Impact of the European Gas Network on the Operation of Great Britain's Gas and Electricity Networks

Oluwabamise T Olanrewaju
School of Engineering
Cardiff University

A thesis submitted for the degree of
Doctor of Philosophy

February 7, 2017

Content

List of Tables

List of Figures

Declaration

This work has not been submitted in substance for any other degree or award at this or any other university or place of learning, nor is being submitted concurrently in candidature for any degree or other award.

Signed………………………………………………. Date……………………..

STATEMENT 1

This thesis is being submitted in partial fulfilment of the requirements for the degree of PhD

Signed……………………………………………….. Date……………………..

STATEMENT 2

This thesis is the result of my own independent work/investigation, except where otherwise stated, and the thesis has not been edited by a third party beyond what is permitted by Cardiff University's Policy on the use of Third Party Editors by Research Degree Students. Other sources are acknowledged by explicit references. The views expressed are my own.

Signed………………………………………………..Date……………………..

STATEMENT 3

I hereby give consent for my thesis, if accepted, to be available online in the University's Open Access repository and for inter-library loan, and for the title and summary to be made available to outside organisations.

Signed………………………………………………..Date……………………..

Summary of Thesis

Recent events of natural gas supply disruption in Europe have led to severe consequences of supply shortages to some European Member States. As the United Kingdom increasingly depend on imported gas supply from different sources including Continental Europe, the effect of gas supply disruption in Europe on UK's gas consumers is in question. This thesis investigated the effect of gas supply disruptions in Europe on the operation of the Great Britain's gas and electricity network using a set of modelling tools.

An optimisation model of the European gas network was developed to assess the resilience of the European gas network to the loss of gas supply through the Ukraine transit pipelines to Europe. The results showed that unserved gas demand occurred in South East Europe. It was shown that additional interconnector capacities of selected pipelines and higher storage withdrawal rate in South East Europe minimised unserved gas demand in South East Europe.

A soft-link coupling of the European Gas Network model (EGN) and the Combined Gas and Electricity Network model (CGEN) was developed and used to examine the effect of a 90-day loss of Ukraine transit capacity in Europe on the operation of GB gas and electricity network at a period of limited LNG supply to Europe. The result showed that in a high gas demand situation, industrial customers would experience some amount of unserved gas demand.

The effectiveness of the mitigation options to prevent or mitigate unserved gas in GB was analysed using the EGN-CGEN model. Then a cost-benefit assessment tool was used to rank the mitigation options according to the net benefit of reducing the cost of unserved gas demand in GB. It was shown that diversification of gas supply sources and routes in Europe would deliver significant security of supply benefit to GB gas and electricity network.

Acknowledgements

First of all, I am exceeding grateful to God for the grace to start and the strength to complete this research work.

I would like to express my sincere thanks and appreciation to my supervisors, Professor Nick Jenkins and Professor Jianzhong Wu for their continued support, patience encouragement and insightful contribution to the development of this thesis and my research progress.

I would like to specially thank Dr. Modassar Chaudry and Dr. Meysam Qadrdan for their support, technical guidance and very helpful feedback regarding my work.

I would like to acknowledge the research funding I received from the Research Councils UK thorough the HubNet project, Top and Tail Transformation project support.

I would like to thank Dr. Daniel Adeuyi, Dr.Brian Boye, Sandra Akande, and Ademola Agunbiade for their encouragement, continuous help during my research work and for their valuable friendship.

I would like to express my profound gratitude to my family especially my parents Florence and Paul Ogunbunmi, for their invaluable support and encouragement at all times.

Finally, I am exceedingly grateful to my husband Imole for his constant support, understanding and encouragement throughout my research study.

Nomenclature

Abbreviations

BCM	Billion Cubic Metre
CCS	Carbon Capture and Storage
CM	Cubic Metre
ENSTOG	European Network System Transmission Operator for Gas
EU	European Union
GB	Great Britain
IEA	International Energy Agency
IRD	Import Route Diversification
LCPD	Large Combustion Plant Directive
LNG	Liquefied Natural Gas
LP	Linear Programming
MCM/D	Million Cubic Metre per Day
MILP	Mixed Integer Linear Programming
MINLP	Mixed Integer Non-Linear Programming
NLP	Non-Linear Programming
TANAP	Trans Anatolian Natural Gas Pipeline
TSO	Transmission System Operator
UK	United Kingdom

Parameters

D	Diameter, m
f	Friction factor
L	Pipe length, mm or m
k	Pipe roughness, mm
P	Pressure, Pa or bar
Q	Gas flow, mcm/d
Re	Reynolds number
T	Temperature, K
Z	Compressibility factor

Subscripts

b	Bus
g	Generator
i,j	Node
s	Storage
t	Time

Superscripts

elecshed	Unserved electrical energy
gasshed	Unserved gas demand
inj	Injection rate
sp	Spot price
sup	Supply
wd	Withdrawal rate

Chapter 1

Introduction

1.1 Global Natural Gas Outlook

According to the world energy outlook, natural gas demand is projected to increase from 3.3 tcm in 2010 to 4.9 tcm in 2035 [1]. The strongest demand growth is expected to come from Asia where it is mainly driven by gas consumption in the industrial and electricity sectors [2]. Global gas supply is projected to increase at an average yearly rate of 1.75 % between 2012 and 2035 [3]. Significant contributors to the growth in gas production will be the North America, Eurasia and Middle East. Collectively, they will account for 61% of global gas production by 2035 [1]. In the European Union, natural gas production is projected to decline significantly by 43% in 2035 from current levels [4].

Substantial growth in unconventional gas (shale gas and coal bed methane) production is expected to contribute significantly to future gas supply. Unconventional gas is natural gas sourced from different geological formations by means of horizontal drilling and fracturing. The United States is the largest producer of shale gas which accounted for 43% of total natural production in 2013[5]. Gas production in the United States (US) is projected to increase from 689 bcm in 2013 to 800 bcm in 2035 driven by significant development in shale gas production [1].

Global gas demand and supply balance is achieved by means of inter–regional gas trade through pipeline supplies and Liquefied Natural Gas (LNG) shipment. Pipeline transport accounts for 68% of global natural gas supplies [1]. Significant developments in the LNG supply chain is expected to take place in the period towards 2030 and LNG supplies are projected to increase by 62% in 2035 from 304 bcm in 2013[1].

1.2 Natural Gas Development in Europe

Natural gas is an important component of the European energy mix and accounted for about 22% of primary energy consumption in 2015 [6]. Natural gas is expected to play a significant role in achieving the climate and energy targets of the European Union (EU). In comparison to oil and coal, natural gas emits less carbon dioxide during combustion and offers significant potential to reduce CO_2 emissions in the power generation

Access to secure, adequate and affordable gas supplies within Europe is an important goal of the EU [7]. At present, the level of access to secure gas supplies varies significantly across member states. Gas systems predominately in North-West Europe can receive natural gas from multiple supply sources, while gas systems in the Baltic region rely on a single source of supply [8]. Planned investment in cross-border gas infrastructure between member states is expected to increase the number of alternative gas supply routes across Europe in order to improve security of gas supply.

In order to facilitate the operation and delivery of this interconnected European gas system, a Ten Year Network Development Plan (TYNDP) is published every two years by the European Network Transmission System Operators for Gas (ENSTOG) [9]. The TYNP provides an assessment of the European gas transmission network development and future scenarios of gas demand and supply to Europe.

1.2.1 Evolution of European Natural Gas Demand

Several scenarios have been developed to estimate the future projections of natural gas demand in Europe [10], [11]. Figure 1.1 depicts two different demand scenarios across EU gas consumption sectors: power generation, residential and commercial, industry, transport and others.

In the EU Energy Trends Scenario, the overall demand decreases by 24% in 2030 relative to 2010. This scenario assumes that long-term energy targets on energy efficiency, deployment of renewable energy technologies and other low carbon technologies are achieved in a timely manner. The Eurogas Scenario shows a demand increase of 8.7% by 2030 over the same period. This scenario assumes that current national energy policies are maintained with limited future investment in the gas sectors.

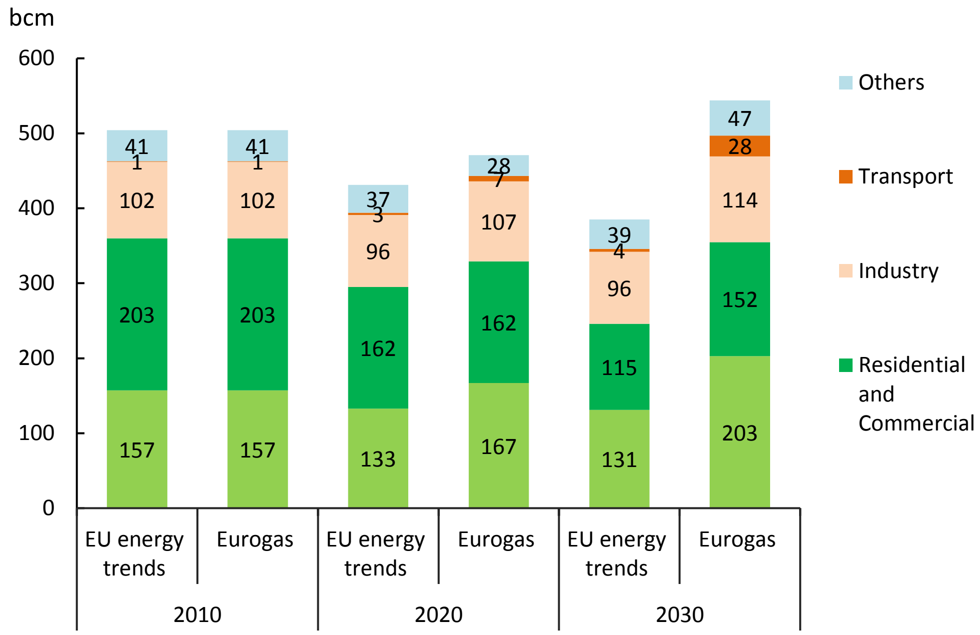

Figure 1.1. Comparison of European Union gas demand projections

In both scenarios, gas demand for power generation steadily increases towards 2030. Gas-fired generators are expected to displace coal and oil generators from the EU electricity generation mix. In contrast, gas demand in the residential and commercial sector decreases considerably by 2030 in both scenarios. Natural gas is used for space heating and hot water in the domestic & commercial sector. The demand profile has a seasonal pattern of peak demand in winter months and low demand in summer months [12]. The demand reduction in this sector is driven by energy efficiency improvement in buildings and the deployment of renewable heat technologies such as heat pumps [10], [13].

The future outlook of gas demand in Europe will be influenced by other factors including benchmark carbon-price, cost of competing fuels, the deployment of carbon capture and storage at commercial scale (CCS), economic growth, environmental legislation and national energy policies of member states [14],[15].

1.2.2 European Gas Supply Outlook

European Union gas supply comes from indigenous production, LNG and pipeline imports from Russia, Norway, Algeria and Libya. Historically, indigenous production, especially from the Netherlands and the United Kingdom, was the main source of gas supply in the EU [16]. As indigenous gas production declines, increasing reliance on imported gas supply is anticipated to meet future gas demand [17]. EU gas imports are projected to reach 85% of total supply by 2035 [1].

Table 1.1 Maximum gas supply scenarios to the European Union (bcm) [18]

	2015	**2020**	**2025**	**2030**	**2035**
Russia	174	194	198	201	212
Norway	124	127	106	82	82
Algeria	42	45	51	55	59
Libya	11	11	11	11	11
Azerbaijan	0	4	11	16	16
Turkmenistan	0	33	26	28	37
LNG	134	165	191	217	242

Table 1.1 present the maximum gas supplies available to the EU from several sources. Russian gas supply to Europe increases by 22% (38 bcm) between 2015 and 2035. On the other hand, natural gas supply from Norway to Europe peaks at 127 bcm by 2020 and then declines to 82 bcm by 2035. Potential gas supplies from Turkmenistan (in the Caspian region) to the EU is estimated to increase substantially to 36.6 bcm in 2035 from current levels (Table 1.1). Presently, there is no gas pipeline connecting Europe to gas reserves in Turkmenistan. However, some pipeline projects are under consideration to address this limitation [9].

LNG supplies to EU member states is sourced from several producing countries including Qatar, Algeria and Nigeria. Qatar is the highest LNG exporter to Europe with 47% share of LNG import in 2014[19]. The EU closely follows Asia as the second largest LNG supply destination in the global LNG market. Table 1.1 shows that LNG import is projected to increase rapidly from 133.9 bcm in 2015 to 242.4 bcm in 2035 exceeding Russian gas supply by 2030.

1.3 Natural Gas Supply System

Natural gas supply system involves the transportation of natural gas from production wells to the different end users. In Europe, the natural gas supply system consists of a complex pipeline network, liquefied natural gas terminal gas (LNG) terminals and gas storage facilities.

1.3.1 Transmission Network

Natural gas is transported from production fields through a network of transmission pipelines directly to distribution networks, large power stations and large industrial consumers. Domestic and commercial consumers are supplied through the low pressure distribution network. The gas transmission networks are characterised by high pressure (in excess of 40 bar) and long distance pipelines.

In Europe, the Transmission System Operators (TSO) own and operate the transmission network. The TSO is responsible for balancing demand and supply, ensuring the reliable and safe operation of the network within the specified pressure limits [20]. The European gas transmission network comprises the natural gas transmission infrastructure of individual countries integrated as a single entity for delivery and transport of natural gas supplies across Europe.

Compressor stations are installed along the long distance high pressure pipelines to maintain gas pressure in the network within acceptable limits. Compressor stations consist of a single or multiple compressor units driven by a gas turbine or an electric motor.

In recent times, electricity driven compressor are preferred over gas turbine drivers as they offer lower maintenance, lower noise levels and no greenhouse gas emissions [21]. In Europe, 7000 MW compression capacity has been planned alongside pipeline projects to improve network capacity and security of supply [22].

1.3.2 Gas Storage

Natural gas storage provides an important source of supply flexibility. Storage facilities function as a buffer capacity during periods of peak demand, seasonal demand variation or in the event of gas supply disruptions [23].

Underground storage facilities are classified according to four technical characteristics. These are cushion gas capacity, working gas capacity, withdrawal rate and injection rate [24]. The cushion gas capacity is the volume of gas retained in the reservoir to maintain adequate pressure in the facility. The working gas capacity is the volume of gas that can be withdrawn from or injected into a storage facility. The summation of the cushion case capacity and working gas capacity constitute the total gas storage capacity. The withdrawal rate refers to the rate at which natural gas can be extracted from a storage facility on a daily basis while injection rate is the rate at which gas molecules can be pumped into storage for future use.

The three major types of underground storage facilities used in Europe are depleted oil/gas fields, aquifers and salt cavern. Table 1.2 presents the types of storage facilities classified by their key characteristics. Total gas storage capacity of existing storage facilities is 108.3 bcm [25]. Several development projects have been planned across the EU and if completed, will increase storage capacity by 20% in 2020 from current levels [22].

Table 1.2 Key characteristics of underground storage facilities [24]

Storage Features	**Depleted Fields**	**Aquifer**	**Salt Cavern**
Main function	Seasonal facility	Seasonal facility	Fast cycle facility
Storage capacity	Usually large capacity	Large capacity	Low capacity
Cushion gas	High cushion gas requirement	High cushion gas requirement	Low cushion gas requirement
Withdrawal and Injection rates	Low rates	High rates	High rates

Cost	Low operating cost	High operating cost	High operating cost

1.3.3 Liquefied Natural Gas Facilities

Liquefied natural gas is natural gas cooled to its liquid state at a temperature of about -612^{o}C and kept at high pressure [16]. The volume of LNG is greatly reduced to about 600 times less than the volume of its gaseous form. Natural gas is converted to LNG at liquefaction terminals. After production, LNG is transported by specially designed ships (LNG tankers) to regasification terminals located at LNG importing countries. For long distance gas transport beyond 3000-5000km, large LNG shipment shows favourable economic justification compared to pipeline capacity [26]. At the regasification terminal, LNG is transformed into its gaseous state (regasified) and discharged into pipelines connected to the transmission network. LNG regasification terminals are spread across the coastlines of South and Northwest European countries. In 2015, the total existing LNG regasification capacity among EU member states was 198 bcm/y [16].

1.4 Interaction between European Gas Supply and GB Gas and Electricity Networks

The European gas transmission network comprises the natural gas transmission infrastructure of individual countries integrated as a single entity for delivery and transport of natural gas supplies across Europe. Great Britain's (GB) natural gas network is connected to the European gas network via six undersea pipelines linked to Norway, Belgium and the Netherlands. Norwegian gas is delivered via Langled pipeline to Easington terminal while Vesterled, Tampen & Gjoa gas pipelines link with St. Fergus terminal in Scotland. Also, the BBL pipelines (Balgzand Bacton Line) from Netherland and Interconnector pipeline (IUK) from Belgium come ashore at the Bacton gas terminal. Total import capacity from Norway and continental Europe is presently about 46.6bcm/y which is 1/3 of UK's import capacity [27].

Historically, GB was a major producer and exporter of natural gas. Since 2004, the decline in domestic gas production led to increasing reliance on gas import to meet its domestic gas demand. Thus, GB's import infrastructure has increased in relation to peak demand and they are more diversified to receive supply from various sources including LNG. Total capacity of existing LNG regasification terminals is 53.1 bcm/y [27].

Whilst the current level of GB's import capacity is understood to be relatively robust, there is increasing uncertainty about how future supply patterns will develop. Gas supply to GB is influenced by a number of external factors including the evolution of the global LNG market and developments in the European gas network. There is increasing competition in the global LNG market as more countries in Europe and in other parts of the world expand their regasification capacities [28]. In a tight LNG market (i.e. when demand exceeds supply), GB may not attract sufficient LNG supplies at prices acceptable to its gas consumers.

At the same time, continental gas supplies to the GB network is determined by the demand and supply situation in mainland Europe. In 2009, the disruption of Russian gas supplies through Ukraine to Europe led to higher gas spot prices. During this period, increased gas export from GB to the continent on the cross-border interconnector between GB and Belgium occurred due to higher gas prices on the continent [29]. During the crisis, Norwegian gas supplies to continental Europe increased, this resulted in less gas export from Norway to GB [30].

GB is committed to increasing the share of renewable generation in electricity generation mix. 48 GW of wind generation capacity would be connected to the electricity network by 2030 [31]. Wind power is variable and requires other flexible generators to ramp up and down to balance electricity demand. Gas-fired plants have the capability to rapidly adjust their output power and complement the variable generation from renewable energy sources such as wind.

The GB natural gas network is coupled to the GB electricity network through gas-fired plants. Currently, installed capacity of gas-fired plants accounts for 34% of GB generation mix [32]. In the period between 2013- 2025, gas generation capacity is expected to increase by 32% [32]. In contrast, coal generation capacity will decline to comply with the Large Combustion Plant Directive (LCPD).

The increasing interdependency of both network have implications for security of supply. The electricity network will increasing depend on imported gas supplies to meet gas demand in power generation. An interruption in the gas supplies could lead to additional stress on the power system and loss of power supply.

Given the growing interdependency between the gas and electricity network and the increasing reliance on gas import, it is essential that the security of GB gas and electricity networks is assessed in relation to European gas supply situations.

1.5 Thesis Objectives

The objectives of the research described in this thesis were to:

- Develop an optimisation model of the European gas network to determine gas flows on cross border interconnectors and utilisation of storage facilities and LNG terminals across Europe.
- Investigate the impact of the loss of Ukraine transit capacity on operation of the European gas network for two demand scenarios in 2015.
- Assess the resilience of the GB gas and electricity networks to a potential loss of the Ukraine transit capacity during a period limited LNG availability to Europe in 2030.
- Assess the role of mitigation options to improve the security of gas supply to GB.

1.6 Contributions of this thesis

- Developed a linear optimisation algorithm of the European gas supply system to examine gas flows in Europe.

- Investigated the impact of the loss of Ukraine transit capacity on the European gas supply system. Locations and volume of unserved gas demand were identified and mitigation measures were modelled.
- A soft-link approach was used to integrate a detailed technical model of the GB gas and electricity networks to a simplified model of the European gas network.
- The soft-linked model was used to examine the impact of the loss of Ukraine transit capacity on the operation of GB gas and electricity networks during a period of limited LNG supply to Europe in 2030.
- A set of six mitigation options were identified and analysed to improve security of gas supply to GB using the soft-linked model. A cost-benefit assessment of the mitigation options was conducted.

1.7 Thesis outline

This thesis has six chapters.
Chapter 2 presents a review of natural gas systems models and security of gas supply. The key features of security of supply with relevance to natural gas are described. Security of supply challenges in Europe are highlighted and security of supply measures are outlined. The types of gas network models used in studies to address security of supply issues are presented. The chapter ends with a review of gas and electricity system modelling techniques and their applications.

Chapter 3 outlines the simplification of the European gas network and the development of a simplified European gas model in Fico Xpress optimisation suite software. A detailed description of the optimisation model is provided including the mathematical formulation (Figure 1.2). In this chapter, the European Gas Network (EGN) model was used to conduct a study of the impact of the loss of Ukraine transit capacity on Russian gas supply to Europe for a high gas demand case and a low gas demand case in 2015. The capability of the European gas network to cope with the supply shortage was analysed and locations of unserved gas demand were identified.

In chapter 4, a soft-link methodology is used to couple the European Gas Network (EGN) model with the Combined Gas and Electricity Network (CGEN) model. Firstly, the features of the CGEN model are described including its network components. The stages involved in soft-linking the European gas network model and CGEN are presented. The integrated EGN-CGEN model is used to examine the effect of the loss of Ukraine transit capacity in Europe on the operation of GB gas and electricity networks during a period of limited LNG availability to Europe over 90 days of winter (Figure 1.2).

Chapter 5 presents the modelling of six mitigation options to improve physical security of gas supply in GB. The effectiveness of the mitigation options in reducing or eliminating unserved gas demand in GB was investigated using the EGN-CGEN model. Then a cost-benefit assessment of the six mitigation options was conducted as shown in Figure 1.2.

Chapter 6 presents the conclusions of the main findings and recommendations for future work.

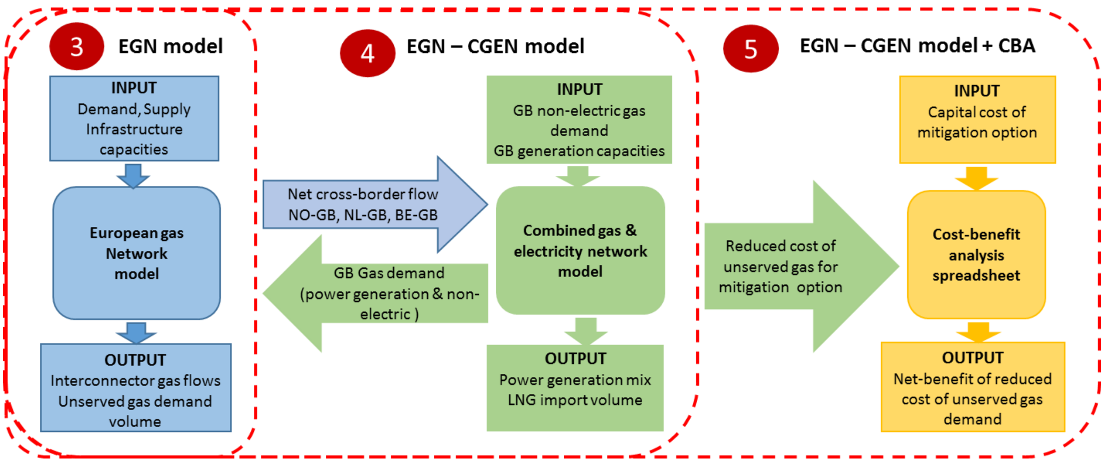

Figure 1.2. Structure of the Integrated EGN-CGEN model and the thesis outline

Chapter 2

Literature Review

2.1 Introduction

Security of gas supply is a primary concern of the European Union. These concerns relate to gas import dependence and the risk of gas supply disruptions. The EU have identified key gas infrastructure investments required to upgrade the existing European gas network and improve security of gas supply.

Gas networks and electricity networks are interconnected by gas-fired generators. By 2030, gas-fired generation is expected to complement a large penetration of variable renewable generation in Europe due to its flexible operational characteristics. Gas-fired generators possess short start-up time and high ramp rate best suited to respond to fast changes in renewable generation output. The growing use of gas-fired generators in electricity generation leads to greater interdependence between the gas and electricity networks. The availability of reliable and secure gas supply becomes increasingly important to the operation of both networks.

A holistic approach to these issues requires the development of a suitable modelling tool to assess the security of gas supply risks on the gas network and its impact on the electricity network. This chapter presents a literature review of the security of gas supply in Europe, the development of models used to analyse natural gas systems and the interdependence between gas and electricity systems.

2.2 Security of Gas Supply in Europe

According to the IEA, security of gas supply is defined as the uninterrupted availability of natural gas at an affordable price [33]. Historical events of gas supply disruption to Europe have highlighted challenges in the regional approach to security of gas supply across the 28 different member states. In order to address these problems, the EU has adopted appropriate directive and regulations to improve security of gas supply. It is expected that these policy actions will drive investment in gas infrastructure projects that would enhance the resilience of the European transmission network against gas supply risks [34].

2.2.1 Gas Supply and Import Dependency in Europe

The domestic gas production in Europe has decreased from 258 bcm in 2000 to 163 bcm in 2013 [35],[36]. As Europe's domestic gas production continue to decline, EU member states would increasingly rely on imported gas supply from various LNG sources, Russia, Norway, Algeria and Libya. Figure 2.1 illustrates the levels of import dependence across EU countries in 2014.

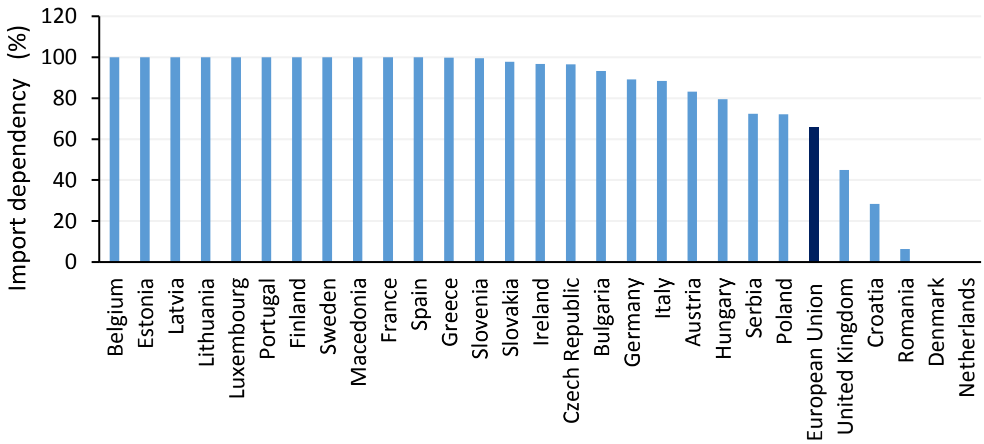

Figure 2.1. Import dependence among EU countries in 2014 [37] Error! Reference source not found.

In Figure 2.1, only two countries (Denmark and Netherlands) use domestic gas production to meet gas demand [38]. About 13 countries have 100% import dependency, some of which are solely reliant on Russian gas supply through a few transit routes. In 2014, the aggregated level of gas import in the EU was 66%.

2.2.2 Security of Gas Supply Challenges in Europe

The impact of gas supply disruption on EU member states depends on the level of reliance on gas imports, duration of the supply crisis, the volume of lost gas supplies and availability of alternative supply options. The risks of security of gas supply in

Europe arise from political and technical challenges. Three cases of gas supply disruption in Europe and the mitigating actions taken at the EU level to address these challenges are discussed in this subsection.

- **Political**

The most prominent threat of supply disruption in Europe has been the geopolitical/ gas price dispute between Russia and Ukraine. In January 2009, Russia shut off gas supplies through Ukraine, which resulted in a supply shortage of about 300mcm/d to 12 EU member states for two weeks [39]. A wide range of gas emergency measures were utilised in the affected countries to mitigate the impact of the supply shortage [40]. Most countries relied on gas withdrawn from storage facilities, imported gas from alternative suppliers and LNG import to replace the lost gas volumes. In other cases, the supply shortage was compensated by switching to fuel oil and coal for heating and electricity generation especially in countries with limited access to other gas supply sources [39]. This gas supply crisis highlighted the need for a robust European gas transmission system that can adequately cope with various gas supply and demand patterns.

In 2011, political instability in Libya resulted in a loss of Libyan gas export to Europe for a duration of 8 months between February and October [41]. The supply disruption resulted in a supply shortfall of 25 mcm/d in Italy on the single pipeline, which connects Libya to Europe. This loss, representing about 10% of Italian gas consumption was replaced by higher LNG import and pipeline import from Austria. This availability of LNG supply limited the impact of gas supply disruption on gas consumers Italy and Europe.

- **Technical**

In January 2010, a technical problem in Norwegian Kroll gas field led to significant decline of 250 mcm of Norwegian pipeline supply to the UK over a four-day period [42]. The supply shortage occurred during a period of very high gas demand due to a severely cold winter. The lost gas volume was replaced by higher LNG import and European pipeline import and lower gas consumption in industry and power generation (demand-side response).

The cases of gas supply disruption in Europe highlight the limited capability of the European transmission system to cope with a major gas supply crisis. Some of the inherent system challenges include insufficient interconnector capacities between member state gas networks and limited diversification of imported supply sources and routes.

2.2.3 Strategies for Diversification of Gas Import Routes

Figure 2.2 shows the level of import route diversification among EU member states. Import Route Diversification (IRD) index is used to evaluate the ability of a country to diversify its gas supply entry points based on the gas import capacity of the given country [9].

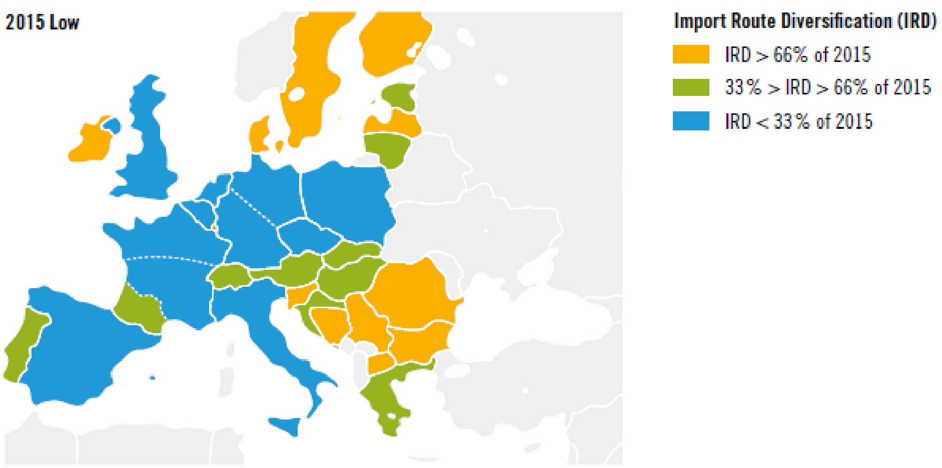

Figure 2.2 Level of import route diversification among EU member states [9]

The countries denoted by the blue colour have well-diversified gas import capacity. All countries in North West Europe are shown to have a well-diversified import capacity except the Republic of Ireland. On the other hand, countries denoted by the yellow colour have the least diversified gas import capacity and they are mainly located in the Balkan and Baltic regions. The three main strategies for improving import route diversification are: bi-directional flow capability on interconnectors, additional gas interconnection and improved LNG infrastructure.

