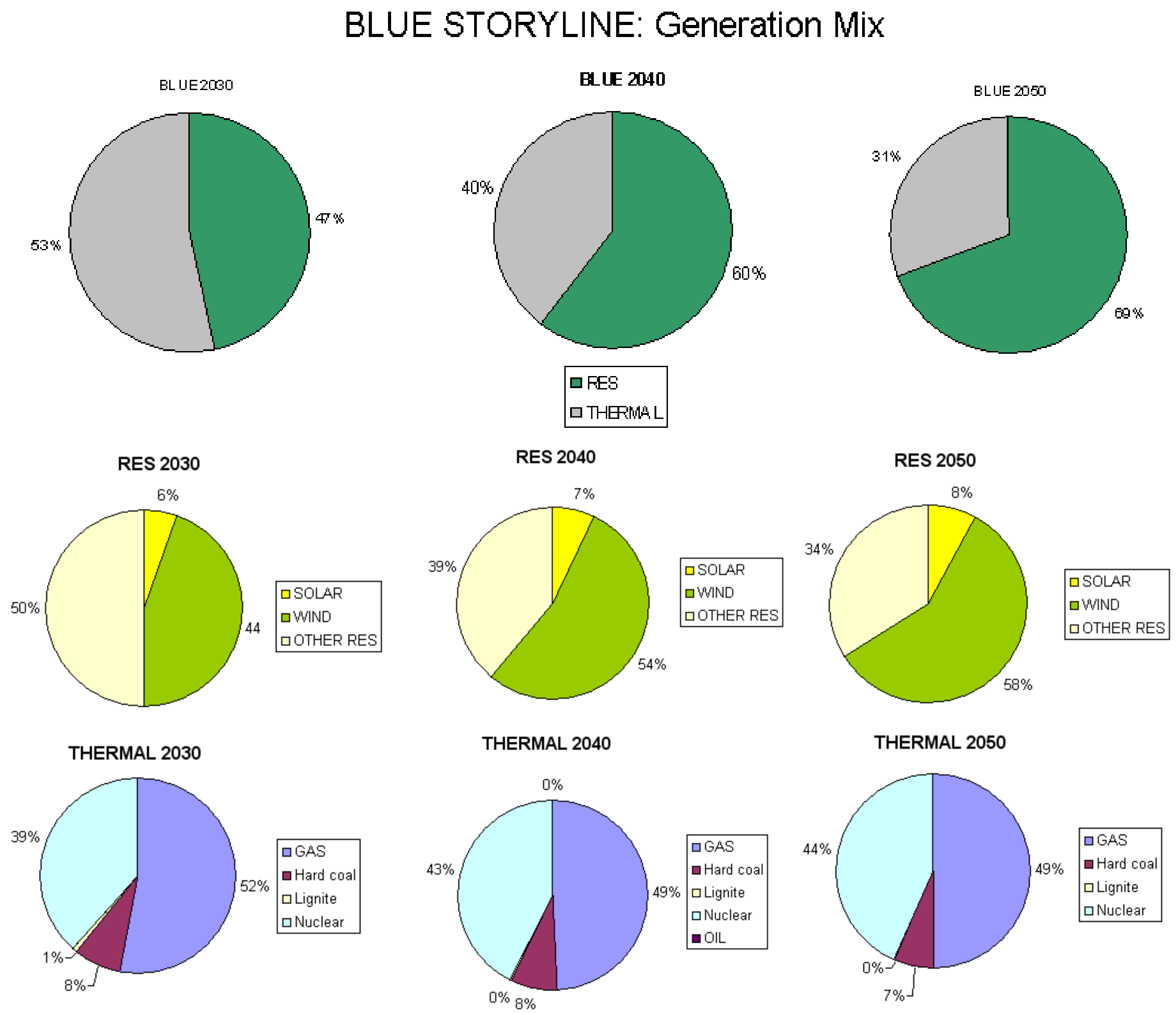


Figure 3-10 European electricity generation mix in the Blue storyline

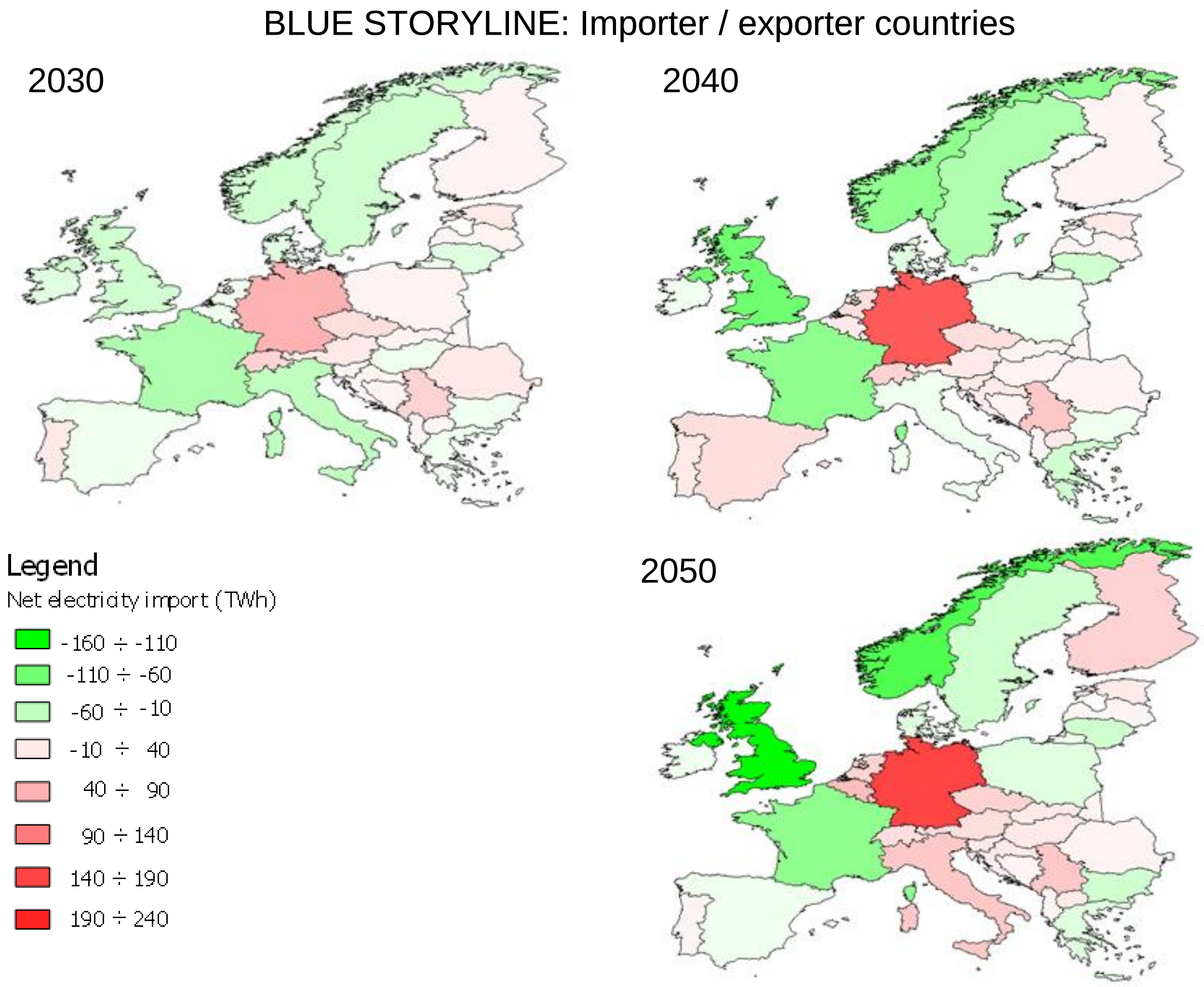


Figure 3-11 Electricity importing and exporting countries in the Blue storyline

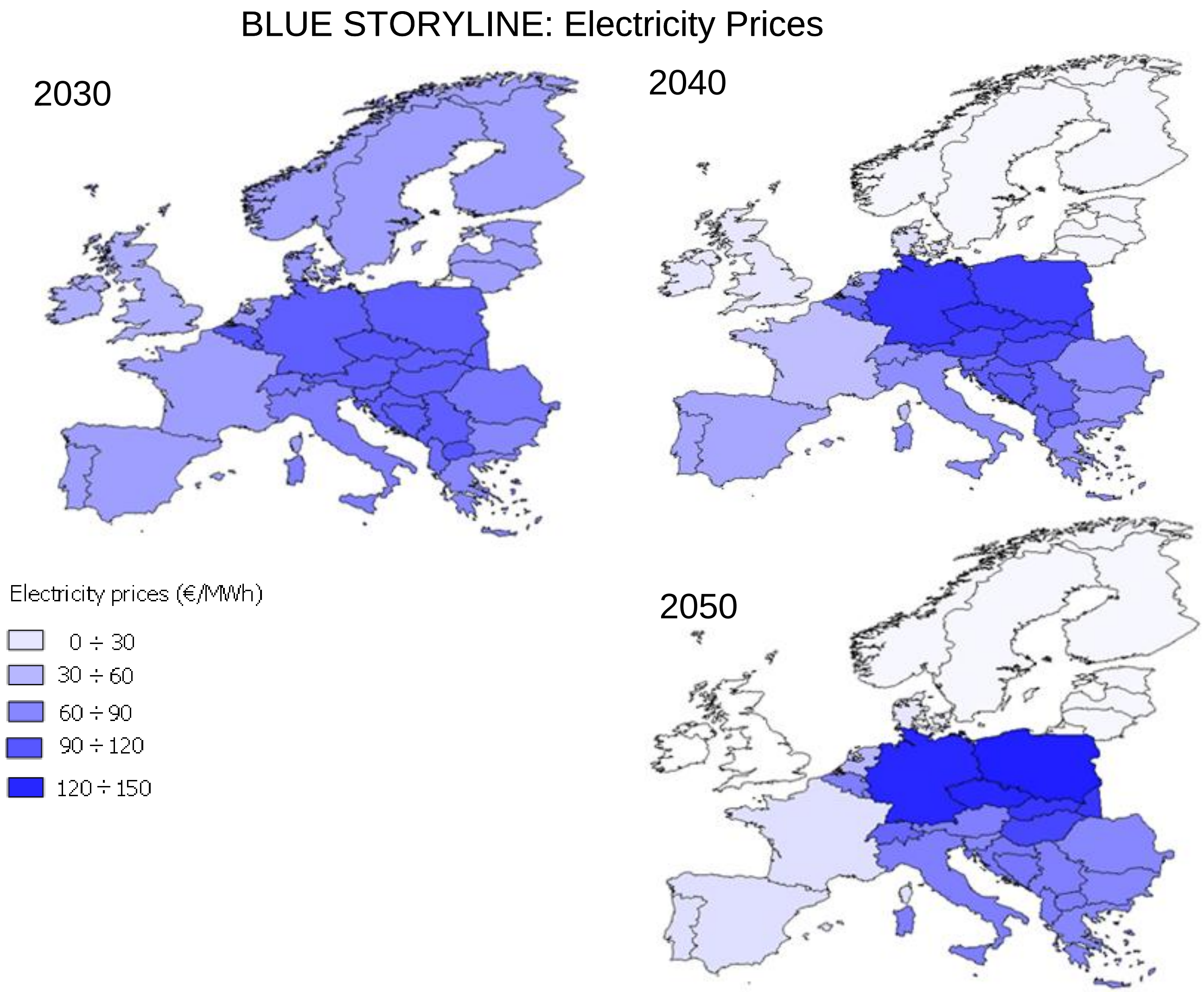


Figure 3-12 Electricity prices across Europe in the Blue storyline

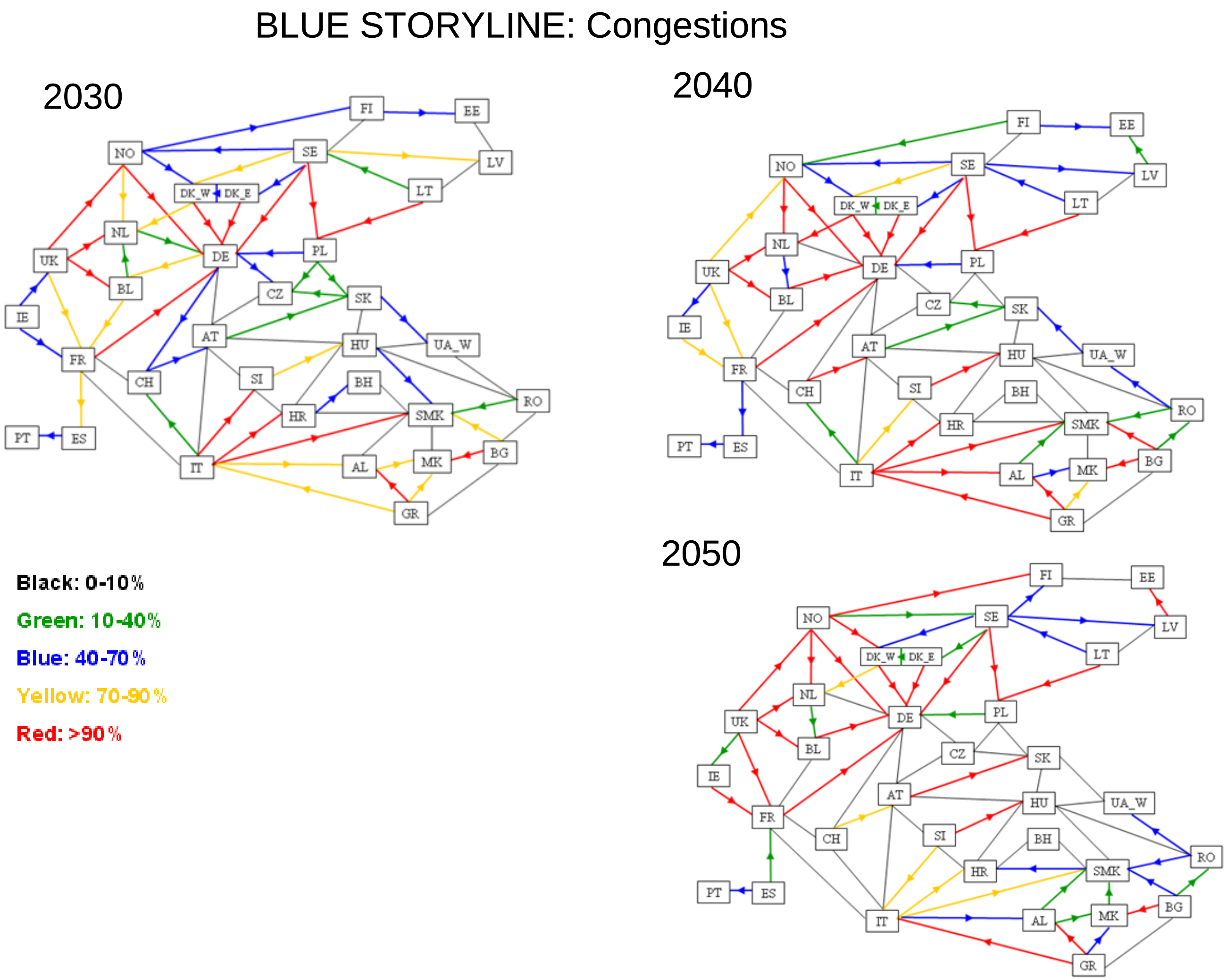


Figure 3-13 Level of congestion on electricity interconnections across Europe in the Blue storyline

	Load shedding	Energy In Excess
2030	-	ES: 75 GWh IE: 490 GWh PT: 35 GWh UK: 1395 GWh
2040	DE: 22 GWh	ES: 758 GWh IE: 3323 GWh PT: 113 GWh UK: 17002 GWh
2050	-	ES: 2114 GWh IE: 10782 GWh PT: 158 GWh UK: 53181 GWh

Table 3-8 Energy In Excess and Energy Not Produced in the Blue storyline

	2030(A->B)	2030(B->A)	2030-2040	2040-2050
PT->ES	-3000	3000	0 (0%)	600 (20%)
ES->FR	-4000	4000	3000 (75%)	3000 (43%)
FR->IT	-2595	4200	3000 (71%)	3000 (42%)
IT->CH	-6540	3710	0 (0%)	3000 (81%)
FR->CH	-2300	3200	3000 (94%)	0 (0%)
FR->DE	-3150	3000	3000 (100%)	3000 (50%)
FR->BL	-3100	4000	3000 (75%)	3000 (43%)
CH->DE	-1500	3200	3000 (94%)	0 (0%)
DE->BL	0	980	0 (0%)	0 (0%)
BL->NL	-2400	2400	3000 (125%)	3000 (56%)
NL->DE	-5350	4500	0 (0%)	0 (0%)
DE->DK_W	-2000	1500	600 (40%)	1500 (71%)
DE->PL	-3000	3100	3000 (97%)	3000 (49%)
DE->CZ_W	-3800	2300	1500 (65%)	1500 (39%)
DE->AT	-6880	6880	0 (0%)	0 (0%)
CH->AT	-1400	1400	600 (43%)	1500 (75%)
IT->AT	-2200	2200	1500 (68%)	0 (0%)
IT->SI	-2150	2150	0 (0%)	1500 (70%)
CZ_E->PL	-2000	800	3000 (375%)	1500 (39%)
PL->SK	-1400	1500	3000 (200%)	3000 (67%)
CZ_E->SK	-1000	2000	300 (15%)	300 (13%)
AT->CZ_W	-2000	1100	600 (55%)	1500 (88%)
SK->HU	-2100	3000	1500 (50%)	3000 (67%)
AT->HU	-1200	1500	0 (0%)	0 (0%)
AT->SI	-1200	1200	0 (0%)	0 (0%)
HU->SMK	-600	600	0 (0%)	300 (50%)
HU->RO	-1400	600	0 (0%)	0 (0%)
SMK->BG	-650	500	600 (120%)	1500 (136%)
SMK->RO	-850	500	600 (120%)	600 (55%)
RO->BG	-950	950	0 (0%)	0 (0%)
BG->GR	-1400	1500	0 (0%)	0 (0%)
AL->GR	-300	150	600 (400%)	600 (80%)
AL->SMK	-1200	1250	600 (48%)	600 (32%)

BH->SMK	-1900	2000	0 (0%)	0 (0%)
MK->GR	-300	350	300 (86%)	300 (46%)
MK->SMK	-600	1100	0 (0%)	0 (0%)
HR->BH	-1600	1530	0 (0%)	300 (20%)
HR->SMK	-600	680	300 (44%)	600 (61%)
HR->SI	-1900	1900	1500 (79%)	3000 (88%)
HR->HU	-2500	3000	1500 (50%)	1500 (33%)
RO->UA_W	-400	400	0 (0%)	300 (75%)
HU->UA_W	-1150	650	300 (46%)	600 (63%)
SK->UA_W	-400	400	600 (150%)	1500 (150%)
DK_E->SE	-1300	1700	600 (35%)	300 (13%)
NO->SE	-5250	5450	0 (0%)	0 (0%)
SE->FI	-2700	2800	0 (0%)	0 (0%)
FI->NO	-1000	1000	0 (0%)	0 (0%)
LT->LV	-1900	2100	0 (0%)	0 (0%)
LV->EE	-1300	1400	0 (0%)	0 (0%)
Total [MW]			44100	48900
Annualized AC cost [€/MW]			5948	5738
Total AC costs per decade [M€]			3124	3350,6

Table 3-9 AC network expansions across Europe in the Blue storyline

	A->B	**B->A**	**2030-2040**	**2040-2050**
GR_IT	-1000	1000	0 (0%)	0 (0%)
AL_IT	-2000	2000	0 (0%)	0 (0%)
SMK_IT	-1000	1000	0 (0%)	0 (0%)
HR_IT	-1000	1000	0 (0%)	0 (0%)
FR_IE	-1000	1000	1000 (100%)	0 (0%)
FR_UK	-3000	3000	2000 (67%)	1000 (20%)
UK_BL	-1000	1000	1000 (100%)	1000 (50%)
UK_NL	-1320	1320	1000 (76%)	1000 (43%)
NL_NO	-1700	1700	2000 (118%)	1000 (27%)
NO_DE	-2400	2400	2000 (83%)	1000 (23%)
SE_DE	-600	600	600 (100%)	1000 (83%)
SE_PL	-600	600	600 (100%)	0 (0%)
LT_PL	-1000	1000	0 (0%)	0 (0%)
LV_SE	-700	700	0 (0%)	0 (0%)
EE_FI	-1000	1000	0 (0%)	0 (0%)
SK_AT	-1500	1500	0 (0%)	0 (0%)
HU_SI	-900	900	0 (0%)	0 (0%)
BL_DE	-1000	1000	0 (0%)	0 (0%)
DE_DK_E	-1150	1150	550 (48%)	1000 (59%)
NL_DK_W	-600	600	0 (0%)	0 (0%)
NO_DK_W	-1600	1600	0 (0%)	0 (0%)
DK_W_SE	-680	740	360 (49%)	0 (0%)
MK_BG	-450	250	200 (80%)	250 (56%)
AL_MK	-500	500	200 (40%)	250 (36%)
DK_W_DK_E	-600	600	600 (100%)	0 (0%)

Total [MW]	-28300	28160	12110	7500
Annualized DC cost [€/MW]			25175	23665
Total DC costs per decade [M€]			3636,8	2110,5

Table 3-10 DC network expansions across Europe in the Blue storyline

3.1.4 Green storyline

Summary of storyline results:

- Electricity balance: from 2030 till 2050 East Europe transfers from an importing region to an exporting region due to the increasing amount of available RES sources;
- Germany remains an electricity importing country, the import level being constantly increasing from 2030 till 2050;
- Cross-border lines that connect Germany with the European system are the most frequently congested. This is true in all three Green storylines, despite the significant increase of the European AC transmission network capacity (60000 MW in the 2030-40 decade, 57000 MW in the 2040-50 decade). This network increase is functional to maximize the exploitation of the high amount of RES energy available from generation regions to consumption zones: notwithstanding the significant increase of RES generation, Germany remains strongly dependent on import coming from other countries where cheap (typically RES) energy is available. Hence, the strong congestion at its borders;
- The combined effect of higher amount of available RES energy and transmission network upgrade allow to:
  - Reduce prices (58 €/MWh in 2030, 48 €/MWh in 2040, 39 €/MWh in 2050): prices stay similar Europe-wide, except for Germany that starts with higher prices (75 €/MWh) in 2030 but thereafter tends to converge to the same figures as the other European countries;
  - Reduce total European operative costs (i.e. CO_2 and fuel cost) from 2030 to 2050 of 74%;
- Main expanded interconnections: ES->FR (12000 MW), FR-DE (12000 MW), DE-> PL (12000 MW), PL->SK (8100 MW);
- Despite the network expansion, due to the significant RES expansion there is exceeding (not dispatched) wind and solar energy in Spain in 2050;
- Load shedding is present in Germany in 2030, and then overcome thanks to the grid expansion that facilitates the import from other countries.

Figure 3-14 shows the generation mix for the **Green** Storyline: it can be seen that the generation ratio (RES/THERMAL) shows a large increase, from 46% in 2030 to 73% in 2050. The RES mix is dominated by wind (44-48%) and followed by other RES (40%) and solar (11-16%). Concerning the thermal power plants, generation from gas fired power plants decreases a lot, passing from 48% in 2030 to 21% in 2050. An opposite trend can be observed for the nuclear generation, from 41% in 2030 to 79% in 2050. Moreover, all the coal fired power plants, that in 2030 provided 7%, are switched off in 2050. Concerning the electricity balance of countries (see Figure 3-15); it can be observed that Italy is an electricity exporting country in 2030, while in 2050 becomes an electricity importing country. The Scandinavian Peninsula and the East-Europe are basically independent, while the Iberian Peninsula is to be considered an electricity exporting country. Regarding electricity prices, Figure 3-16 shows that Germany has higher prices in 2030 (80€/MWh) with respect to the rest of Europe (40€/MWh), but afterwards the prices decrease up to 20 €/MWh in

2050. Observing Figure 3-17, the number of congested lines stays very low, and limited mainly to the corridors that connect Germany with the neighboring countries.

The most extensively expanded corridors are:

- ES->FR corridor by 150% decade 2030-40 and 67% in decade 2040-50;
- FR->DE corridor by 200% decade 2030-40 and 43% in decade 2040-50;
- BL->NL corridor by 250% in decade 2030-40;
- DE->PL corridor by 194% in decade 2030-40 and 66% in decade 2040-50;
- CZ_E->PL corridor by 188% in decade 2030-40 and 65% in decade 2040-50;
- PL->SK corridor by 140% in decade 2030-40 and 167% in decade 2040-50;
- HU->SMK corridor by 55% in decade 2030-40 and 133% in decade 2040-50;
- SMK->BG corridor by 180% in decade 2030-40 and 21% in decade 2040-50;
- AL->GR corridor by 1200% in decade 2030-40 and 46% in decade 2040-50;
- AL->SMK corridor by 144% in decade 2030-40 and 30% in decade 2040-50;
- MK->GR corridor by 171% in decade 2030-40 and 61% in decade 2040-50;
- RO->UA_W corridor by 150% in decade 2030-40 and 210% in decade 2040-50;
- SK->UA_W corridor by 375% in decade 2030-40 and 175% in decade 2040-50.

