UNIVERSIDAD PONTIFICIA COMILLAS

ESCUELA TÉCNICA SUPERIOR DE INGENIERÍA (ICAI)

OFFICIAL MASTER'S DEGREE IN THE
ELECTRIC POWER INDUSTRY

Master's Thesis

INTERDEPENDENCIES BETWEEN THE LONG-TERM INVESTMENT DECISIONS OF THE POWER AND GAS INDUSTRIES: THE CASE OF THE UK

Author: **Dan Donna Peng**

Supervisor: **Dr. Pablo Dueñas Martínez**

Madrid, July 2016

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Summary

This thesis was set out to explore the interdependencies between long-term investment decisions of the UK's power and gas industries. The interdependencies between these two network industries have been growing during the past two decades. Technical, commercial, and regulatory decisions made with narrow scope, without considering potential interaction between the two industries, might cause unwanted consequences or fail to take advantage of opportunities.

Four complementary studies have been conducted to offer different lenses through which to view gas and power interdependencies: a literature review of research traditions in long-term investments in power and gas sectors, a case study that dissects the UK's gas-to-power supply chain segment-by -segment, an econometric study that test for cointegration between gas and power prices series, and a System Dynamics simulation model that allows for quantitative testing of uncertain scenarios. The findings of the more general studies have been able to inform the research methodology of subsequent, more specific studies.

The first study, the methodological review, has identified seven lines of inquiries active in gas and power research on long-term investments. It found that gas sector researchers most commonly investigate *the evolution of supply and demand*. On the other hand, power sector researchers most commonly investigate *the design of regulatory frameworks*. The exploratory research objective of this thesis re-articulated in terms of these lines of inquiries.

The case study found that in the UK's gas to power supply chain, mainly coordinated through the market mechanism, uncertainties plague two particular segments: domestic gas production and power generation. The regulatory actions carried out by the government to achieve is sustainability and security goals, mainly targeting the power generation segment, exposes power and gas sector agents to regulatory uncertainty.

The cointegration study found that the UK's gas prices are cointegrated with the North-western European gas hub's prices, and that the UK's power prices are cointegrated with the Dutch electricity price. It also found that the Dutch power price is driven by the North-western European gas prices, which have experience a transitioning relationships with the German import price during 2011-2015.

Finally, the SD simulation model developed is validated using a base case scenario: 2011-2015 historical data and the author's best estimates for 2016-2030 are used. The simulation results show that the model captured key features of the UK gas and power markets and sector investment decisions, but deviation existed concerning the price-responsiveness of LNG supply, the level of gas-fired power generation given historical costs, the uptake of biomass generation, and the price of power and marginal cost for power generation.

Acknowledgements

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Contents

1 Introduction

In the last two decades, there has been important convergence between the previously parallel electricity and natural gas industries in a number of countries. This converging trend has been exhibited in several dimensions. Firstly, increasing use of gas-fired power generation plants has led to increasing physical flows that bridge natural gas with electricity. Secondly, the emergence of multi-utility companies that market both electricity and natural gas to consumers has created agents whose decision-making spans commercial activities in both sectors. Finally, being network industries, power and gas industries in many countries have undergone liberalization and privatization around the same time, sometimes overseen by the same regulatory body, and they are encountering comparable regulatory challenges.

Although the two industries have developed multi-dimensional interdependencies, the study of these influences, of their nature and impact, is still at a nascent stage. Existing research literature abounds with studies that focus on physical, commercial, and regulatory decision making in either of the two industries, but relatively few take both into consideration as an integrated supply chain. Consequently, the potential consequence of not taking gas-and-power interdependencies into consideration is not well known. This may lead to unwanted consequences when physical planning/operational, commercial, and regulatory decisions are made with a narrow scope; or, this may lead to missed opportunities for leveraging cross-industry coordination.

This thesis contributes to the emerging body of research on gas-and-power interdependencies by articulating the interdependencies, qualitatively and quantitatively, as they are exhibited in the United Kingdom, with a chosen focus on long-term investments. Shorter-term interdependencies are also studied, to the extent that they influence long-term investments. Multiple approaches are used to adequately portray the multidimensional and interdisciplinary nature of these interdependencies, including a methodological literature review, a country case study, an econometric study, and a System Dynamics model. Respectively, they compare the leading issues and research methodologies that are active in each sector, outline the key segments of interest in the UK gas-to-power supply chain, provide empirical evidence for gas and power price interdependencies across markets, and propose a simulation model to formally capture the most important gas-power long-term investment interdependencies. The studies assembled within the thesis can be read independently, but, when viewed together, they enhance each other, since the findings of each study has informed the methodology of the following one.

The amount of natural gas used for power generation globally has increased steadily since 1973, from 212 to 1167 Mtoe in 2012 (IEA, 2012). This represents 21.8 per cent and 41.5 per cent of world gas production, respectively. As the cleanest-burning fossil fuel, natural gas is often portrayed as the transition fuel that will bridge the fossil fuels dominated present to a future powered by renewable forms of energy. Also, natural gas-fired generators have favourable modular investment costs and are flexible to operate. Therefore, the global volume of natural gas used is expected to increase in the mid-term, and its role in power generation is expected to persist (IEA, 2015).

The UK is a country that exemplifies this trend. In the UK, the share of natural gas in total fuel input for electricity generation increased from less than 1% in 1989 to more than 40% in 2010 (DECC, 2013a). During the same period, the share of electricity generation as part of the total natural gas consumption has increased from 1% to 34% (DECC, 2013b). In its Gas Generation Strategy, the UK government announces that it expects gas to continue playing a major role in the UK's electricity mix over the coming decades, as decarbonisation of the power system occurs (DECC, 2012).

As this convergence continues, the power industry becomes an important downstream industry of the natural gas sector, and coordination across this extended supply chain becomes important. The operational flexibility for which natural gas generators are prized is conditional upon the availability and flexibility of their input fuel. Hence, it becomes important to understand both the new risks to which the power sector is exposed via natural gas, and the challenges that the gas sector needs to overcome in supplying the extremely dynamic power sector.

Increasing physical interdependencies between the power and gas industries is accompanied by an overlapping set of actors. All of the six largest energy suppliers in the UK provide both electricity and gas retail services. They are important players in both power and gas wholesale markets. The transmission network system operator, National Grid, own and manages most of the gas and power transmission network in the country. The national energy regulator, Ofgem, is responsible for overseeing power and gas wholesale/retail markets.

The interdependence of power and gas in regional energy systems is of interest to this set of overlapping actors: power and gas system operators or integrated utilities, regulators, and government bodies responsible for overall energy policy. A better understanding of such interdependencies will allow these agents to evaluate the reliability, competitiveness, and sustainability of the joint power and gas supply chain, to facilitate short-term and long-term coordination between the two industries, and to evaluate the effect of market actions, regulatory mechanisms, and energy policies on both sectors.

The first studies on gas and power interdependencies gravitated toward the physical interdependencies of the two networks, which have directly observable consequences over the short-term: interruptions in natural gas supply to power generators will stress the capability of the power system to meet demand. Over time, interdependencies in other dimensions, such as mid-term commercial operations and long-term infrastructure investment decisions, are also being explored.

As the scope of research is expanded to include longer time-scale and other layers of the gas-to-power socio-economic system, the challenge is increasing, because such research needs to appropriately incorporate gas-power interdependencies at the underlying dimensions. For example, studying the possible effects that energy policy directed at the power sector might have on the gas industry will require a good understanding of the physical and commercial arrangements between the two sector in the given energy system. Therefore, gas-and-power independency research increasingly requires analytical tools from a wide range of domains (engineering, business, economics, regulation, and policy), and an inter-disciplinary perspective to synthesize insights gathered using these diverse tools.

This thesis aims to explore the physical and informational interdependencies of gas and power sectors in the UK. The proposed research is focused on long-term interdependencies in power and gas sector investment decisions, but interdependencies at other time-scales and dimensions are also examined in so far as how they affect long-term investment interdependencies. At the centre of the thesis is a System Dynamics simulation model that formally represents causal connections between select long-term investments decisions in the gas-to-power supply chain. It can be used as a virtual laboratory to test the effect of particular sets of uncertain variables on gas production and power generation investment.

Surrounding the simulation model are three complementary studies which have anchored and informed the model formulation process. A literature review focused on existing research dialogues and methodologies was conducted to survey the field, situating the current thesis along-side on-going research efforts on long-term investment in the gas and power industries. A qualitative case study, taking a segment-by-segment supply chain approach, highlights the key areas of interest for gas and power interdependencies investigation for the UK. And, an econometric study examines the cointegration between gas and power price series for a range of markets interconnected with the UK, quantifying the strength and direction of price interdependencies.

The System Dynamics model proposed is strengthened by the triangulation of research methodologies. The methodological review revealed the weaknesses of a System Dynamics model relative to other research methodologies: any quantitative formalization is highly dependent on the modeller's qualitative understanding of the system being modelled, and System Dynamics' endogenous focus might lead to negligence of important correlations between variables exogenous to the UK energy system. In response, the case study and the cointegration study are conducted to provide qualitative knowledge on the UK's gas-to-power supply chain and to quantify potential correlation between a set of key exogenous variables.

This thesis document is organized in four major parts. The chapters are arranged to provide increasingly detailed views of the long-term investment interdependencies of the UK's gas-to-power supply chain. The following chapter is the literature review, where lines of inquiries and research methodologies active within the gas and power research communities are presented. The choice of methodologies made for this thesis is discussed. Chapter 3 is the qualitative case study of the UK, laying the ground for the scoping of the simulation model. Chapter 4 is the econometric study, which empirically asses the relationships between market prices of gas/power/other energy commodities across markets interconnected with the UK. The future pathway of these prices are important exogenous variables that will be fed to the simulation model. Given the large scope of the simulation model study, it is presented in two consecutive chapters. Chapter 5 documents how the System Dynamics model is developed and provides the mathematical formulation of various model components. Chapter 6 documents the inputs used for the base case scenario and its simulation results, which are compared to historical results as part of model validation. It then discusses future research that should follow the development of the current model. Finally, Chapter 7 concludes.

2 Literature review

The nature of the research proposed is at least partially exploratory. The nature of interdependencies between gas and power sectors' long-term investment decisions is not defined at the beginning of the project. Identification of these interdependencies need to take place, before they can be evaluated. Therefore, the literature review for this project is epistemological: its purpose is to inform the author of the key issues in the area of interest and the methodology that other researchers have adopted to investigate them, so that the identification of power and gas interdependencies for the UK is informed by research traditions. This section starts with a review of the research methods that have been used, in recent years, to analyse and discuss long-term investment decisions in the electricity and natural gas industries. A more detailed presentation of System Dynamics, a promising methodology, follows. Finally, the choice of research methodology for this project is deliberated.

2.1 Survey of the field

Coordination within the liberalized power and gas industries is a complex and interdisciplinary field, requiring an understanding of the underlying physical characteristics of the commodity supplied, a familiarity with the economic principles which have guided the design of these new markets, and a sensitivity toward the socio-political environment in which physical and commercial transactions take place. Research literature in this field is also made complex by the abundance of methods and perspectives that different researcher tackling the same problem might adopt. In order to be able to digest viewpoints coming from different perspectives and participate in 'insight arbitrage' across disciplines and domains, it is necessary to have an overview of the research traditions that exist, not only in terms of their scope of study and conclusions, but also of their accepted methods of investigation. The following review is a literature review of research methodologies and research scope, not a review of the conclusions that various authors have reached.

As part of this project, 89 peer-reviewed articles and academic working papers, sampled based on their mention of and relevance to long-term investment decisions within the gas and power industries, have been reviewed along three dimensions:

1. Line of inquiry: the articles' main research questions are related to long-term investment decisions in the power and gas sectors in different ways, either directly or tangentially, and can be grouped as part of different on-going research dialogues;
2. Research method: the articles answered their research questions using different methodologies, ranging from the very quantitative econometric analysis to the mostly qualitative case studies;
3. Domain: some of the articles referred exclusively to the power industry (39), and some others exclusively to the gas industry (40); a smaller number included the energy sector in general within their scope (10).

In the remainder of this review, for each domain, the lines of inquiry are used as the organizing threads, and the research methods that are used to provide answer to each line of inquiry are briefly summarized. Since the literature that can be reviewed is inexhaustible, the following comparison does not claim to be authoritative and definitive; they mainly serve as guidance for the author to select a research methodology that is appropriate for the identification and evaluation of interdependent investment decisions in the power and gas industries.

Within research on the gas industry, there are seven main lines of inquiry with long-term investment as their intersection point. The number of articles pertaining to each line of inquiry is indicated between parenthesis:

1. Evolution of supply and demand (19)
2. Evaluation of energy policy (5)
3. Role of long-term contracts (5)
4. Competition in European market (4)
5. Design of regulatory frameworks (3)
6. Investment decision making under uncertainty (3)
7. Representation of market via models (1)

The evolution of supply and demand is the line of inquiry that dominates in the gas sector. Researchers focus on deriving long-term outlooks on future supply and demand. They use mostly qualitative research methodologies (10) such as the analysis of strategic drivers and scenario analysis as commonly as they use quantitative approaches (9) such as optimization and equilibrium models, simulation models, and econometric analysis. The qualitative research mainly present factors that are responsible or could be highly influential in the evolution of future natural gas supply or demand, while highlighting their recent trends, disaggregated by geographic areas. The drivers listed range from physical (reserve availability), technological (availability and costs of technology) and political (policy goals within a region or geopolitical relations between regions). The quantitative analysis based on models differ mainly in their levels of detail and/or assumptions about market competition. Models typically contain only a subset of the considerations included in the qualitative analysis.

The less researched lines of inquiry explore, respectively, whether the state or possible developments in the gas sector of a particular jurisdiction meet its energy policy targets; the drivers and implications for the use of long-term contracts in the gas industry; the distribution of market power in the European gas wholesale market; the effect of gas market regulation on investment in infrastructure; the effect of uncertainty on investment; and the development of models to better represent the gas market. In these research dialogues, case studies (7) and optimization/equilibrium models (7) are the most popular.

Within research on the electricity sector, the role of long-term contracts and competition in European market are not active lines of inquiry. This fact highlights its difference from the gas sector: the market for electricity is not as regionally integrated as the one for natural gas, and long-term contracts are a more important form of commercial arrangement in the gas industry than in the power industry. The five other ones applicable to gas are also applicable to electricity. They are:

1. Design of regulatory frameworks (25)
2. Representation of market via models (6)
3. Investment decision making under uncertainty (5)

4. Evolution of supply and demand (2)
5. Evaluation of energy policy (1)

It can be seen that the dominating line of inquiry in the power sector is the design of regulatory frameworks. Most of the references are focused on offering suggestions for the development or the improvement of regulatory measures for the liberalised power sector, especially those that target long-term generation adequacy. The most popular research methodology is simulation models (8), the presentation of frameworks of considerations when selecting a regulatory tool (5), examples of applying a regulatory tool in a stylized market (4), and case studies (4).

The other lines of inquiry active in the power sector respectively test model formulations/paradigms used to represent different market decisions; study the effect of uncertainty on investment decisions; simulate the effect of investment (long-term supply/demand) on market outcome (short-term supply/demand) or vice versa; and evaluate particular energy policy programmes in the power sector. The use of optimization/equilibrium and simulation models remains popular (9/14) within these lines of inquiry.

When research is on energy long-term investment in general and does not differentiate between power and gas or actively include both, the lines of inquiry active are:

1. Evaluation of energy policy (5)
2. Investment decision making under uncertainty (2)
3. Representation of market (2)
4. Design of regulatory framework (1)

Unsurprisingly, most studies in this domain have a focus on overall energy policy, thus consider the joint domains of gas and power. Most researchers develop or review tools such as frameworks or models that can be used to evaluate energy policy involving multiple energy forms (5) with some demonstration of application. Of the remainder, one particular paper investigates the effect of uncertainty in the gas sectors (price uncertainty) on investment in the power sector using financial modelling (Bistline, 2014), while another considers the uncertainty caused by regulatory instruments in general via a stylized example (Burns & Riechmann, 2004). Finally, in a highly original paper, human subject experiments are used by Arango to investigate the effect of market complexity on subjective decision making, potentially leading to endogenous commodity cycles (2012); and a simulation model is used to represent dynamic interactions between the power and fuel (including gas) markets (Gutierrez-Alcaraz & Sheble, 2009).

Table 1: Articles reviewed focused on the domain of natural gas

	Optimization and equilibrium model	Analysis of strategic drivers	Case studies	Econometrics studies	Simulation model	Literature review	Scenario analysis	Theoretical example
Evolution of supply and demand	(Dieckhöner, Lochner, & Lindenberger, 2013; Egging, Holz, & Gabriel, 2010; Huppmann, 2013; Lochner & Bothe, 2009; Perner & Seeliger, 2004; Remme, Blesl, & Fahl, 2008)	(Bilgin, 2009; Cayrade, Lavoro, & Franlab, 2004; Christie, 2012; Economides & Wood, 2009; Kjarstad & Johnsson, 2007; Kumar et al., 2011; Medlock, 2012; Ruester & Neumann, 2008; Weijermars, 2012)		(Maxwell & Zhu, 2011)	(Chyong, Reiner, & Nuttall, 2009; Eker & Daalen, 2013)		(Correljé & van der Linde, 2006)	
Evaluation of energy policy	(Skea, Chaudry, & Wang, 2012)		(Elkins, 2010; Finon & Locatelli, 2008; Stern, 2004; Wright, 2005)					
Role of long-term contracts		(Neuhoff & Neumann, 2011)		(Mulherin, 1986; von Hirschhausen & Neumann, 2008)		(Creti & Villeneuve, 2005)		(Neuhoff & von Hirschhausen, 2005)
Competition in EU market	(Dorigoni, Graziano, & Pontoni, 2010; Lise, Hobbs, & van Oostvoorn, 2008)	(Dorigoni & Portatadino, 2008)	(Eikeland, 2007)					
Design of regulatory frameworks	(Shaton, 2014)		(Hirschhausen, 2008); (Rahm, 2011)					
Investment decision making under uncertainty	(Midthun, Fodstad, & Hellemo, 2015; Sönmez, Kekre, Scheller-Wolf, & Secomandi, 2013)			(Pierru, Roussanaly, & Sabathier, 2013)				
Representation of market	(Egging, Gabriel, Holz, & Zhuang, 2008)							

Table 2: Articles reviewed focused on the domain of natural gas

	Simulation model	Optimization and equilibrium model	Case studies	Presentation of framework	Theoretical examples	Human subject experiments	Literature review	Econometrics study
Design of regulatory frameworks	(Alishahi & Moghaddam, 2012; Assili, Javidi, & Ghazi, 2008; Cepeda & Finon, 2011; de Vries & Heijnen, 2008; de Vries, 2004; Hasani & Hosseini, 2011; Olsina, Garcés, & Haubrich, 2006; Pasaoglu Kilanc & Or, 2008)	(de Vries & Ramirez Ospina, 2012; Neuhoff & de Vries, 2004)	(Arango & Larsen, 2010; F. Roques, Newbery, & Nuttall, 2004; Simshauser, 2008; Stenzel & Frenzel, 2008)	(Batlle & Pérez-Arriaga, 2008; De Vries, 2007; Olsina, Pringles, Larisson, & Garcés, 2014; F. A. Roques, 2008; Vázquez, Rivier, & Pérez-arriaga, 2002)	(Finon & Pignon, 2008; Joskow & Tirole, 2007; Keller & Wild, 2004; Unsihuay-vila, Member, Souza, Perez-arriaga, & Balestrassi, 2010; Wen, Wu, & Ni, 2004)	(Arango, Castañeda, & Larsen, 2013)		(Arango & Larsen, 2011)
Representation of market	(Sanchez, Barquin, Centeno, & Lopez-Pena, 2007)	(Murphy & Smeers, 2005; Oliveira, 2008)				(Pasaoglu, 2011)	(Ventosa, Baíllo, Ramos, & Rivier, 2005; Weidlich & Veit, 2008)	
Investment decision making under uncertainty	(Hasani-Marzooni & Hosseini, 2011)	(Kettunen, Bunn, & Myth, 2011; Kettunen, 2008, 2009)			(Awerbuch, 1993)			
Evolution of supply and demand	(Olsina, Roscher, Larisson, & Garces, 2007)	(Qadrdan, Chaudry, Wu, Jenkins, & Ekanayake, 2010)						
Evaluation of energy policy			(Toke, 2011)					

Table 3: Articles reviewed without a specified domain

	Optimization and equilibrium model	Presentation of framework	Theoretical examples	Simulation model	Human subject experiment	Literature review	Scenario analysis
Evaluation of energy policy	(Anandarajah & Strachan, 2010)	(Helm, 2002; Le Coq & Paltseva, 2009)				(Weijermars, Taylor, Bahn, Das, & Wei, 2012)	(Costantini, Gracceva, Markandya, & Vicini, 2007)
Investment decision making under uncertainty	(Bistline, 2014)		(Burns & Riechmann, 2004)				
Representation of market				(Gutierrez-Alcaraz & Sheble, 2009)	(Arango & Moxnes, 2012)		
Design of regulatory framework			(von Hirschhausen, Beckers, & Brenck, 2004)				

2.2 System dynamics

System dynamics (SD) is a computer-aided approach for analysing and designing decision-making principles that has its roots in control theory. It can be used in two related but different ways. It can be used qualitatively to portray the workings of a system, typically though causal loops and stock-and-flow diagrams, helping people to better understand the system and think about it. Or, the system, perceived as feedback loops, stocks, and flow, can be simulated quantitatively by specifying the relationships between different variables as mathematical equations. Because system dynamics is often taught and applied via existing SD software packages, which are capable of converting illustrative diagrams made for qualitative analysis to a system of differential equations directly, with minimal user input, the two uses of system dynamics are rarely differentiated explicitly. However, in this thesis, this difference becomes important, and the first use of system dynamics will be referred to as the SD approach, whereas the second approach, which includes the quantitative specification of causal relationships, will be referred to as SD modelling. In this section, the basic elements of the SD approach are introduced, and their relevance for the analysis of long-term investment decisions are presented. Then, the use of SD modelling in studying long-term investment decisions is presented.