- **Bi-directional flow capability on gas interconnectors**

Since 2009, a number of pipeline projects have implemented bi-directional flow capacity on cross-border interconnectors in Central and Eastern Europe to eliminate flow restrictions and improve the integration of gas networks in these regions. Bi-directional flow capability enables the transportation of gas through pipelines in both directions. Completed pipeline projects with bi-directional flow capabilities include the interconnector between Poland and Czech Republic and the interconnector between Germany and Poland [34]. These pipeline projects enable countries in South East Europe to have unrestricted access to gas supplies in North West Europe.

- **Additional gas interconnections**

Several pipeline projects have been proposed and even completed to bypass transit countries along import routes and bring new gas volumes to Europe. Examples of import pipeline projects include the Nord Stream 2 pipeline and the Trans Adriatic Pipeline (TAP). The Nord Stream pipeline 2 has a planned capacity of 55 bcm per annum [43]. The proposed project is expected to bring Russian gas supply through Germany to Europe in order to avoid gas transport through transit countries such as Ukraine and Belarus. The TAP pipeline would deliver Caspian gas supplies through Turkey to South East Europe. The pipeline has an initial capacity of 10 bcm annually and it is routed through Albania to cross the Adriatic Sea into Southern Italy. If completed, the project will contribute to reducing the reliance on Russian gas supply in South East Europe [44].

- **Improved LNG infrastructure**

LNG supplies provide a key alternative to pipeline import as a means to diversify gas supply and improve security of gas supplies in the EU [45]. The newly constructed Klaipeda LNG regasification terminal in Lithuania has a maximum import capacity of 4 bcm annually [46]. This LNG import terminal provides another supply source for countries in Baltic region to reduce their dependence on Russian gas supply. In 2015, LNG supplies of 50 mcm accounted for 21% of total gas consumption in Lithuania [11]. Additional LNG regasification projects have been planned in France, Croatia, Italy and Netherlands. Currently planned EU LNG projects will increase current annual LNG import capacity of 198 bcm to 234 bcm by 2020 [47].

2.2.4 Security of Gas Supply Regulation

In 2010, the European Union established the regulation on security of supply (EU 994/2010) in response to the January 2009 Russia-Ukraine gas crisis [48]. This regulation introduced a set of common standards to help prevent and mitigate the impact of a supply disruption if it occurs. These common standards include security of supply standards, national risk assessment and emergency plans as well as regional coordination of security of supply measures.

- **Security of supply standard**

The security of supply standard requires that on a day of exceptionally high demand, all EU countries have adequate capacity to meet their total gas demand in the event of an outage of the single largest gas infrastructure. This requirement can be fulfilled through both regional and national infrastructure capacity. In addition, gas suppliers must ensure that protected (domestic) customers are supplied in severe conditions including seven consecutive days of peak demand and 30 days of high demand situations. These supply criteria must be fulfilled in the event of the loss of a gas infrastructure on a normal winter day.

- **Risk assessments and emergency plans**

The security of supply regulation requires that EU countries conduct a risk assessment to identify potential risks to securing gas supply and examine the adequacy of the existing gas infrastructure to cope in the event of various scenarios of supply disruptions under different demand conditions. The risk assessment must include EU supply standards and interaction with gas networks of other EU countries. In addition, national regulation authorities are obliged to prepare preventive actions and emergency actions that remove or mitigate the identified risks. These plans should be updated every 2 years.

- **Regional coordination**

Regional coordination in the implementation of security of supply measures is a key priority of the European Union. EU member states are segmented into regions for detailed assessment of location specific challenges and proposed solutions toward gas supply security. This regional approach is expected to improve cooperation between member states in effective prevention and mitigation of potential gas supply risks. It also aims to reduce the cost of improving security of supply to EU consumers and increases solidarity among member states in the case of a gas supply disruption

2.3 Gas Network Models

Gas network models are mathematical representations used to describe gas flow in gas networks [49]. Major parameters considered in the development of gas network models include flow rate, pressure, pipe length, pipe diameter, suction pressure and discharge pressure of compressor stations. These parameters are used for the design, operation and planning of gas networks.

A simple gas network is presented in Figure 2.3. The network is comprised of nodes and arcs. The capacities and pressures of the supply point, demand points and compressor station are represented by nodes while the arcs represent the pipeline flow rates determined from pipe lengths and diameters. The relationship between pressure and flow in pipelines and compressor stations are described by non-linear equations.

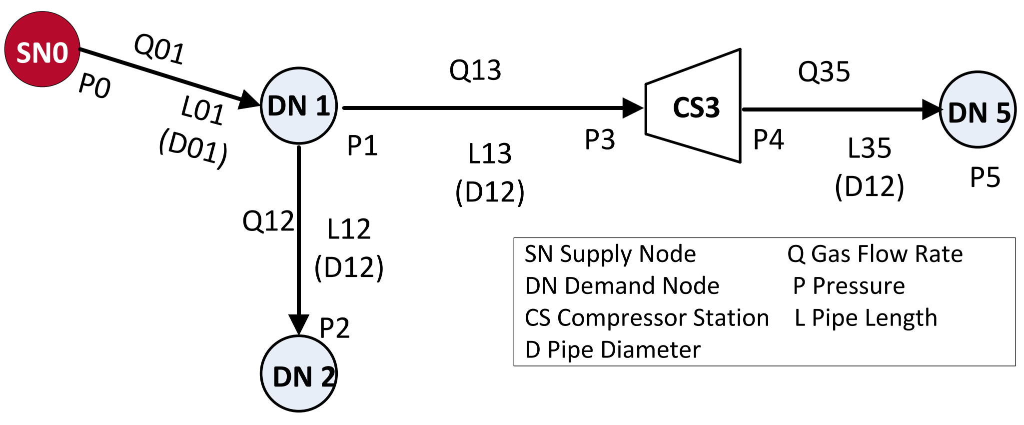

Figure 2.3 A simple gas network structure

2.3.1 Fundamental Gas Flow Equation

The flow rate of gas moving along pipelines is determined by physical dimensions of the pipeline, properties of gas and the pressure drop across the pipeline [21]. The general flow equation for steady state gas flow in horizontal pipelines is given by [50]:

$$Q_n = C\frac{T_n}{P_n}\sqrt{\frac{(P_1^2 - P_2^2)D^5}{fSLTZ}} \qquad 2.1$$

where Q_n is gas flow at standard condition (m^3/d), C is constant, T_n is temperature at standard condition (288 K), P_n is pressure at standard condition (0.01 MPa), P_1 is gas pressure at inlet of the pipe, P_2 is pressure at outlet of the pipe, D is internal diameter of the pipe, f is friction factor, S is gas specific gravity, L is pipe length, T is gas temperature, Z is compressibility factor.

The derivation of Equation 2.1 is based on the following assumptions:

- Gas flow in steady state condition
- Kinetic energy changes along the pipeline is negligible
- Gas flow through pipeline is constant temperature due to heat exchange with the surrounding through the pipe wall
- Constant compressibility and friction factor along the pipeline.

The friction factor is used to determine pressure loss in gas flow due to friction with the wall of the pipeline. The calculation of pressure loss in transmission networks is required to determine the capacity of compressors and the location of compressors stations along the long distance pipelines.

For high pressure gas flow, friction factor is a function of the Reynold number and pipe roughness as given by Equations 2.2 and 2.3 [50].

$$\sqrt{\frac{1}{f}} = 4logRe\sqrt{f} - 0.6 \qquad 2.2$$

where Re is the Reynold number.

The Reynold number is a dimensionless value used to classify gas flow as laminar flow and turbulent flow. Laminar flow occurs when the Reynold number is less than 2000 while turbulent flow is observed as the Reynold number exceeding 2000 [50].

$$\sqrt{\frac{1}{f}} = 4log\left(3.7\ \frac{D}{k}\right) \qquad 2.3$$

where D is the internal diameter of the pipe and k is the roughness of the pipe wall. Gas flow through high pressure transmission pipelines are classified as turbulent flow.

2.3.2 Types of Gas Networks Models

There are two methods used in the modelling of gas networks. These are numerical or simulation methods and optimisation methods [50].

Simulation models are used to study the behaviour of the gas network under a given condition. The simulation approach involves the calculation of nodal pressures and the flow rates on individual pipelines by solution methods that require several complex iterations [50],[51]. Many studies have developed numerical models to examine the operation of gas network. In [52] a discretization method based on the finite element scheme was used to handle the partial differential equations in transient analysis of gas networks. A comparison of isothermal and non-isothermal transient gas network model was presented in [53].

Optimisation models are used to determine the best solution to a gas network problem among a set of feasible solutions subject to a given set of constraints [54]. Optimisation models consist of decision variables, constraints and an objective function. Decision variables are elements of the gas network model whose values are to be determined from the optimal solution e.g. gas flow rate through pipelines and compressor stations [54].

Constraints are equality or inequality equations used to restrict the values assigned to the decision variable. For example, gas flow through pipeline is constrained by the maximum technical capacity of the pipeline [54]. The objective function is the quantitative component of the gas network model expressed as a function of the decision variables which is maximised or minimised e.g. minimisation of operational cost or maximisation of gas flows [55].

Optimisation models are used in the literature to address various natural gas transmission network challenges such as; how to design a new network, expansion of existing networks and the minimisation of gas supply cost and the cost of fuel consumed in compressor stations.

A major difference between the optimisation models and numerical simulations is that an optimal solution is always achieved in a single optimisation run.

2.3.3 Types of Optimisation Methods used in Gas Network Modelling

Optimisation methods have been used extensively in the literature to develop gas network models. These methods are broadly classified as Linear Programming (LP), Non-Linear Programming (NLP), Mixed Integer Programing (MILP) and Mixed Integer Non-linear Programing (MINLP) optimisation.

- **Linear optimisation model**

Linear programming (also known as linear optimisation) (LP) is used to formulate and solve mathematical models represented by linear equality or inequality constraints and linear objective functions [55].

The standard form of the problem is presented below:

$$Min\ C^T x \tag{2.4}$$

$$Subject\ to\ \ Ax \leq b \tag{2.5}$$

$$x \geq 0 \tag{2.6}$$

where C^T is transpose matrix of a known coefficient, x is a non-negative vector, A is a known matrix of coefficients and b is a known coefficient. The goal of this LP problem is to minimize the objective function.

Linear optimisation models have been implemented for wide range of gas network studies. In [56], a gas network model was developed using the linear optimisation. The model considered demands, supply capacities at different entry nodes, mass balance at each node and the flow capacities of the pipelines. However, the pipeline pressures were not considered. The model was used to optimise natural gas dispatch within the network. The study in [57] presented an LP model to minimise the gas supply cost including production cost, pipeline transportation cost, LNG regasification cost and storage operation cost in the gas network. Similarly, in [58] a linear optimisation model was used to project future gas supply to Europe by 2030, in order to minimise the total investment and operating cost of gas production and supply of the network.

- **Non-linear optimisation in gas networks**

The non-linear programming optimisation problem is formulated as a set of non- linear constraints and/or a non-linear objective function. Examples of the application of non-linear optimisation to gas network gas problems include fuel cost minimisation, minimum operational cost in gas networks and optimal dimension of gas pipelines.
An example of a non-linear optimisation problem is given by:

$$Min\ C^T x \qquad 2.7$$

$$Subject\ to\ \ Ax^2 \ \leq b \qquad 2.8$$

$$x \geq 0 \qquad 2.9$$

where C^T, A , b are parameters and x is the decision variable. The objective function is presented in Equation 2.7. The non-linear constraint is given by Equation 2.8 and the Equation 2.9 shows the non-negative constraint on the decision variable.

Several algorithms have been developed to solve different types of non-linear optimisation problems in gas networks. Some examples include linearization approach [59], dynamic programming[60], and heuristic methods [61].

The work done in [62] involved the formulation of a gas transmission network model to minimise total supply cost subject to linear and non-linear constraints. A piece-wise linear approximation approach was used to handle the non-linearity of gas flow equation and a simplex algorithm extension was applied to solve the relaxed model. In [63] a non-linear gas network model was presented to minimise the total fuel cost of the compressor stations in the network. The non-linearity of gas flow through pipes, pressure limits at each node and compressor stations were modelled as a set of non-linear constraints. A lower bound scheme was used to relax the non-linear cost function and obtain an optimal solution.

A dynamic programming algorithm was proposed by [64] for minimising the cost of fuel consumption in compressors stations within the gas network subject to non-linear flow-pressure constraints. The model included a representation of bi-directional gas flows in pipelines, operation of compressor stations and gas stored in pipelines (linepack). The solution method was shown to achieve global optimality when applied to cyclic gas network configuration. The study in [61] presented a heuristic method to minimise fuel costs in a gas transmission network. A two-stage iterative solution approach was applied to a non-linear optimisation model. In the first stage, the flow variable was fixed while the pressure variable was optimised by dynamic programming. In the second stage, the pressure variable is fixed while the optimal flow variable is calculated.

- **Other optimisation models**

Mixed integer linear programming and mixed integer non-linear programming models are also regarded as variants of linear and non-linear programming models. The key feature that differentiates the MILP and MINLP models from other models is that discrete variables (0,1) are included in the model formulation.

In relevant literature, a mixed integer non-linear gas network model was formulated to minimise the cost of fuel consumed by compressors [65]. A piece-wise linear algorithm was used to linearize the non-linear constraints and solve the model. In [66] a MILP model was presented to optimise the scheduling of a set of compressors and minimise the total operating cost of the gas network. The components of the total operating cost include the fuel cost, maintenance cost, start-up and shut-down costs of the compressors.

Majority of the models discussed in this section have focussed on the operation and planning of specific components of gas transmission systems such as the pipeline network and compressor stations. However, an extensive analysis of the operation of gas transmission system is essential when addressing security of supply challenges in gas networks. In addition to the pipeline system, the production sources, storage facilities and different types of demand requirement should be taken into consideration.

2.3.4 Modelling Security of Gas Supply

Several studies have applied optimisation models to analyse the security of gas supply in national and regional gas networks. This is due to the fact that optimisation models take account of the interaction between different components of the gas network [67]. Hence such models have the capability to provide further understanding of the impact of supply risks on various components of the gas network over multiple time scales (long-term or short term) [68]. Finally, these optimisation models can be used to assess the security of supply benefits derived from additional investments in gas infrastructure projects in any given national or regional gas network [69].

A couple of optimisation models have been developed to examine the impact of different scenarios of gas supply disruptions on security of supply at regional or national levels [70],[71], [72], [73]. All these models are privately owned and not available as open-source modelling tools. Thus, the European Gas Network model was developed to conduct studies related to security of gas supply in Europe.

The Gas Emergency Flow (GEMFLOW) model designed in [72] is based on a Monte Carlo probabilistic approach. The model depicts European countries as nodes interlinked by the aggregated capacities of cross-border pipelines between adjacent countries. The model has the capability to simulate several scenarios of a given supply disruption within Europe and also quantify the risk of the supply disruption to all European countries. The Monte-Carlo approach prevents unserved gas demand in EU countries by allowing the system to randomly match gas demand and supply based on a set of predefined rules. However, the optimal strategy for gas dispatch within Europe is not based on the cost of system parameters. Hence the system operation cost is not considered.

In [73], a decentralised model of congestion control was proposed for the European gas system in the event of an emergency crisis. The model includes a fair distribution strategy that allows maximum gas flow through the available network capacity during a gas supply crisis in order to minimise unserved gas demand. However, the operation of gas storage facilities was not modelled or considered in this model.

A linear optimisation model of the European gas market was developed in [71]. The objective function of the model maximises the social welfare to gas consumers across Europe, subject to the capacity of the transport infrastructure. The model comprised a simplified representation of gas infrastructure facilities in Western and Central Europe as well as pipeline and LNG supply from imported sources. The model was used to identify gas transport constraints and analyse the impact of investment in gas transport facilities on the future development of the European gas market. However, gas dispatch within South East Europe was not considered in the model.

The TIGER gas model was developed as a linear optimization model of gas supply across the European gas market [70]. The model presented a detailed representation of the European gas supply system including individual characteristics of storage facilities, LNG terminals, domestic production fields and demand locations. The objective function of the model minimises the total cost of gas supply required to meet demand constrained by the capacities of pipelines, storage facilities, LNG terminals and production volume. However, the non-linear relationship between gas flow and pressures were not taken into account. The model was applied to assess the impact of gas supply interruptions on the operation of the European gas market [41],[70].

The European gas network (EGN) model presented in Chapter 3 of the thesis was also formulated using the linear optimisation modelling approach similar to the TIGER model [70] but the main differences are:

- The network linear optimisation was applied to the EGN due to its computational advantages. Network linear optimisation models is a special type of linear optimisation model that solves very large network problems very quickly.
- In the EGN model, the non-linear relationship between gas storage and gas withdrawal rate was formulated using piece-wise linearization approximation (see Appendix C). This formulation provides a more realistic profile of gas storage operation.

Other models investigated the adequacy of future gas network investments required to ensure security of supply, based on a range of future demand scenarios. However, these models include a simple representation of European gas network components and demand centres. Large gas consumer countries in Europe are represented individually, while smaller European countries are aggregated into regional gas demand centres. Gas flow on interconnectors due to gas disruption or demand fluctuation over short-time scales (daily) is not fully captured in these studies because of their yearly time granularity. Examples of European gas network planning models developed in literature include The Gas market System for Trade Analysis in a Liberalising Europe (GASTALE) [74] and GASMOD [75].

GASTALE is a game theory equilibrium model developed in [76]. The model depicts a simple representation of the European natural gas system including individual LNG and pipeline exporters to Europe. The GASTALE model has a temporal investment period of 5 years and includes gas market agents such as consumers, producers, transmission system operators, storage operators and traders. The model has been applied to evaluate security of gas supply and the value of future gas infrastructure investment in Europe [77].

A similar modelling approach is used in GASMOD formulation but in this case it includes a two-stage game of natural gas export to Europe (upstream suppliers) and wholesale gas trade within Europe (downstream traders) [75]. The model was applied to examine the impact of different scenarios of gas demand and supply on security of gas supply in Europe.

2.4 Interdependence of Gas and Electricity Systems

Traditionally natural gas systems and electrical power systems are operated separately by the respective system operators. The use of gas-fired generators in the power generation, links the natural gas and electricity systems. The share of gas used in global power generation increased from 1752 TWh (14%) in 1990 to 4827 TWh (23%) in 2010 [78],[79].

The rapid growth of gas-fired generators in the power sector is driven by economic and environmental reasons [80]. Gas-fired generators (e.g. combined cycle gas turbine) are cost effective to build, and can be operated at high efficiency [81]. During operation, gas-fired generators produce less carbon dioxide per unit of energy than coal and oil generators [81].

The integration of significant capacity of renewable electricity generation such as wind and solar to the power system is expected to contribute to the delivery of environmental and climate change targets in several countries in Europe towards 2030 [82]. Gas-fired generators have the capability to ramp up and down to balance the variable power generated from renewable generation.

The increasing interaction between gas and electricity systems have attracted the attention of energy regulators and system operators to assess the impact of interdependence of both systems on the reliability of power supply and security of gas supply.

2.4.1 Similarities and Differences between Natural Gas Supply Systems and Electricity Power Systems

Natural gas supply systems and electric power systems are important energy infrastructure. Both systems have transmission and distribution networks which are used to transport energy (gas or electricity) from production sources to the different categories of final consumers [83]. Natural gas is obtained from gas production wells while electricity is produced by different types of generation technologies such as wind generators, coal-fired power plants, gas-fired plants and hydro power plants [83]. In the gas system, the transmission and distribution networks are characterised by different pressure levels while the electricity transmission and distribution networks operate at different voltage levels [84].

Although the gas and electricity systems include similar transport networks, both systems are operated differently based on their unique technical and physical characteristics. Electricity travels at the speed of light while gas flows through pipelines at 40- 60 km/h [85]. In electric power system operation power demand and supply is balanced on a second by second basis. On the other hand, the gas system can be balanced over a range of time scales (hourly / daily) due to the availability of gas stored in pipelines (linepack) or underground facilities.

2.4.2 Technical Challenges of Integrated Gas and Electricity Systems

The growing interdependence between natural gas and electricity systems presents new challenges with regards to the operation and planning of the integrated system.

In a power system with a high penetration of gas-fired generators, the disruption of gas supply or the loss of a major gas network component (e.g. pipeline) may curtail the delivery of gas to gas-fired generators and consequently constrained power supply. Also, the regulatory arrangement for gas supply to priority consumers during a major supply disruption may lead to a forced interruption of gas supply to gas-fired generators and additional power supply outages.

At periods of severe weather conditions and limited gas supply, a coinciding peak in gas and electricity demand may lead to a sudden spike in gas and electricity prices. As Europe’s reliance on imported gas supply increase, the closer integration of gas and electricity systems in Europe could expose the power system to gas supply shocks and volatile gas prices [84].

The increase in the variability of gas demand for power generation poses a major challenge of managing the gas network within acceptable pressure limits [86]. Consequently, gas compressors are frequently used to manage linepack and system pressure leading to an increase in operational cost in the gas network.

Limited harmonisation in the long-term planning of gas and electricity networks is another challenge related to interdependence of both networks. For example, planned investment in cross-border electricity transmission capacity, electricity storage and demand response mechanism is expected to optimally manage variability and uncertainty of geographically dispersed renewable power generation across Europe [87]. The uncertainty surrounding the future gas use for power generation presents a barrier to investment in strategic projects identified to improve security of gas supply in the short-term. This is because some of the strategic projects investments may become stranded assets in the long-term [9].

However, a coordinated approach to infrastructure investment in both networks will ensure optimal utilisation of gas and electricity systems to provide the flexibility requirement of variable renewable power generation.

2.4.3 Model-Based Analysis of Integrated Gas and Electricity Systems

Recent research studies have focused on the development new integrated gas and electricity models to analyse the interactions between gas and electricity networks. Most studies have focused on short-term analysis of integrated gas and electricity system.

In [88], an optimal power flow model was combined with gas network constraints to create an integrated gas and electricity network model. The model was used to analyse the impact of gas pipeline outage on the operation of the power system. The result showed the gas pipeline outage led to the loss of gas-fired generation and electric load shedding in the power system. In [89], gas network constraints were coupled with a security constrained unit commitment (SCUC) power system model. The integrated model was to assess the effect of dual fuel generators on power system security during a gas infrastructure outage. The results showed that the fuel switching capacity of dual fuel generators could increase power system security. An integrated gas and electricity model was developed to examine the impact of wind forecast errors on the gas network [90]. The results of the study showed that increasing uncertainty of flexible gas demand raised the cost of gas system balancing. All the studies reviewed above have applied integrated gas and electricity network models to test or fictitious systems.

Only a few integrated gas and electricity optimisation models have been developed to analyse real gas and electricity systems. A detailed representation of the GB gas and electricity transmission system is presented in [67]. The combined gas and electricity network model (CGEN) is a multi-period non-linear optimisation model. The model was used to investigate the effect of multiple gas infrastructure outages on the operation of an integrated GB gas and electricity network. It was shown that gas infrastructure failures resulted in unserved gas demand to the gas network and a significant reduction in gas-fired generation output generation.

In another study [86], the CGEN model was used to examine the effect of wind power generation on GB gas network. It was shown that when low wind generation coincides with high gas demand a rapid depletion of line pack could result in gas system pressure constraint. The rapid variation in gas demand for power generation increases gas compressor usage and leads to high operational cost. In Chapter 4 of this thesis, the CGEN model was enhanced by including of cross-border gas interconnectors between GB and neighbouring European Countries.

Some studies have examined the long-term planning of integrated gas and electricity network. In [91], the CGEN model was used to examine the impact of strategic investment in the gas network on enhancing security of energy supply in the integrated gas and electricity network. The model presented a combined optimisation of investment and operational decisions for the gas and electricity networks. In another study, the CGEN model was used to investigate the additional gas and electricity infrastructure required to deliver a low carbon energy system by 2030 [92]. It was shown that coordinated planning of gas and electricity network enabled timely and efficient allocation of infrastructure capacity expansion in the development of optimal energy networks.

A complementarity model was developed to investigate the potential substitution effect of long-term investment in a coupled European gas and electricity market [93]. The results showed that a coordinated planning approach would deliver optimal infrastructure investments in an integrated gas and electricity system [94]. In [95], a combined gas market model (GASTALE) and an electricity market model (MTSIM) was used to assess cross-border infrastructure requirement (2030-2050) in Europe’s gas and electricity markets. The results showed that large scale deployment of renewable power generation combined with high energy efficiency measures resulted in significant reduction in the use of natural gas transmission capacity by 2050.

2.4.4 Synergies between Gas and Electricity Systems

The integration of gas and electricity systems has significant opportunity to deliver security of supply, environmental benefits and optimal infrastructure investments in both systems. Some measures identified to enhance efficient coordination between gas and electricity systems include harmonisation of system balancing in both system across different time scales, development of flexible gas supply products and a combined approach to renewable energy development [80],[84].

Power system operation requires real time (moment-by-moment) balancing of demand and generation. In the gas network, balancing is usually performed on a daily basis. The availability of within-day linepack flexibility services can contribute to the harmonisation of system balancing in the gas and electricity networks. Such arrangements will increase the efficient utilisation of the network capacity, improve reliability of the power system, reduce high cost of cumulative gas imbalance penalties incurred by shipper and lower gas prices to gas-fired generators [96].

Access to gas storage can increase flexible gas supply to gas-fired generators and improve security of gas supply [81]. Gas storage facilities is used extensively for various applications including balancing short–term and seasonal demand variations depending on the storage characteristics [24]. The efficient management fast cycle storage facilities can improve reliability of within-day balancing in both gas and electricity systems.

Coordinated network planning of both markets promotes the exploitation of not just renewable power generation but renewable gas production and transport using the existing gas network. Renewable gas refers to gas produced from renewable energy sources such as biomethane derived from biogas obtained from organic waste and hydrogen. Power-to-gas systems convert electricity to hydrogen through the process of electrolysis. Regional and national gas transmission pipeline networks could provide storage capacity for biomethane and hydrogen produced from renewable power generation. In Europe, renewable gas development and supply could contribute to less reliance on imported gas supply, additional flexibility for variable renewable power generation and lower carbon dioxide emissions [97].

2.5 Summary

A review of literature related to security of gas supply in Europe, gas network models and the integrated gas and electricity system was presented.

Security of gas supply was defined and issues surrounding security of gas supply in Europe were highlighted. A number of alternative measures planned to enhance security of European gas supply were presented.

Gas network models were presented with a specific focus on optimisation models. Different types of optimisation models used in modelling gas network were discussed and relevant literature on the analysis of security of gas supply using gas network optimisation models was reviewed.

Interdependence of gas and electricity systems were presented. Challenges and opportunities for exploiting integrated gas and electricity system were discussed and existing models of integrated gas and electricity system in literature were reviewed.

In closely coupled gas and electricity networks, security of gas supply has serious implications for a secure and reliable power system. Integrated models of gas and electricity systems are best suited to provide a better understanding of security of gas and electricity supply under various operating conditions.

Chapter 3

Vulnerability Assessment of the European Natural Gas Supply

3.1 Introduction

The primary function of the European gas network is to ensure efficient dispatch of gas supply across Europe. The disruption of gas supplies along major transit routes has highlighted the limited capability of the gas network to adequately respond to such a gas supply crisis.

In January 2009, the disruption of Russian gas supply to Europe through Ukraine resulted in the loss of between 10% – 100% of imported gas supply to 12 European countries [98]. Some of the limitations that this event highlighted include dependency of some member states on a single source of supply/route, the lack of bi-directional flow in some interconnectors between countries and limited gas storage capacities in some of the affected member states.

A simplified model of the European gas network was developed to model gas flows in Europe using linear optimisation. The European gas network model was formulated and solved using the FICO Xpress optimisation suite.

The European gas network model was used to analyse the impact of a loss of the Ukraine transit capacity on gas supply from Russia to Europe in the winter of 2014/2015. Two demand scenarios were modelled; A Reference Demand Case and a High Demand Case. To mitigate the impact of the supply shortage, the impact of increasing the capacities of selected interconnectors within Europe was compared against increasing the maximum storage withdrawal rates in South East Europe.

3.2 Simplification of the European Gas Network

The European gas network consists of 128 underground storage facilities, 68 LNG regasification terminals connected by a complex and an extensive pipeline structure. The implementation of a detailed model of such large networks has a significant computational cost. Furthermore, the transmission pipeline data (such as pipe lengths and diameters) for all European countries represented in the model required to conduct a detailed study was inaccessible. Since the focus of this model is to analyse cross-border flows on gas interconnectors between adjacent European countries and the utilisation of available gas infrastructure, the capacities of transmission pipelines was deemed adequate to represent gas dispatch within Europe. The European gas network (EGN) was simplified to reduce network complexities and simulation time in order to provide a suitable representation of the network for modelling purposes.

The following assumptions were applied to simply the European gas network:

- Only gas flow capacities on cross-border interconnectors between European countries were considered. The capacity of the pipeline network within individual countries was neglected.
- Units of gas capacity are presented as million cubic metres at standard conditions of temperature 15ºC and pressure 101.325 kPa [22].

3.2.1 Network Parameters

The simplified European gas network consists of 40 nodes and 63 interconnectors that comprise the Ukraine transit capacity shown in Figure 3.1. A list of the country codes is presented in Appendix A.

The model assigns a node to each country and each node has a set of nodal parameters. For each European country, the nodal parameters include the total production capacity, the total storage capacity and the total LNG capacity if applicable. The nodal parameters for non-European gas exporting countries are limited to their total export capacities to Europe.

