The Economics of Natural Gas Infrastructure Investments

Theory and Model-based Analysis for Europe

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Abbreviations

ACER	Agency for the Cooperation of Energy Regulators
AR(3)	Third-order autoregressive
bcm	Billion cubic meter
bcma	Billion cubic meter per year
ENTSOG	European Network of Transmission System Operators for Gas
ERGEG	European Regulators' Group for Electricity and Gas
EU	European Union
EUR	Euro
EWI	Institute of Energy Economics at the University of Cologne
FOC	First order condition
GAMS	Generic Algebraic Modeling System
GB	gigabyte
GHz	gigahertz
GIE	Gas Infrastructure Europe
hp	Horsepower
IEA	International Energy Agency
IGU	International Gas Union
LMP	Locational marginal price
LNG	Liquefied natural gas
LP	Linear program
m^3	Cubic meter
MBtu	Million British thermal unit
mcm	Million cubic meter
MWh	Megawatt hour
OME	Observatoir Méditerranéen de l'Energie

SoS	Security of supply
TSO	Transmission system operator
TYNDP	Ten-Year Network Development Plan
UN	United Nations
USD	United States Dollar
WGV	Working gas volume

Country Codes ISO 3166-1-alpha-2 codes
http://www.iso.org/iso/english_country_names_and_code_elements

In model:

Variables	see Table 3.1 (page 35)
Parameters	see Table 3.2 (page 36)
Symbols	(Analytical Model) see Section 2.2

Summary

This work examines the economics of natural gas infrastructure investments. The dissertation encompasses a theoretical perspective as well as an applied analysis for the European gas market between 2010 and 2025. The considerations underlying this investigation, the chosen approach and selected results are summarized in the following:

1. Changing supply structures, security of supply threats and efforts to eliminate bottlenecks and increase competition in the European gas market potentially warrant infrastructure investments. However, which investments are actually efficient is unclear.

2. From a theoretical perspective, concepts from other sectors regarding the estimation of congestion cost and efficient investment can be applied - with some extensions - to natural gas markets. Investigations in a simple analytical framework, thereby, show that congestion does not necessarily imply that investment is efficient, and that there are multiple interdependencies between investments in different infrastructure elements (pipeline grid, gas storage, import terminals for liquefied natural gas (LNG)) which need to be considered in an applied analysis.

3. Such interdependencies strengthen the case for a model-based analysis. An optimization model minimizing costs can illustrate the first-best solution with respect to investments in natural gas infrastructure; gas market characteristics such as temperature-dependent stochasticity of demand or the lumpiness of investments can be included. Scenario analyses help to show the effects of changing the underlying model presumption. Hence, results are projections subject to data and model assumption - and not forecasts. However, as they depict the optimal, cost-minimizing outcome, results provide a guideline to policymakers and regulators regarding the desirable market outcome.

4. A stochastic mixed-integer dispatch and investment model for the European natural gas infrastructure is developed as an optimization model taking the theoretical considerations into account. It is based on an extensive infrastructure database including long-distance transmission pipelines, LNG terminals and gas storage sites with a high level of spatial granularity. It is parameterized with assumptions on supply and demand developments as well as empirically derived infrastructure extension costs to perform model simulations of the European gas market until 2025.

5. In the framework of the conservative demand forecast of the European Commission, efficient infrastructure expansion (starting from the 2010 infrastructure with all projects under construction being completed) is limited. The constant demand in combination with the newly created import capacities on the LNG (UK, Spain) and pipeline (Nord Stream, Medgaz) side means the gas infrastructure is well equipped to deal with declining European production. The reduction of flexibility provided by domestic production is compensated by flexible LNG imports if the global LNG market remains well supplied.

6. A second simulation shows that, if demand continues to grow, investments in pipeline interconnections and additional LNG import infrastructure until 2025 are substantial. Additionally, efficient investments in storage in the UK and Italy are identified.

7. Further scenario analyses illustrate the effects of changing the presumptions on the supply side: A low LNG price does not increase LNG investments significantly, but reduces the requirements for pipeline investments in Europe, especially in East to West direction on the continent. An assumed decline in the flexibility of LNG imports in Europe, conversely, would greatly reduces efficient LNG capacity additions as the option to flexibly import natural gas is one of the favorable characteristics of such facilities. Consequently, investments in natural gas storage would have to increase substantially to provide flexibility through a different technology. This is also true if flexible LNG is replaced by either additional gas volumes imported via long-distance transmission pipelines from the Caspian region or if it is substituted by gas production from unconventional sources in Europe. The latter implies pipeline investments from the production sites (in Poland and Ukraine) to Central Europe are necessary. Additional Caspian gas means the route via Turkey to Southeastern and Central Europe needs to be built up. Various pipeline interconnections in the different countries along the route would also be efficient.

8. The simulation of emergency scenarios demonstrates that redundant infrastructure capacities and gas stocks in excess of the volumes required to balance supply and demand can be efficient - even if the emergency probability is low.

9. Modeling a one-month disruption of Russian transits via Ukraine and Belarus in 2020 shows that the infrastructure is rather resilient against such a threat. Reasons are alternative routes such as Nord Stream and the infrastructure investments made in the aftermath of the 2009 Ukraine transit disruption. Only limited additional investment in interconnection capacities between countries in Eastern Europe are found to be efficient. However, it also becomes evident that, with an emergency probability as low as two percent, it is efficient to stock up to 10 billion cubic meter of natural gas additionally in European gas storage facilities. Germany and Italy, the countries with the largest storage capacities, stock the majority of these volumes which are diverted to Eastern Europe should a crisis occur.

10. Conversely, the infrastructure is found to be less resilient regarding a prolonged supply stop from North Africa as seen for Libya in 2011. Italy would be affected particularly from a combined export disruption in Libya and Algeria, making significant investments in interconnections with Central and Northern Europe efficient. Additionally, further LNG import capacities would also be efficient to mitigate the consequences of a North African pipeline export stop. These investments in redundant import capacities become more efficient the higher the probability of the emergency.

11. The work allows some meaningful conclusions for policymakers, regulators and investors - and highlights the requirement of further research. With respect to the general results, it is illustrated how developments in one region (unconventional gas production, a new import corridor from the Caspian region) have significant implications for investments in geographically separated markets. The efficiency of investments in additional storage capacity is greatly affected by developments in the global LNG market and the composition of the European supply mix. Investments in redundant capacity to enhance security of supply are also found to be beneficial even if the probability of the respective emergency is low. However, it is also shown that a detailed analysis is required to identify specific, means-tested investment options - universal infrastructure standards may be of limited value. Furthermore, investments benefiting one region may efficiently take place outside the borders of that region. Important questions for further research, then, are (i) how these efficient investments can be incentivized through a regulatory framework and (ii) who bears their costs. Regarding the applied analysis, further work may also target an improved modeling of interdependencies of the infrastructure system with natural gas consumption in the power and industry sectors (demand side responses).

1 Introduction

1.1 Motivation

The European Union's rising import dependency on natural gas requires additional investments in import infrastructure and natural gas storage. At the same time, the Third Energy Package addresses, amongst other things, the strengthening of the single European market and the facilitation of cross-border energy trade which implies increased and better coordinated investments in gas transportation capacities between member states. Additionally, security of supply concerns in the aftermath of prolonged disruptions of gas supply following a dispute between Russia and Ukraine triggered investments in a number of projects supposed to enhance security of supply by promoting physical market integration and enabling reverse gas flows. By definition, these are investments in redundant capacities which might not be of use if the emergency does not occur.

Hence, many infrastructure investments have already taken place or are schedule to take place in the next decade.

However, the identification of investment projects, which are actually efficient, is difficult. An encompassing theoretical approach as well as applicable tools allowing an evaluation of proposed investments and the identification of required ones is missing. Potentially, infrastructure projects which are efficient for an investor or a national regulator may not be efficient from a system perspective; some of the supposedly security-of-supply-enhancing ones might not be efficient to provide a certain level of security of supply from a social welfare-perspective.

This dissertation project contributes to improving the understanding of efficient investment decisions from a welfare point of view and provides a tool which can be applied for such analyses of infrastructure investments in the European gas market. We provide an analytical framework for the identification of congestion and efficient investment in natural gas infrastructure systems accounting for stochasticity of demand and interdependencies between different elements in the system. With a model of the European gas infrastructure based on these analytical relationships, we identify cost-efficient infrastructure investment. Thereby, we focus on projects to (i) adapt the European gas infrastructure system to the changing supply structures, and (ii) to increase security of supply in the light of potential supply disruptions from North Africa or the Eastern European transit countries.

1.2 Structure

This PhD thesis is structured as follows:

- Chapter 2 presents the institutional and the economic background for coordinated investments in the European gas market. With respect to the economics, congestion costs, optimal investment levels, their determinants, and the interdependencies between them are derived analytically. The relevant literature is reviewed; some studies of applied analysis for the European gas market are also discussed. From the regulatory and legislative perspective, the mechanisms installed to ensure a coordination of investments, and the regulatory institutions envisaged to control these procedures are briefly presented.

- The optimization program applied in our analysis is presented in Chapter 3 including its mathematical formulation and a description of the incorporation of supply and (stochastic) demand modeling.

- The numerical assumptions of the simulations in this work regarding supply and demand, infrastructure endowments as well as investment options and investment cost parameterization are documented in Chapter 4.

- Chapter 5, Section 5.1 presents the results with respect to the optimal investment decisions in gas supply infrastructure in the European gas market and Section 5.2 discusses the value of the model approach and a cost sensitivity.

- Section 5.3 illustrates scenario simulations; results on additional investments to increase security of supply in the light of recent (and potential) natural gas supply disruptions are provided in Section 5.4.

- Chapter 6 offers some concluding remarks in the form of the analysis' policy implications and recommendations for further research.

1.3 Contributions and acknowledgments

The work of some of the author's colleagues at the Institute of Energy Economics at the University of Cologne (EWI) contributed to the analyses presented here.

Namely, David Bothe and Martin Lienert worked on the conceptual design of an early version of the applied model (Chapter 3) as published in Lochner and Bothe (2007a). This early design was then implemented by David Bothe and the author. The design and implementation of enhancements to the model regarding temporal granularity, stochasticity and endogenous investments, and the version of the model presented here, were carried out by the author.

Although the respective analyses have been updated, the study at hand also draws on joint work with Jan Richter and David Bothe with respect to model parameterization: David Bothe co-authored the respective modeling exercise on global gas markets (Lochner and Bothe, 2009) which, methodology wise, is used for commodity cost parameterization (Section 4.1.5); Jan Richter the estimation of pipeline and LNG regasification terminal investment costs (Lochner and Richter, 2010), see Sections 4.5.1 and 4.5.3.

The validation of the model, the background to the upstream supply capabilities, and some discussion on the EU security of supply regulation (Sections 3.6, 4.1.1 and 5.4.3 respectively) are partially based on joint work with Caroline Dieckhöner in the context of larger research project (EWI, 2010b) and a joint publication (Lochner and Dieckhöner, 2011).

Therefore, the author would like to thank the aforementioned persons for their contributions to the work of this dissertation project. Further discussions with and suggestions from, in alphabetical order, Marc Oliver Bettzüge, Caroline Dieckhöner, Dietmar Lindenberger, Timo Panke, Moritz Paulus and Johannes Trüby were greatly appreciated. Efforts by David Bothe, Caroline Dieckhöner and EWI's student staff team (notably Dennis Schramm, Jörg Fiedler, Yves Matushek and Claudius Holdermann) regarding database updates and research of further model input parameters are also acknowledged. Additionally, comments on different versions of the applied model by representatives of various companies and institutions as well as the participants of numerous seminars, workshops and conferences between 2007 and 2010 also motivated improvements in the methodology.

2 Background and Theoretical Considerations

This section provides the foundation and framework for the analyses in this dissertation. Section 2.1 discusses the existing academic literature on efficient investments in grid infrastructure and the modeling thereof. Section 2.2 presents an analytical framework for the applied analysis. Section 2.3 briefly discusses the results of selected studies of "required" investments in European natural gas infrastructure; the institutional framework for infrastructure investments in the gas market is outlined in Section 2.4.

2.1 Literature survey

The work in this dissertation project draws on two related strings of the literature: (i) spatial modeling of natural gas markets and (ii) the valuation of transport infrastructure and investments based on competitive locational prices.

The latter (infrastructure valuation and efficient investments) is the focus of this work; the modeling approach our mean of choice to investigate it. The relevant literature regarding both aspects is discussed in this order.[1]

Competitive price formation, the economic valuation of transport and storage capacity, and the value of system bottlenecks are sparsely discussed simultaneously in the literature when it comes to natural gas markets specifically.

All articles considering grid-related issues are thereby to some extent inspired by and yield similar results than analyses on the economic valuation of transmission capacity in electricity markets. With the exception that large-scale storage does not (yet) play an important role in electricity markets, and is therefore mostly neglected in theoretic considerations, the two goods do exhibit similarities with respect to grid-boundedness and the natural monopoly character of their transmission.[2] Overviews of investment in and the economic valuation of transmission capacity in electricity markets are, for instance, provided by Hogan (1998) and Stoft (2002).

1 The first paragraphs on the valuation of transport infrastructure thereby draw on Lochner (2011).

2 With the exception of sea transportation of natural gas as liquefied natural gas (LNG). Furthermore, loop flows (Kirchhoff's second law) complicate (analytical) models of electricity grids. Flows on natural gas pipelines can be controlled individually (through compressor stations) in most cases enabling a more simplified representation of grids in models.

The most common approach is thereby based on locational marginal pricing which assigns each node, i.e. a system connection, entry or exit point, an individual competitive locational price. Assuming a competitive market, this price equals the total system marginal costs of supplying one additional unit of energy at the respective location and the marginal value of this unit to consumers - hence, the term locational marginal price (LMP). The concept was first introduced by Schweppe et al. (1988) and was developed further by Hogan (1992) and Hogan (1998) with the latter work summarizing intermediate enhancements to the LMP framework by the author. A critical discussion of the LMP concept with respect to its application in congestion pricing is provided by Rosenberg (2000).

Taking these LMPs, the value of a transportation service of energy from one location to another is then determined by the difference in the respective LMPs: The value of a transmission service from location 1 to 2 equals the price in 2 minus the price in 1 ($p_2 - p_1$) in equilibrium. $p_2 - p_1$ also represents the per-unit-and-time-period economic value of the transmission asset and first-best transmission charge. According to economic theory, this value should also equal the variable cost of transmission from 1 to 2 if the line from 1 to 2 is not congested: If the LMP difference exceeds variable transmission costs albeit capacity being available, the no-arbitrage assumption would be violated as additional arbitrage could take place until prices only differ by the variable transport costs between the nodes. If, on the other hand, the line is congested, full arbitrage cannot take place. Then, prices are not determined by total system supply and demand but by residual supply and demand at the respective location (node). Consequently, the existence of congestion on a line between two locations is defined as the LMP difference between these nodes exceeding variable transport costs between the nodes (Stoft, 2002).

The application of the LMP method to theoretically value transmission assets in gas markets was pioneered by Cremer and Laffont (2002) and Cremer et al. (2003). They provide a normative benchmark for the theoretically optimal gas transportation charges in a network by determining prices for each node in the system.

A relevant difference between gas and electricity markets is the aforementioned possibility to store gas in large-scale storage systems enabling demand balancing and intertemporal arbitrage. Hence, storage facilities are an important component of the infrastructure system, which can possibly constitute an infrastructure bottleneck, too, and which impact competitive locational prices and therefore the value of transmission assets. The optimal value and investment in gas storage is, for example, explored by Chaton et al. (2008) without considering interaction with the grid. With a system perspective and appreciating the important role of storage in natural gas markets, Lochner (2011) extends the simplified gas network model by Cremer and Laffont (2002) by including a storage and intertemporality (see Section 2.2 in this dissertation). The concept of multiple time periods is thereby complementary to LMPs: After all, a storage is just a transmission asset between two time periods and can therefore be treated similar to a pipeline (which enables transmission between two locations).

Hence, the simple model presented in Section 2.2 can be used to illustrate the relevant interdependencies between the gas infrastructure elements with respect to the valuation of congestion and capacities.

With respect to the general economic dynamics, gas markets thereby do not differ fundamentally from electricity markets - or any other market for that matter: In the short-term, infrastructure capacities are set and cannot be changed quickly; demand and supply are much less elastic than in the long-run. Hence, while infrastructure bottlenecks can be eliminated in the long-term and are therefore less relevant for price formation than the overall supply and demand situation (Stern, 2007), this is not true in the short-term. When the infrastructure is fixed, prices in a competitive market might differ regionally as the scarce transport infrastructure can constitute a physical impediment which limits trade. Hence, due to the costly and limited infrastructure (pipeline grid), supply and demand might differ between geographically separated locations leading to different competitive locational prices, which are determined by supply and demand at the respective node. Supply thereby encompasses all available gas volumes at the respective point including local production, supply from past time periods[3] and potential transports to the node from all other natural gas sources on all available routes. Accordingly, the node's demand curve is made up by local consumption with the marginal willingness to pay differing between consumers. It also accounts for the opportunity costs of future consumption, for which gas can be injected into the local storage, and potential demand from other markets, provided there is transport capacity available to get the gas to the alternative market. As in electricity markets, if transmission capacity between nodes is not constrained, arbitrage causes LMPs to equalize (apart from differences resulting from transport costs). Scarcity of capacity, on the other hand, may cause the residual supply and demand functions in the separate markets to differ resulting in different prices. The difference between LMPs (minus variable transport costs) is the cost of congestion and the economic value of transmission assets between the respective markets. The same logic applies to storage: If storage capacity is unconstrained, arbitrage over time is possible and price differences should not exceed variable storage costs (in a microeconomic analytical framework with perfect foresight, such as the one presented in this paper); without storage, price formation between time periods is independent from each other.

Modeling gas markets for analyses with respect to these properties to obtain an insight into efficient investments has not been done explicitly with a highly granular model. However, there is a history of modeling spatial goods markets in general and natural gas markets specifically.

A first analyses of equilibria in spatial markets is provided in the seminal work of Samuelson (1952) who employs a linear program (LP) to characterize the equilibrium

3 Presuming there is a storage at this location and gas was previously stocked there.

in a perfectly competitive interconnected regional market. Based on a linear program he derives the relationships of supply, demand and prices in a spatial equilibrium through marginal inequalities.

The representation through the first order conditions is thereby a generalization of the LP. Harker (1984) uses the expression in complementarity format to introduce further characteristics into spatial equilibria, i.e. strategic behavior by agents, by including decision variables of one player into the equilibrium condition of the other players. This allowed him to model markets without the assumption of perfect competition.

First applications to gas markets were provided by Beltramo et al. (1986) for the North American and Boucher and Smeers (1985)[4] for the European gas market. Both articles analyze trade patterns under perfect competition. The incorporation of strategic behavior in gas market modeling was pioneered by Mathiesen et al. (1987) who models the European gas market as a Cournot game. Since then, a number of models were developed to represents the (global or European) gas market under different assumptions of market power. A number of them is presented in the subsequent paragraph with a focus on nodal prices and implications for infrastructure investments.

Such models computing nodal prices in natural gas markets are only available to a limited extent in the literature and usually differ with respect to their definition of a node.[5] Models focusing on long-term developments such as Perner and Seeliger (2004), Seeliger (2006) and Möst and Perlwitz (2009) usually define a whole country as a node implying that there are no bottlenecks within each country's national grid. This appears to be an appropriate assumption as the models analyze investments in gas production and cross-border transportation assets (and the electricity sector in the case of Möst and Perlwitz (2009)). In the long-term, the other infrastructure can then be presumed to be expanded to suit the requirements of these developments. While all three models compute nodal prices internally, they are not discussed specifically as investment decisions are endogenous. The same holds true for the models by Holz et al. (2008) and Lise and Hobbs (2008), the latter of which even aggregates Europe to just five nodes (regions) and, hence, fully abstracts from potential congestion between countries on the continent. However, this may be appropriate as both papers focus on the implications of (upstream) market power instead of infrastructure investments. In this context, Holz et al. (2008) actually compute prices under different assumptions with their game-theoretic model. Although these are not nodal prices in the sense of competitive locational prices as in Stoft (2002) (apart from one simulation assuming a competitive market), they indicate the value of additional supply at each node (= country) and, therefore, allow implicit conclusions on the value of assets on an aggregated basis.

Short-term considerations of the European gas grid with higher temporal and spatial granularity are provided by Lochner and Bothe (2007a), Neumann et al. (2009) and

4 The paper uses the same methodology as Beltramo et al. (1986) based on an earlier working paper publication of the North American model.

5 The work by Beltramo et al. (1986) also computed regional prices for the North American gas market but without considering implications for infrastructure investments.

Monforti and Szikszaia (2010). Lochner and Bothe (2007a) develop the so-called TIGER model, an extended and enhanced version of which is applied for our analysis. While they do not compute nodal prices, they provide a network flow model of the European gas market with over 500 nodes covering all major long-distance transmission pipelines individually.[6] A similar linear optimization approach is used by Neumann et al. (2009). Instead of the minimization of commodity and dispatch costs given a fixed demand (Lochner and Bothe, 2007a), they maximize social welfare by including an estimated demand elasticity and compute nodal prices. Bottlenecks between nodes are then identified by considering congestion mark-ups and the utilization of assets. However, their model's spatial granularity of one node representing one country does not allow them to consider specific assets individually; the temporal granularity of one month might underestimate the strain on the systems on individual high (peak) demand days. The model by Monforti and Szikszaia (2010) was set up to investigate system resilience in the light of security of supply stress situations rather than physical market integration. It abstracts from modeling storage operations explicitly but alters the amount of gas available from storage sites through Monte-Carlo simulations. A later version (Szikszai and Monforti, 2011) includes a temporal dimension but still refrains from an economic optimization. With the same regional resolution as Neumann et al. (2009), they cover a wider geographical area (EU-27 plus Norway and Switzerland). Although it is also a network model consisting of edges and nodes, gas dispatch is not based on economic principles but certain "rules"[7] disabling the computation of competitive locational prices.

The inclusion of stochastic elements in energy market models in general or natural gas market specifically is also documented in the literature. An overview of such efforts is provided by Wallace and Fleten (2003). One of the first approaches by Murphy et al. (1982), for instance, investigates power generation investments with uncertain load projections. Stochasticity, which might arise from demand or the availability of renewable energy sources (wind, hydro power), has also been incorporated in other system optimization models, albeit mainly for electricity markets. Regarding natural gas markets, optimization models typically focused in the simulation of single elements (storage, production site) with the uncertainty arising from market prices (Wallace and Fleten, 2003). A stochastic equilibrium dispatch model for the natural gas market is provided by Zhuang and Gabriel (2008) who focus on the impact of uncertainty on the long-term contract and spot market (and the quantities traded there). Investments in natural gas infrastructure in a system optimization with stochasticity have not been investigated so far.

6 Applying this model, Lochner (2011) shows how an identification of congestion and valuation of infrastructure can be approached.

7 Domestic demand is first covered from domestic sources such as local production and storage; then, gas volumes flow in from neighboring countries or even from further upstream, if possible.

2.2 Analytical analysis: Infrastructure valuation and efficient investments

This section illustrates the application of the nodal pricing concept to gas markets with respect to the identification of congestion, the economic valuation of transport and storage infrastructure and the optimal level of investment. (The general model and the first subsection (2.2.1) are thereby based on a chapter in a published article by the author (Lochner, 2011) which is part of this dissertation. The second part of that paper, which is an exercise on the numerical quantification of the value of transportation assets, is omitted here as a similar analysis is provided in Section 5.1.1.) This analysis thereby constitutes the analytical foundation for the applied analysis in Section 5. For illustrative purposes, a simple three node model is used - the large-scale model developed for the applied analysis is presented in Chapter 3.

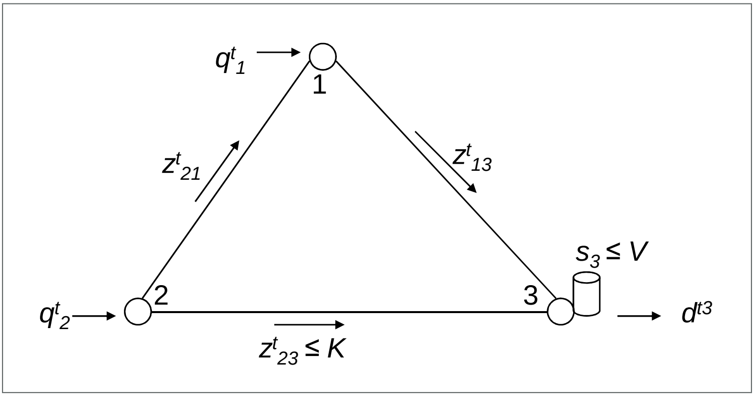
The gas flow network and storage model helps to illustrates the relevant interdependencies between prices and the value of an asset. The model consists of two upstream and one downstream market represented by three nodes (number 1, 2 and 3). Hence, two nodes are sources of gas with supply q_i ($\forall i \in \{1, 2\}$) and one is a gas sink with demand d_3. Three pipelines connect the three nodes as illustrated in Figure 2.1. As a simplification, pipelines from 2 to 1 (#21) and 1 to 3 (#13) have no capacity restriction, the maximum capacity of the line from 2 to 3 (#23) is K. Pipelines are further described by a length l_{ij}. z_{ij} is the variable for volume flows on the pipeline from i to j with $i, j \in \{(2, 1), (1, 3), (2, 3)\}$. (This model (developed by Lochner, 2011) is, thereby, an extension of the model by Cremer and Laffont (2002) and Cremer et al. (2003). Enhancements include adding storage and temporality; all non-storage related results in this section are, hence, identical to the findings of Cremer et al. (2003).)

The costs of pipeline transmission for one unit of gas along one unit of length is c_{ij} for a flow from i to j. At nodes 1 and 2, gas is produced by independent (vertically unbundled from the transmission system) producers at costs of $C_i(q_i^t)$ for nodes $i \in \{1, 2\}$ and time $t \in \{0, 1\}$. Demand is inelastic at d_3^t for $t \in \{0, 1\}$. These assumptions may represent an accurate framework for short-term considerations in competitive gas markets. Even in Europe, where upstream competition is limited due to the small number of regionally separated suppliers, a large majority of supply contracts at the well-head (or the border where the gas enters the European Union) have their prices indexed to commodities other than natural gas (e.g. crude oil, fuel oil, coal, ...). Hence, the supply price is somewhat fixed and may deter suppliers from Cournot behaviour in the short-term[8], which is a sufficient precondition for our model.

On the storage side, we regard one gas storage in the downstream market which is presumed to be used in a welfare-maximizing way. We denote the per-unit variable costs of the storage (which is assumed to incur in the period when gas is injected into the storage) with $c_{storage}$ and include a working gas volume constraint of V. The

8 A discussion on price indexation in this context is provided by Breton and Kharbach (2009).

Figure 2.1: Three node grid with storage



variable for the amount of gas injected into the storage is denoted as s_3. For simplicity, we assume that period $t = 0$ is the off-peak period (summer) and 1 is the peak period (winter). The duration of each period can be incorporated with a proportion factor along the line of Gravelle (1976) with ω and $(1 - \omega)$ being the durations of the off-peak and peak periods respectively. However, to keep the model discrete, we simplify to $\omega = (1 - \omega) = 0.5$ which allows us to subtract from period duration altogether.

To obtain the interdependencies between the different infrastructure elements, we study the first-best dispatch of natural gas. As the market result in an assumed perfectly competitive market equals the welfare maximizing result achieved by a benevolent social planner, we can simply maximize social welfare taken pipeline and storage capacity as given. The social welfare function is given as the sum of consumer surplus, producer surplus and transmission system operator (TSO) as well storage system operator revenue minus the cost of the infrastructure system:

$$\begin{aligned} SW \quad = \quad & \sum_{t=0}^{1} \frac{1}{(1+ir)^t} \Big[\\ & + \left(S(d_3^t) - p_3(d_3^t)d_3^t\right) \\ & +(p_3(d_3^t)d_3^t - p_1(q_1^t)q_1^t - p_2(q_2^t)q_2^t - c_{13}(z_{13}^t)l_{13} - c_{21}(z_{21}^t)l_{21} \\ & -c_{23}(z_{23}^t)l_{23}) + \left(p_1(q_1^t)q_1^t - C_1(q_1^t) + p_2(q_2^t)q_2^t - C_2(q_2^t)\right)\Big] \\ & -c_{storage}(s_3) - G - H \end{aligned} \tag{2.1}$$

with G and H representing the (annualized) capital costs for pipelines and storage respectively. $S(d_3^t)$ represents gross consumer surplus at node 3 and $C_i(q_i^t)$ the production function (technology) at node i. ir is the interest rate between the two periods.[9]

As the in- and outflows of each node have to be balanced in each period (for instance, what is produced at node 2 has to flow away from node 2), we can replace the produced and consumed quantities at the nodes as follows (with z_{ij} being the variable for volumes flows on the pipeline from i to j with $i, j \in \{(2,1),(1,3),(2,3)\}$):

$$\begin{aligned}
q_2^t &= z_{21}^t + z_{23}^t \forall t = 0, 1 \\
q_1^t &= z_{13}^t - z_{21}^t \forall t = 0, 1 \\
d_3^0 &= z_{13}^0 + z_{23}^0 - s_3 \\
d_3^1 &= z_{13}^1 + z_{23}^1 + s_3
\end{aligned}$$

This allows optimizing over the dispatch variables $z_{ij}^t \ \forall \ ij \in \{(2,1),(1,3),(2,3)\}$ and $t \in \{0,1\}$ and s_3 (Cremer et al., 2003). As we assume perfect competition in the upstream (firms supply at marginal cost) and downstream market (price equals marginal gross consumer surplus), we can rewrite the derivatives of the production functions and the gross consumer surplus with the respective inverse supply and demand functions: $p_1^t = C_1'^t$, $p_2^t = C_2'^t$, $S'^t(d_3) = p_3^t(d_3)$ for $t \in \{0,1\}$.

Hence, we obtain the following simplified first order conditions (FOCs) for all $t = 0, 1$:

$$\frac{1}{(1+ir)^t}\left(p_3^t - p_2^t - c_{23}' l_{23}\right) - \eta^t = 0 \tag{2.2}$$

$$\frac{1}{(1+ir)^t}\left(p_3^t - p_1^t - c_{13}' l_{13}\right) = 0 \tag{2.3}$$

$$\frac{1}{(1+ir)^t}\left(p_1^t - p_2^t - c_{21}' l_{21}\right) = 0 \tag{2.4}$$

$$-p_3^0 - c_{storage}' + \frac{1}{1+ir} p_3^1 - \lambda = 0 \tag{2.5}$$

$$K - z_{23}^t = 0 \tag{2.6}$$

$$V - s_3 = 0 \tag{2.7}$$

where η^t is the Lagrange multiplier for the transmission capacity constraint in periods $t = 0, 1$ and λ is the Lagrange multiplier for the storage capacity constraint.

Spatial price differences can easily be established by looking at period $t = 0$. Rearranging equation (2.2) yields

$$p_3^0 = p_2^0 + c_{23}' l_{23} + \eta^0 \tag{2.8}$$

i.e. the price at the downstream node exceeds the price at the upstream node by variable transport costs $c_{23}' l_{23}$ if the pipeline is not congested ($\eta^0 = 0$). If congestion

9 Notation is, hence, analogue to Cremer et al. (2003) apart from introduced time indices, the interest rate and the storage parameters.

exists, the price at node 3 will increase by the shadow cost of the constraint η^0 (Cremer et al., 2003). In our framework (see paragraph on optimal transmission tariff), $\eta^0 = c'_{13}l_{13} + c'_{21}l_{21} - c'_{23}l_{23}$ (equation 2.14). Hence, in the case of congestion on pipeline #23, the price p_3^0 will increase to the supply cost of the next marginal unit, which would be transported over pipelines # 21 and #13. I.e.

$$p_3^0 = p_2^0 + c'_{13}l_{13} + c'_{21}l_{21} \tag{2.9}$$

As the competitive producer price p_2^0 is assumed to remain constant, the price increase at node 3 will cause the price difference to node 1 to rise, presuming that $c'_{13}l_{13} + c'_{21}l_{21} > c'_{23}l_{23}$.

Generally, such increasing regional price differences (in excess of marginal costs transport costs), hence, imply some form of transport infrastructure bottleneck, in this case on pipeline #23. It is, however, important to stress that an infrastructure bottleneck is not necessarily inefficient (see further discussion in Section 2.2.2 on optimal investment).

Temporal price relationships are similarly evident from equation (2.5). If the storage capacity restriction is not binding,

$$p_3^1 = (1 + ir)\left(p_3^0 + c'_{storage}\right) \tag{2.10}$$

i.e. the price in $t = 1$ equals the price in $t = 0$ plus the storage and interest costs. Similarly to spatial price differences, a binding storage constraint impacts the temporal price relationship.

2.2.1 The value of transmission and storage services

Based on the FOCs in equations (2.2) to (2.7), which are consistent with fixed upstream prices, a competitive downstream market and a regulated transportation infrastructure, we can derive the optimal transport and storage charges, which imply the economic value of the marginal capacity unit of the transmission and storage asset respectively.

Optimal transmission tariff

The value of providing the service of transporting a good from A to B is represented by the difference in the value of the good between B and A. In an efficient market without trade restrictions and transport costs, arbitrage would lead prices to equalize in all markets. With transport cost and trade restrictions, this is not necessarily the case and prices may differ (EWI, 2010b, Lochner, 2011). Hence, transporting the good from A to B adds $p(B) - p(A)$ to its value. Theoretically, the transport service should, hence, be optimally priced at its value which equals the price difference.

This can easily be derived from our simple model. As shown by Cremer et al. (2003), rearranging the FOCs for the off-peak period transport variables (equations 2.2 to 2.5) for the price difference between nodes yields the transport tariff f. It is a function of variable costs, plus potentially the shadow costs of the pipeline capacity constraint in case of congestion:

$$f_{23}^t = p_3^t - p_2^t = c_{23}' l_{23} + \eta^t (1+ir)^t \quad (2.11)$$
$$f_{13}^t = p_3^t - p_1^t = c_{13}' l_{13} \quad (2.12)$$
$$f_{21}^t = p_1^t - p_2^t = c_{21}' l_{21} \quad (2.13)$$

Rearranging for the shadow cost of the capacity restriction in $t = 0$ (subtracting equation (2.4) from (2.3) and substituting into (2.2)) yields:

$$\eta^0 = c_{13}' l_{13} + c_{21}' l_{21} - c_{23}' l_{23} \quad (2.14)$$

Hence, the shadow costs for the capacity constraint of pipeline #23 are, intuitively, the extra costs incurred by using the dearer, unconstrained route via pipelines #21 and #13. More generally, as long as physical transport capacity between two locations is available, the dearest utilized route determines the price difference and, thus, the value of transportation on all routes.

Optimal storage tariff

In order to assess the shadow cost of the storage constraint, storage needs to have a positive value as it would not be used otherwise.[10] Generally, such a positive value can for example be the result of higher marginal production costs (for higher production volumes) or a higher willingness to pay in the peak period. The same effects can, however, be shown by including the simple assumption that the pipeline constraint is binding in the peak-period. In the European gas market, this can be thought of as the consequence of higher winter demand which, despite possibly constant import prices, drives up prices as congestion on pipelines increases.

Therefore, suppose the pipeline capacity constraint is binding in period 1 but not in period 0 ($\eta^0 = 0$). η^1 is obtained similar to equation (2.14):

$$\eta^1 = \frac{1}{1+ir} \left(c_{13}' l_{13} + c_{21}' l_{21} - c_{23}' l_{23} \right) \quad (2.15)$$

10 In this case, storage can be thought of a transportation asset to supply gas from one time period to another. Without scarcity and storage costs, intertemporal arbitrage would, theoretically, lead to identical prices in both periods.

From FOC (equation 2.2), we know that the prices at node 3 in periods 0 and 1[11]:

$$p_3^0 = p_2^0 + c'_{23} l_{23} \tag{2.16}$$
$$p_3^1 = p_2^1 + c'_{23} l_{23} + \eta^1 (1 + ir) \tag{2.17}$$

To obtain the shadow cost of the storage constraint, we substitute these prices into equation (2.5) and replace with the pipeline shadow cost (equation 2.15). As we presumed competitive market structures in production, p_2^t (for $t = 0, 1$) equals marginal costs at node 2. Further assuming constant marginal costs and the absence of a production capacity constraint and constant returns to scale production functions, $p_2^1 = p_2^0 = p_2$ will hold true, simplifying the equation for λ to:

$$\lambda = \frac{1}{1 + ir}(c'_{13} l_{13} + c'_{21} l_{21}) - c'_{23} l_{23} - c'_{storage} - \frac{ir}{1 + ir} p_2 \tag{2.18}$$

Thus, the shadow cost of the storage constraint equals the increase in transport costs for using the more expansive unconstrained route in period 1 minus the cost of using the less expensive route in the earlier period, the cost of the subsequent storing of the gas and the foregone interest associated with the earlier purchasing of the gas.

The optimal storage tariff can then be expressed as the difference between prices at node 3 between periods 0 and 1, which is the value of the storage. From (2.5):

$$\frac{1}{1 + ir} p_3^1 - p_3^0 = \lambda + c'_{storage} \tag{2.19}$$

Trivially, we find that the equilibrium storage charge equals the marginal cost of storing gas if the storage volume constraint is not binding ($\lambda = 0$).

If $\lambda > 0$, substituting from equation (2.18) yields that the storage charge is optimally set at:

$$\frac{1}{1 + ir} p_3^1 - p_3^0 = \frac{1}{1 + ir}(c'_{13} l_{13} + c'_{21} l_{21}) - c'_{23} l_{23} - \frac{ir}{1 + ir} p_2 \tag{2.20}$$

i.e. the storage charge equals the cost increase in period 1 arising from using the more expensive transmission lines due to constrained storage and congested transmission line #23 in that period.

Substituting η^1 from (2.15), the shadow cost of the storage constraint λ from equation (2.18) can be rewritten as:

$$\lambda = \eta^1 - c'_{storage} - \frac{ir}{1 + ir}(p_2 + c'_{23} l_{23}) \tag{2.21}$$

11 $p_3^t \; \forall t \in \{0, 1\}$ could also be expressed in other terms in our framework. We analyze this case as it is more interesting since it will combine the storage and pipeline capacity shadow costs.

Thus, the shadow cost of storage capacity can also be expressed as the difference of the shadow cost of the transmission capacity constraint in period 1 (in period 0 terms) less the marginal storage costs less the foregone interest credit as a results of incurring the purchasing and transport costs in period 0 instead of in period 1 (when storing the gas).

Substituting into the optimal storage charge we find that it should equal the shadow cost of the pipeline constraint minus the foregone interest credit in optimum:

$$\frac{1}{1+ir}p_3^1 - p_3^0 = \eta^1 - \frac{ir}{1+ir}(p_2 + c'_{23}l_{23}) \tag{2.22}$$

Optimal transmission tariff in the presence of storage

We now again turn to the optimal transmission tariff to investigate how it is influenced by storage capacity. As discussed before, the optimal transmission charges f can be expressed as the differences in prices between the respective nodes (see equations (2.11) to (2.13), page 18).

Due to pipelines #21 and #13 being unconstrained, their optimal tariff is given by the respective marginal costs. The constrained pipeline's (#23) optimal charge depends on the shadow cost of the congestion. To look at the impact of storage capacity, we again assume the constraint to be only binding in the peak period, i.e. $\eta^0 = 0$. To obtain η^1 we rearrange (2.21):

$$\eta^1 = \lambda + c'_{storage} + \frac{ir}{1+ir}(p_2 + c'_{23}l_{23}) \tag{2.23}$$

Substituting into the optimal transmission tariff (in period 1 terms) in equation (2.11) yields:

$$\begin{aligned} f_{23}^1 &= p_3^1 - p_2^1 = c'_{23}l_{23} + (1+ir)\lambda + (1+ir)c'_{storage} + ir(p_2 + c'_{23}l_{23}) \\ f_{23}^1 &= (1+ir)\left(c'_{23}l_{23} + \lambda + c'_{storage}\right) + ir\, p_2 \end{aligned} \tag{2.24}$$

If the storage is not constrained ($\lambda = 0$), in optimum transmission on #23 should be charged at the marginal cost of storing plus the transport costs on the less expensive route in the off-peak period and plus the foregone interest by purchasing the gas in the earlier period (all in period 1 terms). Hence, the presence of (unconstrained) storage and an unconstrained transport route in an earlier period put an upper bound on the tariff for the congested pipeline in the peak period.

If $\lambda > 0$, then substituting from (2.18) yields the intuitive result that the transmission tariff for #23 in period 1 also has to equal the costs of the alternative unconstrained transport route (because using that route is always an alternative to storage and can therefore not be cheaper in order for storage to be viable):

$$
\begin{aligned}
f_{23}^{1} &= (1+ir)\left(c_{23}'l_{23} + \frac{1}{1+ir}(c_{13}'l_{13} + c_{21}'l_{21}) - c_{23}'l_{23} - c_{storage}' \right. \\
&\qquad \left. - \frac{ir}{1+ir}p_2 + c_{storage}'\right) + ir\,p_2 \\
f_{23}^{1} &= c_{13}'l_{13} + c_{21}'l_{21} \qquad (2.25)
\end{aligned}
$$

Complementing the previous observation, the costs of the alternative transport route constitute an upper limit on storage costs.

In equilibrium the economic values of storage and pipeline infrastructure, hence, depend on each other: Specification in the storage infrastructure determined the congestion costs of pipeline routes and vice versa.