2.2.1 Basic principles

The basic principles of the SD approach are four nested concepts (Forrester, 1968):

- An endogenous view of dynamic behaviour, considering a system as closed.
    A. Feedback loops as the basic structural blocks of the closed system.
        i. Stocks (accumulation of actions) as one type of variable within a feedback loop.
        ii. Flows (actions) as the other type of variable, which are decided as follows:
            a. A goal is fixed;
            b. The measure of interest which is compared to the goal;
            c. The discrepancy between goal and observation;
            d. An action driven by the discrepancy.

In other terms, the SD approach focuses on how reinforcing (positive feedback) and balancing (negative feedback) loops within a system may be responsible for its dynamic behaviour, rather than focusing on exogenous factors. It also distinguishes between level variables, such as the total installed capacity for power generation in the UK or gas in underground storage, and flow variables, such as the construction of new power plants or withdrawal rate of gas from storage. Stock variables are the cumulative results of historical flows adding or subtracting from it. Finally, in the SD approach, a flow is specified as the result of a decision: a goal/target is set for certain variable within the system; the variable of interest is periodically compared to the goal (comparative to the set point in control theory) and corrective action is taken based on the discrepancy observed. For example, a certain carbon dioxide emission target is set. The current rate of carbon emission is regularly compared to the target, and, depending on the deviation from the target, corrective policy measures are adopted.

These fundamental concepts from the SD approach are relevant to the study of long-term investment decisions in the gas and power industries, because:

1. power and gas infrastructure are stocks that deteriorate gradually overtime, while investment decisions are flow variables that add to them with a delay;
2. liberalized gas and power industries are coordinated through the market, which is essentially a feedback mechanism via price, where bids and offers (in the short-term), investment and decommissioning (in the long-term) are driven by current or expected market outcome;
3. regulation of liberalized gas and power industries is dynamic: regulatory measures are added or suspended based on the most recent market outcome and their performance relative to the regulatory targets, amounting to another feedback loop.

2.2.2 Application to power and gas sector long-term investment

The body of work in research literature that uses the SD approach and SD modelling to investigate long-term investment decisions is presented below. Ten out of the twelve studies are focused on the power sector.

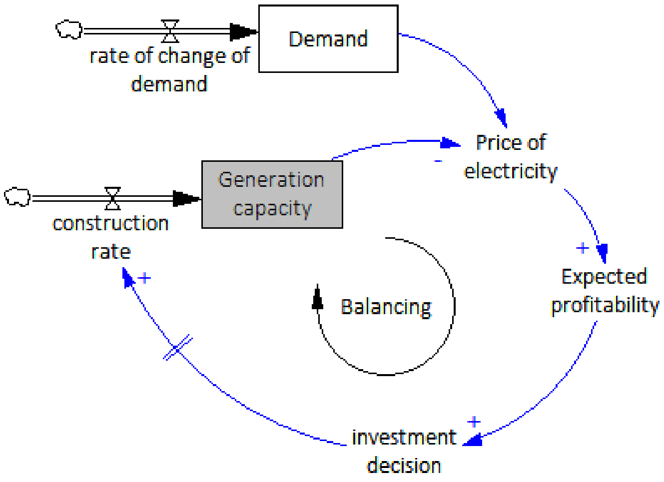

Figure 1: Core feedback dynamic in power sector investment

The majority of them (8/12) use SD simulation models as a virtual laboratory and explore the impact of different regulatory measures that have as aim to encourage long-term investment in the power sector. All of these studies have drawn their system boundary around the supply side of the power industries: in the downstream, change in demand is specified exogenously (some via a deterministic rate, some via randomly generated sequences of growth rate), not responsive toward electricity prices; in the upstream, fuel prices and investment costs are assumed to be constant for the duration of the simulation. The causal feedback loop that is central to all studies is Figure 1, an example of causal loop diagrams commonly used in SD modelling of generation investment.

In this balancing feedback loop, investment decisions in the power industry is driven by expected profitability of the decisions involved, which is based on the expected price of electricity, among other things. If the price of electricity is high, while all other factors remain equal, then investments will be made, and new generation capacity will come online, with a delay, until the forecasted price of electricity no longer offers returns in line with the investors' expectations. Exogenous demand, the key uncertainty in this feedback loop, might increase and push up the price of electricity, triggering generation investment until the generation capacity is at equilibrium with demand once more. Particular studies mainly differ in how they derive the price of electricity based on supply and demand, and how the price of electricity is translated into investment decisions via the computation of expected profitability. The accounting of the cumulative generation capacity based on investment decision, factoring in the construction lag, is trivial.

Most commonly, authors represent electricity by a load duration curve that, through intersection with the supply curve, yields the price duration curve. Perfect competition is assumed, so the generators bid their marginal cost and the supply curve is formed by sorting generation capacity by ascending variable cost, including fuel cost, variable O&M, and emission cost (if applicable). If the generation capacity available cannot meet the demand, then the price of electricity is set to be the price of interruptible contracts or the Value of Lost Load (VOLL), at which demand curtailment occurs. Some authors include a mark-up over the variable cost when reserve margin is tight, to account for the price spikes that occur during supply scarcity, so that the price is:

$$p = (1 - LOLP)\,p_m + LOLP \times VOLL \tag{2.1}$$

Where p_m is the system marginal cost, the Loss of Load Probability (LOLP) is computed given the reserve margin with assumptions about the units available (Assili et al., 2008; Olsina et al., 2006; Pasaoglu Kilanc & Or, 2008).

The distribution of prices or the average price of power is then forecasted, through backward-looking methods such as trend extrapolation and exponential smoothing, to future electricity prices. Adaptive expectations is commonly used in SD modelling studies to represent the forecasting process instead of rational expectations, given the practitioners have a descriptive rather than normative view of human rationality (Cepeda & Finon, 2011).

The forecasted average price and the average utilization of a particular generation technology, or alternatively, the forecasted distribution of prices, are used to calculate the expected Net Present Value of investment for given technologies Non market-based revenue such as capacity payments are also included in this economic assessment, if they do exist. The range of generation technology under consideration is generally constrained to thermal units. Once it is ascertained that a type of technology is profitable given forecasted conditions, a range of different heuristics is used to generate the investment decision based on existing information.

De Vries assumes the expected profits in a given year (in €/MW) can be converted directly to investment needed (in MW) through multiplication of a calibrated scaling factor (in $MW^2/€$), and that the flow of investment in the development pipeline is known, so that capacity under construction is deducted from the investment needed (De Vries, 2004). In his later work, an iterative screening curve algorithm is used to determine the optimal volume of investment, assuming perfect information about investment in the pipeline and decommissioning plans (De Vries & Heijnen, 2008).

Olsina, Assili, and Hasani compare the expected profitability of a technology in terms of IRR to the industry hurdle rate and, given the value of the ratio, scale up the reference investment rate (one at which only capacity decommissioned is replaced) using a logistics function. This assumes that investors' tendencies to invest vary non-linearly with the relative profitability of the project. For Pasaoglu & Or, if the NPV assessment is positive, the size of investment is a modeller specified function of the perceived demand-supply gap, aggression of the investor, their investment costs, and capacity addition limit (if it exists) (Pasaoglu Kilanc & Or, 2008). For Cepeda & Finon, the technology with the highest NPV among those assessed is selected for investment, but it is not specified how the capacity addition is determined (Cepeda & Finon, 2011).

Alishahi's study is different from the others, given only the SD approach is applied (through the presentation of a causal loop diagram), but the model used is not a SD model linked through specified causal relations. It is a nested optimization model that solves for optimal long-term investment and short-term market generation at the same time (Alishahi & Moghaddam, 2012). Therefore, the causal loop based structure is not observed for this model.

Two other studies involving SD modelling do not focus on capacity mechanisms: Sanchez et. al offer formulations for an improved representation of oligopoly and differentiated capital costs, given most SD models dealing with generation expansion assume perfect competition and do not differentiate between firms; he also includes a power forward market prior to the spot market (Sanchez et al., 2007). Hasani extends earlier work by incorporating stochastic wind generation as an additional exogenous variable in addition to uncertain demand (Hasani-Marzooni & Hosseini, 2011).

As for the two SD models focused on the gas sector, Chyong et al. only consider natural gas exploration and production endogenously, assuming exogenous demand, while Eker & Van Daalen include investment in natural gas import, renewable gas production (biogas and green gas), as well as non-renewable gas production (conventional and non-conventional) (Eker & Daalen, 2013). The latter also models power-sector's demand for natural gas endogenously, thereby including investment in power generation capacity as part of the model. The first study models natural gas exploration investment as a function of the industry's return on investment and the relative reserve demand ratio; it also models natural gas production investment as a function of the industry's return on investment. However, the decision process for investment is not explicitly modelled, and the industry's return on investment is not computed explicitly. The second study models investment in power generation as a modeller defined function of expected supply gap, return on investment, and societal acceptance; it models investment in natural gas supply infrastructure as a modeller defined function of shortage of gas supply, societal acceptance, and expected gas availability from different import sources.

An important observation about the nature of SD models surveyed above is that they range from highly quantitative, consisting of sophisticated subcomponents including optimization and equilibrium models, to highly qualitative, based on causal relationships hypothesized by the modeller and specified using their own judgement. This flexibility in the formulation of SD models makes them interesting candidates for bridging qualitative and quantitative research paradigms. For example, it is possible to quantify a qualitative analysis of strategic drivers, completing the causal loop diagram, then specifying causal relationship only using expert judgement. Then, as the understanding of causal relationships improve, the representation of specific links can become more detailed and accommodate more complex relationships. However, the high flexibility of SD models also mean that their validity is greatly affected by the soundness of the assumptions behind the causal links modelled and the adequacy of their mathematical specification.

2.3 Choice of methodology

Once the lines of inquiry and methodologies commonly used are known, the original research goal is placed within the lines of inquiry discovered, and the most appropriate methodologies for accomplishing it are weighed.

The original research goal– to explore the physical and informational interdependencies of UK gas and power sectors' investment decisions – is now articulated in terms of how it contributes to the most active line of inquiry in the gas sector, in the power sector, and for energy sector in general. In terms of "Evolution of supply and demand", studying the interdependency between the gas and power sector means understanding how power sector developments can affect gas demand. In terms of "Design of regulatory frameworks", studying the interdependency between the gas and power sectors means evaluating how uncertain upstream fuel costs (such as the cost of natural gas) can affect the outcome of regulatory measures in the power sector. Finally, in terms of "Evaluation of energy policy", studying the interdependency between the gas and power sectors means that the overall energy policy goals of the UK, involving both power and gas, need to be identified, against which the joint performance of these sector, under gas supply and demand uncertainty as well as policy-driven regulatory changes in the power sector, is to be evaluated.

It is found that System Dynamics is a candidate methodology to be used for accomplishing the research goals above, because:

- The visual nature of the causal loop diagram that underpins the SD approach is helpful in illustrating the hypothesized interdependencies between the UK power and gas sectors during the exploratory stage, facilitating communication between researchers and other stakeholders;

- The focus on endogenous feedbacks of the SD approach lends it well to the study of effects of additional regulatory measures on the self-regulated power market, and the range of existing SD models of the power sector can be readily extended to represent the similarly self-regulated gas market;
- The flexible formulation of SD modelling is friendly toward the quantification of qualitative analysis (an important fraction of gas-sector research), since the formulation of various causal links in the SD model do not have to follow a strict formalism.

However, by itself, System Dynamics is not enough to accomplish the research goals above, because:

- Before specifying the existence of causal relationships between the UK's power and gas sectors, it is necessary to gain a well-ground qualitative understanding of it, as the SD approach itself cannot provide content knowledge;
- There might be correlation between the exogenous factors that influence the UK's gas and power markets, especially between the prices of energy systems with which the UK trades energy. SD is not able to contribute to the understanding of those relationships, given SD is focused on endogenously produced dynamics;
- Like other deterministic models, by itself, pure SD modelling provides a tool for understanding system dynamics given a set of inputs, but it does not address the range of uncertainty within the inputs.

Given the above, the SD model developed for this project is informed by a case study of the UK's power and gas sector, written with an eye to identify possible internal feedbacks, and an econometric analysis that test for relationships between UK's power and gas prices and those in other jurisdictions. Finally, once a working SD model is obtained, it needs to be evaluated against a wide range of scenarios, sets of inputs which are judged plausible and possible, to be able to offer robust insights about interdependencies between the UK's power and gas long-term investments.

3 Case study

This case study is presented in five parts. The existing state and historical development of natural gas and electricity use in the UK are reviewed, with a focus on the following points: the scale of gas and electricity use in the UK's energy system, the country's self-sufficiency with respect to natural gas, and the role of natural gas in its power generation. Following that, the ownership structure of the UK's gas and power industries is identified. Then, the maturity of the country's supply chain infrastructure and the available coordination mechanisms are assessed. The government's policy agenda and its potential interaction with industry self-regulation are then discussed. Finally, the insights that this analysis provides over long-term interdependencies of the UK's natural gas and electricity sector are summarized at the end.

3.1 Historical development

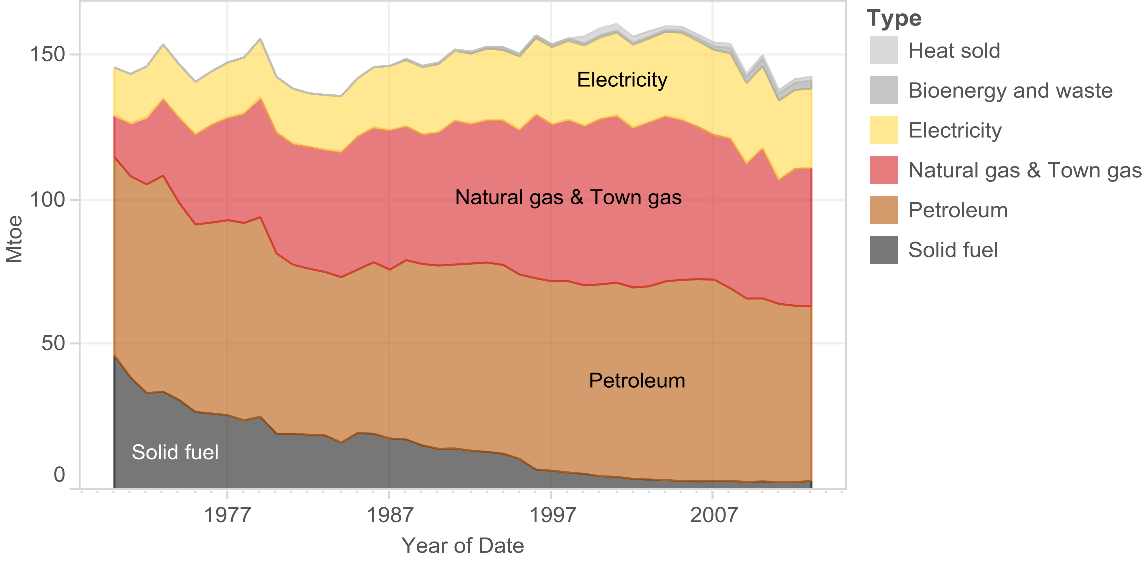

Figure 2: Final energy consumption by fuel, 1970 to 2013[1,2] (Data source: DECC)

Today, in the UK, a blend of domestically supplied and imported petroleum (oil and its derivative products), gas, and electricity form the three pillars that supply final energy use in the country (Figure 2). Between 1970 and 2013, solid fuel (defined as coal and its derivatives) continued to see its final use outside of electricity generation diminish. The share of energy supplied by petroleum has also fallen. It has withdrawn from all sectors except for transportation.

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[1] Primary fuel consumed for electricity generation is accounted for under 'electricity'.
[2] The use of town gas was marginal in 1970s, ending completely in 1979. Its exact quantity can be seen in Figure 27, as gas supplied from other sources.

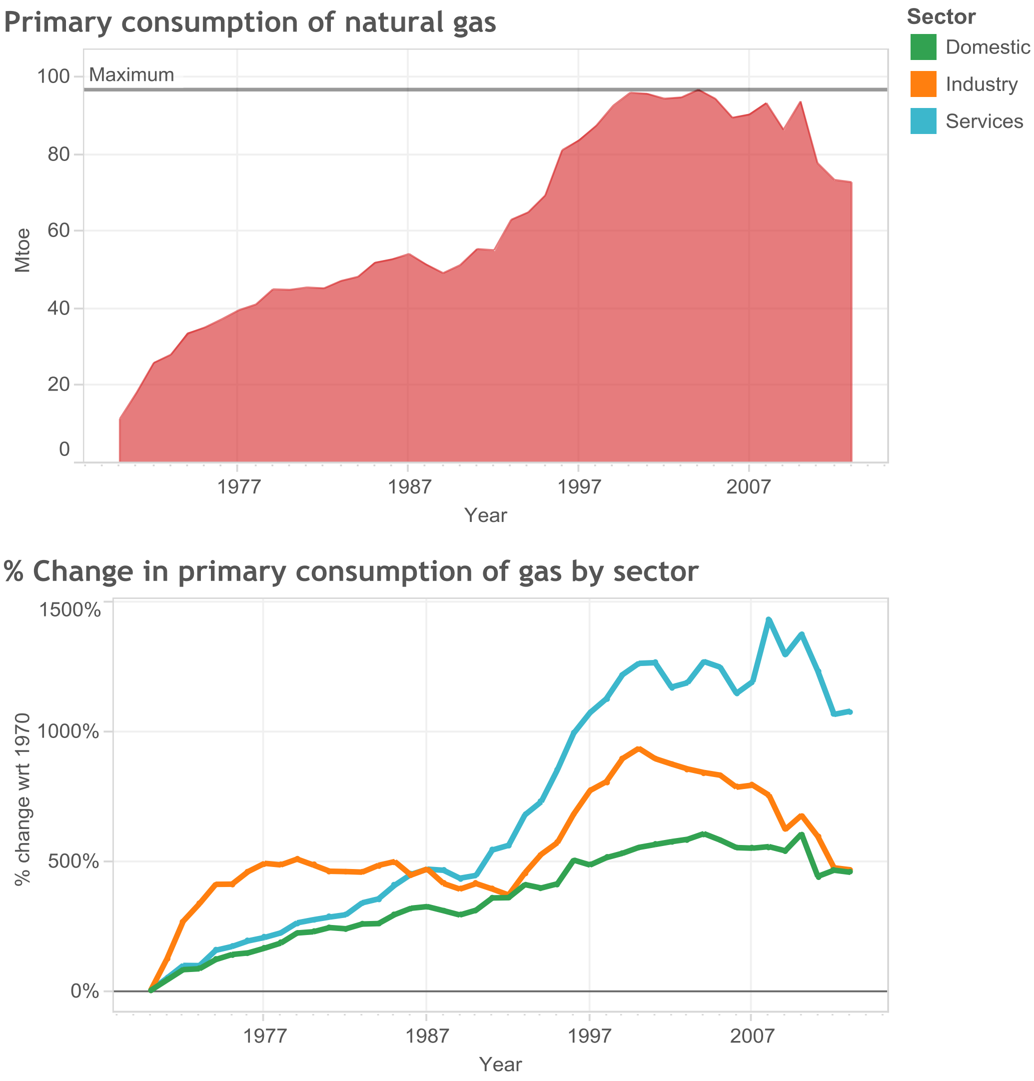

Figure 3: Primary natural gas consumption in the UK and changes in sectoral use (Data source: DECC)

Natural gas has been the UK's most important primary energy source since 1996. Its share represented 35 per cent of total supplies in 2013.[3] During the 1970s and 1980s, gas consumption by the domestic and service sectors increased steadily. Then, from the early 1990s until 2000, the 'dash for gas', a sudden rise in gas-fired power generation (shown under industry use) drove up total gas consumption rapidly (Figure 3). Consumption by the service sector also picked up pace during this period. The year 2004 marked the beginning of decline in total gas consumption, registering consumption declines in all sectors, but the decline within the industrial sector began before that.

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[3] Primary energy use includes use as a power generation fuel.