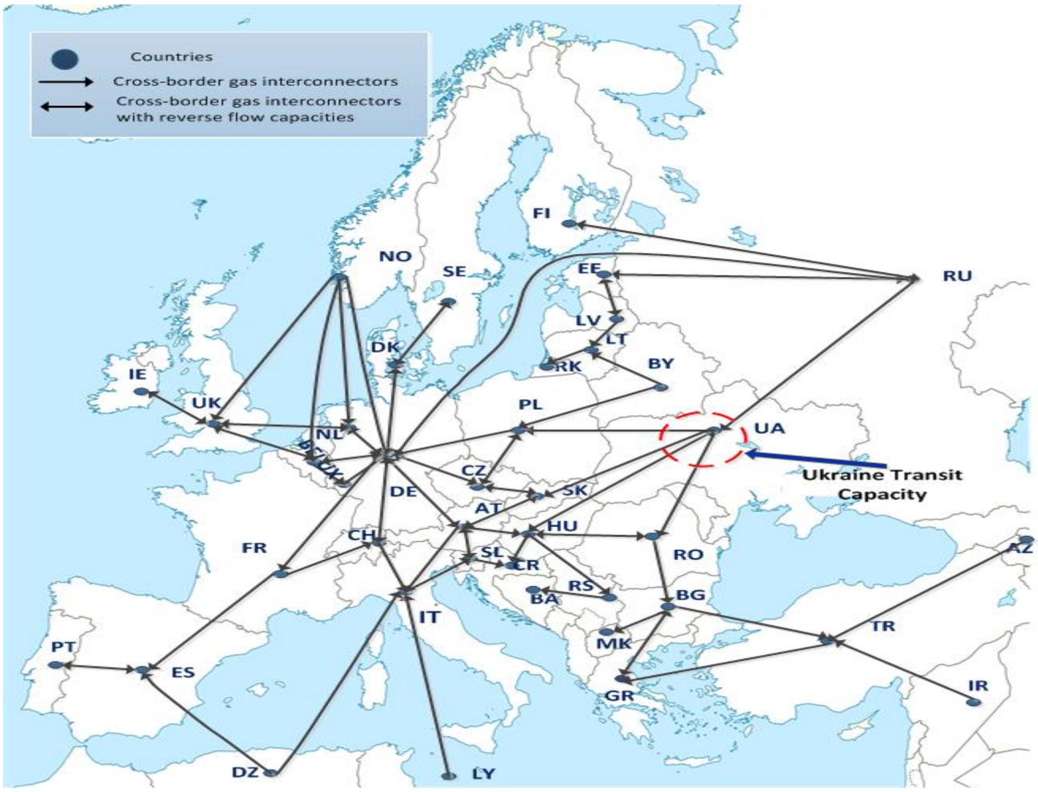

Figure 3.1 Simplified European gas network

Cross-border gas pipelines are characterised by different pipe lengths and flow capacities. A single pipeline or several pipelines can connect two neighbouring countries based on their domestic network configuration. Multiple cross border pipelines capacities between countries are totalled to represent a single pipeline capacity using Equation 3.1.

$$Q_{eq} = \sum_{i=1}^{n} Q_i \tag{3.1}$$

where Q_{eq} is the equivalent flow capacity in the single equivalent pipeline and Q_i are original individual pipeline capacities.

3.3 Formulation of the European Gas Network Model

The European gas network (EGN) model is formulated using the commercial optimisation tool FICO Xpress optimisation suite [99]. Fico Xpress is a mathematical modelling tool for large-scale modelling and optimisation applications. The tool provides a variety of robust optimisation solvers for linear programming, mixed linear and non-linear problems.

The EGN model is developed as a linear programming optimisation model to examine optimal operation of the gas network. The linear optimisation approach assumes efficient dispatch of natural gas along all supply routes across Europe, neglecting the inefficiencies due to market operation or contractual arrangements. A single Europe wide transmission system operator was assumed to manage the efficient gas demand and supply balance within the European gas network model.

Figure 3.2 shows a graphical representation of the simplified European gas network model. The key inputs to the model are the demand, supply capacities (domestic production and imported gas), the capacities of gas infrastructure (interconnectors, LNG regasification terminal and storage facilities) and the cost parameters (supply/production, transportation and, where relevant, LNG import cost and storage costs). The model is suitable for calculating the quantity of demand-supply shortfalls at different nodes in the network over a given modelling horizon with a daily to weekly time step.

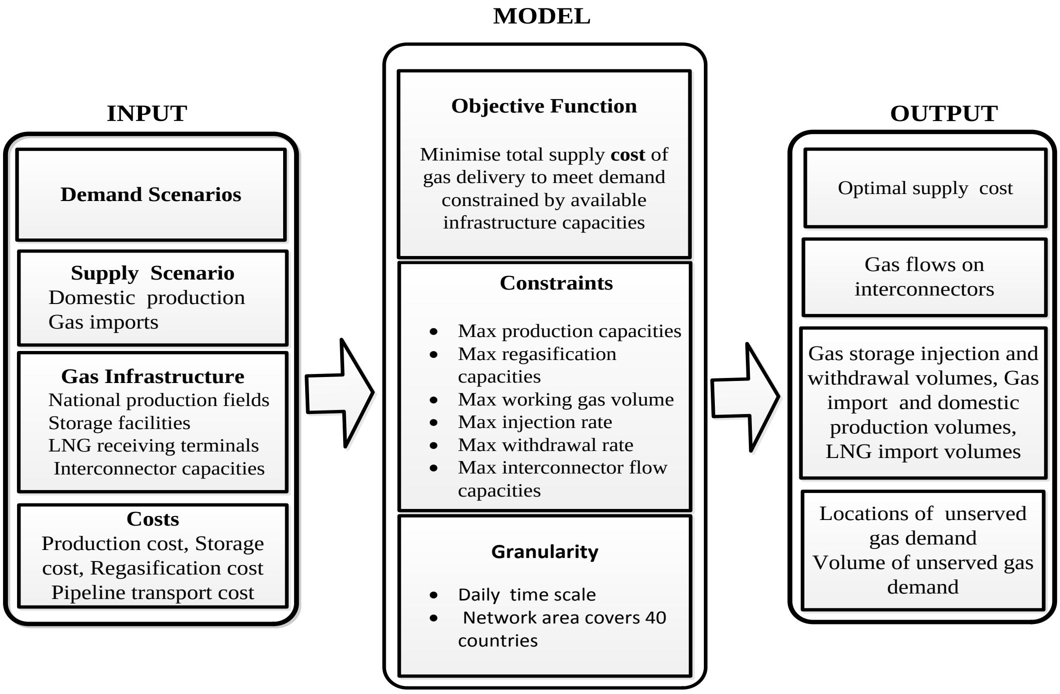

Figure 3.2 Flow diagram of the European gas network model

3.3.1 Objective Function

The objective function of the model minimises the total cost of the supply of natural gas supply to meet demand over the time horizon as expressed in Equation 3.2. The total supply cost includes costs of gas supplies (from domestic production and pipeline imports), gas transport, storage operation, LNG import and unserved gas demand.

Minimise total supply cost =

$$\sum_t \left\{ \underbrace{\sum_i PRC_{i,t}\, PR_{i,t}}_{prod\ /pipeline\ import} + \underbrace{\sum_i \left(IC_{i,t}\, S^{in}_{i,t} + WC_{i,t} S^{wd}_{i,t}\right)}_{storage\ operation} + \underbrace{\sum_j TC_{i,j}\, TQ_{i,j,t}}_{Gas\ flows} + \underbrace{\sum_i LC_{i,t}\, L_{i,t}}_{LNG\ import} + \underbrace{\sum_i DZC_i\, DZ_{i,t}}_{unserved\ gas\ demand} \right\} \quad 3.2$$

where:

$PRC_{i,t}$ Cost of gas production/cost of gas imported at node *i* at time *t* (€/mcm)

$PR_{i,t}$	Production/ supply volume at node *i* at and time *t* (mcm/d)
$IC_{i,t}$	Cost of gas injected into storage at node *i* and time *t* (€/mcm)
$S_{i,t}^{in}$	Gas volumes injected into a storage at node *i* at time *t* (mcm/d)
$WC_{i,t}$	Cost of storage withdrawals at node *i* (€/mcm)
$S_{i,t}^{wd}$	Storage withdrawals at node *i* and time *t* (mcm/d)
$TC_{i,j,t}$	Cost of gas transportation in a cross-border interconnector between node *i* and *j* at time *t* (€/mcm)
$TQ_{i,j,t}$	Gas flows on interconnector between nodes *i* and node *j* at time *t* (mcm/d)
$LC_{i,t}$	Cost of LNG delivered (cost of gas and transport) to node *i* at time *t* (€/mcm)
$L_{i,t}$	LNG volumes delivered at node *i* and time t (mcm/d)
DZC_i	Cost of unserved demand at node *i* (€/mcm)
$DZ_{i,t}$	Unserved gas demand at node *i* at time *t* (mcm/d)

3.3.2 Optimisation Constraints

The constraints of the optimisation are the technical limitations and characteristics of production, transport storage and LNG facilities.

- **Production**

For nodes that possess production capacity, the production volume is restricted by the maximum daily supply capacity:

$$PR_{i,t} \leq PR_i^{max} \quad \forall i,t \qquad 3.3$$

where PR_i^{max} is the maximum supply capacity at node *i* (mcm/d)

- **LNG Import**

Similar to the production constraints, at every node and for each time step, the LNG regasification volume is restricted by the maximum daily regasification.

$$L_{i,t} \leq L_i^{max} \quad \forall i, t \tag{3.4}$$

where L_i^{max} is the maximum regasification capacity at node *i* (mcm/d).

- **Transport pipeline flow**

Gas flow through interconnectors is restricted by the maximum capacities $TQ_{i,j}^{max}$ of the interconnectors given by:

$$TQ_{i,j,t} \leq TQ_{i,j}^{max} \quad \forall i, j, t \tag{3.5}$$

Each interconnector is linked by a pair of nodes (*i*,*j*). Gas flow in either direction is permitted if flow capacity exists between *i* and *j* and between *j* and *i*.

- **Storage**

Storage operation is determined by the characteristics of the storage facility which include working gas volume (WGV), gas withdrawal rates and gas injection rates. Working gas volume is the volume of gas that can be withdrawn from storage. For every time step the storage level is constrained by the maximum storage capacity (WGV):

$$S_{i,t} \leq \ S_i^{max} \ \forall i, t \tag{3.6}$$

where S_i^{max} is the maximum working gas capacity at node *i* (mcm), $S_{i,t}$ is current storage level at node *s* and time *t* (mcm/d).

Also, the gas volume in storage for each time step must be balanced by the difference in gas injection in a day and withdrawal in a day:

$$S_{i,t} = S_{i,t-1} + S_{i,t}^{inj} - S_{i,t}^{wd} \quad \forall i, t \tag{3.7}$$

Gas withdrawal rate is also restricted by the maximum withdrawal rate:

$$S_{i,t}^{wd} \leq \ S_{i,t}^{wd\_max} \quad \forall i, t \tag{3.8}$$

where $S_{i,t}^{wd\_max}$ is the maximum withdrawal rate at node *i* (mcm/d).

Gas injection rate is limited by the maximum injection rate:

$$S_{i,t}^{in} \leq S_{i,t}^{in\_max} \quad \forall i, t \tag{3.9}$$

where $S_{i,t}^{in\_max}$ is the maximum injection rate at facility *s* at time *t* (mcm/d).

The volume of gas withdrawn from or injected into a storage facility varies with the current storage level. Withdrawal rates are highest when the storage is full while injection rate is highest when the storage facility is empty because of the pressure level in the storage. This non-linear relationship is expressed as [100]:

$$S_{i,t}^{wd\_mx} = K_1^{wd} * \sqrt{S_{i,t}} \quad \forall s, t \tag{3.10}$$

$$S_{i,t}^{in\_mx} = K_1^{in} * \sqrt{\frac{1}{S_{i,t}^{inj} + S_i^{base}} + K_2^{in}} \tag{3.11}$$

where K_1^{wd}, K_1^{in} and K_2^{in} are factors that describe the features of the storage facility, S_i^{base} is the volume of cushion gas at node *i* (mcm). However linear approximations were derived for the non-linear storage constraints and presented in Appendix B.

3.4.3 Nodal Balance

At each node in the network, gas demand must be balanced by gas supply (Equation 3.12). For each time step gas inflows at each node (gas supply, storage withdrawal) are balanced by gas outflows (gas demand, storage injection).

$$D_{i,t} - DZ_{i,t} = \sum_{i,j} TQ_{i,j,t} + PR_{i,t} + L_{i,t} + S_{i,t}^{wit} - S_{i,t}^{in} \tag{3.12}$$

3.4 Model Demonstration

The European gas network model was validated by comparing the cross-border flows calculated by the model for 2010 with data of the aggregated gas flow across Europe for the 2010 gas year. The results of the comparison between simulations and actual data are presented in Table 3.1.

Table 3.1 Comparison of gas flows and LNG import simulation result to actual data for 2010.

From Country	To Country	Actual (bcm)	Simulated (bcm)
LNG Import	Belgium	6.4	4.5
Netherland	Belgium	19.7	21.3
Norway	Belgium	7.0	14.6
United Kingdom	Belgium	8.8	3.5
Czech Republic	Germany	17	21.8
Norway	Germany	32.2	27.0
Poland	Germany	33	22
Belgium	France	13.5	16.0
LNG Import	France	14	10
Norway	France	19.1	18.5
Austria	Italy	18.5	20.0
LNG Import	Italy	12.6	11.0
Norway	Netherland	12.9	9.2
Algeria	Spain	9.1	9.0
LNG Import	Spain	27.8	28.7
Netherland	United Kingdom	8.2	4.5
Norway	United Kingdom	25.0	30.0
LNG	United Kingdom	18.6	14.1

The results of the simulation matched the real data except for a few cases. The reason for the lack of agreement is believed to be that the long-term contracts between gas producers and destination countries are not taken into account in the simulation as the supply terms and prices of long-term contracts are in most cases not publicly available.

3.5 Description of the Case Studies

The case studies were based on the gas demand for winter 2014 and two demand cases were defined as Reference Demand Case and High Demand Case as shown in Figure 3.3 [13]. The simulation has a daily time step and was run over 182 days from October 2014 to March 2015.

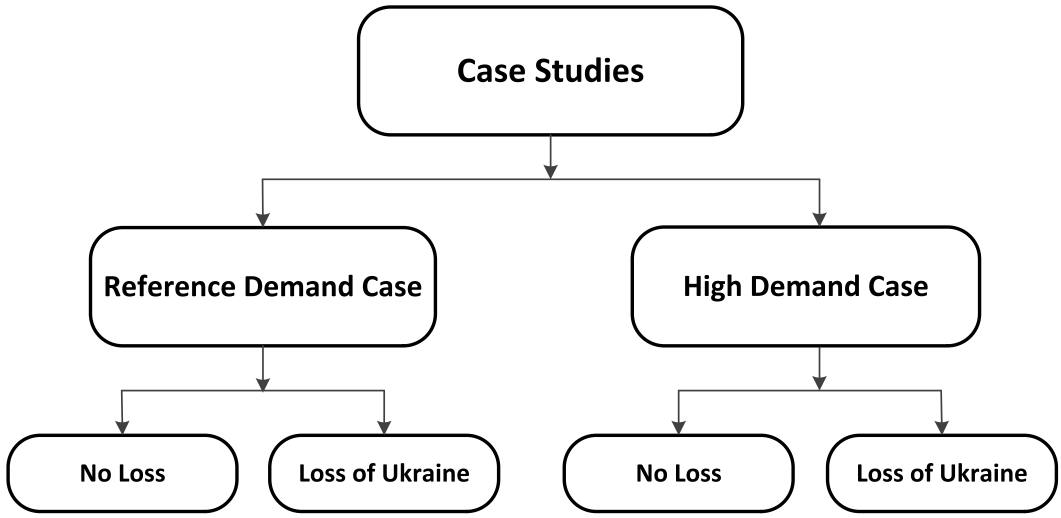

Figure 3.3 Structure of the case studies

3.5.1 Demand Assumptions

- **Reference Demand Case**

The Reference Demand Case represents a low winter gas demand situation in 2014. Daily demand was derived as average daily consumption calculated from historical monthly demand consumption for all European countries [101]. The daily demand was calculated by dividing the number of days in each month by the monthly gas consumption. For example, the daily demand data of Netherlands and Spain is shown in Figure 3.4. The demand data for all European countries are presented in Appendix C.

- **High Demand Case**

The High Demand Case assumed a 20% increase in the gas demand of the Reference Case to reflect a cold winter condition across all European countries.

- **Peak Day Demand**

A peak day demand was applied to the Reference Demand Case and High Demand Case. The 1 in 20 peak day demand is the highest demand for gas in a day which occurs once out of 20 winters [102]. This gas standard is used to test the resilience of the system to an extreme stress condition. It was assumed that peak demand occurred on the same day in all the European countries.

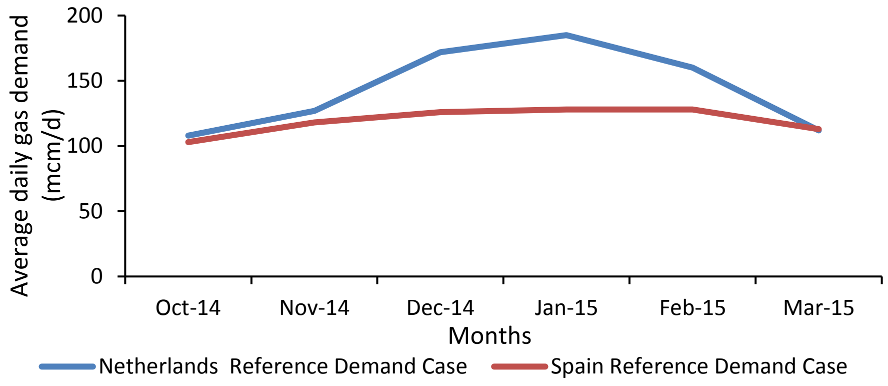

Figure 3.4 Average daily demand profile of Netherlands and Spain for 2014 winter

3.5.2 Gas Supply Assumptions

Supply data was obtained from the ten-year network development plan [13] (see Appendix B). The delivery of imported pipeline supplies was determined from historical supply volume to Europe and the suppliers' production capacity. Based on historical winter supply, average gas supply from pipeline import sources and LNG import was increased by 10% to obtain the maximum available supply [38].

Table 3.2 European winter gas supply for 2014 – Major gas supply sources

Supply source	**Maximum supply (mcm/d)**
Russia	500
Norway	330
Algeria	111
Libya	30
Aggregated national production in the EU	725
Total LNG import to Europe	355

3.5.3 Cost Assumption

The costs of domestic production in the Europe, LNG supplies and imported pipeline gas to Europe are presented in Appendix B.

3.5.4 Supply Disruption Assumption

The loss of all transmission capacities to Europe routed through Ukraine was examined in the **Reference Demand Case** and **High Demand Case** for 30 days from mid-January to mid-February (see Figure 3.3). The 30-day period included the **peak day demand**. The duration of the supply disruption was selected to determine whether the EU security of supply standard for domestic gas consumers is attained over the coldest 30 days of winter across Europe (see 2.2.4).

3.5.5 Mitigation Measures

Two different mitigation measures were applied to each of the demand cases.

- Additional interconnector capacities in Europe.

Transmission capacities of selected interconnectors were increased to allow greater gas flow from west to east Europe. This increase in capacity could be achieved by investment in additional compression stations or upgrading existing stations with additional compressor units. The flow capacity of the following interconnectors was adjusted [103] :

1. Flow capacity on the Hungary-Romania interconnector was increased from 4.09 mcm/d to 8.18 mcm/d.
2. Flow capacity on the Hungary-Serbia interconnector was increased from 11.2 mcm/d to 22.4 mcm/d.
3. Reverse flow capacity of 9.6 mcm/d was also allowed on the Greece-Bulgaria interconnector.
4. Flow capacity of the Russia-Germany interconnector was extended from 85 mcm/d to 150 mcm/d.

- Higher storage withdrawal rates in South East Europe

A 50% increase in maximum withdrawal rate was applied to Serbia, Romania and Bulgaria. These countries primarily rely on imported gas from Russia through the Ukraine transit capacity (see Figure 3.1). The increase in maximum withdrawal rate could be achieved by increasing the number of withdrawal wells in an existing storage facility. The cost of the well construction range between 15% - 33% of the total capital cost of a new storage facility [23].

3.6 Simulation Results of Case Studies without the Loss of Ukraine Transit Capacity

The results are presented as average day gas volumes over the 182 days of winter 2014/2015 (including the peak day).

3.6.1 Domestic Production and Import Gas Volumes to Europe

Figure 3.5 shows the comparison of gas supply volumes from domestic production and import sources without the loss of the Ukraine transit capacity. Domestic gas production accounted for 30% of total supplies in the Reference Demand Case and 28% of total supplies in the High Demand Case. The average gas supplied from Russia was 500 mcm/d, accounting for 30% of total supplies in the Reference Demand Case and 27% of total supplies in High Demand Case. LNG volumes increased from 185 mcm/d in the Reference Demand Case to 335 mcm/d in the High Demand Case.

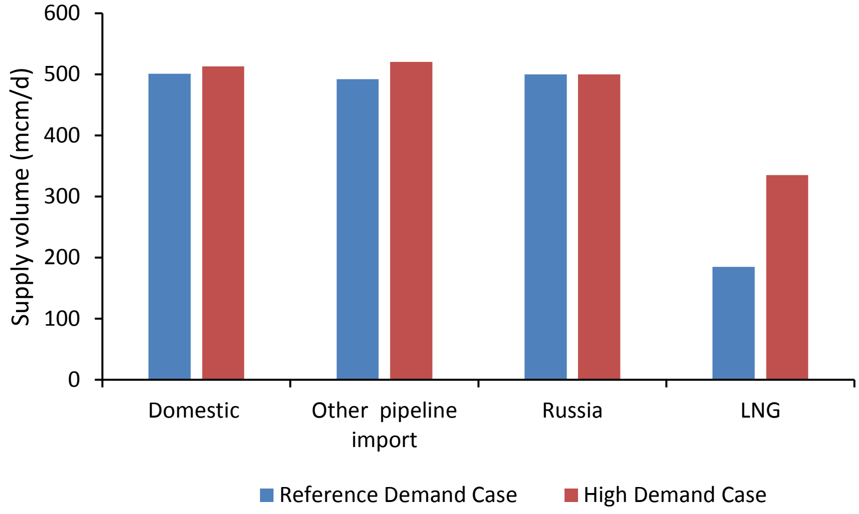

Figure 3.5 Average domestic production and gas import supplies to Europe - No Loss Case

3.6.2 Gas withdrawn from European Storage Facilities

Gas volumes withdrawn from storage facilities are presented in Figure 3.6. Gas storage facilities in Other Europe showed the largest gas withdrawals of 132 mcm/d in the Reference Demand Case and 224 mcm/d in the High Demand Case. Storage withdrawals in German increased from 95 mcm/d in the Reference Demand Case to 185 mcm/d in the High Demand Case. Central Europe storage withdrawals increased by 217% in the High Demand Case compared to the Reference Demand Case while gas withdrawals in South East Europe increased by 28% in the High Demand Case as against the Reference Demand Case.

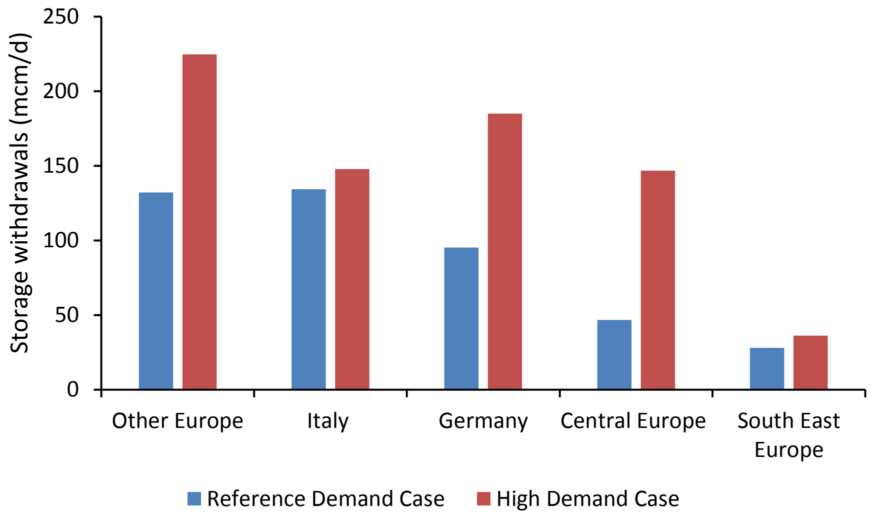

Figure 3.6 Average gas withdrawn from European storage facilities - No Loss Case

(South East includes Bulgaria, Croatia, Romania, Serbia and Turkey
Central Europe includes Austria, Czech Republic, Poland, Hungary and Slovakia
Other Europe comprises storage facilities in European countries excluding South East Europe, Germany and Italy)

3.7 Impact of the Loss of Ukraine Transit Capacity

The loss of the Ukraine transit capacity was then applied for a 30-day period. The results of the simulation with the supply disruption for the High Demand Case are presented as average gas volume over the 30-day period including the peak day.

3.7.1 Domestic Production and Imported Gas Volume to Europe

Figure 3.7 presents the domestic production and imported gas volume to Europe in the High Demand Case. The loss of Ukraine transit capacity resulted in a 52% decline in Russian gas volumes supplied to Europe in compared to the No Loss Case. To compensate for the lost gas volumes, Domestic production volume increased by 12 mcm/d relative to No Loss Case. In addition, LNG supplies increased by 7.7% in the in the Loss Case to replace some of the supply shortfall.

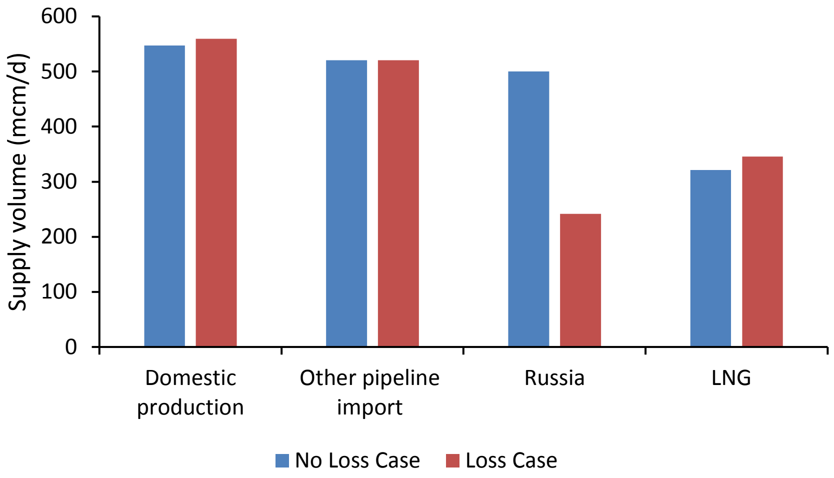

Figure 3.7 Domestic production and gas import to Europe - High Demand Case

3.7.2 Gas Withdrawn from European Storage Facilities

The storage withdrawn from European storage facilities in the High Demand Case is shown in Figure 3.8.

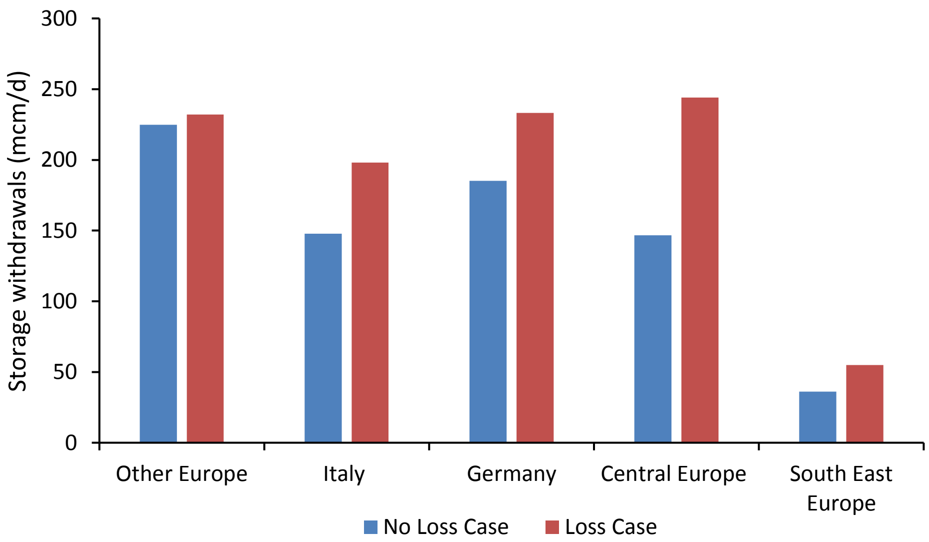

Figure 3.8 Gas withdrawn from storage - High Demand Case

Additional withdrawals from gas storage of 8 mcm/d in Other Europe, 51 mcm/d in Italy, and 48 mcm/d in Germany was used to replace some of the missing gas volumes in the Loss Case. Central Europe showed the largest increase in storage withdrawals of 92 mcm/d in the Loss Case compared to the No Loss Case. The reason for this is that many countries in Central Europe and South East Europe rely on the Russian gas supply through the Ukraine transit capacity. Storage withdrawals increased by only 18 mcm/d in South East Europe in the Loss Case due to the limited storage capacity in that region.

3.7.3 Unserved Gas Demand

Average daily unserved gas demand is calculated over the 30-day duration of the supply disruption. The average daily unserved gas demand in countries affected by the supply disruption in the High Demand Case is presented in Table 3.3.

Table 3.3 Average daily unserved gas demand - High Demand Case

Loss Case					
Country	**Macedonia**	**Bosnia**	**Bulgaria**	**Romania**	**Greece**
Unserved gas demand (mcm/d)	1.3	2.0	9.6	4.1	0.8
% of average daily demand curtailed	97.4	78.7	60.7	7.2	4.2

Unserved gas demand did not occur in any country in the No Loss Case. However, in the Loss Case unserved gas demand was noted in south eastern European countries that primarily depend on the Russian gas supply through the Ukraine transit route and have limited access to alternative supply sources or transport routes. In Bulgaria, Bosnia and Macedonia between 61% - 97% of average day gas demand was unmet in the High Demand Case. The supply disruption resulted in curtailment of heating demand (domestic & commercial sectors) in only Bosnia. However, a third of the gas-fired district heating plants have the capability to switch to fuel oil to supply domestic heating [104]. In 2013, heating demand accounted for less than 2% of total gas consumption in Bulgaria, 24% of total gas consumption in Bosnia and 2% of total gas consumption in Macedonia [105], [106], [107].

On the other hand, gas supply to industrial and power generation sector was completed curtailed in Bulgaria, Macedonia and Romania. In 2013, the industrial sector accounted for 70% of total gas consumption in Bulgaria, 70% of total gas consumption in Bosnia and 90% in total gas consumption in Macedonia [106],[107], [108]. In these countries, the industrial sector is dominated by steel and metal industries reliant on natural gas as fuel for their production process [109]. Hence, the missing gas supply have consequences of severe economic costs and losses. In 2013, the use of gas in power generation ranged between 0% - 2% in Bosnia, Macedonia and Bulgaria [110].

In Greece and Romania, less than 10% of average day gas demand was curtailed in the High Demand Case respectively. The availability of LNG supply to Greece provides an alternative to diversify gas supply from Russia through Ukraine. However, the existing LNG import capacity was not sufficient to avert the disruption of gas supply to some industrial consumers. In Romania, only gas use in power generation was affected by the supply shortfall.

3.8 Simulation Results of the Mitigation Strategies

Figure 3.9 presents gas flow on selected interconnectors and storage utilisation in the High Demand Case (Loss of Ukraine), Higher storage withdrawal rates and Additional interconnector capacities.