2.2.2 Optimal investment level

As the focus of our subsequent analysis includes uncertainty and investments in natural gas infrastructure, we extend this framework by including investment costs and stochasticity. Discrete instead of continuous investment options, which are also of relevance in our applied analysis, are discussed at the end of this section. We reduce complexity of the model by reducing it to two nodes and one pipeline (node 1 and pipelines #21 and #13 in Figure 2.1 are omitted). In addition to the previous section, we add the option to import LNG at node 3 (z_{LNG}^{t}) at a price of p_{LNG}^{t} through regasification capacity R. The capacity rent of the LNG import facility is denoted as ζ^t ($\forall\, t \in \{0,1\}$). Hence, all investment options considered in the model-based analysis in this paper are included.[12]

Starting from the social welfare optimization problem (equation 2.1), the pipeline fixed costs H are replaced by $CP(K)/N$ and storage fixed costs G by $CS(V)/N$ where N denotes the number of off-peak periods the capacity can be used for, i.e. its technical lifetime[13].[14] The regasification capital costs ($CL(R)/N$) and regasification constraint (which we assume to be non-binding in $t=0$) are added. Thus, $CP(K)/N$, $CS(V)/N$ and $CL(R)/N$ can be interpreted as the per-peak-and-off-peak-period (annualized) costs for pipeline, storage and LNG import capacity respectively. For simplicity, they shall simply be referred to as annual capacity costs subsequently.

12 Again, the results on pipeline investments are identical to Cremer et al. (2003). All other results are new.

13 The technical lifetime, i.e. the duration the asset is actually in operation, is the relevant time period from a social welfare perspective - as opposed to the economic lifetime over which the asset is depreciated. In the theoretical framework assumed here, the two would be identical anyway.

14 Please note from equation (2.1) that capital costs incur only once every two periods, i.e. only once for peak and off-peak period. Thinking of $t=0,1$ as summer and winter, N would thus be a year.

Furthermore, θ is introduced as the stochastic demand parameter for period 1. It is a random variable distributed over $[\underline{\theta}, \overline{\theta}]$ according to the distribution function $F(\theta)$ with a density of $f(\theta)$. θ, thereby represents the short-term deviations of natural gas demand from the average demand as a consequence of external factors such as temperature (which drives household gas demand, see Section 3.5). The price in $t = 1$ also becomes a function of θ.

This will change the FOCs for z_{23}^1 (equation 2.2), s_3 (equation 2.5), η^t (equation 2.6) and λ (equation 2.7) and produce two new FOCs:

$$\frac{\partial L}{\partial z_{23}^1} = \frac{1}{1+ir}\left(p_3^1(\theta) - p_2^1 - c_{23}' l_{23}\right) - \eta^1 \tag{2.26}$$

$$\frac{\partial L}{\partial s_3} = -p_3^0 - c_{storage}' + \frac{1}{1+ir} p_3^1(\theta) - \lambda = 0 \tag{2.27}$$

$$\frac{\partial L}{\partial z_{LNG}^1} = \frac{1}{1+ir}\left(p_3^1(\theta) - p_{LNG}^1\right) - \zeta^1 \tag{2.28}$$

$$\frac{\partial L}{\partial \eta^0} = CP(K)/N - z_{23}^0 = 0 \tag{2.29}$$

$$\frac{\partial L}{\partial \eta^1} = CP(K)/N - z_{23}^1 = 0 \tag{2.30}$$

$$\frac{\partial L}{\partial \zeta^1} = CL(R)/N - z_{LNG}^1 = 0 \tag{2.31}$$

$$\frac{\partial L}{\partial \lambda} = CS(V)/N - s_3 = 0 \tag{2.32}$$

$$\frac{\partial L}{\partial K} = \eta^0 + \eta^1 - \frac{CP'(K)}{N} = 0 \tag{2.33}$$

$$\frac{\partial L}{\partial V} = \lambda - \frac{CS'(V)}{N} = 0 \tag{2.34}$$

$$\frac{\partial L}{\partial L} = \zeta^0 + \zeta^1 - \frac{CL'(R)}{N} = 0 \tag{2.35}$$

Optimal investment under uncertainty

Based on these derivatives, the optimal investment levels under risk neutrality[15] can be expressed as:

$$\frac{CP'(K,\theta)}{N} = \frac{1}{1+ir}\left(\int_{\underline{\theta}}^{\overline{\theta}} p_3^1(\theta) \cdot f(\theta) d\theta - p_2^1 - c_{23}' l_{23}\right) \tag{2.36}$$

15 For pipeline investments Cremer et al. (2003) show how risk aversion increases the optimal investment level.

for pipeline investments (assuming $\eta^0 = 0$ as in Section 2.2.1);

$$\frac{CS'(V,\theta)}{N} = \int_{\underline{\theta}}^{\overline{\theta}} \frac{1}{1+ir} p_3^1(\theta) \cdot f(\theta) d\theta - (p_3^0 + c'_{storage}) \tag{2.37}$$

for storage investments; and

$$\frac{CL'(R,\theta)}{N} = \frac{1}{1+ir} \left(\int_{\underline{\theta}}^{\overline{\theta}} p_3^1(\theta) \cdot f(\theta) d\theta - p_{LNG}^1 \right) \tag{2.38}$$

for LNG regasification investments.

Hence, annualized marginal investment costs in pipeline capacity need to equal the expected shadow cost of the capacity restriction. Marginal storage costs in optimum are equal to the expected value of the storage. The marginal LNG regasification capacity costs equal the expected value of importing LNG at the fixed cost.

Pipeline vs. storage vs. LNG import capacity investment

With the no-pipeline-congestion assumption for the off-peak period holding, i.e. $\eta^0 = 0$, we substitute $\frac{\partial L}{\partial K}$ and $\frac{\partial L}{\partial V}$ into equation (2.21):

$$\frac{CS'(V,\theta)}{N} + c'_{storage} + \frac{ir}{1+ir}(p_2^0 + c'_{23} l_{23}) = \frac{CP'(K,\theta)}{N} \tag{2.39}$$

Thus, in optimum, the per-period marginal capacity cost for pipeline equals the per-period marginal capacity cost for storage plus the extra costs incurred for storage (which are the marginal cost of storing one unit plus the foregone interest credit by purchasing and transporting this one unit of gas in the earlier off-peak period).

Hence, marginal annual pipeline and storage capacity costs are not equal in equilibrium but the former exceeds the latter by the extra cost incurred for the storing of natural gas. The optimal ratio is not affected by θ under risk neutrality, though optimal marginal investment costs are (see equations 2.36 and 2.37).

Relating LNG investment to storage investments yields

$$\frac{CS'(V,\theta)}{N} + p_3^0 + c'_{storage} = \frac{CL'(R,\theta)}{N} + \frac{1}{1+ir} \, p_{LNG}^1 \ , \tag{2.40}$$

LNG vs. pipeline investments can be expressed as:

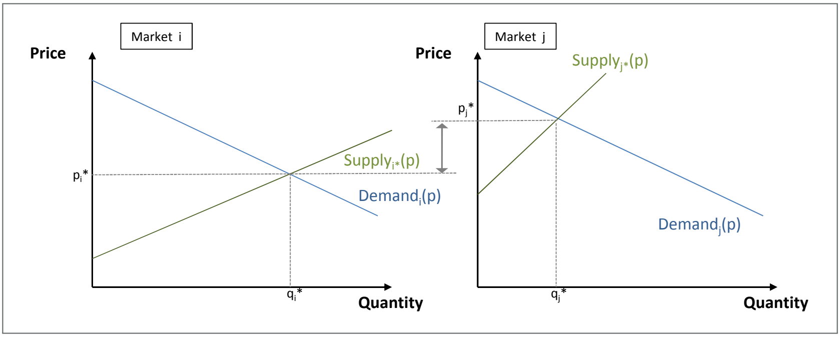
$$\frac{CL'(R,\theta)}{N} + \frac{1}{1+ir} \, p_{LNG}^1 = \frac{CP'(K,\theta)}{N} + \frac{1}{1+ir} \left(p_2^1 + c'_{23} l_{23}\right) \tag{2.41}$$

This simple analytical analysis has, therefore, shown that there are significant interdependencies in investments in the different infrastructure elements. These interdependencies need to be considered in the applied analysis strengthening the case for a model-based approach.

Discrete investment

While the previous argumentation has focused on marginal investment costs, investment decisions in infrastructure projects are usually discrete. Hence, a lumpy amount of capacity can be provided for a certain price. This paragraph briefly illustrates the implications for investment decisions.

Figure 2.2: Marginal investment optimality condition

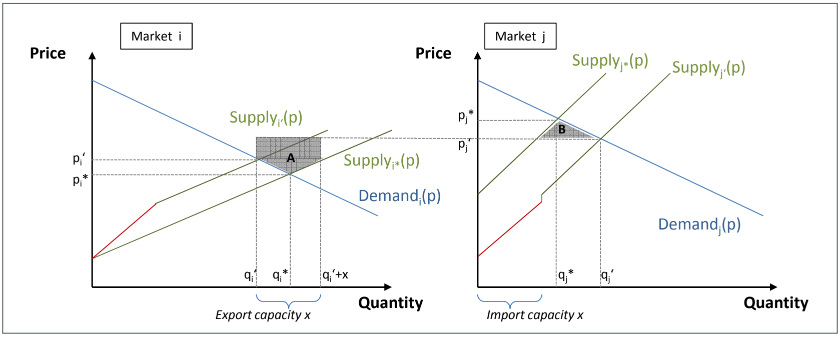


The decision for a one-period investment at the margin is briefly summarized in Figure 2.2. Congestion costs are determined by the price difference in the two markets. In equilibrium they are equal to marginal investment costs (equation 2.36). So, assuming variable transport costs of zero, $p_j * -p_i'$ reflects the increase in gross welfare benefit of another marginal unit of transport capacity. Investment in this marginal unit of interconnection capacity between the two markets should be made if the cost of investment does not exceed $p_j * -p_i'$. Total welfare would increase.

The same holds true for lumpy investments. However, welfare gains, in this case, cannot easily be determined by the price difference as this price difference is a function of the amount of investment. Hence, welfare effects for the whole project have to be considered. Figure 2.3 illustrates the effect for a capacity addition of x between two markets i and j. The capacity between the two markets thereby changes the slope of the supply curve up to the quantity which can then be traded. For all $q \leq x$, the supply curve is the aggregated curve (*Supply*$_{i*}(p)$ + *Supply*$_{j*}(p)$); the residual curve determines supply for all $q > x$. For market i, this implies that the slope of *Supply*$_{i'}(p)$

is twice the slope of $Supply_{i*}(p)$ for all $q \leq x$ as for each domestically offered unit, one would be offered in market j (as $Supply_{i*}(p) \leq Supply_{j*}(p)$). For $q > x$, $Supply_{i'}(p) = Supply_{i*}(p) + Supply_{i'}(x)$, i.e. the the supply curve is shifted upwards by the marginal cost increase caused by exported volumes. In market j, $Supply_{j'}(p) = Supply_{i'}(p)$ for all $q \leq x$; the residual supply curve for all $q > x$ is shifted downwards by the marginal cost decrease from importing units $Supply_{j*}(x)$.

Figure 2.3: Discrete investments between two markets



The transmission capacity has the following implications on the demand-supply equilibrium: In market i, consumer surplus decreases due to the increase in price. However, producer surplus increases due to the price rise and the exported volumes sold at a higher price. The total gray-shaded area A in Figure 2.3 represents the total welfare gain as this is the increase in producer surplus which is not a redistribution of consumer surplus. Likewise, producer surplus declines in market j as local output falls. However, the gain in consumer surplus arising from the imports at lower prices more than compensates this decline. The local welfare gain is the shaded area B.

Hence, applying the same theoretical concept that investment is efficient if its costs do not exceed the gross welfare gain, investment in capacity x should be made if investment costs are less or equal than the sum of $A + B$ (in the example of Figure 2.3). Assuming that we find investment to be efficient, and that a price difference remains (as in the example in Figure 2.3), further extension of capacity by another x units should be judged according to the same principle.

2.3 Selected studies on European infrastructure investments

While there are many encompassing studies investigating the future requirements regarding electricity transmission grids or power plant installations in Europe with a high level of detail[16], few such investigations exist for the European natural gas market.

Available (academic) studies usually focus on selected parts of the system or model the infrastructure with a lower granularity. The aforementioned studies by Perner and Seeliger (2004) or Möst and Perlwitz (2009) fall into the latter category; they do not focus on infrastructure investments specifically (but upstream developments and interactions with the electricity sector respectively). Further examples of applied academic analysis include Remme et al. (2008), who also focus on upstream developments, or the various papers investigating strategic behavior (e.g. the aforementioned Holz et al. (2008) article or other papers by the author or Lise and Hobbs (2009)).

Albeit with a high level of aggregation, an encompassing investigation of infrastructure requirements is also provided by Lise et al. (2008) for various demand scenarios. Results of their dynamic modeling exercise (parameterization of their model stems from 2005) are not necessarily comparable with our investigation as many of the "small" pipeline interconnection projects between countries and large-scale import infrastructure projects (Nord Stream, LNG terminals) found to be efficient in their setting have been implemented since then. However, they also discuss the trade-off between different investment options and find, in the case of flexibility provision, storage investments to be more efficient than LNG investments.

Studies focusing on selected issues are, for instance, ECN (2011) with respect to natural gas storage and ENTSOG (2009) with respect to the pipeline grid.

ECN (2011), which uses a model based on Lise et al. (2008), do not find significant gas storage investment requirements in the European gas market until 2020 due to the high working gas volume capacity of existing European storage facilities and other flexibility options. This, thereby, contradicts the earlier findings of the Lise et al. (2008) analysis. However, it is not necessarily an inconsistency in the model as circumstances, particularly the higher availability of short-term LNG, in the global gas market have changed over time - which makes this option economically more beneficial.

ENTSOG (2009) published the network development plan of the association of European TSOs. Although it is not a model-based or academic analysis, it is of importance as it reflects planned investments by TSOs which they are required to report (see also next section). Methodologically, the study compares peak demand assumptions for the following ten years with import, storage deliverability and production capacities to determine if a demand-capacity gap emerges or not. If that is the case, it is then

16 See for instance EWI (2010a), Lindenberger et al. (2008), Matthes et al. (2008), Nagl et al. (2011), amongst many others.

assumed that infrastructure investments are necessary. Economics are not taken into account. Furthermore, as capacities are considered and not volumes, it is also not clear if natural gas is actually available in the locations where capacity is sufficient.

Commissioned by regulators to obtain a perspective on the analysis by ENTSOG (2009), EWI (2010b) performed an integrated analysis with respect to congestion in the European transmission system until 2019. While this explicitly included the modeling of storage, efficient investments were not derived and congestion was largely discussed with respect to pipeline congestion. Their results confirmed the findings of ENTSOG (2009) as capacities are the prerequisite for transporting volumes. However, the model-based approach also enabled the identification of additional infrastructure congestion (which also implies a potential investment requirement), especially on days with high demand in North-Western Europe and in some Eastern European countries. Whether it is efficient or not to remove this congestion is not addressed.

2.4 Institutional framework for European natural gas infrastructure investments

In a complex, interconnected system like the European natural gas infrastructure, interdependencies between different infrastructure elements are significant. As shown in the analytical analysis with the simplified three node network, congestion costs - and therefore the benefits of additional investments - may be impacted by other pipelines or storage facilities (and LNG terminals for that matter).

Hence, doing analyses with a European model is the appropriate approach. With respect to actual investments, which may be carried out by various different investors in pipeline, LNG and storage infrastructure, coordination between investment projects is, thus, essential for designing and developing an efficient infrastructure system.

Currently, such issues are regulated on the European level through Directive 2009/73/EC (Common rules for the internal market in natural gas)[17], Regulation 715/2009 (Conditions for access to the natural gas transmission networks)[18] and the legislation establishing the European Energy Regulator ACER (Agency for the Cooperation of Energy Regulators), Regulation 713/2009[19].

According to the German Federal Energy Regulator Bundesnetzagentur (2010), there is no clear hierarchy with respect to planning between the national, regional and European level. Plans are supposed to be based on and incorporate all aspects.

On a national level, TSOs have to compile and submit so called network development plans to the national regulatory authority. These plans should consider the period of

17 http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:211:0094:0136:en:PDF

18 http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:211:0036:0054:EN:PDF

19 http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:211:0001:0014:EN:PDF

the next ten years from the date of preparation and are to be updated annually. They detail the respective TSO's scenario for the development of the natural gas market and planned investments over the time period. The focus is thereby on investments in the following three years and their detailed schedule.[20] Prior to publication, the TSO has to publicly consult its gas market scenario assumptions and adapt or label objections by stakeholders accordingly. The national regulatory authority also has to do a public consultation on the network development plans with current and prospective users of the infrastructure and, where applicable, ensure consistency between the plans of different national TSOs. If the regulator has any objections, it can appeal the development plan and ask the TSO to make adjustments. Furthermore, the regulator has to ensure consistency of the national development plan with the European network development plan and therefore with the expansion plans of other European TSOs.[21]

The national development plan then becomes a binding plan for the national TSO.

The European ten-year network development plan (TYNDP) is supposed to be based on the national plans. Likewise, national TSOs of course have to respect the European plan in their market expectations, although the latter is not binding (Bundesnetzagentur, 2010). The responsibility for the European TYNDP plan is with the association of European TSOs (ENTSOG). It has to include an integrated network modeling, the development of demand and supply scenarios and an evaluation of system adequacy with respect to these scenarios (Regulation 715/2009 Art. 8 (3b)). The plan is set up every two years; coherence with national plans is checked by ACER. Inconsistencies need to be addressed in either the European or the national plans in consultation with the respective national regulatory authorities and the European commission. The plan is consultated publicly similar to the approach on the national level.

These plans are mainly concerned with pipeline infrastructure. LNG terminal and storage projects, which are treated differently from a regulatory perspective in different member states, enter the plans as part of the framework scenarios in which the plans are embedded. As these are consulted with stakeholders, investors in LNG and storage projects are then required (not legally but out of their own interest) to ensure the inclusion of their projects in these scenarios. (Of course, investors may also approach TSOs with respect to network connections separately.)

The suitability of this approach regarding the coordination of investments still has to be proven. So far, there are no national plans in most countries, the European plan does not yet include the modeling approach it is supposed to encompass. The interdependencies between the different infrastructure elements theoretically outlined in

20 Regarding Germany, the first national ten-year network development plan by each TSO is to be submitted on April 1, 2012 according to the draft of the respective adaptations in the German law on the energy industry (EnWG, see Deutscher Bundestag, 2011). The remainder of this section with respect to national planning uses the example of Germany.

21 Potential conflicts are to be resolved by ACER.

Section 2.2 are not sufficiently recognized. Nevertheless, it is a first approach to an institutionalized coordination of investment projects in - mainly - pipeline infrastructure. Compilation and publication of the TYNDPs is going to increase the transparency regarding planned investments and the underlying framework assumptions by TSOs. Both may be of significant value in a liberalized European gas market.

This institutional framework shapes the reality of investment decisions in natural gas infrastructure. Because of the natural monopoly character of grid investments, market inefficiencies and potential strategic behavior, they are necessary. Apart from the interdependencies outlined in the previous section, the institutions impact what efficient investments - which are at the heart of this study - from the perspective of an investor are.

3 European Gas Infrastructure Dispatch and Investment Model

3.1 Overview

Recognizing the importance of interdependencies within the European natural gas infrastructure with respect to the analysis of new investment projects, physical market integration, and security of supply, the TIGER natural gas infrastructure model was developed at the Institute of Energy Economics at the University of Cologne (EWI). Model development was mainly done by Lochner and Bothe; early publications focused on the impact of new infrastructure projects on existing systems (Lochner and Bothe, 2007a,b).[22] The model is based on an extensive database of the European gas market infrastructure containing all relevant high-pressure long-distance transmission pipelines, all LNG import facilities and all natural gas storage (see also Figure 3.1 and Section 4.4 on infrastructure parameterization).

For our analysis, we extend the model from a pure dispatch model to an investment and dispatch model of the European gas infrastructure. Furthermore, we include demand stochasticity and extend the model horizon.

The model is, hence, a stochastic linear optimization model minimizing the expected total cost of gas supply in the European gas market. This includes capital costs (for new projects) as well as operating costs. The optimization is subject to the relevant technical constraints of the infrastructure from an economic perspective (i.e. some simplifications are necessary, see this section's closing paragraphs). The linear optimization approach thereby implicitly assumes functioning competition in the competitive segments of the natural gas value chain and an efficient utilization of infrastructure assets, i.e. effective regulation of the natural monopoly pipeline infrastructure and either a competitive storage market or its effective regulation[23].

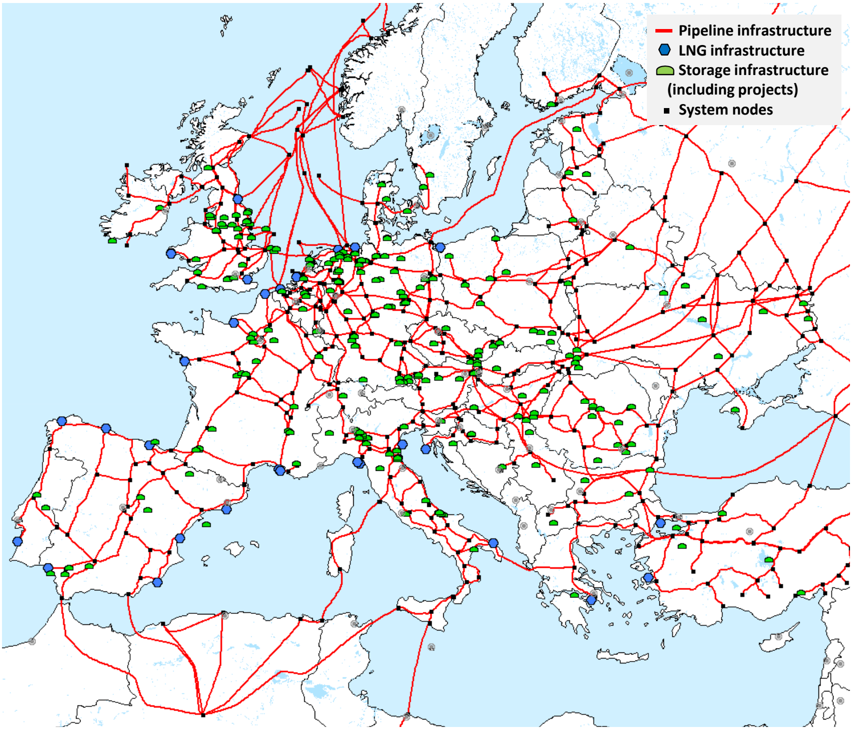
Inputs of the model include infrastructure, supply and demand assumptions.

Pipelines, LNG and storage are thereby included as they exist today based on the aforementioned database of the European gas infrastructure (see Section 4.4) with

22 Further publications of analyses based on different versions of the model include Bothe and Lochner (2008), Bettzüge and Lochner (2009), Dieckhöner et al. (2010), Lochner (2011), Lochner and Dieckhöner (2011) and Dieckhöner et al. (2011) as well as a large-scale study for ERGEG, the European Regulators' Group for Electricity and Gas (EWI, 2010b).

23 Depending on whether storage is regulated or not. The same holds true for LNG import facilities.

Figure 3.1: Modeled infrastructure elements in Europe



Source: EWI, illustration including selected pipeline and storage projects.

individual characteristics for each infrastructure element. This includes location, connections to other infrastructure and capacities (transmission capacity for pipeline, working gas volume / injection and withdrawal rates for storage facilities, annual import and hourly regasification capacities for LNG terminals). Further cost relevant characteristics (pipeline length, type of storage) are also assigned to each element. Infrastructure expansion options and applicable costs are assigned in the same way.

On the upstream side, it is assumed that gas is sold at price-inelastic commodity costs which implies that there are either non-gas-indexed long-term contracts or upstream competition. The latter is relevant for LNG where prices for short-term LNG cargos are presumed to form in the global market with Europe being a price-taker. Assumptions on border prices and available volumes are given to the model (Section 4.1).

With respect to demand, the model does not incorporate an explicit price elasticity in the short-term; this is not possible in the linear program framework. However, we assume two threshold prices above which demand declines: an interruptible contract price above which industrial consumers reduce their demand, and an infinitely high threshold price above which other consumers are assumed to reduce consumption.[24] A detailed description of the incorporation of demand assumptions is provided in Section 3.5, the numerical assumptions are provided in Section 4.2.

On the output side, the model then produces results on:

- the realization of infrastructure investment options,
- gas flows in the European gas market,
- the utilization of infrastructure elements in a high level of spatial (pipelines, LNG terminals, storage) and temporal (typical, representative days) detail,
- potential demand curtailment where the model choses to do so,
- and node-specific (locational) marginal costs which can be interpreted as short-term price estimators in a competitive market.

Suitability of the modeling approach

Such a model is an appropriate tool to analyze efficient infrastructure investments with a high level of spatial and temporal granularity. It offers a top-down perspective accounting for the numerous interdependencies between (investments in) different infrastructure elements outlined in the previous chapter. As an optimization model, its results can be interpreted as the first-best market outcome. Institutions (see Section 2.4), inefficiencies potentially occurring because of strategic behavior by players, insufficient regulation of the natural-monopoly-pipeline grid, or significant transaction costs arising from a lack of transparency or harmonization of market designs are not replicated by the model. However, incorporating such inefficiencies itself requires strong assumptions regarding their manner and scope - which in turn would greatly impact the results. Using the optimization approach yields the advantage that results are solely based on objective data (which is varied in scenario analysis). Thus, they are not forecasts but projections based on the used data. The results reflect the social-welfare maximizing outcome as implemented by a benevolent social planer - or as they would materialize in a perfectly competitive market without transaction costs or uncertainties (except the implemented ones). Hence, results constitute a first-best benchmark, which itself offers valuable insights into the economics of efficient infrastructure investments for regulators, policymakers and investors.

24 This second threshold price is chosen to be so high that it only becomes relevant when supply costs rise to infinity, which is the case only when demand can no longer be met due to restrictions on the upstream or infrastructure side.

With respect to the level of abstraction on the technical side, the presented model offers a suitable compromise between an accurate representation of the system and computability. In a large-scale model, some simplifications are inevitable: It is not possible to model all physical grid interdependencies explicitly, e.g. pressure levels along a pipeline, individual compressor stations or the impact of temperature on transport capacity. Hence, only the aforementioned characteristics of the infrastructure are incorporated into the model. While this does not allow a highly detailed representation of the physical aspects, a technical model may also not be necessary for investigating the economics of infrastructure investments in a European context: The functioning of an single compressor station in Central Europe may generally not impact the dynamics of investments or system operation in, say, the United Kingdom. (As Section 3.6 shows, model gas flows represent actual gas flows rather well.) A more technical representation of all infrastructure may, therefore, only have a limited impact on the general results, while it would greatly increase complexity. A European perspective, which is clearly more important for the analyses in this work, would no longer be possible with a technical gas flow model (no such model exists, see Section 2.1).

3.2 Mathematical model formulation

The mathematical program specifying the model described in the previous section is presented subsequently. Firstly, Section 3.2.1 presents the objective function; the constraints to the optimization are outlined in Section 3.2.2.

3.2.1 Objective function

The objective function minimizes capital as well as expected commodity plus and expected variable costs incurred in the supply process:

$$
\begin{aligned}
\text{min Total Cost} \quad = \quad & \sum_{y} \frac{1}{(1+ir)^{y}} \Bigg(\sum_{y,i,j} cc_{i,j}^{pipe} \cdot cap_{i,j}^{pipe} \cdot K_{y,i,j}^{pipe} \qquad (3.1) \\
& + \sum_{y,m} cc_{m}^{st} \cdot cap_{m}^{st} \cdot K_{y,m}^{st} + \sum_{y,n} cc_{n}^{LNG} \cdot cap_{n}^{LNG} \cdot K_{y,n}^{LNG} \Bigg) \\
& + \sum_{sc} \theta_{sc} \left[\sum_{t} \upsilon_{t} \left| \frac{1}{(1+ir)^{y}} \right|_{t \in y} \Bigg(\sum_{i} oc_{i}^{p} \cdot PR_{sc,t,i} \right. \\
& \qquad + \sum_{i,j} oc_{i,j}^{pipe} \cdot T_{sc,t,i,j} + \sum_{m} oc_{m}^{st} \cdot S_{sc,t,m} \\
& \qquad \left. + \sum_{n} oc_{n}^{LNG} \cdot L_{sc,t,n}^{import} + \sum_{i,z} dc^{z} \cdot DR_{sc,t,i}^{z} \Bigg) \right] .
\end{aligned}
$$

It is minimized over the variables

$$K^{st}_{y,m}, K^{LNG}_{y,n} \in N \text{ and } T_{sc,t,i,j}, K^{pipe}_{y,i,j}, PR_{sc,t,i}, DR^{z}_{sc,t,i}, S_{sc,t,m}, L^{import}_{sc,t,n} \in R_{+} \,.$$

for all nodes i, all pipelines from nodes i to j, all storage facilities m and LNG terminals n and all modeled days t ($\forall t \in \{1, ...36\}$), years y ($\forall y \in \{2015, 2020, 2025\}$) and (stochastic) demand scenarios sc. For the definition of the variables and parameters, see Tables 3.1 and 3.2. Please note that the terms comprising the capacity variables and the capacity costs are added up over the years in the objective function, i.e. capacity costs are expressed as annuities incurring in every time period. As decommissioning of capacities is not allowed in the model, this does not change the optimization.

The specification of the modeled years y illustrates that we model three representative years: 2015, 2020 and 2025. Intra-year time periods t reflect 36 typical demand days (three for each month), see Section 3.5.

Table 3.1: Model variables and element sets

Variables		Indices	
$K^{pipe}_{y,i,j}$	Pipeline expansion	i (and j)	Nodes (locations)
$K^{st}_{y,m}$	Storage capacity dummy	m	Storage facilities
$K^{LNG}_{y,n}$	LNG expansion stage	n	LNG import terminals
$PR_{sc,t,i}$	Production/import volume	t	Time periods (days)
$T_{sc,t,i,j}$	Transported volume	y	Years
$S^{l}_{sc,t,m}$	Stored gas volume	$prodreg$	Production regions
$S^{in}_{sc,t,m}$	Storage injection	z	Demand groups
$S^{out}_{sc,t,m}$	Storage withdrawal	$\forall z = 1, 2$	
$L^{import}_{sc,t,n}$	Imported LNG volume	sc	Scenarios
$L^{regas}_{sc,t,n}$	Regasified LNG volume	$\forall sc = 1, ..., 5$	
$L^{stored}_{sc,t,n}$	LNG stored in terminal		
$DR^{z}_{sc,t,i}$	Demand curtailment		

3.2.2 Optimization constraints

The optimization of this objective function is subject to a number of technical restrictions arising from production, transport pipelines, storage facilities and LNG terminals.

Table 3.2: Model parameters

Parameter	Definition
$cc_{i,j}^{pipe}$	Pipeline unit capital cost (annuity)
cc_m^{st}	Storage unit capital cost (annuity)
cap_m^{st}	Storage expansion capacity
cc_n^{LNG}	LNG terminal unit capital cost (annuity)
cap_n^{LNG}	LNG terminal stage expansion capacity
oc_i^p	Commodity cost
dc^z	Demand reduction cost
$oc_{i,j}^{pipe}$	Operating cost pipeline
oc_m^{st}	Operating cost storage
$kcons^{in}$	Storage compressor consumption during injection
$kcons^{out}$	Storage compressor consumption during withdrawal
oc_n^{LNG}	LNG delivery operating cost
θ_{sc}	Weight of scenario
υ_t	Weight of modeled day
$\overline{pr}_{y,prodreg}$	Annual supply limit
$pr_{y,prodreg}^{flex}$	Factor for flexibility of supply
$k_{i,j}^{pipe\_exist}$	Existing Pipeline Capacity
$k_m^{st\_exist}$	Existing Storage Capacity
$k_n^{LNG\_exist}$	Existing LNG Capacity
$s_{t,m}^{max\_in}$	Nominal maximum storage injection rate
$s_{t,m}^{max\_out}$	Nominal maximum storage withdrawal rate
f_m^{in}	Actual maximum injection rate as function of $s_{t,m}^{max\_in}$, $S_{sc,t,m}^l$
f_m^{out}	Actual maximum withdrawal rate as function of $s_{t,m}^{max\_out}$, $S_{sc,t,m}^l$
l_n^{regas}	Factor for maximum regasification capacity
$d_{sc,t,i}$	Demand
ir	Interest / discount rate

Capacity variables are only constrained to ensure their time consistency:

$$K_{y,i,j}^{pipe} \geq K_{y-1,i,j}^{pipe} \ , \ \forall y, i, j \tag{3.2}$$

$$K_{y,m}^{st} \geq K_{y-1,m}^{st} \ , \ \forall y, m \tag{3.3}$$

$$K_{y,n}^{LNG} \geq K_{y-1,n}^{LNG} \ , \ \forall y, n \tag{3.4}$$

We do not need to further limit expansion. The storage variable is a binary variable ($K_{y,m}^{st} \in \{0,1\}$), so storage facilities cannot be larger than the predefined storage site's capacity. With respect to pipelines, we assume that an unlimited expansion of any one (existing or potential future) connection is possible; the same holds true for the capacity at LNG import terminals.

Production is aggregated to production regions $prodreg$ but assigned for individual nodes. For these regions, annual production is limited; daily production is also limited by a production flexibility factor which is set to calculate a peak supply capacity on a given day (see Section 3.4):

$$\begin{aligned} \sum_{t\in y, i\in prodreg} \upsilon_t \cdot PR_{sc,t,i} &\leq \overline{pr}_{y,prodreg} && (3.5)\\ \sum_{i\in prodreg} |PR_{sc,t,i}|_{t\in y} &\leq \upsilon_t \overline{pr}_{y,prodreg} \cdot pr^{flex}_{y,prodreg} && (3.6)\\ & \forall sc, t, i \end{aligned}$$

Transport pipeline flow is restricted to the capacity of pipelines:

$$T_{sc,t,i,j} \leq k^{pipe\_exist}_{i,j} + K^{pipe}_{y,i,j} \cdot cap^{pipe}_{i,j}\ , \quad \forall sc, i, j, t \in y',\ y' \leq y \qquad (3.7)$$

For all combinations of nodes i, j where there is no pipeline, the right-hand side of equation (3.7) is zero implying that the flow on the pipeline has to be zero, too. Pipeline directionality is taken into account by differentiating between capacities between i and j and between j and i.

Storage operations are subject to restrictions on working gas volume (WGV) and maximum injection and withdrawal rates. Furthermore, each storage needs to adhere to a balance constraint ensuring that injections and withdrawals (and the resulting storage level) are in equilibrium over time. This balance constraint (equation 3.9) also takes into account the natural gas consumption of compressors during the injection and withdrawal process:

$$\begin{aligned} S^{l}_{sc,t,m} &\leq k^{st\_exist}_{m} + K^{st}_{y,m} \cdot cap^{st}_{m}\ , \quad \forall sc, m, t \in y',\ y' \leq y && (3.8)\\ S^{l}_{sc,t,m} &= S^{l}_{sc,t-1,m} + \upsilon_t \Big(S^{in}_{sc,t,m} \cdot (1 - kcons^{in}) && (3.9)\\ & \quad - S^{out}_{sc,t,m} \cdot (1 + kcons^{out})\Big) \qquad \forall sc, t, m \end{aligned}$$

The constraints on injection and withdrawal in each time period are a function of the current storage level as they change with the pressure inside the storage. If the storage is filled close to its capacity limit, pressure inside is high. This implies that a lot of compression is needed to inject further gas into the facility; the injection rate declines ($S^{in}_{sc,t,m} \downarrow$). Less compressor power is needed for withdrawals increasing the withdrawal rate($S^{out}_{sc,t,m} \uparrow$). The reverse is true for a low pressure inside the storage. The functions modeling these constraints (f^{in}_{m} and f^{out}_{m}) are therefore an upper bound for the actual injections and withdrawals:

$$S^{out}_{sc,t,m} \leq f^{out}_m(s^{max\_out}_{t,m}, S^l_{sc,t,m}) \tag{3.10}$$
$$S^{in}_{sc,t,m} \leq f^{in}_m(s^{max\_in}_{t,m}, S^l_{sc,t,m}) \tag{3.11}$$
$$\forall sc, t, m$$

The actual form of f^{in}_m and f^{out}_m depends on the type of storage (depleted field, aquifer, salt cavern or LNG storage). Our assumptions for the function form was established in interviews with experts from E.ON Gas Storage GmbH, BEB Erdgas und Erdöl GmbH (storage devision) and MVV Energie AG. They are depicted in Figure 3.2 (except LNG storage); their mathematical formulation with $K^{st\_tot}_m$ ($= k^{st\_exist}_m + K^{st}_{y,m} \cdot cap^{st}_m$) being the total storage capacity is as follows for the withdrawal rates:

$$f^{out}_m = \begin{cases} s^{max\_out}_{t,m} \cdot (0.4 + \frac{3}{2} S^l_{sc,t,m}) & \forall\, 0 \leq S^l_{sc,t,m} \leq 0.4 \cdot K^{st\_tot}_m \\ s^{max\_out}_{t,m} & \forall\, 0.4 \cdot K^{st\_tot}_m < S^l_{sc,t,m} \leq K^{st\_tot}_m \end{cases}$$
$$\forall \quad m \in m_{depleted\ field}$$

$$f^{out}_m = \begin{cases} s^{max\_out}_{t,m} \cdot (0.3 + \frac{7}{6} S^l_{sc,t,m}) & \forall\, 0 \leq S^l_{sc,t,m} \leq 0.6 \cdot K^{st\_tot}_m \\ s^{max\_out}_{t,m} & \forall\, 0.6 \cdot K^{st\_tot}_m < S^l_{sc,t,m} \leq K^{st\_tot}_m \end{cases}$$
$$\forall \quad m \in m_{aquifer}$$

$$f^{out}_m = \begin{cases} s^{max\_out}_{t,m} \cdot (0.3 + \frac{7}{3} S^l_{sc,t,m}) & \forall\, 0 \leq S^l_{sc,t,m} \leq 0.3 \cdot K^{st\_tot}_m \\ s^{max\_out}_{t,m} & \forall\, 0.3 \cdot K^{st\_tot}_m < S^l_{sc,t,m} \leq K^{st\_tot}_m \end{cases}$$
$$\forall \quad m \in m_{salt\ cavern}$$

$$f^{out}_m = s^{max\_out}_{t,m} \quad \forall \quad m \in m_{LNGstorage}$$

and for the injection rates:

$$f^{in}_m = \begin{cases} s^{max\_in}_{t,m} & \forall\, 0 \leq S^l_{sc,t,m} \leq 0.8 \cdot K^{st\_tot}_m \\ s^{max\_in}_{t,m} \cdot (4.2 - 4 S^l_{sc,t,m}) & \forall\, 0.8 \cdot K^{st\_tot}_m < S^l_{sc,t,m} \leq K^{st\_tot}_m \end{cases}$$
$$\forall \quad m \in m_{depleted\ field}$$

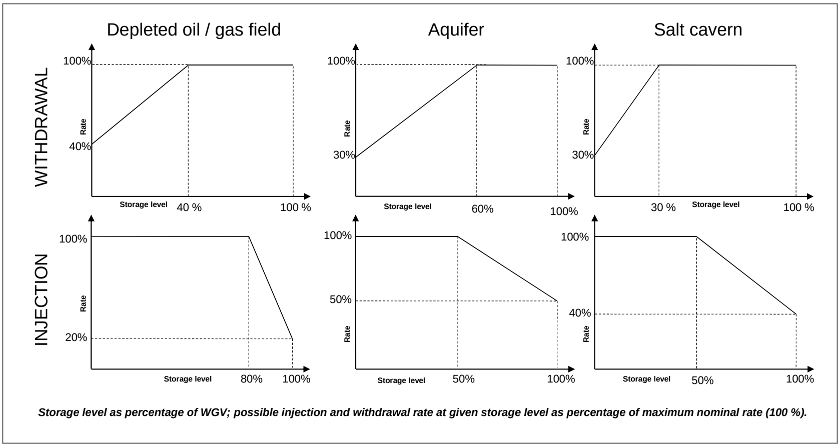
$$f^{in}_m = \begin{cases} s^{max\_in}_{t,m} & \forall\, 0 \leq S^l_{sc,t,m} \leq 0.5 \cdot K^{st\_tot}_m \\ s^{max\_in}_{t,m} \cdot (1.5 - \ S^l_{sc,t,m}) & \forall\, 0.5 \cdot K^{st\_tot}_m < S^l_{sc,t,m} \leq K^{st\_tot}_m \end{cases}$$
$$\forall \quad m \in m_{aquifer}$$

$$f^{in}_m = \begin{cases} s^{max\_in}_{t,m} & \forall\, 0 \leq S^l_{sc,t,m} \leq 0.5 \cdot K^{st\_tot}_m \\ s^{max\_in}_{t,m} \cdot (1.6 - \frac{6}{5} S^l_{sc,t,m}) & \forall\, 0.5 \cdot K^{st\_tot}_m < S^l_{sc,t,m} \leq K^{st\_tot}_m \end{cases}$$
$$\forall \quad m \in m_{salt\ cavern}$$

$$f^{in}_m = s^{max\_in}_{t,m} \quad \forall \quad m \in m_{LNGstorage}$$

Additionally, there is a storage condition across the stochastic demand scenarios ensuring that storage levels in the different (stochastic) demand scenarios cannot be lower than in the highest demand (1 in 20 winter) scenario. This is to emulate that the gas market does not know winter demand in advance, only the probability of the

Figure 3.2: Storage injection and withdrawal rates as function of storage level



Source: Own illustration based on expert interviews.

different realizations of the stochastic demand (see Section 3.5). Hence, independent of which scenario the model is in, the storage level has to behave in such a way that it is sufficient for all scenarios. Without this condition, the gas stock in the warm winter scenarios would not account for the possibility that the winter could be much colder and, thus, not accurately represent the costs of this uncertainty.

$$S^{l}_{sc,t,m} \geq S^{l}_{sc',t,m} \; , \quad \forall m, t = 28, sc, sc' = sc^{\text{highest demand}} \tag{3.12}$$

This does not imply that gas stock levels in all scenarios automatically equal the worst case (high demand) stock level: If gas stocks are deemed too costly for that, the model can reduce levels in ALL scenarios and chose to opt for other flexibility options in the (not so likely) high demand case.