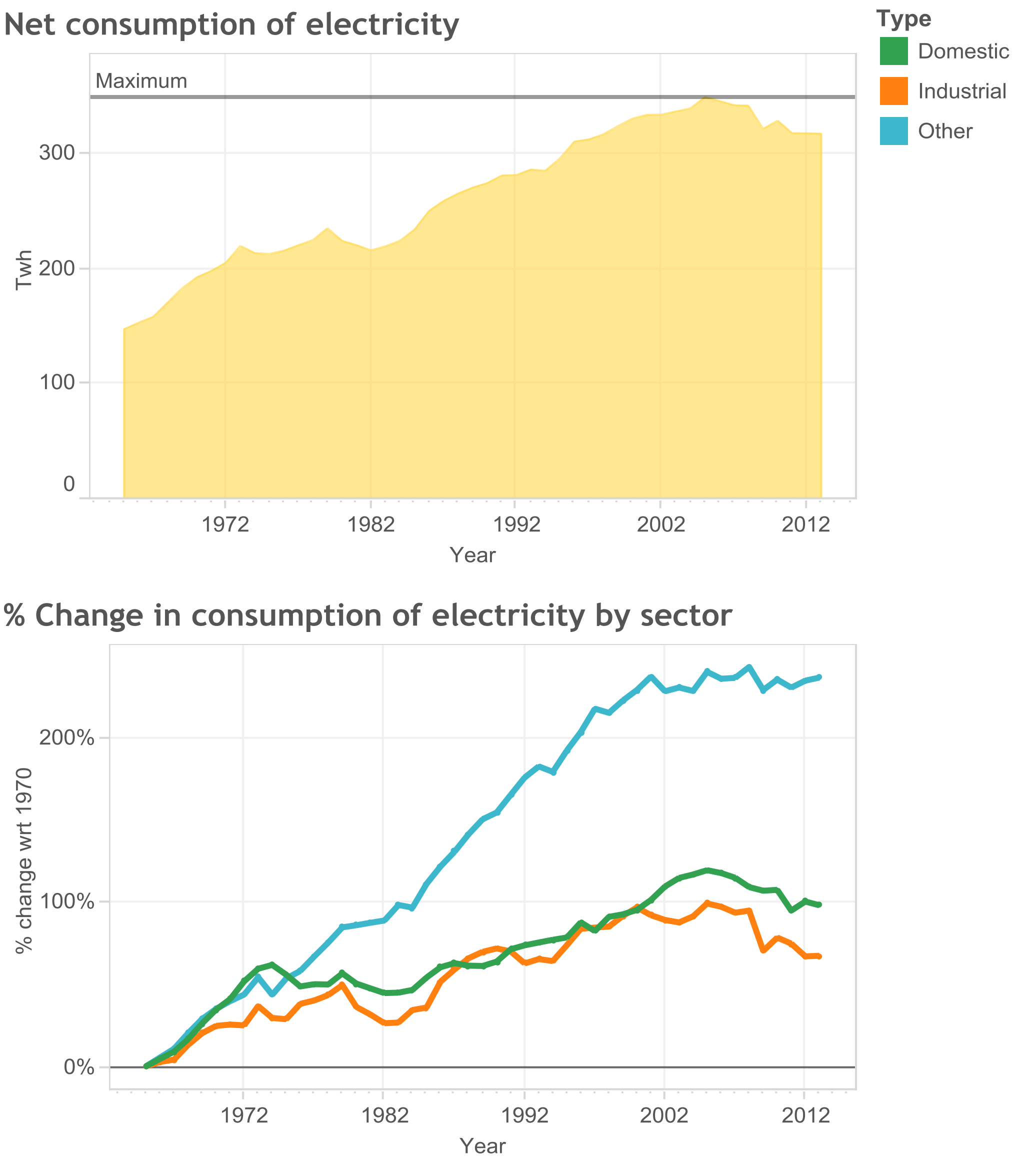


Figure 4: Net electricity consumption in the UK and changes in sectoral use (Data source: DECC)

The net consumption of electricity, which includes both primary and secondary electricity production and excludes industry's own use and transmission losses, more than doubled between 1970 and 2005. In 2013, net electricity consumption was 13 per cent of total primary energy consumed. The greatest increase was seen in the sector labelled 'other' (this includes public administration, transport, agricultural and commercial sectors), as can be seen in Figure 4. The domestic and industrial sectors were also sources of growth up to the mid-2000s.

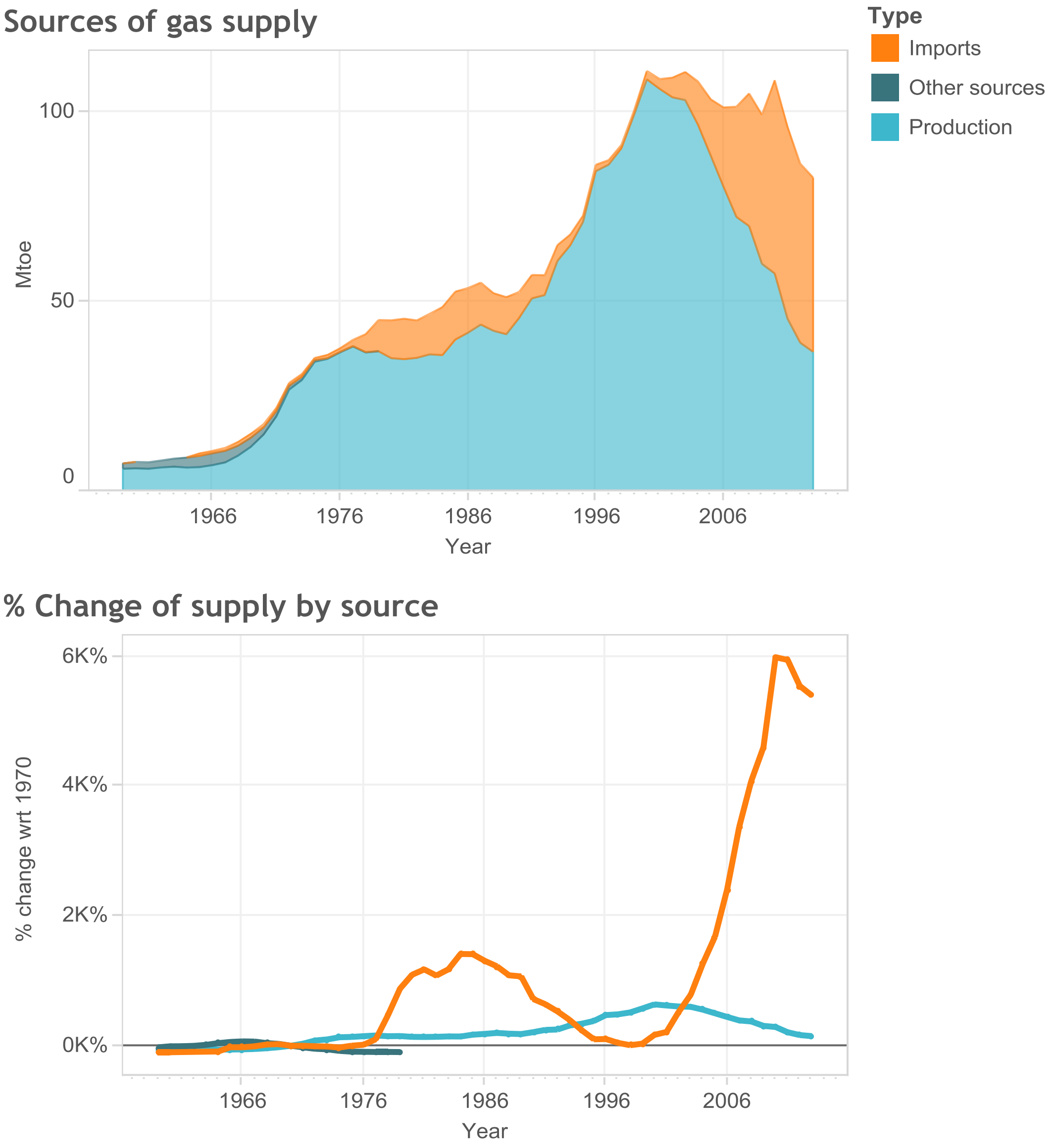
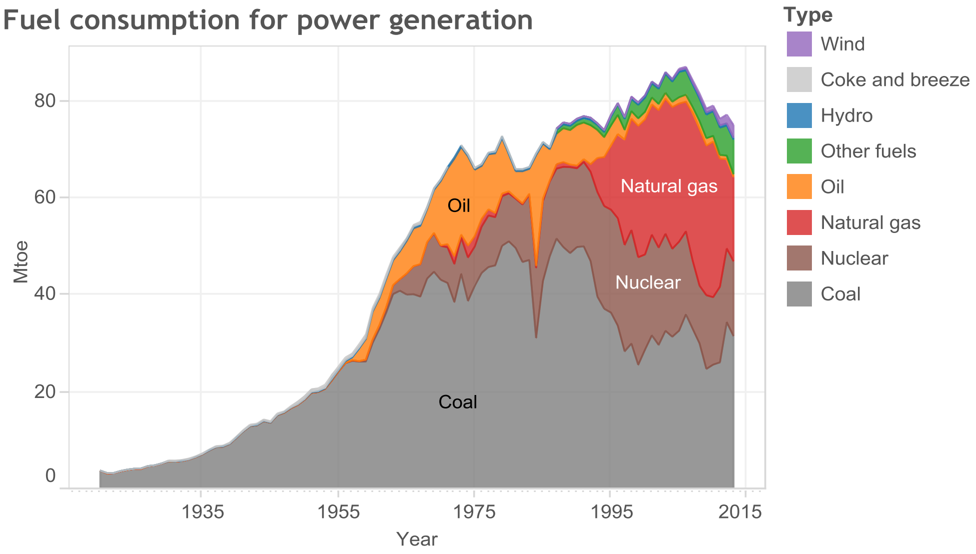


Figure 5: Sources of UK natural gas supply (Data source: DECC)

The first instances of gaseous fuel consumption in the UK were associated with town gas, which was manufactured from coal. The discovery of natural gas fields in the North Sea in the 1960s enabled a complete phase-out of manufactured gas, which was replaced by methane. Import of natural gas was negligible until the discovery of the Frigg field; this field straddles the UK–Norway border and contributed up to a quarter of total supply by 1984. In 1985, the government blocked an agreement to purchase further Norwegian imports from the Sleipner field.[4] Import levels then decreased, as the production from Frigg declined, to extremely low levels by 1998, while domestic production increased rapidly. The reversal of the trend occurred even faster: domestic production began to decline by 2001 and imports accounted for more than half of gas supply by 2013 (Figure 5).


Fuel consumption for power generation

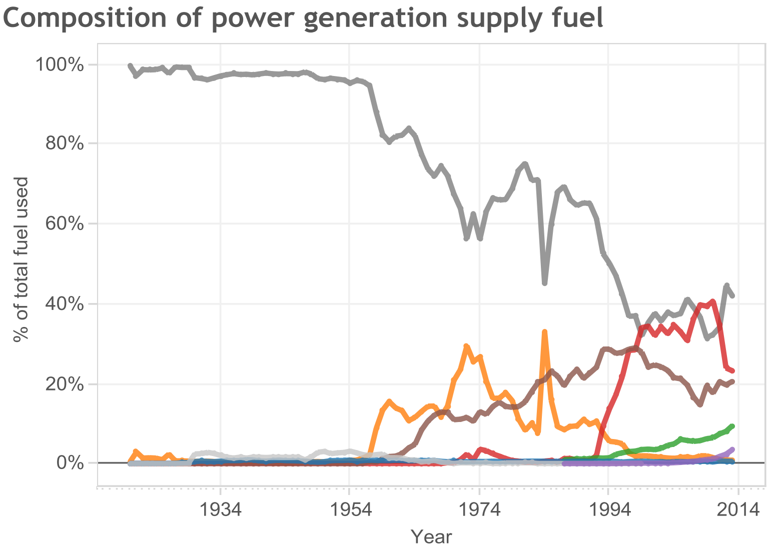

Composition of power generation supply fuel

Figure 6: Fuel for power generation in the UK (Data source: DECC)

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[4] The government's motivation in blocking the deal was to secure a market for the development of domestic gas reserves. Balance-of-payments considerations also played a role (Haugland, Bergesen, & Roland, 1998).

In order of importance, the most important fuels for power generation in 2013 were coal, natural gas, and nuclear energy. The share of nuclear generation has settled at around 20 per cent since the 1980s, while natural gas, through the dash-for-gas, suddenly captured a large share of generation at the expense of coal. During recent years, inter-fuel competition between coal and gas has been observed. The contribution from oil-fired generation has, overall, been negligible since 2000. Pumped hydro and renewable resources other than wind have been aggregated under the 'Other fuels' category. Together with natural flow hydroelectricity generation and wind, they accounted for 13 per cent of total power generation in 2013 (Figure 6).

Natural gas dependence and power dependence, the respective ratios of gas consumption and net electricity consumption over total primary energy supply, are computed for the UK between 1970 and 2013. In Figure 7, it can be seen that the country's dependence on natural gas has grown in two phases: 1970 to 1992, where the rate of increase suggests the logistic function commonly associated with diffusion of technology, and 1992 to 2008, which represents sustained quasi-linear growth. On the other hand, dependence on (net) consumption of electricity has increased steadily at the same pace for the past 30 years.

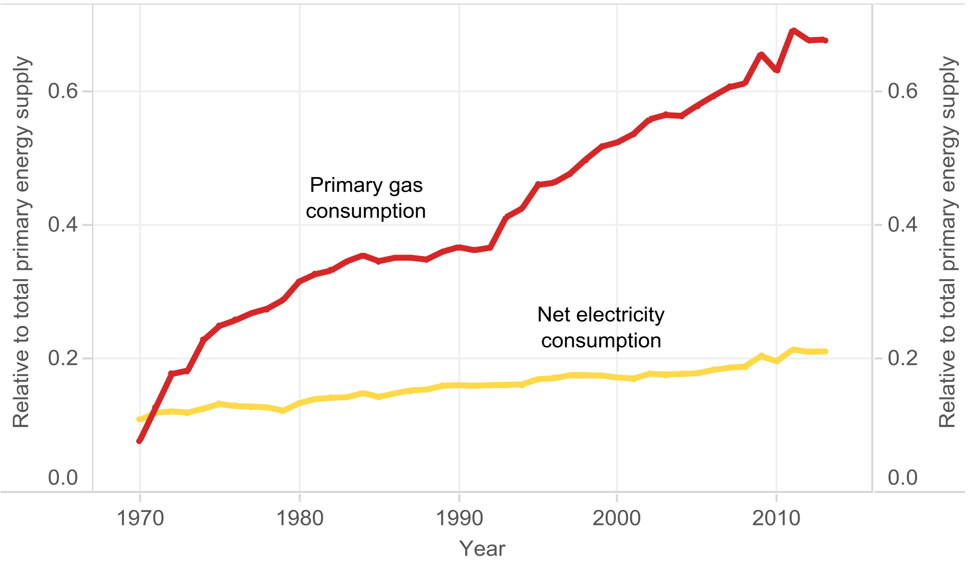

Figure 7: Measures of natural gas and electricity dependence (Data source: DECC, authors' own calculations)

3.2 Structure

In terms of industry structure, the UK is a country at the forefront of the privatization and liberalization movement. Both the natural gas and power industries underwent structural reform between the late 1980s and early 1990s. For the gas industry, the Gas Act 1986 made provisions for the privatization of the British Gas Corporation, then a state-owned entity, and established a framework to regulate the privatized industry, creating the Office of Gas Supply

(Ofgas). This was amended by the Gas Act 1995, which developed a new licensing regime, introducing competition into the downstream gas market. On the other hand, the Electricity Act 1989 established the Office of Electricity Regulation (Offer) and a licensing regime for the power sector. The Utilities Act 2000 combined the Ofgas and the Offer to establish the institution currently in charge of power and gas sector regulation: the Gas and Electricity Markets Authority (GEMA) and its supporting arm, the Office for Gas and Electricity Markets (Ofgem) (Simmonds, 2002). The upstream gas industry is regulated differently from its downstream counterpart under a licensing regime established through the Petroleum Act 1998; this applies to oil and gas exploration and production in the UK. The highly decentralized structure is presented in Table 4, and the companies which are active in several segments are highlighted. The group of six companies active in both the gas and electricity sectors, also known as the 'Big Six' (those companies – with the exception of National Grid – that are highlighted in Table 4), dominate gas supply, and power generation and supply. Each area of activities requires a separate licence that comes with a set of conditions that must be met by the licensee; these conditions are set by the regulator, Ofgem.

Three of the Big Six were also recently active in upstream gas production, but two of them (E.ON and RWE) have decided to dispose of their upstream assets in the North Sea as part of wider restructuring efforts, while UK-based Centrica is said to be planning to downsize its exploration and production arm to focus on the North Sea and East Irish Sea (Adams, 2015a, 2015b; Reuters, 2015).

3.3 Infrastructure and its use

Due to the long history of natural gas and electricity use in the country, the UK has very mature downstream gas and power sector infrastructure. The adequacy of upstream infrastructure, especially in the power sector, is subject to debate in the current energy policy debate, framed by the concept of the 'energy trilemma'. Therefore, the retail markets and the transmission and distribution networks are omitted from this study to improve focus. A description of the existing infrastructure is presented first; there is then a discussion of coordination mechanisms. This is followed by a section concerned with the management of imbalances and flexibility.

3.3.1 Existing infrastructure

The UKCS is a mature hydrocarbon basin. Total installed production capacity for all the platforms is not known, but a figure of 120 Mcm per day is inferred from the peak production rate in 2014 (Le Fevre, 2015). The reserves that remain are, relative to previous production, more expensive and challenging to produce. Total known reserves (total remaining reserves plus cumulative production) have slowed since the late 1990s (Figure 8). Gradual decommissioning of fields that are no longer profitable, together with their associated offshore pipelines, is taking place.

Table 4: Ownership structure of the UK gas-to-power supply chain

Company	Gas production	Gas export	Gas import	Gas transmission	Gas distribution	Gas storage	Gas supplier	Power generation	Power transmission	Power distribution	Power interconnector	Power supplier
BG	Yes		Yes									
Centrica	Yes					Yes	Yes	Yes				Yes
BP	Yes						Yes					
Celtique Energy	Possible											
Chevron	Yes											
ConocoPhillips	Yes											
Cuadrilla	Possible											
Dart Energy	Possible											
Eni	Yes						Yes					
ExxonMobil	Yes		Yes									
L1 Energy	Yes											
Perenco	Yes											
Shell	Yes											
Third Energy	Yes											
Total	Yes						Yes					
UK Methane	Possible											
Interconnector (UK) Ltd.		Yes	Yes									
Bord Gais		Yes										
National Grid			Yes	Yes	Yes	Yes			Yes		Yes	
BBL Company			Yes									
Excelerate			Yes									
Qatar Petroleum			Yes									
Gassco			Yes									
Northern Gas Networks					Yes							
SGN					Yes							
Wales & West Utilities Ltd.					Yes							
Scottish Power						Yes	Yes	Yes	Yes	Yes		Yes
E.ON	Yes					Yes	Yes	Yes				Yes
EDF						Yes	Yes	Yes				Yes
Humbly Grove Energy						Yes						
SSE						Yes	Yes	Yes		Yes		Yes
RWE Npower	Previously						Yes	Yes				Yes
British Energy								Yes				
Dong Energy								Yes				
Drax Power								Yes				
Intergen								Yes				
International Power/Mitsui								Yes				
Scottish Hydro Electric Transmission									Yes			
Electricity North West Ltd.										Yes		
Northern Powergrid										Yes		
UK Power Networks										Yes		
Foreign TSOs											Yes	
EirGrid											Yes	
Mutual Energy Ltd.											Yes	

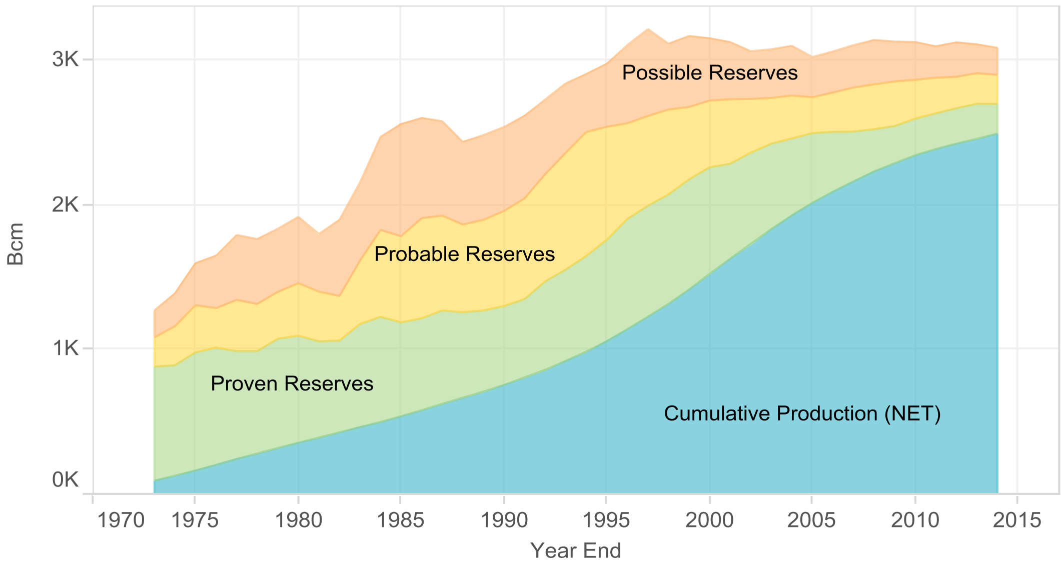

Figure 8: Evolution of UKCS total known reserves (Data source: Oil and Gas Authority, 2015)

Unconventional gas reserves such as shale gas and coal bed methane exist in the UK; however, the industry is still in its infancy, with several companies holding exploration licences, but no commercial production has begun. A large number of exploration wells are needed before any realistic estimate of potential resources can be made (Le Fevre, 2015). In reaction to domestic production decline, a wave of investments was made in import pipelines (BBL; Langeled; Tampen Link; Gjøa) and LNG import terminals (Dragon, South Hook, LNG Grain, Teesside GasPort) in the 2000s. These facilities, combined with the existing infrastructure, can deliver imports at a maximum rate of 229 Mcm per day. Gas export capacity is more limited, in the form of the Interconnector, which is capable of bi-directional transport between the UK and Belgium, and the UK–Ireland gas interconnector, at 89 Mcm per day. When benchmarked against other European countries, the UK has low storage capacity with respect to its gas consumption level: combined storage capacity of the eight existing facilities is 4.6 Bcm or 6 per cent of annual consumption, and the maximum delivery rate is 154 Mcm per day (Bradshaw & Watson, 2014).