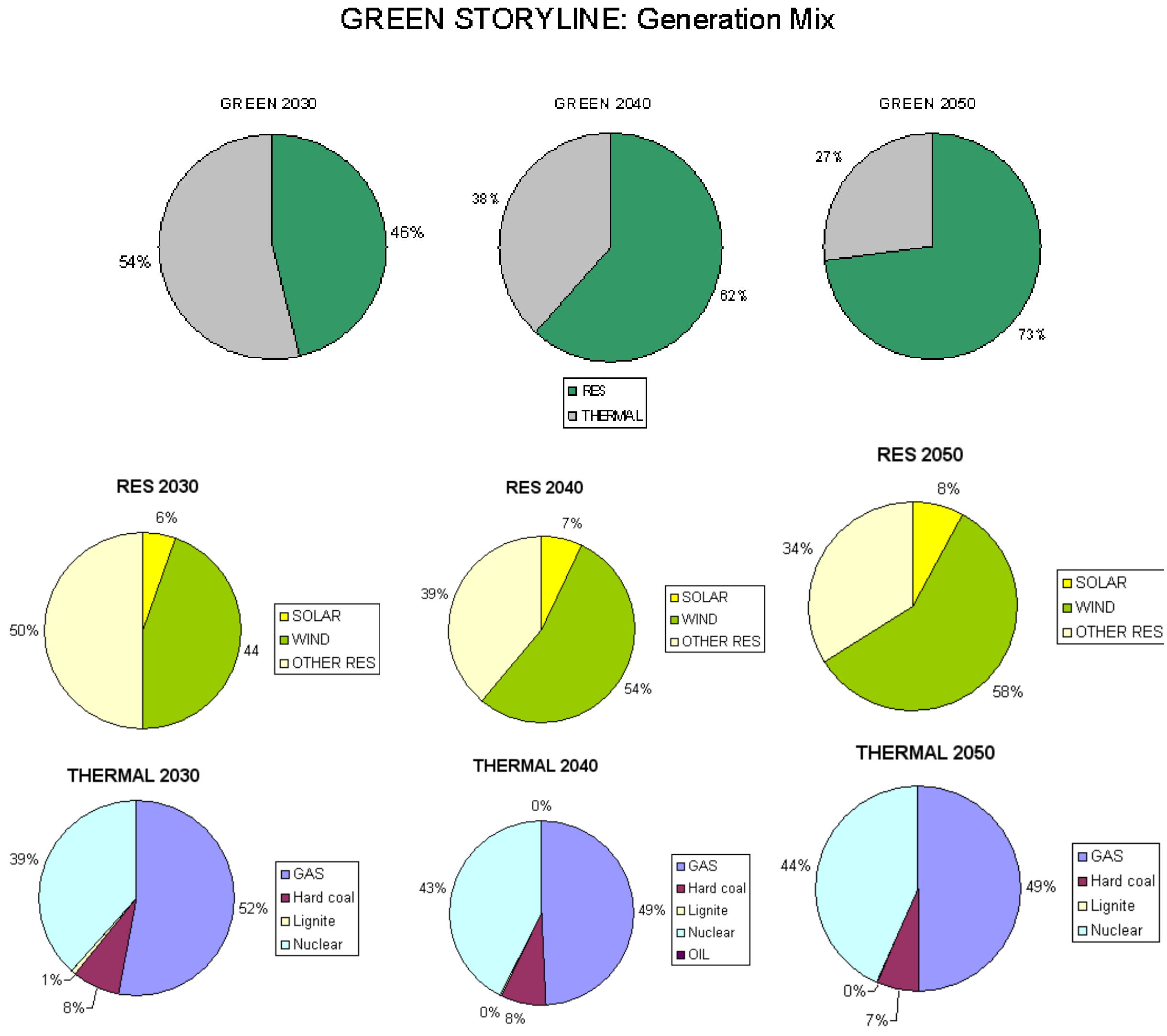


Figure 3-14 European electricity generation mix in the Green storyline

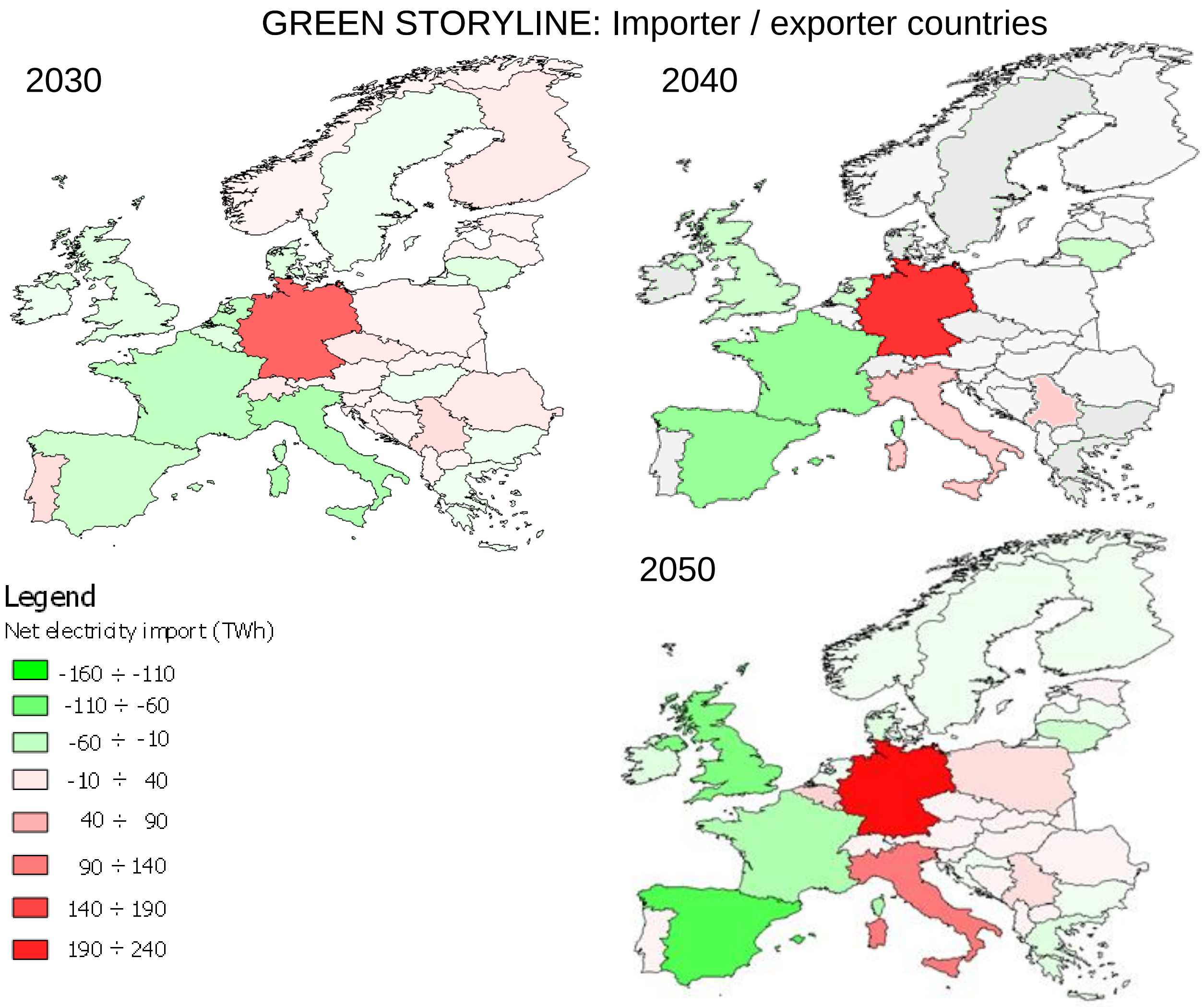


Figure 3-15 Electricity importing and exporting countries in the Green storyline

GREEN STORYLINE: Electricity Prices

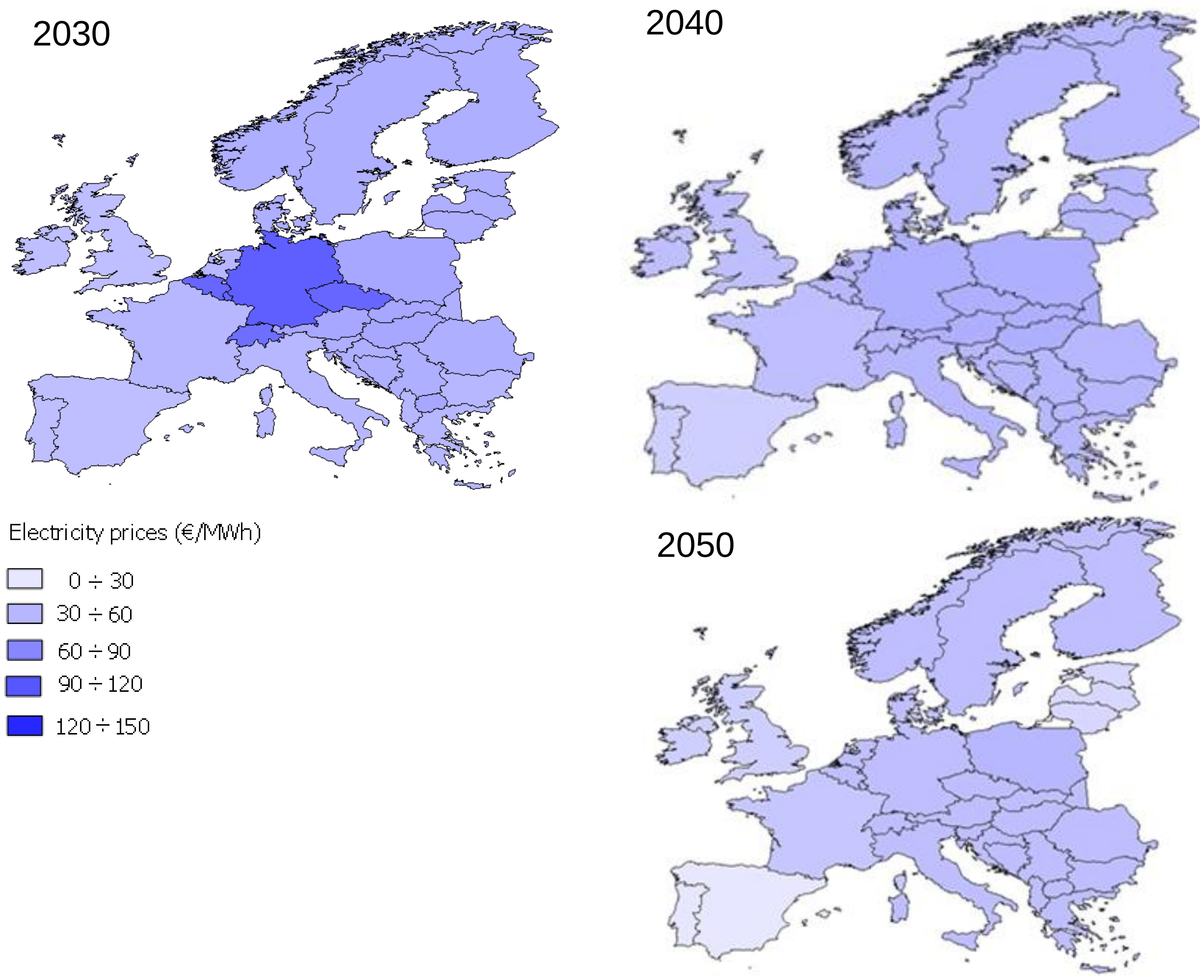
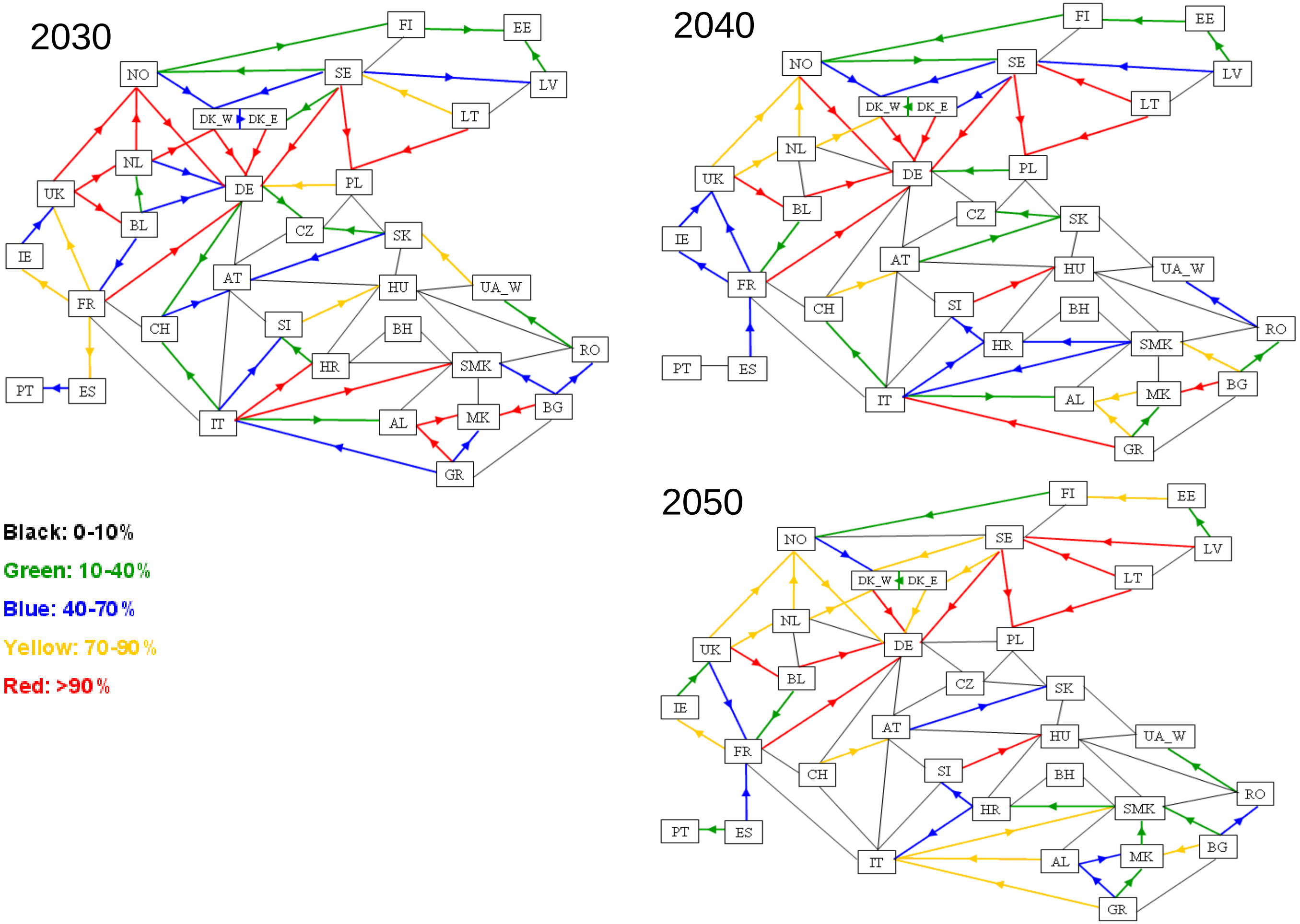


Figure 3-16 Electricity prices across Europe in the Green storyline

GREEN STORYLINE: Congestions



Black: 0-10%

Green: 10-40%

Blue: 40-70%

Yellow: 70-90%

Red: >90%

Figure 3-17 Level of congestion on electricity interconnections across Europe in the Green storyline

	Load shedding	Energy In Excess
2030	BL: 168 GWh CH: 0,2 GWh DE: 447 GWh	ES: 1548 GWh IE: 65 GWh PT: 826 GWh UK: 105 GWh
2040		ES: 11784 GWh GR: 7 GWh IE: 168 GWh PT: 2436 GWh UK: 207 GWh
2050		ES: 38376 GWh GR: 6 GWh IE: 490 GWh PT: 4870 GWh UK: 655 GWh

Table 3-11 Energy In Excess and Energy Not Produced in the Green storyline

	2030(A->B)	2030(B->A)	2030-2040	2040-2050
PT->ES	-3000	3000	1800 (60%)	300 (6%)
ES->FR	-4000	4000	6000 (150%)	6000 (60%)
FR->IT	-2595	4200	3000 (71%)	3600 (50%)
IT->CH	-6540	3710	0 (0%)	0 (0%)
FR->CH	-2300	3200	2100 (66%)	3300 (62%)
FR->DE	-3150	3000	6000 (200%)	6000 (67%)
FR->BL	-3100	4000	2100 (53%)	300 (5%)
CH->DE	-1500	3200	1800 (56%)	1500 (30%)
DE->BL	0	980	0 (0%)	0 (0%)
BL->NL	-2400	2400	6000 (250%)	0 (0%)
NL->DE	-5350	4500	0 (0%)	600 (13%)
DE->DK_W	-2000	1500	900 (60%)	0 (0%)
DE->PL	-3000	3100	6000 (194%)	6000 (66%)
DE->CZ_W	-3800	2300	0 (0%)	4500 (196%)
DE->AT	-6880	6880	0 (0%)	0 (0%)
CH->AT	-1400	1400	1200 (86%)	0 (0%)
IT->AT	-2200	2200	1500 (68%)	0 (0%)
IT->SI	-2150	2150	900 (42%)	0 (0%)
CZ_E->PL	-2000	800	1500 (188%)	1500 (65%)
PL->SK	-1400	1500	2100 (140%)	6000 (167%)
CZ_E->SK	-1000	2000	300 (15%)	1200 (52%)
AT->CZ_W	-2000	1100	900 (82%)	1200 (60%)
SK->HU	-2100	3000	1200 (40%)	1200 (29%)
AT->HU	-1200	1500	0 (0%)	0 (0%)
AT->SI	-1200	1200	0 (0%)	0 (0%)
HU->SMK	-600	600	300 (50%)	1200 (133%)
HU->RO	-1400	600	300 (50%)	0 (0%)
SMK->BG	-650	500	900 (180%)	300 (21%)
SMK->RO	-850	500	1200 (240%)	0 (0%)
RO->BG	-950	950	0 (0%)	0 (0%)
BG->GR	-1400	1500	1200 (80%)	1200 (44%)

AL->GR	-300	150	1800 (1200%)	900 (46%)
AL->SMK	-1200	1250	1800 (144%)	900 (30%)
BH->SMK	-1900	2000	0 (0%)	0 (0%)
MK->GR	-300	350	600 (171%)	600 (63%)
MK->SMK	-600	1100	0 (0%)	0 (0%)
HR->BH	-1600	1530	300 (20%)	300 (16%)
HR->SMK	-600	680	300 (44%)	300 (31%)
HR->SI	-1900	1900	1200 (63%)	600 (19%)
HR->HU	-2500	3000	1500 (50%)	900 (20%)
RO->UA_W	-400	400	600 (150%)	2100 (210%)
HU->UA_W	-1150	650	300 (46%)	300 (32%)
SK->UA_W	-400	400	1500 (375%)	3300 (174%)
DK_E->SE	-1300	1700	0 (0%)	0 (0%)
NO->SE	-5250	5450	0 (0%)	0 (0%)
SE->FI	-2700	2800	0 (0%)	600 (21%)
FI->NO	-1000	1000	300 (30%)	300 (23%)
LT->LV	-1900	2100	0 (0%)	300 (14%)
LV->EE	-1300	1400	0 (0%)	300 (21%)
Total [MW]			59400	57600
Annualized AC cost [€/MW]			5759	5424
Total AC costs per decade [M€]			3863	3720

Table 3-12 AC network expansions across Europe in the Green storyline

	2030 (A->B)	2030 (B->A)	2030-2040	2040-2050
GR_IT	-1000	1000	0 (0%)	0 (0%)
AL_IT	-2000	2000	0 (0%)	0 (0%)
SMK_IT	-1000	1000	0 (0%)	0 (0%)
HR_IT	-1000	1000	0 (0%)	0 (0%)
FR_IE	-1000	1000	1000 (100%)	0 (0%)
FR_UK	-3000	3000	2000 (67%)	1000 (20%)
UK_BL	-1000	1000	1000 (100%)	1000 (50%)
UK_NL	-1320	1320	1000 (76%)	1000 (43%)
NL_NO	-1700	1700	2000 (118%)	1000 (27%)
NO_DE	-2400	2400	2000 (83%)	1000 (23%)
SE_DE	-600	600	600 (100%)	1000 (83%)
SE_PL	-600	600	600 (100%)	0 (0%)
LT_PL	-1000	1000	0 (0%)	0 (0%)
LV_SE	-700	700	0 (0%)	0 (0%)
EE_FI	-1000	1000	0 (0%)	0 (0%)
SK_AT	-1500	1500	0 (0%)	0 (0%)
HU_SI	-900	900	0 (0%)	0 (0%)
BL_DE	-1000	1000	0 (0%)	0 (0%)
DE_DK_E	-1150	1150	550 (48%)	1000 (59%)
NL_DK_W	-600	600	0 (0%)	0 (0%)
NO_DK_W	-1600	1600	0 (0%)	0 (0%)
DK_W_SE	-680	740	360 (49%)	0 (0%)
MK_BG	-450	250	200 (80%)	250 (56%)

AL_MK	-500	500	200 (40%)	250 (36%)
DK_W_DK_E	-600	600	600 (100%)	0 (0%)
Total [MW]	-28300	28160	12110	7500
Annualized DC cost [€/MW]			23665	22156
Total DC costs per decade [M€]			3422	1979

Table 3-13 DC network expansions across Europe in the Green storyline

3.2 Storyline comparison

In order to extract the most important information provided by each storyline, the main action is to compare the results (i.e. prices, congestion, and total CO_2 and fuel costs) and put them in relationship with the general storylines assumptions. For this reason, the general storylines hypotheses are first summarized and then a comparison of the results will be presented.

Hypothesis overview

The main assumptions/hypothesis of each Storyline is shown in Table 3-14. It can be observed that:

- **Yellow** and **Green** storylines have in common:
  - Low demand;
  - Low fuel costs;
  - Low CO_2 emissions costs;
  - 6000 MW maximum additional capacity at each border (per decade).
- **Red** and **Blue** storylines have in common:
  - High demand;
  - High fuel cost;
  - High CO_2 emissions costs;
  - 3000 MW maximum additional capacity at each border (per decade).

Moreover, each storyline is characterized by different costs of new interconnection capacity installation:

- **Red** storyline has very high installation costs (about 6200 €/MW for AC lines and about 30000 €/MW for DC lines);
- **Yellow** storyline has high installation costs, a little bit lower than the **Red** storyline (about 6000 €/MW for AC lines and about 26000 €/MW for DC lines);
- **Blue** storyline has medium installation costs (about 5800 €/MW for AC lines and about 24000 €/MW for DC lines);
- **Green** storyline has very low installation costs (about 5500 €/MW for AC lines and about 22000 €/MW for DC lines).

Regarding renewable energy sources, each storyline is characterized by different hypotheses on the amount of energy provided to the network:

- **Green** storyline: significant RES deployment: hydro, solar, wind and wave;
- **Red** storyline: lowest amount of energy provided by RES sources.
- **Blue** and **Yellow** storyline are in the “middle”, in the sense that the **Yellow** storyline contains: a lot of wind and wave and less wind offshore, and the Blue storyline: very much wind offshore, solar, wind onshore and wave.

Yellow • Low demand • Low CO_2 costs • Low fuel costs • Maximum expansion/interconnection: 6000 MW • High new capacity installation costs • High solar, wind offshore, wave • Less offshore wind	**Green** • Low demand • Low CO_2 costs • Low fuel costs • Maximum expansion/interconnection: 6000 MW • Very low new capacity installation costs. • Very high solar deployment • High energy from hydro, wind offshore, wind onshore, wave.
RED • High demand • High CO_2 costs • High fuel costs • Maximum expansion/interconnection: 3000 MW • Very high installation costs of new capacity • Reduced renewable deployment	**BLUE** • High demand • High CO_2 costs • High fuel costs • Maximum expansion/interconnection: 3000 MW • Medium costs for installation of new capacity • Very high deployment of wind offshore • High solar, wind offshore, wave

Table 3-14 – Overview of storyline features

General overview of results

As regards operational costs (i.e. total EU CO_2 emissions and fuel costs), it can be observed (see Figure 3-18) that the 2030 **Green** storyline is the most advantageous one, mainly because demand, CO_2 costs and fuel costs are lower and RES penetration the highest. For the same reasons, the **Yellow** storyline has very low operative costs, only 34% more costly than the **Green** storyline, due to the lower availability of energy from RES-sources. The 2030 **Blue** and **Yellow** storylines show a different behaviour: the 2030 **Blue** storyline is 129.5% more expensive than 2030 **Green** storyline, while the 2030 **Red** storyline is the "worst", being by 321% more expensive. These two storylines show these high operative costs mainly because demand, CO_2 and fuel costs stay very high. Analyzing a single Storyline trend, operative costs of the **Green** Storyline decrease from 2030 to 2050, mainly because in two decades the AC transmission network expands a lot (see Table 3-12: 60000 MW in 2030-40 decade, and 57000MW in 2040-50 decade), improving the possibility to dispatch power plants more efficiently and less costly, and allowing taking advantage of the high amount of energy available from renewable energy sources. Also in the **Blue** storyline the program finds its optimum by installing a high amount of AC transmission capacity (44000 MW in the decade 2030-40, and 49000 MW in the decade 2040-50), allowing to reduce the initially high operative costs (at 2030). The **Yellow** and **Red** storyline show a different behaviour: concerning the first one, operative costs at 2050 are more or less at the same level as at 2030. This is due to the fact that CO_2 and fuel costs in the **Yellow** Storyline are low, while new capacity installation costs are high: the program decides to install little new AC capacity (in total 28000 MW for the decade 2030-40 and 16000 for the decade 2040-50). The high CO_2 and fuel costs together with the lack of new line installation (resulting in an under dimensioned network) cause, also in the **Red** storyline, an increasing trend of the operative costs from 2030 to 2050.

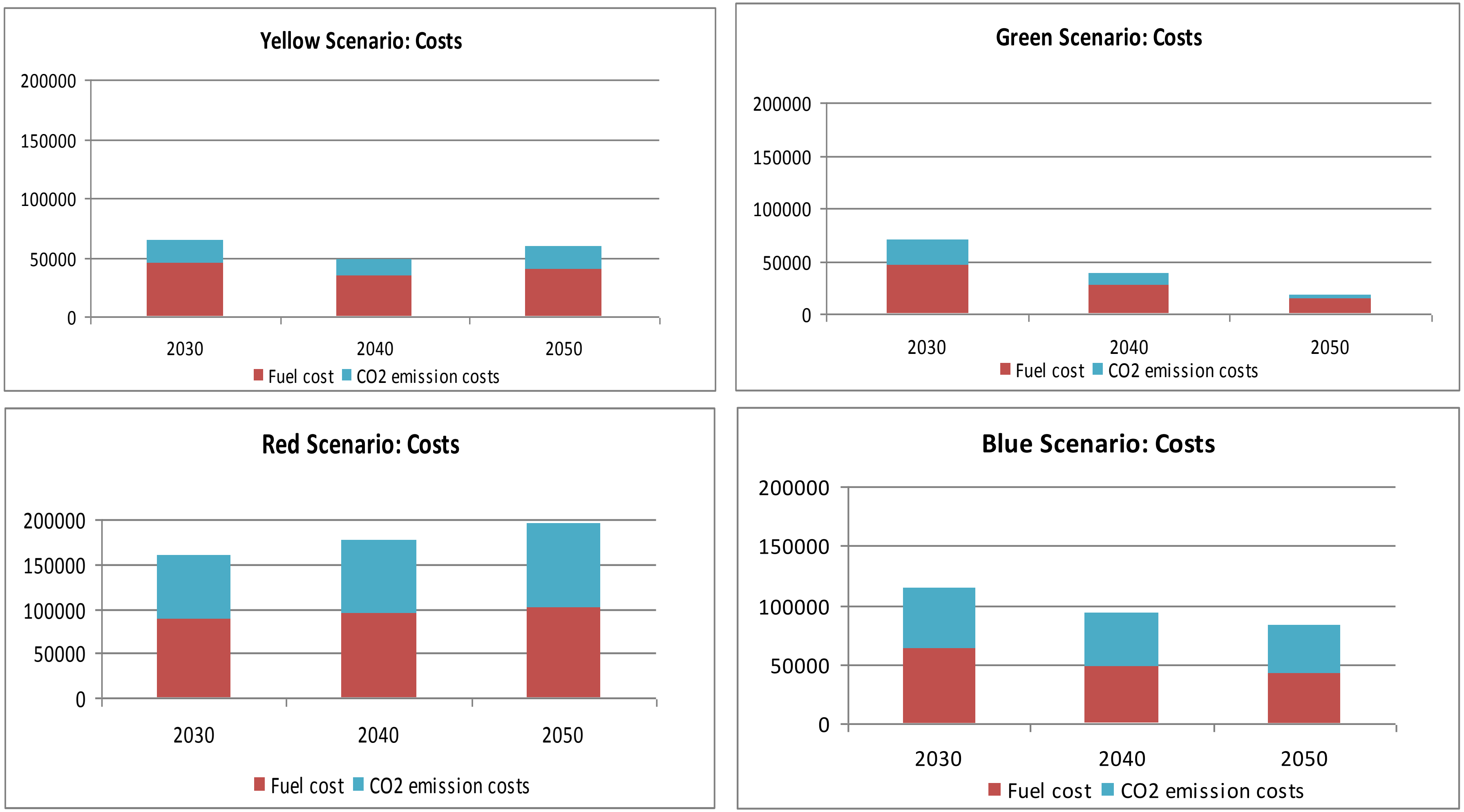


Figure 3-18 – Overview of operational cost across four storylines [in M€]

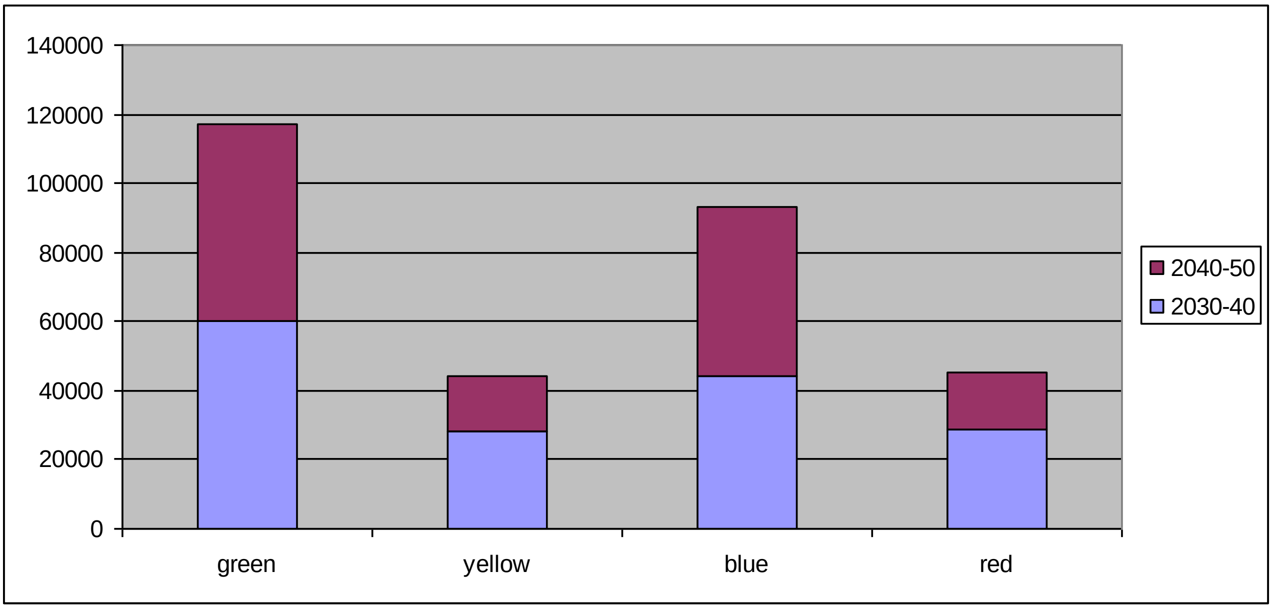


Figure 3-19 New installation capacity [MW]

Focusing on grid expansion, the **Yellow** and **Red** Storylines are the ones in which the installation of new capacity is lower. In the **Yellow** storyline this happens because installation costs are high, especially compared with the low operative costs. The **Red** storyline “decides” to install only this amount of new MWs because, on one hand, installation costs are very high, and, on the other hand, the very low amount of energy available from renewable energy sources does not justify the necessity of major installations.
A consequence of these different levels of capacity installation can be observed in the number of line congested (see):

- In the **Green** storyline, the high amount of new capacity installed keep the network debottlenecked: only 10 lines are congested more than 90% of the hours in 2050;
- In the **Blue** storyline, the high amount of new capacity installed is useful in order to face the quite high demand level, but is not enough for network debottlenecking;
- In the **Yellow** storyline, the amount of installed new capacity is insufficient; however, as demand stays low, the network is not significantly congested: only 10 lines are congested more than 90% of the hours in 2050, similar results for the 2050 **Green** storyline;
- In the **Red** storyline, the program decides not to install many lines: actually, installation costs are the highest among the four storylines. This fact, together with the high load demand, results in a high number of congested lines (22).

Regarding the electricity balance of countries, it can be observed that Germany experiences a large power deficit in all storylines. This situation is due to the very high Germany load level with respect to the installed capacity (that from 2030 to 2050 is constant or, in some storylines, decreasing) and, additionally, due to the availability of inexpensive energy for RES coming from neighbouring regions. Installation of new interconnection capacity allows for an exploitation of this energy. This replaces the use of coal and gas power plants, which have relatively higher operational costs. Surely, the fact that the national networks are neglected (and consequently national bottlenecks are not taken into account) could bring to the overestimation of the exploitation of this RES energy. Furthermore, with the closure of the nuclear power stations, if we exclude RES (that is not able to satisfy entirely the inner load); Germany has a high-cost coal power park.

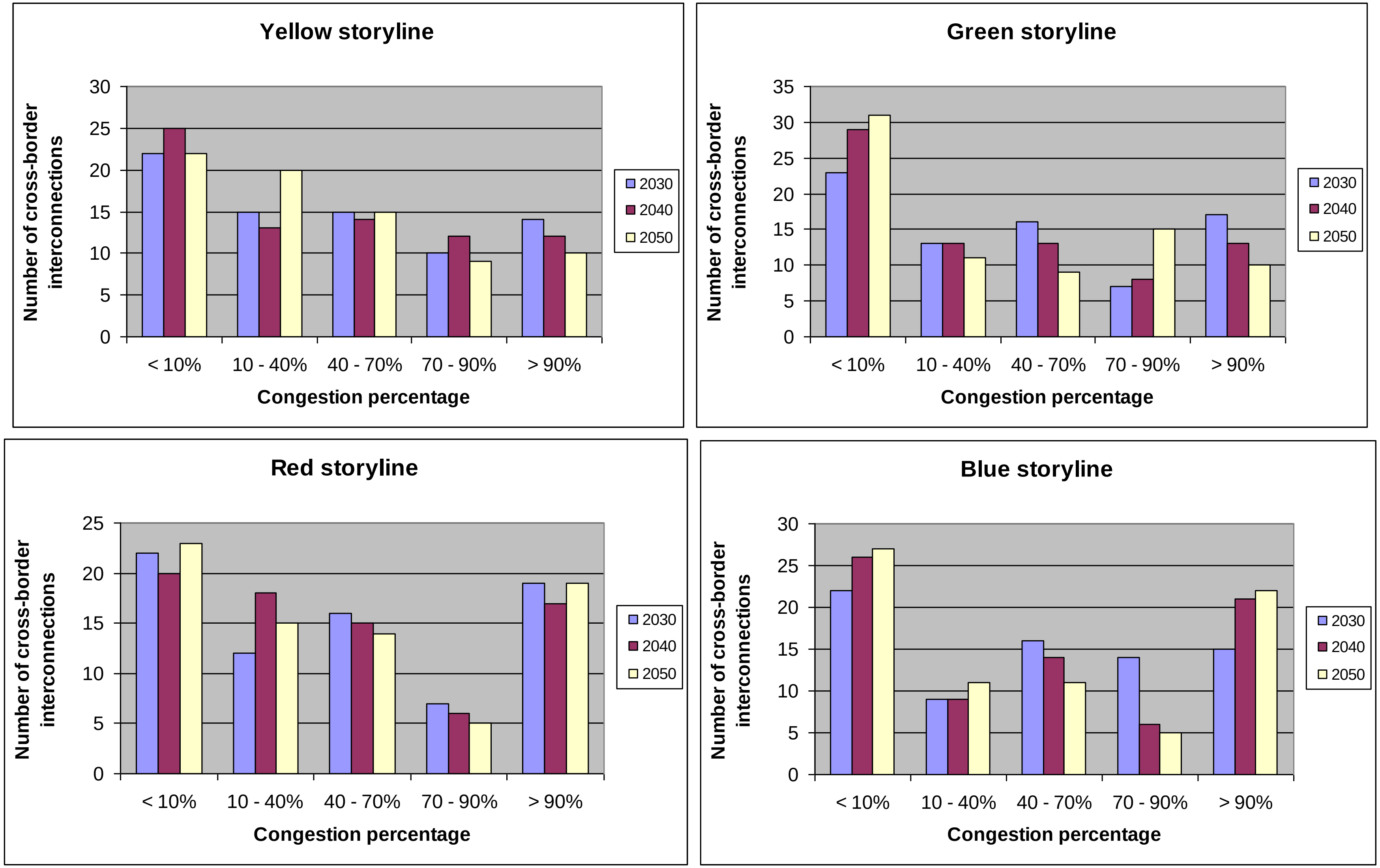


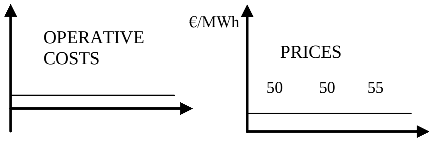
Figure 3-20 – Overview of level of congestion across storylines

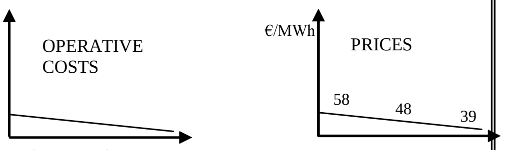
Concerning the different figures for the yearly medium prices (€/MWh) in the different storylines:

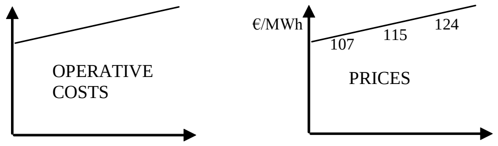
- In the **Yellow** storyline, 2030 prices are low (see Table 3-15), and remain at this level in the two next decades;
- In the **Green** storyline, 2030 prices are low, and decrease in the two next decades;
- In **Red** storyline, 2030 prices are very high, and increase in the two next decades;
- In the **Blue** storyline, 2030 prices are quite high, and keep constant in the next two decades.

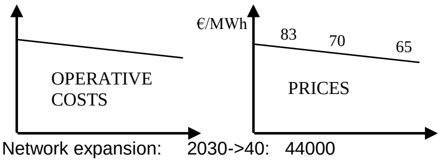
	2030	2040	2050
Red	107	115	124
Yellow	50	50	55
Blue	83	70	65
Green	58	48	39

Table 3-15 - medium electricity prices (€/MWh).

<table>
<tr><th>YELLOW</th><th>GREEN</th></tr>
<tr><td>


Network expansion: 2030->2040: 28000
2040->2050: 16000
Low amount because operative costs are already low (i.e low demand level)
Number of lined congested more than 90%of hours at 2050:10
</td><td>


Network expansion: 2030->2040: 60000
2040->2050: 57000
High amount to exploit energy from RES sources
Number of lined congested more than 90%of hours at 2050: 10
</td></tr>
<tr><th>RED</th><th>BLUE</th></tr>
<tr><td>


Network expansion: 2030->40: 29000
2040->2050: 16000
Low amount because expansions costs are very high
Number of lined congested more than 90%of hours at 2050:22
</td><td>


Network expansion: 2030->40: 44000
2040->2050: 49000
High amount in order to exploit RES energy and decrease operative costs but high demand level
Number of lined congested more than 90%of hours at 2050:18
</td></tr>
</table>

Table 3-16 Overview of results across the four storylines

4 RESULTS GAS MARKET ANALYSIS

4.1 Introduction

This chapter presents the results of the storyline analysis obtained with the gas market model GASTALE. Data acquired in the gas market analysis is also available via the web-based user-interface developed in the SUSPLAN project. This tool may be accessed via http://www.susplan.eu. As was described in Chapter 2 the storyline analysis adopted in this study involved a continuous interaction between the electricity and gas models and led to interdependency between the results of each model. The goal of this study is to identify key future infrastructure developments for both the electricity and gas market and provide recommendations for an efficient and effective development of energy infrastructure in the future. This essentially requires a combined assessment of electricity and gas infrastructure, which is provided in Chapter 5.