LNG import terminals are subject to maximum output rates and annual nominal import capacities; LNG storage tanks are included in the same fashion as underground natural gas storage:

$$\sum_{t \in y} \upsilon_t \cdot L^{import}_{sc,t,n} \leq k^{LNG\_exist}_{n} + K^{LNG}_{y,n} \cdot cap^{LNG}_{n} \tag{3.13}$$

$$L^{regas}_{sc,t,n} \leq l^{regas}_{n} \left(k^{LNG\_exist}_{n} + K^{LNG}_{y,n} \cdot cap^{LNG}_{n} \right) \tag{3.14}$$

$$\forall sc, n, t \in y', \; y' \leq y$$

$$L^{stored}_{sc,t,n} = L^{stored}_{sc,t-1,n} + \upsilon_t \left(L^{import}_{sc,t,n} - L^{regas}_{sc,t,n} \right) \quad \forall sc, t, n \tag{3.15}$$

Energy balance in the system at all times ensures that the market clears. For all scenarios sc, nodes i and time periods t it needs to be true that the sum of gas volumes *entering* a node are equal to those *leaving* it:

$$\begin{aligned} & PR_{sc,t,i} + \sum_j T_{sc,t,j,i} + \sum_{m \in i} S^{out}_{sc,t,m} + \sum_n L^{regas}_{sc,t,n} \\ = \quad & \sum_j T_{sc,t,i,j} + S^{in}_{sc,t,m} + \sum_z DR^z_{sc,t,i} + d_{sc,t,i} \end{aligned} \tag{3.16}$$

As this condition needs to be true for all nodes i and all time periods t, it also ensures that the system as a whole is in equilibrium in each time period and over time.

Formulating the Lagrangian of the optimization problem and solving the problem would not only provide results for all optimization variables (see Table 3.1), but also allows an interpretation of the shadow costs (Lagrange multipliers) of the restrictions. The shadow cost of the energy balance constraint (equation 3.16), thereby, indicates the total system cost of supplying one additional unit of gas at the respective node and the respective time. These can, hence, be interpreted as location and time specific marginal costs, which constitute nodal prices (LMPs) in a competitive market (see Lochner, 2011).

3.3 Model implementation

The optimization problem outlined in the previous section is implemented as a computable program in the language of the high-level modeling system GAMS (Generic Algebraic Modeling System)[25].

GAMS provides an environment taking care of technical machine-specific issues (for instance computer memory management, calculations, data input and output routines) allowing the user to focus on modeling. For solving optimization problems, it works with a number of different solvers. Hence, depending on which solver GAMS is used with, it can compute various types of mathematical problems. Apart from linear and mixed integer problems solved in the context of this work, this also includes nonlinear models.

For the optimization problem outlined in Section 3.2, we use the CPLEX solver. CPLEX is named after the simplex algorithm which it implemented in the programming language C. It is the fastest solver available for linear and mixed integer linear models.

25 See http://www.gams.com or the user guide by McCarl (2003).

GAMS (in combination with different solvers) is intensively used in operations research or the economic modeling of complex technical systems. Applications to energy system modeling include the modeling of electricity (Bartels, 2009) and natural gas markets (Holz et al., 2008, Seeliger, 2006).

The specific complexity of the model in the previous section is significant. It varies depending on the specific parameterization with respect to investment options and number of periods or stochastic scenarios modeled. The version used for the analysis in this book (see for instance the scenario simulations in Section 5.3) can be characterized as follows:

- 2,659,341 equations (1 objective function and 2,659,340 constraints),
- 2,399,596 variables,
- including 426 binary variables,
- resulting in a model size of 7.93 gigabyte (GB).

The number of simplex iterations required to solve the model greatly depends on the (scenario-specific) parameterization. Apart from the number of iterations, computation time was found to depend on computational capabilities of the respective machine and the aspired accuracy of the solution. While high accuracy is generally desirable, the simplex algorithm can take a very high number of iterations to find the one optimal solution. However, a solution value (objection function) very close to the optimum may already be obtained after a fraction of the iterations necessary to find the one optimal solution. GAMS enables to specify the level of accuracy the solution should have. We allow the model to declare a solution as optimal if the solution value is as close as 10^{-4} percent to the theoretical optimum (also estimated by GAMS). Despite that computation time can be up to 10 hours on a machine with four parallel operating 2.83 gigahertz (GHz) processors (Intel Core 2 Quad) and 8 GB of working memory (plus 30 GB swap file). Thereby, working memory and number of processors are less relevant than the type of processor. For instance, simulation on a machine with up to 16 usable parallel processors and 96 GB working memory took up to 400 percent longer because of a slightly less capable processor core (Intel Xeon with 2.67 GHz).[26]

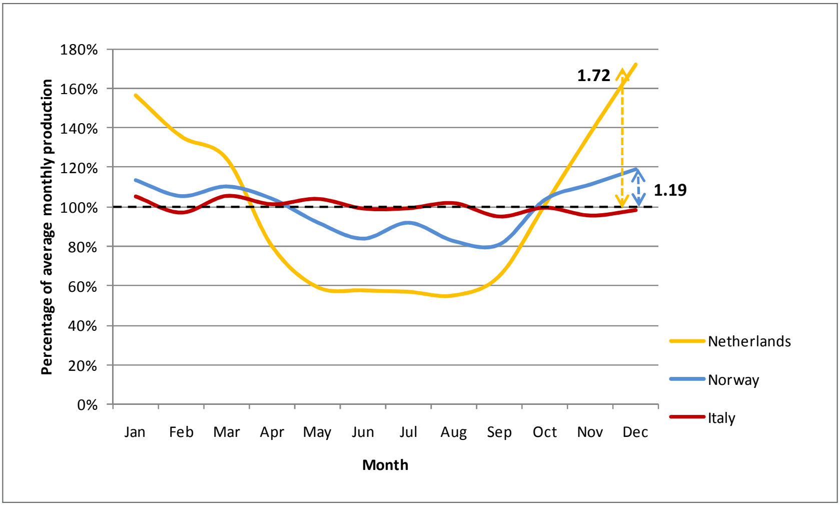
3.4 Modeling of gas supply

With respect to natural gas supply, volumes and prices need to be specified for the model simulations (see Section 4.1). However, gas production can be an important provider of flexibility in the gas market. Therefore its inclusion for the different production regions, as well as the definition of these regions, is discussed in this section.

26 The computation time during which a parallelization of the solution process is possible is limited to the early simplex iterations anyway. Memory-wise, the problem is not too large for the machine we used.

Supply flexibility

Figure 3.3: Production flexibility factor



As investments in production capacity (and therefore production flexibility) are not accounted for endogenously in our model, we need to make assumptions on and specify the extent to which production can be flexible.

Therefore we introduce a production flexibility factor ($pr^{flex}_{y,prodreg}$, see equation (3.6) on page 37) indicating possible production variations. It illustrates by how much monthly peak production may exceed average monthly production in a given year. We estimate the current values from historical data and make projections on their future development. Generally, it is calculated as:

$$pr^{flex}_{y,prodreg} = \frac{365 \cdot \text{peak production day}_{y,prodreg}}{\text{annual production}_{y,prodreg}} \tag{3.17}$$

$$pr^{flex}_{y,prodreg} \in R \left| 1 \leq pr^{flex}_{y,prodreg} \leq 365 \right|$$

If there is no production volatility, average production equals peak production and the factor becomes 1. If all production takes place on one day, $pr^{flex}_{y,prodreg} = 365$.

Exemplary, the production flexibility factor is illustrated for the Netherlands, Norway and Italy in Figure 3.3 (based on average monthly data between 2007 and 2009 from IEA, 2010a). For the Netherlands, this factor was estimated to be 1.72 indicating relatively high production flexibility in the fields: peak production exceeds average production by 72 percent. For Norway and Italy, the corresponding values were 19 and 5 percent respectively implying a much flatter production profile.

The numerical assumptions for all supply countries are presented in Section 4.1.4 (page 72).

Production regions

Table 3.3: Production regions in model

Algeria (Hassi R'Mel Field)	Ireland
Austria Azerbaijan (Shah Deniz)	Lybia (Wafa Desert)
Bulgaria	Netherlands (Groningen & offshore)
Croatia	Norwegian North Sea
Danish North Sea	Poland
France	Romania
Germany (Lower Saxony)	Russia
Hungary	UK North Sea
Iran	*LNG (global supply)*

Supply from in total 20 production regions is injected into the system at the respective grid nodes, where production is located, or at the relevant border (or regasification terminals) points, where the volumes are imported. All production regions are listed in Table 3.3.

3.5 Stochastic demand modeling

Natural gas is mainly consumed in production processes in industry, by gas-fired power plants for electricity generation, and by households for heating (and cooking and the provision of warm water)[27]. In 2008, household demand made up 39 percent of total European gas consumption; 34 percent were consumed in gas-fueled power stations and the rest in the industry sector (IEA, 2010a). In the model, we include the three sectors separately. Household demand is thereby assumed to be temperature-dependent and therefore stochastic in the short-term. Power sector gas demand and industry gas demand are included based on historical load profiles and with an implicit elasticity (see Section 3.5.5).

The (stochastic) household demand scenarios are derived by combining a number of recognized statistical algorithms. They are generated outside the optimization problem (exterior approach, see Shapiro (2003)) and subsequently incorporated into the

27 The household demand in the statistical definition typically also includes small businesses, e.g. in the service sector.

model as scenarios. Scenario generation includes the following steps: Based on historic temperature data, we model country-specific annual temperature curves including its stochastic element (normally distributed variable), Monte Carlo simulation allows us to create a set of temperature curves (10,000). Evaluation of these curves yields temperature distributions for each country for individual days (or the winter as a whole). Based on these distributions, temperature levels can be assigned with probabilities. To obtain the respective demand for the different temperature levels, we estimate temperature-demand curves for private households through regression analyses with historic daily household demand data (and the aforementioned temperature data) for each country. Applying the estimated temperature-demand curve yields household gas demand data. Hence, we get frequency distributions for natural gas demand by households and are then able to construct scenarios. For instance, a '1 in 20' winter, an often used criterion in the gas industry as an exceptionally cold winter putting lots of stress on the system, can be constructed for a scenario by extracting the median demand from the 5 percent quantile of the highest demand. (The full approach is described in detail in the remainder of this section.)

These scenarios are thereby constructed on an individual per-country basis. We refrain from modeling temperatures in Europe in one model explicitly taking all correlations into account as this would exceed the scope of this analysis. Intuitively, stochasticity temperatures without perfect correlation imply that observing a '1 in 20' winter in one country (for instance Germany) is more likely than observing a '1 in 20' winter in all countries (in Europe) at the same time. Hence, the European '1 in 20' winter would be expected to yield lower gas demand than the sum of all individual European countries' '1 in 20' winter demands. This is not necessarily the case. Slonosky et al. (2001) show in a principal component analysis of European temperatures from the 1770s to 1995 that temperatures in all countries are determined by common factors, especially in winter.[28] Variations in zonal circulations determine 70 percent of the temperature at that time of the year.[29] These atmospheric conditions are not limited to single countries but affect Europe as a whole. Thus, a cold winter in one country is likely to coincide with a cold winter in all other European countries. Therefore, modeling individual winters and combining them afterwards may not (or only slightly) overestimate demand in a '1 in 20' winter. Furthermore, the relevant legislation requiring companies and EU member states to ensure system adequacy (European Union, 2010) also implicitly presumes the case of simultaneously occurring winter conditions.

The afore-described procedure enables the individual creation of scenarios for seven countries representing 86 percent of European household gas demand. The reason for the limited analysis is the lack of availability of historic daily gas demand data required to estimate the temperature-demand-curves. For the seven countries, data

28 Winter temperatures are more relevant in the context of our analysis due to higher gas demand (Slonosky et al., 2001, find that correlation between European temperatures is actually lower in summer).

29 The results are robust to different approaches to identify zonal circulation, which is difficult to measure. Even simple indices like pressure differences explain at least 50 percent of European temperature variations (Slonosky et al., 2001).

was obtained from the respective TSOs[30] with the exception of Germany[31]. For all other countries (the remaining 14 percent of household gas demand), our analysis is limited to modeling temperatures and applying (relative) temperature-demand curves as estimated from countries with a similar demand structure (see last paragraph in Section 3.5.2). Temperature data for representative stations in all European countries is provided by Klein Tank et al. (2002).

Subsections 3.5.1 to 3.5.4 describe the applied approach for household sector demand in more detail. Industry and power sector gas demand are discussed in 3.5.5. These demand sectors are then aggregated to the total model demand in Section 3.5.6 which also discusses the fragmentation to regions (smaller than countries).

3.5.1 Temperature modeling

There is a wide literature on modeling temperature in the academic literature, usually in the context of finance where modeling of temperatures is required to value and price futures on agricultural products or weather derivatives.[32] According to Cao and Wei (2004), temperature models have to adequately capture the following characteristics of temperature: (1) Temperatures have a seasonal (cyclical) pattern. (2) They are volatile but there is an average temperature they tend to revert to. (3) There is an autoregressive component in the deviation from the average temperature, i.e. a warmer than average day is likely to be followed by another warmer than average day. (4) This residual (difference of actual to historic average temperature on a given day) is higher when the temperature is lower, i.e. the standard deviation of any day's temperature is a function of the median temperature of that day. (5) And there may be some global warming trend relevant for long-term projections. The literature also offers a wide choice of models incorporating all or some of these properties: Generalized autoregressive conditional heteroscedasticity models, autoregressive (AR) processes, autoregressive-moving average models and autoregressive fractionally integrated moving average models are widely used; in continuous time models the temperature is displayed as Ornstein-Uhlenbeck or Levy process.[33]

We decide to model temperature as an AR process. (Temperature in this case always refers to the daily average temperature defined as the mean of the minimum and maximum temperature measured at a weather station on a given day.) The model captures the desired temperature properties, is sufficiently general, and can be applied to all relevant countries (some other models are found to be only accurate for some countries). AR models are, therefore, "widely accepted as a sufficient compromise between manageability and accuracy" (Ritter et al., 2010).

30 TSO sources: Gaz de France (France), Enagas (Spain), National Grid (UK), Gaslink (Ireland), Snam-ReteGas (Italy), and Gas Transport Service (Netherlands).

31 For Germany, temperature-demand curves are also not estimated because of a lack of publicly available data. However, the functional relationship for Germany was investigated and published by Hellwig (2003).

32 See for instance Cao and Wei (2004), Campbell and Diebold (2005) and Roustant et al. (2003).

33 A summary of temperature models is provided by Ritter (2009) and Ritter et al. (2010).

As the aforementioned properties of temperature models affect either the average temperature (properties (1) and (5)) or the stochastic element ((2) to (4)), the temperature curve for one year T_t ($\forall t = 1, ..., 365$) can be modeled as

$$T_t = s_t + R_t \tag{3.18}$$

with s_t being the long-run daily average temperature on a given day and R_t being the stochastic temperature residual.[34]

The relative simplicity of the approach follows from setting s_t equal to the average historic temperature $\overline{T}_t$. A global warming trend could be easily incorporated by allowing $\overline{T}_t$ to increase over time (see Cao and Wei, 2004). However, as the model developed here is a short-term model and the temperature model is used to illustrate relative deviations of actual demand from average demand (and not a change in total demand due to global warming), the applied model does not require a global warming trend.

The residual R_t is described as an autoregressive process with a lag of three (AR(3) process):[35]

$$R_t = \sum_{i=1}^{3} \rho_i R_{t-i} + \sigma_t \epsilon_t \tag{3.19}$$

with ρ_i being the weight of the respective residual from day $(t - i)$, σ_t the day-specific standard deviation of the stochastic element, and the random variable $\epsilon_t \sim i.i.d.\ N$(0, 1). The standard deviation of the temperature residual is modeled as a sinus curve to capture its seasonal pattern:

$$\sigma_t = \sigma_0 - \sigma_1 \cdot |\sin(\pi t/365 + \phi)| \tag{3.20}$$

with ϕ capturing "the proper starting point of the sine wave" (Cao and Wei, 2004).

Hence, the model includes the desired temperature properties. The seasonal structure (property 1) is ensured through $\overline{T}_t$, the random element (2) via ϵ_t, the autoregressive characteristic (3) through the AR component (equation 3.19), and the pattern of the residual's standard deviation (4) is included in equation (3.20).

To obtain the temperature models for each of the European countries, we estimate the required parameters ($\rho_i \forall i = 1, 2, 3, \sigma_0, \sigma_1, \phi$) through regression analysis using historic temperature data (Klein Tank et al., 2002), which is employed to calculate $\overline{T}_t \forall i = 1, ..., 365$. Hence, we estimate ρ_i in equation (3.19).

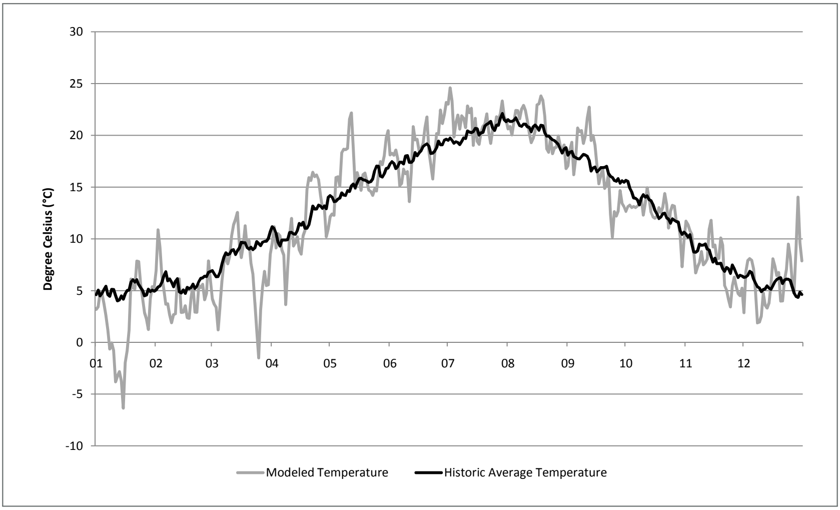
Exemplary, the following paragraph illustrates the temperature modeling for the data from a Paris temperature station (Paris-14E Parc Montsouris), which is used as a

34 The applied model is generally based on Cao and Wei (2004) with some denotations adapted according to Ritter (2009).

35 Models in the literature usually use a lag of either three or four. The (subsequently presented) regression analyses yielded the best fit for three lags.

reference for French weather.[36] Taking temperature data from 1 Jan 1980 to 31 Dec 2010, average daily temperatures are calculated. The resulting residuals are regressed in an AR(3) process to estimate $\rho_i \forall i = 1, 2, 3$ and the respective standard deviations. Equation (3.18) with $\epsilon_t \sim i.i.d.\ N(0, 1)$ and the parameters then yields a exemplary temperature curve for Paris. An example for such a curve is displayed in Figure 3.4, repetition of the model in a Monte Carlo simulation with new sets of ϵ_t yields 10,000 curves (Figure 3.5).

Figure 3.4: Paris average daily temperature and modeled temperature example



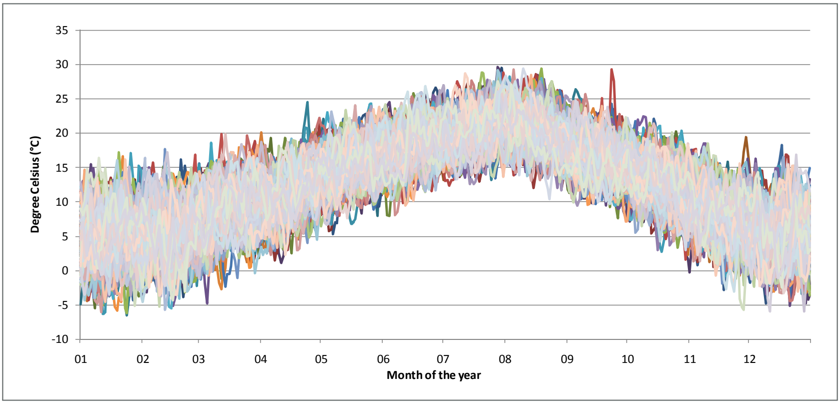
3.5.2 Estimating temperature-demand curves

Based on historical daily demand and temperature data, temperature-demand curves can be estimated through regression analysis.[37] The general relationship between temperature and natural gas demand is thereby not simple, as illustrated in the exemplary depiction of historic daily natural gas demand by households and temperature for France (1442 observations between 2007 and 2010) in Figure 3.6. Generally, one can distinguish three groups of observations. At relatively high temperatures,

36 Generally, French temperatures may differ significantly between the North and the South. However, more than two thirds of French gas consumption and almost all gas consumption by households takes place in Northern France. Therefore, the chosen temperature may yield an appropriate approximation.

37 The data for the Netherlands was based on average monthly household gas demand and temperatures between 2005 and 2010. While aggregated averages reduce the number of observations, it is nevertheless possible to estimate a function for the subsequent steps of the analysis.

Figure 3.5: Set of modeled temperatures for France



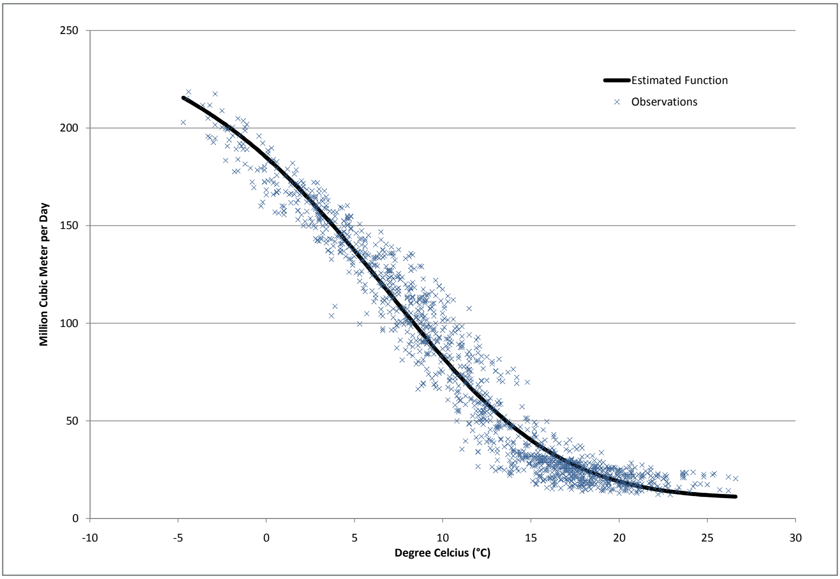
demand is relatively low and does not vary greatly with temperature. At low temperatures, the changes also appear to be small. Hence, there seems to be a lower and an upper bound for household gas demand: On the one hand, when it is warm, only non-space-heating gas demand (warm water, cooking) remains. On cold winter days, on the other hand, most heating capacities may be in operation limiting the potential for further demand increases, even if it gets even colder. In between these two sections of gas consumption, the (absolute) slope of the relation between gas demand and temperature appears to be rather high.

There are three approaches explaining this relationship functionally (see Hellwig, 2003): piece-wise linear, polynomial, or sigmoid functions. For separate linear regressions for the three aforementioned groups, the observations would need to be categorized into these groups. Finding the boundaries of these groups is difficult, and the fit of the curve in all three groups may not be satisfactory. According to Hellwig (2003), the fit of a polynomial curve is much better. However, the representation of the relationship outside the boundaries of the original sample is rather unsatisfactory due to the properties of the polynomial function. Therefore, we apply the sigmoid function proposed by Hellwig (2003), which is also illustrated in Figure 3.6 with the parameters estimated for France. Being a special case of the *S*-shaped logistic function, the sigmoid function is a suitable representation of the temperature-demand relationship.

The general form of the function according to Hellwig (2003) is:

$$Consumption = \frac{A}{1 + \left(\frac{B}{T_t - 40}\right)^C} + D \tag{3.21}$$

Figure 3.6: Temperature-demand curve for France

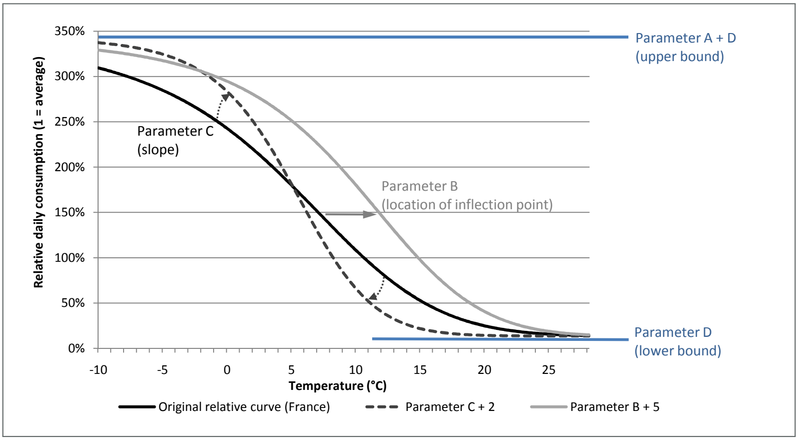


with parameters A, B, C and D specifying the exact shape of the function. The subtraction of 40 from the temperature ensures that the point of discontinuity ($T_t - 40 = 0$) is moved outside the relevant section of the function as none of the temperature models (Section 3.5.1) produced average daily temperatures above 40 degrees Celsius. The general form of the sigmoid function applied here is presented in Figure 3.7, which illustrates the effect of the individual parameters. A and D determine the aforementioned upper and lower levels of gas consumption. B determines the dilation of the curve to the left (from the plus 40 degree Celsius starting point) and therefore essentially the location of the inflection point. The parameter C influences the range of the aforementioned sections where temperature elasticity of demand is high or low respectively, and this elasticity itself.

For each country, the parameters A, B, C, D of the sigmoid function (equation 3.21) are estimated with a weighted least squares approach.[38] The weights thereby correct for the lower number of observations at the upper and lower end of the temperature scale, which are nevertheless of great importance as especially seldom but extreme

38 For Germany, an estimation is not possible due to a lack of data. Therefore, we use the sigmoid curves for Germany estimated by Hellwig (2003) for different types of dwellings and aggregate them to a single curve. The (weighted) aggregation thereby takes into account the number of dwellings of each typ and their energy consumption from Loga et al. (2007).

Figure 3.7: General form of the sigmoid curve



Source: Own illustration based on Hellwig (2003).

weather events should be captured in the analysis at hand. The estimated parameters for the seven countries where data was available are reported in Table 3.4. Parameters A and D obviously refer to the absolute values of the countries' household demands in the unit used (here: million cubic meter (mcm)). To enable a cross country comparison abstracting from absolute figures, we also include the parameters as a percentage of average daily demand across the year as A' and D' respectively.

Table 3.4: Estimated parameters of the sigmoid function of selected countries

	A	B	C	D	A'	D'
France	251.40	-34.90	6.02	10.39	3.24	0.13
Germany	365.31	-36.06	6.01	17.21	2.80	0.13
Great Britain	397.50	-36.72	5.80	44.93	3.19	0.36
Ireland	9.95	-36.04	6.50	0.44	1.60	0.07
Italy	316.25	-35.42	5.26	23.80	3.43	0.26
Netherlands	156.46	-34.21	7.80	14.95	2.48	0.24
Spain	120.80	-44.62	3.49	46.06	1.92	0.73

Source: Own calculation.

It also needs to be noted that comparing the data is nevertheless not advisable without an actual visualization of the sigmoid curves in the relevant temperature range. Figure 3.6 shows that the highest observations of household gas demand are around 220 mcm per day. Table 3.4, however appears to suggest that the upper bound is around 260 mcm/day ($A + D$). This would, however, only be realized at very low temperatures which are unlikely for France. The parameters in Table 3.4 should therefore merely be treated as parameters of the temperature-demand function which are only relevant in combination with the distribution of temperatures.

The relative parameters also allow the application of the temperature-demand curves to countries where no daily historical demand data is available. We do so by assigning these countries to one of the countries in Table 3.4 where demand structures as well as the general climate are assumed to be similar. We match the following country pairs:

- Switzerland, Slovenia and Croatia based on Italy,
- Belgium, Denmark, Luxembourg and Sweden based on the Netherlands,
- and Portugal and Greece based on Spain.

However, there are no observations for Eastern Europe. Therefore, we apply the detailed relative sigmoid function parameters calculated by Hellwig (2003) for different dwelling types in Germany, and calculate country specific figures based on the countries demand structure (Eurostat, 2011, IEA, 2010a). The results for the relative parameters are provided in Table 3.5.

Table 3.5: Relative sigmoid parameters Central and Eastern Europe

	A’	B	C	D’
Austria	2.77	-35.97	6.02	0.13
Bulgaria	2.81	-36.12	5.94	0.13
Czech Republic	2.73	-35.80	6.12	0.14
Hungary	2.84	-36.23	6.10	0.13
Poland	2.79	-36.00	6.07	0.13
Romania	2.84	-36.14	6.07	0.13
Slovakia	2.79	-35.92	6.22	0.13

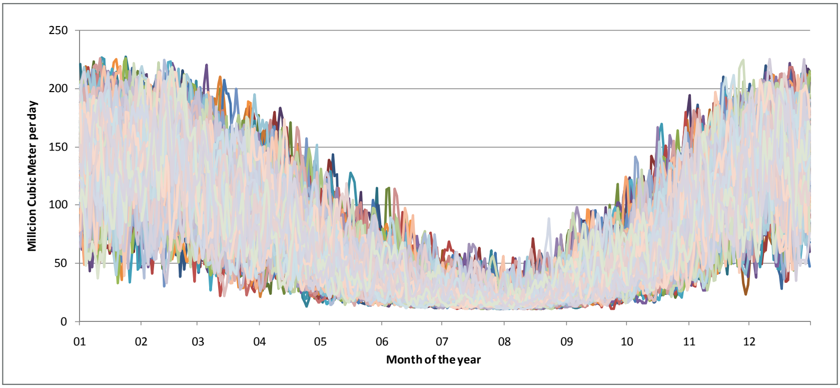
Source: Own calculation.

3.5.3 Household demand frequency distributions

A combination of the temperature-demand curves from Section 3.5.2 with the modeled temperature curves from 3.5.1 allows an investigation of the demand distributions.

Therefore, Figure 3.8 illustrates the application of the temperature-demand curve for France for each of the modeled temperatures from Figure 3.5.[39] The stochastic element resulting from the temperature's stochastic property becomes clear: Demand on a winter day can vary in a range from 50 to about 230 mcm/day. (Please note that this range is much smaller in summer (about 40 mcm/day) due to the lower standard deviation of the temperatures and the flatter temperature-demand curve in high temperature ranges.)

Figure 3.8: Set of modeled demand curves for France



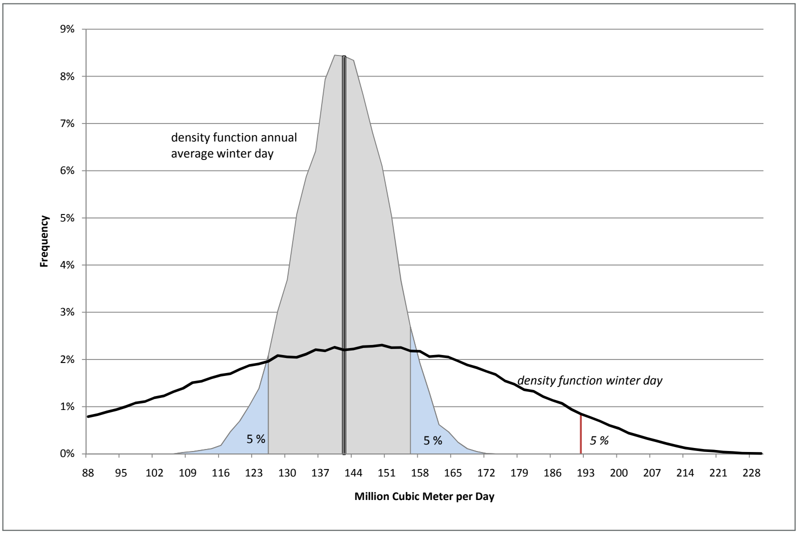
In order to set up scenarios with probabilities for stochastic deviations from the average temperature, we derive density functions from the obtained results (Figure 3.9). For an arbitrary winter day[40] (black curve in Figure 3.9), average demand by French households is 142 mcm/day. Five percent of winter days see this demand rising to at least 192 mcm/day. With a sufficient number of observations, household consumption can be expected to be at least that high on '1 in 20' days.

The '1 in 20' winter is not defined by the likelihood of a single cold winter day but by aggregated demand over the course of the winter. After all, the aforementioned demand of at least 192 mcm/day can only be expected to be observed on '1 in 20' days, not on 90 days in a row. Therefore, Figure 3.9 also displays the frequency function of annual average winter day demand (shaded area) yielded from applying the temperature-demand curve to the temperature results from the Monte Carlo simulation. The results are straightforward: due to enlarging the number of stochastic impacts (90 daily temperatures instead of 1), standard deviation of the distribution

39 It is only possible to illustrate up to 255 curves in one diagram. Therefore, the 10,000 estimations yielded from the Monte Carlo simulation cannot all be displayed. This is evident from Figure 3.9 which shows that there is a (low) probability of demand being outside the area indicated in Figure 3.8.

40 Metrological definition of winter: Dec 1 until Feb 28.

Figure 3.9: Demand density function for winter average and winter day (France)



declines.[41] Hence, a '1 in 20' winter for France means that household demand is, on average over the whole winter, at least about 156 instead of the all-winter-average of 142 mcm/day. Considering that the mean demand within that 5-percent-quantile is 158 mcm/day, this equals about 11 percent (above average), which does not sound critical. However, as French household demand between December and February is expected to be 16.5 billion cubic meter (bcm) in an average winter in 2020 (see Table 4.6 in Section 4.3), a cold winter means that an additional 1.8 bcm might be required if the winter is a '1 in 20' instead of an average one. In setting scenarios for the stochastic impact of temperature, the specification of these volume and probability values is crucial as it determines the optimal flexibility provision (where different options may differ with respect to capital and operating costs).

For the demand projections used in this study, the impact of the stochastic effects is discussed in Section 4.3.

41 Please note that the the median of average daily winter demands (one for each winter) is slightly lower than the median winter day demand due to the 'fat' left tail of the winter day demand distribution: There is a chance of rather warm days (with corresponding low demand) in winter, which decreases mean daily winter demand. However, there are only few such days which do not significantly impact the median winter day demand.

3.5.4 Household demand scenarios

Generating scenarios for stochastic programming is intensively discussed in the respective operations research and applied statistics/mathematics literature. An encompassing overview is for instance provided by Di Domenica et al. (2009). With respect to the generation of scenarios from previous Monte Carlo analysis, Shapiro (2003) suggests a sample average approximation (SAA) scheme as an exterior approach (where the scenarios are generated outside the optimization model). Thereby a sample of size sc of the (here 10,000) observations would need to be chosen randomly for inclusion as a scenario. If sc is large enough, Shapiro (2003) shows that numerical results converge to the solution of simulating all random observations.

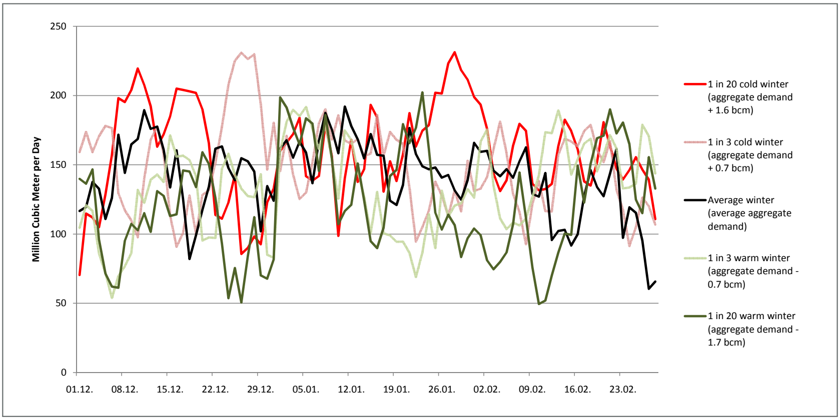
Due to the complexity of the model applied here, such an exterior approach is suitable. However, the complexity also disallows the incorporation of a sufficient number of randomly selected scenarios n in order to achieve sufficient convergence. Recognizing such constraints, Greenwald et al. (2006) show that selecting important scenarios greatly improves computation time with acceptable losses of accuracy with respect to the stochastic solution. However, they do not specify general rules for an appropriate way to select such important scenarios.

We, therefore, make this selection of scenarios out of the 10,000 simulations as follows: Due to the importance of a '1 in 20' winter as an often used criterion for gas market resilience to extreme conditions, the median winter out of the highest demand 5 percent quantile is selected for each country; so is the low demand equivalent. Their probability is 5 percent each. The remaining 90 percent of demand scenarios in the density function are fractionized into three equal 30 percent quantiles (which is the probability that one of the scenarios in this range is realized). For each of the quantils, we select the respective median scenario (i.e. the one with equal numbers of scenarios with higher and lower demand WITHIN the quantil) as the respective scenario to be modeled. This yields five representative scenarios with an accumulated probability of 1. Denoting the probability of stochastic demand as $\theta^T_{temperature-level}$ (with $temperature-level = 1, ..., 5$ for the scenarios in order of ascending demand), their values are $\theta^T_1 = \theta^T_5 = 0.05$ and $\theta^T_2 = \theta^T_3 = \theta^T_4 = 0.3$.[42]

Exemplary, the five demand scenarios for France are depicted in Figure 3.10. For the type day approach in our investment model, these scenario curves are aggregated to three typical days per month: a weekday (D1), Saturday (D2) and Sunday (D3). (The distinction is relevant for assigning industrial and power sector demand values, see Section 3.5.5.) The weekday has a weight of 5/7 of the month, Saturday and Sunday represent 1/7th each (υ_t in Section 3.2, which represents the weight in a whole year, i.e. 5/(7*12) and 1/(7*12) for the individual days). These days should thereby incorporate the features of the scenarios, for instance that even warmer winters see peak

42 Scenario probability θ_{sc} as presented in Section 3.2 would then be set equal to $\theta^T_{temperature-level}$ (for all *sc* = *temperature-level* $\in \{1, ..., 5\}$) for the simulation in Chapter 5 (except Section 5.4, where we introduce stochastic scenarios not related to temperature).

Figure 3.10: Five stochastic demand scenarios for France



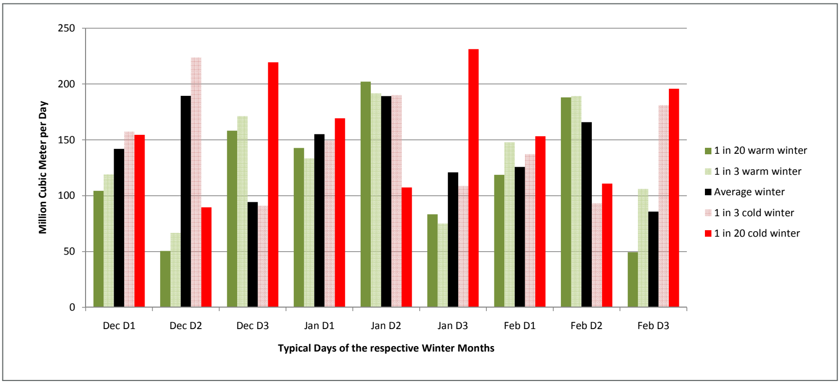
demand days of at least 190 mcm/day and that total aggregate winter demand should deviate from average winter demand by the respective value.

To make this conversion, we apply a GAMS program to convert the selected curves from 365 days to three typical days per month taking the aforementioned restrictions into account.[43] Results for the same scenarios for France are depicted in Figure 3.11. Comparing with Figure 3.10 demonstrates that the properties of the curves are captured, for instance the demand peak in the '1 in 3 cold winter' scenario in December or the generally low demand in the two green colored scenarios in January and February. Nevertheless, these two scenarios also see single days of relatively high demand. As weekdays have the highest weight in the month, this typical day category allows the most intuitive evaluation of total demand in the scenarios. In Figure 3.11 it becomes clear that the '1 in 20 cold winter' is therefore usually the one with the highest demand on this typical day - although other scenarios may see even higher demand in a single month (but not over the whole of the winter), for instance the '1 in 3 cold winter' is actually colder in December.

Based on this methodology, we calculate the 36 typical demand days for each of the five scenarios and each of the countries mentioned in the previous sections. Their construction as relative demand days (as percentage of an average annual demand

43 Hence, the program determines the three typical demand values for each month and each scenario subject to three restrictions: (i) The peak demand day observed in the full data in each month needs to be represented in the respective month. (ii) The same holds true for the day with the lowest. And (iii), each month's total demand has to be reflected by the weighted sum of the representative typical days. The typical day with the highest weight (D1) is adjusted accordingly. As a month is only represented by three typical days, these conditions completely determined their specification based on the full data set.