Russian gas supply through Germany increased by 44% with Additional interconnector capacities strategy compared to the High Demand Case (Loss of Ukraine). The expansion of the Russian - Germany interconnector allowed the diversion of Russian gas supply from Ukraine transit capacity. In addition, higher gas flow on cross-border interconnectors from Western Europe to South East Europe was noted as a result of additional capacities on selected interconnectors within South East Europe.

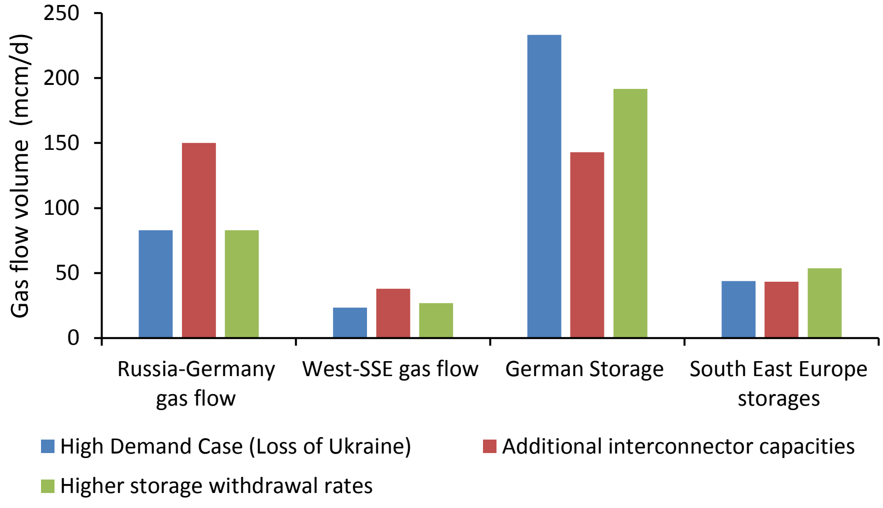

Figure 3.9 Gas flows on selected interconnectors and storage utilisation in the High Demand Case (Loss of Ukraine) and the different mitigating measures

Gas withdrawn from German storages deceased by 38% in the Additional interconnector capacities strategy and by 16% in the Higher storage withdrawal rates strategy compared to the High Demand Case (Loss of Ukraine). This showed that German gas storage withdrawals was also used to compensate for the supply shortage to South West Europe when the loss of Ukraine transit capacity occurred. However, with the implementation of the mitigation strategies, Germany storage volumes initially sent to South East Europe was substituted by higher gas flows on cross-border interconnectors and increased gas withdrawals from storage facilities within South East Europe.

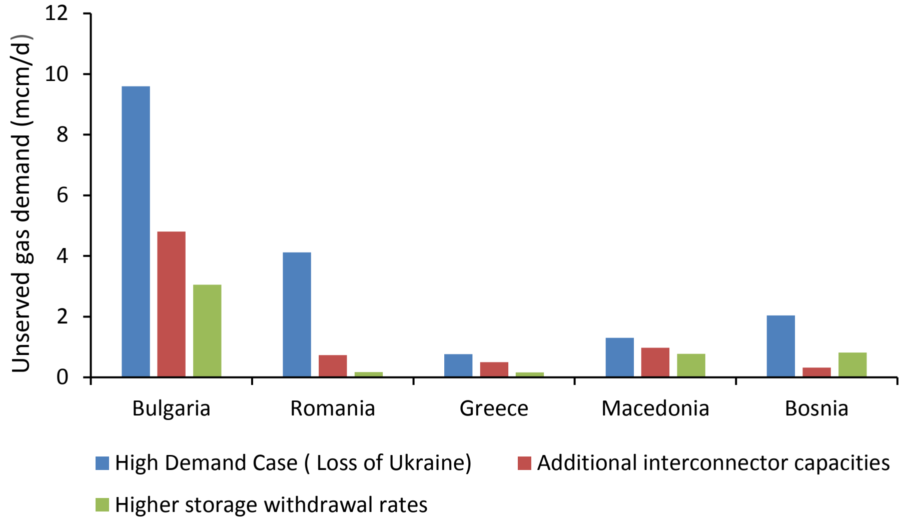

Figure 3.10 Unserved gas demand in the High Demand Case (Loss of Ukraine) and the different mitigating measures

In Figure 3.10, implementation of additional interconnector capacities resulted in the decreasing unserved gas demand decreased by 3mcm/d (50%) in Bulgaria, 3.4 mcm/d (82%) in Romania and 1.7 mcm/d (84%) in Bosnia compared to High Demand Case (Loss of Ukraine). On the other hand, higher storage withdrawal rates resulted in a 95% decline in unserved gas demand in Romania and a 78% decline in unserved gas demand in Greece compared to the High Demand Case (Loss of Ukraine).

3.9 Summary

A European gas network model was described. The model represented all gas interconnectors including routes to major import sources, LNG terminals and storage facilities in Europe. The model was used to investigate the impact of the loss of gas transit capacity through Ukraine on European gas supply for winter 2014/2015.

In the event of a 30-day loss of Ukraine transit capacity, the simulation results showed that a combination of LNG supplies and available stored gas will be used to compensate for the supply shortfall.

However, considerable unserved gas demand was evident in Macedonia, Bosnia, and Bulgaria in South East Europe. The results of the study showed that domestic gas supply in Bosnia was adversely affected in Bosnia due to the supply disruption. It was shown that showing that this region was reliant on the Ukraine transit route and had limited alternative supply routes.

The results of the study showed that additional capacities on selected gas interconnectors including reverse flow capacity on some gas interconnectors enabled Russian gas supply through Germany and Central Europe reach South East Europe in order to reduce the missing gas volumes. It was also shown that higher storage withdrawal rate in some countries in South East Europe reduced instances of unserved gas in the region.

Chapter 4

Integrating Models of the European Gas Network and Great Britain's Energy Networks

4.1 Introduction

In 2014, the UK imported 43 bcm of natural gas of which 58% came from Norway, 26% from LNG and 16% from continental Europe [31]. As domestic production declines, the UK will increasingly rely on imported gas to meet its future demand [111]. According to the 2015 National Grid Future Energy Scenarios (FES), future gas supplies to GB will depend on the demand and supply balance in Europe and developments in the global LNG market [31].

The European gas network model (EGN), which was presented in Chapter 3, was coupled to the GB combined gas and electricity network model (CGEN) and used to investigate the interdependencies between the European gas network and GB's gas and electricity networks. A soft-linking approach was employed to couple the EGN and CGEN models. The integrated (EGN – CGEN) model was applied to a set of scenarios to assess the impact of supply shocks in the European gas network on the operation of the GB gas and electricity networks.

The combined gas and electricity network model (CGEN), originally developed by Chaudry et al [3] is a multi-time period optimisation modelling tool. It is used to examine the interaction of gas and electricity networks as an integrated system. The key features of the CGEN model are presented in this chapter. However, a detailed description of the model formulation is provided in Appendix D.

4.2 The Soft-Link Approach: Coupling EGN model and the CGEN model

A soft link methodology was used to integrate the European gas network model (EGN) and the combined gas and electricity network model (CGEN). The structure of the integrated model is shown in Figure 4.1. The EGN is depicted in the upper section of Figure 4.1. The model was developed to analyse natural gas supply across 37 countries in Europe. The key model inputs include each European country's gas demand, domestic production as well as aggregated capacities of storage and LNG facilities. The non-linear relationship between pressure and gas flow through pipelines is not represented in this model.

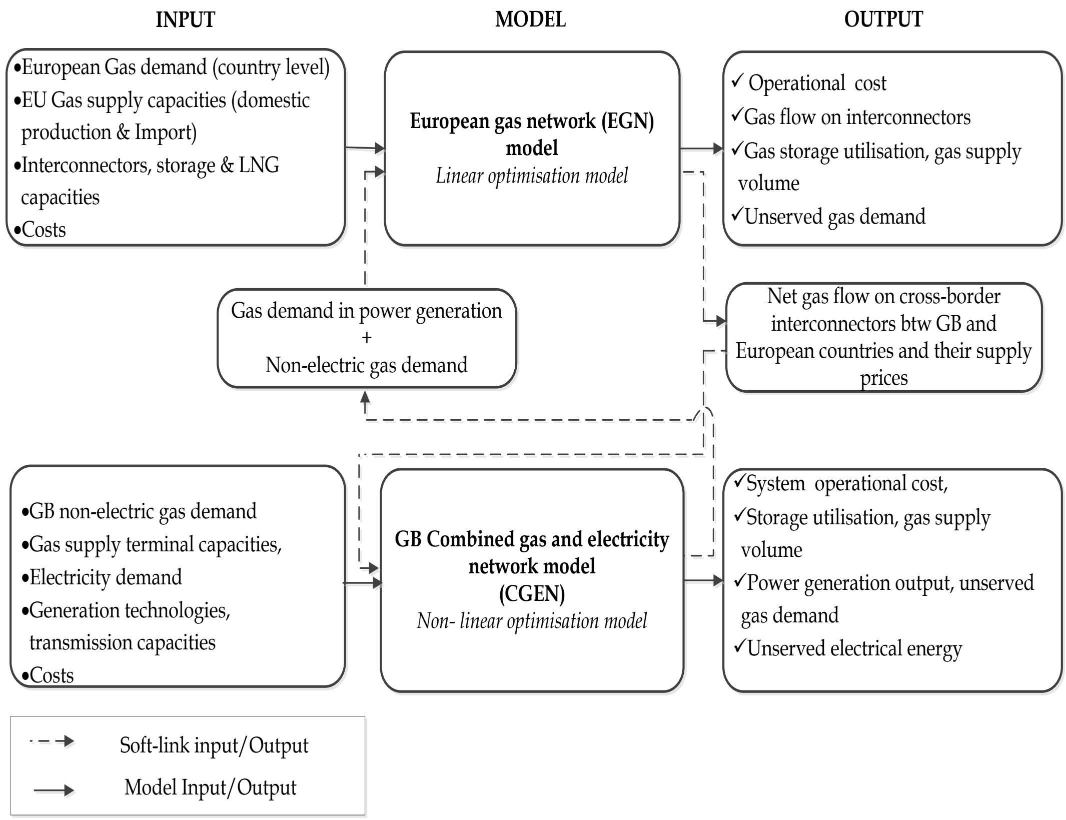

Figure 4.1 Structure of the integrated EGN- CGEN model

The CGEN model is shown in the lower section of the Figure 4.1.

The CGEN model is depicted in the lower section of Figure 4.1. The model includes a detailed representation of the GB gas and electricity networks. The key inputs of the model include gas terminal capacities, gas transmission pipelines parameters (comprising diameters, lengths and pressures), operational characteristics of compressor stations and storage facilities, electricity generation technologies and electricity transmission lines. Model outputs include volume of gas supplied at terminals, storage utilisation, change in linepack and power generation output.

The soft link methodology involved an exchange of a set of variables between the models in an iterative process. The variables taken from the EGN are **gas flow on cross-border interconnectors between GB and continental Europe and their corresponding gas supply prices.** Three cross-border interconnectors link GB to the rest of Europe namely; Norway to GB interconnector **(NO-GB)**, Netherland to GB interconnector **(NL-GB)** and the bi-directional interconnector between GB and Belgium **(GB-BE)**.

The **total GB gas demand** is a variable obtained from the CGEN model. The total GB gas demand was calculated as the sum of the non-electric gas demand and the amount gas used by gas-fired generators for power generation. The non-electric demand is an exogenous input while the amount of gas used by gas-fired generation for power generation is endogenously determined in the CGEN model. The CGEN model calculates the gas used for electricity generation based on the price of natural gas relative to the cost of generating electricity using alternative generation technologies such as coal. Hence, gas used for power generation decreases when gas prices are high and vice versa.

4.2.1 Description of the CGEN model

The CGEN model was modified to include the individual cross-border pipelines between GB gas network and neighbouring European countries. Figure 4.2 shows a schematic diagram of the GB gas network coupled by cross-border pipelines at Norway, Netherland and Belgium to the rest of the European gas network. GB gas terminals receive gas from offshore production fields, LNG import and cross-border pipelines with Continental Europe.

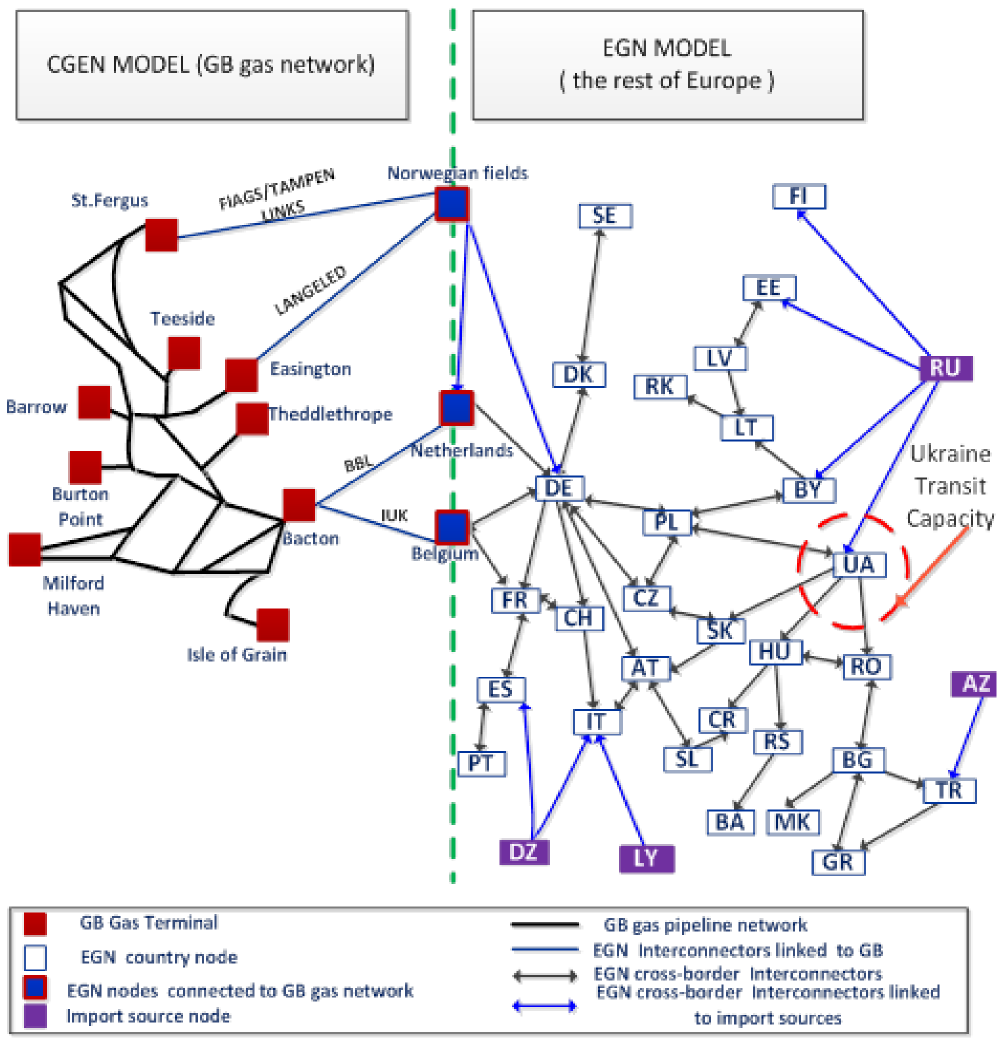

Figure 4.2 Linkages between GB gas network and the European gas network

In this study, Continental Europe refers to all EU countries, Bosnia, Macedonia and Serbia. It excludes GB and Republic of Ireland.

- **The Objective Function**

The objective function of the CGEN model is to minimise the combined operational cost of gas and electricity networks whilst meeting gas and electricity demand. The operational cost includes costs of gas supplies, gas storage operation, change in linepack, electricity generation, unserved gas demand and electrical energy as expressed in Equation 4.1. The general formulation and description of the CGEN model is presented in Appendix D.

Minimise total operational cost (£) =

$$\sum_t ts \times \left\{ \underbrace{\sum_a C_{a,t}^{gas} Q_{a,t}^{supp}}_{gas\ supplies} + \underbrace{\sum_s \left(C_{s,t}^{wd}\ Q_{s,t}^{wd} - C_{s,t}^{inj} Q_{s,t}^{inj} \right)}_{storage\ operation} + \underbrace{\sum_h C_t^{sp} \partial LP_{h,t}}_{change\ in\ linepack} + \underbrace{\sum_g C_g^{gen}\ P_{g,t}}_{electricity\ generation} + \underbrace{\sum_i C^{gasshed}\ Q_{i,t}^{gasshed}}_{unserved\ gas\ demand} + \underbrace{\sum_b C^{elecshed}\ Q_{b,t}^{elecshed}}_{unserved\ electric\ energy} \right\} \qquad 4.1$$

where :

$C_{a,t}$	gas cost from terminal a at time t (£/m^3)
$Q_{a,t}^{supp}$	gas supplied from terminal a at time t (m^3/d)
$C_{s,t}^{wd}$	cost of gas withdrawn from storage facility s at time t (£/m^3)
$Q_{s,t}^{wd}$	volume of gas withdrawn from storage facility s at time t (m^3/d)
$C_{s,t}^{inj}$	cost of storage injection into storage facility s and time t (£/m^3)
$Q_{s,t}^{inj}$	volume of gas injected in storage facility s at time t (m^3/d)
C_t^{sp}	spot gas price at time t (£/m^3)
$\partial LP_{h,t}$	changes in linepack of pipe h at time t (m^3/d)
C_g^{gen}	generation cost of generator g (£/MWh)
$P_{g,t}$	power output from generator g at time t (MW)
$C^{gasshed}$	cost of unserved gas demand (£/m^3)
$Q_{i,t}^{gasshed}$	volume of unserved gas energy at node i and time t (m^3/d)
$C^{elecshed}$	cost of unserved electrical energy (£/MWh)
$Q_{b,t}^{elecshed}$	unserved electric power at bus b and time t (MW)

4.2.2 Stages Involved in the Soft-Link Approach

The coupling of the CGEN and EGN models is described in the following steps below:

Step 1: The EGN model received gas demand, domestic production and storage capacities for each European country as input data (Section 3.4).

Step 2: The EGN model was run to obtain gas flow on the European interconnectors linked to the GB gas network and their corresponding gas supply prices.

Step 3: The gas supply prices and cross-border gas flow profiles calculated in the EGN were used as input in the CGEN model.

Step 4: The CGEN model was run to obtain the amount of gas consumed in electricity generation.

Step 5: The gas demand in electricity generation was used to calculate the total GB gas demand profile which was updated in the next run of the EGN model.

Step 6: Steps 3, 4 and 5 were iterated (repeated sequentially) until the gas flow on the interconnectors linked to the GB network and total GB gas demand profile reaches the convergence criterion or after four iterative cycles. The convergence criterion was given by Eq.3.2.

$$\frac{N_k - N_{k-1}}{N_k} \leq 0.05 \qquad 4.2$$

where N is the GB gas demand data exchanged between the EGN and CGEN models, k is the iteration number.

Once the models converged and a solution was reached, the loss of Ukraine transit capacity was applied in the EGN. The resulting cross border gas flows on the interconnectors connecting GB to Europe were imported into CGEN model to examine the impact of the supply disruption on gas dispatch in GB gas and electricity networks.

4.3 Description of Scenarios

Two scenarios of GB wind generation capacity and non-electric gas demand shown in Figure 4.3 were modelled using a daily time step for 90 days of cold winter (January-March) in 2030. The modelling period was selected to cover the days of coldest winter demand and low gas storage levels across Europe. Historical gas demand data obtained from [112] showed that January and February were the two consecutive months of the highest gas demand in the winter season in GB and Continental Europe. By the end of the winter season in March, gas storage stocks often reach their lowest levels [113].

The minimum storage levels at the end of winter (March) depends on a number of factors including a prolonged cold winter condition in March or the loss of a key supply source. For instance, GB storage level reached 3% of maximum storage capacity in March 2013 due to a prolonged cold weather condition [113].

The scenarios were defined as the Reference Scenario and the Slow Transition Scenario. The key features of the scenarios are presented in Table 4.1.

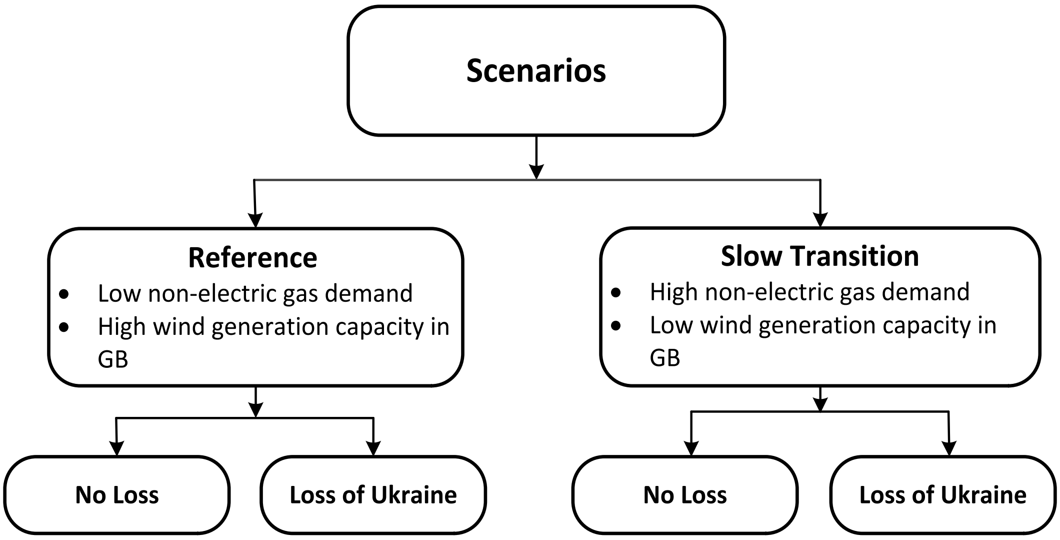

Figure 4.3 Structure of the scenarios

Table 4.1 Key features of the scenarios

Parameters Assumptions	**Reference**		**Slow Transition**	
	No Loss Case	**Loss Case**	**No Loss Case**	**Loss Case**
GB non-electric gas demand (bcm)	23		27	
Installed GB wind generation capacity (GW)	51		41	
European Union gas demand (bcm)	136			
Total capacity of European gas interconnectors (mcm/d)	2981	2595	2981	2595

4.3.1 Reference Scenario

This scenario assumed that GB's non-electric gas demand was **23 bcm** for 90 days of winter and **51 GW** of installed wind generation was connected to the GB electricity network. The generation capacities and non-electric gas demand for the GB system were taken from the 2015 Future Energy Scenarios (FES) published by the National Grid [31]. These assumptions reflect a situation when GB's environmental and low carbon energy targets are met by 2030 [114].

Gas demand for individual countries in Continental Europe was taken from the ENSTOG Ten Year Network Development Plan (TYNDP) [18]. The gas demand obtained from individual countries in Continental Europe was aggregated. This value is 136 **tcm over 90 days**. Using 2009/2010 daily demand data obtained from several TSO websites and other available sources, a daily demand profile was generated for each country to reflect similar weather conditions across Europe in both scenarios [115],[116].

4.3.2 Slow Transition Scenario

The Slow Transition Scenario assumed a higher non-electric gas demand of **27 bcm** and lower wind generation capacity of **41GW** in GB than in the Reference Scenario (see Table 4.1). Gas demand in continental Europe remained unchanged in this scenario.

4.3.3 Cases

For each scenario, two cases were defined based on the loss of Ukraine transit capacity for 90 days of winter. The results of the case study conducted in chapter 3 showed that the 30-day loss of the Ukraine transit capacity has no adverse impact on gas supply in GB. Therefore, the duration of the impact of the supply disruption was analysed for 90 days to assess the resilience of the GB gas and electricity networks to a prolonged loss of a major gas supply source in Europe.

No Loss Case: The loss of Ukraine transit capacity is not applied in this case and the total capacity of Russian import pipelines to Europe is 687 mcm/d (see Table 4.1).

Loss Case: This is the case when the loss of the Ukraine transit capacity (386 mcm/d interconnector capacity between Ukraine to Europe) occurred.

4.3.4 Modelling Assumptions

The following assumptions were applied in modelling the scenarios:

1. In both scenarios, LNG supply to Europe was assumed to be limited due to severe winter conditions in other major LNG importing countries.

2. Modelling of the scenarios did not consider all contractual constraints, like take or pay obligations and other typical contractual arrangements of gas trade. This is because, contractual prices are not generally known but are usually confidential therefore the optimisation was based on estimations of border prices.

3. All storage facilities except Germany and Netherlands were assumed to be available at 80% of maximum working gas capacity at the beginning of the winter.

4. German and Dutch storage were assumed to be available at 70% of their maximum working capacities due to the limited access to these storage supplies as a result of their existing long-term contractual arrangements.

4.3.5 Input Data for GB Gas and Electricity Networks in the CGEN Model

The GB daily electricity demand profile for the Reference and Slow Transition scenarios was derived from historical winter electricity consumption data for 2009/2010 and scaled to 2030 values obtained from 2015 FES [117]. Wind generation data of January-March 2010 was scaled up to 2030 values of wind power capacity obtained from 2015 FES in the Reference Scenario and in the Slow Transition Scenario.

The electricity demand and wind generation profiles are shown in Figures 4.4 and 4.5. The Reference Scenario has a total generation capacity of 130.5 GW and the Slow Transition Scenario has a generation capacity of 120.5 GW. The capacities of the different generation technologies at each bus and the transmission line capacities are provided in Appendix E. The electricity generation cost for the different technologies are provided in Appendix E.

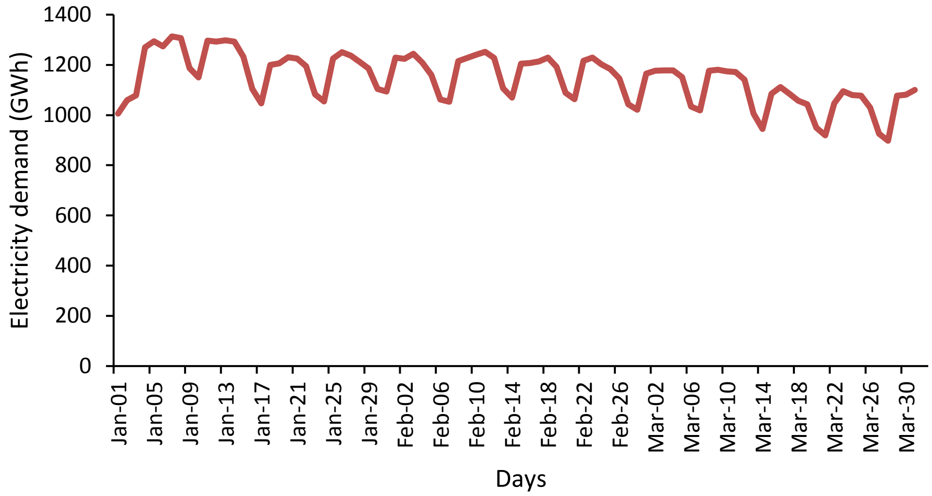

Figure 4.4 GB daily electricity demand

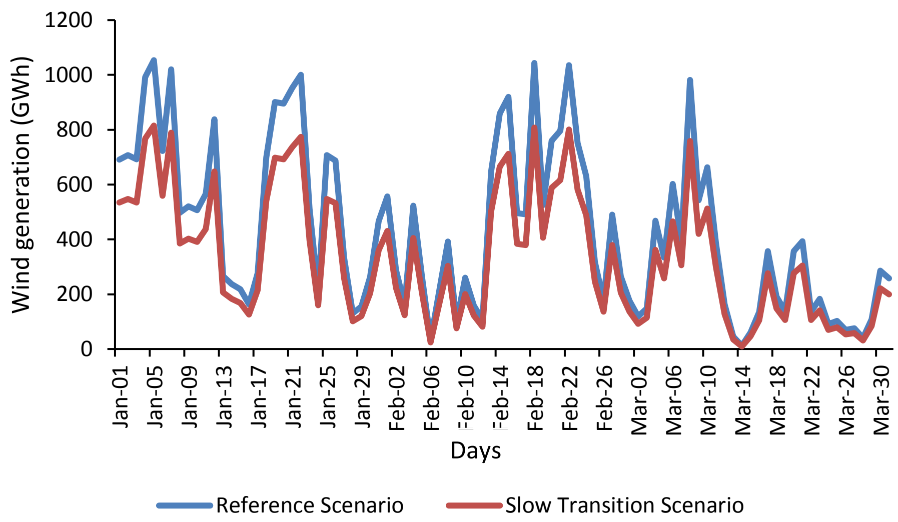

Figure 4.5 GB daily wind generation

GB gas demand was split into non-electric demand and gas demand for power generation. In both scenarios, the non-electric demand profiles were derived from historical winter demand data for 2009/2010 including a peak winter day. The wind demand data for March was increased by 20% to reflect a period of prolonged high gas demand towards the end of winter. The demand profiles of GB non-electric gas demand are shown in Figure 4.6 [27].

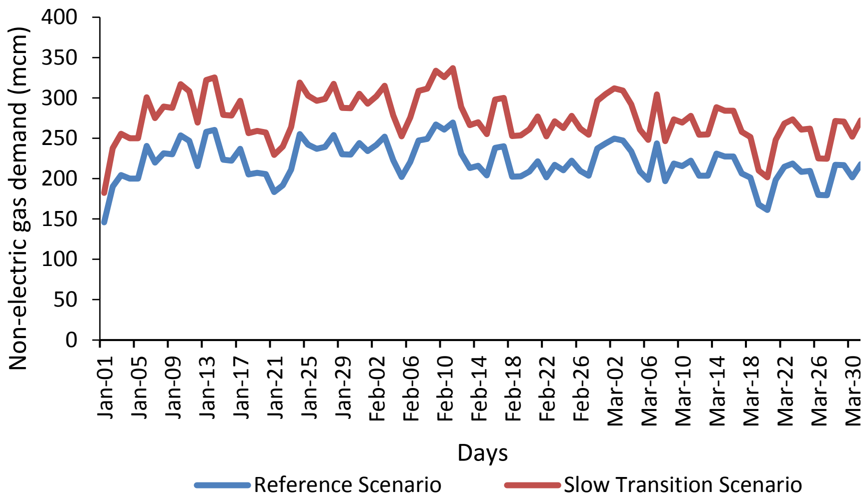

Figure 4.6 GB non-electric gas demand profiles

The maximum daily gas supply capacity at individual gas terminals and maximum daily capacity at each GB storage facility were obtained from National Grid Gas Ten Year statement are presented in Appendix E. The cost data for GB network parameters are provided in Appendix E.

4.3.6 Input Data for the EGN Model

European supply data includes indigenous production, LNG and pipeline import sources - Russia, Norway, Libya, Algeria and Azerbaijan (see Fig 4.2). Based on historical winter supply, the gas supply from pipeline import sources and LNG import was increased by 10% to obtain the maximum daily available supply [101]. The maximum daily supply potential and costs of gas supply for the various supply sources is given in Appendix C.