For a clear comprehension of the underlying developments in the combined infrastructure assessment, the previous chapter discussed the developments on the electricity market separately, whereas this chapter presents the results on gas market developments. Whereas the focus of the study is both on energy infrastructure developments and the manner in which these are affected by the transition to a more sustainable electricity system, a proper understanding of identified infrastructure developments requires a basic understanding of developments on other – non-infrastructure – aspects of the gas market, such as gas prices, gas demand developments and the sourcing of gas. Section 4.2 discusses the gas market developments in each of the four storylines. Thereafter, Section 4.3 presents a comparative assessment of the four storylines, with a strong focus on transnational infrastructure developments. These sections should altogether lead to a good understanding of the different developments on the gas market in the four storylines, which allows for a better comprehension of the overall assessment of gas and electricity infrastructure developments in Chapter 5.

4.2 Results per storyline

This section is divided into four parts, with each part devoted to one of the four storylines. The main insights from each of the four assessed storylines are discussed in separate subsections (0-4.2.4). The section thereafter (Section 4.3) provides a comparative assessment of all four storylines. Before turning to the storyline descriptions, some comments need to be made regarding the time horizon adopted in the presentation of results. Chapter 2 explained that the focus of this study is on the period 2030-2050. In order to bridge the period 2010-2030, a number of assumptions have been made and supportive model analyses performed. This was extensively discussed in Section 2.2. The storyline results presented in the next sections will generally cover the whole period 2010-2050 and not just focus on the latter two decades. A reason for doing so is to provide the reader with a proper point of reference for results in the period 2030-2050. In the text accompanying the figures, the focus will largely be on the developments in 2030-2050.

4.2.1 Red storyline

Summary of storyline results:

- Gas demand in the EU increase with 313 billion m^3 to 838 billion m^3 in 2050.
- UK, Germany and Italy remain large gas consumers, Poland becomes another large consumer.
- The increase in gas demand largely originates from the electricity sector.
- The large increase in the EU gas import gap is accommodated by pipeline supplies (75%) and LNG supplies (25%).
- Natural gas prices increase by about 12% in 2050 compared to the 2010 level.
- Large expansion of EU internal pipeline capacity and EU external LNG and pipeline import capacity is required.
- Main transit corridors are the Southern Europe pipelines bringing gas from Africa to Spain and Italy and the South-eastern European pipelines bringing gas from Russia and Central Asia to central Europe.
- The UK, Iberian Peninsula and Italy become the most important LNG import hubs in Europe.

Below we discuss the main observations regarding gas market developments in the **Red** storyline. This discussion is supported by Figure 4-1, Figure 4-2, Figure 4-3, and Figure 4-4. These figures show the **Red** storyline developments concerning the EU demand for gas, EU gas prices, sourcing of gas consumed in the EU and the investment requirements.

Gas demand

The **Red** storyline depicts a business as usual future where gas has a relatively large share in electricity production. From 2010 onwards the demand for gas in the electricity generation sector strongly increases as gas is the preferred fuel. The increase in gas demand between 2010 and 2050 is almost fully accounted for by the power sector. Its share in total EU gas demand increases from little over 30% to nearly 50% in 2050. Gas demand in the residential and industrial sector also increases over this time span, but at a lower and more constant pace. These gas demand developments ultimately lead to a total gas demand in the EU in 2050 of 838 billion m^3 per year, which is an increase of 312 billion m^3 compared with 2010. The UK, Germany and Italy remain the largest gas consuming countries, whereas the gas demand in other regions, most notably Poland, continues to increase strongly.

Gas supply

Contrasting with the increasing demand for gas is the development in the supply from indigenous EU gas production. When excluding the non-EU member Norway, total EU gas production steadily declines from about 163 billion m^3 per year in 2010 to only about 30 billion m^3 per year in 2050. This decline causes a very large gap between required gas supplies and indigenous resources in 2050 of about 815 billion m^3. This implies an increase in gas supply gap of 125%. In the **Red** storyline the 2050 supply gap is addressed by LNG gas supplies for about 25% and by pipeline supplies for about 75%. An increase in LNG supplies takes place in the period 2010 and 2040, whereas a strong increase in pipeline supplies from outside the EU continue until 2050.

Gas prices
The EU average gas price in the **Red** storyline increase from a current level of about 6.3 € per GJ to about 7.0 € per GJ in 2050 (an 11% increase).[30] Prices in the residential sector are generally higher than the average due to additional distribution costs and taxes, whereas the prices for the power sector and industrial sector are lower. A sustained difference between gas prices prevailing in the different gas consumer categories is storyline independent, and hence, is observed in the results of all four storylines. The additional margin on top of wholesale gas market prices is the lowest for gas consumers in the electricity sector, which is conform reality. Gas prices in the EU member states bordering main gas supply regions tend to have gas prices somewhat below the EU-average.

Infrastructure investment
The large increase in the supply gas between EU gas demand and EU gas production leads to a large increase in EU external gas supplies and a consequent need to strengthening the external gas supply infrastructure. Not reflected in Figure 4-4, but an important pre-condition in especially this storyline, is that sufficient investment takes place in new gas production assets across large gas exporting countries such as Russia and Algeria. The largest increase in gas infrastructure (LNG facilities and pipelines alike) requirements is observed in the 2010-2030 period, where the internal depletion of EU is the strongest and demand growth still robust. An important observation is that not only external supply lines need to be upgraded, but that also gas pipeline capacity within the EU requires strong investment. Although there is already considerable EU internal gas pipeline capacity, further capacity upgrades are necessary to accommodate the changing gas flow pattern within Europe. Over the period 2020-2050, on average every additional 3 ½ billion m^3 of EU import capacity (either LNG or pipeline) needs to be matched with an additional 1 billion m^3 of EU internal pipeline capacity at some point. Towards the end of the 2010-2050 period the level of required infrastructure investment significantly reduces due to the much slower increase in overall gas demand. In each decade until 2050, required investment in pipeline capacity dominates required investment in LNG capacity: this means that ´piped gas´ will be the main way of transporting gas to the EU market.

Supply corridors and hubs
In the **Red** storyline a particularly large increase in EU gas supply pipelines takes place in the Algeria – Southern Europe corridor (i.e. Spain / Italy), and the Turkey – South-East Europe corridor. The latter can be related to specific investment projects of Nabucco and South Stream, but in order to accommodate the required EU external gas supplies even further expansion of these corridors is required beyond what is currently proposed. I.e. there are also investments in these corridors beyond 2030, albeit at a much lower level. The North Stream project supplying gas from Russia to Germany is realized but not further expanded in the 2030-2050 period. Large increases in LNG import capacity occur in the UK and the Iberian Peninsula in the period 2010 to 2020 and, beyond that period, especially in Italy. In the 2010-2050 period, about 86% of LNG import capacity investment takes place in Italy (29%), the UK (21%), Spain (19%) and the Netherlands (17%), which leads us to conclude that these countries can be considered LNG hubs in their respective European regions. The investments in EU external import capacity triggers investment in EU internal infrastructure, especially in particular corridors. Main corridor investments are for example required to further distribute external supplies to EU gas consuming

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[30] Gas prices from GASTALE output have been converted from € per m^3 into € per GJ using an average calorific value for natural gas of 40 MJ per m^3 (IEA natural gas information 2010).

countries further into Europe. There is a large expansion of pipeline capacity between Italy and its Northern neighbours, which reflects the need to transit (of part of) LNG imports further into central Europe. The same holds for the Spanish - French pipeline connection. Another corridor heavily invested in is the South-East Europe corridor that further distributes 'Nabucco and South Stream supplies' to central Europe. This storyline also witnesses an increase in a North - South corridor in Eastern Europe, providing more flexibility (i.e. security of supply) to countries like Poland, the Czech Republic, the Baltic States and the Balkan region. It goes without saying that Turkey is a crucial transit country in the South-Eastern Europe corridor. Although part of the infrastructure investments around Turkey aim to bring more gas to Europe, part is also needed to accommodate gas demand growth in Turkey itself.

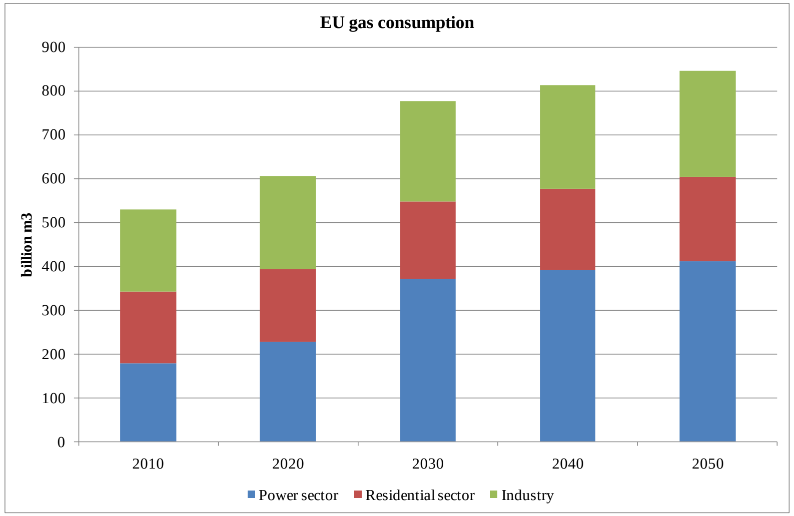

Figure 4-1 EU gas consumption in the Red storyline

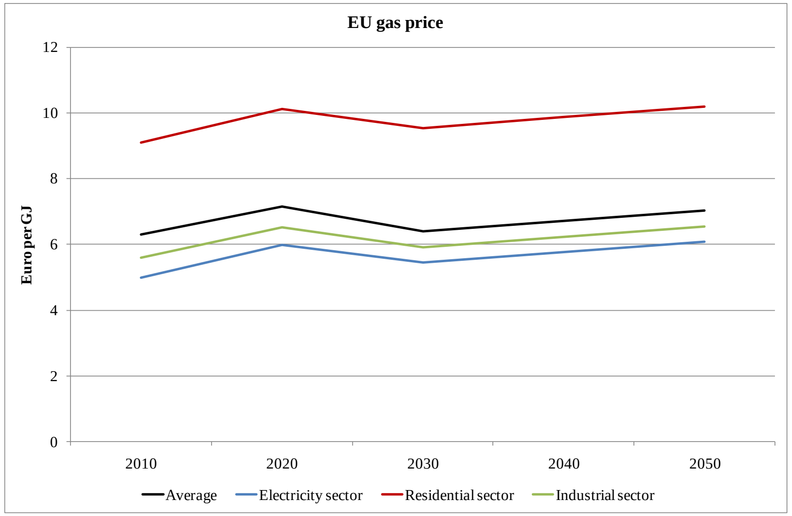

Figure 4-2 EU gas price in the Red storyline

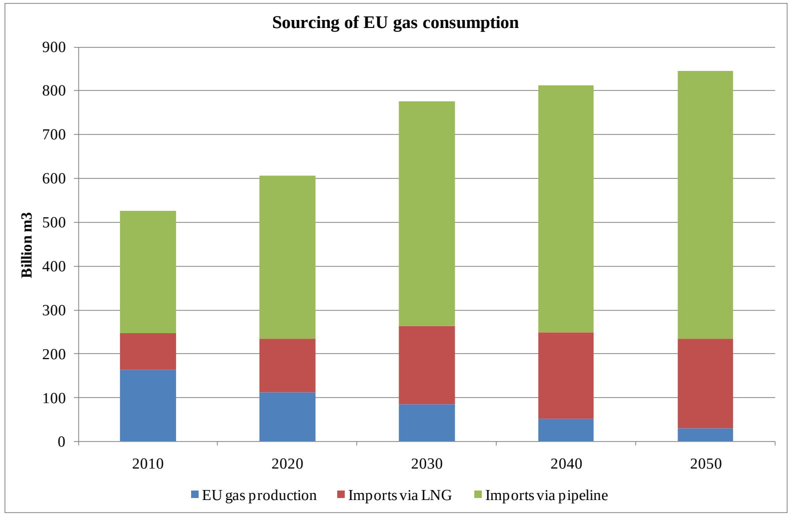

Figure 4-3 Sources of EU gas consumption in the Red storyline

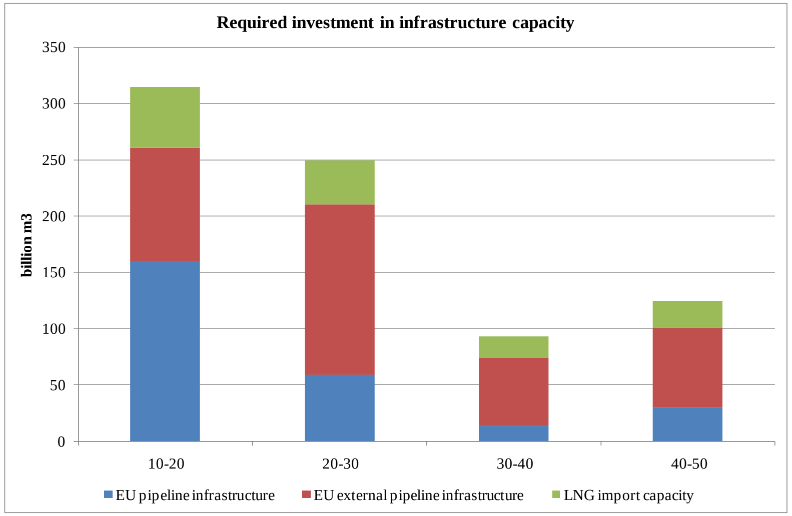

Figure 4-4 Required investment in the Red storyline

4.2.2 Yellow storyline

Summary of storyline results:

- Total gas demand decreases and remains below the 2010 level up to 2050.
- The relative importance of gas in the electricity generation sector remains considerably high due to the relatively slow development of renewable energy technologies.
- EU import dependency remains high with a dominant role for Russian, Norwegian and Algerian gas supplies.
- The average EU gas price is relatively low.
- There are relatively little investment requirements after the gas demand peak in 2020.
- Turkey remains an important gas transit hub for EU gas supplies.
- EU external gas supplies are dominated by pipeline supplies, with relatively small role for LNG supplies.

Below we discuss the main observations regarding gas market developments in the Yellow storyline. This discussion is supported by Figure 4-5, Figure 4-6, Figure 4-7, and Figure 4-8. These figures show the Yellow storyline developments concerning the EU demand for gas, EU gas prices, sourcing of gas consumed in the EU and the investment requirements.

Gas demand

The Yellow storyline represents a future energy system where there is a general positive stand towards a move to a more sustainable energy system but renewable energy technology developments are not strongly advancing. This fore mostly translates into a lower overall energy demand and a lower demand for both electricity and gas. The future demand for gas is relatively low compared to the 2010 level but the share of gas in the electricity sector remains relatively high – due to the earlier mentioned relatively slow development and adoption of renewable energy technologies. After a peak in total gas demand in 2020 of about 600 billion m^3 per year, total demand decreases to about 480 billion m^3 in 2050. However, there is no continuous decline in gas demand: the demand for gas increases a bit in the 2040-2050 decade. This is fully caused by developments in the power sector, where gas demand increases from 161 to 189 billion m^3 from 2040 to 2050. The total production of electricity based on gas decreases from 1014 TWh in 2030 to 790 TWh in 2040, before increasing again to 982 TWh. The share of gas demand from the power sector in total gas demand increases from little over 30% in 2010 to about 40% in 2050. Total EU gas demand in the Yellow storyline remarkably increases from 2040 to 2050. This can be explained as follows. This 'sudden' increase is directly related to developments in the power generation sector in general, and the power generation sector in the UK, Poland, the Netherlands, Italy and Spain in particular.

Gas supply

The decrease in demand for gas from 2020 onwards does not relieve the EU from its challenging task to bridge a considerable gap between total gas demand and EU gas production. The supply gap increases from 363 billion m^3 per year in 2010 to 450 billion m^3 per year in 2050. The majority of this import gap is filled with pipeline gas from Russia and Norway, with the remainder of the gas being served by LNG and pipeline gas from Algeria. Together these three countries provide over ¾ of EU external gas supplies. Overall import dependency in 2050 will be about 93%, compared to about 70% in 2010. EU gas production only amounts to about 30 billion m^3 in 2050. In absolute terms the supply of LNG to the EU market peaks in 2020 at about 120 billion m^3 per year.

Gas prices
The average EU gas price in the 2030 to 2050 period is at a relatively low level of 5.7 € per GJ. This reflects the relatively low level of gas demand and the (marginal) cost of acquiring gas from the major EU external gas producing countries. The gas price in the power, residential and industrial sector remains relatively low compared to the 2010 price level and is more or less constant until 2050.

Infrastructure investment
Due to the decrease in gas demand from its peak in 2020 (at about 605 billion m^3) to about 455 billion m^3 in 2040, there are relatively little investment requirements for gas infrastructure after 2020. The further infrastructure requirements that do materialize after 2020 partly relate to the compensating of part of the indigenous production that further decreases after 2020, but predominantly facilitate an increase in gas demand in non-EU member state Turkey. Turkey is a major transit country for gas destined for Europe but also sees an increase in gas consumption over the 2010-2050 period. A large part of infrastructure investments between Turkey and its neighbours aims to facilitate increasing gas supply to the EU, but certainly not all. Following the earlier observation that the role of LNG gas in-flows reduces over time, investment in new LNG terminals is only observed in the 2010-2020 period (in order to 'serve' the 2020 peak in gas demand) but dwindles in later decades. In the latter decades investment in additional supply pipelines are preferred over LNG import facility investments based on economic considerations.

Supply corridors and hubs
External gas supplies are largely accommodated within the existing and planned East-West corridors when Russian gas supplies are concerned. This essentially means that once realized the North Stream, Nabucco and South Stream pipelines are for large part sufficient for Europe when it comes to sourcing of gas. Associated internal pipeline investments concern the Balkan / central European corridors, and to much lesser extent upgrading of North-West European infrastructure to accommodate Russian supplies from North Stream. Investment in LNG import capacity in the 2010-2030 period takes place in Spain (35% of total LNG investment in the 2010-2050 period), Italy (16%), the Netherlands (16%) and the Balkan region 12%).

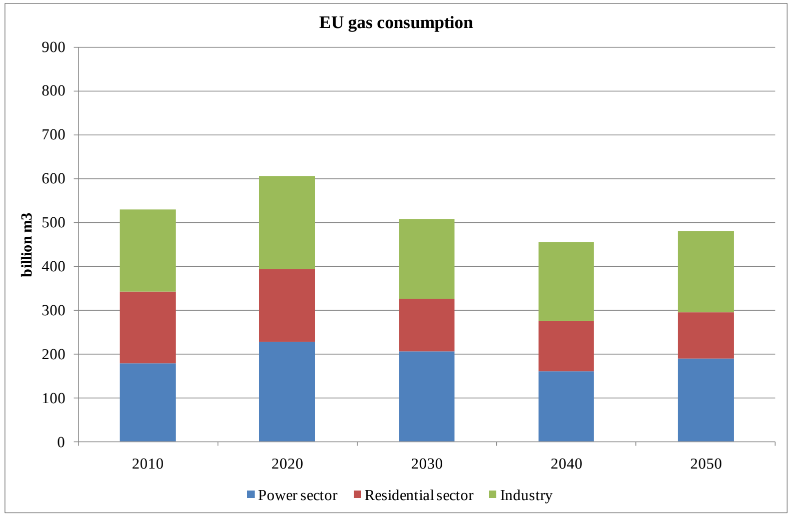

Figure 4-5 EU gas consumption in the Yellow storyline

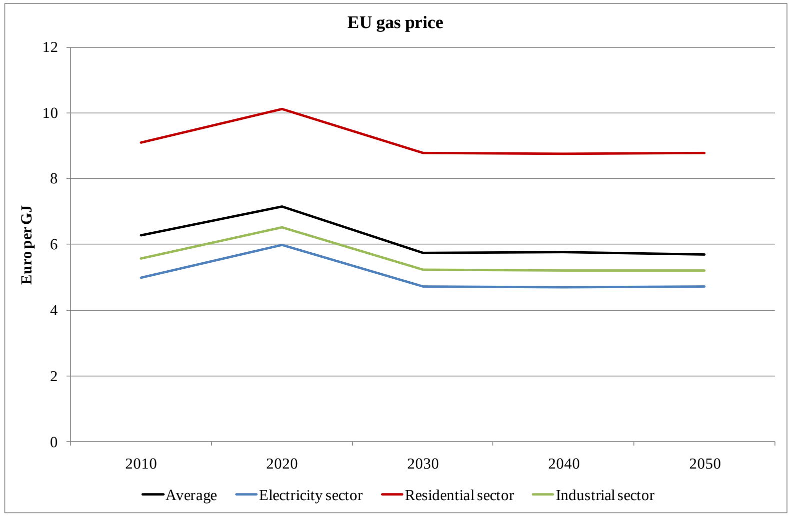

Figure 4-6 EU gas price in the Yellow storyline

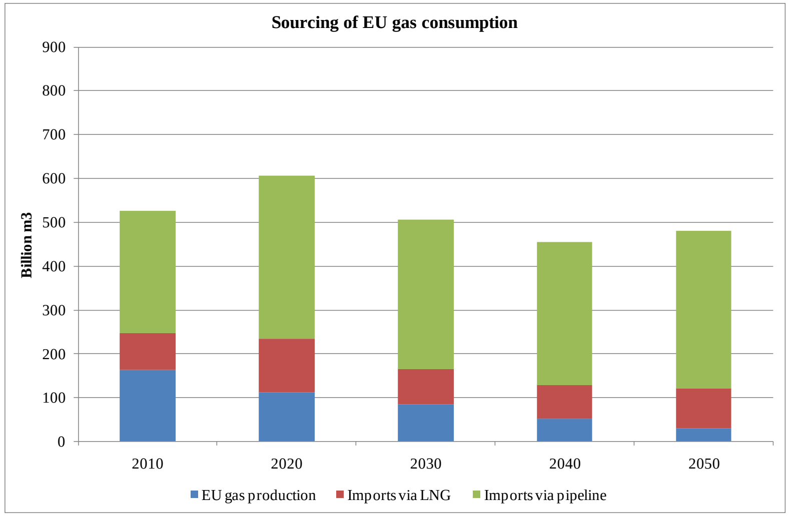

Figure 4-7 Sources of EU gas consumption in the Yellow storyline

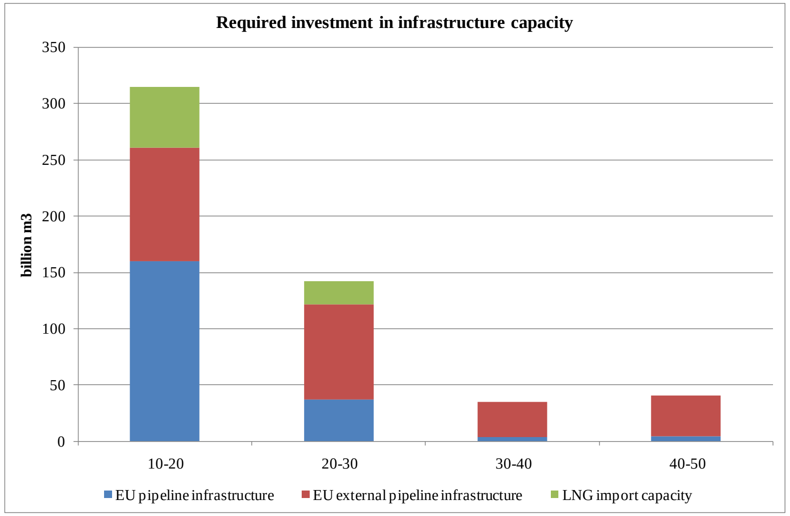

Figure 4-8 Required investment in the Yellow storyline

4.2.3 Blue storyline

Summary of storyline results:

- Total gas EU demand remains relatively high. Although there is substantial technological progress in renewable energy technologies a lack of societal acceptance puts a break on large-scale deployment of renewable energy.
- The exception concerns the large-scale development of offshore wind power based electricity generation and large-scale solar powered electricity generation, which causes substantial differences in gas demand developments across Europe.
- Gas demand strongly decreases in the North Sea region (i.e. the UK) and Italy, but increases strongly in the Balkan region and Poland.
- The EU faces a gap between gas demand and indigenous production of 432 billion m^3 in 2050, which is accommodated by pipeline supplies (50%) and LNG supplies (50%).
- The average EU gas price reaches a low in 2030 due to a large availability of gas infrastructure but then increases to a peak in 2050.
- Gas infrastructure investments are concentrated in the period before 2030, with the necessity for additional investments reduced after 2030 due to large-scale penetration of large-scale wind and solar.
- Important gas corridors in Europe are the North-South corridors in Western-Europe on the one hand and Eastern Europe in the other. Italy turns into an important LNG hub and gas transit country towards 2050.

Below we discuss the main observations regarding gas market developments in the **Blue** storyline. This discussion is supported by Figure 4-9, Figure 4-10, Figure 4-11, and Figure 4-12. These figures show the **Blue** storyline developments concerning the EU demand for gas, EU gas prices, sourcing of gas consumed in the EU and the investment requirements.

Gas demand

Total energy demand in the **Blue** storyline remains relatively high due to a somewhat less positive stand towards the move to a sustainable energy future. Nevertheless, developments regarding new energy technologies are promising, giving rise to a still quite substantial level of renewable in the overall energy mix. The increase in overall energy demand, which is especially robust in the period until 2030, induces a substantial increase in gas demand over the same period due to a large role for gas in the power sector. This leads to an increase in gas demand from 526 billion m^3 per year in 2010 to about 695 billion m^3 per year at its peak in 2030. Of this increase, 70% is due to power sector developments, and only a 6% of this increase originates from the residential sector. However, strong differences between EU member countries and regions are observed. There is for example a strong decrease in the gas demand from the UK and Dutch power sector from 2020 onwards due to the large penetration of renewable energy (mainly wind) at the North Sea, and also gas demand in Germany decreases due to additional wind-based electricity production. In addition, there is a large decrease in the gas demand from the Italian power generation sector from 2030 onwards, which may be explained by a large increase in electricity imports from outside the EU, which mainly corresponds to increased renewable electricity generation based on solar power (the Desertec project). Imports increase from about 5 TWh n 2030 to 25 TWh in 2050. This increase in imports is facilitated by a large expansion of electricity interconnection capacity (as explained in Section 3.1.3). The power sector demand for gas in the Balkan region and in Poland on the other hand quite strongly increases from 2010 to 2050. Growth in residential sector and industrial sector gas demand continue to increase in the 2030-2050 period, at a relative constant rate of respectively 0.4% and 0.7% per annum. The demand for gas in the electricity sector however strongly decreases after 2030 due to the stronger penetration of renewable energy technologies in that sector. More than ¾ of the increase in renewable electricity is due to wind-powered generation units. Gas demand in that sector is reduced with about 100 billion m^3 between 2030 and 2050. This power generation sector impact dominates the impact of increasing demand in the residential and industrial sectors and leads to a small overall decrease in gas demand from 2030 to 2040, and to a stagnation of gas demand from 2040 to 2050.

Gas supply
A steady decline in EU gas production from about 162 billion m^3 per year in 2010 to about 30 billion m^3 per year in 2050 in combination with an initially increasing demand for gas and a relatively stagnating gas demand later on induces a sharp increase in EU import dependency. Gas import dependency increases from about 70% in 2010 to about 95% in 2050. This implies a total of EU gas imports of about 432 billion m^3 in 2050, of which 71% is supplied by the likes of Russia, Norway and Algeria. The increase in gas demand from 2010 to 2030 is met by an equally shared increase in LNG imports and pipeline imports. After 2030, both LNG and pipeline imports remain more or less constant at 460 and 135 billion m^3 per year respectively.

Gas prices
The average EU gas price for end-users peaks in the year 2020 at 7.2 € per GJ, significantly decreases to 6.2 € per GJ in 2030 (due to the significant expansion of EU gas supply capacity until 2020), before slowly increasing again towards 2050 to the 2030 level of 7.2 € per GJ.

Infrastructure investment
Large infrastructure investments are observed in the 2020 to 2030 decade, additional to the large-scale investments in infrastructure identified for the 2010-2020 period. The expansion largely follows from the increased demand for gas and the need to compensate for declining EU internal gas supplies with external sources. In the 2020 to 2030 decade an additional internal EU pipeline capacity of 75 billion m^3 needs to be added to enable additional supplies via the additional external EU import capacity of 200 billion m^3 per year over that same period. The increase in the penetration of renewable electricity generation technologies after 2030 strongly reduces the need for further capacity investments after 2030.

Supply corridors and hubs
Considerable investment in pipeline supply infrastructure is still observed in the Balkan region, and the North-South corridor in Eastern Europe. The investment in Eastern Europe is related to the gas demand increase in the power sector in some Eastern European countries and regions, most notably Poland and the Balkan. In addition there is some investment in LNG import capacity in Italy that facilitates transit of gas to some central European countries. A traditional corridor that remains important throughout the period until 2050 is the North-South corridor in North-West Europe from Norway to Germany/France/Belgium, and the East/West corridor bringing gas from Russia to Central / Eastern Europe. Due to the decrease in UK gas consumption in this storyline (due to the penetration of large-scale wind parks in the electricity sector) the UK turns into a significant transit country for gas after 2020. This is facilitated by the LNG import capacity and Norwegian supply lines that were heavily used in the period until 2030. Outside Europe, Turkey remains a significant gas hub for various gas supply lines. Also Italy becomes more of a gas transit rather than gas destination country after 2030 due to its supply pipelines with North-Africa and its LNG import capacity.

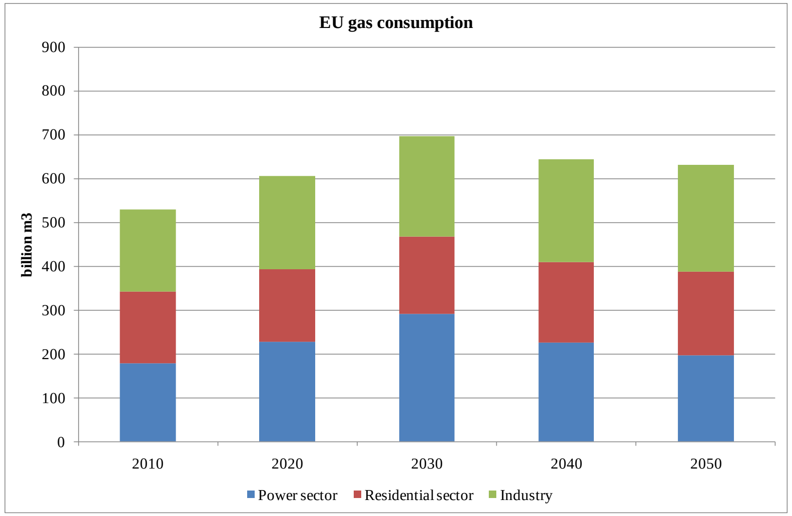

Figure 4-9 EU gas consumption in the Blue storyline

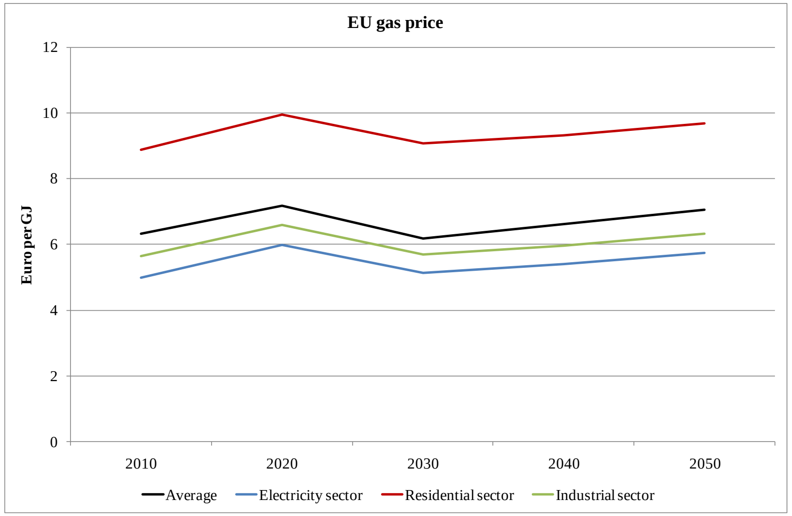

Figure 4-10 EU gas price in the Blue storyline

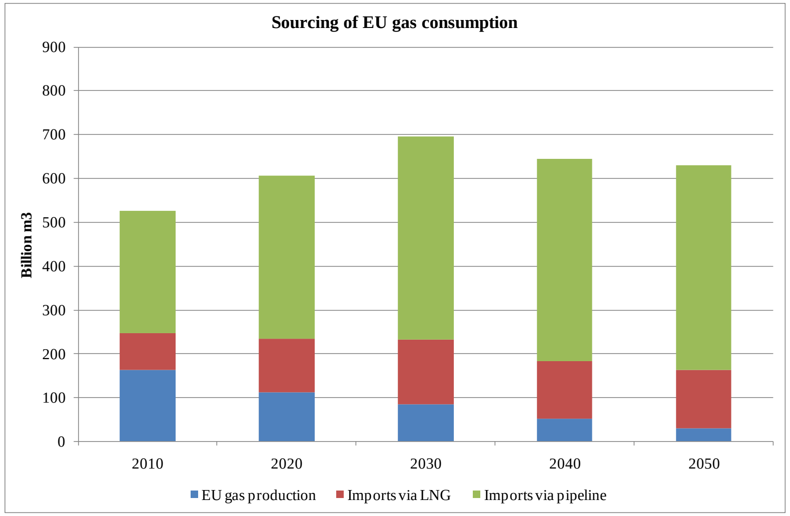

Figure 4-11 Sources of EU gas consumption in the Blue storyline

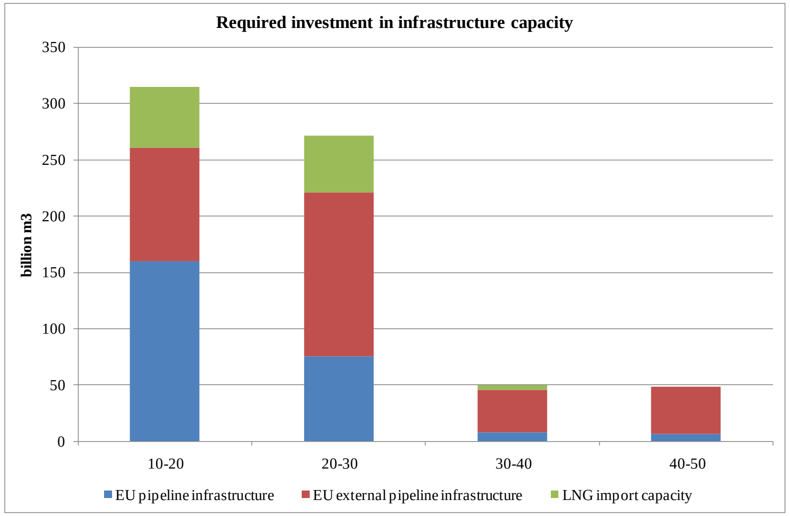

Figure 4-12 Required investment in the Blue storyline

4.2.4 Green storyline

Summary of storyline results:

- Gas demand strongly decreases, which puts a downward pressure on average EU gas prices to 2050.
- Investments in gas infrastructure within the EU are minimal after 2030 and there is only some investment in EU external gas import capacity, mainly in the southeast of the EU.
- Gas supplies mainly originate from Russia with pipelines being the main transport mode.