Figure 3.11: Derived typical winter days for simulations (France)



day) allows for their adjustment to general household demand developments, for instance due to gas supply to an increased number of households in a country or a substitution of natural gas with other heating technologies (see also Section 4.2). This allows for a highly flexible parameterization in the context of the model simulations.

The uncertainties with respect to the (stochastic) temperature arising from the analyses in this section in the context of the specific model parameterization are outlined in Section 4.3 (page 77).

3.5.5 Industry and power generation natural gas demand

The historic data on daily gas demand for countries where such data is available (Italy, France) shows no clear seasonal patterns and only a small standard deviation of the data. As there are no studies on the within year variation of industrial gas demand, we take data from Bartels (2009) for industrial process heat consumption as a proxy. The publication confirms the intuition that industrial demand does not show a significant seasonal dependency. There is, however, a weekly structure indicating consumption to be about 10 percent lower on a Saturday than on a weekday (Monday to Friday) and lower on Sundays than on Saturdays (by another 29 percent). There are some seasonal patterns taking heating requirements by industrial consumers into account, but the general structure is much flatter than household gas demand.

With respect to power sector gas demand, we apply an EU-27 extension of the DIME model by Bartels (2009) to model gas demand in the power sector. It is formulated as a linear optimization model allowing long-term projections as well as short-term simulations. We only use the dispatch model to obtain the patterns for the year 2008, investments for later time periods are not considered. In this electricity market model, the exogenous electricity demand has to be met in each country and at each point in time (two-hour periods). Therefore, the model can cost-optimally dispatch the power plant capacities (and use electricity interconnector capacities for cross-border exchange).[44]

As a result, we obtain total gas consumption in the year 2008 in each country and its respective distribution across the modeled type days and seasons. This allows to allocate the total electricity demand for each of the modeled years along the same pattern in each country. While this neglects potential changes in the relative dispatch of gas-fired gas generation, it provides a reasonable estimation for the allocation of demand projections (see Section 4.2) to individual months and days.

3.5.6 Demand and demand regions

To obtain total demand at a node ($d_{sc,t,i}$), we sum up demand for each of the sectors (households, industry, power generation) for each day on a country level. Large countries are further split down into demand regions, of which there are 56 (for 26 countries) in the model, see Table 3.6.

Table 3.6: Number of demand regions by country

Country	#	Country	#
Austria	1	Lithuania	1
Bosnia-Herzegovina	1	Luxembourg	1
Belgium	1	Macedonia	1
Bulgaria	1	Netherlands	1
Czech Republic	1	Norway	1
Denmark	1	Poland	3
Estonia	1	Portugal	1
Finland	1	Romania	1
France	4	Serbia	1
Germany	7	Slovakia	1
Greece	1	Slovenia	1
Croatia	1	Spain	5
Hungary	1	Sweden	1
Ireland	2	Switzerland	1
Italy	4	Turkey	1
Latvia	1	UK	6

Demand allocation to the demand regions takes place according to historic demand distribution in the country which was obtained from the statistical offices (Ireland,

44 For a detailed description of the model see Bartels (2009) or Paulus and Borggrefe (2011).

Italy, Poland), transmission system operators (UK, Spain) or industry associations (Germany, France) in the respective countries. For all other countries, and within the demand regions, consumption is distributed amongst the nodes in that demand region based on the distribution of the population. As this is only an approximation, the model presented in this work should not be applied to the investigation of congestion within these 56 demand regions. The focus should hence be on intra-country congestion between demand regions or cross-border congestion. Since these regions are sufficiently small, this does, however, not limit the general applicability of the model.

3.6 Model validation

The validation of optimization models with real historic data is difficult because simulation results yield a normative benchmark as to how the system - if all information were available to a benevolent planer - should optimally be run. In complete markets with perfect foresight, where all prices and costs are transparent and where one could hedge against all (price) risks, these simulation results should replicate the actual market outcome.

However, markets in general and natural gas markets specifically are far from complete. Inefficiency is therefore not reproduced by the model. It could, for instance, arise from strategic behavior by market players, non-transparent information or significant transaction costs due to insufficiently harmonized system operation (e.g. with respect to capacity allocation).

However, incorporating such inefficiencies would require strong assumptions regarding their scope and manner which in turn would significantly predetermine the results of the model. Using (mixed-integer) linear programming as an approach yields the advantage that results are solely based on objective data. These results can therefore be interpreted as a first-best benchmark in the sense that they represent the social welfare maximizing outcome.

The model validation is, hence, likely to produce some differences to historic data which needs to be explained. Such a validation for the dispatch in the model is provided in EWI (2010b, Chapter 5); selected results are presented in the following.[45]

For this validation, the model was parameterized for the year 2008 and simulated gas flows were compared with historic data (actual physical cross-border gas flows, which have been gathered from different gas pipeline operators, where available). Results are presented in Table 3.7 and Figure 3.12.

45 We refrain from validating the efficient investment decision part of the model as this requires the inclusion of even more assumptions on possible pipeline routes etc. which one could not have known when testing the model 15 years ago. For a discussion of the difficulties of long-term model validations, see Bothe and Seeliger (2005) who consider investments between 1965 and 1995.

Table 3.7: Model validation: Actual vs. simulated cross border gas flows for 2008

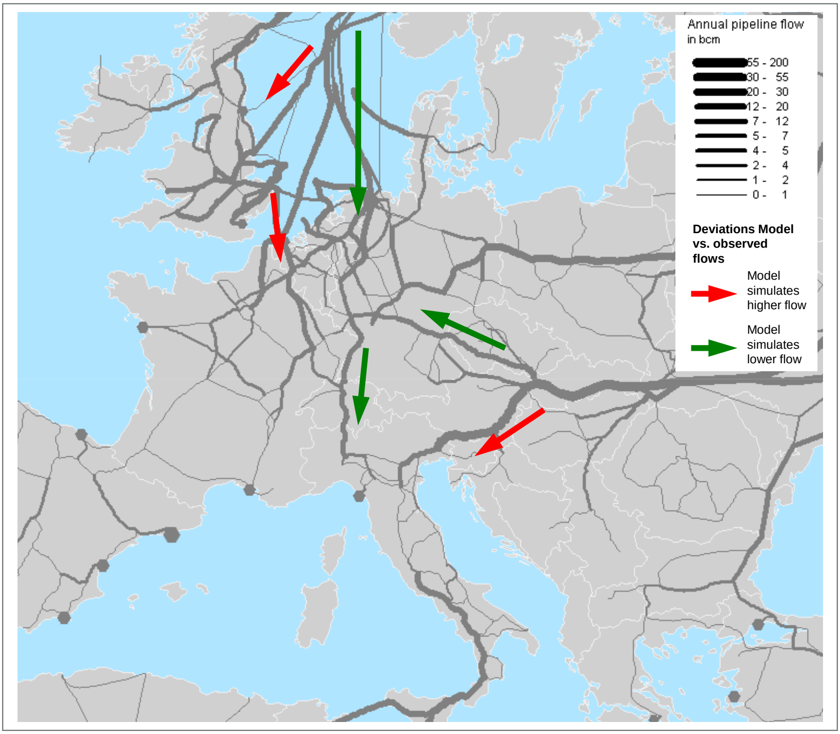
		Inflows			Ouflows	
	From	Actual	Sim.	To	Actual	Sim.
Austria	Slovakia	38.40	46.48	Germany	-2.44	-6.63
				Hungary	-2.28	0.00
				Italy	-25.00	-31.38
				Slovenia	-2.67	-2.37
Belgium	Netherlands	4.90	7.30	France	-16.30	-16.14
	Norway	12.70	12.70	Germany	-3.10	3.03
	UK	3.20	6.54			
	LNG Imports	0.90	2.86			
Czech Rep.	Slovakia	30.70	22.79	Germany	-21.40	-13.34
France	Belgium	16.30	16.14	Spain	-1.76	-0.17
	Norway	15.00	15.00	Switzerl.	-5.10	-0.52
	Germany	8.70	6.89			
	LNG Imports	11.90	8.55			
Germany	Austria	2.44	6.63	France	-8.70	-6.89
	Belgium	3.10	-3.03	Switzerl.	-11.90	-4.76
	Czech Rep.	21.40	13.34			
	Denmark	2.10	2.98			
	Netherlands	17.50	18.60			
	Norway	27.60	28.37			
	Poland	27.98	26.28			
Nether-lands	Norway	12.70	4.40	Belgium	-4.90	-7.30
				Germany	-17.50	-18.60
				UK	-9.20	-8.16
Spain/ Portugal	Algeria	11.50	12.79			
	France	1.76	0.17			
	LNG Imports	31.30	30.43			
UK/ Ireland	Netherlands	9.20	8.16	Belgium	-3.20	-6.54
	Norway	25.00	25.20			
	LNG Imports	1.00	5.37			

Negative values imply net gas flow in reverse direction.
Source: EWI (2010b).

Although the model does not account for contracts but optimizes the dispatch of the total system, gas flow volumes resulting from the simulation are close to real gas flows.

The differences between the actual and simulated gas flows that can be attributed to contract structures not covered by the model. These differences are mainly evident

Figure 3.12: Validation: Deviation of simulated and actual gas flows in 2008



Source: EWI (2010b).

for gas flows between Slovakia and Austria, from there to Italy and Germany, between the Czech Republic and Germany, and Germany and Switzerland as well as for flows between Germany and Belgium. Figure 3.12 illustrates these main differences which can be explained as follows:

- In reality, more Russian gas volumes are transited via the Czech Republic to Germany and more Norwegian gas via Germany and Switzerland to Italy.
- Within the model framework, less gas is transported via the Czech grid and more Russian gas is transited via Slovakia and Austria to Germany and Italy. This is the shorter route to some consumers in Southern Germany and implies a swap of Norwegian and Russian gas volumes in the context of the modeling framework.
- The Norwegian gas physically remains to a larger extent in Germany (instead of

being transited to Italy via Switzerland) while Russian volumes are transported to a larger extent to Italy than to Germany.

Additionally, there remain some uncertainties regarding actual physical gas flows which are only partially published. These concern Norwegian gas flows where BP (2010) had to be included as a source which does not fully distinguish between physical and contractual gas flows, and the Belgian gas balance, which, from the "Actual" column in Table 3.7 implies that domestic consumption would have been unrealistically low in 2008.

The largest differences between simulated and actual gas flows are also illustrated in Figure 10. For all other country combinations evaluated in Table 3.7, the absolute differences between the model projection and the data for actual gas flows are relatively smaller.

The fact that some contractual gas flows are not replicated by the model simulation does not limit the suitability of the model for the purpose of our analysis. This is especially true when considering a time period up to 15 years into the future as the reasons for the deviations between modeled and actual gas flows may be less relevant over time.

Firstly, with increasing separation (unbundling) of gas transport and trading and the efforts by national regulators to enhance efficiency and improve network access, one can expect European gas transportation to become more efficient. Hence, more of the efficient swaps presumed by the model might actually be implemented in reality.

The second reason which causes the modeled flows to deviate from actual gas flows might be differences in gas qualities for natural gas from different sources: The applied model only distinguishes between high (H) and low (L) calorific gas, but not between H gas from different sources (Norway vs. Russia in this case) which might hamper the actual implementation of gas swaps in the short-term. However, with the medium term view of this study, this is less of a constraint as consumers can adapt to changes in gas qualities. As indigenous European production declines, imports increase and new supply sources (LNG, Caspian region) are projected to be tapped for the European market, this may have to happen anyway.

Hence, the medium-term perspective applied in this study and the increasing efficiency in the European gas market may even further increase the overlap of model simulations and actual gas flows.

4 Numerical Assumptions of the Model Simulations

Within the modeling framework, assumptions with respect to supply, demand and the natural gas infrastructure need to be specified. The latter thereby includes the endowment of pipeline links, gas storage facilities and LNG terminals as well as expansion options given to the model, which include new pipelines (or storage or LNG terminal sites) as well as extension options of existing assets. This chapter presents the main assumptions with respect to those parameters and infrastructure expansion costs.

4.1 Natural gas supply assumptions

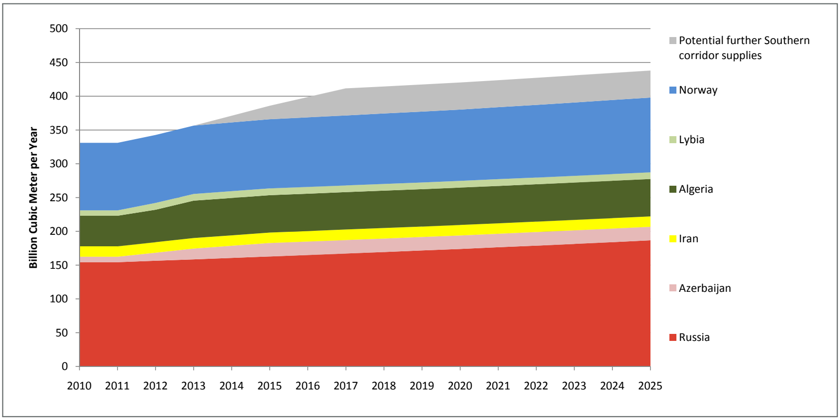
Natural gas supplies to Europe (potentially) include pipeline imports, LNG imports and indigenous gas production. Their discussion in the subsequent sections is followed by our presumptions on supply costs (Section 4.1.5).

4.1.1 Pipeline gas imports

In Figure 4.1 all pipeline gas volumes presumed to be available to the European market are presented (without indigenous production in the EU). For deriving them, a number of well-known forecasts including the World Energy Outlook (IEA, 2010b), the Annual Energy Outlook (EIA, 2011) and the EU's reference projection 'Trends to 2030' (Capros et al., 2010) are analyzed.[46] Methodologically, the results from these sources are considered and compared with an own upstream simulation with the EWI MAGELAN World Gas Model[47] as published in Lochner and Richter (2010). The remainder of this section discusses the different supply regions, which deliver natural gas by pipeline, and their supply potential to the European market. A numerical overview of these non-EU supplies is also provided in the section on supply costs, see Table 4.3 on page 73.

46 This analysis is essentially an update of the discussion in EWI (2010b).
47 Developed by Seeliger (2006).

Figure 4.1: Assumptions on pipeline imports available to the European market



Norwegian supplies

The production forecast for Norway is based on IEA (2010b), where a production increase of 13 percent from 2010 to 2025 to 115 bcm is projected. Barents Sea production, which is liquefied and exported as LNG (there is no link to the European pipeline system), is estimated at 4.5 bcm per year based on the capacity of the respective facilities. These volumes are therefore subtracted to obtain an assumption on the volumes available for export and domestic consumption.

Algerian supplies

Algeria's production capacity significantly exceeds its pipeline export capacity (BP, 2010) as the country also exports LNG. Hence, it can optimize exports and increase pipeline flows to Europe if this is more profitable. As the country's role as an exporter of both, LNG and pipeline gas, may not change according to IEA (2010b), we do not set a limit for Algerian export capabilities to Europe so that exports up to the pipelines' capacities limits are theoretically possible. For the visualization of pipeline export capabilities to Europe (Figure 4.1), we depict Algerian pipeline volumes as the pipeline capacity multiplied with a 90 percent utilization factor.

Libyan supplies

Libya is also an LNG and pipeline gas exporter and is therefore treated like Algeria with respect to pipeline export volume capability.

Russian supplies

According to BP (2010), Russia exported 152.3 bcm to the countries covered by the model in 2009. According to IEA (2010b), Russia's total production capacity is going to increase by 80 bcm per year up to 2025, exports to Europe are expected to increase by 20 bcm to 2020 and by another 41 bcm between 2020 and 2035. Our model simulations (Lochner and Richter, 2010) also show significant production expansions until 2025. We use the IEA (2010b) projection for our analysis; the 2025 data is interpolated from the published figures.

Southern corridor supplies (Caspian region and Middle East)

The spatial horizon of the model ends in Eastern Turkey. As potential gas suppliers in the Middle East or the Caspian region with direct pipeline supply routes to Europe could inject gas volumes there, they are summarized in this group (in alphabetical order).

AZERBAIJAN is already exporting gas to Turkey. Major production increases in the future are expected to come from the Shah Deniz offshore natural gas and condensate field. Due to the existing pipeline connection to Turkey (which can be expanded), the country is one of the most-likely contributors to gas volumes for new import pipelines in the region. However, upstream investments in the aforementioned field will be required to expand production capability. For the simulations in our analysis, we only deem pipeline exports via Azerbaijan towards Turkey to be realistic as new pipelines bypassing Russia from the Caspian region may not be built. This is also confirmed by our supply model simulations (Lochner and Bothe, 2009, Lochner and Richter, 2010). Hence, the only direct import route for Caspian gas to Europe is the South Caucasus Pipeline from Azerbaijan via Georgia to Turkey with a capacity of 8.8 bcm/year. Contracted flows are 6.6 bcm in 2009 and 6.3 bcm/year from 2010 onwards (data from the United States Energy Information Administration as cited in EWI (2010b)). The actual flow in 2009 was slightly higher at 8.8 bcm according to BP (2010). Due to the growing Turkish market and existing and potential transit routes through Turkey to the EU-27, we assume that the South Caucasus Pipeline is expanded to 20 bcm/year in 2012. Hence, we assume Azerbaijani gas flows to Turkey can increase up to this limit as of 2015.

EGYPT is the origin of the Arab Gas Pipeline which currently connects the country to Jordan and Syria. A proposed connection of the Arab Gas Pipeline to the Turkish and

European grid could be filled with additional volumes from Egypt (provided capacities along the existing route are expanded). With 2.19 trillion cubic meters of reserves and 63 bcm of production in 2009, the potential does exist (BP, 2010).

IRAN has contracted exports to Europe: 10 bcm/year to Turkey and 5.5 bcm/year to Switzerland-based utility EGL (volumes are formally destined to power plants in Italy). Hence, Iran has export contract obligations slightly in excess of the pipeline export capacity to Turkey (14.6 bcm/year). Therefore, it is assumed that these volumes can actually be exported to Europe (including the Turkish market) up to that limit over the next decade. With relatively low gas production cost and the world's second largest gas reserves, Iran appeared to be the most viable supplier of gas for projects like Nabucco based on fundamental costs. A pipeline connection to Turkey exists and gas production (mainly for domestic use) is also already the fourth largest in the world (131 bcm in 2009, see BP (2010)). However, the Iranian investment climate in general and the lack of foreign direct investment due to the political situation in particular hamper an increase in production output. As, for instance, the Nabucco consortium has ruled out Iran as a supplier for its project[48], further increases in production seem unlikely.

IRAQ is a potential pipeline supplier of natural gas to the European market. It hosts estimated reserves of more than 29 trillion cubic meters (BP, 2010) and its geographic location is favourable (most resources are actually closer to the European market distance-wise than those in Iran). However, production was only 3 bcm in 2006 and significant investments are required to increase production capacity. Although some investments in associated and non-associated gas fields are likely in the near future, the Iraqi government has also committed itself to purchasing up to 100 percent of the produced gas. Nevertheless, exports to Europe are an option and the proposed Arab Gas Pipeline could deliver gas from Iraq's Akkas field to Syria and then on to Lebanon and the Turkish border at some time during the next decade. Whether that will happen and which volumes would be exported remains, however, uncertain.

TURKMENISTAN, like Azerbaijan, has significant gas reserves and seems politically more stable than Iran. However, Turkmenistan is not yet connected to the Turkish grid due to its geographic location to the East of the Caspian Sea. Hence, apart from significant upstream investments, Turkmen gas for Europe would require a pipeline through the Caspian Sea or around the Caspian Sea via Iranian territory. Furthermore, Turkmenistan is selling natural gas to Russia, Iran and China and these countries appear to be willing to pay prices near the European net-back price. However, exports to Europe might still be feasible. According to industry representatives, it is possible to construct offshore links from the production rigs in the Caspian Sea directly to Azerbaijan under the existing production licenses. Hence, these pipeline links do not require expensive pipeline construction on the bottom of the Caspian Sea. Additionally, the gas fields supplying consumers in China and Iran are located in the East of the country and are, with respect to grid connections, separated from

48 See maps provided at http://www.nabucco-pipeline.com, which do not longer (15/07/2011) show the previous Nabucco link to the Turkey-Iran border.

the ones potentially supplying Europe. Therefore, there is not that much competition for gas from Western Turkmenistan and the country may have incentives to diversify its Western supply routes away from Russia.

Hence, there is some uncertainty associated with further potential pipeline gas imports from the regions of the Middle East or the Caspian Sea. However, these volumes are especially relevant for pipeline projects in the region. A number of countries could provide the gas to fill new pipelines, and it seems realistic that the pipeline is only going to be built if the respective volumes can be contracted. Therefore, we assume that additional supplies of up to 40 bcm per year for this Southern corridor are available. The value of 40 bcma thereby represents the expected capacity of the proposed additional routes to transport the volumes from Turkey into the EU: 31 bcma from Nabucco and 9 bcma for an interconnection via Greece to Italy[49]. We do not specify where these volumes come from as this is beyond the scope of this study and not relevant for the gas flows in Europe which arrive through this Southern corridor. A simulation of the impact of these additional volumes is provided as part of the scenario simulations (Section 5.3.2).

4.1.2 LNG imports

During the last decade, a high number of terminals for the liquefaction of natural gas were installed in several production countries. Further capacities already under construction are scheduled to go online in the next years bringing total liquefaction capacity up to about 350 bcm/year by 2015. In 2009, LNG trade already made up more than 240 bcm / year (BP, 2010) with the three largest exporters being Qatar (50 bcm in 2009), Malaysia (30) and Indonesia (26). Its scale is global: Qatari LNG is transported as far away as South and North America, Australian LNG cargos arrive at European terminals in some cases. Although most of these transported volumes are bound in some form of short-, medium- or long-term contract, there is generally a high degree of flexibility in the market. Firstly, the contracts have such clauses allowing the diversion of volumes. Secondly, most of the contracts are not fixed to single import terminals but to (globally operating) importers who may decide to which of their downstream markets they want the LNG to be delivered. And finally, for the respective price most of these importers may be willing to trade their contracted LNG with other importers. Hence, LNG may move to the markets with the highest prices. In the competitive market setting presumed in our analysis, Europe can be expected to be a price take and LNG - on a cost-base (Lochner and Bothe, 2009) - would be more expensive than pipeline gas.

Thus, if future spot prices in Europe were high (or the opportunity cost of selling LNG elsewhere is low), significant volumes would flow to the European market and would most likely only be constrained by import capacity. This was obvious in the recent past: Looking at prices in 2009, net-backing the United States wholesale price to

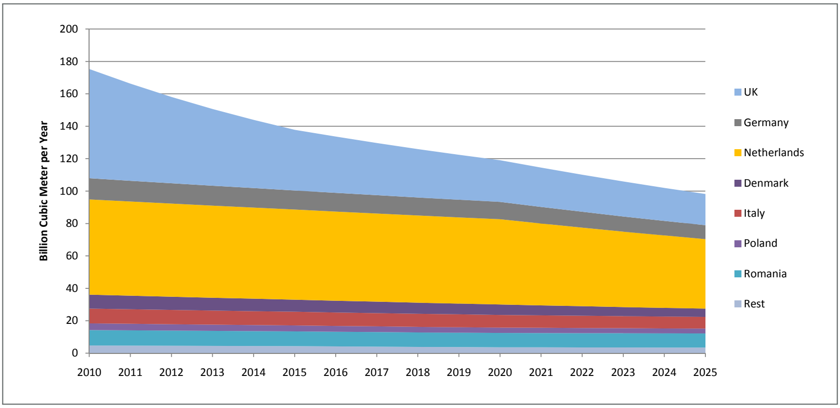
49 See Section 4.4.1: the two proposed projects have a capacity of 8 and 10 bcm per year respectively.

Europe indicates it was profitable to redirect LNG cargos from the US to Europe as long as European wholesale prices exceeded 6.94 EUR/MWh, which was the case during the whole year (see EWI, 2010b).[50] For the model simulations, we therefore do not set an upper bound on LNG volumes to Europe. They are available and can be brought to Europe as long as this is profitable. The relevant factor is, hence, their cost (see Section 4.1.5).

4.1.3 European gas production

Assumptions with respect to the EU's indigenous production (excluding Norway which was discussed in the previous section) are based on Capros et al. (2010) and are, thus, consistent with the demand assumptions (see 4.2). The source does not specifically differentiate with respect to the potential exploration of unconventional gas resources in Europe and their contribution to domestic production. We discuss this potential in a separate paragraph at the end of this subsection.

Figure 4.2: Assumptions on indigenous European natural gas production



The EU supply assumptions are depicted in Figure 4.2. According to this projection, gas production in the European Union declines from about 175 bcm in 2010 to less than 100 bcm in 2025. This equals a decline of 3.8 percent per year. The largest relative (8 percent annually) and absolute fall (48 bcm of annual production) in gas production is forecasted for the United Kingdom whose output declines to less than 20 bcm in 2025. The Netherlands is the largest EU gas producer in 2025 with an

50 Although another constraint was posed by long term contracts which did not allow to reduce pipeline imports at will in favor of LNG.

Table 4.1: EU gas production

Country	Annual production [in bcm]				Change	Percent of total	
	2010	2015	2020	2025	[%]	2010	2025
Austria	1.6	1.4	0.8	0.7	*- 55%*	1%	1%
Bulgaria	0.3	0.2	0.2	0.2	*- 40%*	0%	0%
Czech Rep.	0.2	0.2	0.2	0.2	*- 3%*	0%	0%
Denmark	8.7	7.5	6.5	5.1	*- 41%*	5%	5%
Germany	13.0	11.8	10.7	8.6	*- 34%*	7%	9%
Hungary	2.4	2.1	2.0	1.9	*- 19%*	1%	2%
Ireland	0.4	0.5	0.5	0.5	*+ 20%*	0%	1%
Italy	9.1	8.4	7.8	7.2	*- 21%*	5%	7%
Netherlands	58.7	55.6	52.6	42.9	*- 27%*	33%	44%
Poland	4.1	3.7	3.3	3.0	*- 28%*	2%	3%
Romania	9.5	9.1	8.8	8.8	*- 8%*	5%	9%
UK	67.4	37.4	25.7	19.3	*- 71%*	38%	20%
Total	175.3	137.9	119.0	98.2	*- 44%*		

Source: Own calculation based on Capros et al. (2010).

output of 43 bcm. With 44 percent of indigenous gas production, it is also by far the most important supplier within the EU's border.

Generally, the data on domestic production (also reported in Table 4.1) yields a significant increase in import dependency. With respect to the spatial distribution, it becomes evident that the largest decline is in Northwestern Europe: Until 2025 the Netherlands, UK, Germany and Denmark together lose 72 bcm of annual production compared to 2010, while all other countries' aggregated output declines by only 5 bcm over the same time period. (However, the other countries may see larger increases in demand, see Section 4.2.)

The prospects of unconventional gas production in Europe

Another recently often debated potential source of gas is unconventional gas resources. Such unconventional natural gas resources come in different forms with the most promising ones being coal-bed methane (CBM; gas extracted from coal beds), shale gas (extracted from shale formations), and tight gas (extracted from other low permeable rock formations, e.g. sandstone). While the extraction of such resources used to be unprofitable in the past, technological progress in recent years and economies of scale (spurred by the high gas prices up to 2008), approximately halved production costs and made drilling in these formations in the United States economically viable. Thanks to production from unconventional gas resources, the United States passed Russia as the world's largest gas producing country in 2009

(BP, 2010). With the IEA estimating global unconventional gas resources to total 921 trillion cubic meters (and, thus, more than five times proven conventional reserves), there appears to be a huge potential for this production to significantly shape global gas supply during the coming decades (IEA, 2010b).

The prospects of unconventional gas production on the European continent, however, remain to be seen. Firstly, less than five percent of the global resources are estimated to be in Europe. Secondly, the geological and political difficulties facing unconventional production in Europe may be much larger than in the United States. Geologically, the shale gas formations in Texas are found between 1,500 and 2,500 meters below ground. Austrian energy company OMV, on the other hand, estimates the promising rock formations in a basin near Vienna to be as low as 4,000 to 6,000 meters below ground making drilling significantly more expensive than in the United States. Politically, the new technologies applied to extract unconventional gas resources may also raise environmental concerns. Compared to conventional gas production, the extraction involves significantly more drilling (as deposits are smaller) and the injection of chemicals and water into the ground to increase permeability. The application of such technologies may prove to be much easier in the United States than in densely populated Europe with stricter environment protection laws (although these are also changing in the United States to limit water pollution by unconventional gas production).

Apart from these challenges, it also has to be noted that the exploration of possible basins in Europe, e.g. in Germany, Austria, Poland and Hungary, only began recently; shale gas production in the United States, on the other hand, already started 15 years ago. As unconventional gas production in a large scale involves a lot of drilling requiring many rigs, the respective service industry to install and maintain these facilities is required. Different to North America, such an industry does not exist in Europe: The number of active rigs (oil and gas) was 105 in Europe in December 2010, compared to 1,694 in the United States.[51] This lack of an industry to facilitate large scale production may increase production costs in the short and medium term.

Hence, within the time horizon of our analysis, European production from unconventional gas resources is not expected to play a major role. Nevertheless, to illustrate the infrastructure requirements which would arise from significant unconventional gas production in Europe, such a scenario is presented in Section 5.3.3.

Furthermore, even if large scale unconventional gas production in Europe does not materialize, this does not mean that unconventionals do not have an impact on the European gas market, even today. The significant unconventional gas production in the United States means the country's import demand is much lower than was expected just a few years ago. Many of the LNG upstream facilities entering operation around the world between 2009 and 2012 were meant to cater this demand when they were planned. With lower demand for LNG in North America, these volumes are, thus, to a larger extent available to other markets including Europe. In combination

51 See Baker Hughes Rig Count: http://investor.shareholder.com/bhi/rig_counts/rc_index.cfm

with the economic crisis in 2008 to 2010, this already caused the LNG glut with record numbers of LNG cargos coming to Europe in 2009 and 2010 (BP, 2010, 2011).

In the future, a global natural gas resource base broadened by unconventional resources may also benefit gas consumers in Europe as it enables larger supply diversification. This limits the dependency on individual gas sources or supply countries and the market power of countries with conventional gas reserves, which in turn enhances upstream competition and security of supply.[52]

4.1.4 Supply flexibility

As discussed in Section 3.4, limiting flexibility of supply is required to enable valuations of other flexibility options.

Because of a lack of other data, we calculate the current flexibilities based on the three-year average (2007-2009) of historic monthly data from IEA (2010a).

The results are displayed in Table 4.2. The development of these factors over time (e.g. by how much is Dutch flexibility declining) is, starting from the historic data, based on consultations with industry experts. They are also displayed in Table 4.2 for 2015, 2020 and 2025.

Currently, the highest flexibility is observed for Ireland, The Netherlands, Denmark and Romania. We assume flexibility declines in most countries with Netherlands production being the most flexible one in 2025. However, peak monthly production then is assumed to not exceed average monthly production by more than 26 percent (production flexibility factor of 1.26) there. Pipeline supply from countries further away is less flexible and is going to remain so. We set the production flexibility factor at 1.12 for all non-European supply countries. Norwegian pipeline supply flexibility is assumed to fall from 19 percent in 2009 to 16 percent in 2025.

LNG is assigned with a flexibility factor in in the same way as pipeline supply upstream flexibility to ensure that these imports are not infinitely flexible. The factor is set at a high level of 1.55 reflecting data on actual LNG imports to Europe between 2005 and 2009. The data was obtained from the *Quarterly Report on European Gas Markets* publication of the European Commission.[53]

52 Further discussion of the prospects of unconventional gas are, for instance, provided by Kuhn and Umbach (2011) and IEA (2011). The former explicitly discusses the impacts on and the potential in Europe, while the latter study has a more global focus on natural gas in general.

53 See http://ec.europa.eu/energy/observatory/gas/gas_en.htm for Vol. 1 Issue 1 (Q4 2008) for 2005 to 2007 and Vol. 3 Issue 1 (Q1 2010) for 2008 and 2009 data.

Table 4.2: Development of production flexibilities

Country	2009*	2015	2020	2025
Austria	1.14	1.10	1.05	1.05
Bulgaria	1.10	1.10	1.10	1.10
Croatia	1.15	1.10	1.10	1.05
Denmark	1.25	1.13	1.10	1.10
Germany	1.14	1.13	1.11	1.09
Hungary	1.09	1.07	1.05	1.05
Ireland	2.47	1.91	1.48	1.14
Italy	1.05	1.05	1.05	1.05
Netherlands	1.72	1.33	1.28	1.26
Poland	1.14	1.10	1.05	1.05
Romania	1.25	1.25	1.25	1.25
UK	1.20	1.14	1.12	1.11
Algeria	1.12	1.12	1.12	1.12
Azerbaijan	1.12	1.12	1.12	1.12
Iran	1.12	1.12	1.12	1.12
Libya	1.12	1.12	1.12	1.12
Norway	1.19	1.17	1.16	1.16
Russia	1.12	1.12	1.12	1.12

Source: Own assumptions, *2009 data based on IEA (2010a) for 2007-2009.

4.1.5 Supply costs and value of lost load

Supply Costs

With respect to supply, a specification of supply costs is necessary in addition to which volumes are available. In order to do so, we apply a global gas supply model developed by Seeliger (2006) including enhancements by Lochner and Bothe (2009) with respect to temporal granularity and supply cost evaluations. Results of this model application for the parameterization of this study have been reported by Lochner and Richter (2010).

The resulting supply costs at the EU border (Turkish border in case of Southern corridor volumes) are depicted in Table 4.3. The interesting case thereby is the cost of LNG. As depicted in Table 4.3, the marginal LNG supply in the global market is significantly higher than the marginal cost of pipeline supplies to the European market which is quite intuitive considering that Europe is in a geographical advantageous position in close proximity to a number of gas producing and LNG exporting countries.

However, if Europe wants to import LNG, it has to compete with other potential LNG importers (and all studies indicate that LNG cargos will be necessary for supplying

Table 4.3: Assumption on gas supply costs and reference supply capabilities

Source	(Location of delivery)	Supply cost [EUR/MBtu]	Supply capability [bcm] 2015	2020	2025
Norway	(Production field)	1.83	102.5	105.6	110.6
Russia	(EU border)	2.86	162.8	174.0	186.7
Algeria	(Production field)	1.86	55.4	55.4	55.4
Libya	(Production field)	2.01	9.9	9.9	9.9
Azerbaijan	(Georgia-Turkey border)	3.23	20.0	20.0	20.0
Iran	(Iran-Turkey border)	1.86	15.5	15.5	15.5
LNG	*(see text)*	6.25	∞	∞	∞

Source: Own calculation based on Lochner and Richter (2010).
EU gas production cost uniformly set at 2 EUR/MBtu.

the European market, see also Lochner and Bothe (2009)). The price of LNG is determined by its value in other markets as LNG suppliers, especially in an increasing global market with more short-term trade, always have the opportunity to sell LNG in a different downstream market, e.g. North America, Japan, South Korea, Taiwan, India, China and others. (European importers will likewise also be prepared to redirect their (contracted) LNG cargos to other destinations if the LNG has a higher value there, which of course implies that they are able to meet their European supply obligations through other means.) However, to account for the uncertainty with respect to the LNG price, we also include a scenario simulation with a lower LNG price (see Section 5.3.1, page 121) in our analysis.

To distinguish between the supply costs of LNG to different countries, we assume costs to differ by the respective transport cost differentials (based on OME, 2001) as outlined in Section 4.5.5 (page 94). The aforementioned LNG price refers to the existing terminals nearest to potential marginal LNG suppliers. We identified these marginal suppliers to be located in the Middle East or Africa. The price then applies to the terminals in the Mediterranean (e.g. Barcelona, Fos Cavaou); the respective transport cost from Section 4.5.5 is added for the terminals in the West and North of Europe.

Value of lost load

In case of natural gas price spikes resulting from very high demand in winter or supply disruptions, some price sensitive consumers may chose to reduce their gas consumption. The short-run price elasticity of gas demand may thereby be determined by gas-fired power stations which become uncompetitive if their input factor is too expensive. It is beyond the scope of our analysis to include detailed country-specific elasticity functions for gas demand in the model (which would then be non-linear anyway): the potential and reference prices for price-demand curves heavily depend on the power plant mix in each country and the prices of alternative fuels. Both can be expected to change over time.

However, we include two threshold prices. If they are exceeded, gas demand can be reduced by a certain potential. The first threshold price is based on value of lost load estimated by UKERC (2009) and refers to industrial demand. We assume that total industry demand can be reduced by up to 50 percent of industrial gas consumption if marginal supply costs increase up to this level (about 55 EUR/MBtu). Only allowing 50 percent demand curtailment at this price level aims to mirror that some industrial natural gas consumption may be difficult to reduce in the short-term (industrial processes); the remaining 50 percent would then need even higher prices before demand is reduced. Locational marginal costs would then only increase further if the first 50 percent of the demand reduction potential is fully exploited. If that is the case, the model needs a second threshold price in order to be able to solve. We set this to 100 EUR/MBtu. If that value is reached, demand can be curtailed further (without a limit).[54]

4.2 European natural gas gemand assumptions

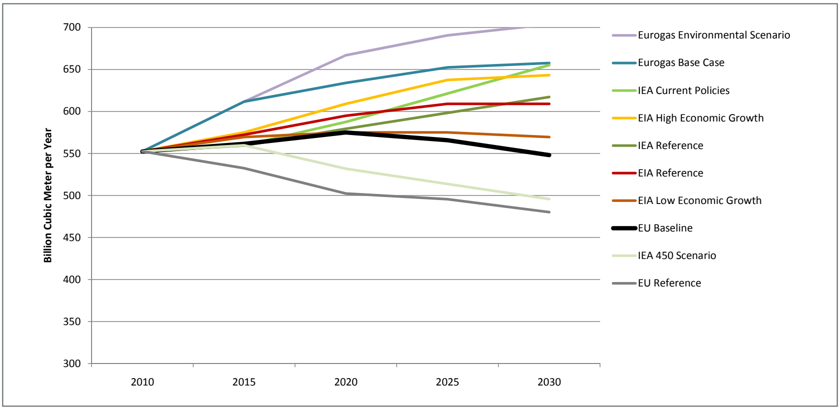
Demand projections for the European natural gas market are associated with uncertainty. Figure 4.3 thereby only lists a selection of the latest projections, i.e. those published since July 2010. These include the reference projections of the EU (Capros et al., 2010), EIA (2010), IEA (2010b) and the European gas industry association Eurogas (2010). Taking further (older) studies into account would further increase the standard deviation of these forecasts. As some of the studies even differ significantly with respect to 2010 consumption, they were normalized to the 2010 gas consumption as published by Capros et al. (2010).[55] Nevertheless, projections for 2025, the last year considered in this study, differ by a remarkable 195 bcm of annual consumption (EU Reference vs. Eurogas Environmental Scenario), see Figure 4.3.

For the purpose of our analysis, we apply the EU Baseline as our **Reference demand** scenario. It is suitable as it assumes the continuation of existing energy policies in the European Union and represents a conservative, but in the view of the author realistic, forecast. Its 2025 consumption projection is 566 bcm. Furthermore, the demand data provided by Capros et al. (2010) has the advantage of being broken down into demand in the different sectors which allows a more accurate application

54 Results of the simulations show that the first threshold price is always sufficient.

55 Furthermore, for the non-EU member states considered in our model (but not included in Capros et al., 2010) the respective (identical) demand projections have been added to all projections in Figure 4.3. This affects Norway (based on IEA, 2010b), Switzerland, Croatia, Serbia, Macedonia, Bosnia-Herzegovina (ENTSOG, 2009) and Turkey (data from Wood Mackenzie consultancy).

Figure 4.3: Different projections on European gas demand



of the different stochastic and seasonal patterns by consumer group described in Section 3.5.

The gas demand figures for the ten largest gas consuming countries covered by the model are displayed in Table 4.4. It becomes evident that gas consumption in Western Europe is at best constant and declining in some countries, notably the UK and the Netherlands. Rises above one percent annually are only observed for Spain over the whole time period. Most of the demand increases stem from (smaller) countries in Eastern Europe and Turkey. Regarding the distribution of gas consumption across sectors, Capros et al. (2010) does not project significant changes over time: In 2010, 32 percent of gas was consumed in power generation plants. Until 2025, this figure rises to 33 percent; the other sectors' shares also do not change significantly.

The explanations for these developments can largely be found in European energy policies. In the household sector, additional consumers are forecasted to gain access to gas-fired heating, especially in Eastern Europe. At the same time, however, efforts to raise energy efficiency are increased implying declining gas consumption per household. In the power sector, the European emission trading scheme (ETS), on the one hand, appears to favor natural gas as the fossil fuel with the lowest specific emissions. Furthermore, additional gas-fueled generation capacities are expected to be needed to balance fluctuating production of renewable energy sources, especially wind and solar power. On the other hand, the increasing total renewable electricity generation - which is additionally promoted through quota systems or subsidies - diminishes the size of the market left to all fossil fuels including natural gas. Hence, the increased capacities may only be required in hours of low renewable production. Full load hours of the power plants are low meaning their aggregated gas consump-

Table 4.4: Reference demand case assumptions for selected countries in bcm per year

Country	2010	2015	2020	2025	Change[a]
Germany	93.9	92.0	94.5	90.7	-0.2%
Italy	79.7	83.6	86.7	84.3	+0.4%
UK	88.8	80.7	77.0	73.0	-1.3%
Turkey	36.9	44.0	50.2	50.2	+2.1%
Spain	36.9	37.8	42.4	45.2	+1.4%
France	46.1	47.6	47.3	44.3	-0.3%
Netherlands	36.6	35.2	33.7	32.3	-0.8%
Belgium	15.4	16.5	17.3	19.5	+1.6%
Poland	16.5	17.1	16.6	16.5	+0.0%
Romania	14.0	13.9	13.4	13.4	-0.3%
Hungary	12.8	13.0	12.9	12.0	-0.4%
Austria	9.4	9.9	10.2	10.3	+0.6%
Rest	65.6	70.0	72.9	74.0	+0.8%
Total	552.5	561.4	574.9	565.7	+0.2%

[a] Average annual change 2010-2015.