Maximum daily capacities of existing interconnectors, LNG and storage facilities were taken from databases compiled by the Gas Infrastructure Europe [118], [47], [25]. In addition, capacities of planned projects identified as key infrastructure required to improve supply diversification and the full integration of the European gas network were implemented in this study [119]. The cost data for gas transport via interconnectors and storage facilities are provided in Appendix C.

4.4 Result of the Reference Scenario

4.4.1 Impact of the Supply Disruption on Gas Supply in Continental Europe

Figure 4.7 presents average daily gas supply volumes to Continental Europe from domestic and import sources in the Reference Scenario over 90 winter days from Jan - Mar

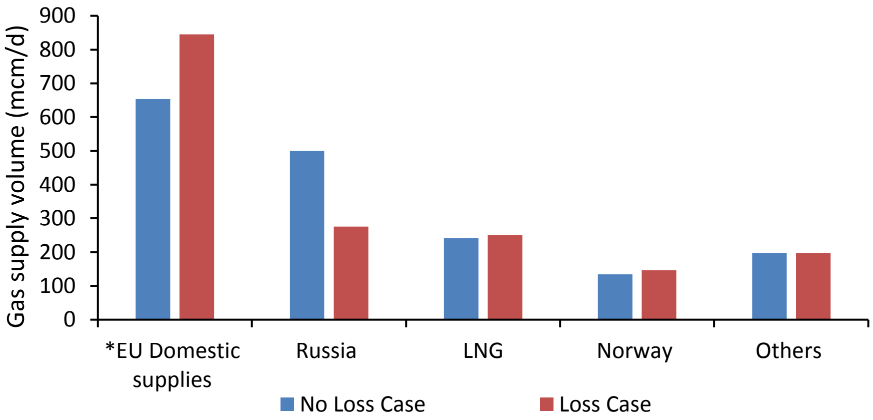

Figure 4.7 EU domestic gas supplies and imported gas supply over 90 days – Reference Scenario

Domestic supplies are composed of domestic production and gas withdrawn from storage facilities in Continental Europe. In the No Loss Case, average domestic production was 127 mcm/d while storage withdrawals contributed 533 mcm/d. Russia supplied the largest volume of imported gas of 500 mcm/d to Europe while the volume of LNG supplied was 241 mcm/d.

The loss of Ukraine transit capacity led to a 43% decrease in Russian gas export to Europe compared to the No Loss Case. The supply shortfall was primarily compensated by higher storage withdrawals. Storage withdrawals increased by 120 mcm/d in the Loss Case relative to the No Loss Case. LNG import increased from 241 mcm/d in the No Loss Case to peak at 251 mcm/d in the Loss Case due to limited available supply. Norwegian gas import only made an additional supply of 12.7 mcm/d in the Loss Case to reach its maximum supply capacity due to a cold winter condition in Continental Europe.

4.4.2 Impact of the Supply Disruption on the Operation of GB Gas Network

Figure 4.8 presents the total volume of gas supplied from different supply sources to the GB gas network over 90 days in the Reference Scenario.

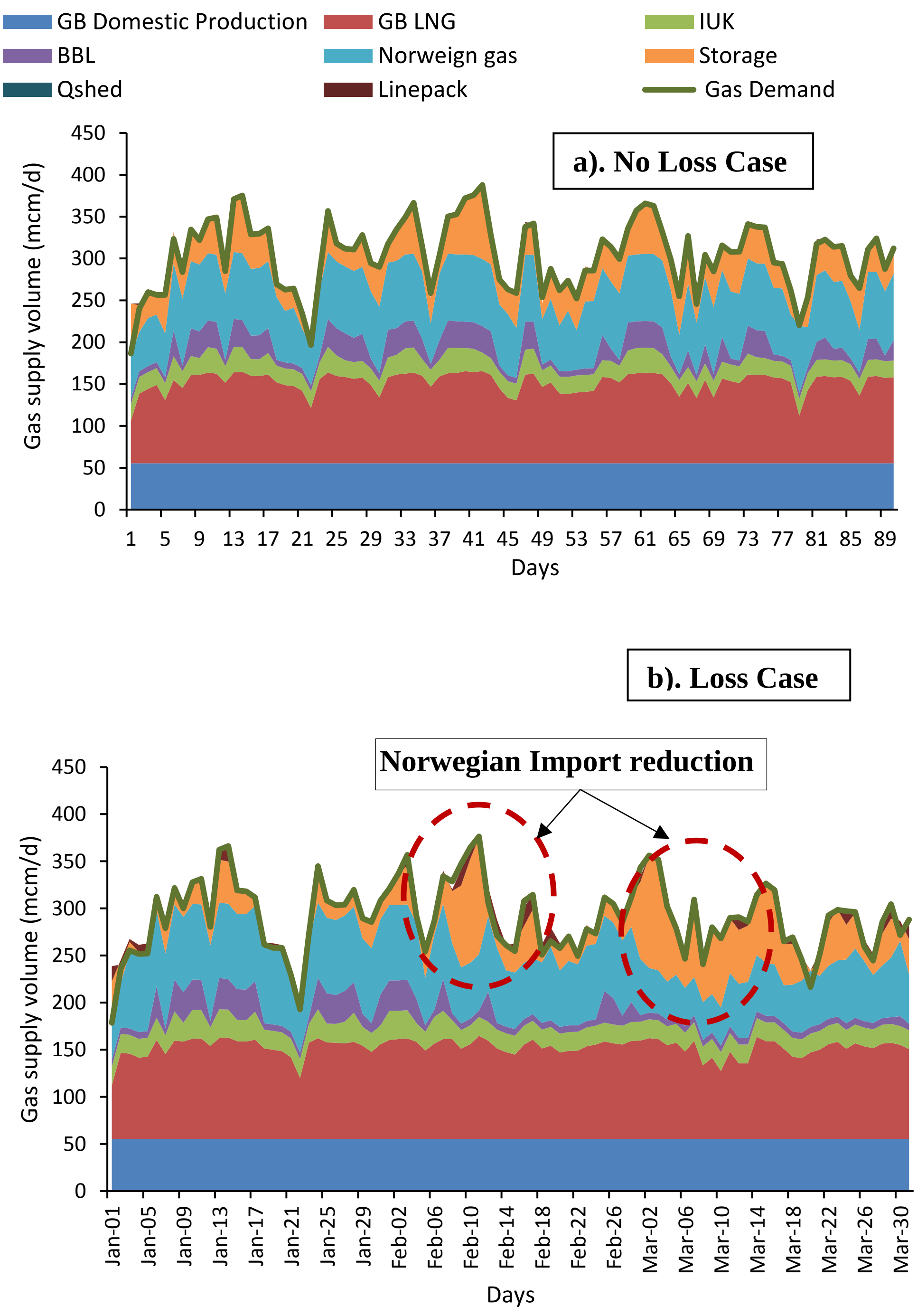

Figure 4.8 GB domestic gas supply and import volumes – Reference Scenario

(BBL is the pipeline interconnector between GB and the Netherlands and IUK is the gas pipeline interconnector between GB and Belgium)

GB domestic gas production contributed just 18% of total GB gas supplies in the No Loss Case due to dwindling gas production capacity in the UK continental shelf. On the other hand, imported gas supply from LNG and Norway provided 56% of total GB gas supply. Norwegian import to GB decreased by 643 mcm (10%) in the Loss Case over the 90-day period when compared to the No Loss Case. The gas supply shortfall led to high gas prices in Continental Europe which attracted more Norwegian gas import to the Continent instead of GB. In order to replace some of the missing gas supply volume in Continental Europe, gas imported to GB on the BBL and IUK pipelines (Continental supplies) decreased by 531 mcm (9%) in the Loss Case compared to the No Loss Case.

However, gas withdrawn from GB storage facilities increased by 300 mcm (9%) in the Loss Case to offset some of the supply shortfall. The supply disruption did not result in unserved gas demand in GB because there was a corresponding reduction of natural gas consumption in power generation to counterbalance the supply shortage. (This is discussed in **section 4.4.3**).

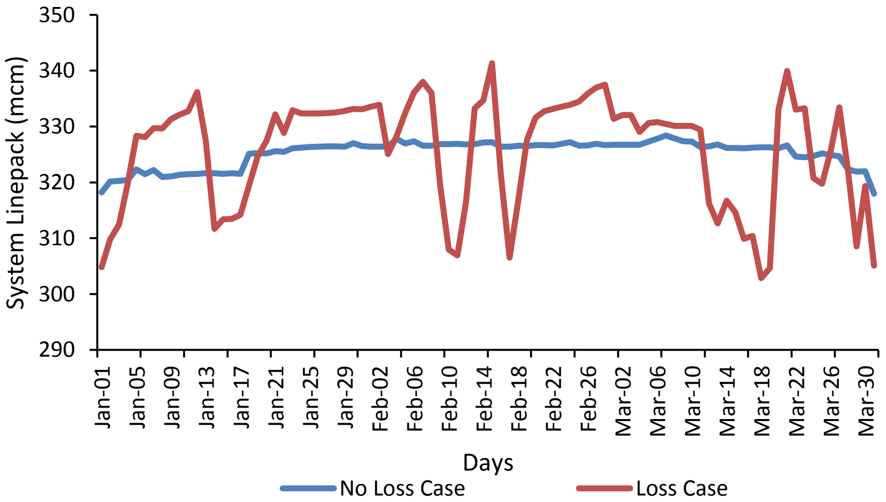

Figure 4.9 Linepack utilisation – Reference Scenario

The system linepack for the Reference Scenario is shown in Figure 4.9. The system linepack maintained a nearly smooth profile with slight variations in the No Loss Case. In the Loss Case, steep drops in the level of linepack occurred on days 17, 41, and 77 while the largest change in linepack of 32 mcm was noted on day 77. Large depletion of system linepack occurred when peak demand in the gas network coincided with low wind generation in the electricity network. Gas-fired generation was frequently used to compensate for the variation in wind power output leading to an increase in total gas consumption in the gas network.

Table 4.2 Total compressor power consumption – Reference Scenario

Slow Transition Scenario	**Average Compressor Power (MW)**
No Loss Case	96
Loss Case	66

Average compressor power consumption over 90 days for the Reference Scenario is shown in Table 4.2. In the No Loss Case, extensive compressor power was used to transport imported gas supply at GB terminals to long distance demand locations across the network. In addition, compressor power was also used to manage line pack fluctuation in a system supporting significant capacity of wind power generation.

In the Loss Case, compressor power consumption decreased by 30% in comparison to the No Loss Case due to less imported gas supply at terminals (i.e. Bacton and Easington). Consequently, rapid depletion of the linepack contributed to balancing the gas network during periods of low wind generation.

4.4.3 Impact of the Supply Disruption in GB Electricity Network

GB power generation from different generation technologies is presented in Figure 4.10. In the No Loss Case, nuclear plants supplied 11TWh of base load generation over the 90 day-period. Power generation from gas-fired generators was 39 TWh while 38 TWh of electricity came from wind power generators. The substantial gas-fired generation was attributed to two factors. CCGT generators could attract surplus gas supplies due to low non-electric gas demand in the gas network. Furthermore, the variation in wind power generation was largely compensated by CCGT power generation.

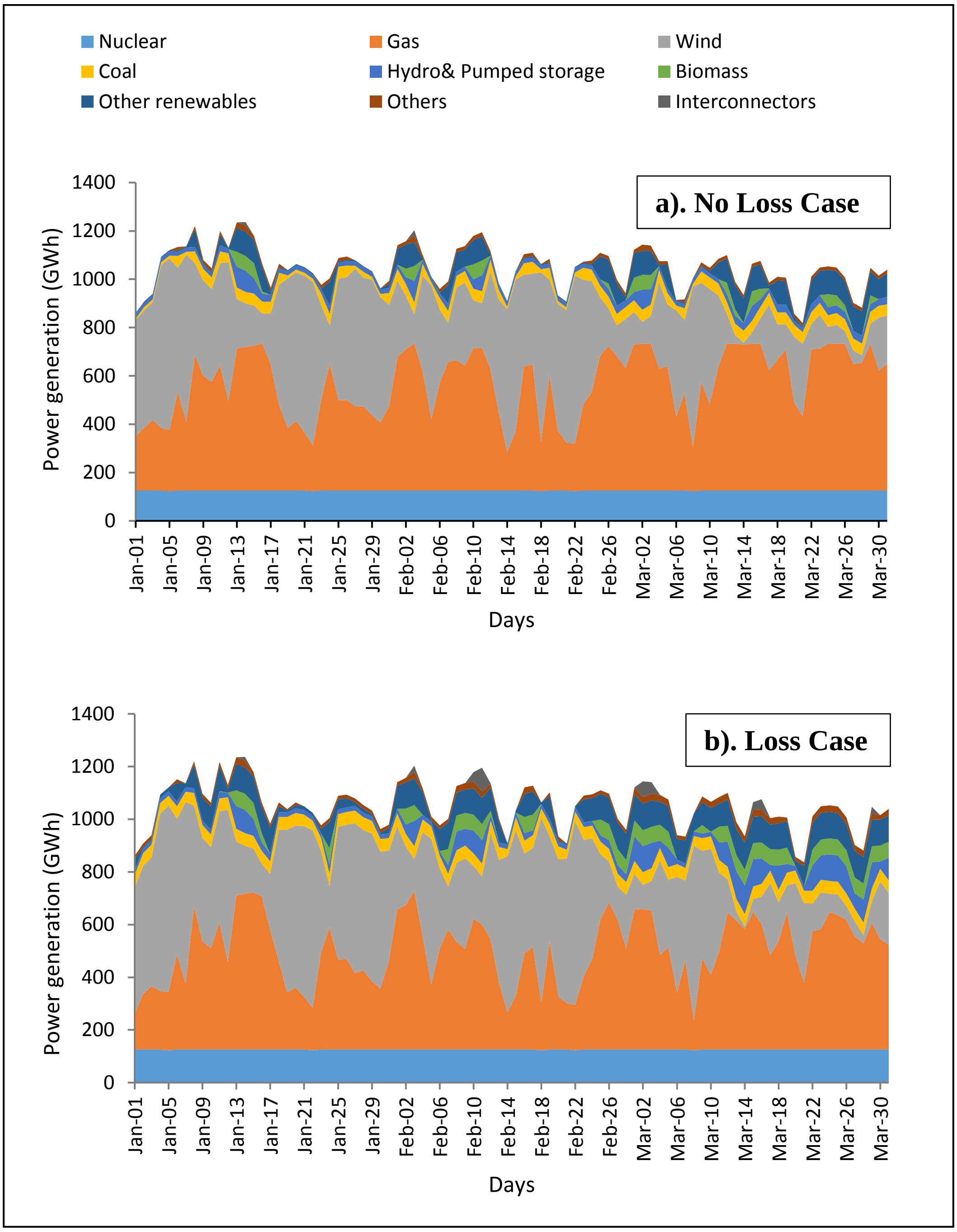

Figure 4.10 GB power generation – Reference Scenario

However, gas-fired generation declined by 7 TWh (18%) in the Loss Case. Higher power output from Other generators (waste, dual fuel and oil) was used to compensate for the reduction in gas-fired generation. Imported electricity through interconnectors had negligible contribution toward total power generation due to the availability of other lower cost electricity generators in the electricity generation mix.

4.5 Results of the Slow Transition Scenario

In this section, the simulation results focus mainly on the impact of the loss of Ukraine transit capacity on the operation of GB gas and electricity networks.

4.5.1 Impact of the Supply Disruption on the Operation of GB Gas Network

The impact of the loss of Ukraine transit capacity on GB gas supplies in the Slow Transition Scenario is shown in Figure 4.11.

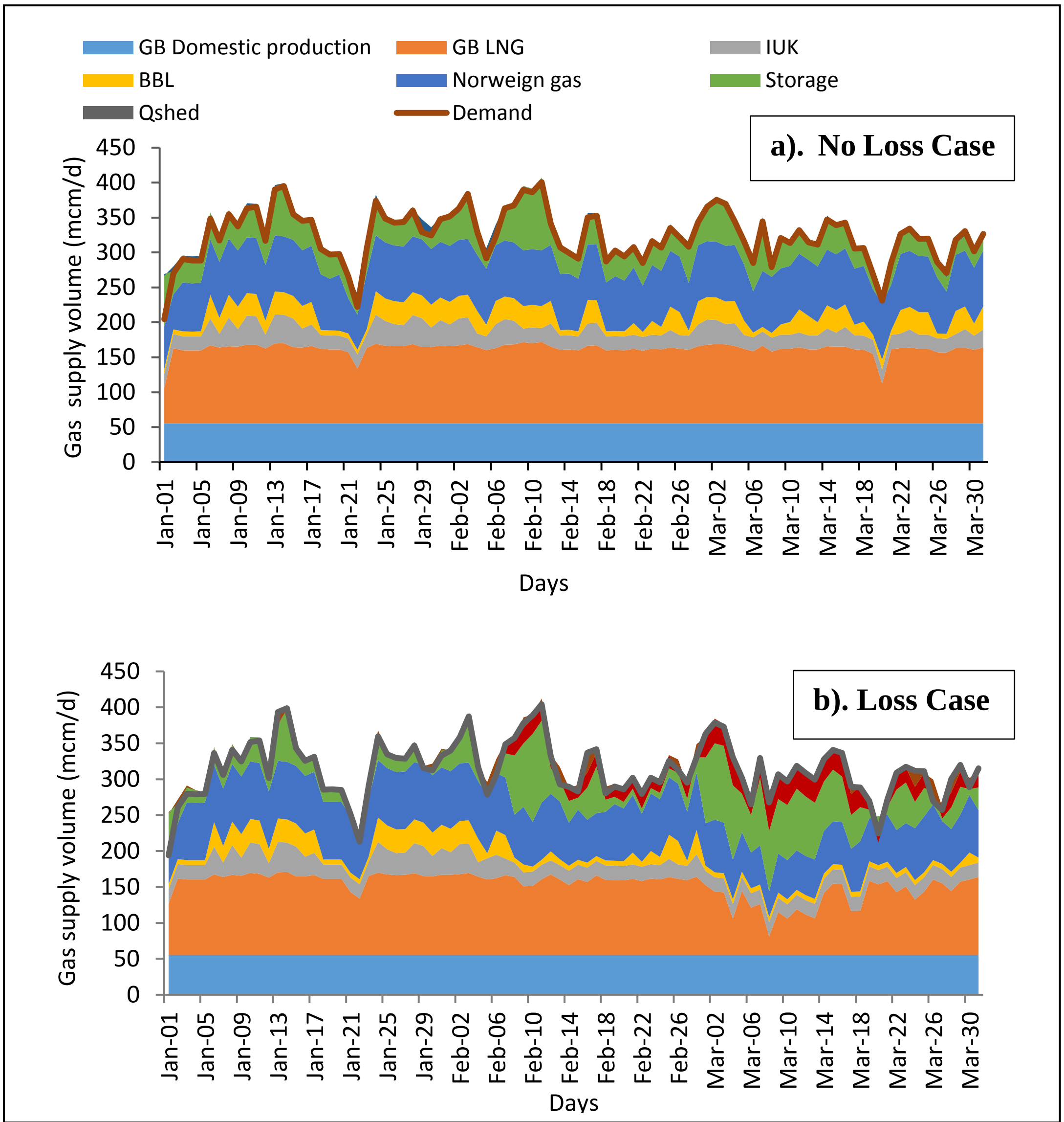

Figure 4.11 GB domestic gas supply and import volumes – Slow Transition Scenario

The supply shortfall resulted in a sudden decline in LNG and Norwegian gas supplies between days 61-70. LNG supply decrease by 20% while Norwegian gas decreased by 30% compared to the condition when no supply disruption occurred (Fig 4.12). The supply disruption combined with limited LNG supply to Europe led to the rapid depletion of gas storage stocks in continental Europe. Consequently, LNG and Norwegian supplies were diverted away from GB to Continental Europe.

Additional storage withdrawals of 253 mcm from GB storage facilities was used to compensate for the supply shortfall during this period (days 61-70). However, storage supplies were not sufficient to prevent unserved gas demand from day 39 to day 90. The results of the study showed that only the large industrial customers were adversely affected by unserved gas demand. A study conducted by London Economics on the estimating the value of lost load among gas consumers in GB suggested that the economic cost of unserved gas demand to the industrial sector could be substantial due to loss of production output or even damage to plant and equipment. For instance, the study estimated that the cost of unserved gas demand to Iron and Steel industry could range between 4.9 £m/mcm – 6.3 £m/mcm [120].

4.5.2 Impact of the Supply Disruption in GB Electricity Network

Figure 4.12 presents power generation from different generation technologies in the Slow Transition Scenario. GB power generation was dominated by power supply from gas-fired plants (34 TWh) and Wind (31 TWh) over 90 days. Electricity interconnectors provided additional power supply on days (13,31,41,61) of high electricity demand and low wind generation.

In the Loss Case, the gas supply shortage restricted gas delivery to gas-fired generators. As a result, gas-fired power output decreased by 30% (10 TWh) relative to No Loss Case. The reduction in gas-fired generation output was mostly replaced by higher electricity import via electricity interconnectors. This is due to the availability of a significant capacity of electricity interconnectors expected to come online in GB electricity network by 2030. Electricity interconnection between GB and multiple European countries is expected to play a key role in the diversification of GB power generation mix, improve security of energy supply and support a large capacity of renewable generation.

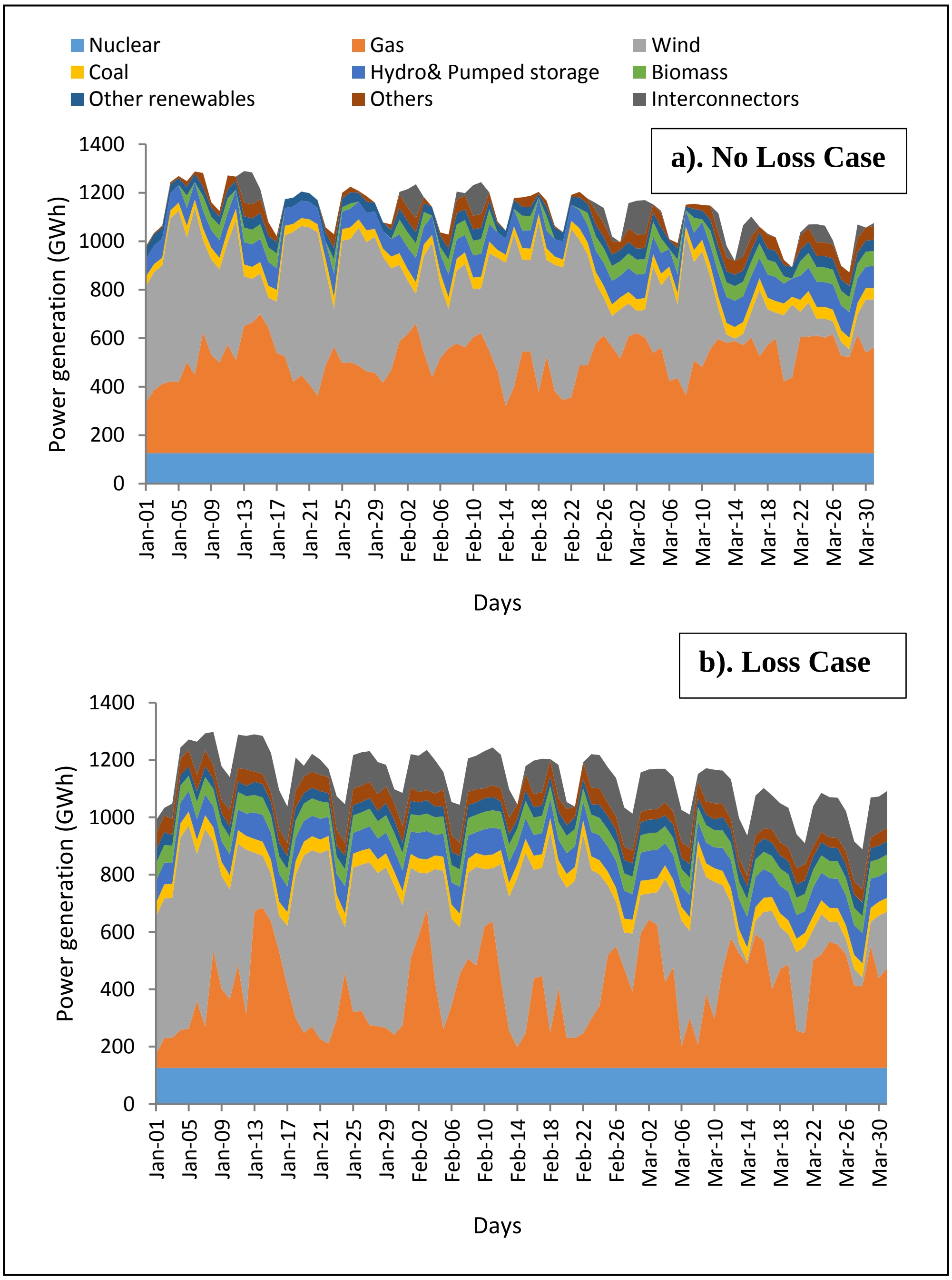

Figure 4.12 GB power generation – Slow Transition Scenario

4.6 Summary

An integrated optimisation model was developed from the European gas network (EGN) model and Combined Gas and Electricity Network model (CGEN) using the soft-link approach. This was used to determine the impact of the gas supply shocks in the European gas network on the operation of Great Britain's gas and electricity networks.

The model was applied to two different scenarios which depict the future evolution of GB energy system in 2030. The Reference Scenario and the Slow Transition Scenario were defined for 90 days of cold winter condition combined with limited availability of LNG caused by a tight global LNG market in 2030. The loss of Ukraine transit capacity was implemented as a supply shock situation over 90 days in both scenarios.

Due to the low gas demand assumed in the Reference Scenario, the loss of the Ukraine transit capacity had no significant effect on the operation of GB gas and electricity networks. The supply shortfall was compensated by GB storage withdrawals in the gas network and lower gas consumption in the electricity network.

In the Slow Transition Scenario, the loss of Ukraine transit capacity resulted in gas supply shortfall in the GB gas network. Some of the missing gas volumes was replaced by higher withdrawal of gas storage volumes in GB and substitution of natural gas generation by electricity imports in the electricity network. However, the industrial sector experienced 20% of average daily demand curtailed (unserved gas demand). This was due to high gas demand assumed in this scenario.

Chapter 5

Mitigation Options to Improve Security of Gas Supply to GB

5.1 Introduction

Since 2001, there has been significant expansion in the import capacity of the GB gas network to compensate for the continuing decline in domestic gas production. However, the analysis presented in Chapter 4 showed that the GB gas network will experience unserved gas demand when a high impact and low probability import supply disruption occurs over a prolonged period of time. The example investigated in this thesis is the loss of gas transit capacity through the Ukraine.

For the study described in this Chapter, a Base Case was established with the following assumptions:

1. GB gas demand was derived from the Slow Progression Scenario of National Grid 2015 Future Energy Scenario [114].
2. LNG supply to Europe was assumed to be constrained to 300 mcm/d under a situation where global LNG demand exceeds available supply.

The loss of the Ukraine transit capacity was applied to the Base Case for a period of 90 days.

Six mitigation Options were identified to improve the security of GB gas supply [30]. The mitigation *Options* are presented in Figure 5.1. The mitigation options are broadly grouped into three *Measures.*

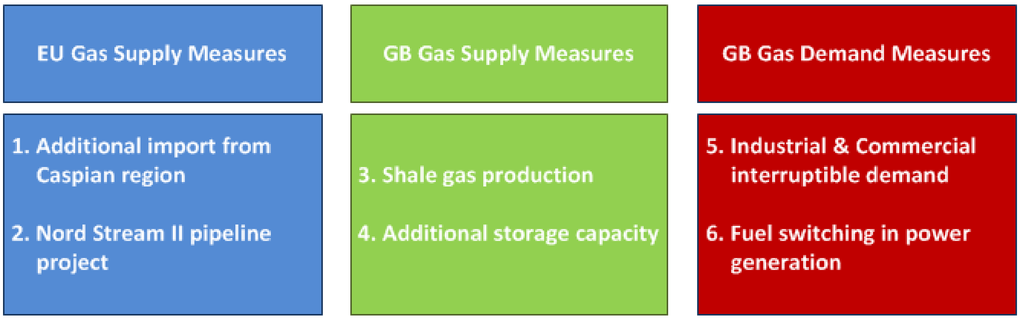

Figure 5.1 Classification of mitigation options

A cost-benefit assessment of the mitigation options was conducted in two stages. Firstly, the integrated EGN-CGEN model **(presented in Chapter 4)** was used to calculate the level of unserved gas demand in the GB gas network, electricity generation and the total operational costs for the different mitigation options. Then, the Net Present Value (NPV) of the cost of avoiding unserved gas demand for each mitigation option was calculated using an Excel spreadsheet.

5.2 Description of Mitigation Options

5.2.1 Additional Gas Import Volume from the Caspian Region

The 2015 BP Statistical Review of Energy estimated that Caspian region has 18.4 tcm of natural gas reserves (mainly in Azerbaijan and Turkmenistan) [121]. These gas reserves can be assessed by the European Union through pipeline imports. The large amount of gas reserves suggests the potential for future increase in gas export capacity from the Caspian region to the EU.

The Trans Anatolian Natural Gas Pipeline (TANAP) Project which is currently under construction, will deliver up to 16bcm/y of Caspian gas supplies through Turkey to South East Europe by 2018 [122]. The pipeline capacity is expected to increase to 31 bcm/y by 2026 [122]. The proposed expansion of the pipeline capacity would contribute to increasing security of EU gas supply.

5.2.2 Nord Stream II Pipeline Project

The Nord Stream pipeline project comprised two off-shore pipelines that runs from Vybord in Russia to Greifswald in Germany through the Baltic Sea. The pipelines were commissioned in 2012 and have a total annual capacity of 55 bcm [123]. The pipelines transport Russian gas directly to Germany in North-West Europe. This project made a significant contribution to security of gas supply in Europe by the reduction of Russian gas flow via Ukraine from 80% to 50% [124].

In 2015, a joint venture was launched between Gazprom Russia and five European companies to extend the capacity of the existing Nord Stream pipelines from 55 bcm/year to 110 bcm/year by the addition of two parallel pipelines [43]. The proposed project would increase security of GB gas supply by enabling gas consumers in North West Europe and Central Europe to completely avoid gas transportation through non-EU transit countries (Ukraine and Belarus).

5.2.3 Shale Gas Development in GB

The recent discovery of significant shale gas resources in England has attracted interests from policy makers and investors. Estimates of the gas in place ranges between 23.3 tcm and 64.6 tcm [125]. Gas in place is an estimate of the total volume of shale gas that exists in any shale formation before any development takes place [126]. The development of GB's shale gas resources will depend on a supportive government policy and regulatory framework, access to low risk financing and good public acceptance [127].

Several studies have investigated the prospects for shale gas development in GB [128], with a focus on the process of shale gas extraction [129], the economic impact of shale gas development on GB [130] and the environmental impact of shale gas exploitation [131]. According to 2014 National Grid Future Energy Scenario, shale gas production is expected to contribute up to 31 bcm per year by 2030 [114]. This shale gas production capacity would reduce import dependency from 75% to 35% by 2030 and represents about 40% of the projected gas demand in 2030 [114].