Below we discuss the main observations regarding gas market developments in the **Green** storyline. This discussion is supported by Figure 4-13, Figure 4-14, Figure 4-15, and Figure 4-16. These figures show the **Green** storyline developments concerning the EU demand for gas, EU gas prices, sourcing of gas consumed in the EU and the investment requirements.

Gas demand

The **Green** storyline represents a future with strong social support for a transition to a more sustainable energy system and a strong development and adoption of new renewable energy technologies. This leads to a relatively low demand for gas in the 2030-2050 period. Total EU gas demand peaks in 2020 at about 605 billion m^3 per year but thereafter rapidly decreases with an average of 2% per annum to a level of about 320 billion m^3 in 2050. The major part of the decrease is due to power sector developments. Smaller part of the reduction originates from energy efficiency measures implemented in the industrial and residential sectors. The picture differs somewhat for some specific EU member states or regions. The timing and rate of decline in gas demand for example differs, with Germany seeing a sharp decline in gas demand in 2020 and Italy only in 2030. This can be explained by country-specific electricity generation mix developments. Most other countries show a more gradual decrease in gas demand over time, starting generally in 2020.

Gas supply

The relatively low gas demand in the 2030-2050 period does not imply that the EU is no longer dependent on external gas supplies. EU gas production is still only at a level of 30 billion m^3 per year in 2050, meaning that an additional 290 billion m^3 needs to be sources externally. Import dependency in 2050 is at a level of 91%. Due to the large amount of available transport capacity between Russia and Europe, the largest share of external gas supplies (about 55%) comes from Russia. Only very small amounts of gas originate from less traditional suppliers such as Qatar, Iran and Egypt. Traditional suppliers Algeria, Norway and Russia together supply 81% of EU gas imports, which represents 73% of EU gas demand. The role of LNG in providing EU gas supplies is only limited: in 2050 17% of EU gas consumption is imported via LNG import terminals.

Gas prices

The average EU gas price drops from 2020 onwards as a result of the strong decline in the share of gas in the power sector, but remains more or less constant due to the higher share of the relatively higher-priced residential gas demand in total gas demand. The price for gas consumed in the power sector reaches only 4.5 € per GJ in 2050, coming down from a high of 6 € per GJ in 2020. This price level reflects that fact that due to overall low gas demand, marginal gas supplies to the EU gas market are not that expensive.

Infrastructure investment

When looking at 2020-2030 period there is some LNG investment in the Balkan (about 9 billion m^3) region and in Italy (12.5 billion m^3). The additional investment in Italian LNG import facilities relates to the fact that Italian gas demand in the power sector continues to increase until 2030 (instead of 2020 for most other countries and regions). This has to do with the penetration speed of renewable energy technologies in the Italian power sector. There are no significant infrastructure investments in pipelines towards and inside the EU after 2020. The only investments that do occur are some small capacity upgrades of a total of 7.5 billion m^3 in the Eastern part of Europe, and a capacity upgrade of EU external gas pipelines bringing gas to Turkey.

Supply corridors and hubs

The amount of gas transported through Europe significantly decreases over the 2010-2050 time span, with a substantial amount of pipeline links no longer in use at all by 2050 (except in situations where security of supply is threatened due to unforeseen interruptions in external gas supplies.. The main supply routes bringing the gas still required are the Russian pipelines to central Europe and to Germany. Smaller gas corridors include the Norwegian supply pipelines to the UK and to Germany, and the Turkish transit pipelines to South-East Europe.

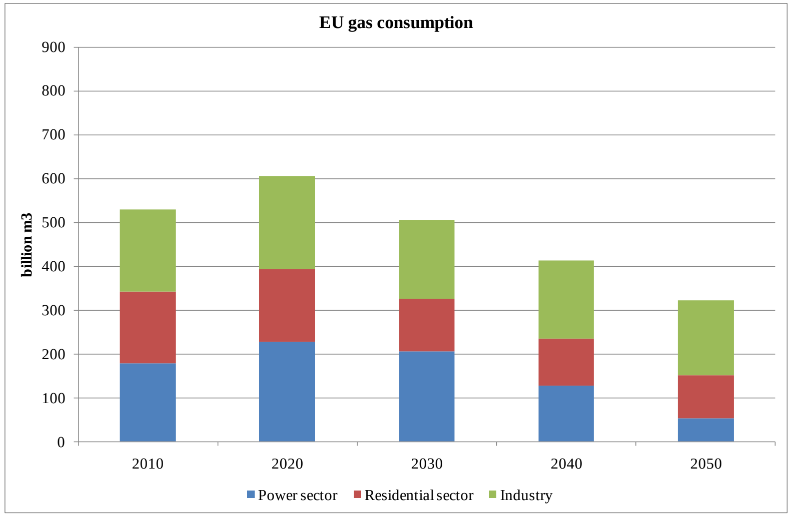

Figure 4-13 EU gas consumption in the Green storyline

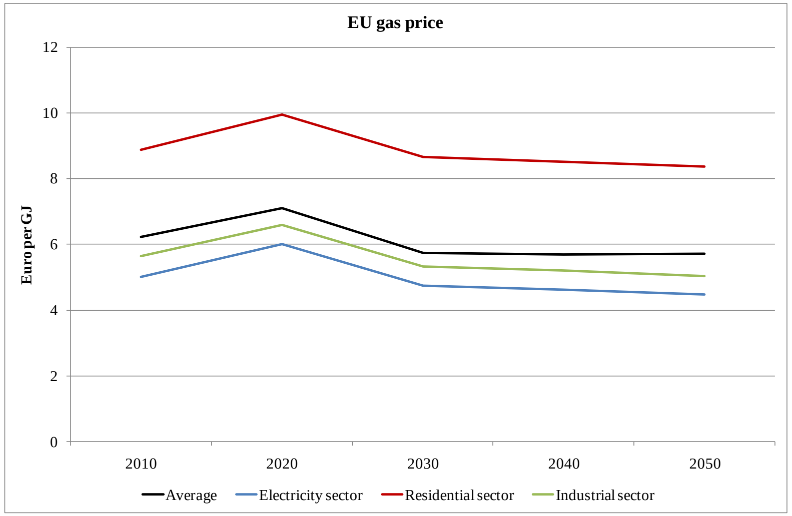

Figure 4-14 EU gas price in the Green storyline

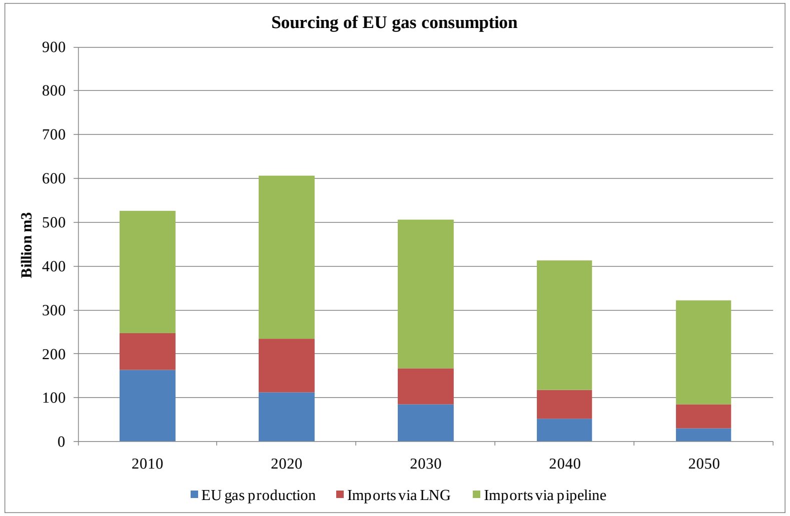

Figure 4-15 Sources of EU gas consumption in the Green storyline

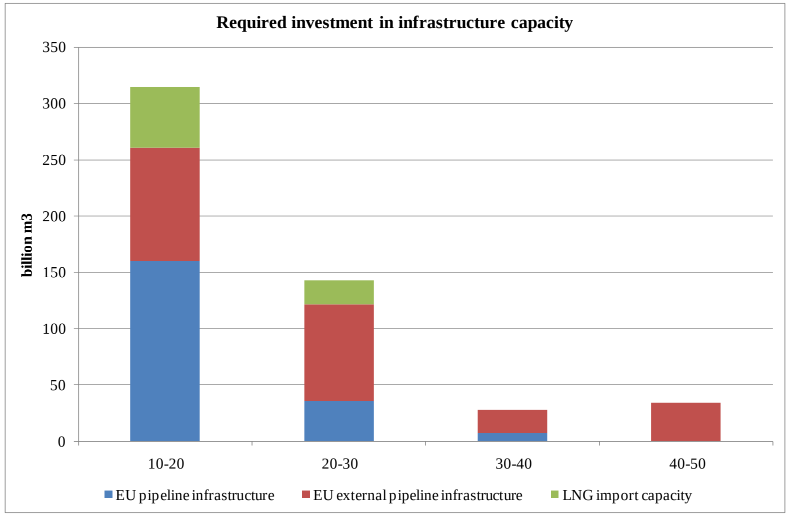

Figure 4-16 Required investment in the Green storyline

4.3 Storyline comparison

The comparison of storyline results in this section will focus on the implications of storyline drivers for gas infrastructure development and security of supply aspects. After a brief descriptive comparison of gas prices and gas demand developments in the four storylines we will turn to discussions on gas infrastructure investment requirements and security of supply aspects such as EU import dependency and EU gas sourcing and diversification.

Figure 4-17 presents the gas price development in the four different storylines. Due to similar background regarding fossil fuel prices the gas prices of the **Yellow** and **Green** storyline on the one hand and the **Red** and **Blue** storylines on the other show a similar development at comparable levels. Note that although it may seem as if the gas price paths in the **Yellow** and **Green** storyline are identical, there are actually small differences between the two. The depicted gas price levels reflect the cost of extracting, transporting and distributing gas to final consumers and include a profit margin for gas supply companies. The actual end-user prices may vary across different sectors with small consumers in the household sector paying higher prices and large consumers in the power generation and industrial sectors paying lower prices. Contrasting the high gas demand storyline's (**Red** & **Blue**) with the low gas demand storyline's (**Yellow** & **Green**) we observe that the average EU gas price in 2050 is about €1.4 per GJ lower in the latter than the former storyline. The price development between 2010 and 2020 that is common for all storyline's reflects the assumption of a business as usual storyline until the starting year of the modelling analyses (2030).

Figure 4-18 shows the demand for gas in the four storylines,[31] whereas Figure 4-19 shows the gas allocation of total gas demand across the three distinguished gas consuming sectors. From this figure we observe that the differences in gas demand are particularly driven by developments in the electricity sector, and, to a lesser extent, by developments in the residential sector. Regional or country-based increases or decreases in gas demand can be considered a primary driver for gas infrastructure investment of different types (see Figure 4-20). Three particular gas infrastructure investments can be distinguished: (1) investment in pipelines bringing gas to the EU border, (2) investment in LNG terminals facilitating EU gas imports, and (3) investment in gas pipelines within the EU facilitating a transit of gas received on the border. The following possible infrastructure impacts of overall EU gas demand and the dispersion of gas demand across the EU can be identified:

- A total increase in EU gas demand necessitates additional external gas supply and thus investment in gas pipelines to the EU and in LNG import capacity;
- A total increase in EU gas demand may necessitate investment in some EU internal pipeline connections for transit purposes;
- A decrease in total EU gas demand, with a strong concentration of decrease in particular regions may trigger investment in internal pipeline connections due to a change in gas flows within the EU.

[31] As was explained in Chapter 2 section 2.2, the gas demand developments after 2020 are the result of an assumed initial path for gas demand that has been adapted in a series of iterations between the gas and electricity model. The presented data points can thus not be considered as input, but are an actual output of the gas market model simulations.

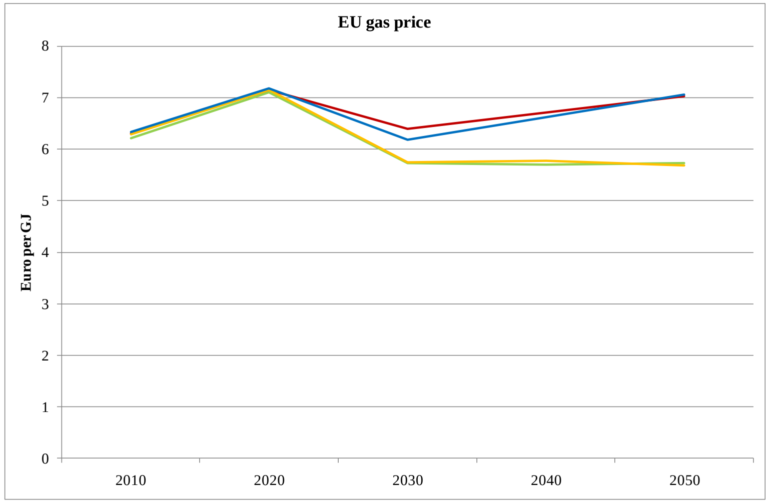

Figure 4-17 EU average gas price across storylines

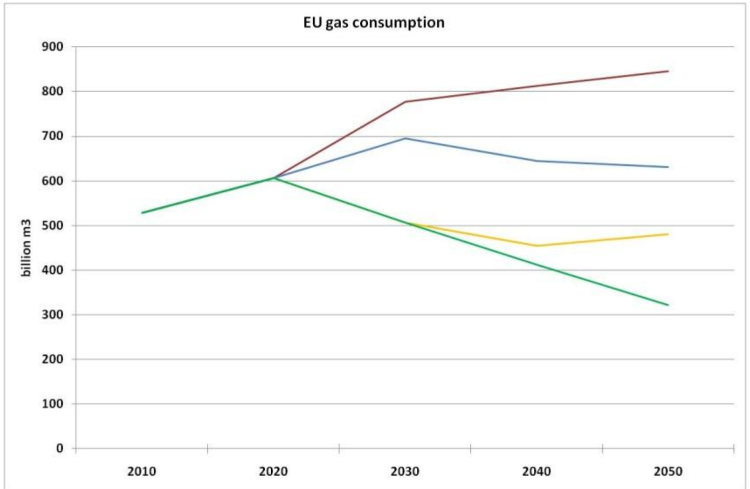

Figure 4-18 EU gas consumption across storylines

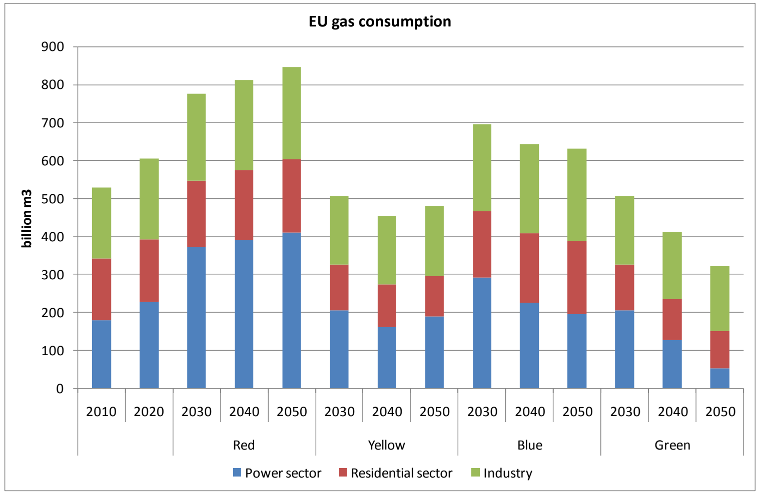

Figure 4-19 EU sectoral gas consumption across storylines

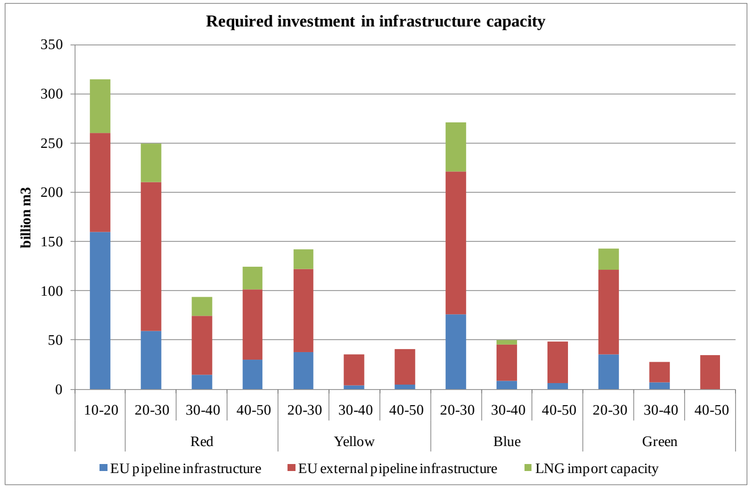

Figure 4-20 Required infrastructure investment across storylines

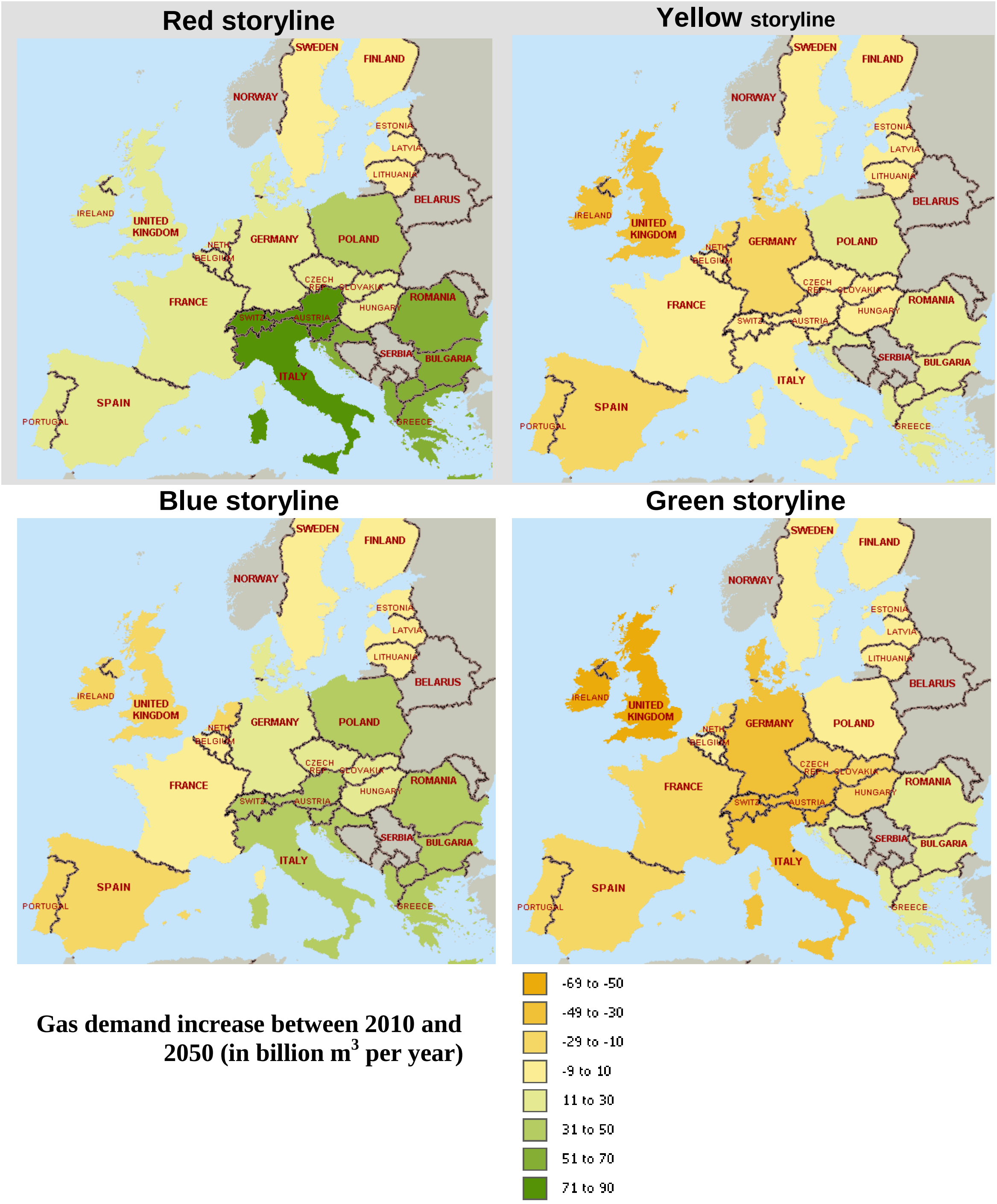

Figure 4-21 Gas demand developments across Europe between 2010 and 2050

The need for investment in new pipelines and LNG terminals enabling more gas imports from outside the EU is the highest in the **Red** storyline. This is explained by the high level of gas demand throughout the period, which results – given the presumed inability of the EU to increase its indigenous gas production – in a much higher gas import dependency. The differences in the level of required investment in gas infrastructure in comparison to other storylines is may be expected based on the gas demand developments. The **Green** storyline has the lowest total investments in the 2010-2050 since it is also the most gas-extensive **Green** storyline. Also the investment level in the 2030-2050 period in the **Blue** and **Yellow** storylines is relatively low due to the decrease or stagnation in gas demand after the 2030 peak in demand. In all storylines the majority of investment takes place in the 2010-2030 period. As explained before (section 2.2.2), investment in gas infrastructure until 2020 is based on currently known projects that are under construction or are proposed, whereas infrastructure additions between 2020 and 2050 follow from the simulation analyses. Although it may be discussed whether all investment assumed to be realized in 2020 will actually be realized by then, the total amount of investment across the whole time period of 2010 to 2050 is likely to be unaffected by this assumption since investment requirements for especially the 2020-2030 period would then be relatively higher. In other words, part of investments currently included in the 2010-2020 total investment level would then likely occur in the 2020-2030 period. After all, the peak in gas demand in 2030 in the **Red** and **Blue** storyline would still need to be accommodated by appropriate strengthening of different parts of the EU gas infrastructure.

The increase in LNG import capacity over time across different storylines is limited. Although investment in LNG receiving terminals continues at a rate of about 20 billion m^3 per decade in the **Red** storyline, almost no LNG investment takes place after 2030 in other storylines. This may be explained by the fact that due to the relatively lower level of gas demand in the other storylines, pipeline supplies are generally preferred over LNG supplies due to economic considerations. Being a relatively more expensive gas supply option for the largest share of EU countries, additional demand for EU external gas is pre-dominantly served by pipelines.

The majority of investment in the EU gas pipeline system within Europe takes place between 2010 and 2030. After 2030 relatively little investment in EU internal cross-border capacity is required. This can be explained as follows. In particularly this period, the impact of changing gas flow patterns throughout Europe is relatively high since the depletion of EU gas reserves is the steepest in this period. New gas external gas sources are required, triggering more investment in new EU import capacity (pipelines and LNG terminals), triggering in turn investments in cross-border pipelines. Interestingly, the level of total infrastructure investment in the **Blue** storyline is higher than in the **Red** storyline, although the total level of gas demand is higher in the latter. This can be explained by a strong transition from gas-based to renewable-based generation in the electricity sector in Northwest Europe in the **Blue** storyline. Due to a large penetration of large-scale wind parks by 2020 at the North Sea in the Northwest European electricity generation mix, there is a large decrease in gas demand in that area. Gas demand in the UK decreases with 24% between 2020 and 2030. Since the UK has very good gas import opportunities in 2020 compared with some other EU countries, the transition in the electricity sector induces large change in gas flow patterns that effectively turn the UK into an important gas transit country that re-exports imported gas further to continental Europe. The additional investments observed in the **Blue** storyline compared with the **Red** storyline are due to cross-border pipeline expansions downstream of the UK gas transit (i.e. the UK-Belgium and Belgium-France interconnections).

The decline in EU gas production is similar across the four storylines, decreasing from 85 billion m^3 per year in 2030 to about 30 billion m^3 per year in 2050. This implies that the depletion of own gas reserves is preferred irrespective of particular future gas demand developments. The dependency on gas imports thus varies with the level of total gas demand: the higher demand for gas over time, the larger the import dependency. Figure 4-22 shows that gas import dependency increases in all storylines but at a relatively slower rate in the low-gas demand storylines (i.e. **Yellow** and **Green**). Gas import dependency of the EU in 2050 varies between 91% (**Green**) and 96% (Red), whereas dependency is 'only' 69% in 2010. This corresponds with an import volume of gas in 2050 between 291 (**Green**) and 815 billion m^3 per year (**Red**). These figures may be compared with a total amount of EU gas imports of about 365 billion m^3 per year in 2010. The difference between the 2050 EU import volumes across the storylines signals that there is large uncertainty with respect to the future gas import level. Although there is a large difference in total EU gas import volume in 2050 across storylines, the import dependency in relative terms is not much affected. Figure 4-23 shows that Russia is the largest supplier of gas to the EU market in all storylines until 2050. The market share of Russian supplies in total EU demand is not the highest in the gas-intensive **Red** storyline (30%) but in the gas-extensive **Green** storyline (little over 50%). The reason for this is that at relatively low gas demand levels Russian gas is the preferred source for imports: other gas suppliers are relatively more expensive and thus only come into the picture when gas demand (and gas prices) is at relatively higher levels. Hence we observe that diversification of gas import sources increases with an increase in total gas demand. In the **Red** and **Blue** storylines the EU dependency on Russia remains at about 30 to 25% of total demand until 2050. After Russia, Algeria is the second-largest EU gas supplier in all storylines, with an average share of about 20% in the **Red** and **Blue** storylines. Norway supplies about 10 to 15% of EU gas demand across the different storylines. The share of other gas suppliers in total EU gas demand varies from 2 to 8% across storylines in the period until 2050.

Figure 4-24 and Figure 4-25 show the investment in EU import capacity and EU internal pipeline capacity respectively. Results concerning the upgrade of internal EU pipeline capacity show that some cross-border investments are robust across the different storylines, whereas other cross-border investments are storyline dependent. Cross-border investment in the gas corridor from Turkey to Central Europe and relatively smaller investment in the Northwest European pipeline system are constant across storylines. The South-East European corridor is an important supply corridor in all storylines. Upgrades in the Northwest European region are, despite of possible changes in gas flow patterns, rather limited due to the already quite developed infrastructure there. The infrastructure in this part of Europe will be increasingly used to accommodate import flows whereas is used to accommodate Dutch and UK export flows previously. Important storyline differences can be observed especially in the Southwest and South of Europe where additional EU internal pipeline investments are required to facilitate for mostly pipeline imports from Algeria (to Italy and Spain) and LNG imports (via Italy). Since the need for additional imports from Algeria and LNG exporting countries is different across storylines, also infrastructure investments are storyline-dependent. Especially in the **Red** and **Blue** storyline Italy is for example transformed into an important gas hub for both LNG and pipeline imports, giving rise to significant capacity upgrades of its interconnections with Germany and Central Europe. In some instances the amount of investment on specific interconnections in the **Blue** storyline exceeds those in the **Red** storyline: this has been addressed in the explanations discussed earlier.

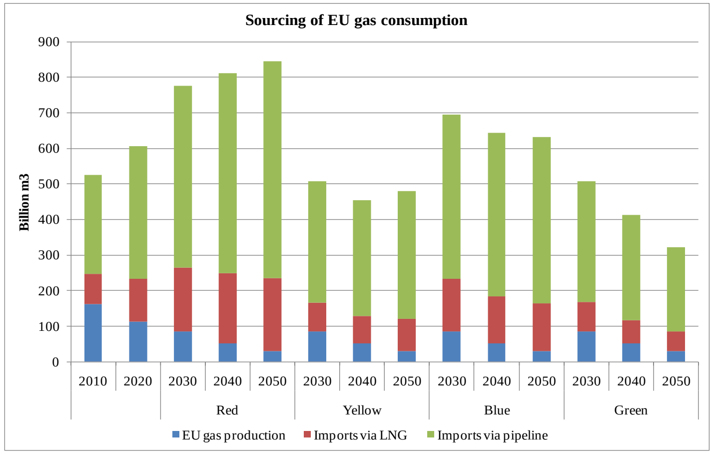

Figure 4-22 Source of EU gas consumption across storylines

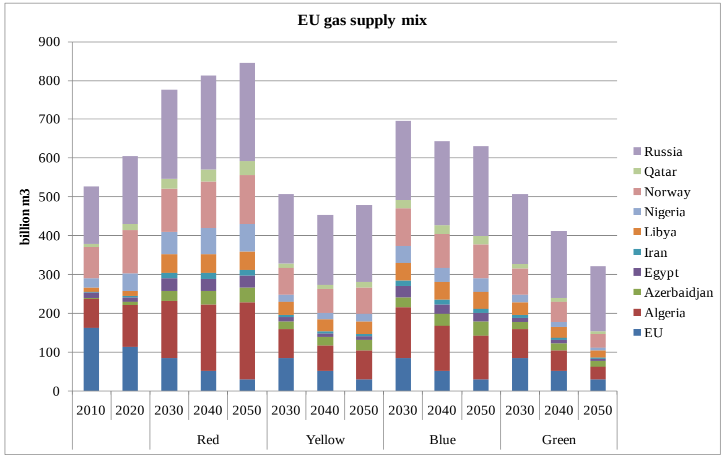

Figure 4-23 Source of EU gas consumption across storylines

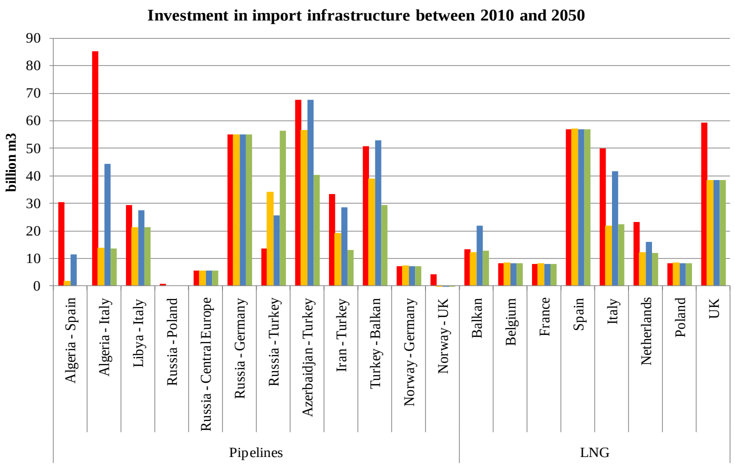

Figure 4-24 Investment in gas import infrastructure across storylines

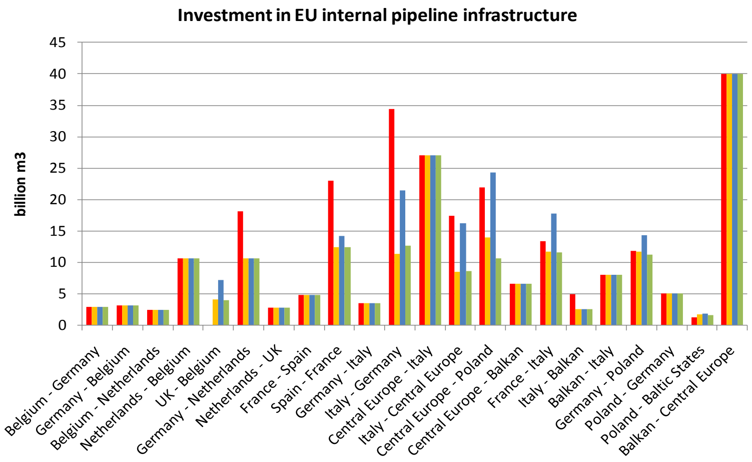

Figure 4-25 Investment in EU internal pipeline capacity across storylines

Based on the gas flows simulated in the analysis, additional observations can be made with respect to the relevance of particular gas corridors and cross-border interconnections in the future gas system. Although the identified infrastructure investments provide an indication of pipeline routes where gas flows are likely to increase over time, it may be informative to assess particular pipelines with a decreasing gas flow as well. In the period to 2050 a shift in EU relevant gas corridors may take place. Comparing the 2010 and 2050 gas flows the following observations are made:

- The increasing depletion of gas reserves in the UK and the Netherlands significantly reduces the gas flows from North-western Europe to neighbouring countries (i.e. Netherlands – Germany, UK – Belgium interconnections).
- A large increase in direct gas flows from Russia to Germany via the proposed North Stream corridor reduces the gas flows from Russia via the Central European corridor in all storylines.
- Italy emerges as a gas hub in all storylines, although its relative importance differs across storylines. Its gas hub position gives rise to a net gas flow from Italy to Germany and Central Europe. The Italian gas imports that allow Italy to become a transit hub originate from Algeria, Libya and various LNG exporting countries.
- Spain increases its importance as gas transit country to varying degree across storylines, due to increased exports of Algeria to the EU borders.
- Across all storylines, Turkey and the Balkan region emerge as important gas hubs. Gas is sourced from Central Asia and Russia, and re-exported to South-East Europe, and from there further into Central and Western Europe.