Source: Own calculation based on Capros et al. (2010).

tion does not increase although capacity increases (which implies that full load hour declines are relatively larger than capacity increases, see Nagl et al., 2011, for a detailed elaboration). Likewise, significant changes in gas demand in the industry sector are also not expected. However, this is only one scenario and events in the first half of 2011 indicate that the role of natural gas in the primary energy mix might also increase.[56]

In order to obtain a view on the impact of recent developments, e.g. Germany's accelerated shut down of nuclear power plants, we also complement our analysis with a **High demand** projection (Table 4.5). Therefore, we apply the Eurogas (2010) Base Case demand projection as a rather optimistic one. According to this demand forecast, European gas demand does not remain more or less constant but increases significantly. In 2015, total demand is projected to be 70 bcm higher than in our Reference case (or 80 bcm higher than in 2010); until 2025 additional demand rises to 103 bcm compared to the reference. Hence, much larger additional investments would be required as the system not only has to be adjusted to increasing import dependency while demand is constant. Instead, total demand increases also impact the system. With respect to demand developments by country and sector, we assume the total relative demand distribution to be identical between the scenarios as Eurogas (2010) does not make specific elaborations on that issue.

The consideration of the two scenarios, thus, enables a broad perspective on invest-

56 See for instance the IEA (2011) 'The Golden Age of Gas' publication.

Table 4.5: High demand case assumptions for selected countries in bcm per year

Country	2015	2020	2025	Change[a]	vs. Reference case[b]
Germany	106.0	108.2	110.2	+1.1%	+22%
Italy	90.7	93.8	96.5	+1.3%	+14%
UK	102.6	105.4	107.8	+1.3%	+48%
Turkey	44.0	50.2	50.2	+2.1%	0%
Spain	41.2	42.5	43.7	+1.1%	-3%
France	52.3	53.1	53.9	+1.1%	+22%
Netherlands	42.3	43.7	44.9	+1.4%	+39%
Belgium	17.8	18.3	18.8	+1.3%	-4%
Poland	18.0	18.2	18.5	+0.8%	+12%
Romania	16.3	16.9	17.4	+1.5%	+29%
Hungary	14.7	15.1	15.4	+1.2%	+28%
Austria	10.7	11.0	11.3	+1.2%	+9%
Rest	73.7	77.1	79.8	+1.3%	+8%
Total	630.1	653.6	668.2	+1.3%	+18%

[a] Average annual change 2010-2015 (2010 data see Table 4.4).

[b] Relative difference to Reference case demand in 2025.

Source: Own calculation based on Eurogas (2010).

ment requirements in the European gas markets in each of two possible worlds - stagnating gas demand as well as increases based on the favorable economic and environmental characteristics of natural gas as a fuel.[57]

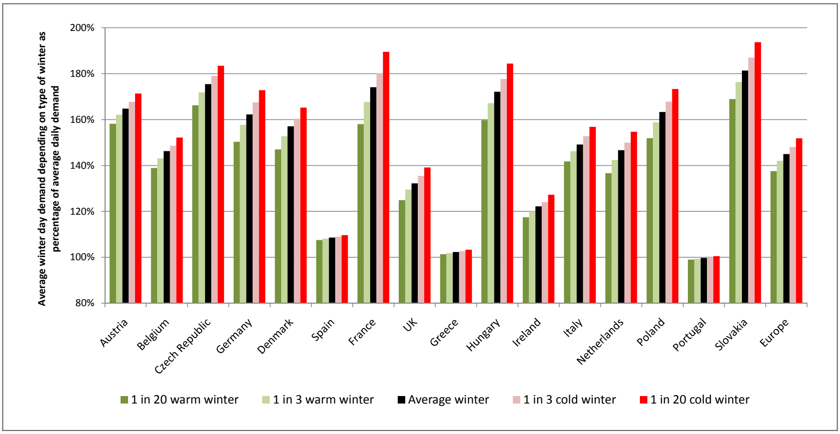
4.3 Excursus: Effect of temperature-related stochasticity

The assumptions of the previous section refer to (sector-specific) annual demand and are assigned to the demand regions, the individual days and the (uncertain) temperature levels as specified in Section 3.5. The scope and distribution of these uncertainties is of significant relevance to the model results and is therefore presented in this excursus.

Figure 4.4 illustrates the demand in each of the stochastic scenarios on an average day (of the scenario) for the winter in 2020 as percentage of the average daily 2020 demand.

57 In the case of the High demand scenario materializing, we also assume pipeline exporters to Europe to be able to increase their exports to Europe. Therefore, the previously outlined supply capabilities for the non-EU gas producers are assumed to be 15 percent higher in this case as reported in, for instance, Table 4.3.

Figure 4.4: Winter 2020 demand depending on temperatures



Two characteristics differing between countries become evident. Firstly, total seasonal demand variations vary greatly. Focusing on the average winter (black bars), we observe the average daily winter demand in France to exceed the average demand by 74 percent. The figure is even slightly higher for the Czech and Slovak Republics (75 and 81 percent respectively). At the same time, average daily winter demand in Portugal is almost equal to average daily demand implying there is no seasonality in demand. The results are similar for Spain and Greece where seasonality of demand is relatively small. This observation is thereby a consequence of the different geographic locations of the countries and the share of household gas consumption of total consumption. The Southern European countries rarely use natural gas for space heating and the heating season is shorter than in the North because of the warmer climate. Hence, a much smaller fraction of their demand is exposed to temperatures which generally determines the demand seasonality in Central and Northern Europe. This also explains the second differing characteristic: Uncertainty between demand in a warm and demand in a cold winter is much smaller in some countries than in others. Considering the volatility of the stochastic daily winter demand, France with a relatively high share of household gas demand sees the greatest volatility. In the Southern European countries, demand uncertainty is relatively small. For most of the other European countries, uncertainty is rather similar. It is slightly lower in Northwestern Europe (UK, Ireland, Netherlands) where the share of gas-fired power generation is higher and where long periods of low temperatures are less likely due to climatic conditions.

How these stochastic deviations from an average winter affect gas consumption over the course of the winter is depicted in Table 4.6 (for the year 2020). Gas consump-

Table 4.6: Demand variations between stochastic scenarios, winter 2020

Aggregate demand Dec2019-Feb2020	Average [mcm]	Difference to average [mcm] by type of winter 1in20 warm	1in3 warm	1in3 cold	1in20 cold
Austria	4,202	-168	-68	+76	+167
Belgium	6,325	-318	-136	+104	+257
Czech Republic	3,903	-204	-80	+80	+179
Germany	38,331	-2,819	-1,073	+1,242	+2,500
Denmark	1,846	-119	-51	+39	+96
Spain	11,512	-110	-50	+43	+112
France	20,589	-1,901	-757	+708	+1,817
UK	25,422	-1,406	-524	+620	+1,326
Greece	1,407	-14	-6	+5	+14
Hungary	5,508	-395	-159	+178	+393
Ireland	1,528	-60	-28	+23	+63
Italy	32,328	-1,595	-635	+785	+1,670
Netherlands	12,355	-843	-360	+275	+681
Poland	6,778	-475	-186	+186	+414
Portugal	1,097	-8	-4	+3	+8
Slovakia	3,174	-218	-88	+98	+217
Europe	176,304	-10,652	-4,203	+4,464	+9,913

Source: Own calculation based on Capros et al. (2010), see also Section 3.5.

tions is by far the highest in Germany in winter due to the countries large share of household gas consumption. Considering aggregated annual demand, the UK and Italy are also large consumers of natural gas (their demand in 2020 is expected to be only slightly below the German level, see Table 4.4). However, their consumption seasonality appears to be relatively low while it is significant for a country like Germany with a large share of household gas consumption. The resulting uncertainty is also larger: A 1 in 20 cold winter in 2020 in Germany would imply that gas consumptions is 2.5 bcm higher between December and February compared to an average winter. If temperatures are unusually high, demand is 2.8 bcm lower. The high temperature exposure of French demand becomes evident from Table 4.6. Despite having only the fourth largest total winter demand, the potential positive deviation from the average is higher than those of Italy or the UK. The table further illustrates the importance of absolute demand size: Although having a seemingly large exposure to stochastic temperature variations, the total winter variability of, for instance the Czech Republic, does not exceed 0.4 bcm (between the highest and the lowest of our stochastic scenarios). This may be less relevant for the European infrastructure system as a whole.

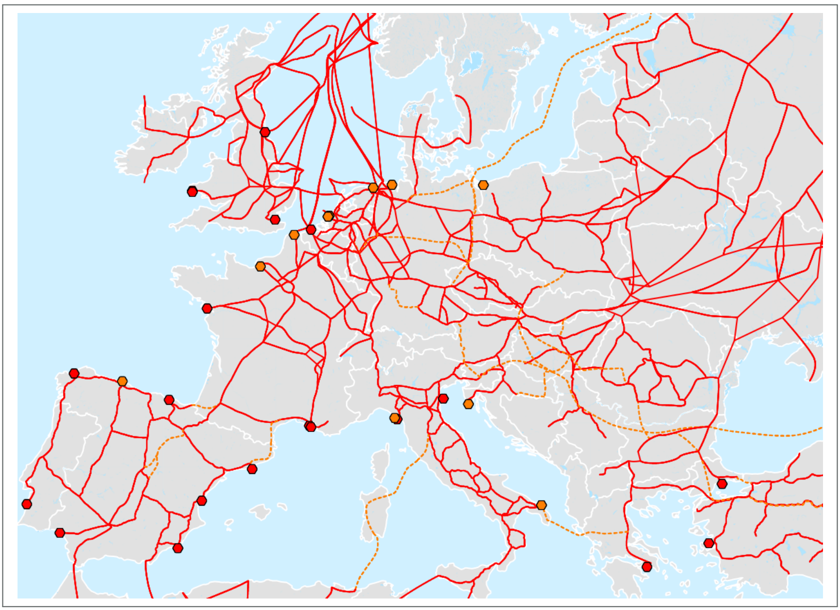
Over all considered countries, demand variability in winter ranges from +9.9 bcm in a 1 in 20 cold winter to -10.6 bcm in a 1 in 20 warm winter. Temperature stochasticity, hence, implies that demand in the coldest winter case may be 12 percent higher than in the warmest possible winter (in the context of our stochastic scenarios). This amounts to a volume of at least 20.5 bcm which may or may not be demanded by consumers.

4.4 Infrastructure endowments and expansion options

The assumptions concerning the infrastructure components of the model simulations are presented in this section. For the scenario setup, all existing infrastructure elements and projects with a final investment decision made until the end of 2010 are included in the simulations.

Regarding infrastructure expansion options, these differ with respect to the type of infrastructure and are also discussed in the following. The costs for expanding the infrastructure are presented in Section 4.5.

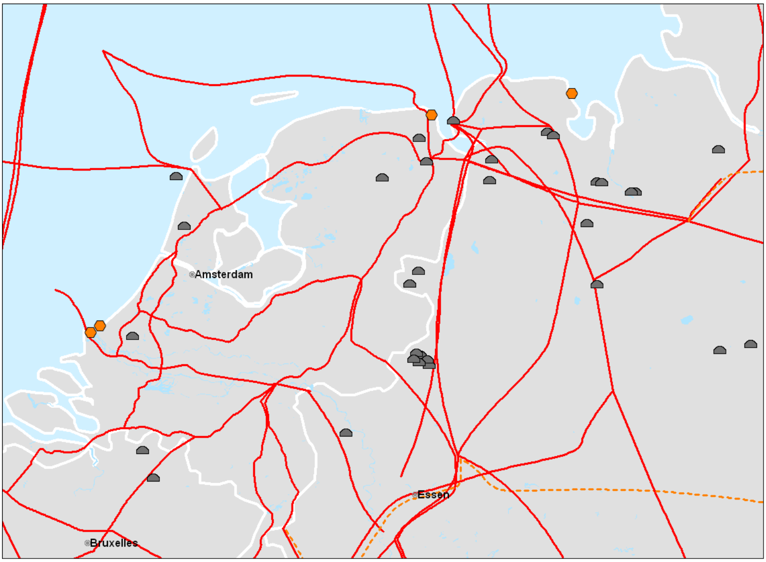
Figure 4.5: Modeled pipeline and LNG infrastructure



4.4.1 Long-distance transmission network

Generally, our analysis considers all long-distance transmission pipelines in the European grid. They are depicted in Figures 4.5 and 4.6 with the latter one demonstrating the level of detail by showing an excerpt with increased zoom on the map.[58] The underlying database includes 684 pipelines and 171 interconnectors between different network operators in the covered model area which includes Europe and the adjacent production regions in Algeria, Libya, Iran, Azerbaijan and Russia. The database was compiled using information from the transmission system operators listed in Table 4.7 as well as data from ENTSOG (2009), the ENTSOG Capacity map datasets published between 2007 and 2010 (GIE, 2011), the Petroleum Economist and various issues of newsletters from *DowJones*, *platts*, *ICIS Heren European Gas Market* and *Gas Matters*.

Figure 4.6: Pipeline and LNG infrastructure - high resolution



For endogenous capacity expansions, the model can chose to increase capacity on any existing route (continuous lines in Figures 4.5 and 4.6) as well as on the routes of projects included in the model (dotted lines).

With respect to the major pipeline projects, we do not include them exogenously, however, the model might chose to endogenously built them:

58 The illustration also includes potential pipeline projects and the LNG infrastructure.

Table 4.7: Transmission system operators covered in model

Country	TSO	Internet source
Austria	BOG	www.bog-gmbh.at
	OMV Gas GmbH	www.omv.com
	TAG GmbH	www.taggmbh.at
Belgium	Fluxys	www.fluxys.com
Bulgaria	Bulgartransgaz EAD	www.bulgartransgaz.bg
Czech Rep.	NET4GAS s.r.o.	www.net4gas.cz
Denmark	Energinet.dk	www.energinet.dk
Finland	Gasum Oy	www.gasum.fi
France	GRTgaz	www.grtgaz.com
	TIGF	www.tigf.fr
Germany	Gasunie Deutschland GmbH	www.gasunie.de
	Ontras-VNG Gastransport GmbH	www.ontras.com
	Open Grid Europe GmbH	www.open-grid-europe.com
	Thyssengas GmbH	www.thyssengas.com
	Wingas Transport GmbH&Co.KG	www.wingas-transport.de
Greece	DESFA S.A.	www.desfa.gr
Hungary	FGSZ Naturel Gas Transmission	www.fgsz.hu
Ireland	Gaslink ISO Limited	www.gaslink.ie
Italy	Snam Rete Gas S.p.A.	www.snamretegas.it
Luxembourg	Creos Luxembourg S.A.	www.creos.net
Netherlands	BBL Company	www.bblcompany.com
	Gas Transport Services B.V.	www.gastransportservices.nl
Poland	GAZ-SYSTEM S.A.	www.gaz-system.pl
Portugal	REN - Gasodutos S.A.	www.rengasodutos.pt
Romania	Transgaz	www.transgaz.ro
Slovakia	eustream, a.s.	www.eustream.sk
Slovenia	Geoplin plinovodi d.o.o.	www.geoplin-plinovodi.si
Spain	Enagás S.A.	www.enagas.es
Switzerland	Transitgas AG	www.transitgas.ch
UK	Interconnector (UK) Limited	www.interconnector.com
	National Grid Gas plc	www.nationalgrid.com
	Premier Transmission Limited	www.premier-transmission.com

Nord Stream II and onshore connection NEL are scheduled to double the Baltic Sea pipelines capacity to 55 bcm/year and provide a connection to the grid in Northwestern Germany (near Hamburg).[59] The first line of the Baltic Sea pipeline Nord Stream with a capacity of 27.5 bcm/year as well as its onshore connection OPAL linking it to the grids in Eastern Germany and at the German-Czech border are part of the

59 See Lochner and Bothe (2007a) for a detailed elaboration on the Nord Stream pipeline.

model's infrastructure endowment as they were completed in October 2011.

Nabucco's route is also shown in Figure 4.5 and is supposed to be commissioned in 2014. The pipeline's capacity between Eastern Turkey and Baumgarten in Austria is planned to be as high as 31 bcm/year. There are several connections to the national grids in Turkey, Bulgaria, Romania, Hungary and Austria which allow for a withdrawal (and consumption) of Nabucco gas on the way to Central Europe, but also for additional injections of natural gas into the pipeline. There is no final investment decision for the project. Major uncertainties include the potential sources of gas for the pipeline.[60]

South Stream is planned to provide a capacity of 63 bcm/year as of 2016. The route of the pipeline is directed from Russia via the Black Sea to Bulgaria with different onshore sections for transporting the gas further on. We allow the model to chose between two onshore connections - if the pipeline is built at all: a route via Serbia, Hungary and Slovenia to Arnoldstein in Southern Austria as well as a route via Serbia and Hungary to Baumgarten in Austria.[61]

GALSI is a proposed pipeline with a transport capacity of 8 bcm/year. Its route roughly runs from Algeria via Sardinia to Northern Italy and its announced start-up date is in 2014. However, the final pipeline route is not clear and the project has been postponed multiple times.

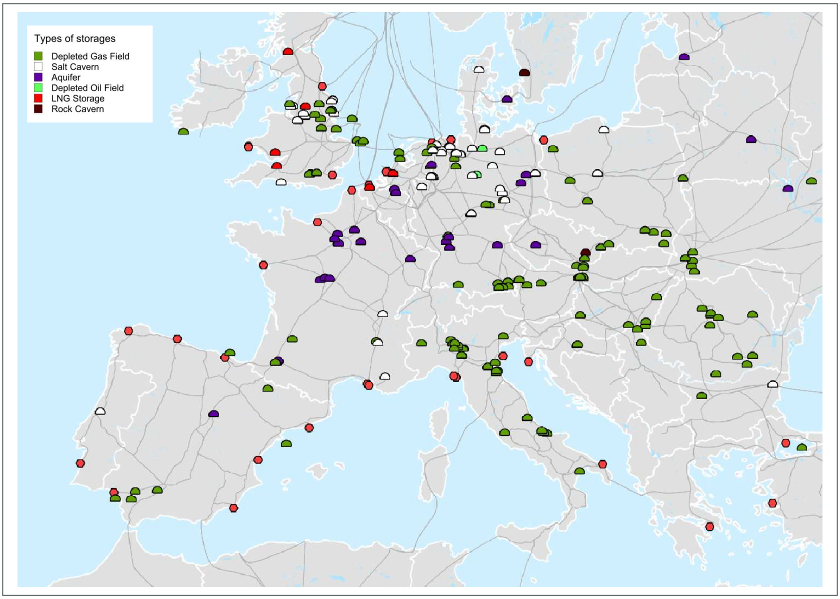
Similar uncertainties are associated with potential intra-European pipeline routes, which are therefore also expansion options the model has to decide on endogenously. They are depicted as the dotted lines in Figure 4.5. The most important ones are the TGL (Tauerngasleitung) as a potential link between Southern Germany, Austria and Northern Italy, the MidCat pipeline between Spain and France, the SEL pipeline in Southern and the MET pipeline in Central Germany and interconnections between the Czech Republic and Poland, Hungary and Croatia, and Romania and Slovakia. Some of these projects have been officially put on hold by the respective TSOs (e.g. SEL), others only received low interest in Open Season procedures (MidCat, TGL). Nevertheless, we give them to the model as potential options to invest in. The same holds true for the Italy-Greece-Interconnector "Poseidon" (which has a proposed capacity of 8 bcm/year).[62] The route of this pipeline route only slightly differs from the Trans Adriatic Pipeline project between Northern Greece and Italy (10 bcm/year).[63] Therefore, only one of the two is included.

60 See discussion in Section 4.1.1.
61 See Dieckhöner (2012) for a detailed elaboration on the Nabucco and South Stream pipeline projects.
62 http://www.igi-poseidon.com
63 http://www.trans-adriatic-pipeline.com

4.4.2 Storage

The gas storage facilities captured in the model database are depicted in Figure 4.7, which also indicates the respective storage type for each location. Please note that, again, storage projects are also included in the illustration. Sources for the storage data are the Storage Investment Database by GIE (2011) and IGU (2009).

Figure 4.7: Location of storage and storage projects



Generally, it can be observed that underground storage largely depends on the geological formation which is required to build the respective facility. With some exceptions, salt cavern storage sites are mainly found in a stretch from the UK to Northern Germany and Poland. Aquifer formations exist between Northern France, Belgium and Germany. Depleted oil or gas fields are converted into storage where gas production takes (or did take) place. Hence, they exist in the aforementioned stretch from the UK to Northern Germany, but also in Italy (North and Adriatic coastline) and some Central and Eastern European regions, namely Southern Germany and Austria, the Eastern Czech Republic and Southern Poland as well as Hungary and Romania. An LNG storage, on the other hand, does not depend on geological formations and can be build above ground wherever one is required. Today, they largely exist at the sites of the LNG terminals (though they are only able to store landed LNG, not gas from the grid) and are proposed at very few further locations in Belgium, the Netherlands and the UK.[64]

As of 2010, the absolute largest storage volume in Europe is located in Germany, see Table 4.8. The country has favorable geological formations for all three types of underground gas storage, but also a high seasonality of demand and a high import dependency leaving storage as the only tool to balance supply and demand within the borders of Germany. The latter is also true for Italy and France, the second and third largest capacity holders in the EU. In relation to 2010 demand (Capros et al., 2010, see previous section), the covered model area can store on average about 17 percent of its demand in gas storage.[65] The relatively largest storage volume in relation to demand has Latvia, which is well interconnected with the neighboring Baltic countries and historically also balances supply and demand for consumption there. Relatively low storage endowments compared to demand can be observed in some Western European countries, namely the UK, Ireland, Belgium and the Netherlands.

With respect to potential expansions of storage capacities in Europe, we include all projects currently, or at any point in time between 2006 and 2010, mentioned as proposed or planned according to the GIE (2011) or IGU (2009) databases. Their aggregated capacity is also listed in Table 4.8. Furthermore, we also enable the model to build LNG storage in each modeled country as they do not depend on geologic conditions.

For all considered countries, total working gas volume can increase from about 92 bcm in 2009 to almost 150 bcm according to these assumptions. The largest potential is thereby in the countries with relatively low storage endowments as of 2010 (UK, Netherlands, Spain), but also in regions with favorable geological formations (Germany, France, Austria, Romania).

4.4.3 LNG import terminals

With respect to LNG terminals, we similarly exogenously include all existing import infrastructure and those with final investment decision as of December 2010 based on the LNG Investment Database of the industry association GIE (2011). They are depicted in Figure 4.8 by country.

The largest importer of LNG in Europe, Spain (BP, 2010), is also still the country with the largest nominal import capacity of almost 70 bcm per year. However, after expansions at the Isle of Grain terminal and the completion of the Milford Haven terminals, the United Kingdom also has import capacities in excess of 50 bcm/year. A number of other countries also have access to their own import infrastructure. All

64 See Section 4.5.2 on storage expansion costs.

65 The calculation for the WGV capacity as share of demand in Table 4.8 takes into account the demand of the the countries without storage which are not listed there (Bosnia-Herzegovina, Estonia, Finland, Greece, Lithuania, Luxembourg, Macedonia, Norway, Slovenia and Switzerland) as their demand fluctuations still have to be balanced in the region as a whole.

Table 4.8: Natural gas storage - aggregated existing capacities and proposed additions

Country	2010 endowment		All potential projects	
	WGV	% of demand	$\sum$ WGV	WGV rise
Austria	4.0	43%	2.8	70%
Belgium	0.7	5%	0.3	43%
Bulgaria	1.4	45%	0.0	0%
Croatia	0.6	16%	0.4	72%
Czech Republic	2.9	32%	0.0	0%
Denmark	1.0	20%	0.0	0%
France	11.8	26%	3.7	31%
Germany	20.7	22%	9.2	45%
Hungary	6.4	50%	0.0	0%
Ireland	0.2	5%	0.0	0%
Italy	18.3	23%	6.7	37%
Latvia	2.3	153%	1.0	43%
Netherlands	5.1	14%	4.4	86%
Poland	1.8	11%	1.6	87%
Portugal	0.2	4%	0.0	0%
Romania	3.2	23%	2.2	68%
Serbia	0.3	12%	0.5	167%
Slovakia	2.2	35%	0.0	0%
Spain	1.9	5%	3.7	193%
Sweden	0.0	1%	0.0	0%
Turkey	1.6	4%	1.5	92%
UK	5.4	6%	18.8	350%
Total	91.7	17%	56.6	62%

Source: Own calculation, not-listed countries do not have storage.

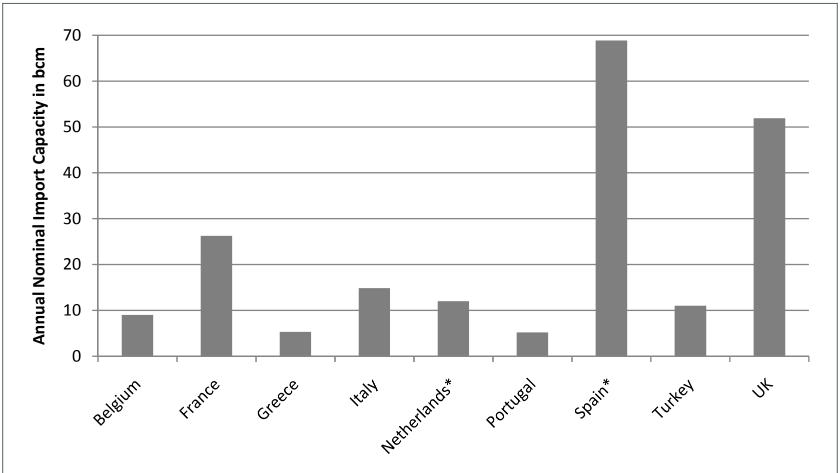
the existing terminal locations are also depicted in Figure 4.5 (page 80). Total import capacity which existed or was under construction at the end of 2010 amounts to 204 bcm per year.

With respect to projects, we assume that all these terminal locations are expandable. While there might be restrictions with respect to the expansion in some ports, this presumption should generally be acceptable as other locations in nearby ports can be found in most cases. In addition, we enable the model to endogenously decide on building additional terminals at the following locations, which are or were all mentioned by the GIE (2011) database as potential LNG terminal sites (and are also shown in Figure 4.5):

- Brindisi / Italy,
- Dunkerque / France,

- Eemshaven / Netherlands,
- Krk / Croatia,
- LeHavre / France,
- Wilhelmshaven / Germany.

Figure 4.8: Existing LNG import capacities



*Including the projects under construction (Rotterdam/NL, Gijon/ES) as of 12/2010.

4.5 Infrastructure cost parameterization

Cost assumptions are critical in an optimization model. Apart from supply cost assumptions, this mainly concerns investment expenditures (including the discount rate of future welfare gains) and operating costs of the infrastructure.[66]

4.5.1 Capital cost of pipelines

Capital costs for pipeline investments are based on extensive datasets derived from the Oil&Gas Journal Databook (2007 to 2009 editions). For transport infrastructure, capital costs are thereby comprised of the costs for compressors and the costs for the

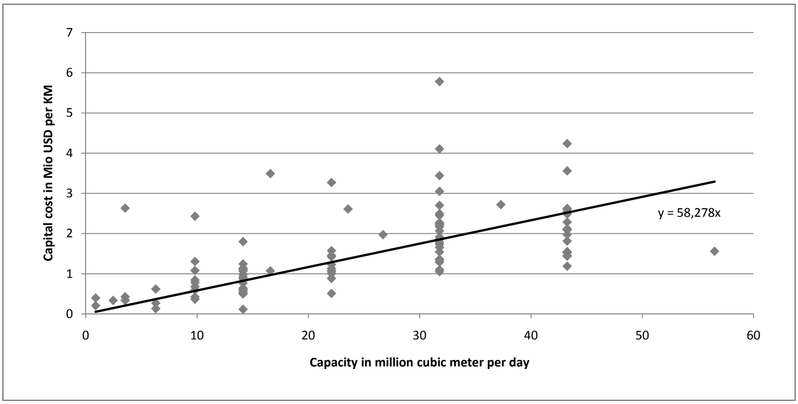
66 The calculations and data presented in Sections 4.5.1 and 4.5.3 are based on the methodology applied in Lochner and Richter (2010). Numerical results are updated for the analysis in this section.

pipeline. The dataset by the Oil&Gas Journal provides data on power, location and cost for the former and route, diameter, length and cost for new projects the latter. (We convert all costs to USD_{2010}.)

Investment costs for compressors largely depend on the power the specific asset requires. Hence, we estimate them to be a linear function thereof and can therefore apply a simple ordinary-least-squares regression. Based on observations for 115 compressor stations installed between 2005 and 2008, our regression analysis yields capital costs of 1,835.19 USD per horsepower (hp) installed. Literature on pipeline economics for natural gas transportation by Perner (2002) and Fasold and Wahle (1993) yields that moving gas over a distance of one kilometer with sufficient speed to obtain an annual capacity of one billion cubic meters (bcma) requires an installed compressor capacity of 8.12 hp including a compressor reserve margin of 33 percent. Hence, for a 1 km pipeline and 1 bcma capacity, compressor investment costs theoretically amount to 14,904.59 USD.

With respect to pipeline investment costs, their estimation follows a similar methodology. The Oil&Gas Journal dataset includes 203 observations, although excluding pipelines shorter than 10 miles reduces this number to 101. The regression, which is illustrated in Figure 4.9, yields a slope of 58278, i.e. investment costs of 58,278 USD per mcm daily capacity per kilometer (or 159,666 USD / bcma / km).

Figure 4.9: Regression on pipeline investment costs



The sum of the two capital cost components amounts to 174,570 USD/ bcma / km for pipeline transportation. As we run the model in Euro, this figure converts to 139,656 EUR. The result is in line with other studies including OME (2001).

4.5.2 Capital cost of natural gas storage

The costs of investments in underground gas storage have been part of large scale studies on the issue. One of the most encompassing ones was produced by United Nations (1999); a more recent and up-to-date analysis was published by Benquey (2010).

Components of storage capital are incurred by real estate purchase, exploration, the drilling of injection/withdrawal wells, the construction of surface facilities (such as compressors and pipeline connections to the respective grid) as well as the purchase of cushion gas. They, therefore, largely depend on natural factors (geological structure such as depth, permeability, volume), the amount of compressive power required or the type of surface facilities needed and market factors such as the proximity to the existing pipeline infrastructure.

There are three types of underground gas storage, depleted fields, salt cavities and aquifers. The feasibility of installing a specific type at a specific location essentially depends on the geological structure in place. (Additionally, LNG storage can theoretically be built (above ground) at almost any location (subject to safety requirements), see previous sections.) All types have different (economic) properties which make them suitable for different purposes. Per-unit investment costs as outlined in the aforementioned study are reported in Table 4.9.[67]

Table 4.9: Storage unit investment costs

Storage type	Capital cost in in EUR per m^3	
	Cedigaz range*	Own assumption
Depleted field	0.60 - 1.10	0.60
Aquifer	0.70 - 1.10	0.90
Salt cavity	0.70 - 1.30	1.02
LNG storage	n/a	1.50

Source: Own calculation and *Benquey (2010).

Depleted fields are sites where oil or gas was produced but where the pressure in the field has declined so that production is no longer economically feasible. Therefore, facilities such as pipeline connections and wells are already in place. The structure is most likely very suitable for storing gas, which reduces exploration requirements. Hence, per-unit investment costs are relatively low (see Table 4.9). The largest cost component is so called cushion gas, which is natural gas which must remain in the storage at all times (inventory) to maintain a minimum pressure. Valuing this cushion gas with the opportunity cost (selling prices at the market), it can be very expensive depending on the gas price.

67 The description of the different storage types in the next four paragraphs draws on the work from United Nations (1999), Lecarpentier (2006), Ramboll (2008) and Benquey (2010).

Aquifers are permeable rock formations, for example former (or current) water reservoirs, which may under certain circumstances also be used as natural gas storage. However, in order to establish if a storage can be built or not, the geological formation and its composition and porosity need to be explored. Exploration is costly and the actual storage capacity of the site may only become clear in the process. The cushion gas issue is even more of a cost factor than for depleted gas fields, as the gas is neither in place from the previous field, nor can it be recovered after the end of storage operations. Additionally, again unlike for depleted fields, technical facilities are not in place at aquifer sites implying that total capital expenditures are likely to be higher than for depleted fields.

Salt cavities have to be transformed into storage facilities through a leaching process which requires various technical installations and is potentially very costly. The provision of other facilities (grid connection, wells, compressors) is similar to aquifers, cushion gas requirements are only about 33 percent of the working gas volume. Nevertheless, the per-unit investment costs are rather high due to the generally small capacity of salt caverns and the costly leaching.

LNG storage do not rely on geological formations and, due to their high costs, are usually rather small. Based on information from recent projects the per-unit cost of capital is estimated by Ramboll (2008) at 1.50 EUR per m^3, i.e. up to twice as costly as underground gas storage. However, for LNG storage not located at the site of LNG terminals, where LNG is arriving and regasification facilities are in place, additional installments for liquefying and regasifying the gas are required. Additionally, operating costs of these two processes are higher than compression at underground gas storage sites (see Section 4.5.5).

With respect to the assumptions in our model simulations, we apply the figure of 1.50 EUR per m^3 for LNG storage (Ramboll, 2008). With respect to the other storage types, we further specify the Benquey (2010) cost ranges provided in Table 4.9 by assembling and evaluating a sample of recent gas storage projects in Europe.[68]

Table 4.10 therefore presents an overview of recent natural gas storage projects in the European gas market where investment costs are published. The list contains 12 salt cavity and 14 depleted field projects implying that there are currently not many aquifers scheduled to be turned into underground gas storage facilities. (The Rivara gas storage project in Italy is one such project; capital costs are, however, unknown.)

The per-unit (of WGV) investment costs of depleted fields range from 0.10 to 1.12 EUR per m^3 with the average actually being slightly below the estimated range from the expert analysis of Benquey (2010) provided in Table 4.9. Although the average specific investment cost in our data sample in Table 4.10 is 0.50 EUR per m^3, we adopt a value of 0.60 EUR per m^3 for our analysis. This value represents the lower

68 Please note that this is a list of published investment cost information for planned, announced and constructed storage facilities. Not all of these projects were, however, realized.

Table 4.10: Selected storage project investment costs

Storage type		WGV	Investment cost		Year y
Site	Country	[bcm]	[10^6 EUR$_y$]	[$\frac{\text{EUR}_{2010}}{\text{m}^3}$]	of source
Depleted gas or oil field					
Haidach	Austria	2400	250	0.10	2007
Haidach	Austria	1200	180	0.14	2007
Chiren	Bulgaria	450	250	0.55	2009
Galata	Bulgaria	1800	250	0.14	2009
Szoreg	Hungary	1200	594	0.47	2007
Ferrandina	Italy	700	400	0.57	2009
Taqa/Bergermeer	Netherl.	4000	800	0.20	2009
Banatski	Serbia	350	50.5	0.14	2010
Castor	Spain	1300	1000	0.77	2010
Gaviota	Spain	800	900	1.12	2009
Bains	UK	560	625	1.12	2010
Baird (offshore)	UK	1700	1400	0.82	2009
Caythorpe	UK	210	110	0.52	2010
Humbly Grove	UK	280	93	0.30	2005
Depleted field average cost				**0.50**	
Salt cavern					
Bernburg	Germany	510	350	0.66	2008
Epe	Germany	200	200	0.94	2007
Etzel	Germany	365	1500	4.11	2010
Staßfurt	Germany	400	300	0.75	2010
Aldbrough	UK	420	320	0.76	2010
Barrow-in-Furness	UK	1512	665	0.44	2010
Fleetwood	UK	400	400	1.00	2010
Gateway	UK	1140	670	0.59	2010
Holford	UK	165	110	0.67	2010
Isle of Portland	UK	1000	560	0.56	2009
Irish Sea	UK	500	278	0.56	2010
Stublach	UK	400	500	1.25	2009
Salt cavern average cost				**1.02**	

Source: Own calculations based on various sources including Benquey (2010).

end of the cost range according to Benquey (2010). We assign this specific cost to those projects where actual investment costs are unknown. For the projects with published data (Table 4.10), the specific costs are applied. For salt caverns, the average per-unit investment cost of our sample (1.02 EUR per m^3, see Table 4.10) lies in the middle of the range provided by Benquey (2010).[69] Thus, we apply this average value in our analysis for projects without published cost information. As no data on storage projects in aquifers is available, we set per-unit investment costs at 0.90 EUR per m^3 which is the average of the Benquey (2010)-range and also reflects the analysis in the previous paragraphs that per-unit aquifer storage investment costs are generally lower than those for salt caverns but higher than those for depleted fields.

4.5.3 Capital cost of LNG import terminals

Investment costs for LNG terminals are basically associated with the construction of LNG storage tanks, off-loading facilities and the various safety systems.[70] Additionally, land purchasing costs may play a significant role. While these and harbor construction cost may greatly depend on the location of a terminal, the other cost factors should not vary significantly across locations.[71] Indeed, as most existing and proposed terminal locations in Europe are located in existing ports, even construction costs for these installments should not vary too much between the European sites. Therefore, and due to a lack of individual data, we estimate LNG terminals costs as a constant per-capacity-unit factor.

With respect to LNG terminals, the number of recently completed or planned and announced projects (with sufficient cost data available) is limited. Thus, we again compile an international instead of a European sample of data for LNG regasification plants consisting of 22 such facilities being constructed or planned between 2005 and 2010.

Converted to EUR_{2010}, capital expenditure for terminal construction range from 46 to 294 EUR / bcma import capacity. While the allegedly low cost were reported for a terminal project in Oregon (USA)[72], the extremely high costs refer to a facility in Singapore where real estate costs may be a major cost contributor. Therefore, and due to potential inaccuracies which may be unavoidable when relying on media-reported data, we exclude these two data points as well as the second lowest and highest observations. Based on the remaining sample (Table 4.11), we estimate average investment costs for a terminal to be 115.55 million EUR / bcma. Again, this figure seems in line with OME (2001) estimates for a "medium cost-level" terminal.

69 In our sample (Table 4.10), eleven observations show specific investment costs between 0.44 and 1.25 EUR per m^3, one observation offers an extremely high value of 4.00 EUR per m^3.

70 For a detailed discussion of LNG terminal (cost) components, also see Tusiani and Shearer (2007).

71 At least in Europe which our model is concerned with. Safety costs may differ more with other safety requirements, for instance, in earthquake-prone Japan (Tusiani and Shearer, 2007).

72 Which is still not built and may not be build due to the declined import demand in North America.

Table 4.11: LNG import project investment cost

Terminal	Capacity [bcma]	Investment cost [million EUR_{2010} / bcma]
Bahamas	8.6	91.07
Colima, Mexico	5.2	89.95
Eemshaven, Netherlands	9.0	140.16
Fieri, Albania	10.0	82.95
Gijon, Spain	7.0	59.69
Guanabara Bay, Brasilia	5.1	162.68
Isle of Grain, UK	4.5	258.06
Joetsu, Japan	6.0	154.17
Kitimat, Canada	9.8	56.96
Kochi, India	6.8	94.04
Krk, Croatia	10.0	80.92
New Brunswick, Canada	10.2	74.83
Rovigo, Italy	6.4	156.86
Rotterdam (GATE), Netherlands	9.0	112.39
Rotterdam (Liongas), Netherlands	12.0	100.85
Sabine Pass, USA	10.3	64.79
Shannon, Ireland	4.1	196.24
Swinoujscie, Poland	7.5	70.59
Swinoujscie, Poland (updated)	5.0	148.20
Average		**115.55**

Source: Own calculations.

4.5.4 Model discount rate

The calculation of the cost efficiency of investments from a welfare perspective requires the application of a discount rate (ir in Sections 2.2 and 3.2). This is necessary as investment is associated with a one-time payment for the capacities in a given year which, in equilibrium, has to be less than or equal than the aggregated welfare gains realized in succeeding years because of that investment.

Our model simulations use an interest rate of 6 percent.

As our model calculates with annuity payments for the duration between the time of investment and the end of the model horizon (see Section 3.2), this interest rate is mainly relevant for the calculation of these annuities.

The annuity approach is necessary as the lifetime of new infrastructure assets is between 25 and 30 years (Seeliger, 2006), i.e. in excess of the 15 year model horizon. Hence, only the remaining annuities until the end of the model horizon are taken into account when optimizing investments.

For illustrative purposes, investment expenditures in the respective years are again expressed as the full investment costs in Chapter 5. This implicitly assumes that the welfare gains of an investment in the not-modeled intermediate years (before 2015, 2016-2019, 2021-2024, post 2026) are identical to the ones in the respective modeled year (2015, 2020 or 2025) closest to the intermediate year. The approach further presumes that the 2025 gas market scenario (demand, supply assumptions) is constant thereafter.

The rate of 6 percent is chosen as it was recently used in other studies on (electricity) grid expansions (Burstedde et al., 2010) and is close to the "historically observed average rate of return to capital", which is around 5.5 percent (Quiggin, 2008).[73]

4.5.5 Operating costs

The operating costs of the infrastructure system are made up by costs to transport gas through pipelines, to inject it into and withdraw it from storage, and to regasify natural gas imported in the LNG import terminals. Thus, they depend on the actual utilization of the assets. For the parameterization of these costs, it is important to note that these need to be system variable costs. To the business of a shipper, a trader, or another user of any component of the infrastructure system, pipeline, storage or regasification tariffs - as published by the relevant infrastructure provider - are variable costs. However, the system variable costs are lower as the infrastructure provider also uses these tariffs to recoup fixed costs. Hence, parameterization by collecting data on actual market tariffs would only be advisable for a dispatch-only model[74]. As soon as investment costs are taken into account additionally, assumptions for the true variable costs have to be applied.