Among the generation portfolio of the 38 major power producers, representing 85 per cent of total generation capacity (80 946 MW), CCGTs have the greatest installed capacity in the UK, followed by coal (including co-firing with biomass), nuclear, and wind (Figure 9). The past few years have seen the retirement of about 12 000 MW of coal-fired and oil-fired power plants, due to compliance with the Large Combustion Plant Directive (LCPD). Most of the nuclear power plants have planned decommissioning dates between now and 2035, given that most of them were commissioned before the 1990s. The remaining power generators, with much more disaggregated ownership, consist mainly of renewable energy generators such as solar photovoltaic panels and wind turbines (Figure 10). At 14 482 MW, they represent 47 per cent of existing renewable generation capacity in the UK.

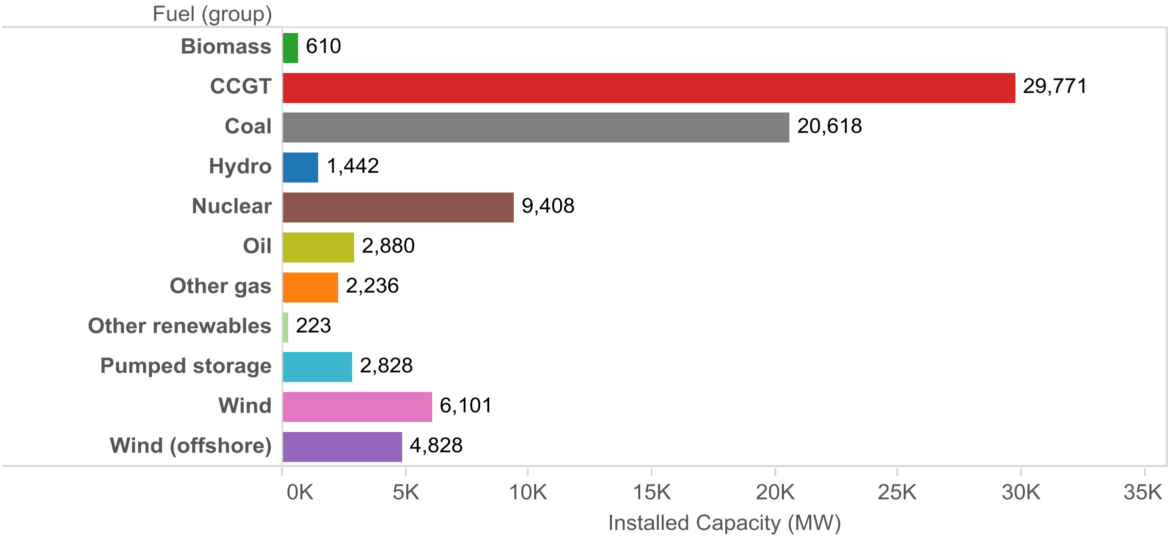

Figure 9: .Major power producer Installed capacity of power generator by fuel type in the UK (Data source: DECC, 2015d)

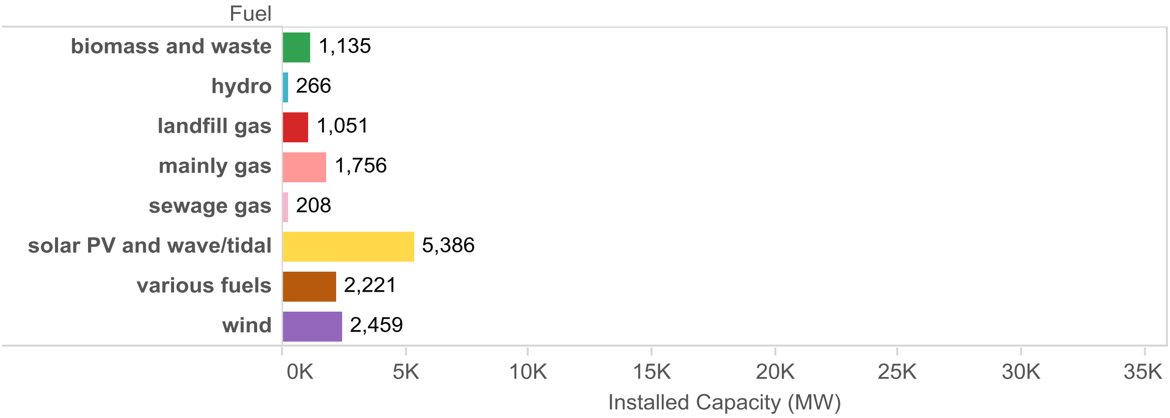

Figure 10: Non major power producer installed capacity of power generator, by fuel type in the UK (Data source: DECC, 2015d)

The UK has established power interconnection with France (Interconnexion France–Angleterre), Northern Ireland (Moyle), Republic of Ireland (East–West), and the Netherlands (BritNed), with a combined capacity of 4000 MW. Further interconnectors with France (IFA2), Denmark (Viking Link), Norway (NSN Link), and Belgium (Nemo Link) are currently planned, to be commissioned by 2020, an addition of 4800 MW (National Grid, 2015b). A 1000 km long interconnector, supplying power from Iceland to the UK, is also under consideration (The Economist, 2014).

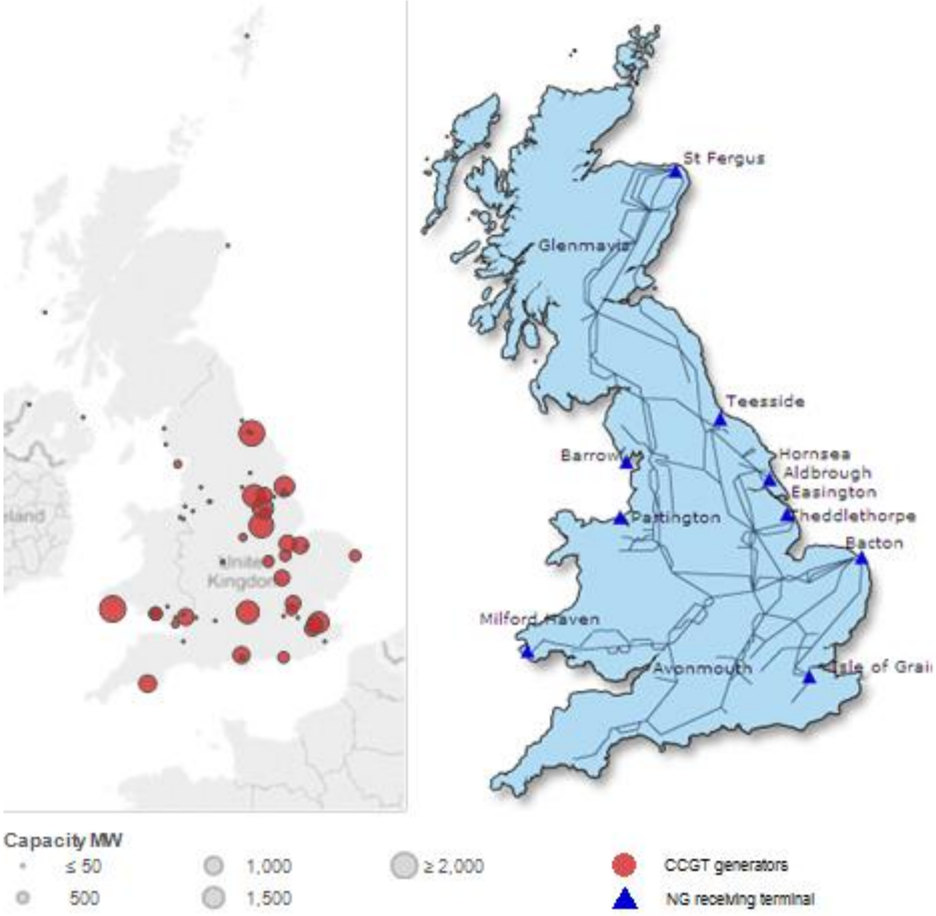

Figure 11: CCGT plants locations and the National Transmission System (Data source: Enipedia, National Grid)

One crucial link of the gas-to-power supply chain infrastructure that needs to be examined is the supply of gas to CCGT plants via the gas transmission network. Figure 11 shows that the gas-fired generators in the UK are mainly located along two corridors: north to south, between Teesside and the Isle of Grain; east-to-west, between Milford Haven and the Isle of Grain. These are the locations of the four LNG gasification terminals built since 2005, of which two are located in Milford Haven. There is also a cluster of power plants close to the Easington terminal, which is the landing point of the Langeled pipeline, commissioned in 2007 to land imported natural gas from Norway.

Natural gas demand outside of power generation, 78 per cent of total gas demand in 2013, is mainly used to provide space and water heating services via gas boilers. The technology is well-established and mature, with limited future growth capacity (Figure 12).

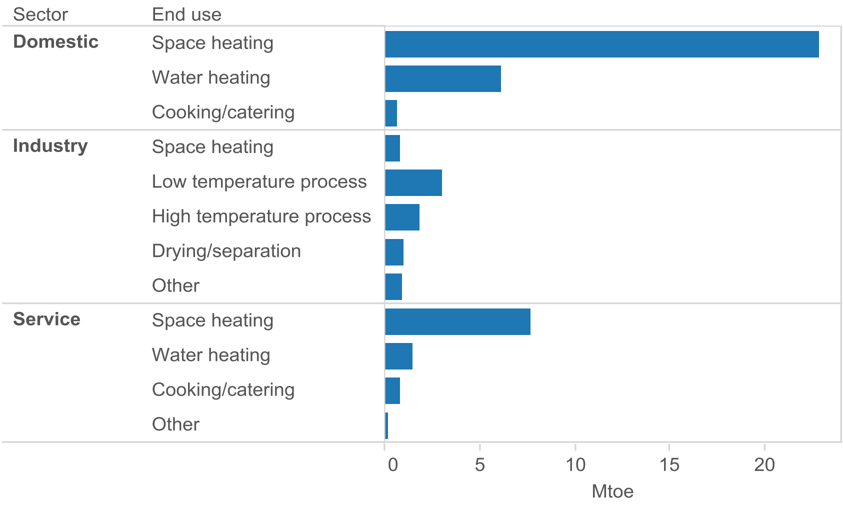

Figure 12: Breakdown of gas consumption in 2013 (Data source: DECC, 2015b)

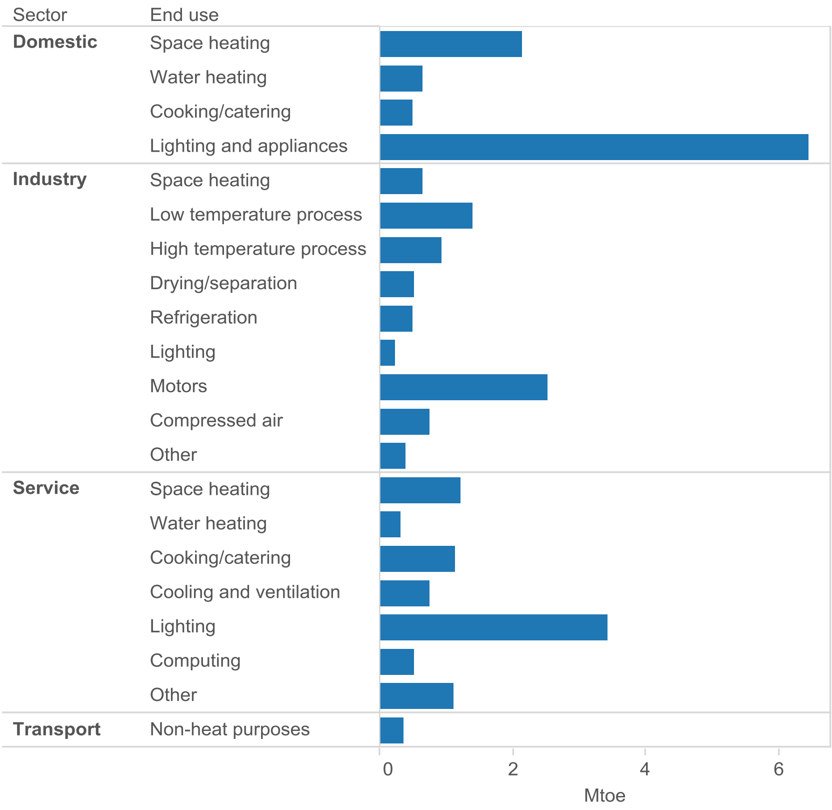

Figure 13: Breakdown of electricity consumption in 2013 (Data source: DECC, 2015b)

Consumption of electricity in the UK comes from diverse sources, the most important being lighting and appliance use in the residential sector. Electrification of heating and transport already occurs, representing 15 per cent and 1 per cent of electricity demand in 2013. Further development is possible, since electrification is seen as a key to decarbonisation in these sectors (Figure 13).

3.3.2 Coordination mechanisms

The power and gas industries rely on market mechanisms for both short-term and long-term coordination. The power and gas wholesale markets take place either via exchanges (ICE, APX UK, and UK N2EX), where energy commodities and derivatives can be traded anonymously and pricing information is published, or via the Over-the-Counter (OTC) market, where parties enter into bilateral contracts and may be brokered, and the price is revealed through price reporting agencies. Within both types of organized markets, spot, prompt, and forward markets can be differentiated, based on the differences in the lead time that delivery date has with respect to the delivery date: spot for delivery within the same day, prompt for delivery between a day and the next month (front month), and forward for delivery beyond the front month. In the UK, spot trading for both power and gas tends to be exchange-based, but this represents the trade of smaller volumes than is the case on the OTC-dominated forward market (Table 5).

Long-term structured contracts signed with gas producers or electricity generators can also be arranged bilaterally; this is typically considered as a subset of the OTC market. An important difference in the organization of power and gas wholesale markets in the UK is the importance of long-term contracts. Long-term sales agreements have supported large capital investments in the gas industry. The take-or-pay clauses which require the buyer to pay for a contractually determined minimum volume, even if delivery is not taken, have transferred price and volume risk to the buyer, to ensure project viability when facing financing institutions. The volumes and prices of such contracts are not as transparent as shorter-term trades, but, according to data on 426 natural gas long-term contracts, in 2015, companies based in the UK have signed long-term contracts which have an annual delivery volume of 35 Bcm, of which 8 Bcm comes from long-term LNG shipments (See Table 3 for Neumann, Rüster, & Hirschhausen, 2015). This quantity is 40 per cent of the total gas consumption in the UK and 75 per cent of total imports. The parallel of long-term gas contracts in the UK power sector are not contracts between power suppliers and foreign gas exporters; instead, they are long-term contracts between the government and (typically) low-carbon generators. However, as a policy tool (feed-in tariffs and the contract for difference) they also exist to transfer risk and encourage upstream investment. The generation reported by the FiT scheme licensees in 2013–14 amounts to 3.3 GWh, or 1 per cent of total UK electricity consumption in 2013 (Ofgem, 2014).

The National Balancing Point (NBP) is the principal delivery point for gas traded in the UK through long-term contracts and short-term trades. It can be conceived as the entire National Transmission Network circumscribed by a number of entry points, a zone for which gas input and output needs to be balanced. Natural gas demand does not vary by much within the same day. Therefore, the gas spot market in the UK, OCM (On the Day Commodity Market) is effectively the balancing market, where shippers balance their own supply/demand portfolios while the gas system operator, National Grid, balances the system as one among many traders, based on information it receives concerning contracted flows. On the other hand, the power system operator (also National Grid) cannot rely on spot trade to balance the power grid, for power balancing needs vary second to second. The power system operator takes over the matching of supply and demand within the power grid an hour before real time consumption (gate closure), and dispatches generation, demand response, or other ancillary services procured through the balancing mechanism and other programmes. Balancing parties provide their likely actual generation/demand level for each half-hour settlement period ahead of gate closure (one hour before), and the charge/payment they are willing to make to deviate from that level.

The presence of gas pipelines, LNG terminals, and power interconnectors that connect the UK to other countries, open to short-term trading, means that the domestic market dynamics, integrated with continental Europe and the global LNG market, are no longer purely determined by fundamentals such as domestic supply and demand. Price integration (the correlation/cointegration of price across markets) can be used as an indicator to assess the level of market integration. Evidence suggests that the European gas hubs – NBP, Title Transfer Facility (the Netherlands), Zeebrugge Hub (Belgium), Central European Gas Hub (Austria), Gaspool (Germany), Net Connect Germany, Points d'Echange de Gaz (France), Punto di Scambio Virtuale (Italy) – are already part of the same integrated market, showing strong price correlation that increases with time (Petrovich, 2013). As for wholesale power markets, the UK has also seen the correlation of its power price with the Dutch price increase by 25 per cent since the establishment of the BritNed interconnector (Castagneto-Gissey, 2014).

Table 5: Power and gas markets in the UK (excluding retail; data source: National Grid, APX, ICE, Nord Pool Spot, Argus, Ofgem E-serve)

Commodity	Mechanism	Market	Duration	Delivery date	2013 volume (TWh)
Gas	OTC	Long-term contract	typically 10 years	N/A	342[5]
Gas	OTC	Forward	month, quarter, season, year	front month to year 3	12131
Gas	OTC	Prompt	day, weekend, week, month	day-ahead to current month	
Gas	Exchange = ICE	OCM (spot)		within-day	108
Gas	Exchange = ICE	Futures	around 7 years	N/A	Not available
Electricity	FiT	Long-term contract		N/A	3.3
Electricity	OTC	Forward	month, quarter, season	front month to season 7	558
Electricity	OTC	Prompt	month, quarter, season	day-ahead to current month	
Electricity	Exchange = APX	Prompt	8 to 48 hours	7 days	3.35
Electricity	Exchange = APX	Spot	0.5 to 4 hours	49.5 hours	10.66
Electricity	Exchange = APX	Day-ahead auction (prompt)	hour	day-ahead	8.57
Electricity	Exchange = N2EX	Day-ahead auction (prompt)	hour	day-ahead	139.4
Electricity	Exchange = ICE	Futures	around 5 years	N/A	Not available

Table 6 Long-term contracts between the UK and natural gas producers (Neumann et al., 2015)

Participant (company)	Seller (company)	Type	Contract conclusion	Start of deliveries	Contract duration	End of deliveries	Yearly volume (Bcm)	Total volume (Bcm)
BP	Statoil	pipeline	2001	2001	15	2,015	2	24
Centrica	Cheniere	LNG	2013	2018	20	2,037	2	48
	Petronas	LNG	2004	2007	15	2,021	3	45
	Qatargas	LNG	2013	2014	5	2,018	2	8
	RasGas	LNG	2006	2008	20	2,027	3	68
	Statoil	pipeline	2002	2005	10	2,014	5	50
	Statoil	pipeline	2011	2015	10	2,024	5	50
	Statoil	pipeline	2011	2015	10	2,024	1	50
Centrica/ British Gas Trading	Gasunie	pipeline	2002	2005	10	2,014	8	80
Gazprom Market and Trading	Dong	pipeline	2006	2007	15	2,021	1	9
Scottish Power	Statoil	pipeline	2005	2007	10	2,016	1	5
Shell UK	Statoil	pipeline	2003	2007	10	2,016	4	40

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[5] Estimated from Table 6.

3.3.3 Management of imbalances and flexibility

The most important cause of imbalance in the gas supply chain has been seasonal temperature changes, as heating load is a major part of demand. Prior to the decline of production, much of the flexibility to meet seasonal variation in gas demand was provided by the beach swing of UKCS production. However, that flexibility has declined with the production level. Today, pipeline import from Norway and the Netherlands is playing a more important role in the management of seasonal supply/demand imbalance, via volume flexibility in long-term contracts rather than short-term trading (Figure 14). Shorter-term imbalances are resolved through short-term trade across the Interconnector, LNG spot cargoes, and storage.