5 REVIEW OF BARRIERS AND SOLUTIONS FOR INFRASTRUCTURE DEVELOPMENT

5.1 Introduction

Pursuing the 20% renewable energy target at 2020, as requested by the Renewables Directive 2009/28/EC [EC, 2009a], is possible only if the RES generation park is significantly expanded in most of the European Countries. Much more stringent constraints to both emissions and renewable energy on longer time horizons are already being debated. However, this will only be possible with the positive concurrence of the two main factors influencing RES development: public attitude and technical development. These are also the two drivers considered for developing the storylines of the project SUSPLAN.

As it is stressed in recent EC communication regarding the Energy Infrastructure Package [EC, 2010b], "*The EU has to assure security of supply to its 500 million citizens at competitive prices against a background of increasing international competition for the world's resources. The relative importance of energy sources will change. For fossil fuels, notably gas and oil, the EU will become even more dependent on imports. For electricity, demand is set to increase significantly*". This will mean that electricity and gas transmission networks are and will stay for long time on the critical path to fulfil the targets fixed by the European Commission and, more in general, to realize a sound energy policy in Europe.

Grid development is driven by policy and market developments. The European targets for the energy sector – competitiveness, security of supply and sustainability – set the overall direction of policy and market developments, and hence constitute important drivers for the grid development in Europe.

The process of **market integration** aiming at establishing one internal EU energy market has started in the 1990s. This process is advancing under the push of both bottom-up regional market initiatives for electricity and gas and top-down measures in EC directives (establishment of ACER, ENTSO-E and ENTSO-G as requested by the Third Internal Energy Market Package[32]). Most initiatives are aimed at tackling market segmentation and removing all constraints preventing an efficient transport of energy between national markets. A higher level of *competitiveness* of the European energy sector is deemed key to increase *affordability* of energy too.

Gas disruptions and electricity blackouts spanning a wide area, renewed the attention for the security **of supply**. Security of supply can be improved through better access to electricity and gas from other countries within Europe as well as abroad, that can only be obtained by removing the many serious bottlenecks that prevent to take full profit of the abundant quantity of generation installed in certain regions of Europe. Moreover, removing grid bottleneck would allow to centralize (and thus make more efficient) the

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[32] Directives 2009/72/EC and 2009/73/EC, Regulations (EC) No 713, (EC) No 714 and (EC) No 715/2009.

management of reserve acquisition to compensate the effects of the well known variability of most RES generation.

Finally, in order to improve the **sustainability** of power systems, electricity networks need to transport increasing amounts of sustainable electricity production from intermittent sources. Green power can only be deployed if the network is contemporarily expanded so as to allow dispatching this power to the customers. New wind generators tend to be connected more often to the transmission network than to the distribution network, whereas distribution is the most common choice for lower rated RES generation like biomass. For both the cases, the need to develop the network is a powerful limiting factor for RES deployment.

De-bottlenecking the European system is a complex issue, in which a lot of aspects interact (Figure 5-1).

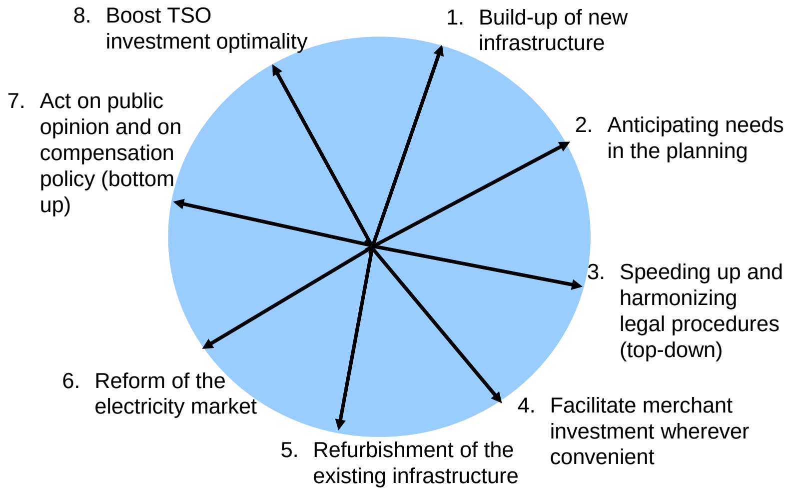


Figure 5-1 Factors influencing system de-bottlenecking (source [REALISEGRID, 2010a])

The joint effect of these aspects leads to important **barriers** that are able to hinder or at least delay the expansion of the networks (electricity and gas), as it would be requested to efficiently tackle the challenges mentioned before. These barriers can be distinguished in four main categories: 1) network planning, 2) authorization procedures, 3) technological development and 4) financing.
In the following of the present chapter, we will get deeper in these categories of barriers, indicating criticalities and possible healing actions.

5.1.1 Barriers depending on network planning issues

According to [KEMA, 2009; Everis and Mercados, 2010] we can mention the following issues, mostly related to the non-coordinated and non-harmonized action of the national bodies charged of the electricity and gas transmission infrastructures:

- *Lack of coordination of network planning* in terms of location and time may result in sub-optimal investment decisions by network operators. At least two issues can be distinguished. Concerning gas infrastructures, the lack of coordination for open season procedures[33] means that decisions have to be taken without knowing the outcome of other open season procedures in other countries. Additionally, seams issues with areas outside the country at hand imply significant risks for network users originating from outside this country [KEMA, 2009].[34]

- National regulators or other authorities might apply *different network security standards* to deliver a high quality of supply for their respective system areas in case of a failure of the largest single gas infrastructure. This is mostly true for gas (in the electricity field, ENTSO-E has inherited the results of a long work done by former UCTE). Future EC legislation on this point is currently under preparation.
- Concerning existing network capacity, *diverging capacity calculation and cross-border allocation mechanisms* between different member states impede a full utilization of the interconnection capacity across national borders. In the case of electricity, the fact that most allocations of cross-border capacity are still not coordinated between different countries brings to neglect the existence of loop flows through third Countries and leads to the necessity to increase security margins. For gas infrastructures, long-term contracts signed between TSOs and suppliers or supply affiliates allow for capacity hoarding by the latter and leave physical and contractual capacity unused.[35] An available short-term capacity is often sold against prices which considerably exceed costs. Second, the lack of backhaul capacity (i.e. capacities against the physical flow direction) also prevents efficient price arbitrage between neighbouring markets, which contributes to a suboptimal use of networks [KEMA, 2009]. Both issues relate to the *lack of proper incentives for TSOs* to make available additional physical and contractual cross-border network capacity.
- *Different network access regimes* at each (administrative) border of gas lines as well as different capacity products at both sides of the border may *result in sub-optimal use of infrastructure*. The former will happen if one country applies an entry-exit model, while another country applies a point-to-point model [KEMA, 2009]. The latter implies incompatible products on both sides of the border which distorts cross-border trading and market access.

5.1.2 Barriers depending on network authorization procedures and public consensus

As stated in the Energy Infrastructure Package communication:

"*Long and uncertain* ***permitting procedures*** *were indicated by industry as well as TSOs and regulators, as one of the main reasons for delays in the implementation of infrastructure projects, notably in electricity. The time between the start of planning and final commissioning of a power line is frequently more than 10 years. Cross-border projects often face additional opposition, as they are frequently perceived as mere "transit lines" without local benefits. In electricity, the resulting delays are assumed to prevent about 50% of commercially viable projects from being realised by 2020. This*

[33] An open season procedure consists of assessment of the market's needs on the basis of an open season notice and through non binding capacity requests from interested parties followed by capacity allocation and capacity contracts (derived from [ERGEG 2008].

[34] For instance, the lack of synchronization in open seasons, and differences in regulatory rules e.g. on reservation of capacity for short term needs.

[35] Contractual congestion happens when physical network capacity is available, but not fully utilized.

would seriously hamper the EU's transformation into a resource efficient and low carbon economy and threaten its competitiveness. In offshore areas, lack of coordination, strategic planning and alignment of national regulatory frameworks often slow down the process and increase the risk of conflicts with other sea-uses later on."

Building up new infrastructure is affected by lengthy authorization procedures that, beyond reflecting the confused and often contradictory administrative procedures for the authorization, are also the consequence of a strong NIMBY attitude by the public opinion towards the new electrical infrastructures. While on the authorization path some actions could be taken in order to promote a harmonized and possibly simplified approach all over Europe, also imposing a maximal responding time for each involved authority, the consensus problem always stays in the background and is much more difficult to solve.

Public attitude towards RES generation is a very powerful driver that strongly conditions both the investments in the electricity and gas sectors and the barriers met by the investors themselves. The reaction of the public opinion towards the proximity of a "green" generator is usually less negative than the one met by conventional generation (supposedly having a more substantial impact on the territory), and by far less negative than the one encountered by the development of new electrical lines (generation usually requires permissions and authorizations on a small local scale whereas the development of new transmission lines requires dealing with a lot of local communities). The development of new network infrastructure faces a number of hurdles. First of all, zones that are densely inhabited or having particular constraints on the usage of the territory (national parks, zones of historical interest, industrial zones, etc) put limitations to new network infrastructure. Strong limitations are insisting also upon touristic zones (landscape limitations). Finally, objective limitations and subjective perceptions on noise and electro-magnetic fields pose further limitations.

Public consensus on the realization of new electricity and gas infrastructures directly depends on the subjective perception of the new line, as highlighted in Figure 5-2. Some of the ingredients of the perception concern direct effects of the new line (on public health, on the environment, etc). Other regard the way how the process is dealt with (who is affected, etc).

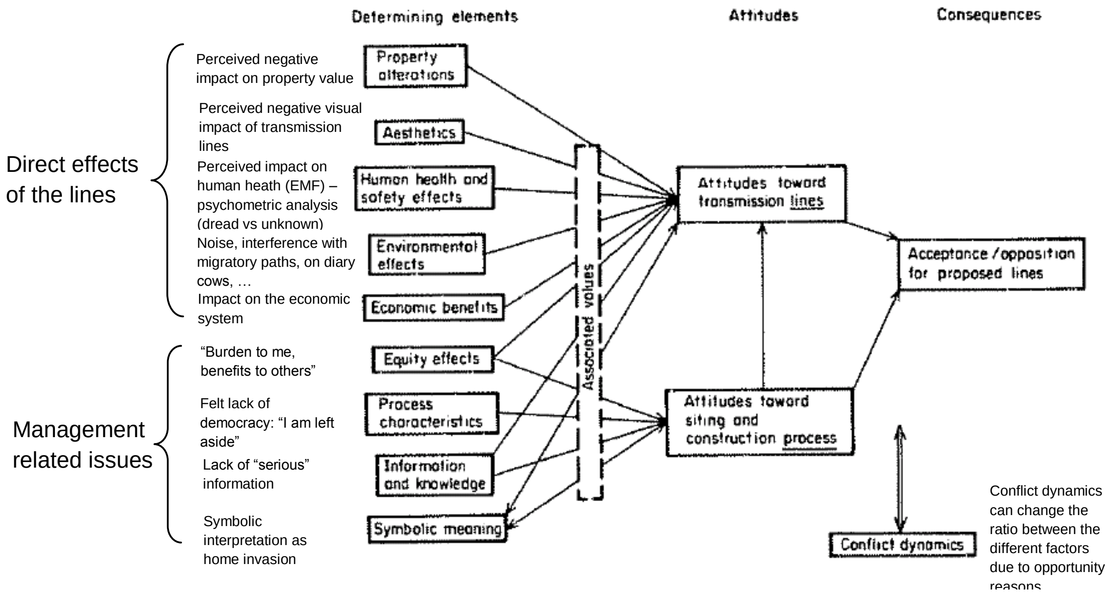


Figure 5-2 Public perception of new infrastructure [Furby *et al.* 1988]

Fundamentally, two approaches could be taken to improve consensus (among others as discussed by [REALISEGRID, 2010a]:

1. Bottom up approach, based on a more equilibrated flow of information to the public opinion that should be duly informed that the deploying green generation is only possible if the necessary new infrastructure is put in place. Inaction costs should be also provided and commented;
2. Top-down approach, in which the role of facilitator, already put in place for some important trans-national projects (e.g. France-Spain interconnector), should be institutionalized for all priority trans-European interconnections. The role of coordinator could be assumed by the freshly appointed new organizations like ENTSO-E and ACER. Additionally, a process of rationalization and harmonization of all the national authorization procedure should be initiated. Furthermore, simplified authorization channels should be applied by the interested Member States to the priority interconnection projects.

Summarizing the above discussion, four important points emerge, concerning authoritative procedure and public consensus:

- *Complicated planning and administrative procedures* to establish new interconnections slow down infrastructure development. The large variety of different authorization procedures at different levels, national, regional, and local, makes the length of authorisation procedures often unpredictable and time-consuming. With respect to cross-border projects, this is exacerbated by differences in authorization systems across borders. Project of European interest should find a priority approval channel within the single states.
- *Public resistance* due to (assumed) damage to the environment and safety risks may impede network investments. This may be explained by lack of political coordination between Member States, which can prevent projects of European interest to get the backing they need to overcome problems during implementation [EC, 2010c]. Also mechanisms to compensate aggrieved parties might be lacking [Lobato *et al.*, 2009].

5.1.3 Barriers depending on technological development

Concerning electricity grids, technological evolution can make it possible to better control and coordinate the flows in the European network. This can obtain, as a side effect, the increase of the net maximum flows through the most critical sections, thus helping to attenuate some problems arising with the authorization of new electricity lines. In fact, the investment in new particularly critical lines could be postponed by refurbishing the existing ones. Re-cabling with low sag conductors and real time thermally monitored cables could allow reducing the security margin applied to the thermal flow limit of the conductors. The usage of HVDC (especially in the new technology family VSC allowing multi-terminal deployments), beyond decoupling systems and not permitting perturbations to spread through wide systems, can be beneficial for reducing the encumbrance of the line and, consequently the rights of way paid for its realization. Phase shifting transformers (PSTs) and Flexible AC transmission system (FACTS) devices can allow to better control flow on parallel paths and other parameters in the grid and, consequently, to enhance the maximum admissible flow of critical sections. Finally, the future availability of DC breakers and of technically and economically appealing large scale storage technologies (beyond the existing pumping hydro stations) may provide the planners with new degrees of freedom for compensating the "variability" effect typical of most of the RES generation.[36]

5.1.4 Barriers depending on investments and financing issues

Concerning electricity networks, the different timescale of the generation and transmission investments constitutes a serious barrier for the planning. Whereas a new generation power plant can be entirely built within a couple of years, a new line is built in no less than five years, and the authorization path can stretch over ten years. If TSOs wait for the new generation being operative and causing congestion in the network, they will be late with their investment and the congestion will sustain for many years, also limiting both the profitability and the positive influence of the RES generation in the energy system. Besides, evaluation ex post is difficult because investments are carried out on a very long time horizon. By contrast, anticipating the investment without knowing if the generation is built or not risk to be based on non realistic assessments of the impact on the system providing wrong signals to the regulator. In all the cases, the definition of performance indices encapsulating the impact of an investment policy on the system and able to evaluate which policy could be preferred is a complex issue.

Additionally, TSOs could be not so motivated to invest in new lines to accommodate green generation. A few factors that could be listed are the following:

- The typical regulatory arrangement for the connection costs of new generation is that the generators are in charge to pay the line leading to the connection point of the network (shallow connection charge). Additional grid reinforcement costs and control costs[37] behind the connection point are socialized through Use-of-System charges. Consequently, generation is typically not responsible of the (often very

[36] See for instance [REALISEGRID, 2010e] for an overview of the potential of new grid technologies.
[37] For instance, the re-phasing apparatuses necessary in order to connect to the network very remote antenna lines leading to off-shore wind generation, with the consequent need of reactive compensation.

significant) costs for expanding the internal sections of the network in order to accommodate the extra flow. Although it is difficult to allocate network costs properly to consumers and producers, it is commonly acknowledged that generation considerably contributes to network reinforcements and associated network costs. Hence, from a ‘beneficiary pays’ point of view it is logical to allocate part of the network reinforcement and control costs to producers. Deep connection charges are often mentioned as an option, but in reality the implementation is plagued by severe barriers (like disputes about computation of these charges and the first mover problem in case of sequential connection inquiries). Consequently, it is advised to implement shallow connection charges, and to allocate part of the grid reinforcement and control costs to producers via use-of-system charges for producers (for more details, see among others [Scheepers, 2004; Nieuwenhout *et al.*, 2010].

- *Large variety in legal and regulatory treatment of new cross-border infrastructure impedes new infrastructure investments*. Especially, differences in regulatory rules concerning the assessment and approval of investment proposals turn out to be a barrier. For instance, it may be difficult to synchronize regulatory approval processes due to national requirements (see for example the Britned cable between the Netherlands and UK). For the gas infrastructure, this is often related to different commercial viability of new investments at national scale as illustrated by a ‘virtual test’ within the Gas Regional Initiative North-West (GRI NW). In this test case, investments would have been approved in benefiting countries, but rejected in transit countries [KEMA, 2009].
- *Cross-border benefits of* certain *infrastructure projects* (notably projects of European interest) are often *not taken into account* in the identification of projects of national interest. EU countries apply different criteria to select the most required investments, which follow their national priorities. This is valid *a fortiori* whenever the trans-national flow from RES generators to the customers they are intending to serve only crosses the Country without bringing direct benefits to it. It seems also likely that national authorities will strive to maintain their priorities, especially in the selection of new facilities such as LNG terminals and storages [Evedis and Mercados, 2010]. Putting in place a mechanism for remunerating transited TSOs is key for motivating their involvement in transnational investments.
- Finally, *financing opportunities of new network investments are unequal between member states* notably due to the determination of diverging regulatory rates of return for investments by national authorities. More broadly, also differences in regulatory principles and regulatory accounting may cause differences in financing opportunities.

5.1.5 Other aspects

Beyond the ones listed above, other issues could have a key role for fostering the debottlenecking of the European electrical system and accelerating the integration of an increasing penetration of RES-generation:

- **Integration of the Internal Electricity Market in Europe**: the creation of a harmonized competitive basis in Europe could be fundamental in order to eliminate all the regulatory biases that push “artificial” trades between the nations, with their consequence on the flows in the network. Actually, as a consequence of different incentivization policies in Europe, the net production costs are not the same and this can cause disequilibrated bidding behaviours being the sources of trans-national flows. Beyond this aspect, also a temporal integration of the markets, from the forward financial market up to intraday and balancing markets could increase the trading possibilities and diminishing the effect of the forecast error that typically affects wind generation. As a side effect, moving gate closure towards real time and coordinating Europe-wind its timing could be also very beneficial for the system.

- **Merchant investment**: private investors could provide additional precious resources for the system. They could also be a driver for pushing the TSOs to put in place additional regulated investments. Integration between generation and transmission investments could also be envisaged: the same investor that installs the RES generator could be involved in the infrastructure investments that have to do with the integration of their own generation. However, what is still lacking in Europe is a legislation that fully defines the framework for merchant investment. One aspect to be clarified is what remuneration can be offered to the investors. If what is "at stake" is only a "third party exemption" of the congestion rates, then private investments are possible only provided that the congestion doesn't disappear. This is, however, a strong limitation to the potential of merchant investments.

5.1.6 Options to remove barriers for gas infrastructure extension

Options related to network planning issues

- Coordination of network planning on a regional scale in general and coordination of open season process in particular for the gas infrastructures [KEMA 2009]. Therefore, the Third energy package requires the establishment of a community-wide ten-year network development plan as well as a regional investment plans. National and regional network development plans need to be coherent with their community-wide equivalent. These plans will coordinate network planning in general. For coordination of open season procedures other measures need to be inventoried.
- Harmonization of network planning standards by provisions for the establishment of European-wide network codes, as mandated by Regulation No. 715/2009/EC [EC, 2009b]. The network code will have to cover different areas, including network security and reliability rules i.e. network planning standards. The network code will be prepared by ENTSO, taking into account the framework guideline and review by ACER/ERGEG. The resulting network code has to be adopted by the European Commission.
- Incentives for TSOs to make available the required amount of network capacity in a cost-efficient way are important. Incentives should be preferably output-based i.e. link the remuneration of TSOs to their actual efficiency performance in terms of cross-border capacity delivered. Different performance indicators can possibly be constructed based on preliminary work of ERGEG. Before such incentives can be implemented, first the large information gap between TSOs and other system actors, notably regulators, concerning the utilization of network capacity need to be decreased. As a first step, the performance indicators need to be complemented by network reference models for regulatory agencies and governmental bodies in order to perform a comparative cost-benefit analysis of the different proposed infrastructure measures.
- The effects of different network access regimes on infrastructure development will probably be largely resolved by forthcoming legislation. Article 13 (2) of Regulation (EC) 715/2009 [EC, 2009b] does not allow the use of the point-to-point model after

3 September 2011. However, different national network access practices, e.g. network tarification, do have an impact on the required amount of gas infrastructure too. Hence, network tarification guidelines could be developed. Such guidelines have been developed for the electricity sector in the past.[38] Incompatibility of capacity products can be reduced by limitation of number of products through further integration in terms of harmonized technical requirements, and limitation of number of trading hubs by selecting one contractual interconnection point out of several physical interconnection points connecting the same entry-exit zones.

Options related to network authorization procedures and public acceptance

- Planning and administrative procedures to establish new interconnections may be eased by the introduction of a one-stop-shop approach for project authorization at regional level, and implementation of (adjustable) deadlines for project authorization.
- European coordinators have been appointed for some key European projects. They should preferably be appointed for all other delayed and/or complex projects too. Furthermore, implementation of a mechanism to redirect (external) costs to the beneficiaries of new investments should be considered. For example, the Inter-Transmission system operator Compensation (ITC) mechanism as used in the electricity sector may offer a solution (see further explanation below).

Options related to investments and financing issues

- A sufficient degree of coordination amongst national regulators needs to be secured. Applicable regulatory rules need to be harmonised.
- Unified criteria for cross-border, and preferably national, investment selection are key for the realization of a truly Internal European Market both for electricity and gas. Furthermore, countries with low or even negative net benefits of new cross-border pipelines should be compensated by the beneficiaries of these lines, for example via the earlier mentioned ITC. Such mechanism exists in a very simplified form for electricity but should be made more cost reflective. An ITC mechanism could be introduced, similarly also for the gas sector [KEMA, 2009], but whether this is the most optimal solution deserves further study [Evides and Mercados, 2010].
- It is recommended to introduce guidelines for more harmonized network regulatory practices across EU-27 countries. These guidelines may include rules for key regulatory principles, regulatory accounting and calculation of regulatory rates of return.

[38] The guideline for the electricity sector has some disadvantages which should be prevented when developing a comparable guideline for the gas sector. First, the bandwidth of costs allocated to generators is quite broad, limiting harmonization across Europe. Second, insufficient attention seems to be paid to the cost-causality principle i.e. consumers have to pay more than the costs they induce to the system (connection, network utilization etc.) and generators less.

6 INTEGRAL ANALYSIS OF ELECTRICITY AND GAS INFRASTRUCTURE DEVELOPMENTS

6.1 Introduction

Following up on the presented and discussed storyline results for both the electricity and gas market separately this chapter takes an integral view on energy infrastructure. It combines the results from the electricity and gas. In section 6.2 we discuss the main energy EU corridors. In section 6.3 we turn to an integral impact assessment: what is the impact of the main storyline drivers on the different aspects of the energy system?

6.2 Energy corridors

6.2.1 Electricity

By analyzing expansions brought by MTSIM to the European transmission corridors, it can be observed that there are some expansions are common to all the Storylines, their expansion seems to be fundamental for a better exploitation of the network potentiality whatsoever the future system scenarios.

In particular, the corridors that connect the Central Europe with the Iberian Peninsula (ES-FR, FR-DE, FR-BL, FR-IT, DE-PL) are expanded in order to exploit all the potential RES generation and feed at minimum marginal cost the consumption centres, e.g. those placed in central Europe. Some corridors placed in Eastern and South-Eastern Europe (AL-GR, RO-UA_W and SK-UA) are significantly expanded in all the Storylines too.

In general, similar trends can be observed in terms of electricity infrastructure reinforcements with respect to the ongoing/expected developments in the period up to 2030. This is particularly the case for some crucial regions and corridors of the pan-European transmission system, like the France-Spain links, the interconnections along the axis Germany-Poland-Baltic countries as well as the Central European region and the North Sea offshore grids concerning the British Islands, the Scandinavian countries and north-western Europe. These regions and corridors are in fact to be considered crucial ones for the fulfilment of RES targets both in 2020 and 2030 storylines. The 2030 electricity infrastructure development storylines in Europe have been created and studied within REALISEGRID [REALISEGRID, 2010c, 2010d]. In consistency with [ENTSO-E, 2010] and long-term TSOs and private (merchant) investment plans. Figure 6-1 shows the map of pan-European reinforcement needs for the years 2016-2020, as selected by European TSOs for the ENTSO-E TYNDP [ENTSO-E, 2010].

For some results of the 2030-2050 storylines, a generally continuous trend in terms of electricity infrastructure reinforcement needs can be observed with respect to developments ongoing/expected in the period up to 2030.

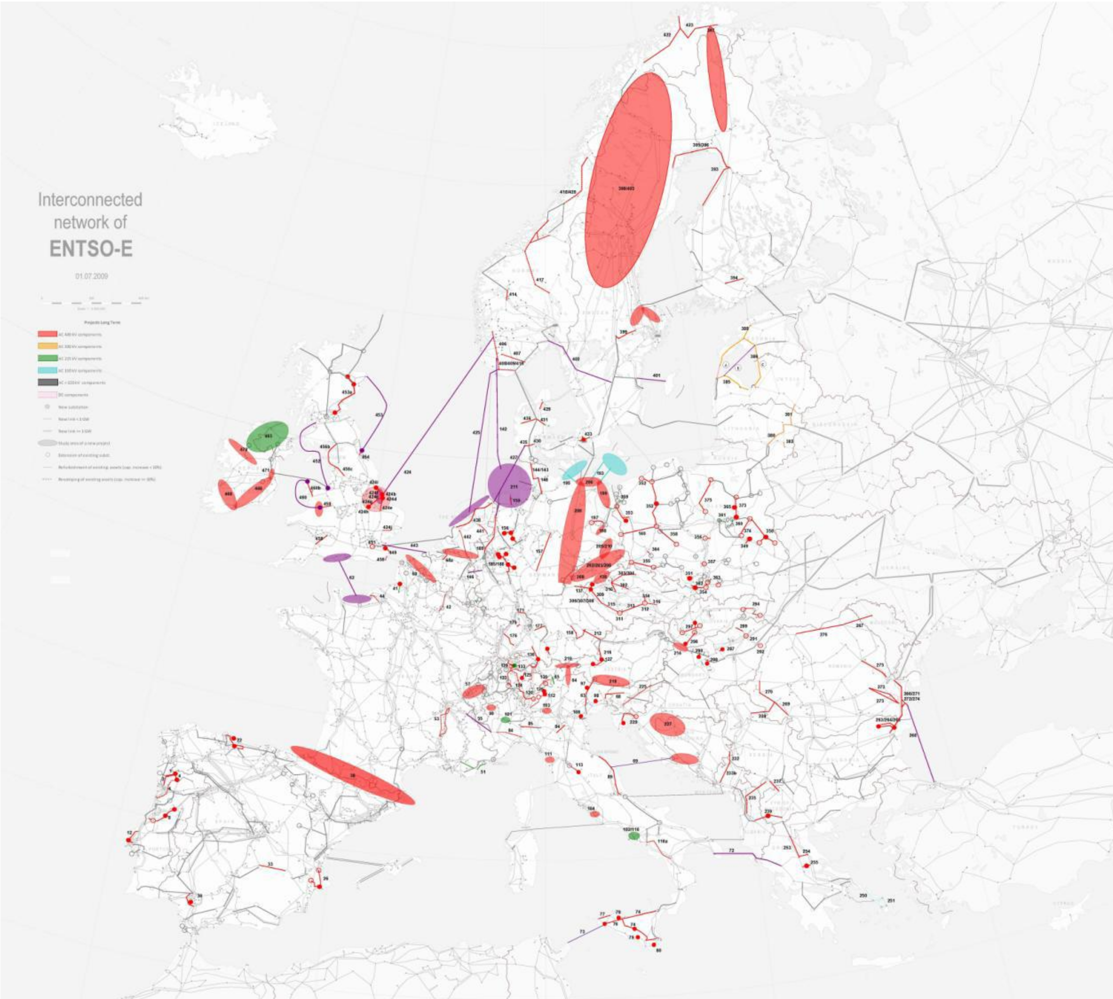


Figure 6-1 European transmission system reinforcement needs in 2016-2020 [ENTSO-E 2010]

Figure 6-2 and Figure 6-3 respectively show the details for the North Sea and the Baltic Sea regions expansion plans over the period 2016-2020 [ENTSO-E, 2010]. The boosting developments of offshore grids in the two regions towards RES integration will be also a feature of the years 2020-2030.

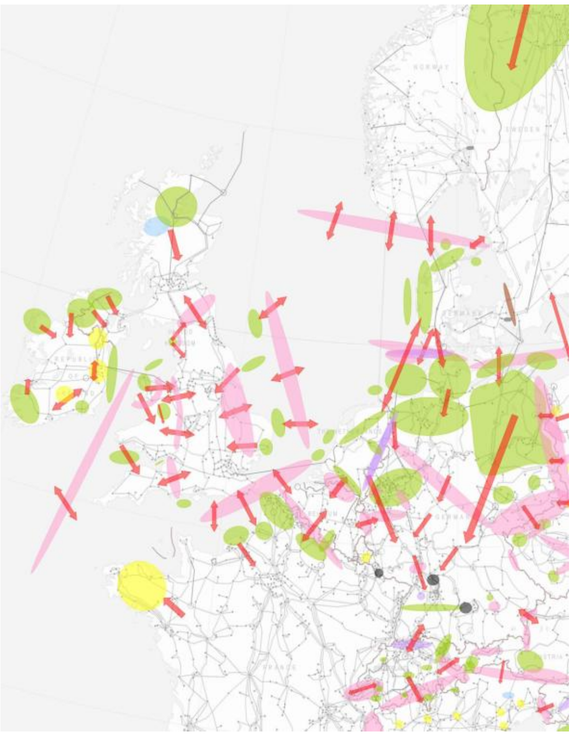


Figure 6-2 North Sea region development plans for 2016-2020[ENTSO-E, 2010]

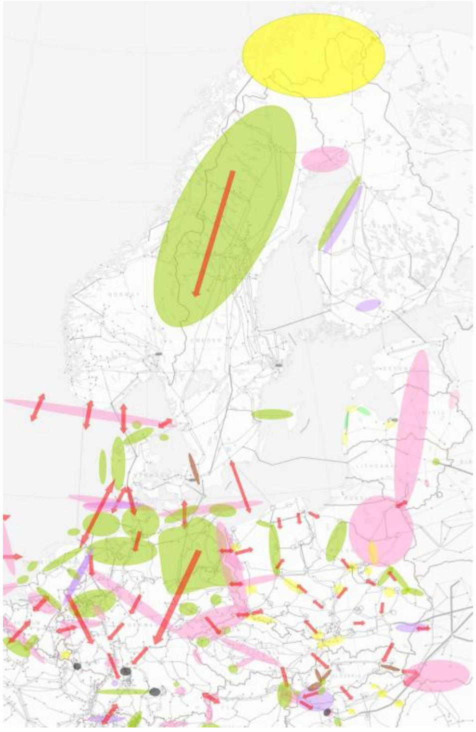


Figure 6-3 Figure Baltic Sea region development plans for 2016-2020 [ENTSO-E, 2010]

For the years 2020-2030 other areas to be crucially expanded will concern the Balkan region and the east-west axis Italy-Turkey through the Adriatic Sea interconnections as well as the corridors at the north-eastern borders of Italy with Slovenia and Austria. The completion of the latter interconnection will allow the exploitation of the north-south axis Germany-Austria-Italy with the consequent transport of RES (by wind) electricity produced in northern Europe. A crucial link in this sense will be the one via Brenner tunnel (see Figure 6-4).