Generally, assumptions with respect to those costs indicate that they are a function of investment costs.[75]

Pipeline operating costs

According to Avidan et al. (1998)[76], pipeline variable costs amount to one percent of pipeline capital costs plus four percent of compressor capital costs (including gas consumption of compressors). Based on the results from Section 4.5.1, applying these factors yields that the variable cost of moving one bcm over a distance of one

73 The article by Quiggin (2008) summarizes the different interest rates, and the arguments in favor and against them, employed in studies on the economic evaluation of climate change policies. Interest rates used in such studies are usually not market-based rates but lower ones.

74 And there are some drawbacks there, too, as for instance entry-exit tariffs, which are variable transport costs to shippers, are derived by TSOs to take network interdependencies into account and do not reflect physical variable transport costs.

75 See Avidan et al. (1998), Perner (2002), Seeliger (2006), Lochner and Bothe (2009) and Lochner and Richter (2010).

76 As cited in Perner (2002).

kilometer costs 1754.28 EUR. This translates to a variable transport cost of 0.048 EUR/MBtu/1000km including the cost of compression.

LNG regasification and transport costs

With respect to LNG regasification variable costs, applying the factor of 3.5 percent of investment costs from Avidan et al. (1998) yields a variable regasification cost of 0.111 EUR/MBtu. With respect to LNG maritime transport, the location of the terminal has to be taken into account additionally to account for potential differences in supply costs to the terminals. For instance, all European LNG imports are likely to come from the Atlantic (including the Mediterranean) Basin or the Middle East. Hence, all cargos, and even more important the marginal (price-setting) ones, to Northwestern Europe arrive from the South. Transport distance to Rotterdam is, hence, going to be about 680 km longer than to Milford Haven in the UK - and supply costs respectively higher. OME (2001) provides a formula for maritime LNG transport cost tc_n^{LNG} as a function of distance which we convert to EUR$_{2010}$:

$$tc_n^{LNG} = 0.209[EUR/MBtu] + 0.0133\left[\frac{EUR/MBtu}{(100km)}\right] \cdot \textit{distance}\ [(100km)] \quad (4.1)$$

The distance-independent term thereby takes account for LNG vessel costs during loading and off-loading of the cargo. As this happens for LNG deliveries to Europe anyway (costs constant for all terminal sites), the only distance relevant factor is the slope of curve related to distance (i.e. the second term). Hence, the 680 km prolonged transport for a delivery to Rotterdam instead of Milford Haven will incur extra LNG transport costs of 0.091 EUR/MBtu based on equation (4.1). The LNG operating cost factor oc_n^{LNG} in the model objective function (equation 3.1) therefore includes regasification cost of 0.111 EUR/MBtu as well as the distance related transport costs from equation (4.1). Transport distances for the calculation of the latter are thereby measured from a notional, geographical isocost line where we assume LNG cargos to have the same value (the commodity costs $oc_i^p\ \forall\ i \in prodreg$). Geographically this line runs through the Mediterranean (where Middle Eastern and North African LNG cargos arrive) and into the Atlantic Ocean Southwest of Portugal (where vessels from Nigeria arrive). As we do not assume LNG deliveries from Norway and Trinidad and Tobago, which are the only other suppliers to Europe,[77] to be price setting, all extra transport costs tc_n^{LNG} to the individual terminals n are calculated from there. Cargos to, for instance, Italy or the Spanish east coast, are, hence, slightly less expensive than those to, say, Northwestern Europe. The highest extra costs (about 0.47 EUR/MBtu) would be incurred for deliveries to a proposed terminal in Poland, if this project is developed model-endogenously.

77 See BP (2010).

Storage operating costs

The operating costs of storage are essentially a function of the compressor consumption during the injection and withdrawal process. Therefore, incorporation in the model takes place by modeling the compressor consumption during injection and withdrawal, see equation (3.9) in Section 3.2.2. Due to a lack of literature on the issue, the factors by which the gas volume is reduced during the injection and withdrawal process respectively were determined in consultations with industry experts from E.ON Gas Storage GmbH, BEB Erdgas und Erdöl GmbH (storage devision) and MVV Energie AG. Based on these interviews, both values ($kcons^{in}$ and $kcons^{out}$ from equation (3.9)) are set at three percent.

4.6 Scenarios

For different purposes, some of the assumptions presented in the previous section are individually altered in the subsequent analysis. These variations and scenarios are summarized in Table 4.12.

The assumptions on production, infrastructure costs, and infrastructure endowment and expansion options as presented in Sections 4.1, 4.5 and 4.4 respectively thereby constitute our **Base Case**. We simulate it in combination with both the Reference and the High demand case as outlined in Section 4.2.

Relevant variations of these assumptions are required for the scenario analysis in Section 5.3 to reflect potential other gas market developments. The resulting scenarios for our analysis are described in the following:

The *flexibility of LNG and its price* may have significant implications for LNG imports and, therefore, the infrastructure system as a whole. In the past (Jensen, 2004), LNG was largely used as an alternative mean of transport instead of pipelines because of its cost advantageousness starting at a certain transport distance between the points of production and consumption. However, with the continuing globalization of the natural gas market, LNG supplies became much more flexible. In our analysis, we therefore assumed that LNG can be brought into the market (or diverted away from the European market) when local prices exceed (fall below) a certain threshold. This LNG threshold is assumed to be higher than the cost of pipeline gas (see Section 4.1.5) in the Base Case. The assumed degree of flexibility in this scenarios is high reflecting data on actual LNG imports in the past (see Section 3.4). Both assumptions are varied in two scenario simulations:

- The price of LNG is reduced to 2.50 EUR/MBtu to reflect an oversupplied LNG market as seen in 2009 when demand was low due to the economic crisis and LNG supply high because of many upstream projects entering operation[78] (Scenario **(S1) Low LNG price**).

- The flexibility of total LNG imports is reduced to the level of Russian pipeline supply flexibility (see Table 4.2, page 72) (Scenario **(S2) Low LNG flexibility**).

Tapping *new pipeline gas supply regions* may also impact the European gas infrastructure. As outlined in Section 4.1 there is some uncertainty associated with pipeline gas exports from the Caspian region and the Middle East to Europe. Pipeline projects such as Nabucco are designed to transport these volumes to the European market. Nevertheless, no such project has a final investment decision as of July 2011, mainly because there are no upstream supply contracts so far. Anyway, if the volumes are available, implications for the European gas infrastructure - apart from the import pipeline - are likely. We consider a case with an additional export capability of 40 bcma from this region as the scenario **(S3) Southern corridor gas**.

The fourth main scenario also concerns gas supply and the prospects of *unconventional gas production in Europe* in the next decade. In the Base Case, the prospects of significant production were assessed to be low. Nevertheless, there is a chance that production may take off if production costs decline and imported, oil-indexed gas remains relatively expensive. Therefore, we want to analyze the infrastructure implications of such an unconventional production increase. According to Kuhn and Umbach (2011) and IEA (2011), the largest unconventional gas resources in Europe may exist in Poland, Ukraine and Germany. (There may also be potential in South-Eastern Europe and Denmark, for instance, but less information is publicly available regarding these countries.) Hence, we assume production from unconventional sources at the same cost as conventional gas production in these countries as of 2015.[79] Production volumes are assigned to model a constant production increase: 10 bcm/year in Poland and Ukraine each as of 2015 which increases to 25 bcm/year in 2020 and 60 bcm/year by 2025. In Germany, production is assumed to only increase after 2015 (10 bcm/year in 2020 and 15 bcm/year in 2025). Hence, by 2020 the three countries could produce about 60 bcm per year from unconventionals (less than 10 percent of EU demand in the Reference demand case) and 135 bcm/year in 2025 (22 percent of European consumption). The scenario is referred to as **(S4) European unconventionals**.

All these main scenarios reflect variations in the supply assumptions.

Further simulation variants in the following chapter also alter other parameters:

- The *simulation without investment* illustrating congestion costs in Section 5.1.1 presumes no infrastructure expansion options.

78 See EWI (2010b) for a discussion of this so called 'LNG glut' of 2009.

79 See Section 4.1. The conventional EU gas production costs were deliberately set a relatively low level to induce that the model brings the projected volumes into the market - subject to the available capacities. Here, the argument is similar: The aim of the scenario is to highlight the impact of unconventional gas volumes on infrastructure investment. Hence, we assume them to be competitive in the market.

- The *sensitivity on infrastructure investment costs* in Section 5.2.3 alters investment costs.
- The *security of supply scenarios* vary assumptions regarding the availability of infrastructure and production facilities. One restricts the availability of Russian transit pipelines and the other one the export volumes from North Africa. (See Section 5.4.)

Table 4.12: Scenarios and variations simulated in Chapter 5

Scenario Base Case
Section 5.1.2, page 105 Variations for High and Reference demand case Based on all assumptions as outlined in Sections 4.1 to 4.5
Scenario (S1) Low LNG price
Section 5.3.1, page 121 Variations for High and Reference demand case As Base Case but LNG supply costs reduced to 2.50 EUR/MBtu
Scenario (S2) Low LNG flexibility
Section 5.3.1, page 121 Variations for High and Reference demand case As Base Case but LNG supply flexibility reduced (to 1.12)
Scenario (S3) Southern corridor gas
Section 5.3.2, page 123 Variations for High and Reference demand case As Base Case but supply volume availability from region Caspian Sea / Middle East increased by 40 bcm per year
Scenario (S4) European unconventionals
Section 5.3.3, page 125 Variations for High and Reference demand case As Base Case but supply volume availability increased for Ukraine (+10 bcm in 2015, + 25 bcm in 2020, + 60 bcm in 2025), Poland (+10, +25, +60) and Germany (+0, +10, +15)
Variation *simulation without investment*
Section 5.1.1, page 102 Variations for High and Reference demand case As Base Case but no infrastructure expansion options
Sensitivities on infrastructure investment costs
Section 5.2.3, page 118 Variations for High and Reference demand case As Base Case but pipeline, storage and LNG capital costs increased by 50 percent individually and together (i.e. four simulations)
Security of Supply Scenario Russian Transits (SoS1)
Section 5.4.1, page 131 Reference demand case and evaluations for 2020 only As Base Case but unavailability of Russian transit pipelines in Belarus and Ukraine for four weeks in January
Security of Supply Scenario North Africa (SoS2)
Section 5.4.2, page 139 Reference demand case and evaluations for 2020 only As Base Case but unavailability of Algerian and Libyan gas volumes for one year

5 Results

At the focus of the model-based analysis with stochastic demand are efficient investments in natural gas infrastructure.

First, we use the model in a setting to outline and valuate economic congestion. Endogenous investments are disallowed until 2025 to illustrate, in a theoretical exercise, where bottlenecks in the European gas market would occur. Subsequently, optimal investments in the framework of the numerical assumptions presented in Chapter 4 are outlined (Section 5.1).

Second, the value of stochastic mixed-integer programing is demonstrated by comparing the results with a deterministic linear program as used by regulators and TSOs in the past; a sensitivity on infrastructure cost assumptions considers the robustness of the model results (Section 5.2).

Third, a scenario analysis illustrates the impact of variations in the gas market development assumptions on efficient investments in Section 5.3.

Fourth, investments to enhance security of supply in the case of supply disruptions are investigated (Section 5.4). Examples of such disruptions include the thirteen day disruption of Russian gas transits via Ukraine in 2009 (see Bettzüge and Lochner, 2009) or the halt of Libyan gas production during the country's political uprising in 2011 (see Lochner and Dieckhöner, 2011). These threats are mirrored in security of supply simulations. With respect to both security of supply scenarios, we show the cost efficient investments to mitigate supply disruptions to consumers depending on the probability of the occurrence of such an emergency. The effect on storage levels of uncertainty regarding supplies is also illustrated.

It should be noted that the results - in line with the model design - are normative. They depict what investments should look like if markets were perfect and players behaved rationally. Reality may differ because markets are not perfect and market players might have strategic incentives (see comments in Section 3.1). As a consequence, an institutional framework has been put in place and is still evolving (see Section 2.4). However, it cannot create a perfect market. The existence of institutions in itself causes further distortions of the perfect market.

The model at hand does not capture these realities. Its results need to be interpreted taking this into account: They cannot identify all investment requirements needed as a consequence of market inefficiencies, strategic behavior or institutional circumstances. They offer a normative benchmark regarding efficient investments in the European gas market.

5.1 Congestion, efficient investments and natural gas flows

5.1.1 Identification and valuation of congestions

As a starting point for the subsequent analysis, we identify bottlenecks and valuate congestion costs in the European gas market through a dispatch-only application of the model with stochastic temperature-related demand. With respect to the model formulation in Section 3.2 we, hence, include additional bounds restricting the capacity expansion variables to zero ($K^{pipe}_{y,i,j} = K^{st}_{y,m} = K^{LNG}_{y,n} = 0$).

While analyzing pipeline utilizations would already indicate potential bottlenecks, they can only be identified by the approach described in Section 2.2. Therefore, we consider the system marginal cost of supplying one additional cubic meter of natural gas at each point in the system and at each time period provided by the model. This allows an investigation of the shadow cost of the capacity restriction on each pipeline. For our analysis, we focus on cross-border connections. Therefore, we select representative nodes in each country and compare the differences in marginal supply costs to the variable transport costs of transporting gas from one node to the other on the route with the lowest transport costs. If the price difference exceeds the transport costs, the congestion mark-up is greater than zero ($\eta > 0$, see Section 2.2); economic congestion, hence, exists.

As further outlined in Section 2.2.2, the aggregated congestion rent has to equal marginal capacity investment costs in equilibrium. Hence, considering the absolute congestion rent already gives an indication whether investment is going to be efficient or not.

The results on congestion costs η are displayed in Table 5.1, aggregated over the time period of the model[80]. The percentage of days over the modeled time period (weighted with the stochastic demand specification's probability) is also included to distinguish permanent from temporary bottlenecks.

For the stochastic simulation with the Reference demand (Capros et al., 2010, see Section 4.2), we observe congestion between a high number of countries, albeit with significantly differing costs and frequencies: Between the Netherlands and the UK, aggregated congestion costs over time amount to less than 50 EUR per MWh daily capacity. I.e. if the interconnecting pipeline had one MWh/day higher capacity, welfare over 15 years would be only 48.61 EUR higher. Regarding the cross-border pipeline from Germany to Denmark, the benefits would be significantly higher (351,295 EUR for one MWh of daily capacity). While the former bottleneck can be expected to occur only 9 percent of time, the latter one is much more likely (63 percent). Apart from Germany-Denmark, congestion costs are also very high from Bulgaria and Greece into Turkey in this simulation without new investments. All other congestion has only

80 Fifteen years and assuming that 2015, 2020 and 2025 are also representative for the two previous and subsequent years respectively.

Table 5.1: Congestion costs in simulation without investment

Country grids (from $\rightarrow$ to)	Reference demand Stochastic $\sum\eta$ ([a])	Days[b]	Reference demand Deterministic $\Delta\sum\eta$ ([c])	Days[b]	High demand Stochastic $\sum\eta$ ([a])	Days[b]
AT $\rightarrow$ DE	86.93	35%	-44.1%	38%	5,165.56	13%
DE $\rightarrow$ AT	0.00	0%		0%	1.39	0%
SK $\rightarrow$ AT	5.16	61%	-4.5%	71%	48.58	75%
AT $\rightarrow$ HU	19.09	6%	-100.0%	1%	23,546.26	51%
AT $\rightarrow$ IT	0.19	1%	+192.2%	0%	0.01	0%
DE $\rightarrow$ BE	57.73	14%	-37.4%	17%	12,878.83	8%
NL $\rightarrow$ BE	81.73	43%	-22.7%	47%	12,891.73	19%
BE $\rightarrow$ FR	10.60	11%	+12.0%	6%	4.90	3%
FR $\rightarrow$ BE	41.00	7%	-45.5%	6%	12,876.68	8%
BG $\rightarrow$ TR	$1.2 \cdot 10^6$	100%	0.0%	100%	$1.193 \cdot 10^6$	97%
GR $\rightarrow$ BG	851.24	83%	+0.5%	94%	21,855.95	100%
CH $\rightarrow$ DE	30.89	3%	-100.0%	0%	5,132.96	3%
IT $\rightarrow$ CH	0.01	26%	-56.6%	19%	0.00	16%
CZ $\rightarrow$ DE-S	57.88	15%	-71.3%	13%	5,160.45	9%
DE-E $\rightarrow$ CZ	0.00	6%	-71.2%	2%	0.69	21%
SK $\rightarrow$ CZ	28.08	45%	+7.9%	63%	13.03	44%
DE $\rightarrow$ DK	351,294	63%	-13.5%	62%	620,697	70%
DE $\rightarrow$ FR	3.02	0%	+137.6%	0%	0.13	0%
FR $\rightarrow$ DE	0.00	0%		0%	5,154.94	4%
NL $\rightarrow$ DE	0.00	0%		0%	7.54	4%
DE-E $\rightarrow$ DE-N	84.11	52%	-49.9%	54%	4.96	12%
DE-N $\rightarrow$ DE-S	2.62	11%	-33.5%	11%	5,164.82	18%
DE-E $\rightarrow$ DE-S	159.89	100%	-26.3%	100%	5,251.04	98%
ES $\rightarrow$ FR	563.37	39%	+2.3%	38%	19,528.90	58%
GB $\rightarrow$ NL	0.00	0%		0%	3.88	3%
NL $\rightarrow$ GB	48.61	9%	-52.1%	6%	12,888.36	10%
GR $\rightarrow$ TR	$1.2 \cdot 10^6$	97%	0.0%	97%	$1.214 \cdot 10^6$	100%
GR $\rightarrow$ IT	439.59	29%	-4.5%	25%	20,380.88	83%
HR $\rightarrow$ HU	679.11	44%	-2.4%	42%	44,725.03	100%
HU $\rightarrow$ HR	41.03	15%	-11.1%	17%	0.30	0%
HR $\rightarrow$ SI	752.69	50%	+1.5%	55%	21,232.77	100%
SI $\rightarrow$ HR	11.79	5%	+3.5%	2%	0.00	0%
RO $\rightarrow$ HU	38.00	11%	-92.4%	3%	23,612.46	59%

[a] Aggregated congestion costs over considered time period in EUR/MWh/day.
[b] (Expected) share of days with $\eta > 0$.
[c] Relative difference in aggregated congestion costs compared to stochastic simulation.

relatively small costs, which can be explained with the high degree of physical market integration in the European gas market: Even if a line is congested, there are multiple other routes which may not be congested and whose transport costs are only slightly higher. Hence, significant price differentials are not observed and the congestion costs are relatively low. This is, for instance, true for congestion between Austria and Germany or within Germany. Intra-German congestion is found to occur frequently, especially between the Northeast and the South (west). However, the economic costs of these bottlenecks are very low (in this demand setting).

To draw some early conclusions on investments, the value how much an investment to remove the congestion should maximally cost is, by definition, given by the aggregated congestion cost on the respective interconnection. For the three aforementioned cases with high congestion costs, investments of several billion EUR would still be beneficial in order to remove congestion through say, an extension of pipeline capacities by 1 bcma.[81] However, this of course ignores long-run price elasticities of natural gas demand in Denmark and Turkey, where demand would decline if gas prices were substantially above the "normal" level due to prolonged supply shortfalls. Nevertheless, it becomes clear where investment would definitely need to take place.[82] Regarding the example of Germany, the same approximation yields that investments to remove the East and the South congestion would only be efficient if costs were below 30 million EUR (which is unlikely, see infrastructure investment costs in Section 4.5.1).

Though not observable from Table 5.1, the data further shows that congestion increases over time. The reason for that is decreasing domestic production and slightly increasing demand. The increase between from 2015 to 2025 is about 90 percent, implying that investment requirements would significantly increase over time.

Further information in Table 5.1 include a comparison with the results of a deterministic simulation and with our High demand case. With respect to the deterministic simulation, we find that it underestimates congestion costs compared to the stochastic simulation in most cases ($\Delta \sum \eta$ in Table 5.1, see discussion in Section 5.2.1 on the value of stochastic modeling).

Higher demand, intuitively, leads to more congestion in general. However, the effect on specific infrastructure depends on the individual interdependencies with the system. Compared to the Reference demand case and focusing on Western Europe, congestion costs rise substantially between, for instance, Spain and France, Germany and Belgium, the Netherlands and Belgium and France and Belgium. Investments there might be beneficial in this demand setting.

However, the higher demand assumption changes the supply mix and therefore gas flows in the European system. Gas from the East may to a larger extend be consumed

81 Assuming that specific congestion costs are the same for one MWh daily capacity and one bcm annual capacity.

82 Regarding the case of Turkey, however, Section 5.1.2 also illustrates the interdependencies between investments, as other infrastructure investment may also reduce the congestion identified in the section.

in Eastern and Central Europe, more LNG is imported in the West. Congestion between Germany and France, for instance, declines with higher demand (and actually increases in the reverse direction from France to Germany, see Table 5.1).

As this brief analysis, and a similar one with a deterministic model for 2015 in Lochner (2011), has shown, the modeling approach with a dispatch model is suitable for identifying and valuating congestion. However, due to interdependencies, definite conclusions on investments cannot be drawn. Investment at one point may impact congestion (costs) on other routes. Temporary congestion on pipeline could, for example, also be removed by investing in storage. And, the discrete nature of infrastructure investments implies that considering marginal investment costs is also problematic. Therefore, the explicit modeling of investment decisions is required to comment on welfare optimal investments in gas infrastructure.

5.1.2 Efficient investments in European natural gas infrastructure

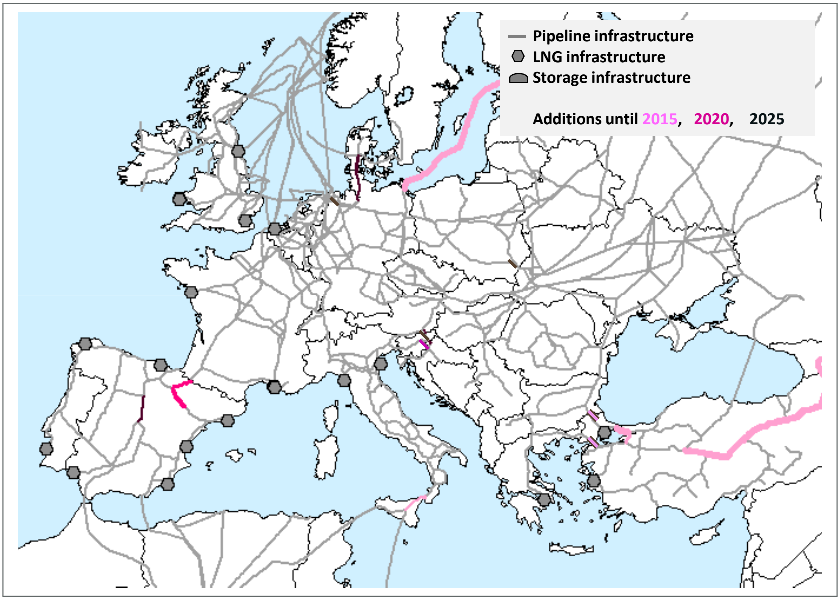
Applying the model described in Section 3.2, we model efficient investments in European gas infrastructure. This section thereby presents the results in the Base Case as described in Chapter 4.

Results for the three modeled years are displayed in Figure 5.1 for the Base scenario's Reference demand case.

The interesting implication from this illustration is that, starting from the 2010 infrastructure, investment requirements under this supply and demand setting are not significant. However, considering the model presumptions and our demand assumptions, this is not surprising. Demand does not rise significantly; construction of the infrastructure to import additional quantities has already started before or shortly into the 2009 economic recession (e.g. Nord Stream pipeline, LNG import terminals in Spain, the UK, the Netherlands). Hence, there are currently excess import capacities which are going to be increasingly used with declining European production. This infrastructure is efficiently utilized by the model. The need for additional import infrastructure is limited: the model decides to add 10 bcm annual capacity to the first line of the Nord Stream pipeline and builds up Southern corridor capacity for some additional imports from the Caspian region or the Middle East.[83] The case of Turkey, thereby, illustrates the aforementioned interdependencies between infrastructure investments: As import capacity is built up from the East the bottlenecks between Bulgaria, Greece and the country illustrated in Section 5.1.1 disappear. Further investments are limited to increasing interconnection within Europe: Pipeline capacities are expanded between Turkey and Bulgaria and Greece in 2015 (and expanded in 2025), between Germany and Denmark (in 2025) and Spain and France (2020) and within Spain (2025) and Italy (2015). Minor interconnection expansions also take place in Central

83 It needs to be noted that maintenance investments in grid infrastructure are not covered by the model. These could increase investment requirements, also with respect to import infrastructure (for instance in Ukraine).

Figure 5.1: Gas infrastructure investments in the Reference demand case



and Eastern Europe (Austria-Slovenia-Croatia, Poland-Ukraine) and at the landfall site of Norwegian pipelines to Germany and the Netherlands.[84] The latter accommodates changes in Norwegian gas flows resulting from high LNG imports into the UK (see Section 5.1.3 and Figure 5.4).

Investments in storage or additional LNG import capacities do not take place in the setting of the Reference demand.

A quantification of the capital expenditures incurred in the Reference and High demand simulations is provided in Table 5.2; an aggregated illustration is also provided in the context of Section 5.2 (see Figure 5.8, page 118).

Table 5.2 thereby also illustrates the temporal distribution of investments in European gas infrastructure. Until 2015, the model endogenously adds the infrastructure needed to deal with the decline in domestic production, which is especially steep in the UK and the Netherlands in this time period. In the Reference demand case, more than 90 percent of all investments are made until 2015. After 2015, demand is constant or actually slightly declining while domestic production declines slow down.

84 The regional distribution of pipeline investments is also illustrated in the context of the scenario simulations in Section 5.3, see Figure 5.12, page 125.

Table 5.2: Infrastructure investment costs until 2025

[in Million EUR_{2010}]	2015	2020	2025	Total
Reference demand case	**5,824**	**90**	**69**	**5,983**
Pipeline grid	5,824	90	69	**5,983**
Storage	0	0	0	**0**
LNG terminals	0	0	0	**0**
High demand case	**7,020**	**2,416**	**4,379**	**13,816**
Pipeline grid	7,020	1,278	1,742	**10,041**
Storage	0	445	1,250	**1,695**
LNG terminals	0	693	1,387	**2,080**

Hence, almost no investments in new infrastructure are required until 2020 or 2025. The spatial distribution is presented in Table 5.3.

The case is different in the High demand simulation with increasing demand post 2015. In this demand case, total investment costs are about 130 percent higher and there are also investments in storage and LNG import facilities. Although more than 50 percent of all investments still take place until 2015, pipeline grid, LNG and storage investments are also significant thereafter.

The timing and specific locations of infrastructure investments in the High demand case are presented in Table 5.3 and further visualized in Figure 5.2. In addition to the infrastructure investments observed in the Reference demand case (Figure 5.1), we find that the pipeline grids are further strengthened within and between Spain and France, in various locations in Eastern Europe (Poland, Romania, Slovakia, Hungary, Croatia, Slovenia, Austria) and in Northwestern Germany. It is noteworthy that in such a demand setting, the proposed interconnection between Greece and Italy is build, albeit with a minimal capacity of only 4 bcm and only in 2025. It is used bi-directionally and, for instance, also supplies gas from Italy to Greece in times of high demand there.

The investments in gas storage are confined to Italy and the UK. The majority of investments takes place in the latter country in salt cavities and depleted gas fields with a total working gas volume capacity of about 2 bcm. The additional LNG import capacities are commissioned in Italy (with a total capacity of 15 bcma) and Croatia, where the Krk terminal is built with an annual import capacity of 3 bcma.

Hence, it can be concluded that the investment projects started (or completed) by 2010, which were included in our existing infrastructure, already contribute significantly to making the system resilient for the changes it is confronted with in the coming decade.

In the Reference demand case, the major reasons for that are the dip in European natural gas consumption following the 2009 economic crisis and the lower than - un-

Table 5.3: Base scenario infrastructure investment by country

Demand case	Reference	High demand case		
Category	Pipeline	Pipeline	LNG	Storage
Austria	4	0	0	0
Bulgaria	18	67	0	0
Croatia	3	1	347	0
Denmark	6	39	0	0
France	0	961	0	0
Germany	7	134	0	0
Greece	0	185	0	0
Hungary	0	17	0	0
Italy	31	85	1,733	424
Norway	28	66	0	0
Poland	11	77	0	0
Romania	0	101	0	0
Russia[a]	1,597	2,040	0	0
Slovakia	0	164	0	0
Slovenia	14	8	0	0
Spain	82	717	0	0
Turkey	4,176	5,367	0	0
UK	4	0	0	1,271

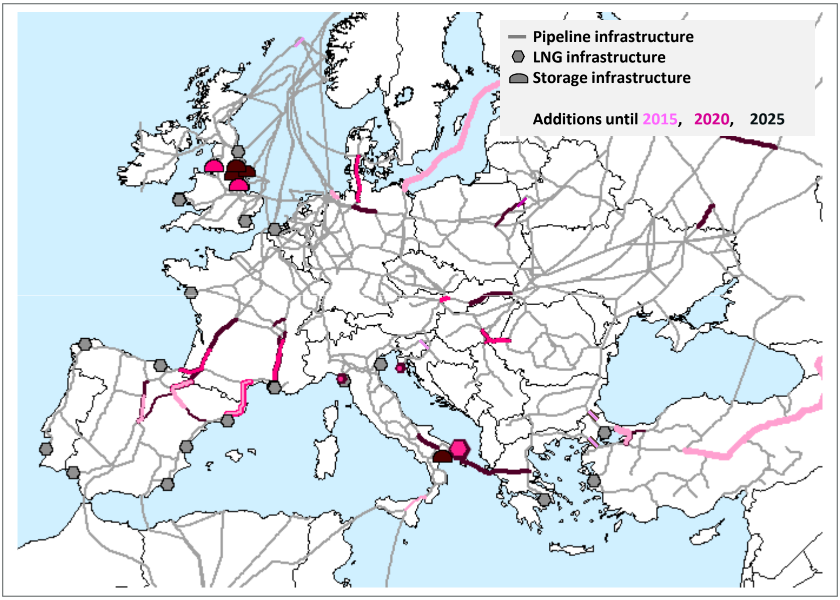
All values in million EUR; only grid investments in Reference case.
[a] Including Ukraine, Belarus, endogenous Nord Stream extension.

til recently - expected consumption growth forecast in this demand case. Hence, a number of LNG or pipeline import projects may not be fully utilized (or cause a significant fall of utilization for existing infrastructure) when they enter operation in the early 2010s. The decline in EU gas production accompanied by sluggish demand growth means utilization increases over the considered 15 year time period. However, new investments would hardly be required apart from improving physical market integration within the European market.

The situation is different if a higher natural gas consumption growth materializes. In this case, the recession's demand dip is compensated by 2015 leading to high utilization of the infrastructure then. In the period to 2025, further investments in physical market integration, import pipelines, LNG terminals and storage facilities are found to be efficient. Especially as of 2020, and with the not fully flexible LNG supplies assumed in the simulations, some investments in additional storage infrastructure in the European market are required.

With respect to the identified congestion in Section 5.1.1, we find that the connections with high congestion costs (Turkey, Germany to Denmark in the Reference demand

Figure 5.2: Gas infrastructure investments in the High demand case



case) see investment projects being implemented. However, there are also routes where positive congestion mark-up are not followed by efficient investments. This is for instance true for bottlenecks within Germany, between Slovakia and Austria or in the Benelux region (compare Table 5.1). Aggregated congestion costs there are just not high enough to warrant investment. This finding illustrates the importance of such a comprehensive analysis of the economics of infrastructure investments: Removing a bottleneck is not necessarily efficient. The aforementioned congestion into Turkey is eliminated by one investment in import infrastructure - although congestion was identified at numerous interconnection points.

5.1.3 Natural gas flows, marginal supply costs and import mix

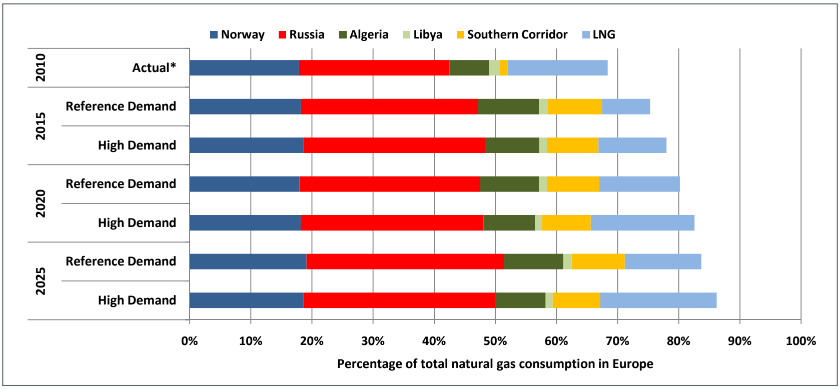
These investment decision have the following implications for the natural gas market with respect to gas flows, the composition of European natural gas supply until 2025[85]

85 Note that the supply mix is of course driven by the assumptions on supply availability, see Section 4.1. Nevertheless, illustrating the actual dispatch of supply volumes by the model improves understanding the results on investments. Scenarios with respect to variations in the supply assumptions are presented in Section 5.3.

and marginal supply costs. In the assumed competitive market, the latter can be interpreted as estimators for the price.

European supply mix

Figure 5.3: European import mix in Base scenario



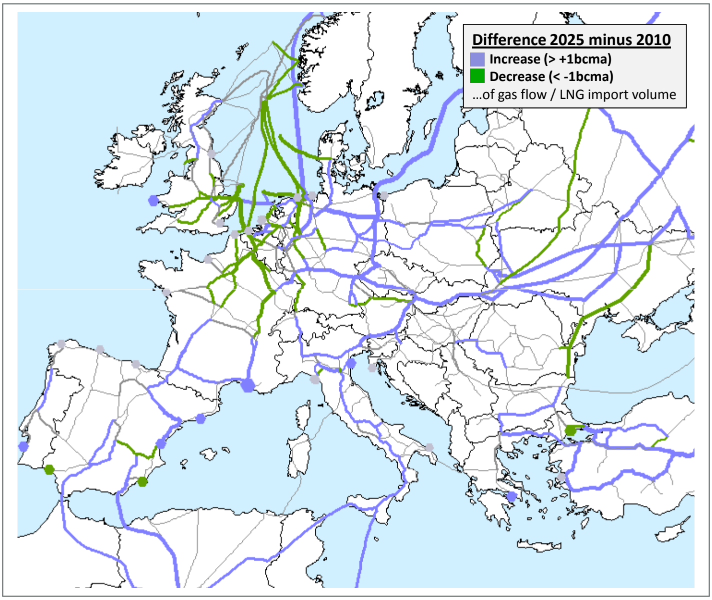
*Results on 2010 share are based on BP (2011).
Country values include pipeline supplies only; all LNG volumes included in separate category.

In line with the supply availability described in Section 4.1, the Russian, North African and Norwegian shares of the total market are more or less constant. This implies that supplied volumes from these countries/regions actually slightly increase as total consumption in the two demand cases and in all investigated years is higher than 2010 consumption. The share of supplies from the so called Southern corridor, i.e. from the Caspian region or the Middle East, increase in the two demand cases and in all investigated years as the existing infrastructure (South Caucasus pipeline) is utilized to a higher level in the model than it was in 2010; furthermore, some routes are expanded endogenously (see previous section). However, the region's share of the European gas market does not exceed 10 percent in our simulations.

With respect to LNG, 2010 imports were exceptionally high due to low LNG spot prices in the well supplied global market. LNG's share of total consumption in Europe was 16.4 percent (BP, 2011). Imported gas volumes from, for instance, Russia were significantly below 2008 levels (131 vs. 154 bcm) as importers only took delivery of their contracted gas at the minimum of what they were obliged to buy. As our simulations assume a tighter global market with higher relative LNG prices until 2015 (in fact, such a development is already taking place in 2011), the share is projected to decline. However, with declining domestic production, LNG may be imported in similar quantities by 2020 in the Reference demand case. In the modeled High demand case, we even see LNG imports of up to 130 bcm in 2025, which would equal a market share of 19 percent of total consumption.

Natural gas flows

Figure 5.4: Gas flows in the European gas market 2025 Reference demand vs. 2010



To illustrate the differences in gas flows between 2010 and the future simulated years, Figure 5.4 depicts a comparison of gas flows in the European gas market with significant increases / decreases of gas flows on pipelines (and of LNG imports in terminals) depicted in different colors. It is clearly visible that gas flows on all import routes increase due to the rising import dependency. Norwegian gas is routed towards the continent as the UK utilizes its LNG import capacity to a higher degree. Contrary to other investigations (Dieckhöner et al., 2011, Lochner and Bothe, 2007a), we also find an increase in the utilization of the traditional Russian import routes via Ukraine and Belarus. This has two reasons: Firstly, Figure 5.4 considers 2025, i.e. a later time period when the other papers, when import demand is higher. Secondly, our reference is 2010 when the flows on these routes were rather low (BP, 2011). Therefore, Figure 5.4 depicts an increase in 2025 relative to 2010, although there is a decline in intermediate years when new infrastructure projects (Nord Stream) become available and cannibalize some gas flows on the older routes.

Figure 5.5: Gas Flows in the Reference demand case

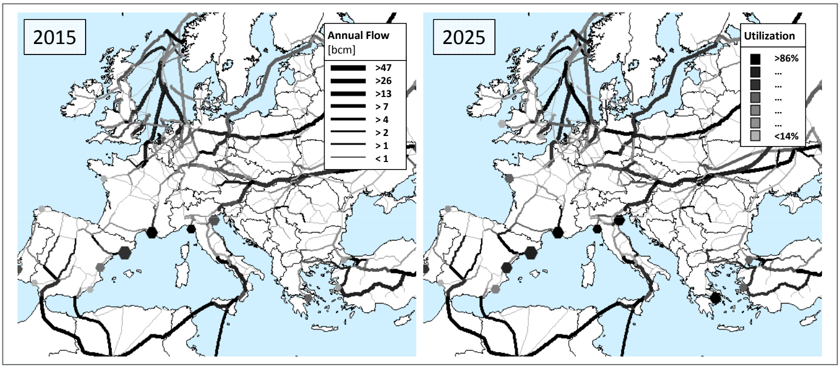
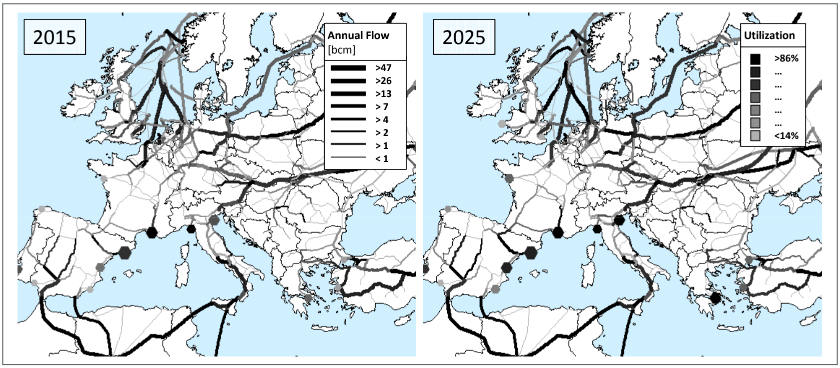


Figure 5.6: Gas Flows in the High demand case



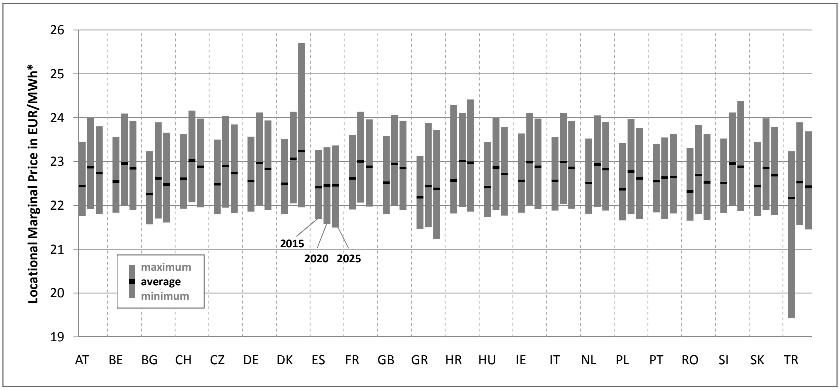
The absolute annual gas flows in 2015 and 2025 are displayed in Figures 5.5 and 5.6 for the Reference and High demand case respectively. The color of LNG terminals and pipelines reflects annual utilization (higher utilization is indicated by darker color), the size of the terminals and thickness of the lines represent the absolute imports/flows.

The following findings are thereby confirmed:

- LNG imports are significantly higher in later periods and the High demand case, especially in Western Europe. Utilization is always higher in Southern Europe.
- Gas volumes from the Southern Corridor remain in South-Eastern Europe.
- Physical market integration in terms of cross-border gas flows increases significantly with higher demand, especially in Southern Europe (Spain-France, Italy-Greece).