5.2.4 Additional Storage Capacity in GB

Gas storage facilities provide additional supply on the GB gas network during supply disruptions and the supply flexibility required to meet short term gas demand variations. [27].

GB gas storage facilities are grouped into long range, medium range and short range storage facilities as shown in Table 5.1. The aggregated capacity of gas storage facilities in GB is 4.6 bcm. In 2014, gas storage facilities provided about 6% of total GB gas demand (75.5 bcm/year) [27].

The only long range storage facility connected to the GB gas network is the Rough storage facility located off the cost of East Yorkshire. The Rough storage represents 70% of GB's total gas storage capacity [132]. The facility is an off-shore depleted gas field used mainly for seasonal storage as natural gas is injected in the summer and withdrawn in winter. Medium range storage comprises fast cycle facilities that have the capability to provide several cycles of gas injection into storage and withdrawal from storage within a year. The short-range storage is used to meet sudden increase in demand over a short period of time. The Avonmouth LNG peak shaving facility is the only short-range storage facility in GB [133].

Table 5.1 Characteristics of existing GB gas storage facilities [27]

Storage facilities	Working gas volume (bcm)	Maximum withdrawal rate (mcm/d)
Long range	3.3	41
Medium range	1.22	100
Short range	0.08	13
Total	4.6	154

5.2.5 Industrial & Commercial Interruptible Demand

Demand side measures are tools used by network operators to reduce or curtail the gas demand of large Industrial and Commercial (I&C) consumers during a situation of gas supply shortage. Industrial and commercial customers can enter into contract with system operators or gas shippers to interrupt their gas supply for a number of days every year in exchange for a discount or fee. Alternatively, a payment is offered to eligible industrial and commercial consumers to bid to reduce their gas consumption at periods of gas supply emergencies.

The current level of demand side response provided by large industrial and commercial consumers in the UK is estimated as 3 mcm/day [134]. This is because previous regulatory arrangement offered limited incentive for the voluntary participation of industrial and commercial to provide demand side response. The compensation offered to I&C customers to reduce or curtail their gas demand during a gas supply emergency did not reflect the true cost of interruption of their gas supplies [134].

In 2014, Ofgem proposed a demand response auction to incentivise industrial and commercial consumers to offer demand side response during periods of gas supply shortage [135]. This would ensure that the responding customers receive appropriate payment when their gas supplies are interrupted to support investment in back-up capacity.

5.2.6 Fuel Switching in Power Generation

Gas-fired generators equipped with dual fuel capacity can switch to distillate fuel to generate power during periods of high gas prices or when there is a need to curtail their demand in the event of a gas supply emergency. CCGTs with distillate back-up capacity have lower efficiency, high maintenance cost and occupy more space than CCGTs without distillate back-up capacity [136].

In the UK, the installed capacity of CCGT equipped with distillate back-up capacity reduced from 8103 MW in 2010 to 2165 MW in 2014 [134]. This is due to the shutting down of ageing CCGT generators equipped with distillate back-up capacity and limited investment in new CCGT equipped with dual fuel capability. The development of additional CCGT with distillate back-up capacity will depend on the UK capacity market.

The UK capacity market is a mechanism designed to make payments to generation stations based on their generation capacity. The capacity market would ensure adequate levels of power generation capacity as increasing generation from renewable energy sources result in the reduction of CCGT operating hour (i.e. lower capacity factor) coupled with the decline of coal generation capacity on the network.
The payment made to capacity providers is to encourage new build power plants especially CCGT generators. The participation of dual fuel CCGT generators in the capacity market will increase reliability of power supply during periods of limited gas supply in the GB gas network.

5.3 Data Assumptions of the Mitigation Options

The modelling assumptions of the different mitigation options are summarised in Table 5.2.

Table 5.2 Capacities of the mitigation options

Mitigation Options	**Type of Measure**	**Implementation**	**Location**
Caspian Supply	EU Gas Supply Measure	Interconnection capacity between Azerbaijan and Greece via Turkey increased from **43.8 mcm/d** to **85 mcm/d.**	European Gas Network model
Nord Stream		Interconnection capacity between Russia and Germany increased from **150 mcm/d** to **225 mcm/d.**	European Gas Network model
Shale gas production	GB Gas Supply Measure	Shale gas production capacity of **20 mcm/d** is applied at a supply node in the GB gas network.	Combined Gas and Electricity Network Model

Additional storage capacity		Two salt cavity storage nodes were defined individually in the GB gas network. Each node was modelled with the following data set: Working gas volume: **500 mcm** Max. injection rate: **20 mcm/d** Max. withdrawal rate: **20 mcm/ d**	Combined Gas and Electricity Network Model
Interruptible demand	GB Demand Measure	Interruptible demand was applied in the GB gas network by allowing (I&C) gas demand to be curtailed. The maximum interruptible demand capacity is **20 mcm/d**.	Combined Gas and Electricity Network Model
Fuel Switching	GB Demand Measure	**4 GW** of existing CCGT generators were modelled to have dual fuel capacity. The variable cost of distillate generation was assumed to be **65 £/MWh.**	Combined Gas and Electricity Network Model

5.4 Modelling of the Mitigation Options

5.4.1 EU Gas Supply Measures

The mitigation options in Europe (EU Gas Supply Measures) are the Caspian Supply Case and the Nord Stream Case. These mitigation options are implemented using:

- **Step 1** Input the capacity of the mitigation option in the EU gas network (**see Table 5.2**)
- **Step 2** Run the EU gas network model for 90 days.
- **Step 3** Obtain the gas flows on interconnectors between GB and continental Europe.
- **Step 4** Input the gas flows on interconnectors obtained from the EGN model into the CGEN model.

- **Step 5** Run the CGEN model for 90 days to calculate the level of unserved gas demand, cost of unserved gas demand and the operational cost of the GB gas and electricity networks.

The cost of unserved gas is calculated by multiplying the volume of unserved gas demand by the value of lost load (VOLL). The assumed VOLL for the various categories of natural gas consumers is presented in Appendix E.

5.4.2 GB Gas Supply Measures

The mitigation options in UK (grouped under the GB Gas Supply Measures) are the Shale Gas Case and the Additional Storage Case. These mitigation options are implemented in the CGEN model (see Table 5.2). The modelling steps are:

- **Step 1** Input the capacity of the mitigation option in the CGEN model.
- **Step 2** Run the CGEN model for 90 days to calculate the level of unserved gas demand, cost of unserved gas demand and the operational cost of the GB gas and electricity networks.

5.4.3 GB Gas Demand Measures

The mitigation options grouped under GB Gas Demand Measures are the Interruptible Demand case and Fuel Switching case. These mitigation options are implemented in the CGEN model. The mitigation options are modelled using the same modelling steps described for the GB gas supply measures in subsection 5.4.2.

5.5 Cost-Benefit Analysis of the Mitigation Options

A cost-benefit analysis is used to determine the economic value of the mitigation options proposed to improve security of gas supply to GB. The cost of reducing unserved gas demand (i.e. benefit) is compared against the implementation cost of each mitigation option. The structure of the cost benefit analysis is presented in Figure 5.2.

The reduced cost of unserved gas demand is calculated as the difference between the cost of unserved gas demand with and without the mitigation option. As the mitigation options decreases the cost of unserved gas demand to GB, the security of supply benefits to GB increases.

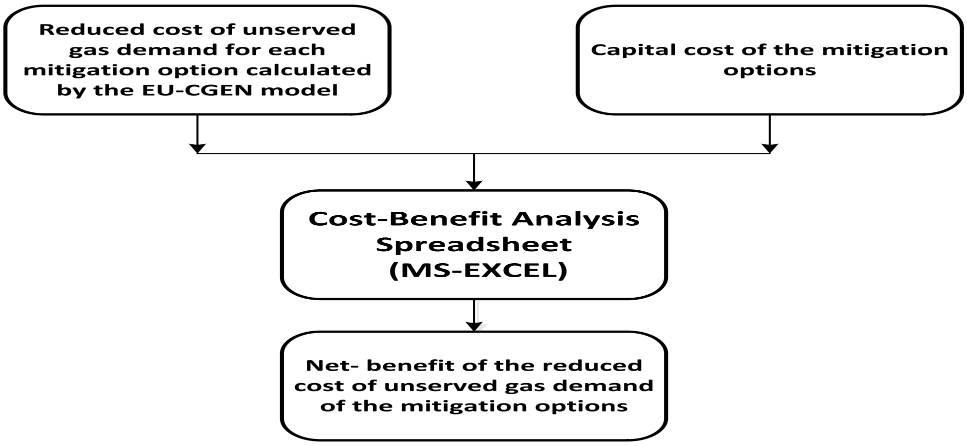

Figure 5.2 Structure of the cost-benefit analysis study

5.5.1 Data Assumptions for the Cost Benefit Analysis

The cost-benefit analysis is calculated using a Microsoft Office Excel spreadsheet. A summary of the inputs to the spreadsheet tool is presented in Table 5.3.

Table 5.3 Inputs to the cost-benefit analysis spreadsheet

Mitigation Options	Asset life (Years)	Discount rate (%)	Implementation Cost (£m)
Caspian Supply Case	35	10%	0
Nord Stream Case	35	10%	0
Shale Gas Case	30	10%	548[137]
Additional Storage Case	30	10%	550 [30]

Interruptible Demand Case	15	3.5%	18[138]
Fuel Switching Case	25	10%	210 [136]

The asset life here refers to the duration of time the mitigation option was put into use (operational). The time taken to complete the construction of the mitigation option is not considered in this study.

A commercial discount rate of 10% is assumed for all mitigation options except the Interruptible Demand Case (see Table 5.3). A social discount rate of 3.5% is assumed for Interruptible Demand Case in line with the social discount rate used in the UK for public sector projects implemented by the government or the transmission system operator [134].

Gas supply disruptions are considered as high impact and low probability events. The probability of a supply disruption gives an indication of how often the supply disruption would occur over a time period. According to a study conducted by the Centre on Regulation in Europe, the probability of a supply disruption and the impact on gas consumers when its occurs, provides a useful measure of security of supply [139].

The annual probability of an outage of Ukraine transit capacity occurring during a period of limited LNG supply to Europe over 90 days was assumed as **2% (i.e. 2- in - 100-year chance)** [140].

5.5.2 Implementation Cost

The cost of implementing each mitigation option as presented in Table 5.3. The implementation cost of mitigation options that involve the construction of physical infrastructure is limited to the capital cost of the project. The capital cost values were taken from various sources reported in literature. The potential development of the Nord Stream and Caspian gas supply projects would be at no cost to the GB gas consumers since they have not direct interconnection with the GB gas network. Hence these mitigation options have zero capital cost. The interruptible demand option has no capital cost because it is assumed to operate as a commercial arrangement between the industrial gas consumers and the system transmission operator. Instead, the implementation cost covers the start-up cost and cost of participation for customers.

5.5.3 Benefit

The reduced cost of unserved gas demand for a given mitigation option with respect to the Base Case is shown in Equation 5.1:

$$PV\_RC^{MO} = \sum_{t=1}^{n} Pr_t \frac{CUD^{BC} - CUD^{MO}}{(1 + discount\ rate)^t} \qquad 5.1$$

where PV_RC^{MO} is the present value of the reduced cost of unserved gas demand for a given mitigation option, Pr_t is the probability of the loss of Ukraine transit capacity in any given year, n is the asset life, t is time in years, CUD^{BC} is the cost of unserved gas in the Base Case, CUD^{MO} is cost of unserved gas due to the implementation of the mitigation option.

5.5.4 Net Benefit

The net benefit is the present value of the benefit less the implementation cost of the mitigation option as shown in Equation 5.2.

$$NPV^{MO} = PV\_RC^{MO} - CC^{MO} \qquad 5.2$$

where NPV^{MO} is the net present value of the benefit derived from a given mitigation option and CC^{MO} is the implementation cost of the given mitigation option.

5.6 Simulation Results

The six (6) mitigation options were modelled to demonstrate their effectiveness on the security of gas supply to GB, during a loss of the Ukraine transit capacity over 90 days in winter. The simulation results of the mitigation options were compared to the Base Case.

5.6.1 Results of EU Gas Supply Measures

Table 5.4 presents the level of unserved gas demand, cost of unserved gas demand and the operational cost of the GB gas and electricity networks in the Base Case, Caspian Supply Case and Nord Stream Case.

The operational cost of the gas network includes the cost of gas import and gas production, storage operation and change in linepack. Operational cost of the electricity network comprises the cost of power generated from the different generation technologies.

Table 5.4 Unserved gas demand and operational costs for EU gas supply measures

Results	**Base Case**	**Caspian Supply Case**	**Nord Stream Case**
Unserved gas demand over 90 days (mcm)	1159	124.3	0
Cost of unserved gas demand (£m)	5096	307	0
Operational cost of gas network (£m)	2337	3469	3396
Operational cost of electricity network (£m)	2082	2003	1532
Total operational cost (£m)	9515	5779	4928

Over the 90-day period, the level of unserved gas decreased from 1159 mcm in the Base Case to 123.3 mcm in the Caspian Supply Case and with the Nord Stream Case, unserved gas demand was totally eliminated. The cost of unserved gas demand decreased from £5096 million during the Base Case to £307 million in the Caspian Supply Case, and further reduced to zero in the Nord Stream Case.

In the Caspian supply case, the reduction in unserved gas demand and cost of unserved gas demand was due to higher gas import from the Caspian region to Southern Europe which minimised the demand for LNG supplies in Continental Europe during the supply disruption.

For the Nord Stream Case, the additional Nord stream pipeline capacity was used to reroute Russian gas supply via Germany to the EU in order to bypass the Ukraine transit pipeline. This resulted in greater gas import to the GB gas network via the two gas interconnectors between GB and continental Europe (IUK & BBL) and prevented unserved gas demand in GB.

The operational cost of the gas network increased by 48% in the Caspian Supply Case and 45% in the Nord Stream Case compared to the Base Case. This was due to the availability of higher volumes of imported gas from the Continent to GB during the supply disruption.

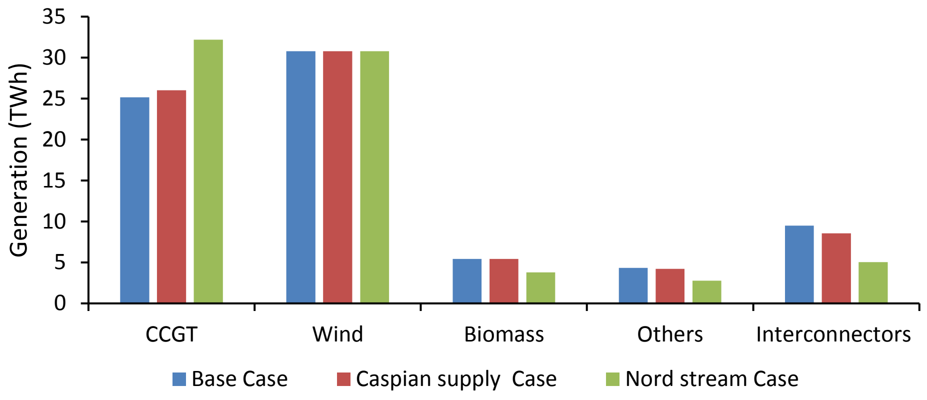

Figure 5.3 GB Power generation from different technologies for EU gas supply measures over 90 days

Figure 5.3 shows GB power generation from different technologies for the Base Case, the Caspian Supply Case and the Nord Stream Case. In the Caspian Supply Case, CCGT generation increased by only 3% (0.9 TWh) with respect to the Base Case, due to the limited gas supply in the gas network.

In the Nord Stream Case, CCGT increased by 28% (7 TWh) with respect to the Base Case due to the additional supply of low cost gas to CCGT generators in the electricity network. As a result, electricity imports from electricity interconnectors decreased by 48% (4.5 TWh) compared to the Base Case.

The slight increase in gas delivery to the electricity network in the Caspian Supply Case resulted in a 3% (£79 million) reduction in the operational cost of GB electricity network compared to the Base Case. In the Nord Stream Case, CCGT power generation displaced expensive electricity import via interconnectors resulting in a 26% (£550 million) reduction in the operational cost of the electricity network compared to the Base Case.

The total operational cost decreased from £9515 million in the Base Case to £5779 million in the Caspian Supply Case and further reduced to £4928 million in the Nord Stream Case.

5.6.2 Results of GB supply measures

Table 5.5 presents the volume of unserved gas demand and the operational cost of the GB gas and electricity network in the Base Case, the Shale Gas Case and Additional Storage Case.

Table 5.5 Unserved gas demand and operational costs for EU gas supply measures over 90 days

Results	**Base Case**	**Shale Gas Case**	**Additional Storage Case**
Unserved gas demand (mcm)	1159	13	119
Cost of unserved gas demand (£m)	5096	32	294
Operational cost of gas network (£m)	2337	3550	3434
Operational cost of electricity network (£m)	2082	1702	1934
Total operational cost of the integrated network (£m)	9515	5284	5662

The level of unserved gas demand decreased from 1159 mcm in the Base Case to 13 mcm in the Shale Gas Case and 119 mcm in the Additional Storage Case. Similarly, the cost of unserved gas demand decreased from £5096 million to £32 million in the Shale Gas Case and £294 million in the Additional Storage Case.

In the Shale Gas Case, the reduction in the volume of unserved gas demand was due to higher output from GB domestic gas production. In the Additional Storage Case, the reduction in the volume of unserved gas was due to the availability of higher volume of stored gas in GB storage facilities compared with the Base Case.

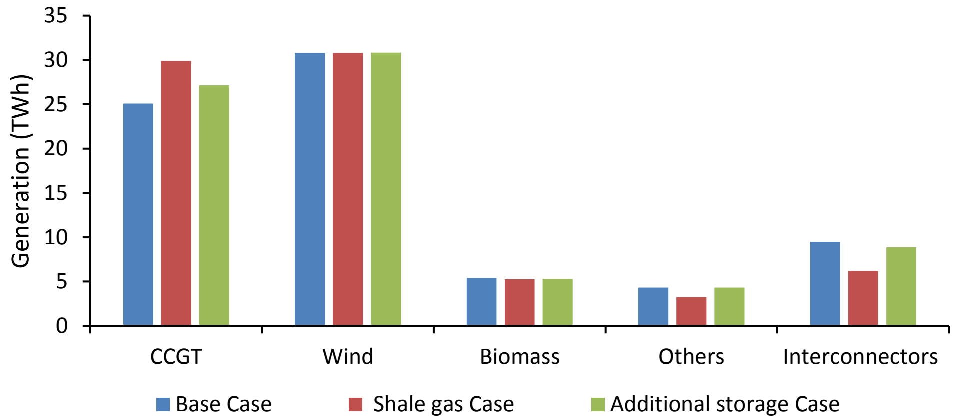

Figure 5.4. GB power generation from different technologies for GB gas supply measures over 90 days

Figure 5.4 shows GB power generation from different technologies for the Base Case, Shale gas Case and Additional Storage Case. In the Shale Gas Case, CCGT generation increased by 21% relative to the Base Case due to the availability of higher gas supply to CCGT generators. As a result, power imported via electricity interconnectors to GB decreased by 35% compared to the Base Case. On the other hand, CCGT generation increased by 8% in the Additional Storage Case relative to the Base due to a slight increase in the volume of gas supplied to CCGT generators. Consequently, operational cost of the electricity network reduced by 19% in the Shale Gas Case and by only 9% in the Additional Storage Case compared to the Base Case.

The total operational cost of the integrated gas and electricity network decreased from £9515 million in the Base Case to £5824 million in the Shale Gas Case and to £5662 in the Additional Storage Case.

5.6.3 GB Gas Demand Measures

The level of unserved gas demand, cost of unserved gas demand and the operational costs of GB gas and electricity networks for the Base Case, Interruptible Demand Case and Fuel Switching Case are shown in Table 5.6.

Table 5.6 Unserved gas demand and operational costs for GB gas demand measures over 90 days

Results	**Base Case**	**Interruptible Demand Case**	**Fuel Switching Case**
Unserved gas demand (mcm)	1159	473	492
Cost of unserved gas demand (£m)	5096	1168	1391
Operational cost of gas network (£m)	2337	4370	3627
Operational cost of electricity network (£m)	2082	1989	2352
Total operational cost of the integrated network (£m)	9515	7527	7370

The level of unserved gas demand in GB decreased from 1159 mcm in the Base Case to 473 mcm in the Interruptible Demand Case and 492 mcm in the Fuel Switching

Case over the 90-day period. The cost of unserved gas reduced from £5096 million in the Base Case to £1168 million in the Interruptible Demand Case and £1391 million in the Fuel Switching Case.

The operational cost of the GB gas network increased by 80% in the Interruptible Demand Case compared to the Base Case due to the high cost of interruptible demand (i.e. the payment made to I & C customers to curtail their gas consumption was assumed as 1.27 £/mcm) [133]. In the Fuel Switching Case, the operation cost of the gas network increased by 55% compared to the Base Case as lower gas demand in power generation made more gas volumes available to other gas consumers in the gas network.

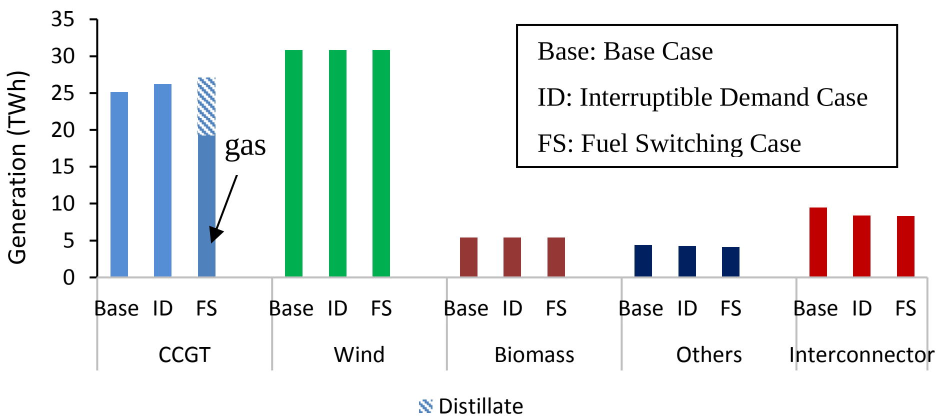

Figure 5.5 GB Power generation from different technologies due to the GB gas demand measures

Figure 5.5 shows the Power generation from different technologies in the GB electricity network for the Base Case, Interruptible Demand Case and Fuel switching Case.

CCGT generation increased by only 4% in the Interruptible Demand Case compared to the Base Case due to restricted gas supply to CCGT generators. The gas demand response provided by Industrial & Commercial (I&C) customers was mainly used to minimise unserved gas demand in the gas network.

In the Fuel Switching Case, gas-fired generation decreased by 21% compared to the Base Case due to the utilisation of distillate fuel (instead of natural gas) in CCGTs generators equipped with dual fuel capabilities. The reduction of gas utilisation in electricity generation, provided more gas volumes within the gas network to minimise the level of unserved gas demand.

In the Interruptible Demand Case, the operational cost of the electricity network decreased by £93 million compared to the Base Case. However, the operational cost of the electricity network increased by £269 million in the Fuel Switching Case compared to the Base Case, due to higher power generation from expensive dual fuel CCGT generators.

The total operational cost for the integrated gas and electricity network decreased by 20.8% in the Interruptible Demand Case compared to the Base Case and 22.5% in the Fuel Switching Case compared to the Base Case.

5.7 Results of Cost Benefit Analysis

Figure 5.6 shows the net present value (NPV) of the reduced cost of unserved gas demand for the six different mitigation options. The NPV gives an indication of the relative cost-effectiveness of the mitigation measures.

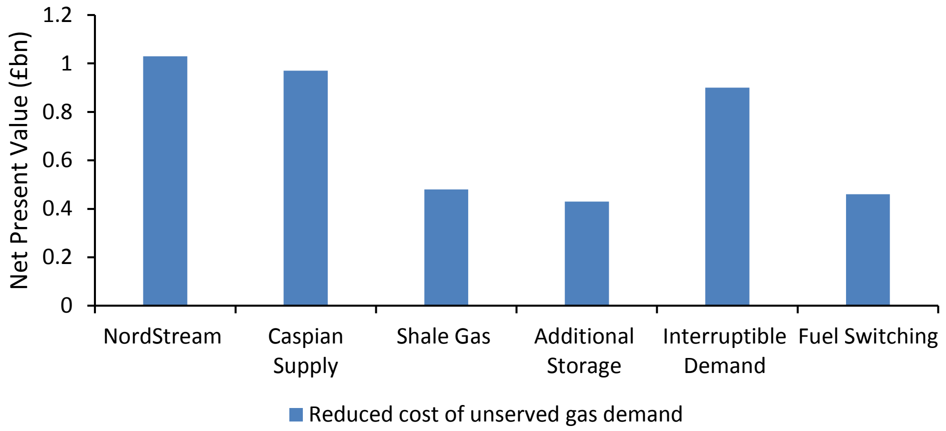

Figure. 5.6 Net benefit of the mitigation options

The Nord Stream Case had a highest positive NPV of **£1.03 billion.** The economic benefit derived from the Nord Stream Case is as a result of two factors. Firstly, the Nord Stream pipeline project provides an alternative route for Russian gas supply to the European Union. Hence the project allowed a complete by-pass of Russian gas transit through Ukraine and eliminated the source of the supply disruption.

Secondly GB bears no investment cost in this project, as GB pipeline interconnectors are not directly linked to the Nord Stream project. Gas imported through European interconnectors to GB can be received from multiple source including domestic gas production in Netherland and imports from Russia, Norway and North Africa and the Caspian. Therefore, it is difficult to determine precisely how much of Russian gas supply transported through the Nord Stream II project will reach GB. Nevertheless, the price of continental gas imported to GB will reflect gas transport tariff on the supply routes.

The Caspian Supply Case showed a positive NPV of **£970 million** as the net benefit of improving security of gas supply in GB. Here, the implementation of this mitigation option enabled higher import of Caspian gas supply to replace some of the missing Russian gas volumes in South East Europe. The implementation of this project enhanced the diversification of gas supply sources in South East Europe resulting in less reliance on Russia gas supply. In addition, cheap pipeline supplies displaced expensive stored gas and LNG supplies in Central and South Europe. Consequently, GB could access higher gas import from the continent Europe and Norway. In addition, the GB gas consumers do not incur any investment cost with regards to this project for the same reason presented in the Nord Stream Case.

The result showed that EU gas supply measure (Nord Stream Case and Caspian Supply Case) were the most cost-effective solutions for improving security of gas supply to GB in the event of the loss of Ukraine transit capacity in Continental Europe.

The economic benefit derived from the Shale Gas Case decreased by 47% when compared to the Nord Stream Case. This is due to the considerable capital cost involved in the exploitation and production of shale gas resources. This option significantly reduced unserved gas demand in GB as expensive domestic gas volumes replaced the missing imported gas supply from the Continent and other sources. Hence the benefits with regards to improving security of supply include a substantial cost.

The Additional Storage Case showed the least economic benefit (NPV of **£430 million)** to improve security of gas supply in GB. This was due to the high capital cost of gas storage facilities. In addition, the short-run marginal cost of storage utilisation (i.e withdrawal and injection) is very low compared to the capital cost. Hence the frequency of storage utilisation to mitigate gas supply disruptions influences its derived economic benefit. For example, if the annual probability of an outage of Ukraine transit capacity increased from 2% to 10% (see section 5.5.1) then the economic benefit of the Additional Storage Case increased from **£430 million to £4.2 billion (980%).**

Investment in new gas production and storage facilities have other benefits besides mitigating unserved gas demand. Some benefits include peak gas demand reductions and supply flexibility to support renewable power generation in the electricity network. However, these benefits were not quantified within the scope of this study.

For GB gas demand measures, the Interruptible Demand Case showed a positive NPV of **£900 million** while the Fuel Switching Case showed a positive NPV of **£460 million**. It was shown in the result that the Interruptible Demand Case would provide significant benefit to improving security of gas supply in GB. Although, the implementation of this option led to a 44% reduction in the volume of unserved gas demand, the corresponding cost of unserved gas demand decreased by 77%. The large economic benefit of the option is mainly driven by the low cost of implementing this mechanism.

5.8 Summary

Six mitigation options to improve security of gas supply in GB were investigated. The mitigation options were modelled using the EGN-CGEN model to determine their impact on the level of unserved gas demand, cost of unserved gas demand, power generation and the cost of operating the combined GB gas and electricity network. A cost benefit analysis was conducted to determine the economic benefits of the mitigation options.

The results showed that all the mitigation options brought about a considerable reduction in the level of unserved gas demand in GB. However, in the Nord Stream Case, unserved gas demand in GB was fully avoided leading to a significant decrease in operational cost of the gas and electricity network. Furthermore, the Nord Stream Case was showed to be the most cost-effective option to improve security of gas supply to GB when Russian gas supply through the Ukraine transit capacity was disrupted.

It is important to note that investment decisions related to pipeline projects in Continental Europe are beyond the control of UK policy makers. Hence, closer regional cooperation among EU member states is essential to drive investment in pipeline projects that deliver indirect security of supply benefits to GB.

It was shown that shale gas development and additional gas storage capacity significantly reduced the level of unserved gas demand in the GB gas network. Consequently, total operational cost of the GB gas and electricity network reduce by 55% in the Shale Gas Case and 40% in the Additional Storage Case compared to the Base Case.

However, the cost-benefit assessment showed that Interruptible Demand Case delivered greater economic benefit when compared with Shale Gas Development Case and Additional Gas Storage Capacity. This was due to the high capital costs associated with shale gas development and the construction of gas storage facilities.

Chapter 6

Conclusion

6.1 Introduction

Security of gas supply risks in the European gas network were identified and their impact on the operation of the GB gas and electricity network investigated. A simplified model of the European gas network was developed to assess the effect of the loss of Russian gas supply through the Ukraine to Europe on gas demand and supply balance across EU member states. In order to investigate the effect of disrupted gas supplies in Europe on the operation of the GB gas and electricity networks, a soft-link approach was used to couple the European gas network model to the GB Combined Gas and Electricity Network (CGEN) model. Six measures to improve security of gas supply to GB were examined and their economic benefits were quantified.

6.1.1 Impact of gas supply disruption on security of gas supply in Europe

Recent events of gas supply disruptions in Europe have highlighted the limited capability of the European gas network to mitigate the impact of gas supply disruptions. A simplified European gas network was developed to investigate the effect of gas supply disruption on security of gas in Europe.

A linear optimisation model of a simplified European gas network was developed to investigate natural gas flows within Europe. The objective function of the model was to minimise the total cost of gas supplied within Europe. The model represented all gas interconnectors including routes to major import sources, LNG terminals and storage facilities in Europe. Each country was represented by a node and country nodes were linked by the gas flows on cross-border interconnectors.

The simplified European gas network model was used to examine the effect of the loss of Ukraine transit capacity on Russian gas supply to Europe in the winter of 2014/15. A Reference Scenario and a High Demand Scenario were investigated. Also, the role of additional interconnector capacities and higher storage withdrawal rate as measures to mitigate the impact of the supply disruption were investigated.