Figure 6-4 Detail of Italy-Austria link via Brenner tunnel

6.2.2 Gas

In this section the main conclusions regarding gas infrastructure investments related to particular gas corridors are reflected.

Results from the gas market analysis on the upgrade of internal EU pipeline capacity show that some cross-border investments are robust across the different storylines, whereas other cross-border investments are storyline dependent. Cross-border investment in the gas corridor from Turkey to Central Europe and relatively smaller investment in the Northwest European pipeline system are constant across storylines. The South-East European corridor is an important supply corridor in all storylines. Upgrades in the Northwest European region are, despite of possible changes in gas flow patterns, rather limited due to the already quite developed infrastructure there. The infrastructure in this part of Europe will be increasingly used to accommodate import flows whereas is used to accommodate Dutch and UK export flows previously. Important storyline differences can be observed especially in the Southwest and South of Europe where additional EU internal pipeline investments are required to facilitate for mostly pipeline imports from Algeria (to Italy and Spain) and LNG imports (via Italy). Since the need for additional imports from Algeria and LNG exporting countries is different across storylines, also infrastructure investments are storyline-dependent. Especially in the **Red** and **Blue** storyline Italy is for example transformed into an important gas hub for both LNG and pipeline imports, giving rise to significant capacity upgrades of its interconnections with Germany and Central Europe. In some instances the amount of investment on specific interconnections in the **Blue** storyline exceeds those in the **Red** storyline: this has been addressed in the explanations discussed earlier.

Based on the gas flows simulated in the analysis, additional observations can be made with respect to the relevance of particular gas corridors and cross-border interconnections in the future gas system. Although the identified infrastructure investments provide an indication of pipeline routes where gas flows are likely to increase over time, it may be informative to assess particular pipelines with a decreasing gas flow as well. In the period to 2050 a shift in EU relevant gas corridors may take place. Comparing the 2010 and 2050 gas flows the following observations are made:

- The increasing depletion of gas reserves in the UK and the Netherlands significantly reduces the gas flows from North-western Europe to neighbouring countries (i.e. Netherlands – Germany, UK – Belgium interconnections).
- A large increase in direct gas flows from Russia to Germany via the proposed North Stream corridor reduces the gas flows from Russia via the Central European corridor in all storylines.
- Italy emerges as a gas hub in all storylines, although its relative importance differs across storylines. Its gas hub position gives rise to a net gas flow from Italy to Germany and Central Europe. The Italian gas imports that allow Italy to become a transit hub originate from Algeria, Libya and various LNG exporting countries.
- Spain increases its importance as gas transit country to varying degree across storylines, due to increased exports of Algeria to the EU borders.
- Across all storylines, Turkey and the Balkan region emerge as important gas hubs. Gas is sourced from Central Asia and Russia, and re-exported to South-East Europe, and from there further into Central and Western Europe.

In the next section we turn to an integral analysis of electricity and gas market developments with regard to various relevant aspects.

6.3 Impact assessment of storylines and infrastructure implications

6.3.1 Introduction

Due to the common storyline basis, the simulation results for the electricity and gas market can be used to provide a quantitative assessment of the impact of the two storyline dimensions, and their underlying drivers, on different aspects of the energy system. Table 6-1, Table 6-2, and Table 6-3 present the main data regarding the different energy system aspects across the four storylines. Table 6-1 and Table 6-2 summarize the results from the electricity market analysis, whereas Table 6-3 summarizes the results from the gas market analysis. Below follows a discussion of the main observations regarding these electricity and gas market results at the same time.

6.3.2 Energy demand and electricity generation mix as drivers

The storylines adopted in this study differ with respect to public attitude towards a transition towards a sustainable energy system on the one hand, and the degrees in which sustainable energy technologies are developed on the other. These storyline dimensions have been translated into the simulation analysis of the gas and electricity market via the level of energy demand (mainly electricity demand) and the electricity generation mix across EU member states. Hence, all results acquired from the simulation analyses can be traced back to these main drivers. In other words, we can use the simulation results to assess the impact of changes in energy demand and the nature of electricity generation. Changes in electricity demand and electricity generation mix affect:

- The (operational and capital) cost of generating electricity;
- The emission of CO_2 in the electricity generation sector;
- The need for electricity and gas infrastructure investment;
- The level of security of supply in an EU member state or region.

		Electricity consumption	Fuel cost		CO_2 emissions		CO_2 cost		Total operational cost		Capital cost		Total electricity cost		Load shedding
		TWh	Billion euro	Euro / MWh	megaton	Ton / MWh	Billion euro	Euro / MWh	Billion euro	Euro / MWh	Billion euro	Euro / MWh	Billion euro	Euro / MWh	GWh
Red	2030	4839	89	18	893	0,18	71	15	160	33	42	9	203	42	886
	2040	5084	94	19	830	0,16	83	16	177	35	46	9	223	44	211
	2050	5338	101	19	798	0,15	96	18	197	37	49	9	246	46	1
Yellow	2030	4162	45	11	468	0,11	20	5	65	16	43	10	108	26	0
	2040	4165	34	8	264	0,06	14	3	47	11	49	12	96	23	0
	2050	4169	39	9	321	0,08	20	5	59	14	52	12	111	27	0
Blue	2030	4853	64	13	627	0,13	50	10	114	23	49	10	162	33	0
	2040	5119	49	9	451	0,09	45	9	94	18	61	12	154	30	22
	2050	5401	41	8	347	0,06	42	8	83	15	71	13	154	29	0
Green	2030	4166	46	11	556	0,13	24	6	70	17	48	12	118	28	615
	2040	4175	28	7	210	0,05	11	3	39	9	59	14	97	23	0
	2050	4194	14	3	66	0,02	4	1	18	4	69	16	87	21	0

Table 6-1 Overview of main results from the electricity market analysis (1)

		AC network expansion		DC network expansion		Total network expansion		Intermittent electricity production[39]		Renewable electricity production		Gas-based electricity production	
		GW	Million Euro	GW	Million Euro	GW	Million Euro	TWh	% of consumption	TWh	% of consumption	TWh	% of consumption
Red	2030							631	13%	1777	37%	1660	34%
	2040	29	2111	7	1920	36	4031	758	15%	1982	39%	1791	35%
	2050	16	1145	5	1210	20	2355	885	17%	2178	41%	1907	36%
Yellow	2030							821	20%	2099	50%	1014	24%
	2040	29	2027	26	3768	55	5795	1027	25%	2415	58%	790	19%
	2050	17	1145	6	1646	22	2791	1212	29%	2253	54%	982	24%
Blue	2030							1036	21%	2359	49%	1282	26%
	2040	44	3124	12	3637	56	6761	1717	34%	3160	62%	927	18%
	2050	49	3351	8	2111	56	5462	2248	42%	3799	70%	778	14%
Green	2030							1040	25%	1990	48%	1010	24%
	2040	59	3863	12	3422	72	7285	1331	32%	2576	62%	623	15%
	2050	58	3720	8	1979	65	5699	1647	39%	2998	71%	224	5%

Table 6-2 Overview of main results from the electricity market analysis (2)[40]

[39] Intermittent generation refers to the electricity generation from wind and solar technologies.

[40] Note that it is not the purpose of this table to sketch a total picture of the electricity generation mix (with separate generation categories adding to a total of 100%). Only three particular types of electricity generation are mentioned. Intermittent electricity generation is reported since it is a category with particular implications for electricity infrastructure expansion. Renewable electricity generation is reported since a sustainable electricity generation system is considered a policy goal. Compared with the intermittent electricity generation category this renewable electricity generation category also includes biomass and hydro-based electricity generation. Gas-based electricity generation is reported due to the link with required gas infrastructure developments. Typically not included in either three categories are coal and nuclear-based electricity generation.

		Gas consumption	Gas price		Imports		Gas infrastructure expansion		Diversification index
		Billion m^3	Euro / GJ	Euro / m^3	Billion m^3	% of consumption	Billion m^3	Billion Euro	
Red	2030	777	6,4	0,26	692	89%	250	58,2	1698
	2040	812	6,7	0,27	761	94%	93	46,9	1736
	2050	846	7,0	0,28	815	96%	125	15,1	1831
Yellow	2030	507	5,7	0,23	422	83%	142	20,8	2009
	2040	455	5,8	0,23	403	89%	35	22,9	2183
	2050	480	5,7	0,23	449	94%	41	4,0	2314
Blue	2030	696	6,2	0,25	611	88%	271	5,9	1679
	2040	644	6,6	0,27	593	92%	50	46,6	1844
	2050	631	7,1	0,28	601	95%	48	6,1	2023
Green	2030	507	5,7	0,23	422	83%	143	6,9	2018
	2040	412	5,7	0,23	361	88%	28	23,0	2322
	2050	321	5,7	0,23	291	91%	34	2,8	3123

Table 6-3 Overview of main results from the gas market analysis

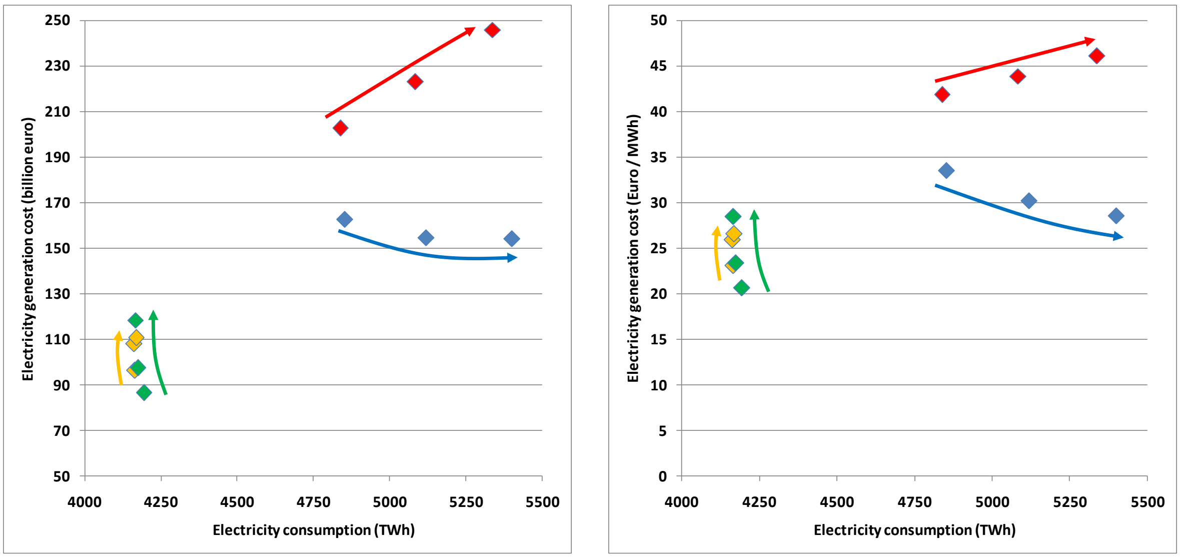
6.3.3 Impact on electricity generation costs

An increase in demand results in the deployment of more, and different, electricity generation units. New electricity demand needs to be facilitated with investment in additional electricity generation units. Hence, additional demand may increase the need for investment and increase capital expenditures. When operating non-renewable electricity generation units incur operational costs related to operation and maintenance on the one hand, and fuel costs on the other. Renewable electricity generation units obviously incur only operation and maintenance costs, and no fuel and CO_2 emission costs. An increase in the share of renewable electricity in the generation mix, by means of additional investments, i.e. capital expenditures, will result in a different dispatch of available electricity generation units. Additional wind-powered capacity may for example displace gas-fired electricity generation units during peak-hours. This shift also implies a change in the total operational cost of the electricity generation mix.

From the results depicted in Figure 6-5 we observe that only in the **Red** storyline total electricity generation costs in absolute terms increase with the amount of electricity consumed. The electricity consumption level in the **Yellow** and **Green** storylines is relatively constant with the cost of electricity generation decreasing in the latter storyline, but remaining more or less constant in the former storyline. The **Blue** storyline combines an increase in electricity demand with a small decrease in total electricity generation costs. This is the net result of an increase in capital costs of electricity generation and a decrease in the fuel costs, which reflects the increasing penetration of renewable based electricity generation in this storyline, from 49% in 2030 to about 70% in 2050. These observations also hold when looking at the relative cost of electricity generation, i.e. the generation cost in euro per MWh. From the comparison of the unit generation cost we learn that the **Red** storyline has the highest per MWh costs by far, of about €45 per MWh between 2030 and 2050. In contrast, the low energy demand storylines (**Yellow** and **Green**) have a generation cost in the range of €20 to €30 per MWh in the same period.

In Figure 6-6 we observe the dynamics of the different cost components that together make up the electricity generation cost, across the storylines. The following conclusions can be drawn:

- The capital cost per unit of electricity generated strongly increases when more and more renewable electricity generation enters the system. This is especially clear when comparing the **Green** storyline with the other storylines.
- The fuel cost and CO_2 emission costs per unit of electricity generated strongly decrease with the amount renewable electricity entering the system.
- The negative impact of an increasing amount of renewable electricity generation on the capital cost per unit of electricity generated is more than compensated by the positive impact on the fuel and CO_2 emission cost per unit of electricity generated.



(a) Generation cost in billion euro (b) Generation cost in euro / MWh

Figure 6-5 Relation between electricity generation cost and electricity consumption (arrows indicate the transition from 2030 to 2050)

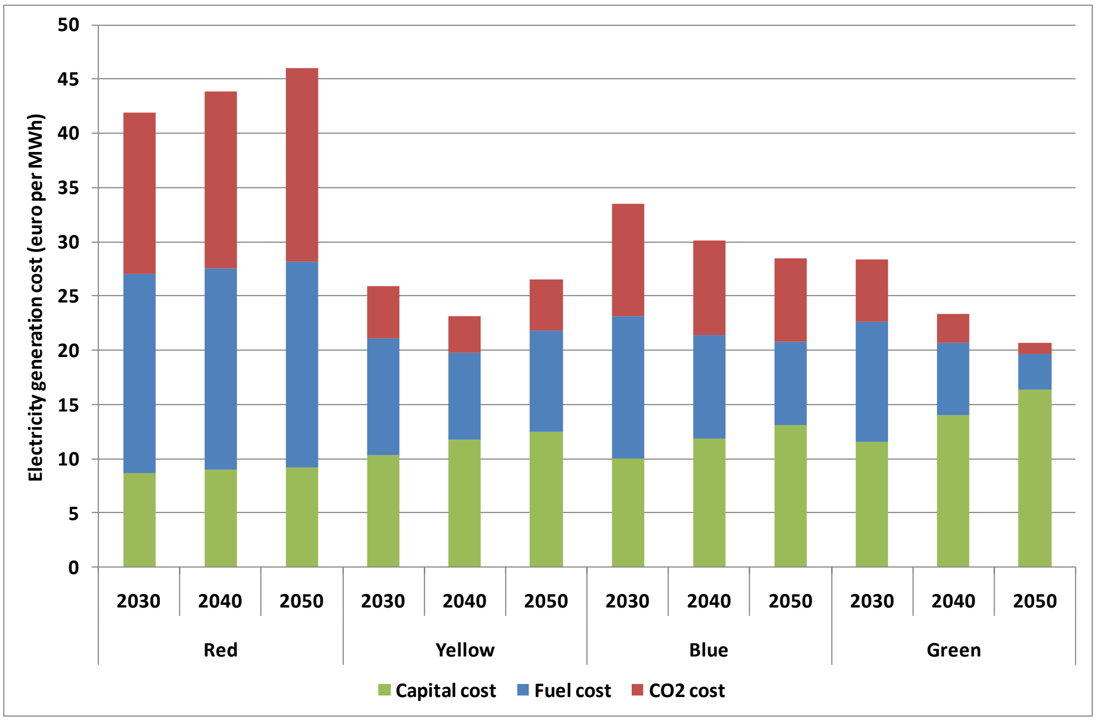


Figure 6-6 Structure of electricity generation costs across storylines

6.3.4 Impact on the level of CO_2-emissions

Both changes in overall electricity demand and a shift in the deployment of non-renewable to renewable electricity generation technologies affect the total level of CO_2-emissions of the electricity system. A ceteris paribus increase in electricity demand will, assuming a fixed generation mix with an average CO_2 emission per produced MWh, result in an increase in total CO_2 emissions. A ceteris paribus increase in the share of renewable electricity generation will, thus assuming a constant level of electricity demand, decrease the total level of CO_2 emissions. The results as included in earlier presented tables confirm this hypothesis. Figure 6-7 shows the relationship between the amount of CO_2 emitted in the electricity generation sector and the share of renewable electricity generation in the electricity generating mix across the four storylines. Although various factors influence the exact position of each storyline and year, the complete picture for all storylines suggests that there is a negative relationship between the two variables. The exact data points suggest that every 1% increase in the share of renewable electricity generation leads to a decrease of CO_2 emissions of about 20 megaton.

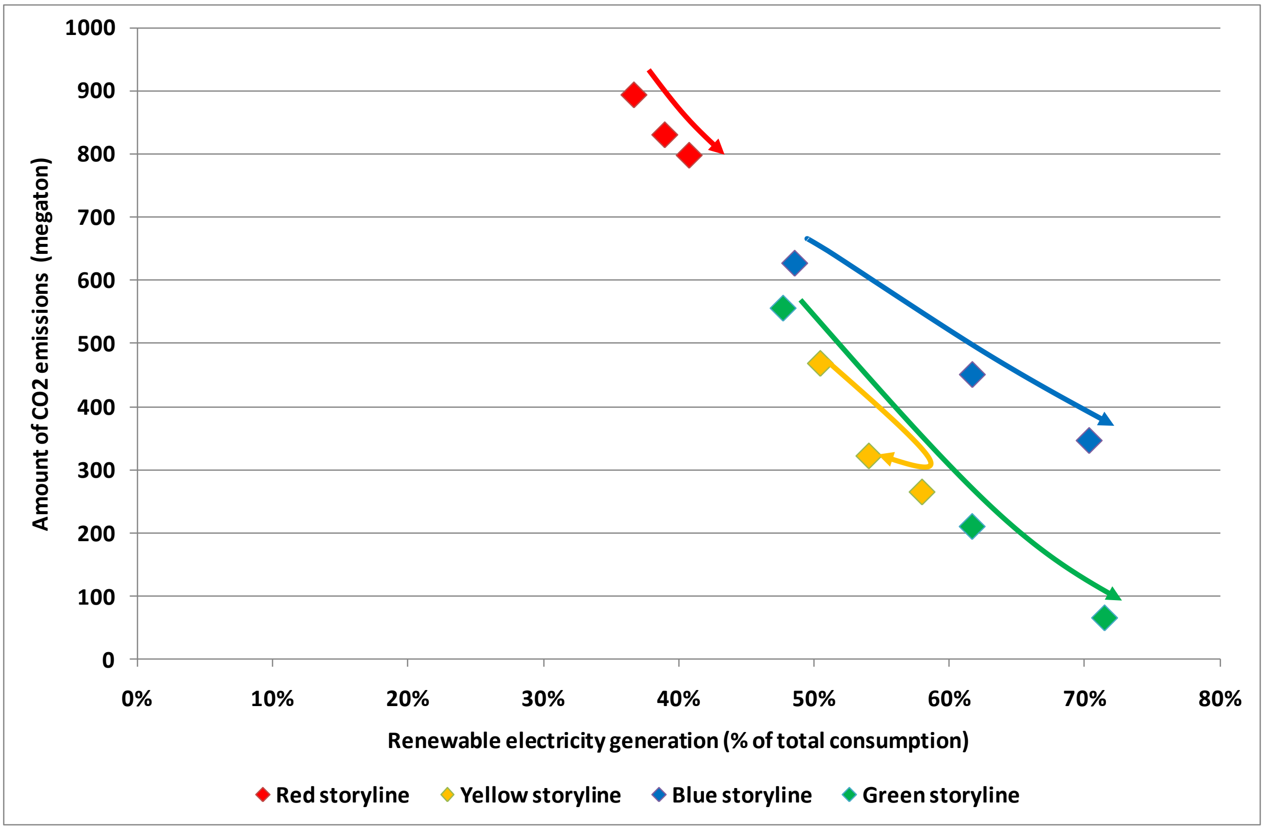


Figure 6-7 Relationship between CO_2 emissions and share of renewable electricity generation (arrows indicate the transition from 2030 to 2050)

6.3.5 Impact on the need for more electricity and gas infrastructure

The locations at which electricity or gas is consumed on the European or regional level is expected to not always match with the locations of electricity generation or gas production. An increase in electricity or gas demand is therefore likely to increase the demand for gas or electricity transmission services. When increases in transmission services on for example particular cross-border interconnections exceed available capacity this will result in congestion: expansion of available capacity may be required, i.e. infrastructure investments are triggered. Figure 6-8 presents a comparison of the need additional network capacity on the electricity and gas market. Apart from the observation that substantial investments in new transport capacity are required on both markets there does not seem to be a high correlation between electricity and gas infrastructure expansion needs for each storyline and decade. For example, large electricity infrastructure upgrades are necessary in the **Green** storyline after 2030, whereas only limited gas infrastructure upgrades are necessary in that very same storyline in the same period. On the other end, the observation is reversed in the case of post-2030 investments in the **Red** storyline: in that case gas infrastructure requirements are relatively larger than electricity infrastructure requirements.

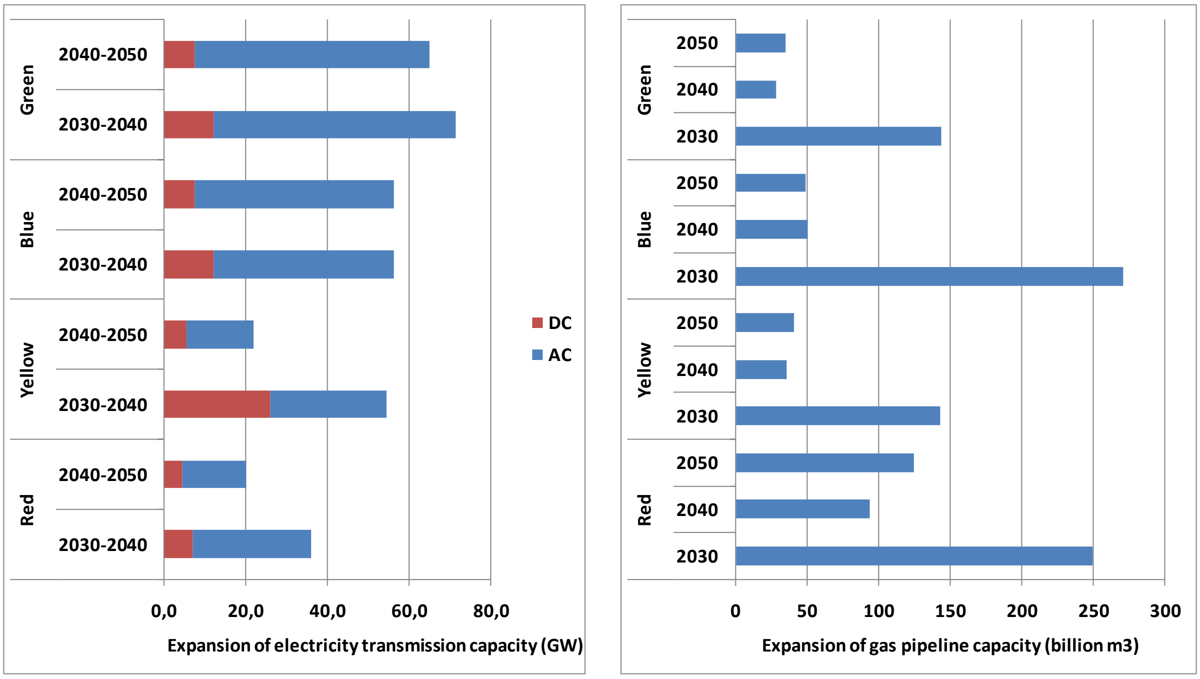


Figure 6-8 Expansion of electricity and gas infrastructure across storylines

Table 6-4 provides estimates for the investment costs associated with the physical infrastructure requirements presented above. In interpreting these figures it is important to note that these infrastructure investments result from an analysis with two models that on some aspects use a simplified representation of reality. For example, in the case of electricity the physical expansion of interconnections between countries is calculated on a GW basis, and does not include a particular distance component. For this reason it is also difficult to compare monetised results with investment cost estimates of the DENA study or of ENTSO-E.

Storyline	Year	Pipeline infrastructure		LNG import infrastructure	Total
		To EU	Within EU		
	2020	37,6	17,9	2,6	58,2
Red	2030	39,2	5,7	2,0	46,9
	2040	12,3	1,9	1,0	15,1
	2050	16,3	3,4	1,1	20,8
Yellow	2030	18,7	3,2	1,0	22,9
	2040	3,7	0,3	0,0	4,0
	2050	5,5	0,4	0,0	5,9
Blue	2030	37,3	6,8	2,5	46,6
	2040	5,2	0,7	0,2	6,1
	2050	6,4	0,5	0,0	6,9
Green	2030	18,9	3,0	1,1	23,0
	2040	2,0	0,8	0,0	2,8
	2050	0,0	0,0	0,0	0,0

Table 6-4 Overview of required investment in gas infrastructure across storylines (in billion € of capital expenditure)

Table 6-4 shows the estimated costs of providing the required gas infrastructure in billion euro.[41] From these figures we learn that additional gas infrastructure investments of about 82 billion euro are required in the period of 2030 to 2050 in the **Red** storyline, whereas only about 25 billion euro would be needed over the same time span in the **Green** storyline. The lion's share of investments concern investments in new EU import infrastructure capacity. Figures from this table may be compared with investment estimates that are part of the Energy Infrastructure Package [EC, 2010b]. There a total amount of required gas infrastructure investment for 2020 is mentioned of 70 billion euro covering import pipelines, interconnectors, storage facilities and LNG terminals.

Table 6-5 combines the investment cost data that was presented earlier in Chapter 3. Expansion requirements are the largest in the **Green** and **Blue** storylines. Total investment in electricity interconnections in the **Red** storyline amount to about 7 billion euro in the 2030 to 2050 period. The estimated required investments in electricity transmission until 2020 are about 140 billion euro according to the Energy Infrastructure Package. The considerable difference between these different figures may be explained as follows. Firstly, the model set-up allows for single connections between different pairs of countries only and does not take into account possibly required upgrades within a national electricity transmission system. This may particularly give rise to large differences for infrastructure cost estimates for large countries like Germany, France, Spain and the UK. Secondly, the figures concern different time spans and within the modelling assessment a considerable increase in interconnection capacity throughout Europe before 2030 was already accounted for. This may have lead to relatively lower total investment cost estimates for the 2030 to 2050 period.

Storyline	Period	AC	DC	Total
Red	2030-2040	2,1	1,9	4,0
	2040-2050	1,1	1,2	2,4
Yellow	2030-2040	2,0	3,8	5,8
	2040-2050	1,1	1,6	2,8
Blue	2030-2040	3,1	3,6	6,8
	2040-2050	3,4	2,1	5,5
Green	2030-2040	3,9	3,4	7,3
	2040-2050	3,7	2,0	5,7

Table 6-5 Overview of required investment in electricity infrastructure across storylines (in billion € of capital expenditure)

What is the particular impact of singled out drivers on the need for infrastructure expansion? Figure 6-9 and Figure 6-10 depict the impact of intermittent electricity generation and the amount of gas used in electricity generation on respectively electricity and gas network investment as observed in the electricity and gas market analyses. From Figure 6-9 we learn that the amount of intermittent electricity generation[42] has a positive impact on the level of network investments. This can be explained by the fact that intermittent generation by means of wind-power is

[41] These estimates are based on indicative investment cost figures of €120,000 and €220,000 per 1 billion m^3 of installed capacity per year per kilometre of pipeline for respectively onshore and offshore pipeline sections and of €60 million per 1 billion m^3 of installed LNG import capacity per year. These indicative figures are based on available investment cost and capacity data for a range of pipeline and LNG import projects across the EU.
[42] Intermittent electricity generation refers to electricity generation with wind and solar technologies.

concentrated in particular areas in Europe that are not necessarily close to Europe's main load centres. Using simple linear regression estimation we computed an indicative value for the impact of additional wind-powered electricity generated: a 100 TWh increase in intermittent electricity gives rise to a need for about 5 GW of electricity network expansion. Obviously, such a rough estimate needs to be interpreted with care since the number of data points on which this interpolation is based is fairly limited and also other factors influence the need for electricity network expansion. Figure 6-10 confirms our expectations regarding the impact of gas consumption in the electricity sector and its gas infrastructure implications: a larger amount of gas consumption gives rise to a larger need for infrastructure investment. However, it must be noted that the highest infrastructure expansion values in this figure all concern the year 2030 (for the respective storylines). This is explained by the fact that especially in the period until 2030 large investment in gas infrastructure is needed as a result of the depletion of European gas reserves. After 2030 this effect is more limited since (a) European reserves are largely depleted, and (b) gas demand not longer increases, and, dependent on the storyline, even decreases.

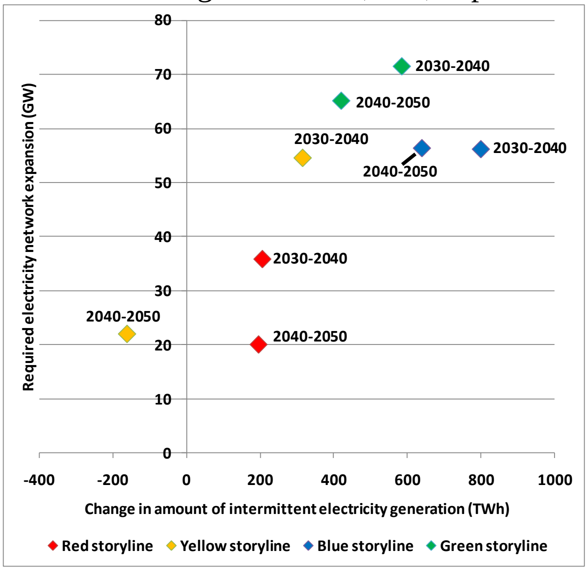


Figure 6-9 Relation between intermittent electricity generation and electricity network investment

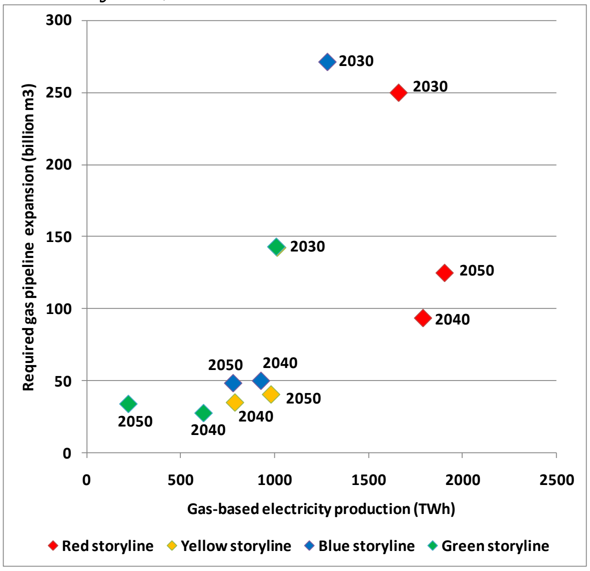


Figure 6-10 Relation between gas-based electricity generation and gas pipeline investment

6.3.6 Impact on security of supply

The level of security of supply of both the electricity and the gas market may be affected when overall electricity demand and electricity generation mix change. Different indicators may be used when evaluating security of supply on energy markets.

Electricity market

For the electricity market there are, in the context of the electricity market analysis in Chapter 3, several indicators in particular that relate to security or reliability of supply. These are the amount of electricity load that has to be shed in particular situations, the back-up electricity generation capacity that may need to be kept online due to intermittent electricity production, and the import dependency of a particular region. From Figure 6-11 we learn that the amount of electricity demand that has to be shed across storylines is limited. To put the data depicted in this figure in perspective: the total amount of load shed in 2030 in the **Red** storyline concerns 0.02% of total European electricity consumption in that year. However, load not being served is obviously undesirable since it may be discomforting and imply economic damage at the specific location concerned. Another often mentioned reliability problem is related to the potential damaging impact of a large increase in the share of intermittent electricity production: when intermittent resources are not producing the system needs to be flexible enough, for example via additional back-up generation capacity, to serve electricity demand.