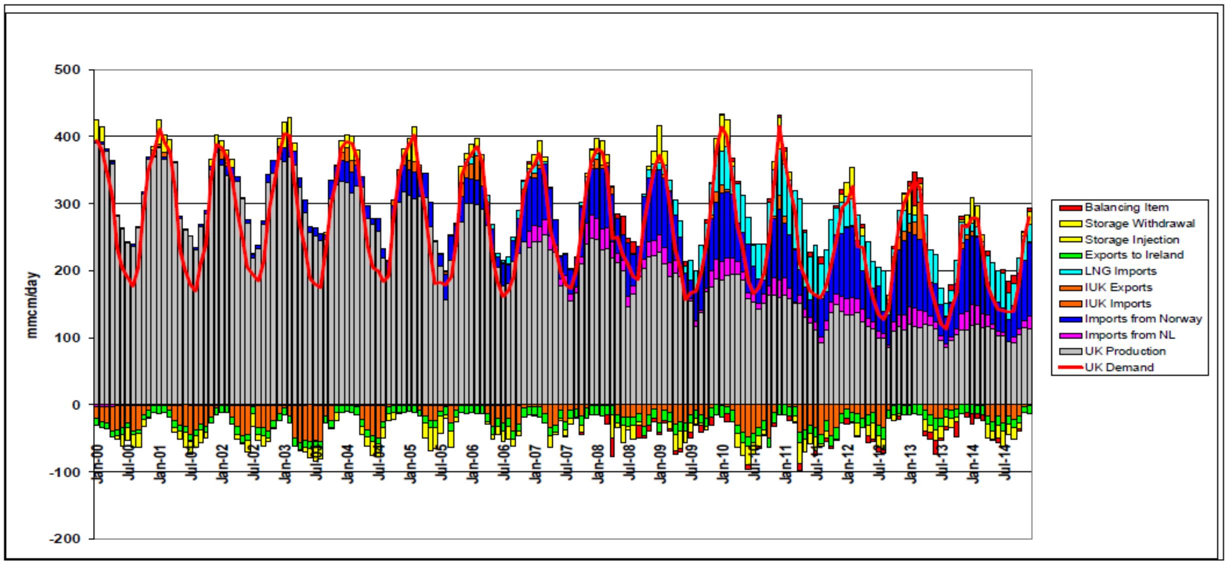
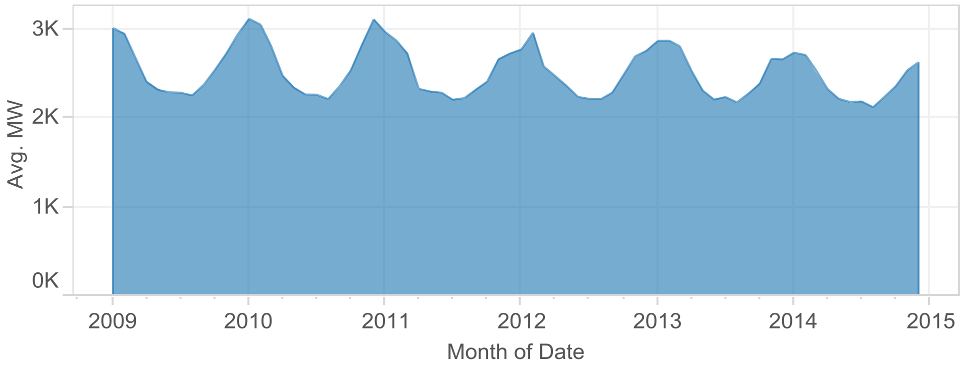


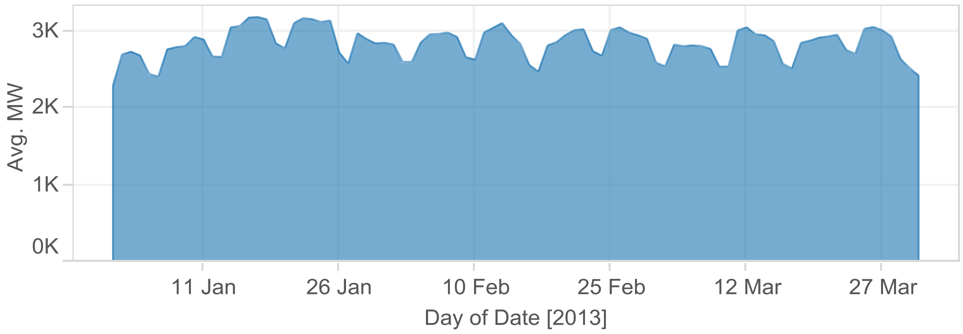
Figure 14: UK gas sources and destinations (Le Fevre, 2015)

In the power supply chain, causes of imbalance occur across many timescales. Variation in demand experiences seasonal, weekly, and daily cycles that are driven by heating/lighting needs, work schedule, and daily schedule (Figure 15). Variation in renewable generators also introduces different scales of imbalance. Solar, hydro (run-of the river and reservoir but not pumped storage), and wind in the UK all exhibit seasonal cycles; more energy is supplied during summer (higher solar intensity) and winter (wet season and windy). On a daily scale, solar generation only occurs during daylight hours, and hydro reservoir can be dispatched to follow daily power demand (observe the pattern of hydro generation in Figure 16). Wind, for the same timescale, does not exhibit any trend at all.

Seasonal demand pattern: monthly resolution



Weekly demand pattern: daily resolution



Daily demand pattern: hourly resolution

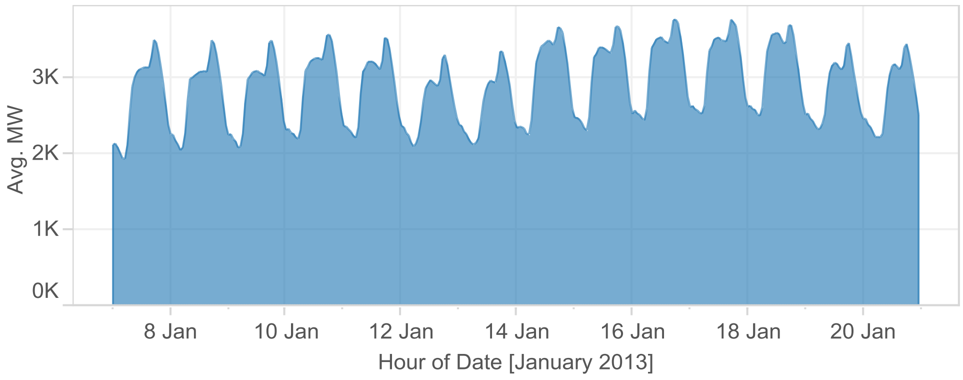
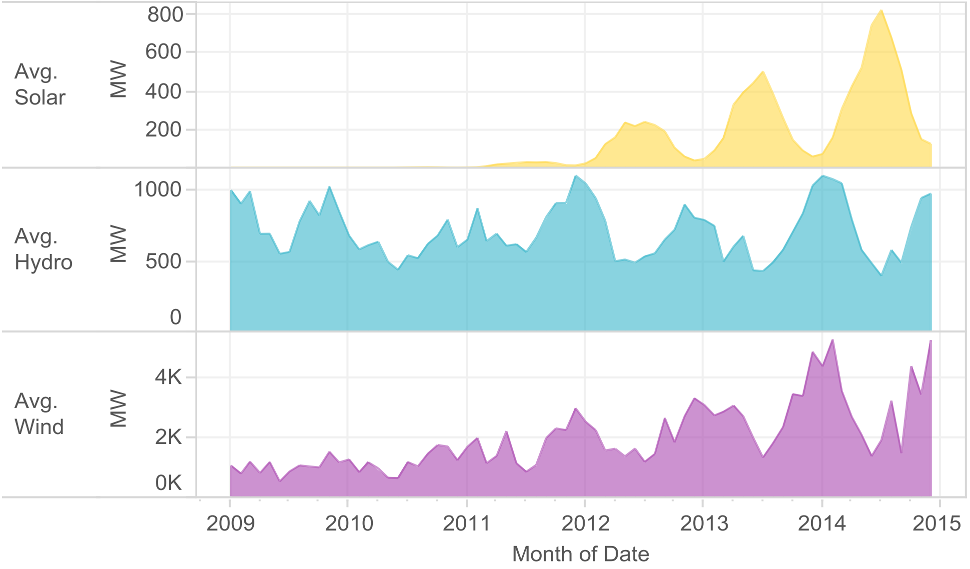


Figure 15: Average UK electricity demand for various temporal resolutions (Data source: Elexon portal, authors' own calculations, demand served by embedded generation estimations have been included)

The main sources of supply-end flexibility are now examined. In the long term, nuclear power generation does exhibit some variation, but in the short term (hourly resolution), it can be considered to be essentially flat and inflexible. Coal and CCGT are both capable of load following, but coal exhibits a seasonal cycle which gas-fired generators do not. On a daily basis, CCGT exhibits hourly variation that matches the variation in hourly demand, which coal generation does not (Figure 17). Thus, it can be concluded that gas-fired generation is dispatched to meet shorter-term imbalances then coal-fired generation.

Seasonal RE supply pattern: monthly resolution



Daily RE supply pattern: hourly resolution

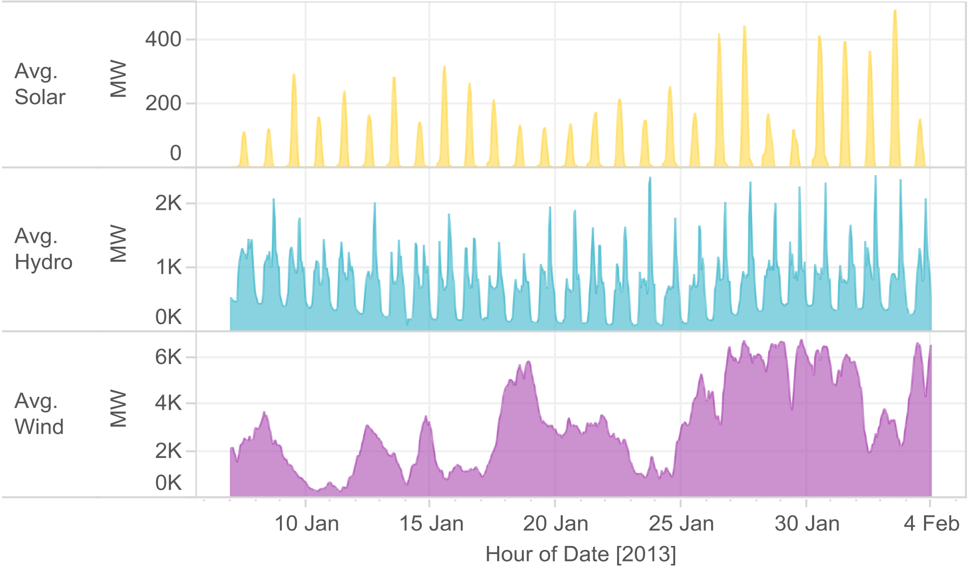
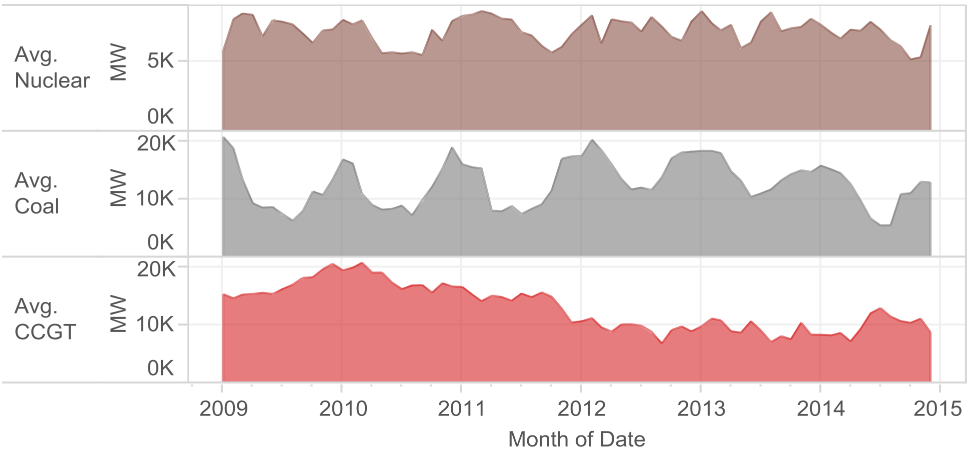
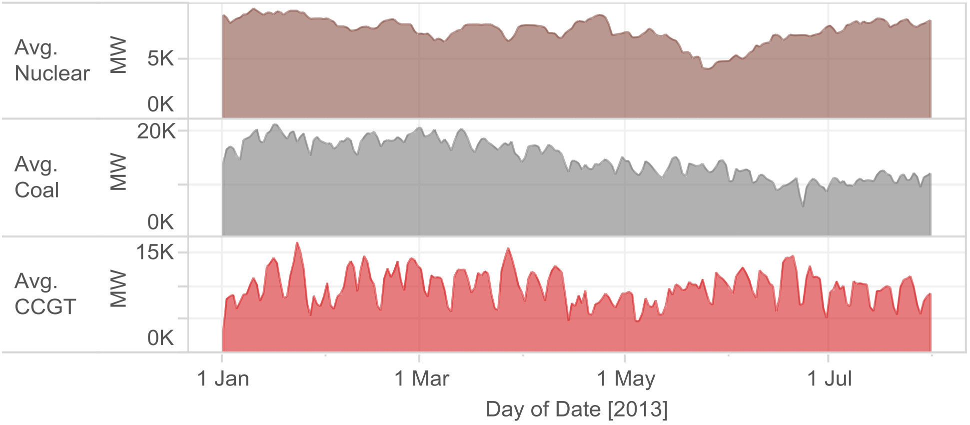


Figure 16: Average UK renewable electricity supply for various temporal resolutions (Data source: Elexon portal, authors' own calculations, embedded generation estimations have been included)

Seasonal thermal supply pattern: monthly resolution



Weekly thermal supply pattern: daily resolution



Daily thermal supply pattern: hourly resolution

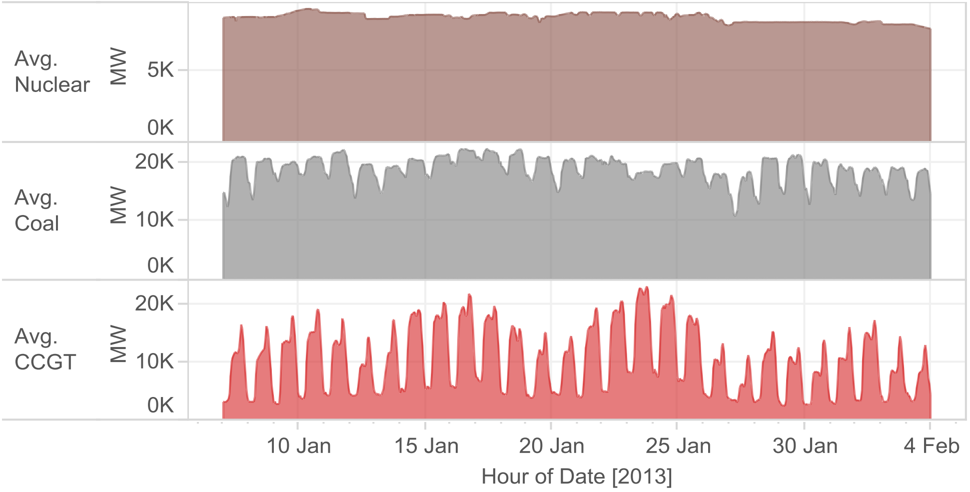
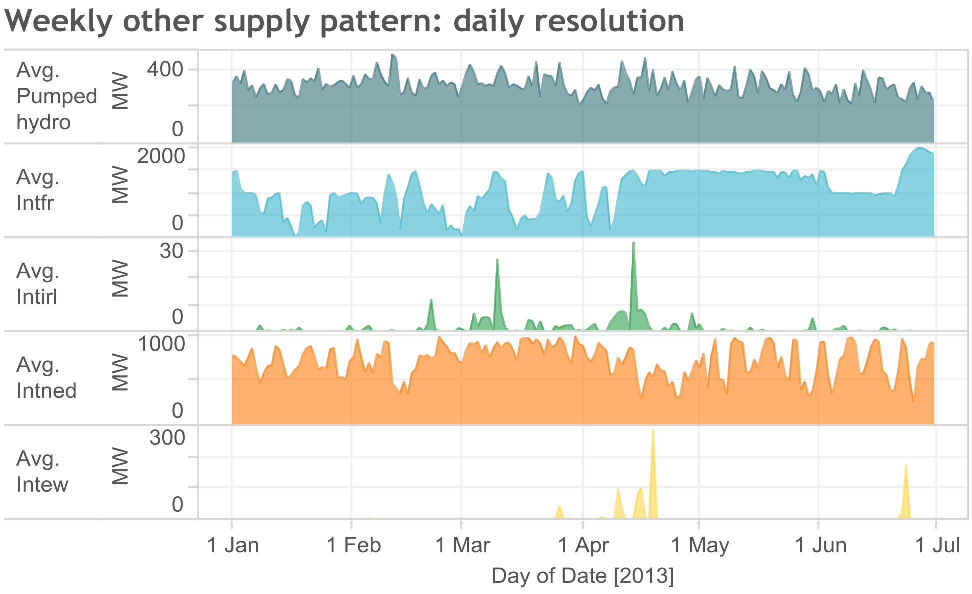


Figure 17: Average UK thermal electricity supply for various temporal resolutions (Data source: Elexon portal, authors' own calculations)



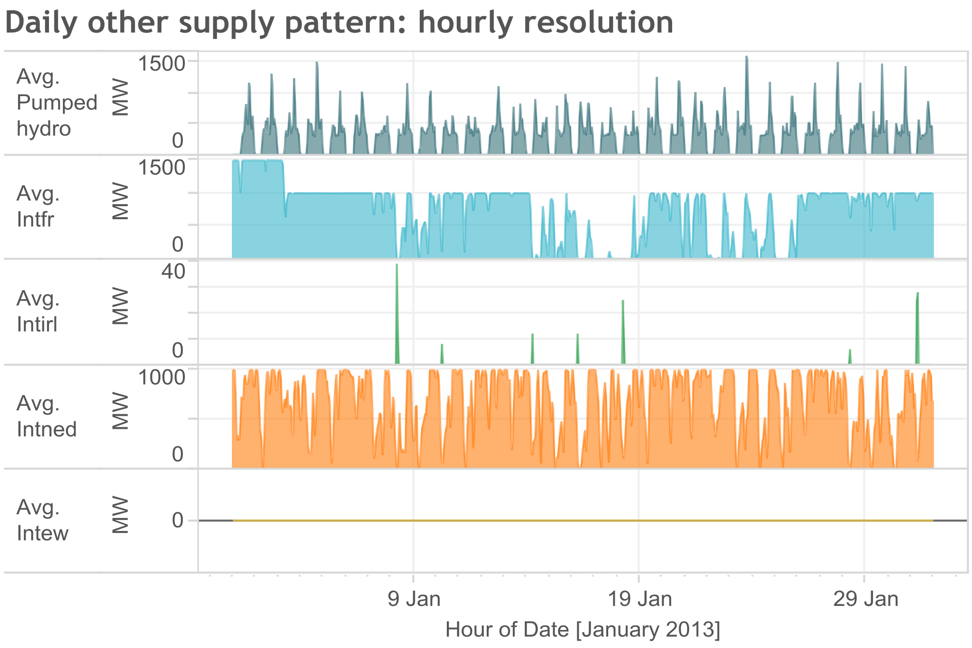


Figure 18: Average UK pumped hydro and interconnector supply for various temporal resolutions (Data source: Elexon portal, authors' own calculations)[6]

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[6] The acronyms used for Intfr: Interconnexion France–Angleterre; Intirl: Moyle interconnector; Intned: BritNed interconnector; Intew, East–West interconnector.

While inspecting the generation pattern for 2009–2013, it can be seen that, of the remaining sources of flexibility (pumped hydro and interconnectors), pumped hydro is clearly dispatched during peak hours only to meet daily peak demand (Figure 18).

As for the four interconnectors, since only import data is available, it is only possible to comment partially on their function in the UK's power market. The interconnectors to Northern Ireland and the Republic of Ireland contribute relatively little to imports. According to other references, they were used solely for exports before 2008 (Bolton, 2013). Compared to the interconnector to France, the interconnector to the Netherlands appears to be much more active in responding to short-term demand variations. Possibly because French exports, coming from low-cost nuclear generation, are less responsive to short-term market signals. The planned addition of new interconnectors, especially ones connected to countries with important flexible generation (such as hydropower from Norway and Iceland), could provide additional sources of supply flexibility.

3.4 Policy and regulation

The current energy agenda of the UK government is articulated in three dimensions: energy security, sustainability, and affordability. This is also known as the energy trilemma – the challenge of 'keeping the lights on, at an affordable price, while decarbonizing the UK power system' (DECC, 2014a). This multi-layered approach evolved from an earlier focus on liberalization and market opening throughout the 1980s and 1990s, and the shift in focus is mirrored on the change in the key government institution that deals with energy. The Department of Energy, established in 1974 in the wake of the 1973 oil crisis and the increasing importance of UKCS oil and gas production, was abolished in 1992, following the privatization and liberalization of the industries. Its core activities, related to setting the energy policy agenda, were then transferred to the Department of Trade and Industry (DTI), while new regulatory authorities such as Ofgas and Offer became responsible for the regulation of the liberalized power and gas industries, and energy efficiency functions were transferred to the Department of the Environment. After the turn of the twenty-first century, the energy policy-related functions were rehoused under the newly created Department of Energy and Climate Change (DECC) which, as its name indicates, puts important focus on tackling climate change. The government policies that are directly relevant to owners and operators of the gas-to-power supply chain have been summarized in Table 7.

Table 7: A non-exhaustive UK energy policy inventory directly relevant to the gas-to-power supply chain (Source: DECC website)

		Sustainability	Security	Affordability
Gas production	UKCS		Creation of the Oil and Gas Authority to maximize the economic recovery of oil and gas and coordinate decommissioning of key assets	
	Unconventional		Establishment of the Office for Unconventional Gas and Oil to encourage recovery of unconventional reserves	
Gas import				
Gas export				
Gas transmission				
Gas distribution				
Gas storage				
Gas supplier		Required to promote energy efficiency measures for consumers through Energy Company Obligation		Analysis of competitive environment by the MCA
Non-power gas consumption		Encourage use of renewable heating through the Renewable Heat Incentive (RHI); receive energy efficiency services promotion from energy supplier		New minimum energy efficiency standard for the private rented sector is in the process of being introduced
Power generation	Renewable/ low carbon	Incentivise investment in renewable generation through renewables obligation (RO), feed-in tariffs, and Contracts for Difference (CfD); incentivise use of low-carbon generation via the carbon price floor	Incentivise investment in renewable generation through renewables obligation (RO), feed-in tariffs, and the Contracts for Difference (CfD)	Analysis of competitive environment by the MCA
	Fossil fuels	Emission performance standards for generators; disincentivise use of carbon intensive generation via the carbon price floor	Provide payment to reliable sources of generation capacity via the Capacity Market	Analysis of competitive environment by the MCA
Power transmission				
Power distribution				
Power interconnector			Provide payment to reliable sources of generation capacity via the Capacity Market	
Power supplier				Analysis of competitive environment by the MCA
Power consumption		Encourage adoption of electric vehicles via match-funding to install electric vehicle charging points (OLEV programme)		

Of the three energy trilemma objectives, only sustainability has clearly stated targets. Through the 2008 Climate Change Act, the UK has legislated that a carbon emission reduction of 80 per cent is to be achieved by 2050, with respect to a 1990 baseline level. The path to the emission reduction target is directed via a set of five-year carbon budget periods, starting in 2008. By 2020, greenhouse gas emissions are to have been reduced by 34 per cent below the base level. A key component of decarbonisation is the adoption of renewable energy: the 2009 Renewable Energy Directive has set a target for the UK to achieve 15 per cent of its energy consumption from renewable sources by 2020, pledged as part of the EU 2020 climate and energy package to meet the EU-level goal of 20 per cent renewable energy by 2020. So far, a large number of measures have been applied in the power generation segment, encouraging renewable and low-carbon generation investments, with some additional measures targeting downstream gas consumption by encouraging investments in low-carbon (high efficiency) and renewable heating technologies.