It was shown that the lost gas due the loss of Ukraine transit capacity was replaced mostly by LNG imports and gas stored in European storage facilities. The loss of Ukraine transit capacity during a high gas demand period resulted in unserved gas demand to different gas consumers including the domestic sector in South East Europe.

It was shown that this region was reliant on the Ukraine transit route and had limited alternative supply routes. The simulation result showed that additional capacities on selected interconnectors allowed the rerouting of Russian gas volume through Germany to South East Europe. Higher storage withdrawal rate in selected countries was shown to reduce unserved gas in the South East Europe.

6.1.2 Soft-linking models of the European gas network to the GB gas and electricity networks

Natural gas account for approximately 25% of all energy supplies in the United Kingdom (UK). The rapid decline of UK's domestic gas production has led to an increased dependence on gas import. The GB network receives imported gas in the form of LNG; and pipelines supplies from the Norwegian continental shelf and continental Europe via Belgium and Netherlands.

A soft-link approach was used to couple the European Gas Network model (EGN) to the Combined Gas and Electricity Network model (CGEN). The soft-link method is summarised in the following steps:

- The EGN was run to obtain gas flows on cross-border interconnectors between GB and Continental Europe and their corresponding gas supply prices.
- The CGEN model was run with the gas flows on cross-border interconnectors between GB and Continental Europe and their corresponding gas supply

prices. The output of the CGEN model was the volume of gas consumed in power generation.

- The total GB gas demand calculated from the summation of GB non-electric demand and the volume of gas consumed in power generation was transferred to the EGN model.
- The EGN model is then re-run and the process is repeated until the exchanged variables reach convergence.

The integrated EGN-CGEN model was used to analyse the impact of the loss of Ukraine transit capacity on the operation of GB gas and electricity network over 90 winter days in 2030 for a Reference Scenario and a Slow Transition Scenario.

The Reference Scenario assumed a low non-electric gas demand and high wind generation capacity in GB while the Slow Transition Scenario assumed a high non-electric demand for gas and low wind generation capacity in GB. It was shown that in the Reference Scenario, the supply shortfall to the GB as a result of the loss of Ukraine transit capacity was replaced by gas withdrawn from GB gas storage and a reduction in the amount of gas use by CCGTs in power generation.

In the case of the Slow Transition Scenario, the results showed that industrial consumers would experience an involuntary interruption of 33% (13 mcm/d) of their average daily demand in the event of the loss of the Ukraine transit capacity. The gas supply shortage in GB limited the operation of gas-fired generation. As a result, imported electricity via cross-border interconnectors compensates for the reduction in gas-fired generation in the electricity network.

6.1.3 Investments options to increase security of gas supply in GB

A case study conducted to examine the impact of the loss of Ukraine transit capacity on the GB gas and electricity networks showed that large industrial and commercial customers in GB would experience some unserved gas demand when the supply disruption occurred over prolonged duration of cold winter condition. As a result, six mitigation options were examined to improve security of gas supply to GB.

A Base Case was defined as the Loss of Ukraine transit capacity in the Slow Transition Scenario. The six mitigation options were modelled using the EGN-CGEN model to determine the volume of unserved gas demand, cost of unserved gas demand and the operational cost of the GB gas and electricity network.

A cost-benefit analysis was used to rank the mitigation options in order of increasing net benefit. The net benefit was calculated as the net present value (NPV) of the cost of reducing unserved gas demand in GB gas network. The results showed that Nord Stream Case eliminated unserved gas demand in GB and provided the highest net benefit (NPV of £1.03 billion) at no investment cost to GB consumers. Consequently, the EU projects aimed at the diversifying supply source and supply routes will provide indirect benefit to improving security of gas supply in GB.

It was shown that Additional Storage Case significantly reduced the level of unserved gas demand in GB gas network by 95% at a positive NPV of £430 million. Nevertheless, this mitigation option provided the least net benefit to justify its cost.
The result showed that interruptible demand contracts with large industrial and commercial customers would improve security of gas supply in GB and provide significant economic benefit to the GB gas consumers.

The impact of the mitigation options on the operation of the electricity network was examined through the operation of the gas-fired generators. It was shown that when large volumes of low cost gas were supplied to CCGTs, gas-fired generation displaced electricity generated by other expensive generators leading to a reduction in the operational cost of the electricity network.

6.2 Future Work

Recommendations for further work are grouped into the following areas:
The European gas network model presented in this study comprises all the relevant components of the gas network. However, it lacks a detailed representation of the pressure-flow relationship in pipeline operation. Therefore, a detailed technical model

of the European gas network can be investigated to provide accurate analysis of gas flow and linepack management along cross-border interconnectors in Europe.

In conventional gas network operation, future gas demand is uncertain as it is affected by several factors that have stochastic profiles such weather conditions and consumer behaviour. In this study, a perfect foresight assumption was applied to the EGN-CGEN optimisation model. The perfect foresight model assumes that the system operator has perfect information of the daily gas demand and gas supplies available over the time horizon. A stochastic modelling approach would result in a more accurate analysis of the effect of security of supply risks on integrated gas and electricity networks.

In this study, the scope of energy storage was limited to pumped storage in GB electricity network as the 2015 FES showed a limited contribution of other. However, other energy storage technologies such as grid-scale battery energy storage systems (BESS) are expected to play a key role in meeting peak demand as it becomes cost-competitive with other competing flexible generation technologies. In addition, active management of customers' electricity demand is anticipated to minimise peak demand and improve system balancing. The impact of BESS and demand side response on the utilisation of electricity interconnectors and gas-fired generation in the GB gas and electricity network should be investigated.

A large penetration of variable renewable generation on the European electricity network is expected to increase flexible gas demand in the European gas network. Therefore, a detailed model of an integrated European gas and electricity model that considers variability of renewable generation is required to analyse the impact of gas supply disruption on the security of the gas and electricity supply across Europe.

References

[1] IEA, “World Energy Outlook,” Paris, 2013.

[2] K. Paik, “Sino-Russian Gas and Oil Cooperation: Entering into a new era of strategic partnership.,” Oxford, 2015.

[3] BP, “BP Energy Outlook 2035,” *country and regional insights -Russia*, 2015. [Online]. Available: http://www.bp.com/content/dam/bp/pdf/energy-economics/energy-outlook-2015/Country_insights_Russia_2035.pdf. [Accessed: 08-Jan-2016].

[4] IEA, “World Energy Outlook: Are we entering a golden age of gas?,” Paris, 2011.

[5] EIA, “Annual Energy Outlook 2015,” 2015. [Online]. Available: http://www.eia.gov/forecasts/aeo/section_energyprod.cfm. [Accessed: 24-Jul-2016].

[6] European Commission, “Energy statistics - supply, transformation and consumption (nrg_10) annual data,” *Eurostat*, 2017. [Online]. Available: http://ec.europa.eu/eurostat/data/database. [Accessed: 10-Feb-2017].

[7] European Commission, “Energy security strategy,” 2015. [Online]. Available: https://ec.europa.eu/energy/node/192. [Accessed: 24-Dec-2015].

[8] ENTSOG, “Baltic energy market interconnection plan,” Brussels, 2014.

[9] ENSTOG, “Ten Year Network Development Plan (TYNDP),” Brussels, 2015.

[10] European Commission, “EU energy, transport and GHG Emissions trends to 2050,” Brussels, 2013.

[11] Eurogas, “Eurogas roadmap 2050,” 2011. [Online]. Available: http://www.eurogas.org/uploads/media/Eurogas_Roadmap_2050_-_summary_13.10.11_01.pdf. [Accessed: 23-Mar-2014].

[12] National Grid, “Winter Outlook 2014/2015,” Warwick, 2014.

[13] ENSTOG, “Ten Year Network Development Plan (TYNDP) 2013-2022- Annex C: Supply & demand corrigendum,” 2013. [Online]. Available: http://www.entsog.eu/publications/tyndp#ENTSOG-TEN-YEAR-NETWORK-DEVELOPMENT-PLAN-2013-2022. [Accessed: 14-Oct-2014].

[14] S. Bassi *et al.*, “Bridging the gap: Improving the economic and policy framework for carbon capture and storage in the European Union,” 2015. [Online]. Available: http://www.lse.ac.uk/GranthamInstitute/wp-content/uploads/2015/06/GRI_LSE_CCS_web.pdf. [Accessed: 12-May-2016].

[15] A. Honore, “The outlook for natural gas demand in Europe,” 2014. [Online]. Available: https://www.oxfordenergy.org/wpcms/wp-content/uploads/.../NG-87.pdf. [Accessed: 10-Jan-2015].

[16] European Parliament, “Liquefied natural gas in Europe,” 2015. [Online]. Available: http://www.europarl.europa.eu/RegData/etudes/BRIE/2015/571314/EPRS_BRI(2015)571314_EN.pdf. [Accessed: 02-Feb-2016].

[17] BP, “BP energy outlook 2030,” 2013. [Online]. Available: http://www.bp.com/content/dam/bp/pdf/statistical-review/EnergyOutlook2030/BP_Energy_Outlook_2030_Booklet_2013.pdf.

[18] ENTSOG, “Ten Year Network Development Plan (TYNDP) 022-150307 Annex C: demand and supply,” Brussels, 2015.

[19] Eurogas, “Statistical report,” Brussels, 2015.

[20] Gasum, “TSO operations and system responsibility,” 2014. [Online]. Available: http://www.gasum.com/transmission-portal/TSO/. [Accessed: 04-Jan-2016].

[21] S. Mokhatab, W. A. Poe, and J. G. Speight, *Handbook of Natural Gas Transmission and Processing*. Oxford: Elsevier, 2006.

[22] ENSTOG, “Ten Year Network Development Plan (TYNP) 2013 -2022, Main Report,” Brussels, 2013.

[23] Ramboll, “Study on natural gas storage in the EU,” 2008. [Online]. Available:

http://www.ramboll.com/projects/rog/natural gas storage in the eu_inactive. [Accessed: 13-May-2015].

[24] C. Le Fevre, “Gas Storage in Great Britain,” 2013. [Online]. Available: https://www.oxfordenergy.org/wpcms/wp-content/uploads/2013/01/NG-72.pdf. [Accessed: 05-Feb-2015].

[25] Gas Infrastructure Europe, “GSE Storage Map,” 2015. [Online]. Available: http://www.gie.eu/index.php/maps-data/gse-storage-map. [Accessed: 14-Nov-2015].

[26] U. Remme, M. Blesl, and U. Fahl, “Future European gas supply in the resource triangle of the former Soviet Union, the Middle East and Northern Africa,” *Energy Policy*, vol. 36, pp. 1622–1641, 2008.

[27] National Grid, “Gas Ten Year Statement,” Warwick, 2014.

[28] International Gas Union, “World LNG Report,” 2015. [Online]. Available: file:///D:/LNG and Unconvetional gas report/IGU-World LNG Report-2015 Edition.pdf. [Accessed: 12-Feb-2016].

[29] J. Watson, “UK Gas Security: Threats and mitigation strategies,” Sussex, 2010.

[30] ofgem, “Gas security of supply report,” London, 2012.

[31] National Grid, “Future Energy Scenarios,” Warwick, 2015.

[32] National Grid, “Electricity Ten Year Statement 2014,” Warwick, 2014.

[33] IEA, “Energy Supply Security 2014,” 2014. [Online]. Available: https://www.iea.org/media/freepublications/security/EnergySupplySecurity2014_PART1.pdf. [Accessed: 03-Mar-2016].

[34] European Commission, “In-depth Study of European Energy Security,” Brussels, 2014.

[35] IEA, “European Union-28: Natural Gas for 2000,” 2000. [Online]. Available: https://www.iea.org/statistics/statisticssearch/report/?country=EU28&product

=naturalgas&year=2000. [Accessed: 10-Mar-2016].

[36] IEA, “European Union-28: Natural Gas for 2013,” 2013. [Online]. Available: https://www.iea.org/statistics/statisticssearch/report/?country=EU28&product=naturalgas&year=2013. [Accessed: 10-Mar-2016].

[37] Eurostat, “Energy Dependence,” 2016. [Online]. Available: http://ec.europa.eu/eurostat/tgm/refreshTableAction.do?tab=table&plugin=1&pcode=tsdcc310&language=en. [Accessed: 21-Jun-2016].

[38] Eurostat, “Supply-gas- monthly data (nrg_103m),” 2014. [Online]. Available: http://epp.eurostat.ec.europa.eu/portal/page/portal/energy/data/database. [Accessed: 05-May-2015].

[39] European Commission, “The January 2009 gas supply distruption to the EU: An assessment,” 2009. [Online]. Available: http://ec.europa.eu/energy/strategies/2009/doc/sec_2009_0977.pdf.

[40] S. Pirani, J. Stern, and Y. Katja, “The Russo-Ukrainian gas dispute of January 2009: A comprehensive assessment,” Oxford, 2009.

[41] S. Lochner and C. Dieckhoner, “Civil unrest in North Africa - risks for natural gas supply?,” *Energy Policy*, vol. 45, pp. 167–175, 2012.

[42] National Grid, “2010 winter outlook & a future view,” 2010. [Online]. Available: http://www.biee.org/wpcms/wp-content/uploads/2010-Winter-Outlook-and-a-future-view.pdf. [Accessed: 12-Jun-2014].

[43] J. Grigorjeva and M. Siddi, “Nord Stream 2: Opportunities and dilemmas of a new gas supply route to the EU,” 2016. [Online]. Available: http://www.delorsinstitut.de/2015/wp-content/uploads/2016/05/20160510_Nord-Stream-2_Grigorjeva_Siddi-ONLIN.pdf. [Accessed: 01-Jul-2016].

[44] TAP, “Trans Adriatic Pipeline,” 2016. [Online]. Available: http://www.tap-ag.com/the-pipeline. [Accessed: 10-Jul-2016].

[45] P. Noel, S. Findlater, and C. K. Chyong, “The cost of Improving Gas Supply in

the Baltic States," 1203, 2012.

[46] AB Klaipedos Nafta, "LNG Terminal," 2015. [Online]. Available: http://www.sgd.lt/index.php?id=633. [Accessed: 07-Aug-2016].

[47] Gas Infrastructure Europe, "GLE LNG map dataset in excel - format," 2014. [Online]. Available: http://www.gie.eu/index.php/maps-data/lng-map. [Accessed: 16-Jun-2014].

[48] European Union, *Regulation (EU) No 994/2010 of the European parliament and of the council of 20 October 2010 concering measures to safeguard security of gas supply and repealing Council Directive 2004/67/EC*. 2010.

[49] R. Z. Ríos-Mercado and C. Borraz-Sánchez, "Optimization problems in natural gas transportation systems: A state-of-the-art review," *Appl. Energy*, vol. 147, pp. 536–555, 2015.

[50] A. Osiadacz, *Simulation and analysis of gas networks*. Gulf Publishing Company, 1987.

[51] H. Üster and Ş. Dilaveroğlu, "Optimization for design and operation of natural gas transmission networks," *Appl. Energy*, vol. 133, pp. 56–69, 2014.

[52] B. C. Dorin and D. T. Leonida, "On modelling and simulating natural gas transmission systems (Part1)," *J. Control Eng. Appl. Informatics*, vol. 10, no. 3, pp. 27–36, 2008.

[53] A. Osiadacz and M. Chaczykowski, "Comparison of isothermal and non-isothermal pipeline flows gas flow models," *Chem. Eng.*, vol. 81, no. 1, pp. 41–51, 2001.

[54] H. F.S and G. J. Lieberman, *Introduction to operations research*, 10th Editi. New York: Mc Graw Hill Education, 2015.

[55] C. Borraz-Sanchez, "Optimization methods for pipeline transportation of natural gas," University of Bergen, Norway, 2010.

[56] H. Cremer, F. Gasmi, and J.-J. Laffont, "Access to pipelines in competitive gas

markets," *J. Regul. Econ.*, vol. 24, pp. 5–33, 2003.

[57] S. Lochner, "Identification of congestion and valuation of transport infrastructures in the European natural gas market," *Energy*, vol. 36, no. 5, pp. 2483–2492, 2011.

[58] J. Perner and A. Seeliger, "Prospects of gas supplies to the European market until 2030—results from the simulation model EUGAS," *Util. Policy*, vol. 12, no. 4, pp. 291–302, 2004.

[59] D. De Wolf and Y. Smeers, "The gas transmission problem solved by an extension of the simplex algorithm," *Manage. Sci.*, vol. 46, no. 11, pp. 1454–1465, 2000.

[60] W. Pepper, B. . Ring, E. . Read, and S. . Starkey, "Implementation of a scheduling and pricing model for natural gas," in *Handbook of networks in power systems II*, 1st Editio., Berlin: Springer, 2012, pp. 3–37.

[61] R. Z. Rios-Mercado, K. Seongbae, and E. A. Boyd, "Efficient operation of natural gas transmission systems: A network-based heuristic for cyclic structures," *Comput. Oper. Res.*, vol. 33, no. 8, pp. 2323–2351, 2006.

[62] R. Weijermars, G. Drijkoningen, T. J. Heimovaara, E. S. J. Rudolph, G. J. Weltje, and K. H. A. A. Wolf, "Unconventional gas research initiative for clean energy transition in Europe," *J. Nat. Gas Sci. Eng.*, vol. 3, no. 2, pp. 402–412, 2011.

[63] S. Wu, R. Z. Ríos-Mercado, E. A. Boyd, and L. R. Scott, "Model relaxations for the fuel cost minimization of steady-state gas pipeline networks," *Math. Comput. Model.*, vol. 31, no. 2–3, pp. 197–220, Jan. 2000.

[64] H. S. Lall and P. B. Percell, "A dynamic programming based gas pipeline optimizer," in *Analysis and optimization of system, Lecture notes in control and information sciences, vol 144*, A. Bensoussan and J. Lions, Eds. Berlin: Springer-Verlag, 2008, pp. 123–132.

[65] M. Lienert and S. Lochner, "The importance of market interdependencies in

modeling energy systems – The case of the European electricity generation market," *Int. J. Electr. Power Energy Syst.*, vol. 34, no. 1, pp. 99–113, 2012.

[66] V. Uraikul, C. . Chan, and P. Tontiwachwuthikul, "A mixed-integer optimization model for compressor selection in natural gas pipeline network system operations," *J. Environ. Informatics*, vol. 3, pp. 33–41, 2004.

[67] M. Chaudry, N. Jenkins, and G. Strbac, "Multi-time period combined gas and electricity network optimisation," *Electr. Power Syst. Res.*, vol. 78, no. 7, pp. 1265–1279, Jul. 2008.

[68] W. Lise, B. F. Hobbs, and F. Van Oostvoorn, "Natural gas corridors between the EU and its main suppliers: Simulation results with the dynamic GASTALE model," *Energy Policy*, vol. 36, pp. 1890–1906, 2008.

[69] F. Gracceva and P. Zeniewski, "A systemic approach to assessing energy security in a low-carbon EU energy system," *Appl. Energy*, vol. 123, pp. 335–348, 2014.

[70] S. Lochner, "Modeling the European natural gas market during the 2009 Russian-Ukrainian gas conflict: Ex-post simulation and analysis," *J. Nat. Gas Sci. Eng.*, vol. 3, no. 1, pp. 341–348, 2011.

[71] A. Neumann, N. Viehrig, and H. Weigt, "InTraGas-a stylized model of the European natural gas network," 2009.

[72] A. Szikszai and F. Monforti, "GEMFLOW: A time dependent model to assess responses to natural gas supply crises," *Energy Policy*, vol. 39, no. 9, pp. 5129–5136, 2011.

[73] R. Carvalho, L. Buzna, F. Bono, M. Masera, D. Arrowsmith, and D. Helbing, "Resilience of natural gas networks during conflicts, crisies and distruptions," *PLoS One*, vol. 9, no. 3, 2014.

[74] W. Lise and B. F. Hobbs, "Future evolution of the liberalised European gas market: Simulation results with a dynamic model," *Energy*, vol. 33, no. 7, pp. 989–1004, 2008.

[75] F. Holz, C. Von Hirschhausen, and C. Kemfert, “Perspectives of the European natural gas markets until 2025,” *Energy J.*, pp. 137–150, 2009.

[76] F. Van Oostvoorn Lise .W, “Anaylsis and assesment of the optimal gas corridors and infrastructure to secure supply in Europe (A model based approach),” Energy Research Centre of the Netherlands, 2007.

[77] W. Lise and B. F. Hobbs, “A dynamic simulation of market power in the liberalised European natural gas market,” *Energy J.*, vol. 30, pp. 119–136, 2009.

[78] IEA, “World: Electricity and Heat for 1990,” 2016. [Online]. Available: https://www.iea.org/statistics/statisticssearch/report/?country=WORLD&product=electricityandheat&year=1990. [Accessed: 23-Feb-2016].

[79] IEA, “World: Electricity and Heat for 2010,” 2016. [Online]. Available: https://www.iea.org/statistics/statisticssearch/report/?country=WORLD&product=electricityandheat&year=2010. [Accessed: 23-Feb-2016].

[80] P. J. Hibbard and T. Schatzki, “The interdependence of electricity and natural gas: Current factors and future prospects,” *Electr. J.*, vol. 25, no. 4, pp. 6–17, May 2012.

[81] I. Vos, “The impact of wind power on European natural gas markets,” Paris, 2012.

[82] European Commission, “Energy Union: Secure, sustainable, competitive, affordable energy for every European,” Brussels, 2015.

[83] R. Rubio-Barros, D. Ojeda-Esteybar, O. Ano, and A. Vargas, “Combined operational planning of natural gas and electric power systems: State of the art,” in *Natural Gas*, Primoz Potocnik, Ed. INTECH, 2010.

[84] European Commission DG for, “Study on synergies between electricity and gas balancing markets,” 2012.

[85] P. Donna and R. Poudineh, “A holistic framework for the study of interdependence between electricity and gas sectors,” Oxford, 2015.

[86] M. Qadrdan, M. Chaudry, J. Wu, N. Jenkins, and J. Ekanayake, "Impact of a large penetration of wind generation on the GB gas network," *Energy Policy*, vol. 38, no. 10, pp. 5684–5695, 2010.

[87] B. Söderbergh, K. Jakobsson, and K. Aleklett, "European energy security: An analysis of future Russian natural gas production and exports," *Energy Policy*, vol. 38, no. 12, pp. 7827–7843, 2010.

[88] M. Urbina and Z. Y. Li, "Modeling and analyzing the impact of interdependency between natural gas and electricity infrastructures," *2008 IEEE Power Energy Soc. Gen. Meet.*, vol. 1–11, pp. 644–649, 2008.

[89] L. Tao, E. Mircea, and M. Shahidehpour, "Interdependency of natural gas network and power system security," *IEEE Trans. power Syst.*, vol. 23, no. 4, 2008.

[90] N. R. Keyaerts, Y. Rombauts, E. D. Delarue, and W. D. D'Haeseleer, "Impact of wind power on natural gas markets: Inter market flexibility," in *Energy Market (EEM), 2010 7th International Conference on the European*, 2010, pp. 1–6.

[91] M. Chaudry, J. Skea, X. Wang, and N. Jenkins, "Modelling UK energy system response to natural gas supply infrastructure failures," *Proc. Inst. Mech. Eng. Part A J. Power Energy*, vol. 226, no. 4, pp. 501–513, Apr. 2012.

[92] M. Chaudry, N. Jenkins, M. Qadrdan, and J. Wu, "Combined gas and electricity network expansion planning," *Appl. Energy*, vol. 113, pp. 1171–1187, 2014.

[93] J. Abrell and H. Weigt, "Electricity markets working papers: Combining energy networks," 2010.

[94] J. Abrell and H. Weigt, "Investments in a combined energy network model: substitution between natural gas and electricity?," *SSRN Electron. J.*, 2014.

[95] O. Ozdemir, K. C. Veum, J. de Joode, G. Migliavacca, A. Grassi, and A. Zani, "The impact of large-scale renewable integration on Europe's energy corridors," in *PowerTech, 2011 IEEE Trondheim*, 2011, pp. 1–8.

[96] N. Keyaerts, E. Delarue, Y. Rombauts, and W. D'haeseleer, "Impact of unpredictable renewables on gas-balancing design in Europe," *Appl. Energy*, vol. 119, pp. 266–277, Apr. 2014.

[97] M. Qadrdan, M. Abeysekera, M. Chaudry, J. Wu, and N. Jenkins, "Role of power-to-gas in an intergrated gas and electricity system in Great Britain," *Int. J. Hydrogen Energy*, vol. 40, pp. 5763–5775, 2015.

[98] European Commission, "The January 2009 gas supply disruption to the EU: An assessment," Brussels, 2009.

[99] FICO, "FICO Xpress optimisation suite," 2014. [Online]. Available: http://www.fico.com/en/products/fico-. [Accessed: 01-Jan-2014].

[100] M. Thompson, M. Davison, and H. Rasmussen, "Natural gas storage valuation and optimisation: A real options application," 2009. [Online]. Available: http://www.apmaths.uwo.ca/(mdavison/ library/. [Accessed: 10-Oct-2014].

[101] Eurostat, "Import (by country of origin)-gas-monthly data[nrg_124m]," 2014. [Online]. Available: http://appsso.eurostat.ec.europa.eu/nui/show.do?dataset=nrg_124m&lang=en.

[102] ENSTOG, "Winter supply outlook 2014/15." [Online]. Available: http://www.entsog.eu/public/uploads/files/publications/Outlooks & Reviews/2014/SO0008-141103_WinterSupplyOutlook2014-15_Review2013-14.pdf. [Accessed: 01-May-2015].

[103] ENTSOG, "Ten Year Network Development Plan (TYNDP) 2013-2022 - Annex A: Infrastructure Projects Corrigendum," Brussels, 2013.

[104] European Commission, "Communication from the commission to the European Parliament and the Council on the short term resilence of the European gas system. Preparedness for a possible disruption of winter supplies from the east during the fall and winter of 2014/2015," Brussels, 2014.

[105] Eurogas, "Statistical report," 2012. [Online]. Available: http://www.eurogas.org/uploads/media/Statistics_2012_21.11.12.pdf.

[Accessed: 24-Jul-2103].

[106] IEA, “Bosnia and Herzegovina: Natural gas for 2013,” 2013. [Online]. Available: https://www.iea.org/statistics/statisticssearch/report/?year=2013&country=BOSNIAHERZ&product=NaturalGas. [Accessed: 27-Sep-2016].

[107] IEA, “Former Yugoslav Republic of Macedonia: Natural gas for 2013,” 2016. [Online]. Available: https://www.iea.org/statistics/statisticssearch/report/?country=FYROM&product=naturalgas&year=2013. [Accessed: 27-Sep-2016].

[108] IEA, “Bulgaria : Natural gas for 2013,” 2016. [Online]. Available: https://www.iea.org/statistics/statisticssearch/report/?country=BULGARIA&product=naturalgas&year=2013. [Accessed: 27-Sep-2016].

[109] Energy Market Partners, “Study on the improvement of interconnection, interoprability, transparency and harmonisation of operational rules of natural gas transportation in the Energy Community,” London, 2009.

[110] Eurogas, “Statistical report 2014,” 2014. [Online]. Available: http://www.eurogas.org/uploads/media/Eurogas_Statistical_Report_2014.pdf. [Accessed: 24-Dec-2015].

[111] M. Bradshaw, G. Bridge, S. Bouzarovski, J. Watson, and J. Dutton, “The UK’s global gas challenge,” UKERC : London, 2014.

[112] European Commission, “Energy statistics - supply, transformation and consumption (nrg_103) monthly data,” *Eurostat*, 2017. [Online]. Available: http://ec.europa.eu/eurostat/data/database. [Accessed: 17-Feb-2017].

[113] Gas Infrastructure Europe, “Historical data,” *Aggregated gas storage inventory*, 2017. [Online]. Available: https://agsi.gie.eu/#/historical//GB. [Accessed: 12-Mar-2017].

[114] National Grid, “UK Future Energy Scenarios,” Warwick, 2014.

[115] European Commission, “Eurostat,” 2014. [Online]. Available:

http://epp.eurostat.ec.europa.eu/portal/page/portal/statistics/themes. [Accessed: 05-May-2015].

[116] ENSTOG, “Winter supply outlook 2010/2011,” Brussels, 2011.

[117] National Grid, “Historical demand data,” 2010. [Online]. Available: http://www2.nationalgrid.com/UK/Industry-information/Electricity-transmission-operational-data/Data-Explorer/. [Accessed: 25-Jan-2015].

[118] ENSTOG, “The European natural gas network -(Capacities at cross-border points on the primary market).” Brussels, 2013.

[119] ENTSOG, “The European natural gas network -(Capacities at cross-border points on the primary market),” 2014. [Online]. Available: http://www.entsog.eu/public/uploads/files/maps/transmissioncapacity/2014/ENTSOG_140612_CAP_JUNE2014.pdf. [Accessed: 03-Aug-2014].

[120] London Economics, “Estimating Value of Lost Load (VoLL),” London, 2011.

[121] BP, “BP statistical review of world energy 2015,” 2015. [Online]. Available: https://www.bp.com/content/dam/bp/pdf/energy-economics/statistical-review-2015/bp-statistical-review-of-world-energy-2015-full-report.pdf. [Accessed: 10-Jul-2016].

[122] TANAP, “Trans Anatolian Natural Gas Pipeline Project,” 2016. [Online]. Available: http://www.tanap.com/tanap-project/why-tanap/. [Accessed: 09-Jul-2016].

[123] Gazprom, “Nord Stream.” [Online]. Available: http://www.gazprom.com/about/production/projects/pipelines/nord-stream/.

[124] EIA, “16% of natural gas consumed in Europe flows through Ukraine,” 2014. [Online]. Available: http://www.eia.gov/todayinenergy/detail.cfm?id=15411.

[125] I. Andrews, “The Carboniferous bowland shale gas study: Geology and resource estimation,” London, 2013.

[126] Shell, “Understanding tight and shale gas,” 2013. [Online]. Available:

http://www.shell.us/aboutshell/shell-businesses/onshore/shale-tight.html. [Accessed: 15-Aug-2012].

[127] C. Taylor, “Getting shale gas working,” 2013. [Online]. Available: http://www.iod.com/influencing/press-office/press-releases/new-iod-report-getting-shale-gas-working. [Accessed: 06-Jun-2016].

[128] Poyry, “How will Lancanshire shale gas impact the GB energy market?,” 2012. [Online]. Available: http://www.poyry.com/sites/default/files/imce/files/shale_gas_point_of_view_small.pdf. [Accessed: 10-Apr-2014].

[129] The Royal Society and the Royal Academy of Engineering, “Shale gas extraction in the UK: A review of hydraulic fracturing,” London, 2012.

[130] Economic Affairs Committee, “The economic impact on UK energy policy of shale gas and oil,” London, 2014.

[131] D. Mackay and S. Timothy, “Potential greenhouse gas emission associated with shale gas extraction and use,” London, 2013.

[132] Centrica, “Centrica Storage,” 2016. [Online]. Available: https://www.centrica.com/about-us/our-brands/centrica-storage.