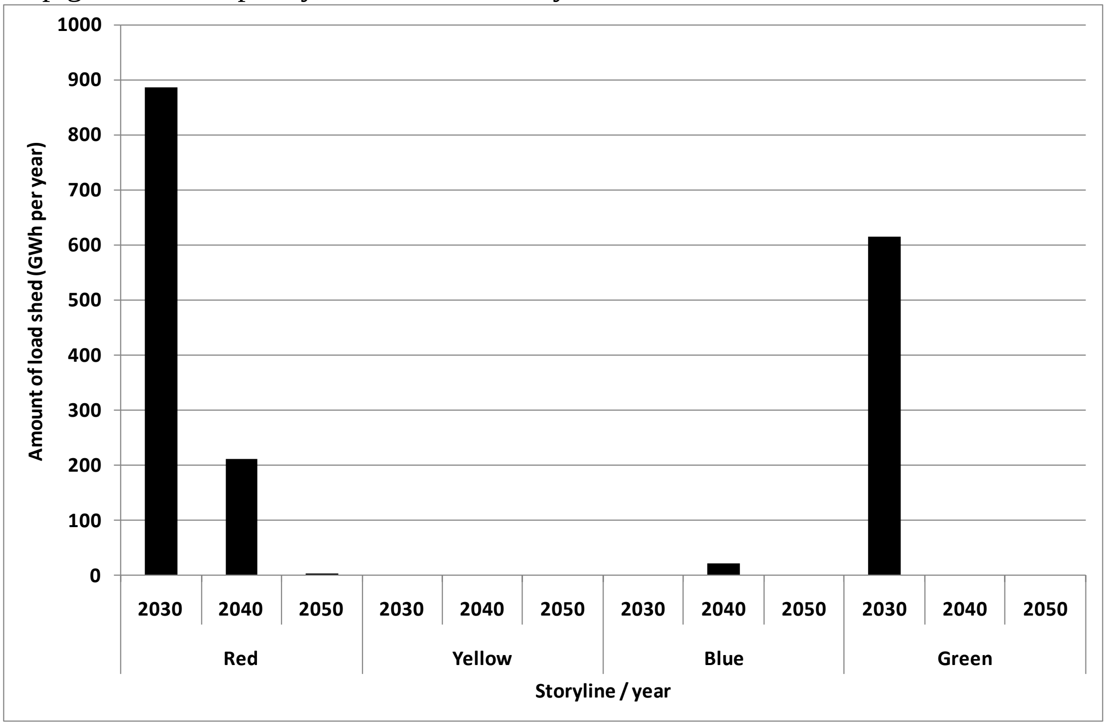


Figure 6-11 Amount of electricity load shed across storylines

Figure 6-12 shows the share of intermittent generation, which encompasses electricity generation from wind and solar power. As especially the penetration rate of wind-powered electricity production largely varies across storylines, the amount of intermittent electricity production ranges from 13 to 42% between the **Red** and **Blue** storyline. This is an indication for the additional need for flexibility in the electricity system and perhaps additional back-up capacity. As is apparent from the results with respect to the amount of load shedding in the various storylines the problem of intermittency is to a large degree sufficiently dealt with across the storylines. The additional investments in electricity infrastructure contribute in this respect.

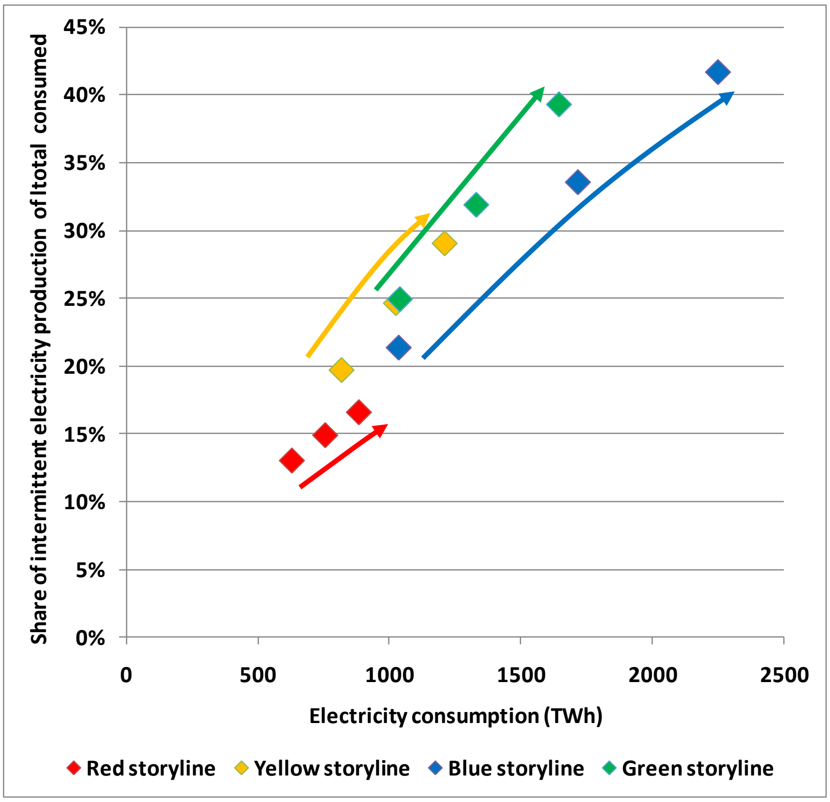
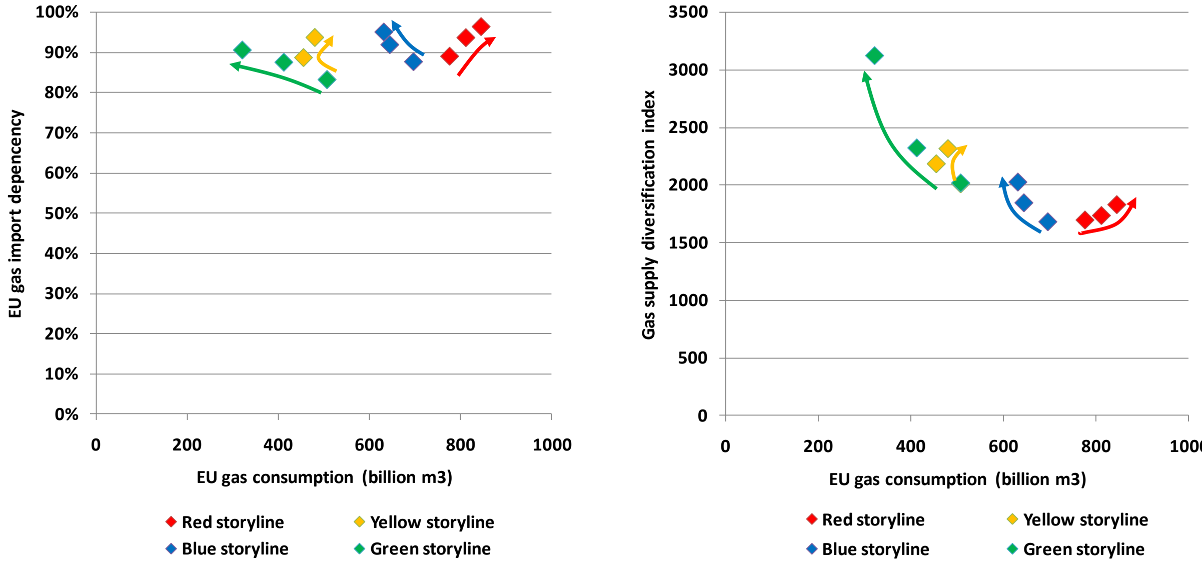


Figure 6-12 Relation between electricity consumption and the share of intermittent electricity production across storylines (arrows indicate the transition from 2030 to 2050)

The degree to which a national electricity system is dependent on electricity imports can also be interpreted as a security of supply issue: the more dependent on foreign electricity production, the more vulnerable the electricity system is to interruptions in electricity supply. Figure 3-3, Figure 3-6, Figure 3-11, and Figure 3-15 in chapter 3 show the import dependency of EU countries across storylines and time. In the **Red** storyline, the central and south-eastern European countries are dependent on imports to varying degree, with Germany relying on imports the most (in absolute terms). In the **Yellow** storyline this tendency is even more pronounced. In the **Blue** storyline the import dependency of Germany again stands out (as opposed to the large exports of especially UK and Norway to continental Europe). In the **Green** storyline also Italy becomes a large electricity importing country, which can be traced back to solar-powered electricity imports from North-Africa. This leads us to conclude that relatively speaking, central European and southern European countries in general are more vulnerable to security of supply risks than northern and western European countries.

Gas market

For the gas market the main indicators for the level of security of supply are the level of import dependency, and the level of diversification gas supplies. Both an increase in import dependency and a decrease in the sources for imported gas suggest a negative impact on security of supply. Figure 6-13 presents the values for these indicators on the basis of the Chapter 4 analysis.



(a) Relation between EU gas consumption and import dependency

(b) Relation between EU gas consumption and concentration of EU gas imports

Figure 6-13 Indicators for security of gas supply across storylines (arrows indicate the transition from 2030 to 2050)

Gas import dependency in absolute terms (volume of required gas imports) is evidently the largest in the **Red** and **Blue** storylines, but when measured in relative terms (for example the amount of gas imports as ratio of total gas consumption) the storylines are comparable: irrespective of the storyline background (and thus the level of gas consumption) the EU import dependency always ranges in the order of 85-95%. Figure 6-13(b) depicts the level of diversification in gas imports across storylines in combination with the total level of EU gas consumption over the 203-2050 period. From the resulting relationship we learn that the starting level of gas demand in 2030 matters for the impact of a change in gas demand on the level of diversification. Gas demand in 2030 in the **Red** storyline is the highest of all storylines but a further gradual increase in gas demand does not increase the concentration of gas imports very much. In the **Green** storyline, where gas demand is quite low in 2030 and is further reduced in years thereafter we find that the concentration of gas imports strongly increases towards 2050.
This can be explained as follows: low gas demand gives rise to relatively lower gas prices, which in turn determines the viability of supplies from more costly gas producers as for example LNG suppliers. Under low gas prices and low gas demand conditions, gas demand is mostly covered by the limited number of nearby gas producers such as Norway, Russia and Algeria. With an increasing gas demand and increasing gas price, more and more remote and 'new' gas suppliers enter the EU market, leading to a more diversified gas supply portfolio. Whether the former or latter situation should be regarded as reflecting a more vulnerable gas system depends on the risk profile of the various supplying countries but in general a more diversified gas supply portfolio may be considered more favourable due to larger number of alternative gas supply countries.

6.3.7 Summary

Table 6-6 presents a summary of the main storyline characteristics. It provides a quick overview on the performance of each storyline compared to others on a number of key indicators. The colouring scales indicate whether a storyline performs generally better or worse on a particular indicator than other storylines. A relatively lower (higher) level of electricity / gas consumption,

CO_2 emissions, need for electricity /gas infrastructure expansion and share of fossil fuels in electricity generation is indicated by the colour green (red).

The **Red** storyline performs relatively the worst on almost all indicators except for the need for electricity infrastructure expansion, whereas the opposite is true for the **Green** storyline. The **Blue** and **Yellow** storylines perform comparable on most indicators, but the higher level of both electricity and gas consumption in the **Blue** storyline gives rise to a slightly more positive picture for the **Yellow** storyline.

Yellow

		2030	2040	2050
Electricity consumption	PWh	4.2	4.2	4.2
Renewable electricity generation	PWh	2.1	2.4	2.3
	%	50%	58%	54%
Gas consumption	Billion m3	507	455	480
Gas imports	Billion m3	422	403	449
Electricity infrastructure expansion	GW		55	22
Gas pipeline expansion	Billion m3	142	35	41
CO2 emissions electricity sector	Megaton	468	264	321

Green

		2030	2040	2050
Electricity consumption	PWh	4.2	4.2	4.2
Renewable electricity generation	PWh	2.0	2.6	3.0
	%	48%	62%	71%
Gas consumption	Billion m3	507	412	321
Gas imports	Billion m3	422	361	291
Electricity infrastructure expansion	GW		72	65
Gas pipeline expansion	Billion m3	143	28	34
CO2 emissions electricity sector	Megaton	556	210	66

Red

		2030	2040	2050
Electricity consumption	PWh	4.8	5.1	5.3
Renewable electricity generation	PWh	1.8	2.0	2.2
	%	37%	39%	41%
Gas consumption	Billion m3	777	812	846
Gas imports	Billion m3	692	761	815
Electricity infrastructure expansion	GW		36	20
Gas pipeline expansion	Billion m3	250	93	125
CO2 emissions electricity sector	Megaton	893	830	798

Blue

		2030	2040	2050
Electricity consumption	PWh	4.9	5.1	5.4
Renewable electricity generation	PWh	2.4	3.2	3.8
	%	49%	62%	70%
Gas consumption	Billion m3	696	644	631
Gas imports	Billion m3	611	593	601
Electricity infrastructure expansion	GW		56	56
Gas pipeline expansion	Billion m3	271	50	48
CO2 emissions electricity sector	Megaton	627	451	347

Table 6-6 Summary of impact on different aspects (evaluation per storyline is relative compared with other storylines)

6.4 Reflection

In performing this study regarding trans-national infrastructure developments in the period until 2050 a range of uncertain factors need to be reflected upon, with the main factors being the storyline drivers of technology development and public support for a transition to a future sustainable energy system. Other elements covered include the uncertain future trajectory of fuel prices and the share of RES in the electricity generation mix until 2050. Needless to say that it is impossible to include all possible influential factors and developments in a scenario analysis as performed in this study. Here we would like to reflect on our study in relation to a number of possibly relevant developments that may be foreseen for the nearer or more distant future.

CCS technology development and deployment

With regard to the electricity sector we have refrained from making assumptions on the penetration of CCS technology in the electricity generation mix. The generation mix assumed in the different storylines does contain coal-and gas-based generation technologies, but only without capturing technology. How would the inclusion of capturing technology affect the results and conclusions of this study? First of all, the actual deployment of these fossil-based generation technologies may be a little different when combined with capturing technology due to a difference in electrical efficiency of the generation technology. This could lead to a somewhat different dispatch of generation units across countries and storylines and hence affect electricity flows and electricity infrastructure investment requirements. Secondly, the inclusion of capturing technology would then obviously result in lower CO_2 emissions into the air. In the study as performed the presence and deployment of fossil-based electricity generation gives rise to substantial CO_2 emissions, whereas CO_2 emissions would be captured and stored when fossil-based generation would be combined with CCS-technology. Finally, when assuming a penetration of CCS technology in the generation mix, the associated capital costs of realising this technology would be much higher compared with the case of fossil-based technology without CCS. In other words, the average costs of electricity generation as computed in Chapter 6 would become relatively higher in the storylines with considerable fossil-based generation.

Development of unconventional gas

With respect to gas market developments we have not included the possible large-scale commercial production of unconventional gas such as shale gas. The future role of shale gas production is uncertain. Although there seems to be quite large technical potential a number of factors may substantially limit its commercial operation. Compared to the successful build-up of shale gas production in the US some marked differences with the case of the EU may hinder shale gas developments in the EU. First of all, large-scale deployment maybe problematic due to the much higher population density in some of the shale gas-rich regions in Europe. Furthermore, there may be environmental barriers in shale gas development related to health issues related to ground water contamination. Finally, the prevailing property right laws across the EU may introduce further barriers for large-scale shale gas production. In the US the government holds the rights to exploit underground minerals, whereas in the EU these rights reside with the landowners. This system is more vulnerable in case of negative public sentiments towards shale gas production. How would large-scale shale gas production in the EU in the period until 2050 impact the results and conclusions of this study? First of all this development would potentially increase the size of world gas reserves, making it a less scarce commodity than previously anticipated by market actors. The commercial exploitation of shale gas around the world could alleviate the concentration of gas reserves around the world and reduce the market power of the currently dominating global gas suppliers. An increase in shale gas reserves and production in the EU would reduce its import dependence and could lead to higher levels of security of supply since gas supplies will then be located relatively closer to consuming markets. This obviously impacts the need for gas infrastructure as well. There will be less need for an increase in gas infrastructure enabling gas imports towards the EU and, depending on the exact geographical spread of shale gas reserves across the EU, a larger need for an increase in internal pipeline capacity. When the location of shale gas reserves matches with the previously depleted conventional gas reserves the need for additional internal gas infrastructure capacity could be very low, but when shale gas reserves are located in different locations a changing gas flow pattern in the EU will result with associated gas infrastructure expansion requirements. A similar line of reasoning applies to the developments with respect to bio-gas. Large-scale bio-gas production has not been included in the gas market analysis, but when this would materialise it would have similar impacts on security of supply and infrastructure needs as shale gas. In addition, an increase in the production and use of bio-gas will potentially reduce the CO_2 emissions from gas-based electricity generation units, leading to relatively lower CO_2 emissions.

Competition on the global gas market

In recent years the further advancement of the LNG business has led to the emergence of a truly global gas market. Previously, only regional markets for gas existed, each with their own demand and supply dynamics. The model deployed in the gas market analysis in chapter 4 does not fully capture this newly emerging reality as it only contains European gas demand and its EU internal and external gas supply countries. The EU is likely to increasingly experience global gas competition via two ways: the competition for LNG supplies with the Asian and American market, and competition for pipeline supplies from for example the central Caucasus region than are able to serve both the EU and Asian (i.e. Chinese) gas market. Increasing competition may affect both short-term supply decisions and long-term investment decisions in the gas market. Depending on the anticipated future energy system, investors in gas production and gas infrastructure assets may decide to re-focus on different export markets. This could for example concern the possible pipeline supplies to China from gas reservoirs that geographically speaking could also have been destined for the EU market. An increased competition in LNG supplies may affect the EU interest in developing more LNG terminals, and could lead to an increase in the price of LNG.

Future role of hydrogen

The long-term energy system perspective until 2050 that is adopted in this study also raises a question on the viability of a hydrogen-based system. Over this time horizon, a successful penetration of hydrogen-based appliances may be reasonable, thereby possibly reducing the need for gas and electricity infrastructure and increasing the need for local or trans-national hydrogen infrastructure. Hydrogen as a possibly competing energy carrier has not been included in this study, but that does not mean to say that we deem a hydrogen-based energy system to be infeasible over time. The inclusion of uncertain hydrogen developments would have increased the number of storylines to be assessed and would have further complicated the performed study. In future studies on sustainable energy systems that can build further on the current work in, among other projects, SUSPLAN, hydrogen will need to play a role as well.

7 CONCLUSIONS AND RECOMMENDATIONS

7.1 Main conclusions

From the analysis on future electricity infrastructure developments we conclude that a strong increase in the penetration rate of especially large-scale renewable electricity generating units (i.e. large-scale offshore wind parks) has large impact on the future need for electricity infrastructure upgrades, both in offshore DC as onshore AC lines. Since most favourable wind locations generally lay in the south-western and north-western parts of Europe a substantial share of future investments need to go to strengthening of the electricity corridors from south and north-western Europe to central and Eastern Europe. Because of the insufficient geographical match between generation and load centres large electricity network upgrades are required.

Future infrastructure developments on the gas market are determined by the inevitable transition towards much higher gas import dependency on the one hand, and the further infrastructure needs resulting from a possibly larger role for gas in the electricity sector on the other. In the period until 2030 the EU will deplete its gas reserves. This increases the need for new gas imports that need to be accommodated by additional infrastructure. For this reason there is already substantial investment in gas pipelines and LNG import terminals needed before the timeframe of 2030 to 2050 on which this study focuses. Infrastructure developments after 2030 are largely dependent on the demand for gas in the electricity sector. The share of gas in the electricity sector is, among other factors, dependent on the penetration rate of centralised and decentralised renewable electricity generation. A future electricity generating mix with a low share of gas (such as in the **Green** storyline) naturally sees a much lower infrastructure investment need a future electricity generating mix with relatively high share of gas (such as the **Red** storyline). Some robust infrastructure implications are identified with respect to gas flows and expansion of particular corridors and cross-border interconnections:

- The increasing depletion of gas reserves in the UK and the Netherlands significantly reduces the gas flows from north-western Europe to neighbouring countries (i.e. Netherlands – Germany, UK – Belgium interconnections).
- A large increase in direct gas flows from Russia to Germany via the proposed North Stream corridor reduces the gas flows from Russia via the Central European corridor in all storylines.
- Italy emerges as a gas hub in all storylines, although its relative importance differs across storylines. Its gas hub position gives rise to a net gas flow from Italy to Germany and Central Europe. The Italian gas imports that allow Italy to become a transit hub originate from Algeria, Libya and various LNG exporting countries.
- Spain increases its importance as gas transit country to varying degree across storylines, due to increased exports of Algeria to the EU borders.
- Across all storylines, Turkey and the Balkan region emerge as important gas hubs. Gas is sourced from Central Asia and Russia, and re-exported to South-East Europe, and from there further into Central and Western Europe.

Analysis on the joint implications of future renewable energy futures on different aspects of the electricity and gas markets we learn that there is a paradox result that the electricity infrastructure cost of integrating renewable electricity are higher in especially low energy demand storylines. This is caused by an increasing need to transfer large volumes of electricity through Europe so to match favourable electricity generation regions with existing load centres. In a high energy demand storyline it is easier to match demand and electricity production locally. However, we need to take into account gas infrastructure developments as well. A high energy demand storyline also causes a larger penetration of gas in the energy mix, although the actual penetration rate varies across storylines. The higher energy demand, the larger the need for gas and the higher the cost of developing gas infrastructure of different types.

Moreover, we find that different future energy backgrounds have different implications for the cost of generating electricity. In particular future energy systems with high penetration rates of renewable electricity, the total costs of fuel (and CO_2 emissions) is low but the capital costs of generation capacity high, whereas this is exactly the other way around in future energy systems with low penetration rates of renewable electricity.

The development of renewable electricity generation, its integration in existing systems, and the required infrastructure expansion that results are hindered by a number of barriers, amongst other barriers of social, technical, and economic nature. From the overview provided in this study we take up a limited number of most crucial barriers to be further addressed in future work within the SUSPLAN project. These barriers include the lack of public acceptance for energy transition in general and specific energy projects in particular, the regulatory and financial incentives for infrastructure operators to build required trans-national infrastructure in a timely and cost-effective manner, and the problems encountered when realising the large EU potential regarding offshore wind power.

7.2 Recommendations

The following recommendations can be based on the results of this study:

- A strong support is needed in particular for the realisation of a number of critical energy corridors on both the gas and electricity market, especially infrastructure expansion requirements that are needed across a wider range of possible future energy market developments (as covered by identified storyline backgrounds). Measures to this purpose can be further developed under the recently launched Energy Infrastructure Package of the EC. In general, the larger the penetration of renewable sources for electricity generation the larger the need for timely investment in electricity infrastructure. In other words, a push for a more sustainable energy system by 2050 should be accompanied by an equally strong support for sufficient electricity infrastructure development.
- Future infrastructure developments require would benefit from more certainty with respect to the long-term EU climate policy. Especially the choice of technology in the electricity generation sector in the medium to long term is prone to specific dynamics and expectations of fuel and especially CO_2 prices. The current ETS does put a price on the emission of CO_2 but is not successful in providing a long-term perspective on a credibly high CO_2 price. This especially harmful in an industry where (generation and electricity and gas infrastructure) investments are capital intensive and need to be depreciated over a time span of 40 or even 50 years. This is something to explicitly take into account in discussions on future pathways to a sustainable energy system in 2050. The current EU preparations for a 2050 energy vision are an example.

  There is a strong need to take into account the fact that electricity and gas markets are strongly intertwined, both in the short term (on operational issues), as well as the long-term, in for example infrastructure development. Focussing on single strategies for either market, whether from a market integration, security of supply or sustainability perspective is bound to give rise inadequate policies and regulations and undesirable energy market developments.

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APPENDIX A: MODEL ASSUMPTIONS AND INPUT DATA

A.1 Fossil fuelled thermal power plants

Generation power plants have been subdivided into:

- steam turbine power plants: fuel oil-fired, natural gas-fired, hard coal-fired, lignite-fired,
- gas turbine power plants: open cycle and combined cycle, all natural gas-fired,
- Nuclear power plants.

As for gas-fired plants, starting from the 2010 total value estimated in [Lise et al., 2006] and taking into account the WEPP (World Electric Power Plants) database (2010 version), 2010 total gas-fired generation has been divided into three different technologies (CCGT, OCGT and ST) on the basis of the 2010 percentage distribution respect to the total value.
It has been supposed that all power plants installed after 2010 are new CCGTs, while those decommissioned are, respectively, STs, OCGTs and CCGTs.

A.1.1 Electrical Efficiency

The ranges of the average electrical efficiencies (%) adopted for the different fossil fuelled generation technologies in the different countries are reported in the following Table A-1. These values have been estimated by RSE, assuming efficiency of new CCGTs increasing 2% per decade.

Technology	Efficiency [%]
Oil fired steam turbine	35 ÷ 36
Natural gas fired steam turbine	32 ÷ 38.8
Repowering	39.7
Hard coal fired steam turbine	33 ÷ 45
Lignite fired steam turbine	32 ÷ 35
Open cycle gas turbine	28.1 ÷ 37
Combined Cycle Gas Turbine	50 ÷ 60
Nuclear	30 ÷ 35

Table A-1 Ranges of the electrical efficiencies (%) adopted for the different fossil fuelled generation technologies

A.1.2 Forced and scheduled unavailability

In the following Table A-2, forced (in p.u.) and scheduled (in days per year) average unavailability rates adopted for the different fossil fuelled generation technologies are reported. As for nuclear generation, for each country, the average unavailability data of the last three years of operation (2006-2008) taken from the IAEA PRIS website[43] have been used.

Technology	Unavailability	
	Unforced [p.u.]	Scheduled [days]
Oil fired steam turbine	0.080	42
Natural gas fired steam turbine / Repowering	0.055	42

[43] http://prisweb.iaea.org/Wedas/WEDAS.asp.

Old hard coal fired steam turbine	0.100	70
New hard coal fired steam turbine	0.055	35
Hard coal fired USC steam turbine	0.055	35
Hard coal fired USC steam turbine with CCS	0.055	35
Lignite fired steam turbine	0.113	70
Open Cycle and Combined Cycle Gas Turbine	0.050	35
Combined Cycle Gas Turbine with CCS	0.050	35
IGCC with CCS	0.050	35
Nuclear	0.001 ÷ 0.293	25

Table A-2 Forced (p.u.) and scheduled (days) unavailability rates adopted for the different fossil fuelled generation technologies

As for the scheduled unavailability, a monthly distribution (shown in Table A-3) of the planned outages as close as possible to reality has been adopted, by concentrating it in the months characterized by a lower load.

Month	Scheduled Unavailability Distribution [%]
January	8.41
February	8.80
March	9.98
April	9.04
May	8.85
June	6.60
July	5.13
August	8.99
September	9.07
October	9.79
November	8.15
December	7.19

Table A-3 Distribution over the year of the scheduled unavailability adopted for the fossil fuelled generation technologies

A.2 Renewable energy power plants

Since renewable energy power plants are in most cases non dispatchable, specific hourly production profiles have been defined and imposed in the simulations, adopting different assumptions according to the operating characteristics of the generation technologies considered, as reported in the following paragraphs.

A.2.1 Hydro generation

The MTSIM simulator can dispatch both reservoir and pumped storage hydro power plants, provided that, among others, data concerning the volumes of reservoirs / basins are defined. The run of the river generation is taken into account as an injection. As for the monthly values of hydro energy production (or consumption) in each country, the average values of all the years available in the Statistical Database of the ENTSO-E website have been taken into account. More details are provided below.

Run of river hydro power plants
The hourly generation profile of run of river hydro power plants has been assumed flat and its level has been differentiated among the four seasons. Values of net generation capacity have been calculated through harmonizing a starting point for SUSPLAN WP2 and WP3 based on available statistics and other scenario studies.

Hydro reservoir power plants
For each node, a basin equivalent volume equal to the estimated annual production has been chosen. It has been assumed that both at the beginning and at the end of the year the reservoirs are half full. Monthly water inflows have been determined subdividing the total annual production on the basis of the average monthly energy distribution calculated by energy statistics. Hourly water inflows are equal to the monthly water inflows divided by the number of hours.

Hydro pumped-storage
The time to empty the basin has been set equal to six hours; this value has been chosen analysing historical values. Hydro pumped-storage efficiency is 70%.

A.2.2 Photovoltaic solar power plants

As for photovoltaic solar power plants, as for year 2030, installed capacity data have been taken from [Lise et al., 2006]. Just like in [SECURE, 2009], data concerning the annual / monthly production of each installed kW at optimal inclination have been taken from the *Photovoltaic Geographical Information System* (PVGIS) of the JRC - *Joint Research Centre*[44], while the hourly generation profiles have been built on the basis of the average daily hours of light in each month taken from Earth Tools[45].

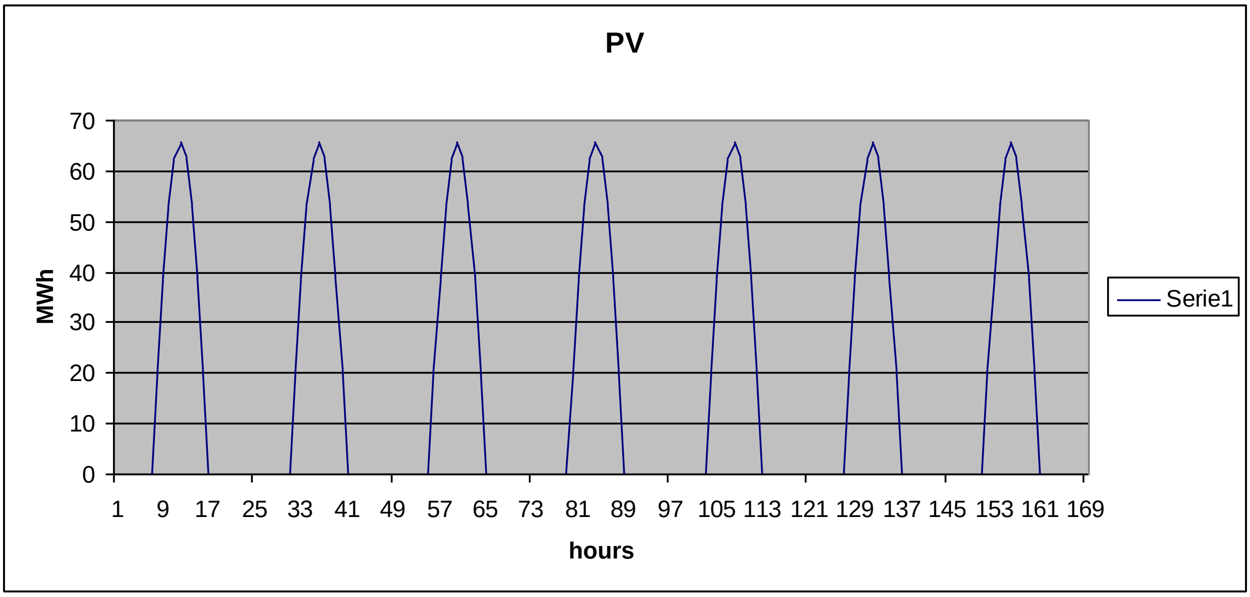

Figure A-1 Exemplary PV electricity production profile

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[44] JRC – Joint research Centre – Photovoltaic Geographical Information System (PVGIS) – Solar Irradiance Data: www.re.jrc.ec.europa.eu/pvgis/apps/radday.php?lang=en&map=Europe.
[45] EarthToolsTM: www.earthtools.org.

A.2.3 Other RES

To estimate the electricity production of other renewable energy sources (biomass, biogas, geothermal, etc.) and of waste non-CHP power plants, a value of 4500 equivalent full-load annual hours has been taken into account[46]. Moreover, a flat generation profile has been assumed (as in [SECURE, 2009a]).

A.3 Electricity demand

The annual values of the 2030-40-50 electrical load (final consumptions plus network losses; pumped storage consumption not included) have been taken from a harmonized starting point for WP2 and WP3 based on available statistics and other scenario studies. As for the hourly profile, each country's 2008 profile has been taken from the ENTSO-E Statistical Database[47], and then it has been scaled adding a constant base load in order to obtain the estimated annual load value. The last step has been to align the working days and the holidays of 2015 or 2030 with those of 2008. An example of load demand profile is reported in Figure A.2.

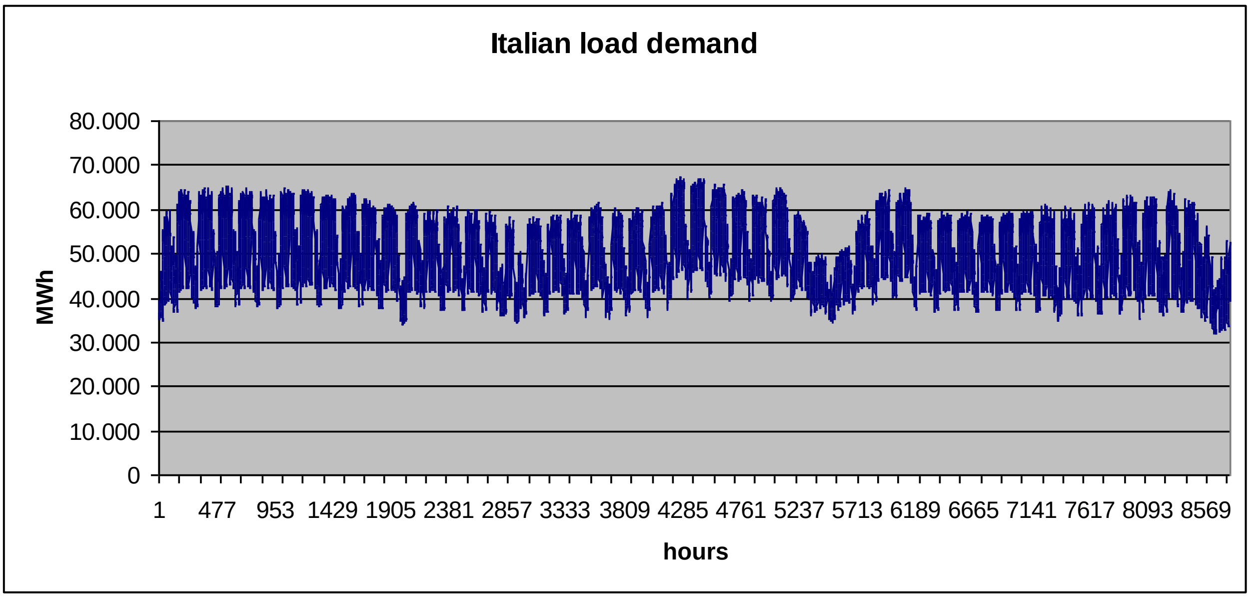

Figure A-2 Exemplary profile of electricity demand

A.4 CO_2 cost and emission factors

From 2030 to 2050, CO_2 prices from WEO 2009 have been taken into account. For **Green** and **Yellow** storylines we used prices referred to the "reference scenario", while for **Red** and **Blue** ones we used prices of the "450 ppm scenario".