For energy security, the government mostly adopts *ad hoc* regulatory measures based on its evaluation of gas and electricity security of supply. The most recent evaluation of gas security of supply, conducted by Ofgem in 2012, was similar to the investigation triggered by the outage of Rough storage and the Russia–Ukraine crisis in 2006 (Kopp, 2015). It found that the gas wholesale market was effective in attracting significant investment in gas import infrastructure in response to declining indigenous supplies, and the diversity and quantity of supplies that can be delivered to Great Britain would protect consumers from supply disruptions in a broad range of events. Further measures could be taken to more fully reflect the value of gas security of supply to consumers, but 'a much fuller and a more rigorous assessment of the risks, costs and benefits of that measure would be needed'(Ofgem, 2012, p. 8). But, a 2013 review of UKCS oil and gas recovery has triggered the setting up of a new upstream regulator, the Oil and Gas Authority, with a mandate to maximize economic recovery of the UKCS reserves (DECC, 2014b). This could potentially enhance security of gas supply, provided uncoordinated decommissioning of important offshore infrastructure is avoided, preventing stranded reserves. Since the recent fall in global oil prices, the Oil and Gas Authority has identified significant reduction in exploration, infrastructure investment, and staffing levels. It proposed remediation measures such as: using fiscal levers to protect critical infrastructure and key production hubs, and supporting the development and implementation of a fiscal regime that instils confidence in the future potential of the UKCS (DECC, 2015).

As for electricity security of supply, assessments around 2010 pointed to a risk of generation capacity reduction, with little confidence that adequate new investment would come forth, due to concerns relating to commercial risks heightened by regulatory uncertainty. Ofgem did not consider that leaving the market arrangements unaltered was in the interests of consumers, and such concerns eventually led to the implementation of the Electricity Market Reform (EMR) in 2014. This is a policy package that includes long-term contracts for low-carbon generation – Contracts for Difference, which will eventually replace the renewable support mechanism (Renewables Obligation) in place – and a capacity market to reward reliable capacity contributions (Newbery & Grubb, 2014). As an EU member, bound by the EU directives for regional power and gas market integration, the UK needs to achieve interconnection of at least 10 per cent of its installed electricity production capacity, as per the requirement of the

European Council. The development of additional interconnector capacity, already in motion, is believed to contribute to electricity security of supply. This attitude is reflected through the inclusion of interconnectors in the second auction of the capacity market, to be held in December 2015 (DECC, 2014c).

Energy affordability has been addressed in two dimensions. It can be interpreted as being the elimination of fuel poverty,[7] on the grounds that access to energy is an essential public service. Or, it can be interpreted to be keeping energy bills at a reasonable level, by promoting efficient market operations. Under the first consideration, targets have been set to alleviate fuel poverty by raising home efficiency in England for as many fuel-poor homes 'as is reasonably practicable' to band E by 2020, and band D by 2025, through energy efficiency standards in rented accommodation (Secretary of State for Energy and Climate Change, 2015). Under the second consideration, Ofgem has asked the Competition and Markets Authority (CMA) to consider whether there are further barriers to effective competition across the wholesale and retail energy markets that make retail energy prices unnecessary high. The CMA has recently published its provisional findings and list of possible remedies, but no regulatory measures have been adopted as of writing (CMA, 2015).

3.5 Discussion

Structurally, Table 4 shows that integration of ownership across gas storage, gas supply, power generation, and power supply, through the 'Big Six' firms is non-negligible. Except for Centrica, which retains gas production assets in the North Sea, the ownership overlap of the downstream infrastructure with the domestic gas production segment is tenuous and decreasing, following E.ON's and RWE's asset disposal. The six firms represent the most important demand in the UK wholesale gas markets, and their preferences for sourcing gas (long-term contracts from a number of gas producing countries/companies, OTC, or exchange trading) will affect the liquidity in the shorter-term trading markets and the composition of the set of countries supplying gas to the UK.

In terms of infrastructure, the UK gas-to-power supply chain infrastructure is very mature, yet uncertainties plague two particular segments: domestic gas production and power generation. Without new investment, the UKCS production capacity is expected to continue its steep decline, but the quantity of investment that can be expected to enhance recovery from declining fields, or to develop increasingly difficult reserves, is uncertain. The generation capacity crunch, due to the implementation of the LCPD, expected retirement of nuclear power plants, and mothballing of non-profitable plants, has been noticed and is being addressed via the EMR, but the outcome of the new regulatory measures is also yet to be observed. New development is also expected in the power interconnectors segment, as the interconnector capacity is expected to double by 2020. In the downstream, gas and electricity consumption devices have a wide established base in the UK. The overall level of energy consumption is unlikely to increase much.

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[7] The term 'fuel poverty' itself is open for interpretation: much of the Hills report, mandated by the DECC to review the issues, is concerned with defining and measuring the phenomenon (See Hills, 2012).

Instead, there is a possibility of overall demand reduction and inter-fuel substitution through the adoption of more efficient energy use practices, adoption of electric vehicles, and electricity or biomass-based heating systems.

In terms of gas and power interdependence in the short term, as embodied in operational decisions, natural gas currently used for power generation represents 9 per cent of overall energy consumption, or 30 per cent of power generation fuels. It is being used to meet variations in power demand at the daily and hourly timescale. So far, the UK gas wholesale market has played an adequate role in supplying, within the timescales required, gas-fired power generation plants, which are conveniently located along major arteries of the gas transmission system. No major short-term coordination failure has been reported. A potential source of flexible power supply that may compete with natural gas in the wholesale power market is flexible hydropower from soon-to-be interconnected countries such as Norway (and potentially Iceland).

In terms of regulation, the energy policy of the UK government is mainly addressed at the power sector. Natural gas is expected to play the role of a balancing fuel, picking up when other forms of generation are not sufficient/flexible. As Table 7 shows, most policy targets and actions are applicable to the mid and downstream of the gas-to-power supply chain (the area of activity of the 'Big Six' firms), power generation being the segment most heavily influenced by policies, as it is perceived to be the main conduit for improving energy sustainability performance, while energy security in terms of power generation capacity has seen as lacking. The power generation owners' (major industry firms and embedded self-generators) reaction to the joint impact of all the regulatory action on their bottom line is a major source of uncertainty, and it influences gas sector planning by making the long-term downstream gas demand uncertain. The impact of the Oil and Gas Authority, newly established as the economic recovery of UK oil and gas reserves is perceived to be under threat, in directing investments toward the UKCS in a low oil price environment, is yet to be observed.

4 Econometric study

An econometric analysis is conducted to gather empirical evidences about the causal relationships behind price formation in the UK gas and power markets and between markets to which they are interconnected. The cointegration approach is adopted to analyse time series of a range of commodity prices across various geographic markets. In this section, the hypothesized relationships between the price series analysed are presented first, along with background information justifying the hypothesized dynamics. Then, the methodology used in this study is introduced. It is followed by a presentation of the data used for analysis. Finally, the empirical results are shown. Their implication for the modelling of the UK's gas and power markets and on exogenous scenario specification is elaborated.

This study is original in the diversity of commodity types (oil, coal, gas, and electricity), applicable geographic regions (Germany, France, the Netherlands, Belgium, the UK, NW Europe in General, and Japan), as well as maturity dates (day-ahead and month-ahead) of the price time series included. They can be divided into three groups (Table 8):

1. Select global energy commodity prices that could possibly influence gas and power prices in Europe (and by extension, those of the UK);

2. UK gas prices of different maturity, and those of hubs physically connected to the UK;

3. UK power prices and those of countries physically connected to the UK.

Table 8: List of energy commodity price series studied

Gp.	Price series	Short name	Commodity	Resolution	Original unit	Source
1	Europe Brent Spot Price FOB	Brent	Crude oil	Daily	USD/bl	EIA
	Coal ARA 6000 kcal NAR	Coal ARA	Coal	Daily	USD/ton	Argus
	LNG Japan average	Japan LNG	Natural gas	Monthly	USD/MMBTU	Argus
	Henry Hub Natural Gas Spot	Henry Hub	Natural gas	Daily	USD/MMBTU	EIA
	Erdgasimporte	German import	Natural gas	Monthly	Euro/MWh	BAFA
2	TTF day-ahead	TTF DAH	Natural gas	Daily	Euro/MWh	Argus
	TTF month-ahead	TTF M1	Natural gas	Daily	Euro/MWh	Argus
	Zeebrugge day-ahead	ZEE DAH	Natural gas	Daily	p/therm	Argus
	Zeebrugge month-ahead	ZEE M1	Natural gas	Daily	p/therm	Argus
	NBP day-ahead	NBP DAH	Natural gas	Daily	p/therm	Argus
	NBP month-ahead	NBP M1	Natural gas	Daily	p/therm	Argus
3	UK OTC base load day-ahead	UK Base	Electricity	Daily	GBP/MWh	Argus
	UK APX Market Index Price[8]	UK APX	Electricity	Hourly	GBP/MWh	Elexon
	APX day-ahead market base	NL Base	Electricity	Monthly	Euro/MWh	APX
	France day base	FR Base	Electricity	Daily	Euro/MWh	EEX
	Germany/Austria day base	DE Base	Electricity	Daily	Euro/MWh	EEX

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[8] The APX Market Index Price is a weighted average price of contracts traded in a time window that lasts from three days before gate closure up to gate closure. It is used as a proxy for intraday prices in this study.

The relationships among such a group of diverse price series are sought because the core goal of the overall study is to study the interdependencies of investment decisions in the UK gas and power markets, which must involve an understanding of the interaction of gas and power prices. Because, the investors' expectation of future prices is believed to be a key piece of information guiding investment decisions in both markets. Therefore, both UK power and gas price series are included in the data set. Additionally, the UK's gas and power markets are interconnected with other regional markets via physical connections in the form of pipelines, LNG terminals, and power interconnectors. Thus, an understanding of how the UK power and gas prices are influenced by those of interconnected markets is also necessary. Furthermore, physical transactions of energy commodities occur in markets of different contract maturity. The bulk of gas is traded in the forward market (month-ahead and beyond) or via long-term contracts, with a smaller volume traded in the spot/day-ahead market, where transactions are subject to shorter-term market forces. Currently, in the UK, gas trading is halved between the OTC and exchanges, and less than 30% is traded to be delivered within a month through these mechanisms (<10% and <50%, respectively) (Ofgem, 2009, 2015). On the other hand, more of electricity is traded in the day-ahead market (forward trading for electricity is limited given its non-storability and power demand is more volatile than gas demand), and more adjustment made in the intra-day market (with lower liquidity). In the UK, more than half of power is traded to be livered within a month: most of exchange trading (25% of total volume) and 40% of OTC trading (Ofgem, 2015). Modelling the price interdependencies in the UK gas and power markets requires a sound knowledge of how prices of different temporality interact. Therefore, gas and power prices of different contract maturity are included to explore the differentiated impact of month-ahead, day-ahead, and intraday market prices.

4.1 Hypothesized relationships

Based on readings of market fundamentals, the following relationships between price time series are hypothesized and illustrated in Figure 19. Double-headed arrows indicate that mutual influence on price is hypothesized, while single-head arrows indicate that a one-way influence is expected to be exerted by one price series on the other.

In group 1, Brent, a benchmark for globally traded crude oil, is expected to drive the price of Japan LNG and the average price of imported gas for Germany, because contracts importing gas to Asian markets and Germany (of which a large fraction is pipelined gas from Russia) are mainly indexed to the price of oil (Rogers, 2015). In recent years, there is an increase in the use of regional trading hubs prices as the price index, therefore the long-term relationship between these prices and Brent might have weakened. The price of coal imported to North-western Europe is not expected to be integrated with that of oil, since it is mainly used in power generation, where oil no longer plays a major role (von Lossau, 2010). The price of natural gas in United States (Henry Hub) could be, but is not expected to be, integrated with the global oil price, since the shale gas production boom in United States is expected to have pushed down US gas price levels, decoupling them from a historic relationship with crude oil (Foss, 2011).

In group 2, the forward markets of North-western European hubs (TTF, ZEE, and NBP) are expected to be integrated in terms of price, with possibly a tighter cointegration between TTF and ZEE: occasionally, decoupling of NBP and TTF/ZEE prices occur due to pipeline unavailability (van Alem, 2013). The month-ahead price for a given date is expected to drive the day-ahead price at the same hub: the day-ahead price deviates from the baseline that is the month-ahead price due to shorter term fluctuations in supply and demand. Integration between the day-ahead prices across different hubs is also expected.

In group 3, the day-ahead price in the UK is expected to drive the intraday market index which incorporate information from the shorter-term intraday market. Integration between the UK's power market and its neighbours is expected to be less extensive: cointegration of price between the UK and the Dutch power markets is more likely than that between the UK and the French, given the lower price of electricity in France, the interconnection is used to supply baseload power to other countries rather than supplying the marginal demand. Furthermore, coupling between the Netherlands, France, and Germany's day-ahead prices is expected (Houllier & Menezes, 2013) .

Finally, among the three groups, integration between the gas and power markets is expected for the UK and for the Netherlands, since both have significant use of natural gas for power generation (Jong & Schneider, 2011). However, it is unclear if the two gas prices will affect the two power prices differently. The hub prices might be having some influence over the German average import price, after revision of long-term contracts between Russia and its customers. On the other hand, the German import price is expected to keep a cap on the hub prices, thus influencing them in return. The long-term relationship between hub prices and the German import price is not expected to be constant, because the study period (2011-2015) is a transition phase for the previously oil-indexed German import price (Rogers, 2015).

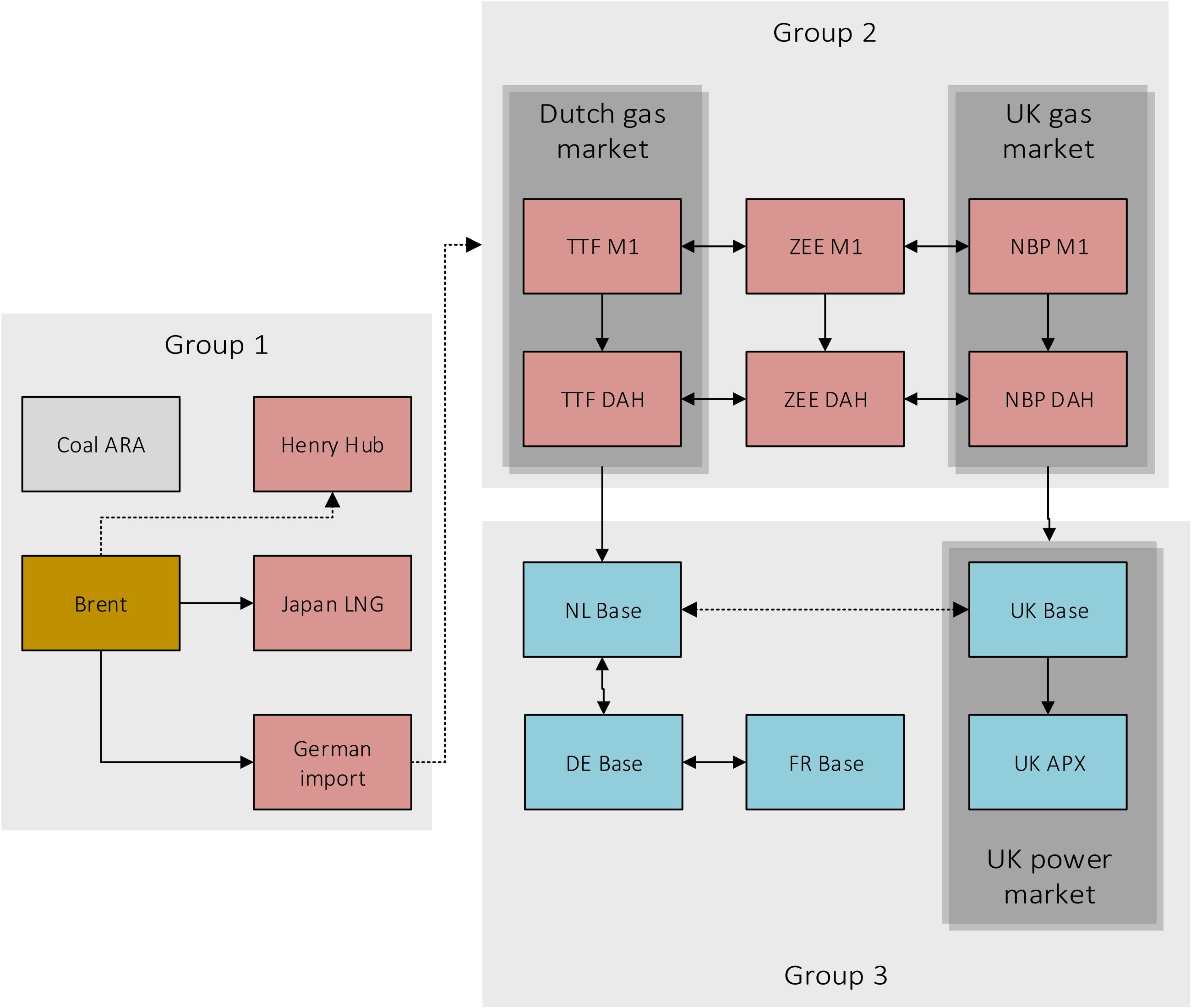

Figure 19: Hypothesized relationships among price series studied

4.2 Methodology

Cointegration, a relatively recently developed field in time series econometrics, is used to identify and to describe the dynamics between the chosen set of energy commodity price series. Applying traditional regression analysis to non-stationary time series might yield spurious results: seemingly significant and a relatively high correlation coefficient could be produced, even when the variables are not causally dependent on each other. Analysing the time series after removing the non-stationarity, either through de-trending or differencing, is a commonly used approach: only the correlation between the stationary residuals or differences are studied. However, this approach has been criticized for removing and ignoring valuable long-run information contained in the trend or level, which is also of interest. Cointegration, an alternative approach which does not require the removal of non-stationarity, pioneered by Clive Granger and Robert Engle in 1987, allows the description of a long-term equilibrium between time series and their reactions to short-term deviation from the equilibrium via error correction models.

A typical cointegration study consists of three parts. First of all, the time series examined are evaluated to test for non-stationarity through unit root tests such as the Augmented Dickey-Fuller (ADF) Test, the Phillips-Perron Test, or the Kwiakowski-Phillips-Schmidt-Shin (KPSS) Test. Once it is statistically confirmed that the series are non-stationary and of integration order 1 (so that their respective differences are stationary), cointegration tests can proceed. If the order of integration is not checked, cointegration on stationary time series could result in spurious cointegration. Depending on the number of cointegrating relationships tested, single-equation methods such as the Engle-Granger Two-Step Procedure (for one cointegrating relation only) or multiple-equation methods such as the Johansen Procedure can be used. During the cointegration test, the number of cointegrating relationships is tested statistically. And, in the case of cointegration, implying the existence of a long-run equilibrium and a corresponding error-correction mechanism, coefficients for equations describing those relationships can also be estimated.

In this section, the principles of the unit root tests used are first introduced. Then, the cointegration test used, the two-step Engle Granger procedure is introduced. Finally, given the large number of hypothesized relationship tested, the testing strategy employed to accommodate them is described.

4.2.1 Unit root tests

A time series can be generalized to have the following form:

$$y_t = TD_t + z_t \tag{4.1}$$

Where TD_t assigns a deterministic trend and z_t represents the stochastic component. A time series can be stationary, trend-stationary, or non-stationary. A stationary time series does not contain a deterministic trend, and its stochastic component is such that there is no cumulative effect. Such a series has a constant mean and variance over time. Trend-stationary series contain a deterministic trend, but, once it is removed, they behave as stationary time series. Finally, a non-stationary time series has a stochastic component that accumulates over time. It can be a random walk (impact of stochastic shocks is accumulated but does not grow) or explosive (the shocks grow increasingly larger).

Non-stationary time series do not have a constant mean or variance; therefore, it could be misleading when inference methods for stationary time series are used on non-stationary series. It is important to check the stationary of time series before conducting further tests on them, since different types of series call for different types of statistical methods. Unit root tests are tests that allow us to infer about the nature of stochastic component of time series, thereby determine the stationarity of the series. The following section briefly introduces the tests employed, for detailed exposition of the statistics involved, please refer to Pfaff (2008) or Maddala (1998).