Locational marginal prices

Figure 5.7: Locational marginal price ranges by country and year (Reference demand case)



Marginal supply costs - which we refer to as locational marginal prices according to the definition provided in Section 2 - are not just a consequence of the investment decisions made, but also their driver. The visualization of real LMPs (in EUR_{2010}) by country in Figure 5.7 thereby further explains the low investment requirements in the Reference demand case: Spatial LMP differences between countries are relatively low, the temporal LMP differences throughout the year do not exceed 2 EUR/MWh. Over time, LMPs are found to increase slightly from 2015 to 2020 in all countries. After 2020, in line with the declining demand in this demand case, marginal supply costs decrease in some countries. Others, for instance Denmark with declining domestic production, sees LMPs rise further.[86]

The average standard deviation of LMPs in all European countries increases from 0.65 to 0.68 EUR/MWh in the respective time period. It is highest in Denmark in 2025 due to the infrastructure bottlenecks and the required investment; it is lowest

86 Note that LMPs are solely driven by congestion, a changing supply mix and investments. Commodity costs were assumed to be constant.

Table 5.4: LMP mean and standard deviation in 2025

[in EUR_{2010}/MWh] Demand case	Average LMP Reference	Average LMP High	Standard Deviation Reference	Standard Deviation High
Austria	22.73	22.92	0.664	7.394
Belgium	22.85	23.21	0.671	7.545
Bulgaria	22.48	22.17	0.661	6.478
Croatia	22.97	23.05	0.771	7.539
Czech Republic	22.74	22.92	0.670	7.289
Denmark	23.24	23.59	1.084	8.144
France	22.89	23.21	0.661	7.533
Germany	22.83	23.17	0.680	7.557
Greece	22.38	22.05	0.672	6.510
Hungary	22.72	22.72	0.668	6.975
Ireland	22.88	23.33	0.685	7.547
Italy	22.86	23.13	0.661	7.537
Netherlands	22.83	23.20	0.665	7.545
Poland	22.61	22.76	0.688	7.295
Portugal	22.65	21.98	0.567	6.180
Romania	22.53	22.26	0.646	6.472
Slovakia	22.69	22.86	0.667	7.287
Slovenia	22.88	23.08	0.730	7.539
Spain	22.46	21.78	0.513	6.130
Switzerland	22.88	23.18	0.672	7.538
Turkey	22.43	22.08	0.683	6.517
UK	22.85	23.27	0.677	7.543

in LNG importing countries Spain and Portugal (see Table 5.4). There, LNG is price setting throughout the year and storages only play a minor role in both demand cases. Hence, an assumed constant LNG price translates into a low variance of LMPs in the region. Of course, if a non-constant LNG price curve were assumed, this would translate into more price movements in that region.

Table 5.4 also displays the difference in the mean LMPs and the standard deviation of prices, exemplary for 2025. Relative to the Reference demand case, the LMPs are higher in the High demand case in most of the countries - but not in all of them. For peripheral markets, which have only limited interconnection with the rest of the modeled system (for instance the Iberian peninsula, Turkey or Greece), LMPs in the High demand case are actually lower. This is a consequence of the efficient market assumption: The increasing demand in the High demand case means congestion of the pipelines is higher (see Section 5.1.1). If a line is congested - or in this case, all lines between the peripheral market and the rest of the European system - prices are formed in residual markets (see Chapter 2). And these prices may temporally be lower in these peripheral markets because of low demand seasonality (Spain) or the availability of low cost pipeline gas imports in close geographic proximity (Turkey, Greece). The overall LMP difference between the High and Reference demand cases in the European market is also limited (+ 0.3 percent in the non-(demand-)weighted average), partly due to our assumption that pipeline gas imports from non-EU suppliers are higher when demand is higher (+ 15 percent).

However, Table 5.4 illustrates that the standard deviation of LMPs is significantly higher in the High demand case. The additional investments required in the High demand case are designed with the exactly efficient capacity. Hence, in some cases, there are still temporary prices spike in one direction or the other if there is significant congestion. On the one hand, cold winter-LMPs may increase up to the level where additional investment is not yet efficient according to the framework in Section 2.2. If stochastic demand is low (and storage capacity already fully utilized), high cost supplies such as LNG might be entirely pushed out of a (residual) market meaning that LMPs are set by the next costly source of supply and that LMPs might drop. Hence, under our model assumptions, higher demand may not necessarily imply a significant price increase (if supply also expands). However, the corresponding higher utilization of the infrastructure system would imply larger standard deviations of prices.

5.2 The value of the modeling approach and infrastructure cost sensitivity

Before the effects of alternative gas market scenarios are outlined in Section 5.3, this section discuss the benefits of the applied stochastic mixed-integer optimization model compared to other optimization models. The determination of efficient investment decisions as described in the previous section is the first one to do so with a model which incorporates the stochastic elements of temperature-dependent household gas demand. To illustrate the value-added from this analysis compared to deterministic simulations, the following subsection contrasts the results to those of a deterministic one (where only the average demand is realized). The same comparison is provided to illustrate the value-added of the mixed-integer approach (Section 5.2.2).

Furthermore, the robustness of results with respect to the infrastructure investment cost parameterization is investigated.

5.2.1 Stochastic versus deterministic modeling

As stochastic modeling is innovative for large-scale gas dispatch models (see literature survey in Section 2.1), Table 5.1 in Section 5.1.1 (page 103) already displayed economic congestion costs of a stochastic and a deterministic simulation. The comparison shows that some bottlenecks are identified and valued similarly in both simulations, e.g. the congestion into Turkey or bottlenecks between Hungary and the neighboring countries, or the low congestion between Germany and the Netherlands or Belgium and the UK (omitted in Table 5.1). However, this is not true for all congestion: bottlenecks into Belgium, between Austria and Slovenia and between the Czech Republic and Germany (in both directions) are significantly underestimated in the deterministic solution. Cases where the deterministic simulation overestimates congestion are very rare and are usually associated with a low probability for the occurrence of the specific bottleneck (see Austria to Italy or Germany to France). As this probability is determined by the distribution of the modeled stochastic demand variation, an overestimation in the deterministic simulation occurs if the specific connection sees more congestion in the mean than in the higher/lower temperature variations. Such a situation can materialize: Lower than average demand can intuitively imply less congestion. Stochastic demand above the mean can cause congestion further up or down the gas flow route: This changes LMPs and price formation in residual markets and can lead to the decline of congestion costs at other locations.

Hence, stochastic modeling does have an impact on estimated congestion costs. It may allow a more accurate representation of actual congestion.

Table 5.5: Storage levels in deterministic and stochastic models in 2015

Country	Deterministic		Stochastic		Difference
	[mcm]	% of WGV	[mcm]	% of WGV	
Austria	3,986	99%	3,826	95%	- 4%
Belgium	675	96%	705	100%	+ 4%
Czech Rep.	1,852	64%	2,373	82%	+ 28%
Denmark	824	86%	890	93%	+ 8%
France	7,466	63%	6,858	58%	- 8%
Germany	15,445	74%	16,690	80%	+ 8%
Hungary	3,380	53%	3,874	61%	+ 15%
Italy	8,989	49%	10,737	59%	+ 19%
Netherlands	2,190	43%	2,368	47%	+ 8%
Poland	1,819	100%	1,819	100%	+ 0%
Spain	354	19%	356	19%	+ 1%
UK	4,869	91%	4,784	89%	- 2%
Rest	8,318	84%	8,377	85%	+ 1%
Total	60,167	67%	63,657	71%	+ 6%

The other major effect of uncertainty concerns storage levels: Table 5.5 compares maximum storage volumes in the deterministic and stochastic modeling approach.[87]

87 Results are derived from simulations with the dispatch-only model from Section 5.1.1 for 2015.

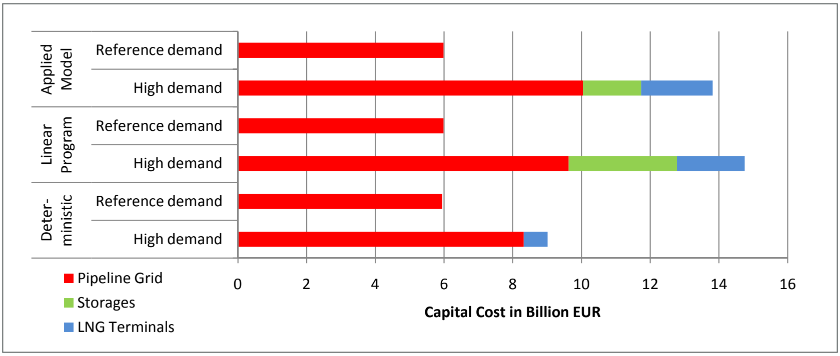
As expected, the total volume of natural gas stocked in all European storage facilities at the day with the highest aggregated storage levels is higher in the stochastic case with uncertainty regarding temperature-related demand in the upcoming winter. The additional stock is about 3.5 bcm. However, there are differences between countries depending on various interdependencies and the parameters describing the demand distribution functions in the different countries. On the one hand, gas stocks are, for instance, significantly higher in the stochastic case in Germany, Hungary, Italy or the Netherlands. On the other hand, there are countries where gas storage volumes are actually lower in the stochastic case, e.g. France, the UK and Austria (albeit on a very high utilization level in the latter two). One reason may include the aforementioned interdependencies - the additional storage volumes in the stochastic case are actually stocked in countries with high available capacities such as Germany, the Netherlands and Italy. From there, they are 'exported' to other markets. The uncertainty with respect to demand may, however, also contribute as it does not necessarily require more gas stocks. As shown in Table 4.6 (in Section 4.3 on page 79), uncertainty implies that gas demand might also be significantly lower than the average winter. Hence, in countries with access to other flexibility options (LNG in the UK and France, for instance), it might also be efficient to stock less gas in order to reduce storage and opportunity costs. In the case of high winter demand, additional volumes could then be provided from LNG sources.

In general, however, gas storage is higher with uncertainty regarding winter demand. Total modeled gas stocks in Europe, though, are still only about 71 percent of WGV (see Table 5.5) while in reality, storage at the beginning of the 2009 and 2010 winters were filled up to between 88 and 97 percent of capacity depending on market area - see GIE (2011) Aggregated Gas Storage Inventory database. Hence, the temperature-induced stochasticity included in our modeling context cannot fully explain the high storage levels observed in reality. Other considerations, for instance reflecting security of supply issues, may also play a role - see Section 5.4.1 on the impact of uncertainty regarding supply disruptions on storage levels.

Moving from the dispatch to the investment model, the differing congestion costs imply that efficient investments would also look different if we had not applied a stochastic model in the previous section. To illustrate the effect, the differences are briefly presented in the following: Total investment cost are illustrated in Figure 5.8. For the Reference demand case, we see that they are only slightly lower than investments in the stochastic simulation. However, the main reason for that is that in this scenario, there are no investments in flexibility provision options LNG and storage anyway. In the High demand case, the difference is very pronounced: With a deterministic model, no efficient storage investments would be identified, investments in LNG import capacities are much lower than in the stochastic model.

Hence, especially for modeling investments in flexibility provision options, considering stochastic factors is important.

Figure 5.8: Amount of investment with different model approach (deterministic, continuous)



5.2.2 Mixed-integer versus linear programing

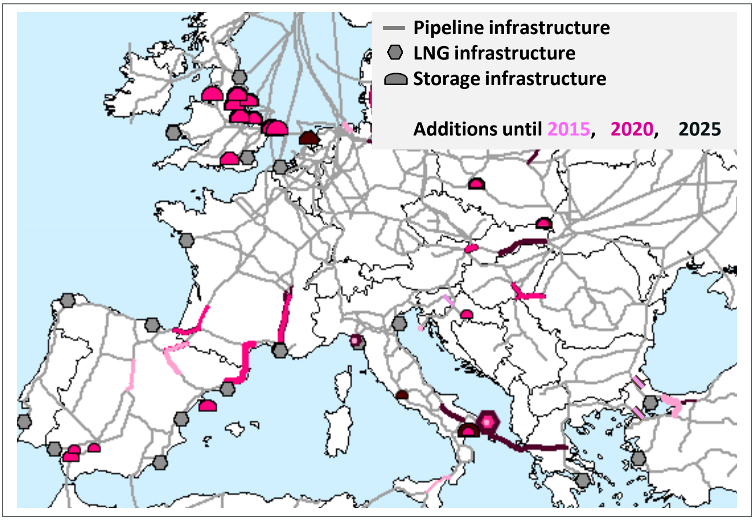
The second feature of our simulation are discrete investment options for storage and LNG terminals. The alternative would be standard linear programing instead of mixed-integer linear programing. The effect on total investment expenditure is illustrated in Figure 5.8 in the previous section. In the Reference demand case, there are no effects. In the mixed-integer model, it was not efficient to invest in storage or LNG infrastructre. Even increasing options to the model, i.e. allowing incremental investments in storage or LNG facilities, does not make these investment options efficient: The aggregated marginal shadow costs on the storage and LNG import capacity constraints are always below marginal investment costs in the Reference demand case.

With respect to the High demand case, we see different investments: pipeline grid and LNG terminals investments decline slightly, storage investments increase significantly. As illustrated in Figure 5.9, storage capacities are now expanded in a number of additional countries as well, i.e. Croatia, the Netherlands, Poland, Spain. (WGV expansions in the UK and Italy already took place in our discrete investment simulation, see Figure 5.2, although investments are now distributed amongst a higher number of projects.) Hence, abstracting from the discrete character of natural gas infrastructure investments, especially in storage facilities and LNG terminals, slightly distorts the results regarding efficient infrastructure investments - especially regarding infrastructure where discrete capacity lumps are large, such as a storage.

5.2.3 Sensitivity on infrastructure investment costs

Concluding this section on model evaluation, we alter the investment cost assumptions outlined in Section 4.5 to test the robustness of the model results.

Figure 5.9: Gas infrastructure investments in the High demand case in LP model

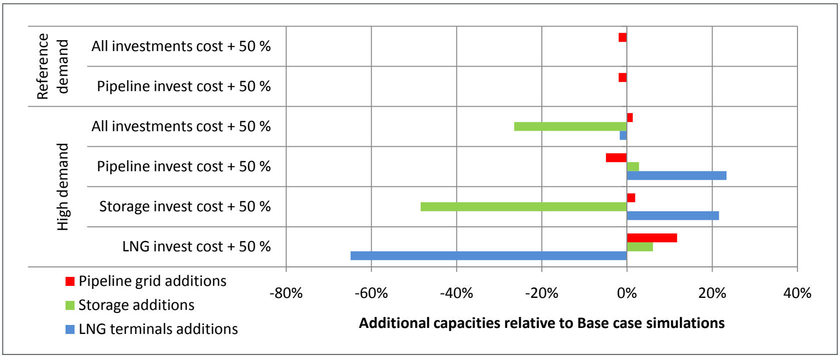


As derived in the analytical determination of the efficient amount of investment in Section 2.2.2, individual investments are only efficient if the (marginal) investment cost does not exceed the (marginal) congestion cost on the pipeline route, storage or LNG import facility. Hence, increasing investment costs implies that higher congestion costs would be necessary to warrant the same amount of investment. So unless congestion costs are high, the optimal level of investment would decline. However, the impact of the different costs on the congestion rents of other infrastructure projects indicates that there may be significant interdependencies. Therefore, we perform four sensitivity simulations of each demand case: Three simulations reflect an individual 50 percent rise in investment costs of each infrastructure category (pipeline grid, storage, LNG terminal). The fourth sensitivity models a 50 percent uniform cost increase for all infrastructure investments.

The impact on added capacities by category is displayed in Figure 5.10 (note that there were no storage and LNG investments in the Reference demand case; hence, cost increases in these categories do not impact investment and are omitted in the illustration). Results are found to differ significantly by infrastructure category.

If pipeline investment costs are 50 percent higher, new pipeline capacity installations do not decline by more than 5 percent relative to the Base scenario cost parameterization in capacity terms. Hence, most of the infrastructure expansions identified by the model remove severe bottlenecks and are therefore still efficient even if the cost for removing this congestion increases. However, in the High demand case, the

Figure 5.10: Impact of investment cost increases on infrastructure capacity additions



slight reduction in pipeline capacity extensions triggers some additional investments in storage and especially LNG import capacities. This new infrastructure then provides some additional flexibility which the more costly pipeline grid cannot provide cost efficiently.

Such an effect is much stronger for the storage investments sensitivity. The few storage investments made (in the High demand case) decline by 48 percent if storage investment costs are assumed to be 50 percent higher. Instead, the model decides to then provide more flexibility through the pipeline grid and additional LNG import terminals. Especially investments in the latter increase significantly.

Regarding LNG import terminals, the cost elasticity of infrastructure investments is also relatively high. Capacity additions decline by almost two thirds; instead pipeline grid extensions increase by 12 percent (from an already high absolute value, see Section 5.1.2). Further storage capacities also assume some of the flexibility provision provided by LNG in the Base scenario parameterization.

If all investment costs increase, total capacity expansions decline by 2 percent in the Reference and 5 percent in the High demand case. I.e. considering the rather large increase of 50 percent, the fall in investment activity is comparably small in capacity terms (in monetary terms investment expenditure, of course, increases). In the High demand case with investments in all categories, there is again some shift between the different investment options: storage extensions decline significantly while LNG and pipeline capacity additions are only affected to a minor degree (negatively and positively respectively).

Hence, the sensitivities on infrastructure cost parameterization illustrate that the overall level of investment is fairly robust with respect to cost assumptions. However, some infrastructure investments are substituted by others if costs increase in one category or across the board. In general, storage capacity extensions appear to be more elastic with respect to costs than LNG terminal and than pipeline capacity additions.

5.3 Scenario analysis

This section shows the results of variations of the input parameters to illustrate the impact and consequences of different developments in the gas market on infrastructure investment in comparison to the Base scenario (Section 5.1.2). Specifically, the focus is on the impact of variations in the presumptions regarding:

- the level of LNG prices and the flexibility of LNG imports (Section 5.3.1),
- the export capability of countries supplying the European market via the so called Southern corridor, i.e. countries in the Caspian region or the Middle East (Section 5.3.2),
- and unconventional gas production in selected European countries (Section 5.3.3).

Hence, these scenarios focus on the gas market supply side and, thereby, complement the previous analysis: Demand variations between the Reference and High demand cases are studied in Section 5.1.2 and throughout the following scenarios; the effects of altering infrastructure investment costs are discussed in the context of the sensitivity simulations in the previous section.

The following subsections present the results of the individual scenarios. A comparison and summarizing remarks are offered in Section 5.3.4.

5.3.1 Scenario simulations on LNG price and flexibility

As discussed in Section 4.6, different developments in the global market for LNG could have significant implications for European infrastructure investments. Two scenarios addressing uncertainty in that market are presented in this subsection: A scenario with a decline in the LNG price because of a global oversupply situation (Scenario **(S1) Low LNG price**), and a scenario where LNG supply flexibility is not higher than the flexibility of pipeline supplies (Scenarios **(S2) Low LNG flexibility**).

While the first scenario should increase the attractiveness of LNG to European consumers, the second one can be expected to reduce it as LNG infrastructure investments may then have to be complemented by storage infrastructure.

Low LNG prices

The scenario analysis with respect to LNG prices ((S1) Low LNG price) yields the following results: In the Reference demand scenario, they lead to an increased utilization of LNG terminals, however, additional LNG terminal investments are not observed. Nevertheless, the increased LNG imports in Western Europe imply that less pipeline grid extensions in East to West direction are made. Hence, pipeline investments decline.

In the High demand case, the situation is different. LNG terminals are already highly utilized so additional import infrastructure is more beneficial. The terminals endogenously added in the Base scenario (see Section 5.1.2) in Italy (Brindisi and Livorno) and Croatia (Krk) are brought forward and equipped with a larger nominal capacity respectively; additional (small) 3 bcma-terminals are added in France (Le Havre and Dunkirk) in the low LNG price simulation. Consequently, investment in East to West pipeline infrastructure are lower than in the Base case, especially with respect to the Greece-Italy interconnection and pipeline upgrades in Eastern Europe and Germany.

Inflexible LNG imports

The decline in flexibility of LNG deliveries conversely reduces its prospects in the European gas market, especially as a tool to provide flexibility. In the (S2) 'Low LNG price flexibility' simulations, this has an impact on investments in the High but not in the Reference demand case. With the lower Reference demand, flexibility appeared to be sufficient in the Base case anyway. Neither additional investments in storage nor in LNG import facilities were commissioned. A decrease in the flexibility of LNG imports at the existing terminals does not appear to change that. Extensions in the pipeline grid compared to the Base case are minor; the overall impact of that scenario in the Reference demand framework is small.

In the High demand case, the impact on efficient investments is substantial. As illustrated in Figure 5.14 (see scenario comparison in Section 5.3.4), investments in LNG terminals and the pipeline grid decline compared to the Base scenario, investments in storage rise. Intuitively, the same amount of LNG imports requires less nominal capacity if cargos arrive less structured throughout the year. Consequently, the pipeline grid would need less capacity if supplies from LNG at the coasts are less structured. Instead, utilization of the existing capacities is higher and the structuring of gas volumes to meet supply and demand takes place in storage facilities which are typically located closer to the centers of demand. This also reduces investments in pipeline capacity between the terminals and the locations of consumption.

Hence, storage investments increase significantly in this scenario. While total WGV additions in Europe amounted to only 2.8 bcm in the (High demand) Base scenario, they increase to more than 14 bcm if LNG supply flexibility is low. (The regional distribution of storage investments for all High demand scenarios (including the Base scenario) is displayed in Table 5.6 in Section 5.3.4.) The largest additional expansions in WGV capacity compared to the Base case take place in the UK. The country can derive significant flexibility from LNG imports and imports flexibility through the interconnections with the continent in the Base case. Both are reduced in the (S2) scenario simulation (less spare storage capacity on the continent), so 10 bcm of WGV are installed additionally. Further storage expansions are observed for LNG importing countries likes Spain and Italy, but also for instance Germany and Poland which are well-integrated into the European energy market and have geologically favorable sites for cost-efficient extensions of WGV capacity.

5.3.2 Scenario simulation on additional Southern corridor supplies

The third scenario assumes that new pipeline gas supply regions for Europe in the Caspian region or Middle East is tapped. An additional export capability of 40 bcma from this region is reflected in scenario **(S3) Southern corridor gas**.

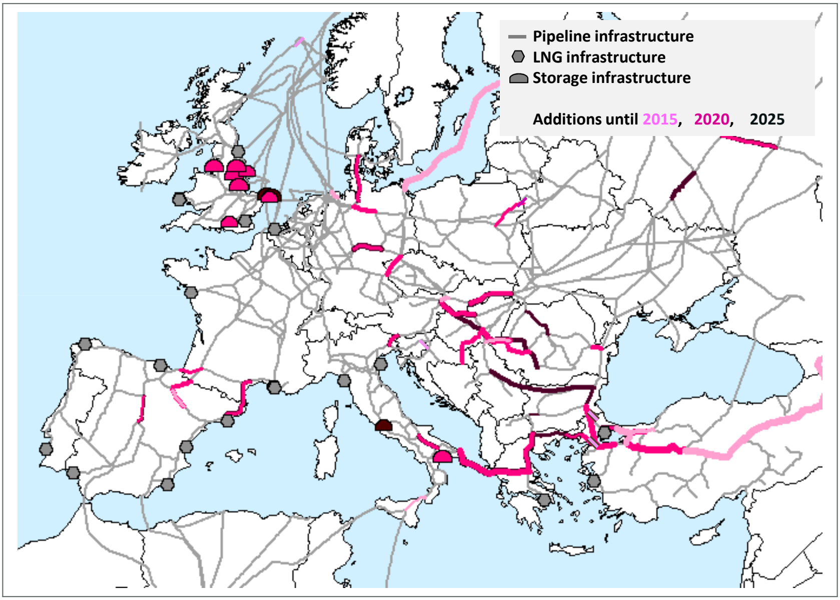
The major impacts on European gas infrastructure investments are illustrated in Figure 5.11 for the High demand case.

With respect to pipelines, the model provides the following results: Capacity on the route via Turkey is added, there is more and temporally earlier investment in an interconnection between Greece and Italy, and different pipeline segments are extended to increase capacity in the Southeast to Central Europe direction in Bulgaria, Romania, Hungary and Austria. This essentially represents the proposed route of the Nabucco pipeline. The regional distribution of investments within Europe is displayed in Figure 5.12. The illustration, thereby, shows that the majority of investments takes place up to the Turkey-EU border. However, the costs incurred in Eastern and Southern Europe are also significantly higher than in the Base case.

As we assume Russian export capability to remain constant relative to the Base scenario, Russian gas volumes are to some extent replaced in Southeastern Europe and need to be redirected. This causes some capacity increases on the more Northern Russian export routes, especially in Central Europe: East to West capacities in Germany are extended on the NETRA and STEGAL pipelines; the Gazelle project in the Czech Republic enhancing connection of the Nord Stream pipeline to Southern Germany (Waidhaus) is also build endogenously.

The resulting change in pipeline flows has impacts on LNG and gas storage investments. The additional volumes available to the European market, which are transported West on the extended pipeline grid, replace mostly LNG. Hence, the LNG investments we observe in the Base scenario (Figure 5.2, Section 5.1.2) do not take place in this scenario (S3). However, this implies that a rather flexible source of supply - LNG - is substituted by a less flexible one which may largely provide unstructured

Figure 5.11: Gas infrastructure investments with additional Southern corridor supplies (High demand)



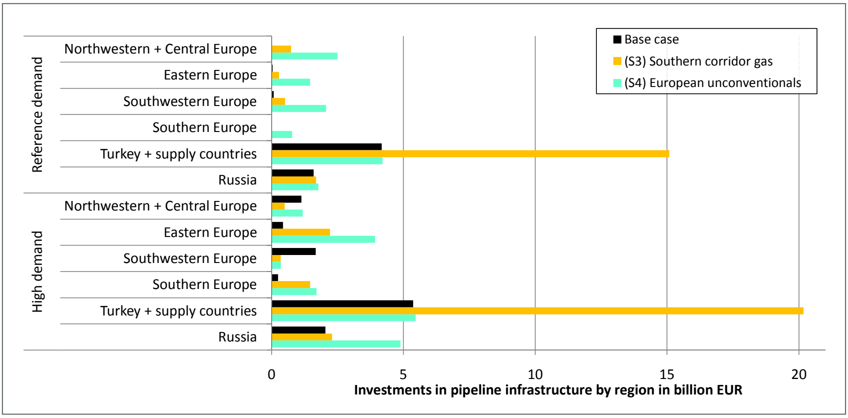
gas volumes throughout the year - pipeline gas transported over long distances from the Caspian region or the Middle East. Hence, flexibility to balance supply and demand has to be provided through other means. The utilization of storage all over Europe increases significantly. In countries where demand for flexibility is high or the storage endowment is low, working gas volume capacities are added. This concerns the same countries where we saw additional WGV capacity in the Base scenario - the UK and Italy. However, investments are much higher: especially the UK is projected to need almost 10 bcm more WGV than in the Base scenario (see also Table 5.6 and the discussion in Section 5.3.4).[88]

These observations for the High demand case are also mostly true for the Reference demand. Pipeline grid extension costs increase significantly (see Figure 5.14). However, they are more confined to Turkey and the supply countries: in Eastern, Southern and Central Europe, grid capacity extensions are significantly smaller, see

88 In the Reference demand case, there are actually also additional WGV investments in Spain. The country is less able to utilize French storage for flexibility provision in the case of less structure pipeline gas volumes being supplied to France. The requirements for domestic seasonal storage capacity in Spain increase as a consequence.

Figure 5.12[89].

Figure 5.12: Pipeline investment costs per region



Caption: Southern Europe: Greece, Italy. *Southwestern Europe*: France, Portugal, Spain. *Eastern Europe*: Bulgarian, Croatia, Czech Republic, Hungary, Poland, Romania, Slovakia, Slovenia, and all Balkan countries. *Northwestern + Central Europe*: all other EU members plus Norway and Switzerland. See Tables A.1 and A.2 in the Appendix for a breakdown by country.

5.3.3 Scenario simulation on unconventional gas production in Europe

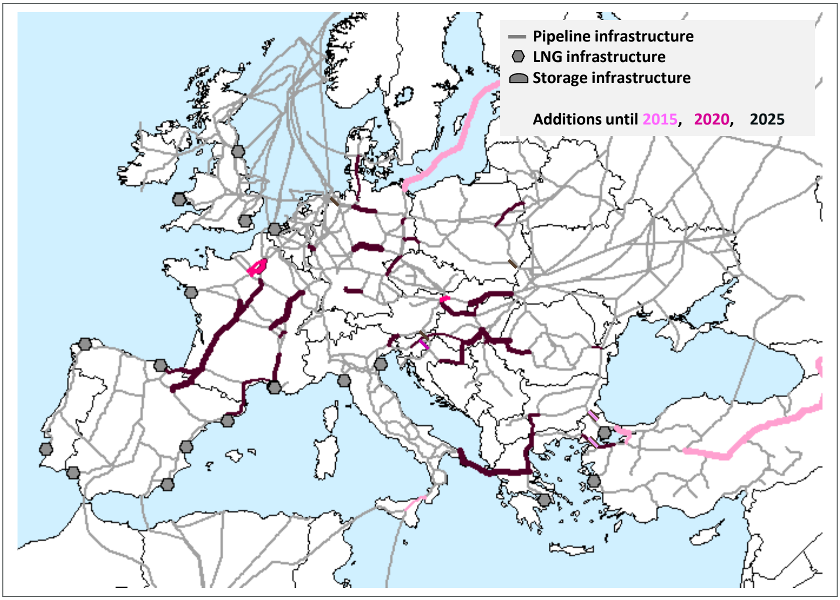
As outlined in Section 4.6, the scenario **(S4) European unconventionals** assumes an increase in production from unconventional sources in Europe from 2015 in Poland, Ukraine and Germany. Joint (additional) production in the three countries is presumed to be 20 bcm per year in 2015, 60 bcm per year and 135 bcm/year in 2025.

The investments in the European natural gas infrastructure in the (S4) scenario with Reference demand are depicted in Figure 5.13. In contrast to the Base scenario (see Figure 5.1 on page 106), significant new investments take place in Eastern Europe, especially past 2020. Total investment expenditure exceeds 11 billion EUR compared to less than 6 bcm in the Base case, see Figure 5.14. In the High demand case, the absolute rise in extension costs for the pipeline grid is similar (albeit starting from a higher level). Additionally, there are significant increases in investments in storage capacity.

Cost increases are thereby caused by four effects:

89 The illustration also includes the regional distribution of pipeline investments in the scenario on (S4) European unconventionals; see next section.

Figure 5.13: Gas infrastructure investments with European unconventional gas production (Reference demand)



Firstly, new pipelines are needed to transport natural gas from the partially remote locations to the main European pipeline grid; the export capabilities of the newly exporting countries, e.g. Poland, have to be upgraded.

Secondly, as more gas volumes (imports plus unconventional production) are available in Eastern Europe in this scenario, these can be transported further West as they far exceed local consumption. Hence, together with the imports from Russia, these "eastern" gas volumes are transported much further to the West implying pipeline expansions across Central and Northwestern Europe (see also the illustration on regional cost distributions in the previous section (Figure 5.12)).

Thirdly, the established suppliers of natural gas into Eastern Europe would - in an efficiently regulated transport market - see some of their traditional transport routes to Europe carrying unconventional gas from Poland and Ukraine instead. Hence, additional investments to strengthen new import pipelines need to be made. This for instance concerns Russia with the effect being especially pronounced in the High demand case, see Figure 5.12. However, it also affects Southern corridor gas volumes: the Greece-Italy interconnection is created as an additional route into the European (Italian) market, see Figure 5.13.

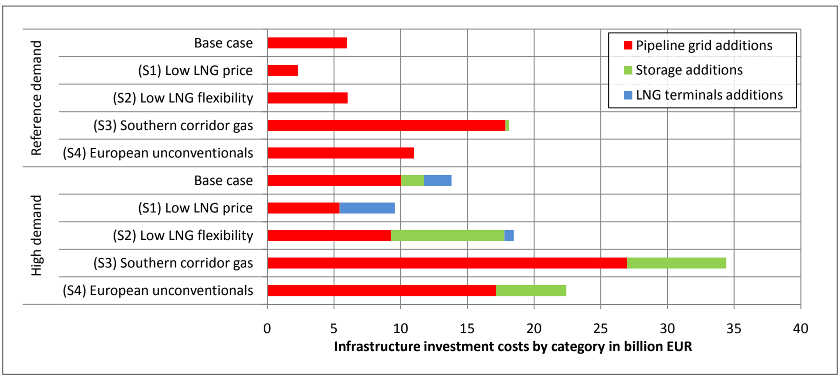
Finally, there is a knock-on effect in South and Southwestern Europe similar to the one arising from the additional Southern corridor volumes (see previous section): As the additional production from European unconventionals replaces some LNG imports, total LNG imports are lower and - in absolute terms - provide less flexibility. To compensate this, additional interconnections for instance between Spain and France are created. The effect is even larger in the High demand case: Here, not only LNG imports but increases in LNG capacities are lower than in the Base case (in fact, the latter decline to zero). Hence, flexibility provision is cost-efficiently enhanced by adding further storage capacities compared to the Base case simulation (see Figure 5.14). Or in other words, adding less flexible gas production is complemented by significant additional investments in gas storage. Regionally, these capacities are located in the UK, Italy and France (Table 5.6, page 129), countries which import less LNG - and build less LNG capacities - if they could import unconventional gas produced within Europe.

As the analysis in this scenario simulation has shown, unconventionals would have a significant impact on European infrastructure requirements. Compared to the Base case (or the LNG price (S1) and flexibility (S2) scenarios), they would require additional investments, especially in pipeline but also in storage infrastructure (in the High demand case). Adding additional LNG import capacities is no longer efficient.

5.3.4 Summary on natural gas market scenarios

The results of the scenarios in the previous sections allow conclusions on the effects of various natural gas market developments on investments in the different infrastructure elements.

Figure 5.14: Investment costs by infrastructure category and scenario



The investment costs by infrastructure category for the scenarios are summarized in Figure 5.14. They illustrate that investments in all infrastructure elements are very sensitive with respect to the supply mix:

- Pipeline grid investments[90] on aggregate are lowest when the share of LNG in the European import mix is highest, for instance when LNG prices are low. However, there is a difference between import pipeline and interconnection pipeline investments: The former are, intuitively, significantly lower as less pipeline imports are efficient in such a scenario. Interconnections between (large) LNG import capacities and the centers of consumption may need to be strengthened if significant volumes of LNG are imported. As these volumes also arrive flexibly to meet demand, the respective pipeline grid needs to have sufficient capacity between the LNG import facility and consumers in times of high demand.

- A rise in pipeline supplies available to the European market, be it unconventional gas produced in Eastern Europe or natural gas from the Caspian region, increases the investment requirements in import and interconnection pipelines. The "new" gas volumes are transported partially on new routes. Furthermore, they also enter the markets previously served by other gas suppliers, for instance Russia (in the case of Central and (South-)Eastern Europe). Hence, some volumes of Russian gas are diverted to other markets, for instance further toward Western Europe implying additional investments in interconnection / transit capacities there as well as in Central Europe.

- The effect of such potential developments on LNG investments is straightforward: Additional pipeline gas volumes from the Caspian region or unconventionals push out some LNG imports if LNG is assumed to be the marginal supplier. This does not necessarily mean that Eastern European unconventional or Caspian gas volumes are transported all the way to the LNG importing countries Spain, France, Italy or the UK. However, they "push" Russian gas further towards Central Europe which implies that Norwegian gas is directed further towards Western Europe and substitutes LNG. Lower LNG prices, conversely, means the imports are more competitive and additional capacity investments are efficient (if there is no excess capacity).

- Storage infrastructure investments are significantly impacted by the flexibility of the European supply mix. (WGV additions in all High demand case scenarios are presented in Table 5.6.) Low LNG prices imply more LNG in the supply mix and more LNG import capacity. As LNG is more flexible than the pipeline gas volumes it replaces (given demand is constant), the requirement for storage as a tool to balance supply and demand declines. In contrast to that, a decline in the flexibility of the supply mix implies an increase in cost efficient storage investments. Such a flexibility decline may either result from flexible volumes

90 A detailed breakdown of investments by country in each scenarios is provided in Tables A.1 and A.2 in the Appendix (page 157).

(LNG) being replaced by less flexible ones (gas imported via long-distance transmission pipelines) or by a decline in the flexibility of LNG imports (which we assumed in one scenario (S2)).

Table 5.6: Storage WGV additions 2015 to 2025 in the High demand case

Country [in mcm]	Base scen.	(S1) Low LNG price	(S2) Low LNG flex.	(S3) Southern corridor gas	(S4) European unconventionals
France	-	-	-	-	750
Germany	-	-	234	-	-
Italy	740	-	897	897	740
Poland	-	-	623	-	-
Spain	-	-	300	-	-
UK	2,085	-	12,091	11,491	7,291
Total	2,825	0	14,145	12,388	8,781

Only countries with any additions are listed.
Reference demand case with only one expansion in one scenario simulation:
462 mcm in Spain in (S3) Southern corridor gas.

Hence, there are significant effects from varying the parameters on investments in all infrastructure elements in the different scenarios. As, apart from the investments in import pipelines, grid investments take place in all scenarios, investments in LNG and storage infrastructure are found to be a lot more sensitive with respect to the scenario assumptions. As Table 5.6 shows, storage capacity additions range from 0 to 14 bcm between the scenarios. Capital expenditure for LNG terminals may be zero or up to 4 billion EUR (see Figure 5.14).

What does this imply for efficient investments?

- The uncertainties we investigated as scenarios should be monitored. Specific investments only efficient in single scenarios are only to be brought forward if the respective favorable circumstances arrive. An example are the aforementioned additional LNG import capacity investments which would require a combination of high demand and no further pipeline gas volumes to be efficient.
- However, there are also investments which are efficient in most if not all scenarios. This is true for a large share of the intra European pipeline capacity additions to increase physical market integrations. They do not only benefit the common market but also security of supply (see next section).

To explicitly decide in which category a potential investment project falls is methodologically difficult. Considering the expected value of the efficiency of an investment would require assigning probabilities to the scenarios. Apart from implementation issues, this is also not the idea behind the scenario approach (which also does not claim to include all potential scenarios).

The evaluation should therefore be more of a qualitative one: The scenario approach showed the impact of different circumstances on projects. These changes in circumstances can be significant and have long-term implications. A stochastic inclusion in the model, which would involve assigning probabilities, may not produce conclusive results. Compared to the results of the Base case, however, the scenarios illustrate which investments are more or less likely to be actually efficient.

Considering these investments which are efficient in many situations gives an impression of potential worthwhile projects from a welfare perspective. Those only efficient under specific circumstances might be more relevant at later points in time; for now, the uncertainty seems to exceed the potential gains in these cases: It is more valuable to wait than to invest.[91]

5.4 Investments to increase security of gas supply

The previous sections discussed cost-efficient investments with the only uncertainty arising from the actual realization of temperature-dependent household gas demand. However, supply disruptions in the recent hast have illustrated that there is also some uncertainty with respect to the actual delivery of physically available gas volumes. Interruptions of deliveries may reduce security of supply (SoS) to consumers; investing in redundant capacities - which would not be required without the possibility of supply disruptions - might be efficient as a consequence.

The analyses with respect to security-of-supply-enhancing investments are based on the Reference demand projection (Capros et al., 2010) for the year 2020. Methodologically, we incorporate uncertainty with respect to the availability of certain transit pipelines (SoS1 Russian Transits) or production from certain gas fields (SoS2 Scenario North Africa) in addition to the temperature-related uncertainty. The probability of these scenarios is α_a with $a =$ SoS1, SoS2.

Hence, we double the number of scenarios in our optimization: For five stochastic demand scenarios, we model ten scenarios. The situation without emergency has a probability of

$$\theta_{sc} = \theta^T_{temperature-level} \cdot (1 - \alpha_a) \quad \forall sc = 1, ..., 5 \text{ and } \textit{temperature-level} = s$$

(see Section 3.5.4, page 54, for $\theta^T_{temperature-level}$); the supply disruption scenario a probability of

$$\theta_{sc} = \theta^T_{temperature-level} \cdot \alpha_a \quad \forall sc = 6, ..., 10 \text{ and } \textit{temperature-level} = sc - 5 \, .$$

91 Note that the value of investing and waiting in this context is discussed in the model framework. I.e. we refer to the value to society. Institutional arrangements and other reasons may provide different incentives for individual investors.

The **SoS1 Scenario Russian Transits** assumes a disruption of Russian gas transits via Belarus and Ukraine for four weeks in January. Hence, the crisis scenario is equal to the one in the simulations of EWI (2010b) and presumes a repetition of the 2009 Russian-Ukrainian gas conflict for a prolonged duration and also affecting Belarus.

The **SoS2 Scenario North Africa** is based on the disruption of Libyan gas exports to Europe between February and October 2011. It further presumes that the uprising in North Africa spreads to Algeria and disrupts the country's gas exports in an equal manner. The nature of this conflict, however, is different: Unlike supply disruptions in the past, it is neither due to a technical issue concerning only single infrastructure elements, nor due to an economic dispute which can be resolved speedily. In a civil-war like conflict (with, in Libya's case, outside military intervention), economic concerns regarding the reputation as a reliable gas supplier for the future are not a priority. Gas supplies might be disrupted for prolonged time periods. As the Libyan export halt already lasted eight months (in summer), it is not unimaginable that such a scenario continues for a whole winter or even a whole year. Hence, we model the worst case to investigate what investments would be necessary to mitigate the consequences of a supply stop from North Africa for Europe during a one year time period.

5.4.1 Resilience against transit disruptions in Eastern Europe

The first part of the analysis focuses on the best measures to mitigate the consequences resulting from transit disruptions.