[46] A more detailed estimation for each source has been carried out for Italy.
[47] See: www.entsoe.eu.

CO_2 prices (€/tCO_2)	2030	2040	2050
Green and Yellow	43.20	52	60.80
Blue and Red	80	100	120

Table A-4 CO_2 costs

Emission factor (tCO_2/GJ)	
Coal	0.106
Gas	0.050
Lignite	0.139
Oil	0.100
Uranium	0

Table A-5 CO_2 emissions factors [Lise et al., 2006]

A.5 Value of lost load (VOLL)

As reported in [SECURE, 2009b], VOLL estimation is a very difficult task and the results obtained are subject to several uncertainties. On the basis of the broad ranges and on the considerations reported in [ENTSO-E, 2010c], we decided to subdivide the European countries taken into account into three groups:

- Developed countries, characterized by a 20 €/kWh VOLL value;
- Developed countries which still have growth margins higher than those included in the first group, characterized by a 10 €/kWh VOLL value;
- Developing countries, characterized by a 3.5 €/kWh VOLL value.

Since the MTSIM simulator does not allow to specify VOLL values for each country, a single "European" VOLL value has been determined calculating the average of each country's value. With these assumptions, the resulting VOLL value is equal to 16.36 €/kWh. In any case, it must be taken into account that the precision of the definition of such a value is definitely not critical for the results of the simulations: it is sufficient to get the right order of magnitude.

A.6 Assumptions for electricity infrastructure development

The studies run for the period 2030-2050 have requested to assume the net electricity exchanges to/from the extra-European countries from/to the pan-European system modelled (see also Figure 2-10. Net exchanges have been based estimated on assumption for the cross border maximum allowable capacities values and for the load utilization factors of the corresponding corridors. Tables A-7 to A-9 respectively show exogenous net exchanges assumptions for the Red, Blue and Yellow, and Green Storyline. Concerning the estimation for the maximum capacity increase of HVDC corridors (internal to the modelled network) as described in Section 2.3.1.2 opportune hypotheses have been made. Table A-9[48] provides those estimations for the four Storylines.

[48] Upgraded HVDC links are marked by "*"

Interconnection (A→B)	Net capacity (A→B) [MW]			Net exchange (A→B) [GWh]		
	2030	**2040**	**2050**	**2030**	**2040**	**2050**
KA→LT	1000	1000	1000	3000	3000	3000
KA→PL	600	1000	1000	3000	5000	5000
RU→LV	400	400	400	400	400	400
LT→BY	2200	2200	2200	2000	2000	2000
RU→EE	1000	1000	1000	900	900	900
RU→FI	1900	1900	1900	12600	12600	12600
RU→NO	50	50	50	220	220	220
BY→PL	1000	1000	1000	6000	6000	6000
UA→PL	1480	1880	2280	9063	11512	13962
UA→UA_W	500	1000	2000	3000	6000	12000
UA→RO	200	1000	2000	1000	5000	10000
MD→RO	1500	1500	1500	7500	7500	7500
TR→RO	600	600	600	3680	3680	3680
TR→BG	500	700	1000	3066	4292	6132
TR→GR	800	1000	1500	4906	6133	9199
IT→MT	200	200	200	1314	1314	1314
TU→IT	1000	1000	1000	6570	6570	6570
DZ→ES	1000	1000	1000	6570	6570	6570
ES→MA	1400	2000	3000	8585	12264	18396
UK→IS	0	0	0	0	0	0
DZ→IT	0	0	0	0	0	0
LY→IT	0	0	0	0	0	0
LY→GR	0	0	0	0	0	0
KA→DE	0	700	700	0	4292	4292

Table A-6 Exogenous net exchanges assumptions for the Red Storyline

Interconnection (A→B)	Net capacity (A→B) [MW]			Net exchange (A→B) [GWh]		
	2030	**2040**	**2050**	**2030**	**2040**	**2050**
KA→LT	1000	1000	1000	3000	3000	3000
KA→PL	600	600	600	3000	3000	3000
RU→LV	400	400	400	400	400	400
LT→BY	2200	2200	2200	2000	2000	2000
RU→EE	1000	1000	1000	900	900	900
RU→FI	1900	1900	1900	12600	12600	12600
RU→NO	50	50	50	220	220	220
BY→PL	1000	1000	1000	6000	6000	6000
UA→PL	1480	1480	1480	9063	9063	9063
UA→UA_W	500	800	1000	3000	4800	6000
UA→RO	200	500	800	1000	2500	4000
MD→RO	1500	1500	1500	7500	7500	7500
TR→RO	600	600	600	3680	3680	3680
TR→BG	500	700	1000	3066	4292	6132
TR→GR	800	1000	1500	4906	6133	9199
IT→MT	200	200	200	1314	1314	1314
TU→IT	1000	1500	2000	6570	9855	13140
DZ→ES	1000	1500	2000	6570	9855	13140
ES→MA	1400	2000	3000	8585	9636	10512

UK→IS	0	0	1400	0	0	9198
DZ→IT	0	500	1000	0	3285	6570
LY→IT	0	500	1000	0	3285	6570
LY→GR	0	0	1000	0	0	6570
KA→DE	0	700	700	0	4292	4292

Table A-7 Exogenous net exchanges assumptions for the Blue and Yellow Storylines

Interconnection (A→B)	Net capacity (A→B) [MW]			Net exchange (A→B) [GWh]		
	2030	2040	2050	2030	2040	2050
KA→LT	1000	1000	1000	3000	3000	3000
KA→PL	600	600	600	3000	3000	3000
RU→LV	400	400	400	400	400	400
LT→BY	2200	2200	2200	2000	2000	2000
RU→EE	1000	1000	1000	900	900	900
RU→FI	1900	1900	1900	12600	12600	12600
RU→NO	50	50	50	220	220	220
BY→PL	1000	1000	1000	6000	6000	6000
UA→PL	1480	1480	1480	9063	9063	9063
UA→UA_W	500	800	1000	3000	3000	3000
UA→RO	200	500	800	1000	1000	1000
MD→RO	1500	1500	1500	7500	7500	7500
TR→RO	600	600	600	3680	3680	3680
TR→BG	500	1000	1500	3066	6132	9198
TR→GR	800	1000	1500	4906	6132	9198
IT→MT	200	400	400	1314	1314	1314
TU→IT	1000	2000	3000	6570	13140	19710
DZ→ES	1000	1500	2000	6570	9855	13140
ES→MA	1400	3000	4000	8585	10512	12264
UK→IS	0	0	1400	0	0	9198
DZ→IT	0	1000	2000	0	6570	13140
LY→IT	0	1000	2000	0	6570	13140
LY→GR	0	0	1000	0	0	6570
KA→DE	0	700	700	0	4292	4292

Table A-8 Exogenous net exchanges assumptions for the Green Storyline

Interconnection (A→B)	Net capacity increase [MW]					
	Red		Blue & Yellow		Green	
	2030-40	2040-50	2030-40	2040-50	2030-40	2040-50
IE - UK	500	500	1000	1000	1000	1000
FR - UK	1000	1000	2000	1000	2000	1000
UK - BL	0	1000	1000	1000	1000	1000
UK - NL	1000	0	1000	1000	1000	1000
UK - NO	1000	0	1000	1000	1000	1000
NO - NL	1000	1000	2000	1000	2000	1000
NO - DE	1000	1000	2000	1000	2000	1000
DK_W – SE*	360	0	360	0	360	0
DK_W - DK_E*	600	0	600	0	600	0
DE - DK_E*	550	0	550	0	550	1000
DE - SE*	600	0	600	0	600	1000
SE - PL*	600	0	600	0	600	0
FR - IE	0	0	1000	0	1000	0

Table A-9 Assumptions on maximum capacity increase of HVDC corridors [MW]

A.7 Electricity infrastructure cost reduction trends

In order to estimate electricity infrastructures cost reduction trends over the years, it has to be recalled that, typically, the costs of a technology decrease with its increasing deployment. This trend has been recorded in many cases of technology developments in the past, and it is especially true for innovative technologies. Particularly in the latter cases, this takes into account the effects of learning experienced by the technology due to the progress over the years in terms of increase of efficiency in manufacturing the same product. In general, for innovative technologies it has been observed that costs tend to decrease at a quite constant rate with each cumulative doubling of deployment capacity [Junginger *et al.*, 2004]. This aspect may be then used to extrapolate projections for future technology cost reductions. This can be mathematically expressed by means of the following formulas for describing a learning experience curve:

$$C_f = C_i * (P_f / P_i)^b = C_i * (2)^b$$

$$PR = 2^b$$

$$LR = 1 - PR$$

where C_f and C_i respectively represent the future and present technology unit cost value, P_f and P_i respectively represent the future and present cumulative technology deployment capacity, b is the experience index (negative), PR is the progress ratio and LR is the learning rate. The progress ratio PR is a parameter that expresses the rate at which unit costs decline each time the cumulative capacity doubles. For example, a PR of 0.8 implies that after one cumulative doubling, unit costs are only 80% of the original costs, i.e. there is a 20% cost decrease.

This approach has been used to estimate the future trend of HVDC technology cost: in this case, a progress ratio of 0.71 has been considered. This leads to a value of b equal to -0.49. The above described approach has then been applied firstly to the 2005-2030 years. The HVDC cost development has been estimated for this period, taking into account the cumulative installed capacity of HVDC in Europe estimated for the period over the years 2005-2030 by REALISEGRID[49]. This first stage leads to estimate a HVDC cost reduction in 2030 amounting to 44% respect to 2005 cost. This serves then as a starting reference for 2030-2050 development trends considered for SUSPLAN studies. By the HVDC cumulative deployment capacity evaluations made for the four storylines, HVDC cost reductions for the years 2040 and 2050 have been estimated for the four storylines. In this case, however, the application of the above described approach would have led to a very significant HVDC cost decrease over the years 2030-2050. A conservative estimation has then been put in place and the following HVDC cost projections (in % respect to 2005 starting value) have been assumed for the four scenarios over the 2030-2050 years:

	2030	2040	2050
Red	56.0	56.0	56.0
Yellow	56.0	53.0	50.0
Blue	56.0	50.0	45.0
Green	56.0	45.0	40.0

Table A-10 Percentage cost reduction of HVDC compared with 2005

[49] FP7 REALISEGRID project, http://realisegrid.rse-web.it.

As it can be seen, the technology development driver plays a major role in these HVDC cost projections. For estimating the HVAC investment cost trends over the years 2030-2050 in the four scenarios, a more conservative approach has been followed considering, on one side, the use of a more mature technology (HVAC conventional overhead lines), and on the other side a less penetrating innovative transmission technology set (HVAC cables). The projections assumed for HVAC transmission (in % respect to 2005 starting value) are then illustrated here:

	2030	2040	2050
Red	80.0	80.0	80.0
Yellow	80.0	80.0	80.0
Blue	80.0	75.0	70.0
Green	80.0	75.0	70.0

Table A-11 Percentage cost reduction of HVAC compared with 2005

As cost components like the local compensation for building new transmission assets are also affected by the storylines, an estimation of this cost has been taken into account by assuming projections (in % respect to 2005 starting value) as in the following:

	2030	2040	2050
Red	80.0	80.0	80.0
Yellow	80.0	50.0	30.0
Blue	80.0	80.0	80.0
Green	80.0	50.0	30.0

Table A-12 Percentage cost reduction of cost related to local compensation schemes compared with 2005

It can be noticed that the public acceptance driver plays a major role in the estimation of this cost component.

A.8 Assumptions on electricity infrastructure development until 2030

The pan-European transmission grid at 2030 is reported in Table A-13 and Table A-14.

AC Interconnection (A -> B)	NTC A -> B (MW)	NTC B -> A (MW)
PT -> ES	3000	3000
ES -> FR	4000	4000
FR -> IT	4200	2595
IT -> CH	3710	6540
FR -> CH	3200	2300
FR -> DE	3000	3150
FR -> BL	4000	3100
CH -> DE	3200	1500
BL -> NL	2400	2400
NL -> DE	4500	5350
DE -> DK_W	1500	2000
DK_E -> SE	1700	1300

DE -> PL	3100	3000
DE -> CZ	2300	3800
DE -> AT	6880	6880
CH -> AT	1400	1400
IT -> AT	2200	2200
IT -> SI	2150	2150
CZ -> PL	800	2000
PL -> SK	1500	1400
CZ -> SK	2000	1000
AT -> CZ	1100	2000
SK -> HU	3000	2100
AT -> HU	1500	1200
AT -> SI	1200	1200
HU -> SMK	600	600
HU -> RO	600	1400
SMK -> BG	500	650
SMK -> RO	500	850
RO -> BG	950	950
BG -> GR	1500	1400
AL -> GR	150	300
AL -> SMK	1250	1200
BH -> SMK	2000	1900
MK -> GR	350	300
MK -> SMK	1100	600
HR -> BH	1530	1600
HR -> SMK	680	600
HR -> SI	1900	1900
HR -> HU	3000	2500
RO -> UA_W	400	400
HU -> UA_W	650	1150
SK -> UA_W	400	400
NO -> SE	5450	5250
SE -> FI	2800	2700
FI -> NO	1000	1000
LT -> LV	2100	1900
LV -> EE	1400	1300

Table A-13 NTC capacity of AC cross-border electricity interconnections in 2030

DC Interconnection (A -> B)	NTC A -> B (MW)	NTC B -> A (MW)
DE -> BL	1000	1000
UK -> IE	1850	1850
UK -> NO	1400	1400
SE -> LT	1000	1000
GR -> IT	1000	1000
AL -> IT	2000	2000
SMK -> IT	1000	1000
HR -> IT	1000	1000
FR -> IE	1000	1000
FR -> UK	3000	3000
UK -> BL	1000	1000
UK -> NL	1320	1320
NL -> NO	1700	1700
NO -> DE	2400	2400
SE -> DE	600	600
SE -> PL	600	600
LT -> PL	1000	1000
LV -> SE	700	700
EE -> FI	1000	1000
SK -> AT	1500	1500
HU -> SI	900	900
BL -> DE	1000	1000
DE -> DK_E	1150	1150
NL -> DK_W	600	600
NO -> DK_W	1600	1600
DK_W -> SE	740	680
MK -> BG	250	450
AL -> MK	500	500
DK_W -> DK_E	600	600

Table A-14 NTC capacity of DC cross-border electricity interconnections in 2030

A.9 The GASTALE model

GASTALE is an equilibrium model containing different gas market actors striving for different optimization goals. Below we briefly characterize the actors and their optimization problems.

A.9.1 Methodology

Gas producers maximize profits by setting production levels and consequential capacity bookings in infrastructure that accommodates gas wholesale market sales in consuming countries. Earnings amount to the wholesale market price received minus the costs of production and infrastructure use. Producers can be assumed to exercise some degree of market power *a la Cournot* game versus competitive gas producers, but are assumed to be price takers with respect to the use of gas infrastructure capacity. Previous studies with the GASTALE model [Lise and Hobbs, 2008; Lise *et al*., 2008] have been based on partial strategic behaviour assumption in which Russia is assumed to exercise market power on 25% of their export potential to EU while all other producers exercise market power on 75% of their production capacity in EU or export potential to EU. These particular assumptions have been found to give the best fit of model output with historic data for the base year 2005.

Transmission System Operators (TSOs) own and operate on- and off-shore pipelines and LNG infrastructure. These actors are assumed to be price-taking. This can be interpreted as them being regulated by regulatory authorities or otherwise being operated in such a way that infrastructure capacity is priced efficiently. Price-taking behaviour of TSOs corresponds to an efficient allocation of scarce capacity where the value of infrastructure services is maximized. TSOs choose investment levels for additional infrastructure capacity so that the discounted payoff from providing additional infrastructure services minus the investment cost is maximized.

Storage System Operators (SSOs) own and operate gas storage facilities and decide on injection and extraction levels throughout the year across seasons. Injection takes place in summer (low demand) whereas extraction occurs in the remainder of the year (during high and shoulder demand seasons). Similar to TSOs, the owners and operators of storage facilities are assumed to be price taking. This implies an assumption of competitive gas storage markets where available gas storage capacity is priced efficiently. In the short-run, storage operators maximize profit from selling gas during medium and high demand periods minus their cost of buying and storing of gas during low demand season. In the long-run storage operators can choose to invest in additional storage capacity. This involves a maximization of the discounted payoff from providing additional storage services minus the associated investment cost.

Mathematical formulation

The GASTALE model is formulated as a mixed complementarily problem. This implies that optimality conditions of market actor's maximization problems together with market clearing conditions give rise to equilibrium outcomes. Market clearing conditions mainly consist of energy balances between market players (supply equals demand) which determine the wholesale gas prices and the prices for the use of gas infrastructure. The solution of the complementary problem consist of wholesale prices per season in each consumption region, the price of using different infrastructures, and production, transport, and storage volumes for three periods as well as the investment levels for additional transport and storage capacity. Note that the solution corresponds to a Nash-type of equilibrium which maximizes each market participant's problem. Hence in equilibrium no individual actor has an incentive to deviate from its strategy. The detailed description of the model and its underlying mathematical formulation is given in [Lise and Hobbs, 2008].

A.9.2 Model input assumptions

Below we briefly summarize the GASTALE input assumptions for consumption and generation.

Consumption

Consumption is defined on a regional (e.g. ITALP which comprises Austria, Italy, Slovenia and Switzerland) or country (e.g. Netherlands, France) level, and consists of three different market sectors, namely: the power generation sector, the industrial sector, and the residential sector. In addition, consumption is divided over three seasons within a year: low, 'shoulder', and high demand periods representing (i) April-September; (ii) February, March, October, November; and

(iii) December-January of each calendar year respectively. Gas consuming sectors have different degrees of seasonal variation. A seasonal variation factor is identified for industry and residential sectors in each country and reflects the historically observed seasonal flexibility of gas demand for that particular sector and country. For power generation sector, the gas consumption levels obtained from MTSIM simulations determine the seasonal variation for each country. Finally, for each demand sector a different price elasticity of demand is assumed. Demand elasticity is not country-specific but uniform across countries. We have assumed a price elasticity of -0.40, -0.25 and -0.75 for respectively the industrial and services, residential, and power generation sectors [Egging and Gabriel, 2006; Lise and Hobbs, 2008]. For example, this means that a 1% increase in the gas price gives rise to a 0.4% decrease in gas demand in industry.

Generation

Gas production to EU is provided by the producers in EU (i.e, UK, NL, Norway etc) and outside EU (i.e, Russia, Qatar, etc). Both the cost and capacity for gas production now and in the future is determined exogenously. Hence, no investment decision-making is modelled for gas production. This means that an assumed gas production capacity and marginal cost curve is put into the model as an external restriction for the whole time period. These marginal cost and capacity curves are derived from earlier GASTALE applications (see earlier mentioned GASTALE studies). Recent IEA publications were also taken into account [IEA, 2010a]. Figure A-3 and Figure A-4 indicate the assumed marginal production cost curves and the development of gas production capacity for the different gas producing countries and the development of gas production capacities respectively identified in the model for the time period (2010-2050).

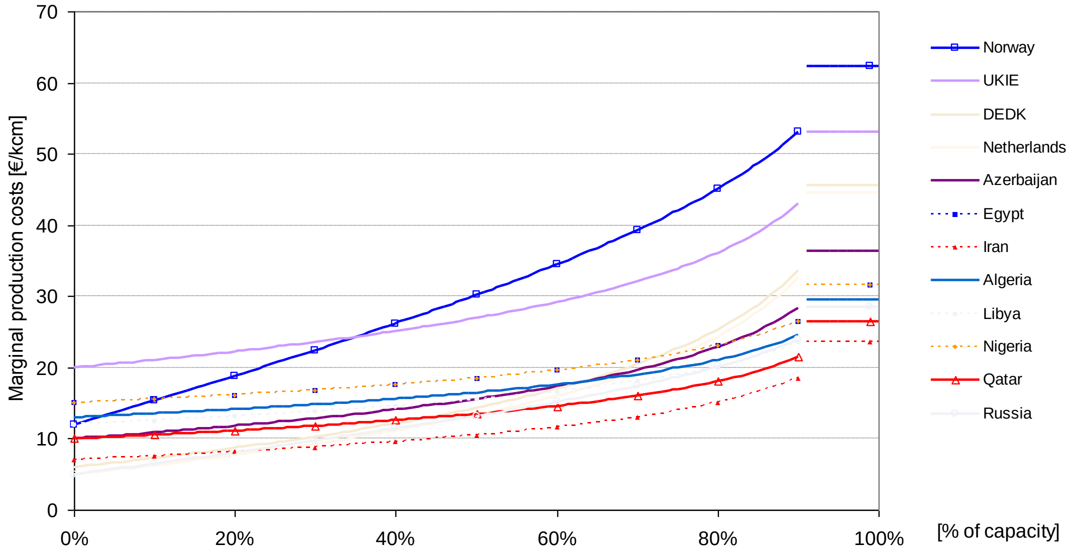

Figure A-3 Marginal cost curve of gas producing regions in GASTALE

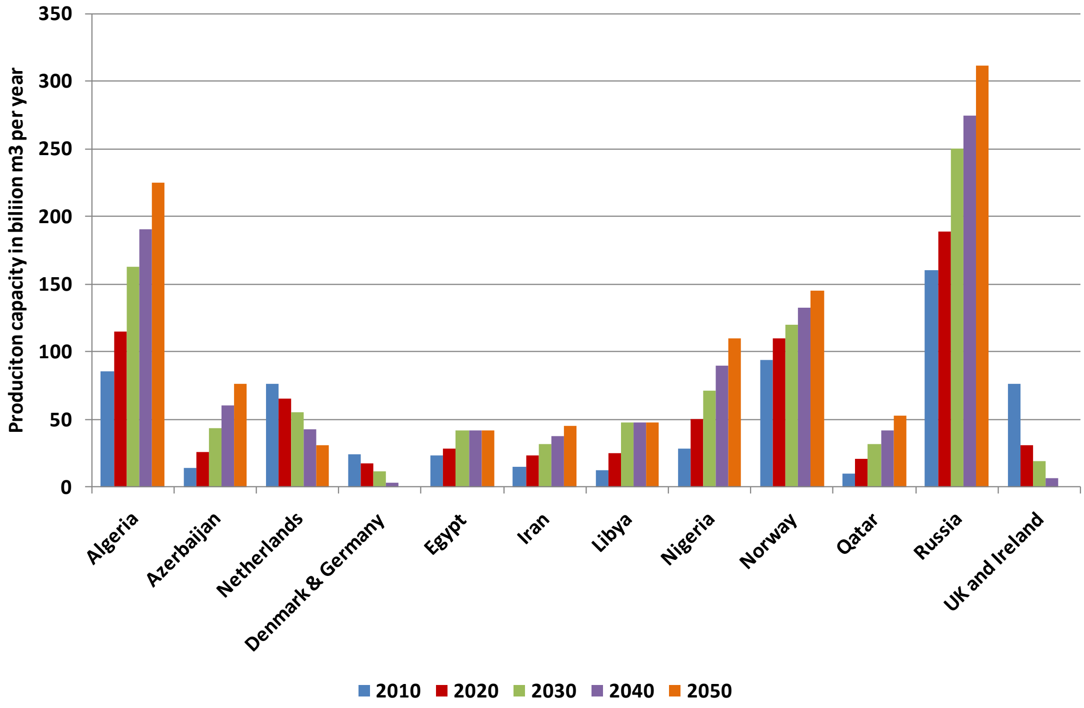

Figure A-4 Assumed production capacity developments until 2050

Marginal Cost of gas infrastructure

GASTALE model uses generic cost data for gas infrastructures. Table A.15 presents the cost for transport gas through pipelines.

	Marginal cost (€/m^3/km)
On shore pipeline	12
Offshore pipeline Mediterranean / Black Sea region	27
Offshore pipeline North Sea and Baltic Sea	21

Table A-15 Cost of gas transport

The marginal cost for additional gas storage capacity varies across countries and is constant over time. In absence of detailed data enabling us to construct a potential storage supply curve for each country, we have used constant marginal costs (including cushion gas). The costs across different regions are given in Table A-16.

Region	Storage cost
Balkan region	35
Baltic states	35
Belgium	34
Central Europe	35
Germany & Denmark	32
France	34
Iberian peninsula	44
Italy and Alpine region	40
Netherlands	30
Poland	35
Turkey	35
UK & Ireland	34

Table A-16 Overview of long run marginal gas storage cost data (in € / 1,000 m^3)

Table A-17 gives the aggregated cost of bring LNG from the producer region to the consuming region. This total cost includes liquefaction, transport and re-gasification but excludes the cost of producing at the gas field.

Consuming region	Producing region						
	Algeria	Egypt	Libya	Nigeria	Norway	Qatar	Russia
Balkan region	57	56	56	66	77	64	79
Belgium	59	68	62	68	62	76	65
France	57	66	60	66	64	74	66
Iberian peninsula	53	62	56	62	68	70	71
Italy and Alpine region	54	60	56	63	74	68	76
Turkey	59	55	56	68	79	63	81
UK & Ireland	58	67	62	68	63	76	65

Table A-17 Overview of total LNG long run operational cost data used in GASTALE (in € per m^3)

A.9.3 Model calibration

For the analysis in this study, we have calibrated base year 2005 model results to fit actual 2005 data. With respect to the model adaptations with respect to seasonal flexibility we have validated model output data on seasonal demand and production with historic data on seasonality in demand and production. For example, the seasonal gas consumption and production in 2005 matches with real data. For each decade between 2010-2050, we set the parameters of the linear demand curve on the 2005 data such that the resulting gas consumption levels in 2010-2050 from the GASTALE simulations are in line with the gas consumption levels assumed for each storyline (See Section 2.1.2.2 for the gas consumption assumptions in each storyline).

A.9.4 Data for period until 2030

Gas pipeline infrastructure capacity 2010 - 2030

Table A.18 presents the gas pipeline infrastructure capacity in the period between 2010 and 2030. Gas infrastructure capacity added between 2010 and 2020 are based on various investment project databases and infrastructure studies, whereas the infrastructure capacity additions between 2020 and 2030 are derived from an initial GASTALE analysis (see section 2.2.2).

	2010	2020	2030			
			RED	YELLOW	BLUE	GREEN
Algeria - Spain	20,8	20,8	36,0	20,8	32,2	20,8
Algeria - Italy	34,3	45,8	80,3	48,1	78,4	47,9
Azerbaijan - Turkey	8,8	20,0	43,8	39,4	43,8	39,4
Balkan - Central Europe	0,0	40,0	40,0	40,0	40,0	40,0
Balkan - Turkey	15,7	15,7	15,7	15,7	15,7	15,7
Belgium - Germany	11,5	14,4	14,4	14,4	14,4	14,4
Belgium - France	31,2	31,2	31,2	31,2	33,1	31,2
Belgium - Netherlands	6,6	8,9	8,9	8,9	8,9	8,9
Belgium - UK	24,6	24,6	24,6	24,6	24,6	24,6
Central Europe - Balkan	6,0	12,6	12,6	12,6	12,6	12,6
Central Europe - Germany	52,0	52,0	52,0	52,0	52,0	52,0
Central Europe - Italy	61,5	88,5	88,5	88,5	88,5	88,5
Central Europe - Poland	0,7	0,7	16,1	10,0	16,0	9,8
Germany - Baltic States	2,9	2,9	2,9	2,9	2,9	2,9
Germany - Belgium	17,7	20,8	20,8	20,8	20,8	20,8
Germany - Central Europe	14,8	14,8	14,8	14,8	14,8	14,8
Germany - France	21,0	21,0	21,0	21,0	21,0	21,0
Germany - Italy	23,7	27,2	27,2	27,2	27,2	27,2
Germany - Poland	1,1	7,0	12,9	12,8	15,5	12,3
Germany - Netherlands	13,1	23,7	23,7	23,7	23,7	23,7
France - Belgium	8,8	8,8	8,8	8,8	8,8	8,8
France - Spain	3,4	8,2	8,2	8,2	8,2	8,2
France - Italy	3,7	3,7	16,0	15,0	20,1	15,2
Spain - France	0,1	12,5	14,7	12,5	14,3	12,5
Iran - Turkey	11,5	11,5	31,3	24,1	31,3	24,5
Italy - Balkan	1,8	4,4	4,4	4,4	4,4	4,4
Italy - Central Europe	6,8	15,1	19,9	15,1	20,4	15,1
Italy - Germany	11,1	13,9	31,1	19,4	31,7	18,3
Libya - Italy	9,9	11,0	39,2	31,0	37,5	31,1
Norway - Belgium	18,6	18,4	18,4	18,4	18,4	18,4
Norway - Germany	50,2	57,5	57,5	57,5	57,5	57,5
Norway - France	18,6	18,3	18,3	18,3	18,3	18,3
Norway - UK	46,2	46,0	47,1	46,0	46,0	46,0
Netherlands - Belgium	40,3	50,9	50,9	50,9	50,9	50,9
Netherlands - Germany	65,7	66,1	66,1	66,1	66,1	66,1
Netherlands - UK	13,1	15,9	15,9	15,9	15,9	15,9

Poland - Central Europe	0,0	0,6	0,6	0,6	0,6	0,6
Poland - Germany	28,5	33,5	33,5	33,5	33,5	33,5
Poland - Baltic States	0,0	0,0	1,2	1,4	1,8	1,4
Russia - Balkan	33,9	33,9	33,9	33,9	33,9	33,9
Russia - Baltic States	22,3	22,3	22,3	22,3	22,3	22,3
Russia - Poland	11,3	11,3	11,3	11,3	11,3	11,3
Russia - Central Europe	121,2	126,7	126,7	126,7	126,7	126,7
Russia - Germany	0,0	55,0	55,0	55,0	55,0	55,0
Russia - Turkey	16,0	16,0	16,0	27,4	18,9	27,9
Turkey - Balkan	2,6	12,4	40,9	31,1	40,9	31,5
Balkan - Italy	0,0	8,0	8,0	8,0	8,0	8,0
UK - Belgium	25,9	25,9	25,9	30,0	33,0	29,9

Table A.18 Gas pipeline infrastructure capacity in the 2010 to 2030 period (in billion m^3 per year)

Table A-19 shows the development of gas storage capacity in the period 2010 to 2030.

	2010	2020	2030			
			RED	YELLOW	BLUE	GREEN
Balkan region	3,8	8,9	8,9	8,9	8,9	8,9
Baltic states	2,3	3,8	3,8	3,8	3,8	3,8
Belgium	0,7	0,8	0,8	0,8	0,8	0,8
Central Europe	15,4	18,3	18,3	18,3	18,3	18,3
Denmark & Germany	25,6	35,2	35,2	35,2	35,2	35,2
France	12,2	14,2	14,2	14,2	14,2	14,2
Iberian Peninsula	6,9	9,3	9,3	9,3	9,3	9,3
Italy, Austria & Switzerland	40,5	65,8	65,8	65,8	65,8	65,8
Netherlands	5,0	9,3	9,3	9,3	9,3	9,3
Poland	6,6	10,5	10,5	10,5	10,5	10,5
Turkey	0,0	2,1	5,3	2,1	4,2	2,1
UK and Ireland	4,7	24,1	24,1	24,1	24,1	24,1

Table A-19 Gas storage capacity in Europe in the 2010 to 2030 period (in billion m^3 per year)

Table A.20 presents the development of LNG import capacity in Europe between 2010 and 2030.

	2010	2020	2030			
			RED	YELLOW	BLUE	GREEN
Balkan region	4,7	4,7	12,4	13,6	21,6	14,1
Belgium	13,9	13,9	13,9	13,9	13,9	13,9
France	24,5	24,5	24,5	24,5	24,5	24,5
Iberian Peninsula	67,9	93,8	93,8	93,8	93,8	93,8
Italy	13,5	13,5	41,0	25,3	42,5	26,0
Netherlands	0,0	12,0	16,3	12,0	16,0	12,0
Poland	0,0	8,4	8,4	8,4	8,4	8,4
Turkey	34,5	34,5	34,5	34,5	34,5	34,5
UK & Ireland	48,2	55,8	55,8	55,8	55,8	55,8

Table A.20 LNG import capacity in Europe between 2010 and 2030