4.2.1.1 Augmented Dickey Fuller Test

The augmented Dickey-Fuller test assumes that the stochastic component $\{z_t\}$ is an $ARMA(p,q)$ process and the following test regression models are used:

$$y_t = \beta_1 + \beta_2 t + \theta y_{t-1} + \sum_{j=1}^{k} \gamma_j \Delta y_{t-j} + u_t \tag{4.2}$$

$$\Delta y_t = \beta_1 + \beta_2 t + \pi y_{t-1} + \sum_{j=1}^{k} \gamma_j \Delta y_{t-j} + u_t \tag{4.3}$$

Where β_1 is a constant, β_2 is the coefficient for a time trend, and $k = p-1$ the lag order of the autoregressive process. The null hypothesis is that of non-stationarity, that the series contains a unit root ($\theta = 1$ or $\pi = 0$). The alternative hypothesis is that $\theta < 1$ or $\pi < 0$: the series has a stationary data generative process. The other alternative, an explosive path for y_t given $\theta > 1$ or $\pi > 0$, is not considered. Statistic values are computed corresponding to hypothesis testing on the value of π , β_1 , and β_2 . The lag order needs to be chosen based on knowledge of the serial correlation in the series studied. It can be specified directly, or derived using the *general-to-specific* method, progressing from an *a priori* chosen maximum lag to the smallest value that yields a statistically significant regression coefficient, dropping the last lagged regressor if it is insignificant until the last lagged regressor is significant or $k = 0$. Finally, the lag could be specified by minimizing the Akaike Information Criterion (AIC) or other information criterion.

A pure random walk process would result in $\beta_1 = 0$, $\beta_2 = 0$, and $\pi = 0$. A random walk with a drift would result in a non-zero β_1 and $\pi = 0$. And, finally, a random walk around a time trend would result in a non-zero β_2 and $\pi = 0$. Similarly, three alternatives hypothesis could be established: series is stationary around a zero mean, around a non-zero mean, or a trend. Consequently, three forms of the test can be applied: imposing a regression model without drift and trend, a regression model with drift only, and a regression model with both. In testing, it is suggested to move from the most general form of the regression model (with deterministic constant and time trend) to the least general (pure random walk). See Figure 20 for proposed testing sequence.

4.2.1.2 KPSS Test

The KPSS Test, compared to the ADF test, is one with a more conservative testing strategy: the null hypothesis is that the time series has a stationary process and the unit root process as the alternative hypothesis. Therefore, if the results of the ADF test indicate a non-stationary process but the result of the KPSS test indicates a stationary one, one should be cautious and opt for the latter result (Pfaff, 2008, p. 103). The test regression models for the KPSS test are:

$$y_t = \xi_t + r_t + \varepsilon_t \tag{4.4}$$

$$r_t = r_{t-1} + u_t \tag{4.5}$$

Here, r_t is a random walk and the error process is assumed to be white noise. The null hypothesis is that the random walk has zero variance so that y_t is either trend-stationary ($\xi \neq 0$) or level-stationary ($\xi = 0$).

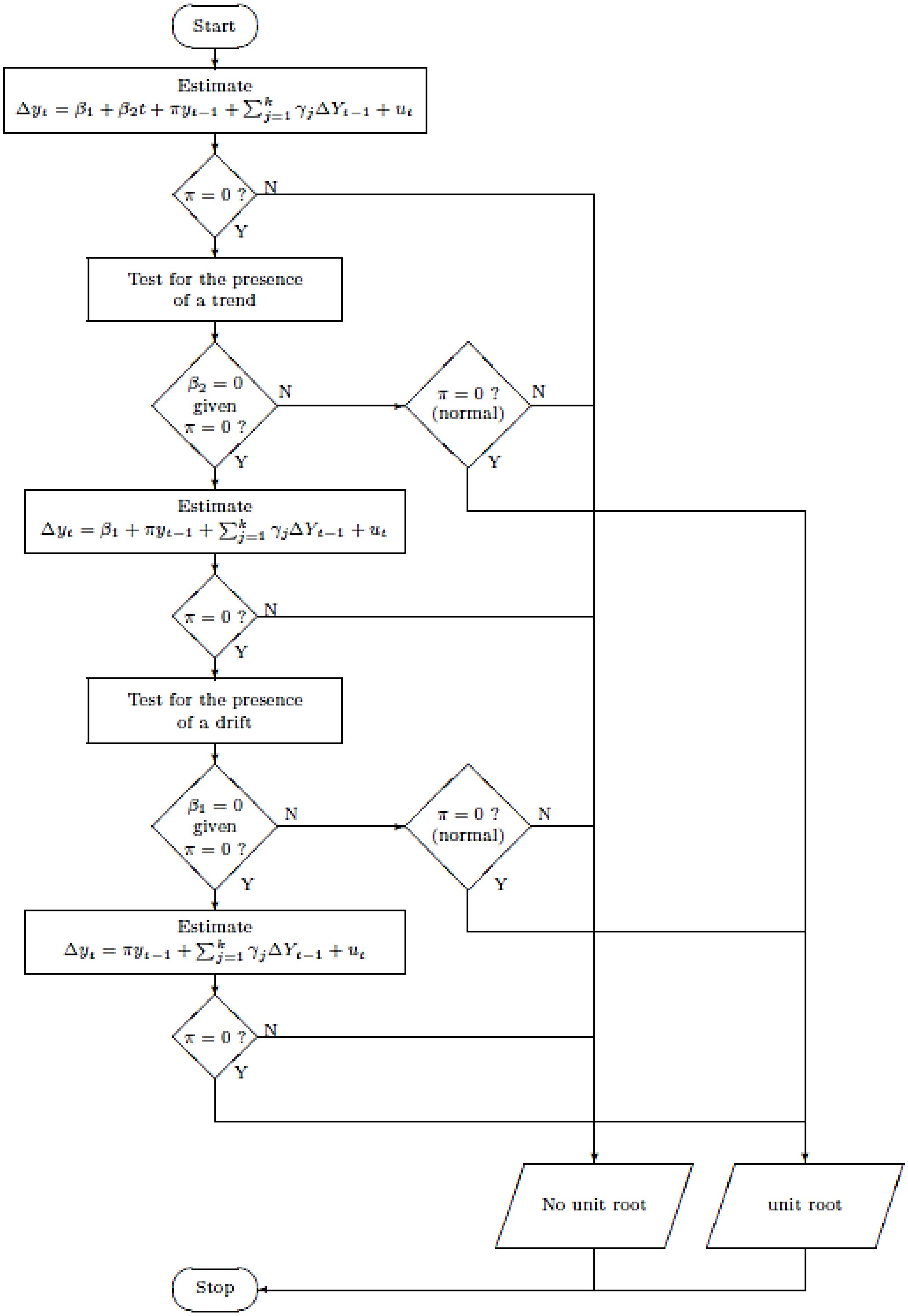

Figure 20: Testing sequence for unit roots (Pfaff, 2008)

4.2.2 Cointegration tests

If cointegration between non-stationary series is shown to be statistically significant, then there must exists an error correction mechanism such that deviation from the long-term equilibrium is corrected by at least one of the variables. Otherwise, it would not be possible for the series to move in tandem in the long run despite short-term fluctuations away from the equilibrium. Suppose a long-term equilibrium relationship between X and Y exists in the following form, with a stationary error term z_t :

$$Y_t = a_0 + a_1 X_t + z_t \tag{4.6}$$

$$X_t = \frac{Y_t - a_0}{a_1} - \frac{z_t}{a_1} = \frac{Y_t - a_0}{a_1} + z_t^{'} \tag{4.7}$$

A typical error correction model is of the form below, where $\varepsilon_{1,t}$ is a white noise process:

$$\Delta Y_t = \psi_0 + \kappa \hat{z}_{y,t-1} + \sum_{i=1}^{K} \psi_{1,i} \Delta X_{t-1} + \sum_{i=1}^{L} \psi_{2,i} \Delta Y_{t-1} + \varepsilon_{1,t} \tag{4.8}$$

The short-term change in Y is a function of the previous error term (estimated value = $\hat{z}_{y,t-1}$), among other short-term influences (ΔX_{t-1} , ΔY_{t-1}). For the same long-term equilibrium, an error correction mechanism could also exist for X, its short-term changes being a function of its deviation from the equilibrium ($\hat{z}_{x,t-1}$).

$$\Delta Y_t = \xi_0 + \lambda \hat{z}_{x,t-1} + \sum_{i=1}^{K} \xi_{1,i} \Delta X_{t-1} + \sum_{i=1}^{L} \xi_{2,i} \Delta Y_{t-1} + \varepsilon_{2,t} \tag{4.9}$$

As part of the cointegration test employed, the coefficients for the error term, κ and λ , are estimated. In a third step, by comparing the coefficients, the Granger causality between the variables X and Y can be assessed. X and/or Y might correct toward the equilibrium because both or one variable drive the other to its expected value; or, X and/or Y might be anticipating or forecasting the other value (Campbell & Shiller, 1988).

4.2.2.1 Engle-Granger Procedure

The Engle-Granger procedure consists of two part. First, the long-run relationship between the pair of variables, both established to be $I(1)$, is estimated through linear regression. Different coefficients can result from the same regression, depending on which of the two variables is chosen as the independent variable (Equations (4.10) and (4.11) are based on the same long-term relationship).

$$Y_t = \beta_0 + \beta X_t \tag{4.10}$$

$$X_t = \beta_0^{'} + \beta ' Y_t \tag{4.11}$$

$$R_{y,t} = Y - \hat{Y} \tag{4.12}$$

$$R_{x,t} = X - \hat{X} \tag{4.13}$$

The residuals of this first regression, which are errors between the actualized variable values and the estimated long-run relationship, are checked for stationarity using augmented Dickey-Fuller-type tests, but with a different set of critical values, since the residuals are estimated instead of measured. If the residuals are stationary, cointegration can be established between the pair of variables. If not, then the regression is said to be spurious.

The first step establishes the long-run relationship between X_t and Y_t.In a second step, error-correction models (ECMs) that measures the short-run dynamics between the two variables are estimated. In this ECM formulation, short-run changes in variable X_t and Y_t (ΔX_t ,ΔY_t)are explained by the error from the long-run equilibrium in the previous period, their own short-term history (own lagged first difference), and the short-term history of the cointegrated variable (lagged first difference of the other variable). If two series are cointegrated, then at least one coefficient of the error term (κ or λ) should be significant and negative, so that a positive error term lead to a negative correction term and vice versa. Otherwise, accumulated short-run changes will drive the two variables away from each other, eliminating long-term cointegration. Estimates that approach -1 suggest a fast error correction towards the long-run relationship, while estimates approaching zero suggest a slow error correction.

$$\Delta Y_t = \psi_0 + \kappa \hat{z}_{y,t-1} + \psi_1 \Delta X_{t-1} + \psi_2 \Delta Y_{t-1} \tag{4.14}$$

$$\Delta X_t = \xi_0 + \lambda \hat{z}_{x,t-1} + \xi_1 \Delta X_{t-1} + \xi_2 \Delta Y_{t-1} \tag{4.15}$$

4.2.3 Testing strategy

To begin, the Augmented Dickey-Fuller (ADF) test is conducted for all 16 price series selected and their first difference to test for their order of integration. The KPSS test, with the null hypothesis of stationarity rather than non-stationarity in the ADF test, is also conducted to confirm the results. Once the integration order of the price series is determined, cointegration tests are conducted. The strategy adopted for this study to test for cointegration is illustrated in Figure 21.

As the first step of the Engle-Granger procedure, estimation of the long-term equilibrium is performed. Given the large number of hypothesis to be tested among 16 different price series, automated regression is conducted for all possible pair-wise combinations (240 pairs, given pairs (X, Y) and (Y, X) are not equivalent). Given only some price series are expected to exhibit a significant exogenous seasonal pattern, seasonal dummy variables are included in the original bivariate regression model to remove the exogenous seasonal patter only if they are significant regressors at confidence level > 95%. The residuals of these regression models then undergo the ADF test to determine their stationarity. In the case the residuals are proven to be stationary, then there is partial evidence for cointegration under Engle-Granger.

As the second step of the Engle-Granger procedure, estimation of the error-correction model is performed. 240 error correction models are tested for their significance. The first differences of the 16 prices series (ΔY_t) are regressed against the residual of 15 regression models in which they are involved ($\hat{z}_{y,t-1}$). Other regressors also include the lagged first differences of the two series that were originally used for the regression (ΔX_{t-1} and ΔY_{t-1}). In the case that $\hat{z}_{y,t-1}$ is a significant regressor for ΔY_t and the correlation coefficient is negative, there is evidence for error correction mechanism for Y toward the long-term relationship between X and Y.

The results of these two steps – residual stationarity and error correction model significance – are compared and synthesized. The series Y is said to be cointegrated with X statistically only if the regression residuals for Y vs. X are stationary **and** there exists a significant error correction mechanism so that short-term changes in Y are driven by its deviation from its long-term relationship with X. Given that a set of relationships is hypothesized between the 16 price series studied, the results of cointegration testing are discussed in terms of

- Proven hypothesized relationships: where cointegration relationships are found where hypothesized;
- Non-proven hypothesized relationships: where cointegration relationships are not found where hypothesized;
- Proven non-hypothesized relationships: where cointegration relationships are found where they are not hypothesized.

Discussion of the last type of relationships is limited, since such an automated data-mining approach can easily lead to the creation of statistical artefacts when not guided by prior knowledge in the form of hypothesis. The relationships of interest in this category are listed to inform future investigation of cointegration between energy commodities.

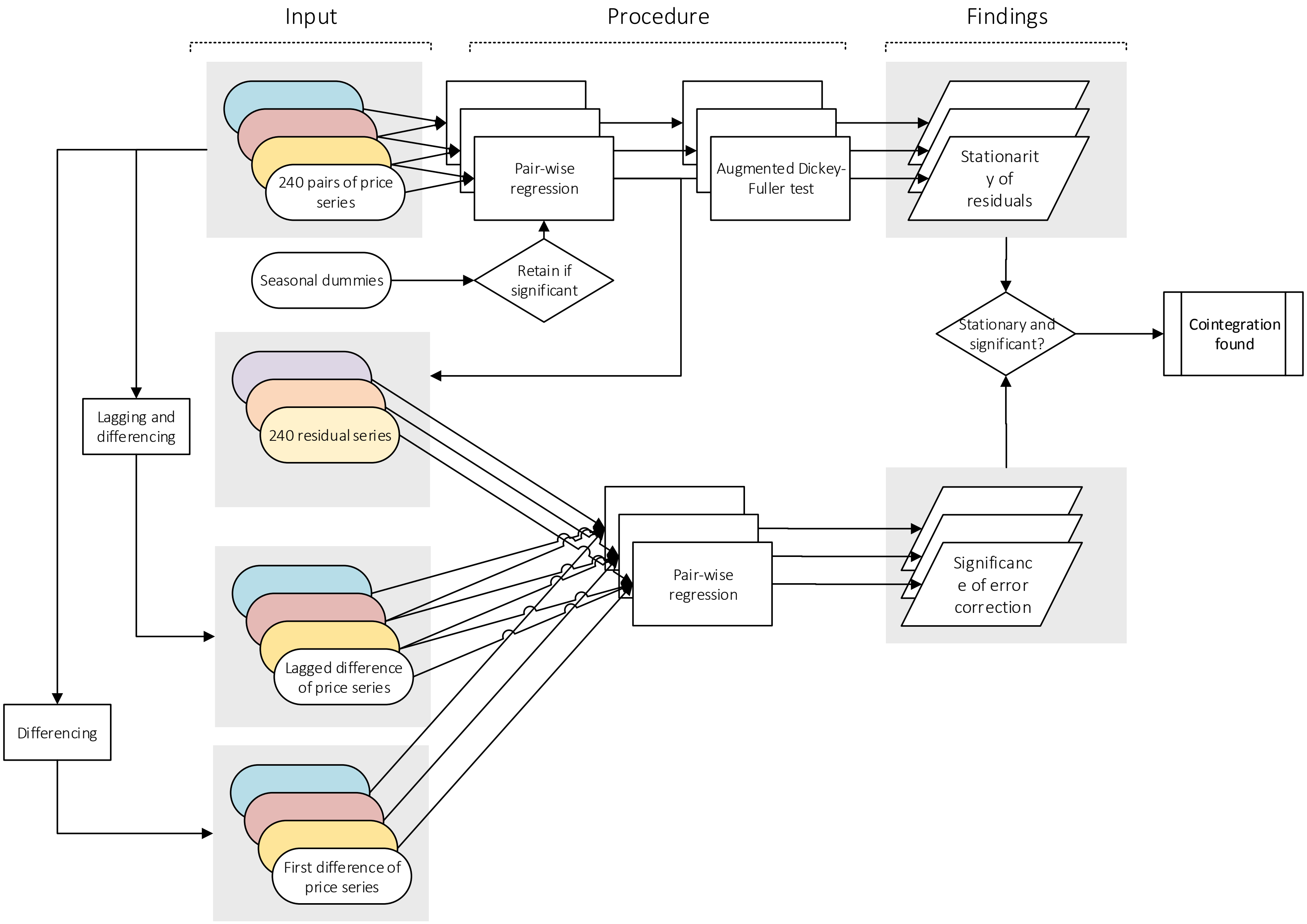

Figure 21: Testing strategy for the cointegration study

4.3 Data

As Table 8 shows, the data used come from a number of sources, in different resolutions, have different physical units, and are denominated in different currencies. For ease of comparison, all prices have been converted to USD/MMBTU using historical exchange rates published by the European Central Bank and the Bank of England. The conversion factors used for energy units are 5.8 MMBTU/barrel oil, 23.79 MMBTU/ton coal, and 0.29307 MMBTU/MWh. For series which have daily resolution, the unweighted monthly average is calculated using all daily data points available for a given month, so that all data used are at monthly resolution for the period January 2011 to December 2015. The three groups of price series are first presented separately, then compared to each other.

Overall, group 1 prices (Figure 22) span a large range: from less than 5 $/MMBTU to 20 $/MMBTU. Among the group, Brent prices can be seen as a ceiling for other fossil fuel energy prices during the same period, the only exception being in 2015, when the fall in Japan LNG prices lagged that of crude by 4-5 months. The gas price series for different continental region are diverged: with Japan LNG being the highest, Henry Hub near coal price levels, and German import in between of them. The important fall in crude oil prices in late 2014 is included in the study period.

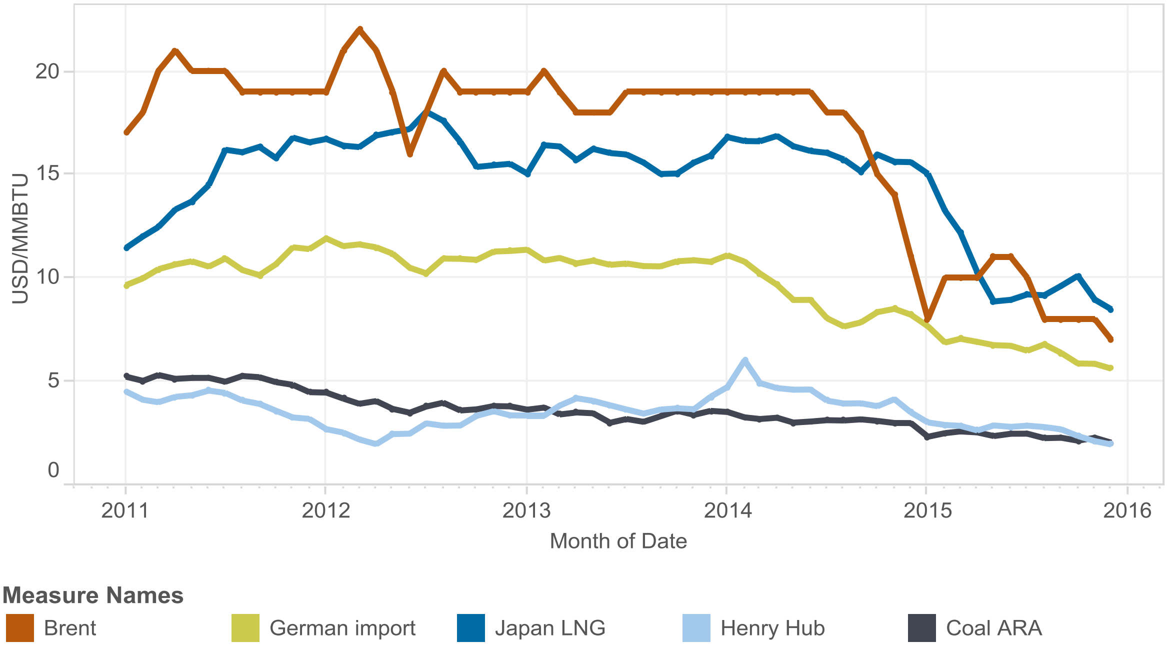

Figure 22: Select global and regional energy prices

Series belonging to group 2, those that represent prices of natural gas at various natural gas hubs in North-western Europe, are much closely coupled visually relative to group 1 series (Figure 23). The maximum difference between any of the series never exceeded 5 $/MMBTU.