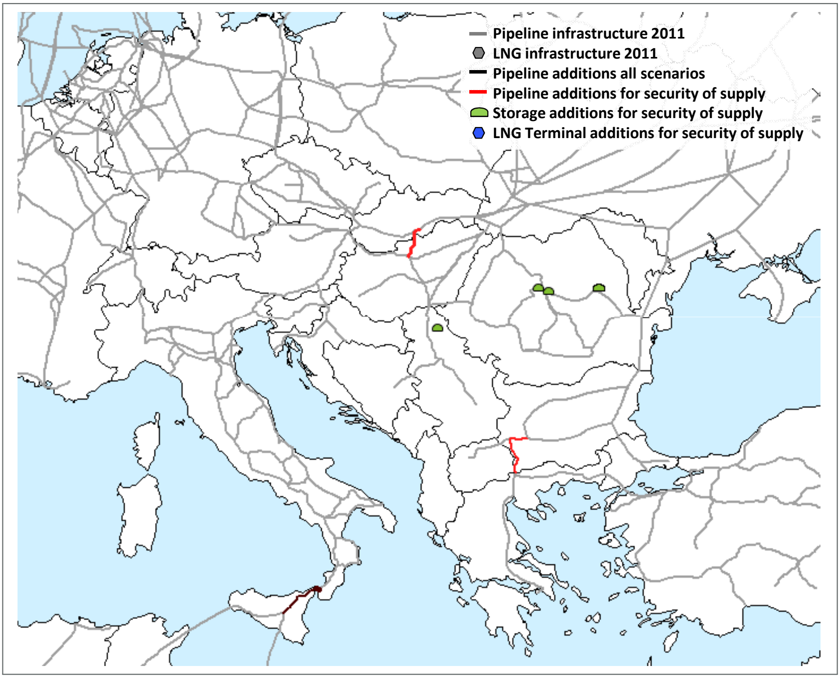
Regarding investments, the options to invest are increased pipeline interconnections, which allow importing gas from other sources or via other routes, additional gas storage facilities, or additional LNG import terminals.

As the first security of supply scenario largely affects Eastern European countries without access to the sea, LNG import capacities are not a directly relevant measure. Of course it would be possible to invest in additional LNG import capacities in other countries and transport the gas to the affected areas. However, our results also show that this option is found to be not cost-optimal by the model.

Assuming demand and supply parameters to be constant, apart from the transit disruption and the demand stochasticity (which is independent of the crisis situation), the main determinants of the optimal investment strategy are the expected (perceived) probability of the emergency (α_{SoS1}), its expected duration in case of a disruption, and the presumed value of lost load (dc^z, see Section 4.1.5).

In the simulation, we regard the case with a disruption duration of one month and the value of lost load from Section 4.1.5. (The effects of altering these assumptions are discussed qualitatively.) Efficient investments for an annual transit disruption probability α_{SoS1} of 0.05 are displayed in Figure 5.15. The distribution between pipeline and storage investments as a function of α_{SoS1} is illustrated in Figure 5.16.

Figure 5.15: Security of supply enhancing investments regarding SoS1 disruption with 5 % probability

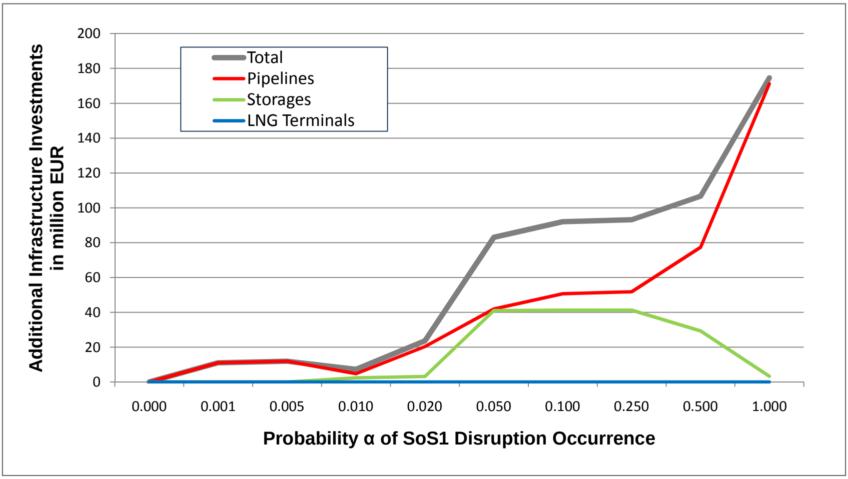


The most explicit results from Figure 5.15 is, however, that only limited additional investments are needed to reduce the consequences to consumers if the transits via Ukraine and Belarus were disrupted in 2020. New pipeline projects like Nord Stream already allow a significant diversion of Russian gas flows, even if transits on the traditional routes were to happen. Furthermore, the investments in reverse flow capacities following the 2009 Russian-Ukrainian gas conflict enable significant gas flows in West to East direction. Hence, even without further specific investments, security of supply is already rather high.

Additional investments found to be beneficial for social welfare in this scenario are pipeline links between Greece and Bulgaria and Hungary and Slovakia and (small) storage facilities in Serbia and Romania.

The effect of changing the emergency probability is displayed in Figure 5.16: Total investment increases with the probability of the occurrence of the supply disruption. With a probability of one percent or less and the assumed demand curtailment costs, investments in additional infrastructure is relatively low as it is more efficient not to

Figure 5.16: Additional SoS1 infrastructure investments expenditures

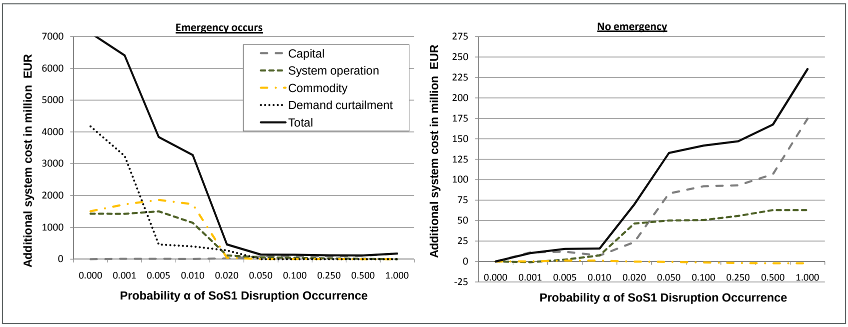


deliver gas to some consumers if the unlikely disruption occurs. If α_{SoS1} increases from one to five percent, investments rise significantly as demand curtailment is no longer necessary in the case of transit disruptions (with $\alpha_{SoS1} = 0.05$). Above that probability threshold, total investments increase slightly with rising disruption probability to further optimize the system for a situation which is then perceived to be more likely.

Pipeline interconnection investments thereby also increase steadily with rising emergency probability. Apart from capacity increases on the links displayed in Figure 5.15, this also concerns additional investment in an interconnection between Hungary and Romania. Please note, the disruption still lasts only one month, even when α_{SoS1} becomes one. As it is assumed that Russian gas exports can be postponed in this case and delivered via excess capacities on the other routes in later months, the model does not find it optimal to increase capacity on one of the other routes, i.e. Nord Stream or Blue Stream, or to build a new route, i.e. South Stream. If one was to assume that a project like South Stream is realized for pure security of supply reasons - to bypass the transit countries Ukraine and Belarus - this analysis implies that such an investment is not cost-efficient, even if the probability of an annual one month transit disruption is 100 percent. Hence, there may be other reasons for such an investment which cannot be replicated by our model - or investors assume that transit disruptions can last much longer than one month.

With respect to storage investments, the results show (Figure 5.16) that efficient investments are low if the emergency probability is either very low or very high. Hence, the security-of-supply contributions of domestic storage reserves in the highly exposed countries from an efficiency perspective are highest for a crisis situation with an existing and perceivable chance of becoming realistic. If the probability is very low, it is not efficient to build a storage and stock gas there which is unlikely to be needed (see demand curtailment argument in paragraph on total investment). If the incident is very likely to happen, it is more efficient to increase interconnection with other countries as this allows (a) a more efficient diversion of gas flows in the not-so-unlikely possibility of a transit disruption, and (b) the utilization of existing and lower cost underground gas storage in Central and Western Europe (see Figure 5.18 and the discussion on efficient storage levels at the end of this section).

Figure 5.17: Total system costs from uncertainty regarding supply disruption



The total additional system costs arising from the uncertainty are depicted in Figure 5.17, broken down into capital, demand curtailment, commodity and operating cost. The illustration further distinguishes between the case of the emergency actually occurring (left hand chart) or its non-occurrence (right hand chart). Commodity cost thereby reflect potential changes in the supply mix, e.g. the requirement to import more LNG during the supply disruption, which is assumed to be more expensive than the Russian gas it has to replace. Operating costs refer to the costs of running the system, e.g. the costs of pipeline transportation and storing gas. Capital costs are identical in the two cases and to the results presented in Figure 5.16.

Intuitively, total operating costs in the Emergency Case (left side) are highest when the probability of the event was low.[92] Hence, less preparations for the emergency are made, the costs to cope with the unexpected situation are then rather high. Especially demand curtailment costs amount to several billion EUR. Operating costs are also significant compared to a situation without disruption but decline if α_{SoS1} increases. The high commodity costs reflect the need to purchase additional LNG to

92 Costs for the $\alpha_{SoS1} = 0$ case were approximated in a simulation with $\alpha_{SoS1} = 0.00001$ as, by definition, there can be no emergency if its probability is zero.

compensate the missing volumes as there were no preparations for the emergency. These costs further rise when α_{SoS1} increases to 0.005 as - in this case - physical interconnection of the region to the European market, which allows to import more LNG via other countries, is improved. Hence, demand curtailment declines as more commodities can be delivered to consumers. Total additional costs decline to below 500 million EUR with a probability of $\alpha_{SoS1} = 0.02$. With α_{SoS1} being 5 percent, it is efficient to avoid all demand curtailment, total additional costs are less than 200 million EUR in the emergency case. (Note that this assumes no cost effect for Russian gas as it is presumed that all deliveries are made later and storage costs in Russia are neglected.)

The relatively high demand curtailment costs in the left hand chart of Figure 5.17, of course, also drive the results: if they were lower, less investments would take place. More demand curtailment would be observable in the emergency case. Higher demand curtailment costs, conversely, would lead to more investment at lower probability levels so that - even if the probability of a supply disruption is very low - there is less demand curtailment. However, the value of lost load selected for the analyses (see Section 4.1.5) may represent a suitable compromise: they allow some demand curtailment at very low probability levels; however, as cut-offs to consumers may not be politically acceptable at a large scale, they also ensure that investment takes place at relatively low emergency probability levels.

The interesting implications in the No-emergency Case arise from additional system operating costs (demand curtailment as well as supply mix changes are not necessary without the disruption), see right hand chart in Figure 5.17. These largely reflect the costs for storing gas. Storing gas which might not be needed is costly, especially due to capital opportunity costs: the model therefore refrains from building up stocks when α_{SoS1} is low. When the transit disruption becomes more likely, building up stocks becomes more efficient, the costs for doing so rise. Even without the emergency, these costs still need to be borne. With a five percent emergency probability, they make up about 50 million EUR annually. As this is still a relatively small number, additional total costs are also driven by capital costs. In the case when no emergency occurs, additional total costs are then highest if the probability of a disruption were large.

Excursus: Storage level and (in-)security of supply

This raises the question of the efficient amount of gas storage to deal with supply disruptions. Several countries oblige gas suppliers to hold strategic gas storage which is only to be used in the case of an emergency as defined by the respective authority. However, the previous analysis with respect to investments has shown that additional storage investments may not be economically efficient depending on the probability of an emergency.

Table 5.7: Storage level with transit disruption probability of 0.00 and 0.01

Country	$\alpha_{SoS1} = 0$ Level[a]	$\alpha_{SoS1} = 0.01$ Level[a]	Δ to $\alpha_{SoS1} = 0$[b]	
Austria	2,229	2,620	+ 391	(+ 18%)
Belgium	691	691	0	($\pm$ 0%)
Bulgaria	771	771	0	($\pm$ 0%)
Croatia	558	558	0	($\pm$ 0%)
Czech Rep.	2,735	2,891	+ 156	(+ 6%)
Denmark	784	788	+ 4	(+ 1%)
France	8,734	8,762	+ 29	(+ 0%)
Germany	17,019	18,693	+ 1,675	(+ 10%)
Hungary	3,611	3,888	+ 277	(+ 8%)
Ireland	154	193	+ 39	(+ 25%)
Italy	12,262	13,184	+ 922	(+ 8%)
Latvia	1,901	2,064	+ 162	(+ 9%)
Netherlands	3,791	4,033	+ 242	(+ 6%)
Poland	1,735	1,737	+ 2	(+ 0%)
Romania	3,049	3,143	+ 93	(+ 3%)
Serbia	178	267	+ 89	(+ 50%)
Slovakia	2,111	2,198	+ 87	(+ 4%)
Sweden	9	9	0	($\pm$ 0%)
UK	2,708	3,259	+ 551	(+ 20%)
Total	65,030	69,749	+ 4,720	(+ 7%)

[a] Aggregated gas stock level on day with highest storage level at the beginning of the winter (1 October) in mcm.

[b] Stock level difference to $\alpha_{SoS1} = 0$ case in mcm (and relative).

Tables 5.7 and 5.8, therefore, illustrates the volume of natural gas stored in storage in selected countries on the day when this aggregated level is highest, i.e. it can be interpreted as the amount of gas stocked in each country before the winter season.

Without the probability of the occurrence of a transit emergency, total gas stocks in the regarded countries amount to 65 bcm in 2020 (second column of Table 5.7). Introducing a one-percent probability of an emergency already increases optimal inventory by about 5 bcm, increasing that probability to two percent (Table 5.8) implies optimal inventories of 75 bcm. Hence, storing gas volumes - if storage capacity is available - is efficient to improve security of supply in the case of the emergency.

The results on stock levels also explain the earlier findings: There is sufficient storage capacity available in Europe. Without any risk arising from supply disruptions, these would not be fully utilized. If there is such a risk, utilization increases by 16 percent implying it is then not necessary to make new investments in the directly af-

Table 5.8: Storage level with transit disruption probability of 0.00 and 0.02

Country	$\alpha_{SoS1} = 0$ Level[a]	$\alpha_{SoS1} = 0.02$ Level[a]	Δ to $\alpha_{SoS1} = 0$[b]	
Austria	2,229	3,012	+ 782	(+ 35%)
Belgium	691	693	+ 2	(+ 0%)
Bulgaria	771	791	+ 19	(+ 3%)
Croatia	558	558	0	($\pm$ 0%)
Czech Rep.	2,735	2,891	+ 156	(+ 6%)
Denmark	784	960	+ 176	(+ 23%)
France	8,734	9,761	+ 1,028	(+ 12%)
Germany	17,019	19,949	+ 2931	(+ 17%)
Hungary	3,611	3,967	+ 355	(+ 10%)
Ireland	154	201	+ 47	(+ 30%)
Italy	12,262	15,195	+ 2,933	(+ 24%)
Latvia	1,901	2,233	+ 331	(+ 17%)
Netherlands	3,791	4,253	+ 461	(+ 12%)
Poland	1,735	1,755	+ 20	(+ 1%)
Romania	3,049	3,150	+ 101	(+ 3%)
Serbia	178	269	+ 90	(+ 51%)
Slovakia	2,111	2,198	+ 87	(+ 4%)
Sweden	9	9	0	($\pm$ 0%)
UK	2,708	3,283	+ 575	(+ 21%)
Total	65,030	75,126	+ 10,096	(+ 16%)

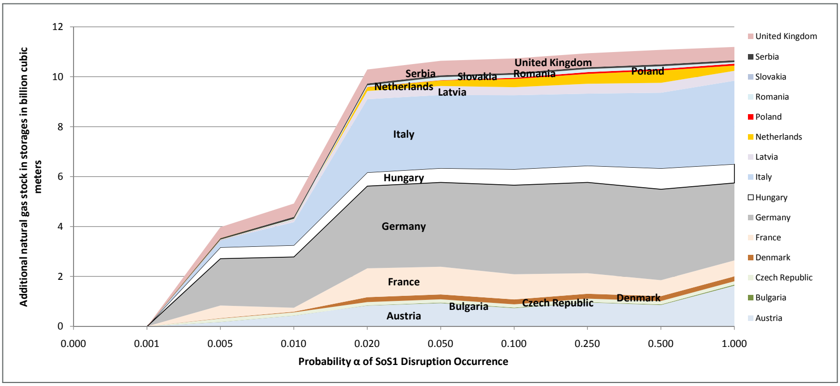
[a] Aggregated gas stock level on day with highest storage level at the beginning of the winter (1 October) in mcm.
[b] Stock level difference to $\alpha_{SoS1} = 0$ case in mcm (and relative).

fected countries. Instead, we find that it is efficient to increase interconnections to the countries with access to the storage capacities.

The largest contributions to the increased gas stocks come from the countries with the largest storage capacities (see Table 4.8 on page 86), i.e. Italy, Germany and France. However, for countries in close geographic proximity to the transit countries, such as Hungary and Austria, it also makes sense to stock some additional gas volumes. Most of the other countries in the region hardly have any excess capacity in their storage facilities implying that gas stocks at the beginning of the winter cannot be increased easily (i.e. without investment).

Considering the amount to additional gas stocks as a function of the emergency probability (Figure 5.18) yields the intuitive result that the more likely the emergency, the higher the gas stock reserves should efficiently be. They increase steadily in most countries until the emergency reaches a probability of about five percent. At that point,

Figure 5.18: Additional gas storage per country depending on emergency probability



most gas storage facilities are completely filled before the winter months. Hence, it is not possible to further increase gas stockage without investment. In this case, as the previous analysis showed, it is then efficient to not invest in additional capacity but to increase interconnection (and therefore indirectly the access to other gas import routes and LNG import terminals).

Total gas stocks in excess of what is stored for seasonal demand balancing (i.e. with emergency probability zero) do not exceed 11 bcm. The further volumes in addition to what is displayed for a probability of 0.02 in Table 5.8 are then essentially stored in Italy and Austria, where additional capacities are still available. If the emergency probability is two percent, these capacities would not be fully utilized.

The annual costs incurred by the model to maintain these additional gas stocks is evident from Figure 5.17.[93] A simple calculation further illustrates the associated costs: Valuating the gas stock efficient for a 2 percent emergency probability with the average European LMP from Section 5.1.3 (22.84 EUR/MWh) yields a costs of 2.5 billion EUR to build up the stock. Assuming a real cost of capital of 6 percent implies that the daily costs of having the capital employed in the 10 bcm stock is about 400,000 EUR.

To summarize, we find that gas stocks in excess of volumes to balance supply and demand - and if capacity is available - are an efficient mean to increase security of supply. Comparing our results with reality[94], Section 5.2.1 showed that the utilization of storage in the case with an emergency probability of zero is low. This finding could

93 Recall that the model presumes an efficient market without price uncertainty. Hence, the excess gas stocks can be sold if the crisis did not occur and costs only include the opportunity cost of capital during the time the gas stock was maintained.

94 Although we only consider the year 2020 and the latest actual data available is from 2010/2011.

imply that the relatively higher actual storage levels in reality already reflect some level of gas stock provision for a supply disruption incident. Historical data[95] showing that, in winters without any emergency incident, storage facilities remain sufficiently filled even at the end of the winter, might confirm this finding.

5.4.2 Resilience against supply disruptions from North Africa

The second security of supply emergency scenario affects Southern Europe as it presumes a prolonged (one year, 2020) disruption of pipeline supplies from Libya and Algeria to Italy and Spain. Italy imports about 8 bcma or 10 percent of its annual consumption from Libya through the Greenstream pipeline. As this pipeline was cut off due to the civil war in Libya for almost eight months, such a scenario is not unlikely. As it is also thinkable that the respective political unrest spreads to further neighboring countries, we include a suspension of Algerian pipeline supplies in the scenario. The country is a more important supplier delivering about 30 percent of Italian gas supplies through the Trans-Mediterranean Pipeline (TransMed, sometimes also referred to as the Enrico Mattei gas pipeline). Additionally, pipelines connect Algeria with the Spanish market: the Maghreb-Europe Gas Pipeline and the recently completed Medgaz Pipeline together supply about 20 bcm or 40 percent of Spanish gas demand. Hence, both countries are equally exposed to gas supplies from North Africa; so is Portugal which is closely linked to Spain. However, as there are no significant gas flows between Spain and France or out of Italy into other markets, further countries are not directly affected through pipeline disruptions from North Africa.

Of course, if unrest in the region also disrupts LNG exports, this would affect all LNG importing countries. With a well-supplied global LNG market, however, consequences would most likely be limited to price effects.

As in the previous section, we investigate efficient investments to mitigate the consequences of such an emergency situation depending on the probability of its occurrence.

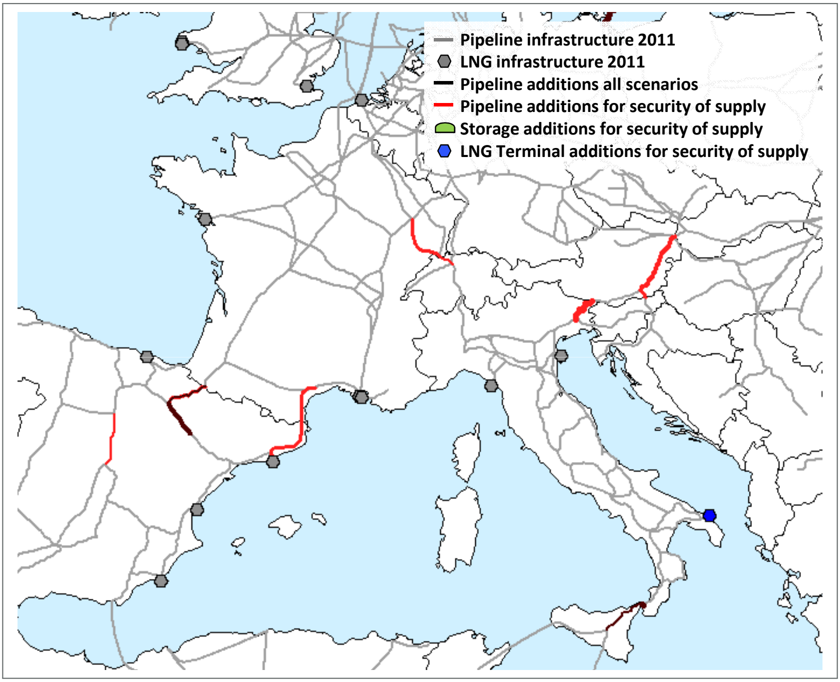
Efficient investments for a probability of $\alpha_{SoS2} = 0.05$ are displayed in Figure 5.19. It becomes obvious that the optimal response when the probability is low but consumer disruptions need to be avoided is a mix of additional LNG import capacity into Italy and the expansion of interconnections towards Italy. The Iberian gas market, with its significant redundant LNG import capacities, already seems well equipped for such a crisis.[96] Hence, investments are confined to some minor upgrades of North to South capacity and an a very small expansion of interconnection to France.

Additional LNG imports to Italy are enabled through a 3 bcma terminal at the proposed terminal location in Brindisi in Southern Italy. The terminal would allow additional LNG

95 See Aggregated Gas Storage Inventory database by GIE (2011).

96 One of the pipelines from Algeria to the Iberian Peninsula, Medgaz, also only entered operations in 2011. Hence, in combination with the regions' lower than expected demand growth, there is significant excess import capacity, especially on the LNG side.

Figure 5.19: Security of supply enhancing investments regarding SoS2 disruption with 5 % probability



imports in an emergency but would be rather low utilized under normal circumstances (of course it would still be used to provide some flexibility in the form of seasonal imports).

Interconnections are enhanced between France and Switzerland (Switzerland and Italy are already well integrated markets) and on the route from Slovakia via Austria to Italy. The first measure would improve the ability to import LNG at French or British terminals and the transportation to Italy should pipeline imports from North Africa stop. Increasing the capacity between Slovakia, Austria and Italy allows diverting large volumes of Russian natural gas towards Italy in the emergency case. Previous analyses[97] have shown that the addition of new routes for Russian gas supplies to Europe (e.g. Nord Stream) cause the utilization of the Ukraine-Slovakia Transgas route to decline or to provide additional volumes towards Italy (if the South Stream pipeline is not implemented). An increase in transportation capacity between Eastern Austria and Italy could allow to do so to an even greater extent if the country requires

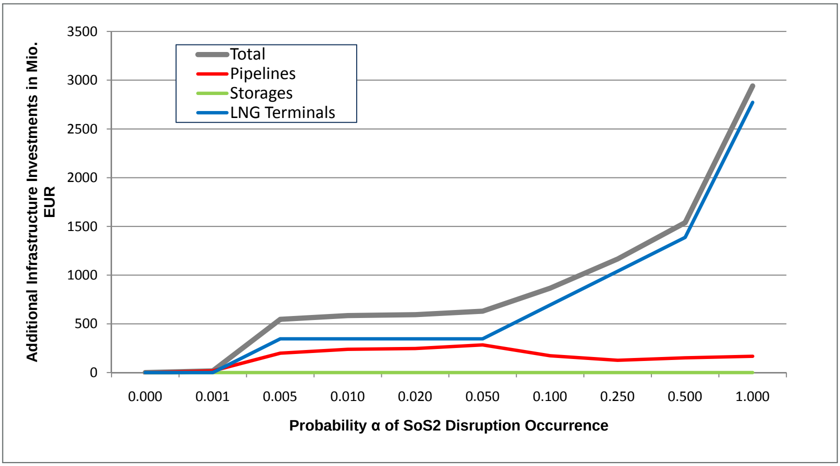
97 See for instance Lochner and Bothe (2007a) or Dieckhöner et al. (2011).

a replacement of its North African imports.

The nature of the assumed emergency scenario also precludes the economic viability of natural gas storage to improve security of supply. As indirectly shown by Lochner and Dieckhöner (2011), natural gas storage are only a measure to increase security of supply for short temporary disruptions. In the case of the prolonged stop of gas supplies from a country as illustrated here, they would deplete quickly and have only limited value. In order to be a meaningful mitigation measure, gas stocks for strategic usage in an emergency would need to be large. Opportunity and the (albeit low) variable costs of storing gas would be significant, which means the measure is not economically viable, especially if the likelihood of the emergence actually occurring is low.

Hence, as obvious from Figure 5.19, LNG import capacities and additional pipeline interconnections are a more cost-efficient solution. They are not associated with variable operating costs if not used, and may provide higher social welfare benefits when there is no emergency as they can be used for trade between markets. The optimal investment ratio in pipelines and LNG import capacities is depicted in Figure 5.20 as a function of the likelihood of the emergency (α_{SoS2}).

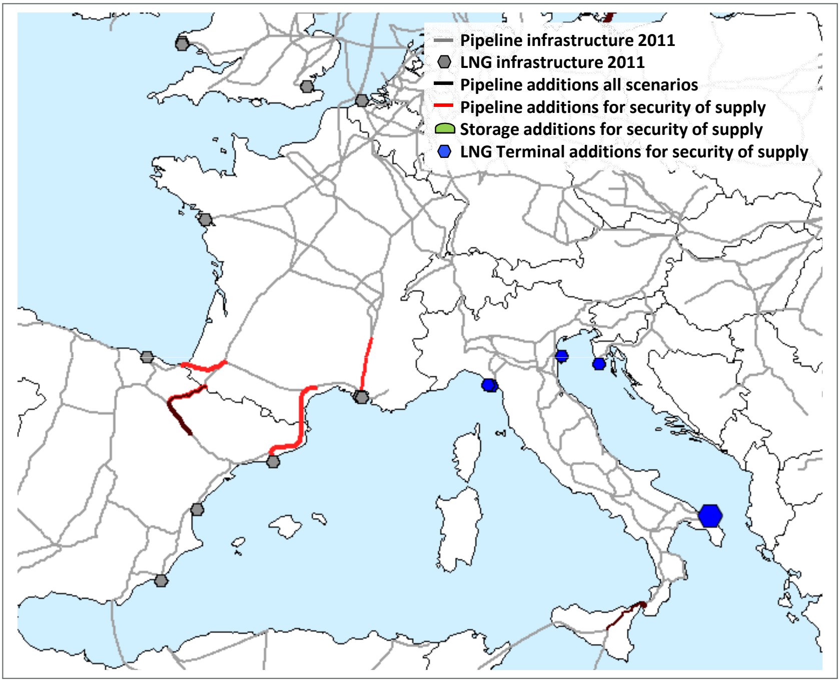
Figure 5.20: Additional SoS2 infrastructure investments expenditures



Similar to the Transit disruption scenario, when the probability is very low, it is efficient not to invest and disrupt gas flows to some consumers if the unlikely event does happen. With rising probability of an emergency, it becomes worthwhile to increase interconnection at some points in the system to allow some additional imports. If the probability reaches 0.5 percent, it already makes sense to build and maintain redundant LNG capacities in order to be able to replace those imports which cannot be substituted through other sources.

Because of the lumpiness of the LNG investments, it is not efficient to expand or build additional capacities unless the probability is higher than 5 percent. While, with an emergency probability of 5 percent, investments in interconnection and LNG import capacities are almost equal in monetary terms, this changes with further increasing α_{SoS2}.

Figure 5.21: Security of supply enhancing investments regarding certain SoS2 disruption (100 % probability)



An even higher likelihood of a prolonged disruption from North Africa implies that the Italian market should actually strive to create complete redundancy regarding its import infrastructure from Algeria and Libya. This is efficiently accomplished through additional LNG import capacities. If $\alpha_{SoS2} = 1$, see Figure 5.21, 24 bcm of annual LNG import capacities at four different locations are endogenously added by the model. One of them is thereby actually located in Croatia which can then supply some additional volumes to Eastern Europe while Russian gas can be transported to a larger extent to Italy. Total capital expenditures increase to 3 billion EUR (see Figure 5.20).

In this case, integration between Spain and France also sees some additional investment to enable importing additional flexibility from storage in Southern France: if LNG terminals are utilized at a high level all year around, they are less able to function as tools to provide flexibility.

From a policy side, the findings in this second security of supply analysis illustrate a complicated issue: Efficient investments to improve security of supply may occur outside the borders of the jurisdiction actually profiting from these investments. In an North African emergency situation with a low probability, this refers to the interconnection between France and Switzerland and investments in Austria. If the probability is high, the Croatian terminal is a good example. Who is bearing the costs of these investments is a critical question with respect to implementation, which cannot be resolved as part of this dissertation project.

5.4.3 Summary on security of supply investments

The two emergency situations investigated showed similarities and differences.

- Firstly, it needs to be noted that enlarging interconnection capacities - at the right locations - always seems to be a suitable measure to improve security of supply. As many investments in improving physical market integration in Eastern Europe have already been carried out after the 2009 crisis, only minor scope for investments remains in the region. As a North African crisis may not have been seriously contemplated in the past, scope for investments remains significant.
- The same holds true for total capital investment in general, which would be much higher to construct an efficient system geared to cope with North African supply disruptions. The current one can much better deal with Eastern European transit issues.
- With respect to storage, we find that they are only in some cases suitable to mitigate the consequences from supply disruptions. Conditions include sufficient WGV capacity being available and a limited emergency duration. In our scenarios, investments in additional storage capacities were not found to be efficient in most cases. Especially for potentially longer crisis situations, strategic gas stocks may not be suitable as increasing market integration is more efficient then. However, if storage capacity is available and assumed crisis duration is low, it is found to be cost efficient to incur the associated costs to maintain gas stocks in excess of the volumes required to balance supply and demand - even if the probability of the emergency is low.

- We also find the probability of the respective emergency of great relevance. If it is low, it may be economically efficient (though probably not politically acceptable) to disrupt supply to some consumers instead of investing for an unlikely event. If the probability is high, the system should be designed to be routinely able to cope with it. In the case of a transit crisis, this means a high level of physical market integration with the rest of Europe; in the North African case it implies building redundant import capacities.

- Finally, it needs to be noted that cost-efficient investments to increase security of gas supply may incur in locations outside the countries benefiting the most from the enhanced system resilience. How - and if - these costs can be efficiently attributed to the consumers benefiting from them is a challenge for policy makers, regulators and further research.

Returning to the introductory remarks of Chapter 5, the specific results depicted above are a benchmark in a normative world. The institutional framework might require different and less efficient investments. Nevertheless, the insights derived in this work can assist to improve the institutional framework regarding efficient investments.

For instance, this analysis also allows some conclusions on the recently adopted regulation "concerning measures to safeguards security of gas supply" by the European Parliament and the Council of the European Union (Regulation 994/2010[98]).[99]

Generally, the regulation is based on a top-down and a bottom-up component: universal security standards and regional risk assessments.[100] Preventive action and emergency response plans are to be set up based on the two.

Our analysis not only stresses the importance for region-specific risk analysis, but also makes the case for region-specific measures instead of universal standards.

The universal infrastructure standard includes the (N-1) criterion and the installation of so called reverse flow capacities at all cross-border connection points. The former requires each country to be able to ensure gas supply at a peak demand day without its single largest infrastructure capacity; the latter that pipelines between countries can be operated in both directions. This feature is to allow that gas can flow against the normally prevailing direction of a pipeline link.

Both universal infrastructure standards have been controversial for two reasons: they are not necessarily efficient and put too much of a focus on capacity instead of volumes. The economic inefficiency arises from the generalization. The individual costs of and the willingness to pay for the provision of additional security are not considered.[101] Furthermore, as seen in the analysis on efficient security of supply enhancing

98 See European Union (2010).

99 The argumentation in the remainder of this section has partially been previously published by the author in Lochner and Dieckhöner (2011).

100 See Noel (2010) for an encompassing discussion of (a final draft of) the regulation.

101 For a discussion of this issue see Ahner and Ruester (2010).

investments, the specific security-enhancing benefits of investments in redundant capacities may differ between projects. This is also not taken into account. Hence, the welfare optimal level of security of supply is unlikely to be provided through a universal standard.

The focus on capacity might further be misleading: the adequacy of capacity is a necessary but not a sufficient condition for a certain level of security of supply. After all, one still needs the volumes to utilize a pipeline, storage withdrawal or LNG import capacity in order to enable delivering gas to consumers. So security of supply might not be as high as what the (N-1) criterion suggests.

Regarding Italy, the country at the focus of our second security of supply simulation, a 2009 analysis by the European Commission (2009) ranked EU members by compliance with the (N-1) criterion: Italy was found to comply handsomely as its production, storage withdrawal and LNG and pipeline import capacity minus the capacity of the largest infrastructure equaled 124 percent of the conceived maximum demand. Only eight EU countries did better than Italy; additional investments from an (N-1) perspective were not required.

Nevertheless, the analysis in this paper have shown that investments would be efficient to mitigate the consequences of disruptions of North African pipeline exports, even if the probability of such a scenario is low. Hence, it is important to make the regional risk assessments identifying such potential risks and to draw the appropriate conclusions from the specific findings: in a prolonged supply disruption, storage may not contribute to security of supply significantly. It is, hence, questionable how much the aforementioned findings from the (N-1) considerations are worth: 70 percent of Italy's (N-1) capacity is storage withdrawal capacity (European Commission, 2009). If storage deplete over time - as they would in prolonged supply disruptions - these withdrawals decline or stop. Gas from all the other capacities (assuming quantities are there) can then satisfy only 54 percent of the theoretical maximum daily consumption in Italy. Thus, new investments might be necessary although (N-1) does not indicate that.

To summarize, a comprehensive evaluation of the probability and societal costs of potential supply disruptions, as well as the costs of increasing the level of security, is necessary. Because of differing supply and consumption structures, each of these factors may vary between individual countries and regions. This strengthens the case for the regional character of the risk assessments already envisaged by the EU, but also for country-specific measures to improve security of supply in addition to rather limited standards mandatory for all EU member states. The analysis in this dissertation are a first indication of what such an analysis could encompass - however, there is scope for improvement, especially regarding the representation of natural gas consumption patterns (industry and power sector price elasticity of gas demand) in a modeling framework (see next chapter).

6 Conclusion

Subsuming the considerations and findings of this work allows to draw a number of relevant conclusions.

In an efficiently organized transport market for natural gas, there are significant interdependencies between different infrastructure elements and the systems in the various European countries. Analytically, it can be shown that they impact congestion as well as cost-efficient investment decisions. A model-based analysis is able to capture such interdependencies. It is therefore a suitable approach for their identification and for investigating the welfare effects of investments.

The large-scale infrastructure model set-up as part of the dissertation project encompasses all relevant infrastructure elements. Nevertheless, it abstracts from some technical details of pipeline operation. Future research might check if a more technical representation of the grid infrastructure becomes computationally possible. More importantly, however, the modeling of demand side interdependencies with respect to power and industrial sectors' price elasticities for demand could also be improved.

Although the cost optimization model approach yields useful results, it needs to be noted that the applied model presumes that the allocation and utilization of capacities in the (regulated) transport segment and access to LNG import and storage facilities are organized efficiently. In addition to transparency and harmonized market designs, competition in the commodity market is also assumed. As the market is not that perfect, results are not forecasts but projections (which should be treated as such). Identified investments are, hence, those which would be needed even if the system were to operate fully efficient. Additional investments, which are for instance useful as they increase competition between two markets or because existing capacities are inefficiently used, would not be identified by the model.

With respect to the general results, the analysis illustrated the theoretical findings from an applied perspective. It is shown, for instance, how developments in one region (unconventional gas production, a new import corridor from the Caspian region) have significant implications for investments in geographically separated markets. Regarding storage, we found that the efficiency of investments in additional storage capacity is greatly affected by developments in the global LNG market and the composition of the European supply mix. Further LNG import capacity investments will largely depend on consumption developments.

From a political perspective, the security of supply simulations have interesting implications - and raise a number of new research questions: Investments in redundant capacity to enhance security of supply are found to be beneficial even if the probability of the respective emergency low. So is the stockage of natural gas in excess of volumes required to balance supply and demand. However, how the provision of both by players in a liberalized commodity market and a regulated infrastructure system can be ensured, is not clear. Furthermore, the costs associated with improving one region's security of supply may efficiently be incurred in a different region.

With respect to security-of-supply-enhancing gas stocks, gas suppliers to consumers in a liberalized market may not have an incentive to maintain these. Gas storage volumes in excess of the quantities needed to balance supply and stochastic demand may not be needed most of the time - but increase costs. Obliging suppliers to hold such reserves - as some EU member states do (Italy, Spain) - is one option. However, the corresponding costs for building up the reserve may deter market entry, which is also not desired. The investment decisions for redundant infrastructure may also be difficult. In unregulated markets (LNG and storage in some countries), the previous argument applies. If the market segment is regulated, investors would have difficulties justifying the investments through market demand - which is not there most of the time. Thus, the requirements for a redundant infrastructure need to be established through different means, which should encompass some evaluation of the welfare-benefits of the proposed investment. As the discussion in Section 5.4.3 illustrated, not all politically initiated investments in redundant reverse flow capacities may enhance security of supply.

The question who pays for enhancing security of supply also needs to be addressed. Firstly, the additional stocks or redundant capacities are not used most of the time, so levying costs on their "usage" is not an option. Secondly, there may be consumers who do not require a very high level of security of supply. Nevertheless, they would benefit from additional security of supply which might be important to other consumer groups. If security of supply is a public good - which needs academic discussion - all consumers should contribute to the costs of enhancing it. If not, there needs to be some differentiation. Thirdly, some consumers are geographically more exposed to security of supply threats. Again, the question arises whether the costs of these threats should be socialized. As Europe consists of many countries and TSOs, implementation would already be difficult. If costs are borne individually, an implementation would be even more difficult as we have shown that costs may incur outside the region which benefits from them.

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Appendix

Table A.1: Pipeline investments by country and scenario (Reference demand)

Country [in Mio. EUR]	Base scen.	(S1) Low LNG price	(S2) Low LNG flex.	(S3) Southern corridor gas	(S4) European unconventionals
Austria	4	4	4	12	40
Bulgaria	18	24	18	92	122
Croatia	3	3	3	8	90
Czech Rep.	0	0	0	0	42
Denmark	6	6	6	6	6
France	0	34	0	516	1,855
Germany	7	7	7	210	600
Greece	0	0	0	0	721
Hungary	0	0	0	55	382
Italy	31	27	31	31	85
Netherlands	0	0	0	0	27
Norway	28	27	28	37	44
Poland	11	0	11	0	55
Romania	0	0	0	47	414
Russia	1,597	1,597	1,597	1,699	1,799
Slovakia	0	0	0	47	292
Slovenia	14	14	14	16	6
Spain	82	222	82	0	215
Turkey	4,176	343	4,176	15,087	4,207
UK	4	0	4	0	0
Total	5,982	2,309	5,982	17,863	11,001

Table A.2: Pipeline investments by country and scenario (High demand)

Country [in Mio. EUR]	Base scen.	(S1) Low LNG price	(S2) Low LNG flex.	(S3) Southern corridor gas	(S4) European unconventionals
Austria	0	17	0	47	317
Bulgaria	67	7	67	457	163
Croatia	1	253	1	47	97
Czech Rep.	0	0	0	77	139
Denmark	39	38	39	38	38
France	961	1,487	545	75	155
Germany	134	81	134	338	669
Greece	185	0	240	1,346	1,533
Hungary	17	19	17	456	662
Italy	85	97	172	142	197
Netherlands	0	0	0	0	0
Norway	66	66	66	66	66
Poland	55	4	75	55	89
Romania	101	0	101	772	836
Russia	2,062	1,920	2,062	2,321	4,914
Slovakia	164	4	201	281	1,571
Slovenia	8	0	8	1	33
Spain	717	1,014	225	275	201
Turkey	5,367	408	5,367	20,172	5,466
UK	0	0	0	0	0
Total	10,029	5,413	9,320	26,966	17,146