[133] DECC, “UK Risk assessment on security of gas supply,” London, 2014.

[134] Poyry, “Gas SCR - Cost-benefit analysis for a demand- side response mechanism,” Oxford, 2014.

[135] Ofgem, “Gas Significant Code Review (SRC),” 2014. [Online]. Available: https://www.ofgem.gov.uk/gas/wholesale-market/market-efficiency-review-and-reform/gas-significant-code-review-scr. [Accessed: 21-Jun-2016].

[136] Poyry, “GB Gas security of supply and options for improvement,” Oxford, 2010.

[137] Poyry, “Macroeconomic effects of European shale gas production,” 2013. [Online]. Available:

http://www.poyry.co.uk/sites/poyry.co.uk/files/public_report_ogp__v5_0.pdf. [Accessed: 16-Feb-2015].

[138] ofgem, "Gas significant code review impact assessment for final policy decision," London, 2014.

[139] C. Poletti, G. Cervigni, A. Creti, and S. Vignetti, "Investment on transport infrastructures for natural gas and electricity," Brussels, 2011.

[140] Poyry, "Security of gas supply in European scenarios, policy drivers and impact on GB," Oxford, 2010.

[141] GLE, "GLE LNG Map," 2011. [Online]. Available: http://www.gie.eu.com/index.php/maps-data/lng-map. [Accessed: 17-Jun-2013].

[142] A. Tomlin, J, "Special ordered sets and an application to gas supply operation planning," *Math. Program.*, vol. 42, pp. 69–84, 1988.

[143] I. Cameron, "Using excel based model for the steady state and transient simulation,in:," in *Pipeline Simulation Interest Group (PSIG), 31st annual meeting*, 1999, p. 20–22.

[144] S. An, Q. Li, and T. . Gedra, "Natural gas and electricity optimal power flow," *Transm. Distrib. Conf. Expo. IEEE PES*, vol. 1, pp. 138–143, 2003.

Appendix A

Table A.1 List of countries and their abbreviations

Country	**Code**
Algeria	DZ
Austria	AT
Azerbaijan	AZ
Belarus	BY
Belgium	BE
Bosnia and Herzegovina	BA
Bulgaria	BG
Croatia	HR
Czech Republic	CZ
Denmark	DK
Estonia	EE
Finland	FI
France	FR
Germany	DE
Greece	GR
Hungary	HU
Ireland	IE
Italy	IT
Latvia	LV
Libya	LY

Lithuania	LT
Iran	IR
Luxembourg	LU
Macedonia	MK
Netherlands	NL
Norway	NO
Poland	PL
Portugal	PT
Romania	RO
Russia-Kaliningrad	RK
Russian Federation	RU
Serbia	RS
Slovakia	SK
Slovenia	SI
Spain	ES
Sweden	SE
Switzerland	CH
Turkey	TR
Ukraine	UA
United Kingdom	UK

Appendix B

Input data for the European Gas Network Model

Table B.1. Reference Demand Case – Winter 2015 Demand for European Countries [13]

Country	Average monthly demand (mcm/d)						Peak day Demand (mcm/d)
	Oct	Nov	Dec	Jan	Feb	Mar	
Austria	29	33	41	43	41	33	76
Belgium	45	61	87	76	70	67	141
Bosnia	1	2	2	2	2	2	3
Bulgaria	8	10	13	14	13	12	17
Croatia	10	11	13	12	13	11	12
Czech Republic	25	31	44	46	44	34	73
Denmark	9	11	15	16	16	13	25
Estonia	1	2	3	4	5	5	5
Finland	12	13	16	16	17	14	23
France	105	169	226	251	225	181	419
Germany	214	247	327	331	320	256	469
Greece	14	14	15	16	16	15	22
Hungary	30	37	50	53	51	39	89
Ireland	13	16	18	18	16	16	25

Italy	212	268	340	356	339	286	486
Latvia	4	5	7	8	8	6	11
Lithuania	8	9	11	12	12	10	17

Country	**Average monthly demand (mcm/d)**						**Peak day demand (mcm/d)**
	Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	
Luxembourg	4	4	5	5	5	4	7
Macedonia	1	1	1	1	1	1	1
Netherlands	108	127	172	185	160	112	416
Poland	51	55	71	74	72	61	85
Portugal	14	14	14	14	16	15	28
Romania	35	40	50	47	52	45	70
Serbia	7	9	11	12	12	10	13
Slovakia	16	18	19	27	28	18	37
Slovenia	3	3	4	4	4	3	6
Spain	103	118	126	128	128	113	205
Sweden	5	5	7	7	7	6	9
Switzerland	6	10	13	15	13	11	20
Turkey	118	128	162	172	166	152	200
United Kingdom	201	262	330	313	292	262	487

Table B.2. High Demand Case – Winter 2015 Demand for European Countries [13]

Country	Average monthly demand (mcm/d)					
	Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**
Austria	35	40	49	52	49	40
Belgium	54	73	104	91	84	80
Bosnia	1	2	2	2	2	2
Bulgaria	10	12	16	17	16	14
Croatia	12	13	16	14	16	13
Czech Republic	30	37	53	55	53	41
Denmark	11	13	18	19	19	16
Estonia	1	2	4	5	6	6
Finland	14	16	19	19	20	17
France	126	203	271	301	270	217
Germany	257	296	392	397	384	307
Greece	17	17	18	19	19	18
Hungary	36	44	60	64	61	47
Ireland	16	19	22	22	19	19
Italy	254	322	408	427	407	343
Latvia	5	6	8	10	10	7
Lithuania	10	11	13	14	14	12
Luxembourg	5	5	6	6	6	5
Macedonia	1	1	1	1	1	1
Netherlands	130	152	206	222	192	134
Poland	61	66	85	89	86	73
Portugal	17	17	17	17	19	18
Romania	42	48	60	56	62	54
Serbia	8	11	13	14	14	12
Luxembourg	5	5	6	6	6	5

Country	Average monthly demand (mcm/d)					
	Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**
Netherlands	108	127	172	185	160	112
Poland	51	55	71	74	72	61
Portugal	14	14	14	14	16	15
Romania	35	40	50	47	52	45
Serbia	7	9	11	12	12	10
Slovakia	16	18	19	27	28	18
Slovenia	3	3	4	4	4	3
Spain	103	118	126	128	128	113
Sweden	5	5	7	7	7	6
Switzerland	6	10	13	15	13	11
Turkey	118	128	162	172	166	152
United Kingdom	201	262	330	313	292	262

Table B.3. European Natural Gas Production Capacities and Cost [65]

Country	Maximum supply (mcm/d)	Production Cost (€/tcm)
Austria	5	164
Bulgaria	2	141
Croatia	5	124
Denmark	16	88
Germany	29	164
Hungary	7	130
Italy	22	164
Netherlands	450	152

Poland	10	160
Romania	29	160
United Kingdom	142	160

Table B.4. European Gas Supply Capacities from Imported Sources and Cost [13],[1]

Country	Maximum supply (mcm/d)	Production Cost (€/cm)
Russia	500	0.1
Norway	330	0.15
Algeria	111.4	0.02
Libya	30	0.09
LNG	355	0.18

Table B.5. LNG regasification capacities[141]

Country	LNG regasification capacity (mcm/d)
Belgium	40.8
France	65
Greece	18
Italy	35.4
Netherlands	32.4
Portugal	32.4
Spain	164.7
Sweden	1.78
Turkey	38
United Kingdom	134

Table B.6. European Gas Storage Capacities

Country	Working gas volume (mcm)	Max withdrawal rate (mcm/d)	Max injection rate (mcm/d)
Austria	7451	86	70
Belgium	700	15	8
Bulgaria	550	4	4
Croatia	550	4	4
Czech Republic	3497	57	41
Denmark	1025	18	8
France	12920	341	163
Germany	21822	535	294
Hungary	6330	82	47
Ireland	230	6	5
Italy	16673	290	137
Latvia	2820	31	12
Netherlands	5278	216	59
Poland	177	33	20
Portugal	177	7	3
Romania	3100	24	30
Serbia	450	5	4
Slovakia	3020	38	23
Spain	4103	32	23
Sweden	8.5	1	0
Turkey	2655	20	18
United Kingdom	4504	121	82

Table B.7. Maximum cross-border capacities of European gas interconnectors

Linking Countries		**Maximum cross border capacity (mcm/d)**	
From (A)	**To (B)**	**Forward flow (A-B)**	**Reverse flow (B-A)**
Austria	Germany	35.27	30.52
Austria	Hungary	11.64	
Austria	Italy	103.27	17.06
Austria	Slovakia	3.27	147.45
Austria	Slovenia	10.28	
Belarus	Lithuania	25.55	
Belarus	Poland	100.39	
Belgium	France	74.55	
Belgium	Germany	27.25	35.82
Belgium	Luxembourg	4.36	
Belgium	Netherlands	35.45	109.10
Belgium	United Kingdom	73.18	56.69
Bulgaria	Greece	12.00	
Bulgaria	Macedonia	2.98	
Bulgaria	Turkey	42.47	3.50
Czech Republic	Germany	128.12	119.76
Czech Republic	Poland	1.36	
Czech Republic	Slovakia	19.00	42.68
Denmark	Germany	2.87	1.55

Denmark	Sweden	6.55	
France	Spain	15.00	15.00
France	Switzerland	20.27	
Germany	France	55.60	
Germany	Luxembourg	2.34	
Germany	Netherland	37.92	164.79
Germany	Poland	3.09	84.64
Hungary	Croatia	6.91	
Hungary	Romania	4.55	
Hungary	Serbia	12.45	
Ireland	United Kingdom	0.00	32.09
Italy	Slovenia	2.55	
Italy	Switzerland		57.82
Latvia	Estonia	7.09	
Latvia	Lithuania	5.62	5.62
Libya	Italy	31.73	
Lithuania	Russia Kaliningrad	10.30	
Algeria	Spain	56.45	
Netherland	United Kingdom	42.57	
Norway	Belgium	53.28	
Norway	France	51.82	
Norway	Germany	101.38	
Norway	Netherland	107.06	
Norway	United Kingdom	115.00	

Portugal	Spain	10.27	17.36

Linking Countries		**Maximum cross border capacity (mcm/d)**	
From (A)	**To (B)**	**Forward flow (A-B)**	**Reverse flow (B-A)**
Romania	Bulgaria	67.00	
Russia	Estonia	4.02	
Russia	Finland	20.45	
Russia	Germany	85.70	
Russia	Latvia	15.00	
Slovenia	Croatia	4.82	
Algeria	Italy	94.00	
Turkey	Greece	5.24	
Ukraine	Hungary	68.18	
Ukraine	Poland	15.75	
Ukraine	Romania	80.72	
Ukraine	Slovakia	219.24	
Russia	Ukraine	389.04	
Russia	Estonia	4.02	
Russia	Finland	20.46	
Russia	Germany	85.70	
Russia	Latvia	15.00	
Russia	Ukraine	389.04	
Russia	Belarus	90.41	
Germany	Switzerland	49.15	
Iran	Turkey	54.65	
Azerbaijan	Turkey	54.79	
Russia	Turkey	43.89	
Serbia	Bosnia	2.00	
Iran	Turkey	54.65	
Azerbaijan	Turkey	54.79	
Russia	Turkey	43.89	

Appendix C

Linear approximation of storage constraints

The volume of gas withdrawn from or injected into a storage facility varies with the current storage level. Withdrawal rates are highest when the storage is full while injection rate is highest when the storage facility is empty because of the pressure level in the storage. This non-linear relationship is expressed as (Thompson et al, 2009):

$$S_{s,t}^{out\_mx} = K_1^{out} * \sqrt{S_{s,t}} \quad \forall s,t \qquad \text{C.1}$$

$$S_{s,t}^{in\_mx} = K_1^{in} * \sqrt{S_{s,t}} \quad \forall s,t \qquad \text{C.2}$$

$$S_{s,t}^{in\_mx} = K_1^{in} * \sqrt{\frac{1}{S_{s,t}^{in}+S_s^{base}} + K_2^{in}} \quad \forall s,t \qquad \text{C.3}$$

where K_1^{out}, $K_1^{in}$and $K_2^{in}$are factors that describe the features of the storage facility, S_s^{base} is the volume of cushion gas at facility s (mcm). However linear approximations were derived the non-linear storage constraints.

The convex gas withdrawal function in equation C.1 is represented by the piecewise linear curve as shown in Figure C.1.

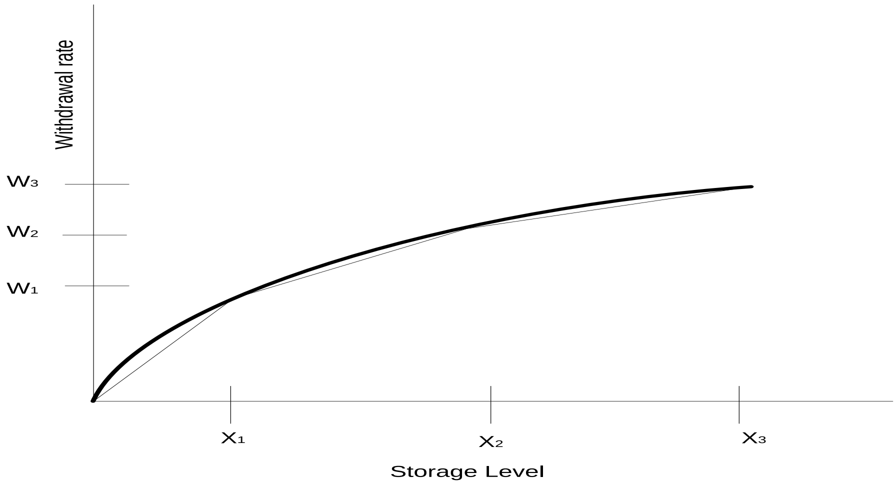

Figure C.1 Piecewise linearization of the withdrawal rate of a storage facility

Here different withdrawal rates ($W_1 \ldots, W_n$) correspond to different storage levels ($X_1 \ldots, X_n$). The linear approximation of the withdrawal rate is given by Equation C.4.

$$S_{s,t}^{wd} \leq \frac{W_{s,n+1} - W_{s,n}}{X_{s,n+1} - X_{s,n}} S_{i,t} - \frac{W_{s,n+1} - W_{s,n}}{X_{s,n+1} - X_{s,n}} X_{s,n} \quad \forall s, t \qquad \text{C.4}$$

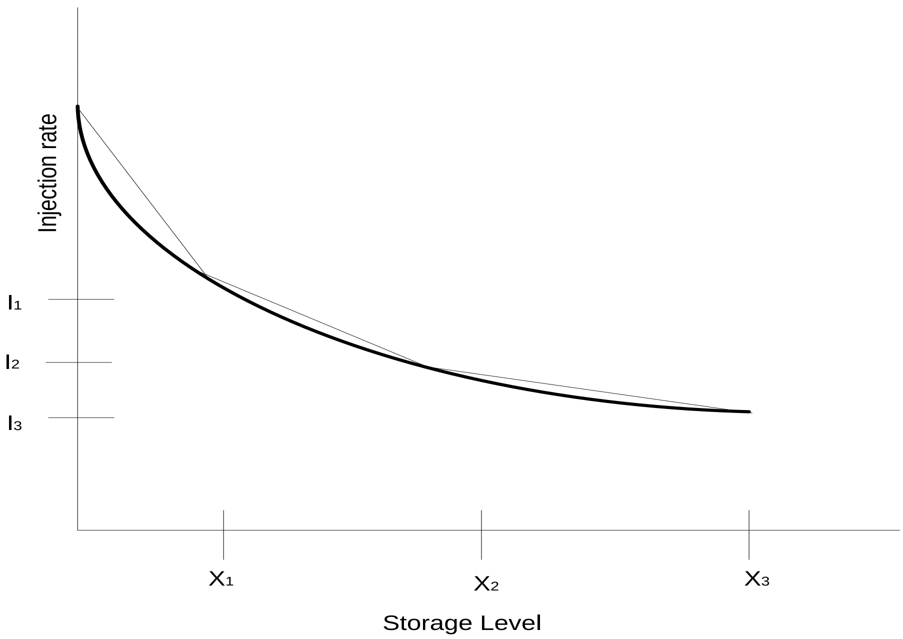

Figure C1.2 Piecewise linearization of the injection rate of a storage facility

On the other hand, Figure C1.2 shows the injection rate is a non-convex function of storage level. The special ordered sets of type 2 (SOS2) variables are used for the piecewise linear approximation of the non-convex function in equation (3.11).
Let ($I_1 \ldots, I_n$) represent set of injection rate corresponding to a set of breakpoints ($X_1 \ldots, X_n$). The SOS2 variables (H_n) are used to form a convex combination of two of the points such that only two adjacent variables H_{n-1} and H_{n+1} can be non-zero if H_n is zero. The linear approximation of the storage injection rate and storage level is given by Equations C1.3 and C1.4 [142].

$$S_{s,t}^{in} \leq \sum_n H_{n,s,t} * \ I_{n,s} \qquad \forall s,t \qquad \text{C1.3}$$

$$S_{s,t} \leq \sum_n H_{n,s,t} * \ X_{n,s} \qquad \forall s,t \qquad \text{C1.4}$$

$$\sum_y H_{s,t,y} = \ 1 \qquad \forall s,t \qquad \text{C1.5}$$

Appendix D

The Combined Gas and Electricity Network Model (CGEN)

The combined gas and electricity network model (CGEN) is a multi-time period optimisation modelling tool used to examine the interaction of gas and electricity networks as an integrated system. The CGEN model is formulated as a non-linear programming problem and solved using Fico Xpress optimization suite.

D1. CGEN Objective Function

The objective function minimises the total operational cost of the integrated gas and electricity network Equation (D.1) while meeting the gas and electricity demand. The operational cost including costs of gas supplies, storage operation, electricity generation and costs of unserved gas and electricity demand.

Minimise total operational cost (£):

$$\sum_t ts \times \left\{ \underbrace{\sum_a C_{a,t}^{gas} Q_{a,t}^{supp}}_{gas\ supplies} + \underbrace{\sum_s \left(C_{s,t}^{wd}\, Q_{s,t}^{wd} - C_{s,t}^{inj} Q_{s,t}^{inj} \right)}_{storage\ operation} + \underbrace{\sum_b C_t^{sp} \partial LP_{b,t}}_{change\ in\ linepack} + \underbrace{\sum_g C_g^{gen}\ P_{g,t}}_{electricity\ generation} + \underbrace{\sum_i C^{gasshed}\, Q_{i,t}^{gasshed}}_{unserved\ gas\ demand} + \underbrace{\sum_j C^{elecshed}\ Q_{j,t}^{elecshed}}_{unserved\ electric\ energy} \right\} \quad \text{D.1}$$

D2. Gas Network

The key components of a gas transmission network were modelling including pipelines, compressors, supply terminals and storage facilities.

D2.1 Gas pipelines

The gas flow rate is in a pipe is determined by the pressure difference between upstream and downstream nodes. The gas flow is assumed to be one-dimensional as the variation of gas properties along the radius of a pipe is negligible compared with the changes along the streamline direction.

The assumptions for this one-dimensional flow are [50] and [13]:

- the cross-sectional area changes slowly along the path of the stream of gas;
- the radius of curvature of the pipe is large compared with its diameter;
- temperature and velocity profiles are approximately constant along the pipe;
- the pipe is horizontal.

The gas flow along a pipe can be described by the continuity equation in Eq. (D.2) and the momentum equation Eq. (D.3) [50].

$$\frac{\partial Q}{\partial x} = -\frac{A}{\rho ZRT}\frac{\partial p}{\partial t} \qquad \text{D.2}$$

where $\frac{\partial Q}{\partial x}$ is change in flow due to changes in distance, A is pipe cross sectional area, ρ is gas density, Z is Gas compressibility, R is Gas constant, T is temperature, and $\frac{\partial p}{\partial t}$ is change of pressure over time.

$$\frac{\partial p}{\partial x} = -\frac{\partial\,(pv)}{\partial t} - \frac{\partial (pv)^2}{\partial x} - \frac{2f\rho v^2}{D} \qquad \text{D.3}$$

where $\frac{\partial p}{\partial x}$ is change of pressure due to changes in distance, v is gas velocity through a pipe, is f friction factor, D is pipe diameter.

A finite difference scheme is used to convert the original partial differential Equations. (D.2) and (D.3) into ordinary differential equations in Equations (D.4) and (D.5)[143]

$$\frac{Q_{X,T}^{n} - Q_{T}^{n}}{\Delta x} = -\frac{A}{\rho_n ZRT}\frac{(p_T^{av} - p^{av})}{\Delta t} \quad \text{D.4}$$

$$\frac{p_{XT} - p_T}{\Delta x} = -\frac{2ZRTf(\rho^n)^2(Q_T^{n,av})\,|Q_T^{n,av}|}{A^2 D p_T^{av}} \quad \text{D.5}$$

- **Linepack modelling**

The linepack of a pipe is the volume of gas stored in a pipe and an important factor that determines the ability to supply gas to demand nodes i.e. packing more gas in the pipe allows fluctuations in demand to be met as gas supply from a distant source will take time (typically hours) to reach the intended destination[67].

A combination of the gas equation of state (Eq. D.6) and Boyle's law (Eq. D.7) is used to calculate the linepack of a pipe [50]:

$$ZR = -\frac{p_n}{\rho_n T_n} = \frac{p}{\rho T} \quad \text{D.6}$$

$$p_{av}V = p_n V_n \quad \text{D.7}$$

$$LP = V_n = \frac{p_{AV}V}{\rho_n ZR\,T_n} \quad \text{D.8}$$

Equation D.8 is suitable for calculating the volume of gas in a pipe when the gas flow is in steady state. This illustrates that the pipe linepack is proportional to the average pressure in the pipe section, therefore, increasing the average pressure of the pipe will increase the linepack and vice versa.

Under dynamic situations, the gas flow into and out of a pipe fluctuates with changing supply and demand. According to the Law of conservation of mass, the change of total gas volume is equal to the difference between the flow into and out of the pipe. Thus, we have:

$$LP(t) = LP_0 + \int_0^t (Q_n - Q_{n,X}) dt \qquad \text{D.9}$$

where, LP_0 is the initial gas stored in the pipe and is calculated by Eq. (D.9) in the steady state condition.

- **Gas compressors**

Compressors are used to boost the pressure lost through friction as gas flow along pipes in the transmission network. The power required from the compressor prime-mover is calculated by Eq. (D.10).

$$P_c = \frac{Q_c^n \, \alpha}{\eta_c \, (\alpha - 1)} \left[\left(\frac{p^{out}}{p^{in}} \right)^{\frac{\alpha-1}{\alpha}} - 1 \right] \qquad \text{D.10}$$

where P_c is power consumption by compressor c , Q_c^n is gas flow through compressor c, in standard condition, c is polytropic exponent, η_c is efficiency of compressor c, p^{out} is pressure of gas from a compressor, and p^{in} is pressure of gas into a compressor.

In practice, the performance of a compressor is constrained by the following equations:

$$1 \leq \frac{p^{out}}{p^{in}} \leq cpr^{max} \qquad \text{D.11}$$

where cpr is the compressor pressure ratio.

$$Q_c^n \leq Q_c^{n,max} \qquad \text{D.12}$$

$$p_c \leq p_c^{max} \tag{D.13}$$

The amount of gas tapped by the compressor is given by [144]:

$$\tau_{c,t} \leq \beta P_{c,t} \tag{D.14}$$

where $\tau_{c,t}$is amount of gas tapped by a compressor, and β is gas turbine fuel rate coefficient of a compressor.

Gas Storage

Gas storage facilities are modelled based on their operational characteristics such as working gas volume, withdrawal rate, and injection rate and cushion gas. The operational characteristics of storage facilities have been introduced in section 3.4.2. The gas storage constraints is expressed by equations (3.6) – (3.11).

However, non-linear storage constraints are solved using sequential linear programming

- **Gas network constraints**

At each node in the gas network pressure and gas flow balance constrains are applied. For each time step, total gas flow into each node (gas supply and storage withdrawal) is equal to total gas outflow from the node (gas demand, gas storage injection, compressor fuel consumption):

$$M_{u,a}Q_a + M_{u,p}Q_p + M_{u,c}Q_c - M_{u,c}\tau^c + M_{u,s}Q_S^s = M_{u,d}(Q^{dem} - Q^{gasshed}) \tag{D.15}$$

where $M_{u,a}Q_a$ is node-terminal incidence matrix, $M_{u,p}$ is node-pipe flow incidence matrix, $M_{u,c}$ is node –compressor incidence matrix, $M_{u,s}$ is node–storage incidence matrix, $M_{u,d}$ is node-load incidence matrix.

$$p^{min} \leq p \leq p^{max} \qquad \text{D.16}$$

where p^{min} and p^{max} are the lower and upper pressure bounds for each pipe in the gas network.

D3. Electricity Network

The electricity network is simplified as a Direct Current (DC) power model. The network consists of mainly generators and transmission lines. The DC power flow formulation reduces computational complexities to obtain MW power flows in each individual line. The DC power flow model is based on the following assumptions:

i. the line resistance in a high voltage transmission system is very much smaller when compared to line reactance, such that resistance and system losses can be neglected
ii. the phase voltage angle difference of a high voltage line is very small
iii. the bus voltage per unit is close to nominal value (~1.0 p.u).

- Power balance constraint

For each time step the power balance equations ensures that total generation is equal to total demand less load shedding:

$$\sum_g P_{g,t} = \sum_j P_{j,t}^{dem} - \sum_j P_{j,t}^{elecshed} \qquad \text{D.17}$$

where $P_{g,t}$ is power output of generation unit g at time *t*, $P_{j,t}^{dem}$ is electricity demand at bus *j* and time t, and $P_{j,t}^{elecshed}$ is unserved electricity at bus *j* and time *t*.

- **Electricity Network Constraints**

The power schedule is kept within the physical limits of the generating units as shown in Equation (4.18):

$$P_g^{gen(\min)} \leq P_{g,t}^{gen} \leq P_g^{gen(max)} \qquad \text{D.18}$$

- **Power transmission**

Power transmission along a line is constrained by maximum transmission capacity of the line.

$$P_{l,t} \leq P_l^{max} \qquad \text{D.19}$$

where $P_{l,t}$ is electrical power transmitted through line l.

D4. Linkage between gas and electricity network

Gas turbine generators provide the linkage between gas and electricity networks. They are regarded as energy converters between these two networks. For the gas network, the gas turbine was considered as a gas load. Its value depends on the power flow in the electricity network. In the electricity network, the gas turbine generator is a source. The relationship between the gas fuel flow and the real electrical power generated is expressed as:

$$P_{g,t} = \eta_g Q_{g,t} H \qquad \text{D.20}$$

where $\eta_g$is thermal efficiency of generator, $Q_{g,t}$ is gas consumption by generator g at time *t*, and is H heat value of natural gas.

Appendix E

GB Gas and Electricity Networks Data

Table E.1. GB Gas Terminals

Gas terminal	Maximum capacities
St.Fergus	84
Teeside	30
Easington	78
Barrow	4
Burton	3
Theddletrope	4.9
Bacton	150
Isle of Grain	65
Milford Haven	95

Table E.2. Maximum Gas Supply Available to GB and Supply Costs

Supply source	Maximum supply available to GB (mcm/d)	Supply cost (£/tcm)
Domestic production	55.37	51
Norway	80	115
*LNG	123	145
*Continental Supplies	75	Dependent on the gas price in the European gas network

*Maximum LNG and Continental Supplies available to GB depends on gas demand and supply balance in the European gas network.

Table E.3 Cost of unserved gas demand for different gas consumer categories[30][120][134]

Disconnection merit order	Consumer Categories	Capacity	Cost of unserved gas demand
1	Large Industrial &Commercial gas consumers	49.42 mcm/d	£4.1 6 /cm
2	Electricity Generation (CCGT)	240 GWh/d	£4/kWh
3	Domestic gas	113.3 mcm/d	*£50/cm
*The cost of unserved gas demand for domestic gas is significantly large to ensure that the disconnection of domestic gas supply is considered as the last option.			

Table E.4. Installed GB Power Generation Data - Reference Scenario (GW)

Busbar	Nuclear	Gas-fired	Biomass/ Coal CCS	Wind	Interconnector	Hydro/ Pumped Hydro	Others
1	-	1.2	0.3	5.2	1	1.6	1
2	-	-	0.6	6.7	1.4	-	-
3	-	-	-	-	-	0.5	-
4	-	-	-	-	-	0.4	-
5	-	0.7	0.8	1	-	0.4	-
6	0.9	0.1	0.6	7.3	-	0.3	0.9
7	1.2	2.6	0.3	4.4	-	-	-
8	-	-	-	0	-	-	-
9	2.4	3.8	0.5	7.3	0.9	2	-
10	-	6.6	1.8	3.6	-	-	-
11	-	-	-	-	-	-	-
12	-	3	0.8	1.7	-	-	0.5

13	-	2	-	7.5	-	-	-
14	-	3.2	3.1	1.7	2	-	1.4
15	0.9	5.9	-	2.3	-	-	1.4
16	5.2	9.8	-	2.3	2	-	2.1
Total	**10.6**	**38.9**	**8.8**	**51**	**7.3**	**2**	**5.15**

Table E.5. Installed GB Power Generation Data - Slow Transition Scenario (GW)

Busbar	**Nuclear**	**Gas-fired**	**Biomass/ Coal CCS**	**Wind**	**Interconnector**	**Hydro/ Pumped Hydro**	**Others**
1	-	1.2	0.3	4.1	1	1.6	1
2	-	-	0.6	5.33	1.4	-	-
3	-	-	-	-	-	0.5	-
4	-	-	-	-	-	0.4	-
5	-	0.7	0.8	0.82	-	0.4	-
6	0.9	0.1	0.6	5.74	-	0.3	0.9
7	1.2	2.6	0.3	3.28	-	-	-
8	-	-	-	-	-	-	-
9	2.4	3.8	0.5	5.74	0.9	2	-
10	-	6.6	1.8	2.87	-	-	-
11	-	-	-	-	-	-	-
12	-	3	0.8	1.23	-	-	0.5
13	-	2	-	6.15	-	-	-
14	-	3.2	3.1	1.23	2	-	1.4
15	0.9	5.9	-	2.05	-	-	1.4
16	5.2	9.8	-	2.05	2	-	2.1
Total	**10.6**	**38.9**	**8.8**	**40.6**	**7.3**	**2**	**5.15**

E.6. GB Transmission line capacities

GB transmission boundaries	Maximum transmission capacities (MW)
TB1	1600
TB2	2800
TB3	3000
TB4	3300
TB5	5150
TB6	7800
TB7	7500
TB8	1661
TB9	3842
TB10	10603
TB11	3908
TB12	5215
TB13	11551
TB14	6174
TB15	8423

E.7. GB Power Generation Cost

Generator	Generation cost (£/MWh)
Nuclear	11.63
CCGT/OGCT/GAS	Dependent on gas price
Coal	20.87
Biomass	50.87
Dual fuel	70
Pumped storage	60
Interconnector	83.75
Hydro	0 (must run)
Wind	0 (must run)