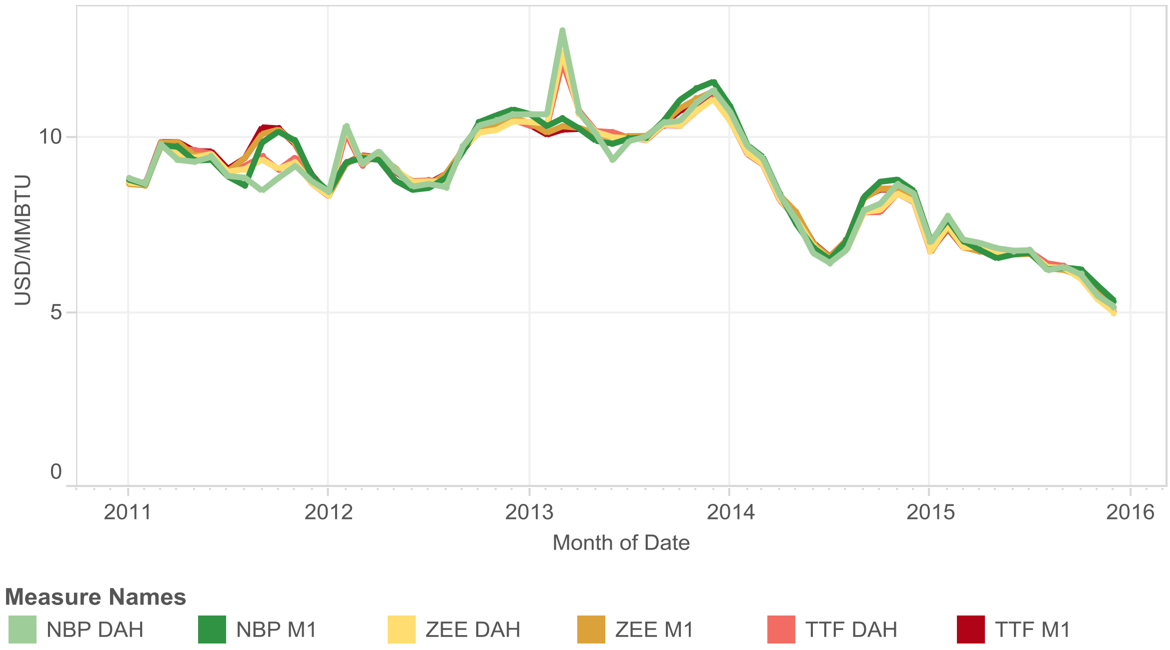

Figure 23: NW European natural gas hub prices

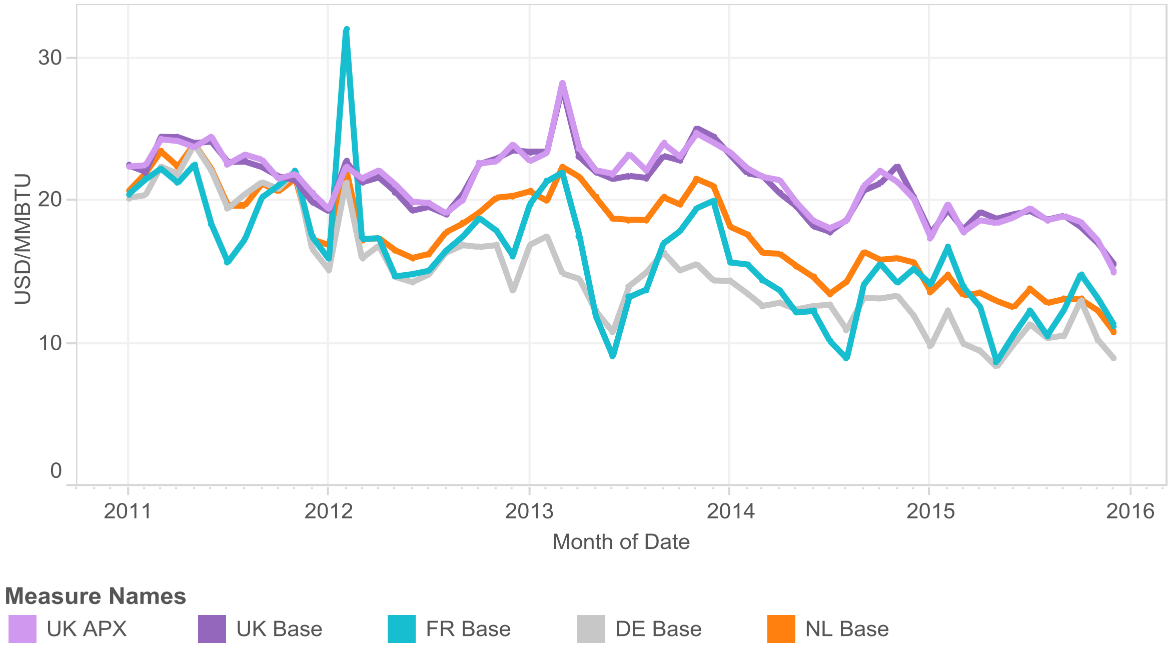

Figure 24: NW European power prices

The group 3 series, on the other hand, show NL Base and FR Base power prices enveloped by that of power in the UK (UK Base and APX) and in Germany (Figure 24). As a whole, group 3 (NW European power prices) exhibit large spikes upward and downward within relative short periods, compared to other energy prices such as coal, gas, and crude oil.

Two peaks are of visual interest, for the upward spike in power prices is echoed by a (smaller) upward spike in gas day-ahead prices from their month-ahead levels. The peak in FR Base occurring in February 2012 can be traced to a severe cold wave in that winter, which drove the French power demand to a new historic record on February 8th, through the use of electric heating (Réseau de transport d'électricité, 2012). On the other hand, the peak in UK power prices in March 2013 can be traced to the week of March 25th 2013, during which severe weather caused power outages in thousands of homes (BBC, 2013). The concomitant peak in day-ahead price can be traced to a tight gas supply exacerbated by a water pump failure in the Interconnector during that same week (Pfeifer, 2013)

After examining the descriptive statistics for all series, it was decided to remove the monthly value of February 2012 from all samples to be studied, because the outlier in FR Base is believed to be a one-off event that influenced the distribution of FR Base unduly. After removing the outlier, it was checked that the FR Base series does no longer have significant positive skewness and positive excess kurtosis. And, the null hypothesis of normally distributed distribution is no longer rejected for FR Base.

In order to analyse seasonality which could be present in the price series studied, the average price of all series is computed for each of the twelve months of the year. Given the data spans 2011 to 2015, each monthly value in Figure 25 is computed by averaging the five values available for that given month. It can be seen that Coal ARA and Henry Hub gas prices show almost no seasonal pattern. NW European gas prices show moderate seasonality (with the exception of average German import price): lower prices are achieved in late-spring to summer, while higher prices are achieved in autumn to winter. Seasonality is most significant for electricity prices, especially FR Base (notice the trough in summer months relative to the peaks in spring and autumn). UK, DE and NL power prices exhibit a seasonal pattern that is comparable to that of NW European gas prices. The seasonal profile of Brent shows lower values in the second half of the year, that is because of the important fall in price occurred in late 2014 included in the data sample. Examining the year-by-year profile of Brent prices leads to the observation that no important seasonality is found in crude oil prices for the period 2011-2015.

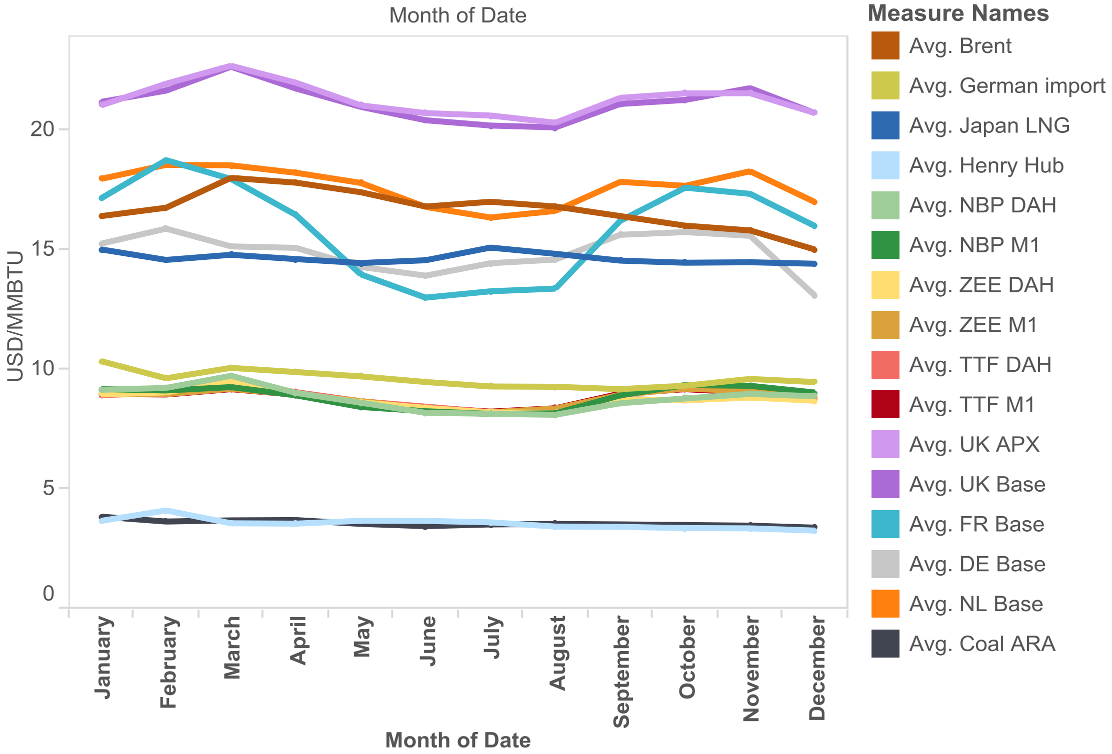

Figure 25: Average price for each month of the year for all series

4.4 Results

This section presents the results from the unit root test, from the estimation of long-term trends, and from the estimation of short-term error correction models.

4.4.1 Unit root tests

The Augmented Dickey-Fuller test has been applied to the price level values of all price series, and the following statistics and critical values (for 95% confidence level) are obtained (Table 9). The optimal lag retained in the ADF test model, selected according to the minimization of the AIC, is also included. In the most general form of the regression model, the statistic testing for the value of π for Coal ARA, FR Base, and DE Base exceed the critical value at 95% confidence level, therefore the null hypothesis of a unit root ($\pi = 0$)is rejected. The β_1 and β_2 statistics for these three series also exceed the critical value, support the alternative hypothesis that a constant term and a time trend exists. Therefore, these three price series are found to be trend-stationary over a non-zero mean. The trend over time for the three series are shown in Figure 26. All other series have failed to reject the null hypothesis of non-stationarity (having a unit root) under all three forms of the ADF test model.

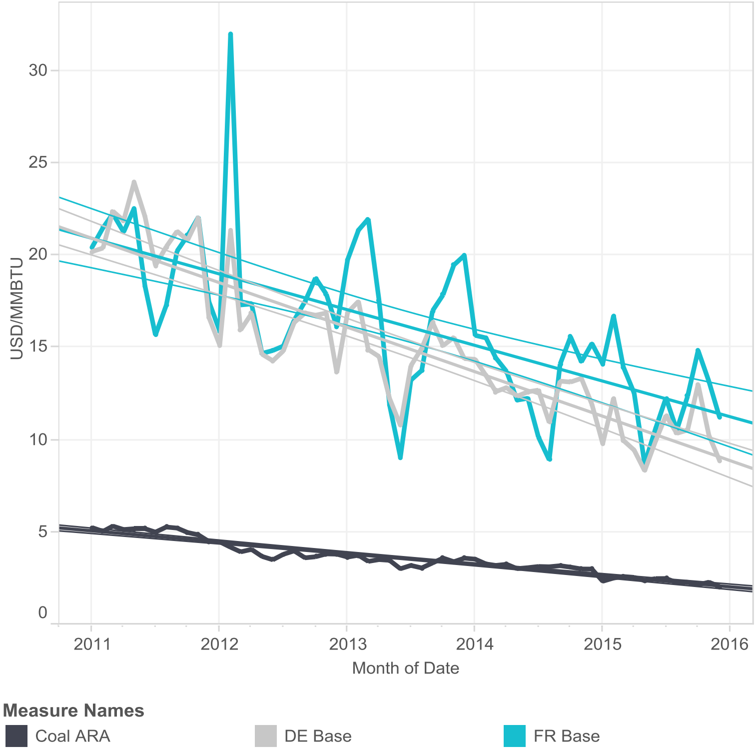

Figure 26: Trend over time for the three trend-stationary series

Table 9: Results from Augmented Dickey-Fuller test on price levels

	Brent	Coal ARA	Japan LNG	Henry Hub	German import	TTF DAH	TTF M1	ZEE DAH	ZEE M1	NBP DAH	NBP M1	UK Base	UK APX	NL Base	FR Base	DE Base
TREND																
lag	1	3	4	1	1	1	1	1	1	1	1	1	1	1	1	1
pi statistic	-1.96	**-3.78**	-0.75	-1.22	-1.71	-2.28	-2.40	-2.26	-2.44	-2.34	-2.60	-2.54	-2.52	-2.00	**-4.17**	**-4.15**
beta1 statistic	2.30	**6.13**	1.95	1.22	2.86	2.98	3.15	2.92	3.16	2.66	3.04	2.81	2.86	2.27	**5.86**	**6.05**
beta2 statistic	2.59	**7.18**	1.68	1.79	1.72	4.14	4.42	4.04	4.47	3.76	4.37	4.13	4.17	3.04	**8.74**	**8.73**
pi c-value	-3.45	-3.45	-3.45	-3.45	-3.45	-3.45	-3.45	-3.45	-3.45	-3.45	-3.45	-3.45	-3.45	-3.45	-3.45	-3.45
beta1 c-value	4.88	4.88	4.88	4.88	4.88	4.88	4.88	4.88	4.88	4.88	4.88	4.88	4.88	4.88	4.88	4.88
beta2 c-value	6.49	6.49	6.49	6.49	6.49	6.49	6.49	6.49	6.49	6.49	6.49	6.49	6.49	6.49	6.49	6.49
DRIFT																
Lag	2	1	4	1	1	1	1	1	1	1	1	1	1	1	1	2
pi statistic	0.30	-1.35	0.68	-1.33	0.00	-0.32	-0.40	-0.33	-0.48	-0.69	-0.92	-1.53	-1.36	-0.43	**-3.03**	-1.35
beta1 statistic	1.19	3.24	1.41	0.92	2.43	0.34	0.34	0.34	0.35	0.45	0.58	1.25	1.03	0.41	4.62	1.36
pi c-value	-2.89	-2.89	-2.89	-2.89	-2.89	-2.89	-2.89	-2.89	-2.89	-2.89	-2.89	-2.89	-2.89	-2.89	-2.89	-2.89
beta1 c-value	4.71	4.71	4.71	4.71	4.71	4.71	4.71	4.71	4.71	4.71	4.71	4.71	4.71	4.71	4.71	4.71
NONE																
lag	2	1	1	1	1	1	1	1	1	1	1	1	1	1	8	2
pi statistic	-1.41	-2.37	-1.29	-0.55	-2.18	-0.81	-0.79	-0.82	-0.77	-0.77	-0.72	-0.54	-0.59	-0.87	-1.43	-1.14
pi c-value	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6

Then, the Augmented Dickey-Fuller test is applied once more to the first difference of all price series (

Table 10). It was found that, with the exception of Japan LNG, the null hypothesis for a unit root is rejected for all series' first difference, with all three regression models. In other words, other than Japan LNG, the first difference of all price series are stationary and do not contain unit roots.

Because the null hypothesis of the Augmented Dickey-Fuller test is one of non-stationarity, it is conservative with respect to finding stationarity. The lag selected based on the minimization of the AIC is also high (lag = 12), which diminishes the power of the test. Therefore, the results for price levels and price first differences are checked via the KPSS test, which uses stationarity as the null hypothesis. For price level values, the KPSS test has found that, except for Henry Hub (level stationarity cannot be rejected) and the FR Base (trend stationarity cannot be rejected), stationarity is rejected for all series (

Table 11). For the first difference values, the KPSS test has found that trend stationarity cannot be rejected for all series, while level stationarity cannot be rejected for all series but Japan LNG and German import (Table 12). Combining results from the two test, it is decided to classify FR Base as trend-stationary (stationary after deterministic trend is removed), and all other series as first-order difference-stationary (stationarity after first differencing) (see Table 13).

Now that the order of integration for all series has been determined, it is found that cointegration tests can be conducted for all $I(1)$ series. The Engle-Granger procedure is performed for all possible pairwise combinations (excluding regression on the variable itself, but including regression between the same variables in both directions, resulting in $16 \times 15 = 240$ tests). Cointegration might be found between the FR Base series and other series, but it could be spurious cointegration, given FR Base is a trend-stationary series. Nevertheless, results for all 240 tests are included for the sake of completeness, and those pertaining to the FR Base series are interpreted with this background knowledge.

Table 10: Results from Augmented Dickey-Fuller test on price first differences

	Brent	Coal ARA	Japan LNG	Henry Hub	German import	TTF DAH	TTF M1	ZEE DAH	ZEE M1	NBP DAH	NBP M1	UK Base	UK APX	NL Base	FR Base	DE Base
TREND																
lag	1	1	**12**	1	1	1	1	1	1	1	1	1	1	1	7	1
pi statistic	-5.50	-6.62	**-2.01**	-5.08	-4.43	-4.83	-3.82	-4.71	-3.79	-4.46	-3.67	-4.82	-5.30	-4.38	-4.78	-6.11
beta1 statistic	10.29	14.84	**1.43**	8.76	6.55	7.81	4.97	7.43	4.89	6.65	**4.57**	7.79	9.44	6.44	7.61	12.52
beta2 statistic	15.27	22.21	**2.03**	13.13	9.82	11.66	7.35	11.10	7.22	9.94	6.77	11.61	14.07	9.62	11.41	18.74
pi c-value	-3.45	-3.45	-3.45	-3.45	-3.45	-3.45	-3.45	-3.45	-3.45	-3.45	-3.45	-3.45	-3.45	-3.45	-3.45	-3.45
beta1 c-value	4.88	4.88	4.88	4.88	4.88	4.88	4.88	4.88	4.88	4.88	4.88	4.88	4.88	4.88	4.88	4.88
beta2 c-value	6.49	6.49	6.49	6.49	6.49	6.49	6.49	6.49	6.49	6.49	6.49	6.49	6.49	6.49	6.49	6.49
DRIFT																
Lag	1	1	**12**	1	1	1	1	1	1	1	1	1	1	1	7	1
pi statistic	-5.48	-6.74	**-1.14**	-4.62	-4.34	-4.61	-3.74	-4.51	-3.71	-4.34	-3.63	-4.74	-5.19	-4.18	-4.84	-6.19
beta1 statistic	15.16	22.73	**0.75**	10.67	9.44	10.68	7.09	10.23	6.99	9.45	6.66	11.29	13.53	8.77	11.72	19.17
pi c-value	-2.89	-2.89	-2.89	-2.89	-2.89	-2.89	-2.89	-2.89	-2.89	-2.89	-2.89	-2.89	-2.89	-2.89	-2.89	-2.89
beta1 c-value	4.71	4.71	4.71	4.71	4.71	4.71	4.71	4.71	4.71	4.71	4.71	4.71	4.71	4.71	4.71	4.71
NONE																
lag	1	2	**12**	1	1	1	1	1	1	1	1	1	1	1	1	1
pi statistic	-4.96	-4.04	**-1.00**	-4.67	-3.76	-4.52	-3.61	-4.43	-3.59	-4.30	-3.55	-4.75	-5.20	-4.13	-5.06	-6.14
pi c-value	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.6	-2.60

Table 11: KPSS test results for price series levels

	Brent	Coal ARA	Japan LNG	Henry Hub	German import	TTF DAH	TTF M1	ZEE DAH	ZEE M1	NBP DAH	NBP M1	UK Base	UK APX	NL Base	FR Base	DE Base
trend statistic	0.56	0.33	0.52	0.33	0.65	0.55	0.53	0.56	0.53	0.53	0.51	0.26	0.31	0.28	0.04	0.16
trend p-value	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	0.10	**0.03**
level statistic	2.02	2.70	1.12	0.38	2.26	1.56	1.65	1.54	1.60	1.35	1.42	1.21	1.31	2.04	1.66	2.49
level p-value	**0.01**	**0.01**	**0.01**	0.09	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**	**0.01**

Table 12: KPSS test results for price series first differences

	Brent	Coal ARA	Japan LNG	Henry Hub	German import	TTF DAH	TTF M1	ZEE DAH	ZEE M1	NBP DAH	NBP M1	UK Base	UK APX	NL Base	FR Base	DE Base
trend statistic	0.03	0.05	0.06	0.11	0.04	0.04	0.03	0.04	0.03	0.04	0.03	0.04	0.04	0.04	0.02	0.02
trend p-value	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
level statistic	0.37	0.06	0.74	0.13	0.53	0.26	0.25	0.25	0.25	0.19	0.20	0.09	0.10	0.09	0.02	0.02
level p-value	0.09	0.10	**0.01**	0.10	**0.04**	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10

Table 13: Order of integration for all price series

Integration order	Brent	Coal ARA	Japan LNG	Henry Hub	German import	TTF DAH	TTF M1	ZEE DAH	ZEE M1	NBP DAH	NBP M1	UK Base	UK APX	NL Base	FR Base	DE Base
I(0)															Yes	
I(1)	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes		Yes
I(2)																

4.4.2 Engle-Granger Procedure

4.4.2.1 Estimation of long-term relationship

Following the Engle-Granger procedure, bivariate regression of the following form is conducted for all possible combinations of variables:

$$Y_{i,t} = \mu + \beta X_{j,t} + \psi D_t \tag{4.16}$$

For $i = 1, \dots N$, $j = 1, \dots, N$ and $j \neq i$, Y_t is the dependent variable, X_t is the independent variable, μ is a constant, and D_t is seasonal dummy variables for the twelve months of the year. The regression tests were performed twice: the seasonal dummy variables were only included in the final regression model, if they were found to be significant at 95% confidence interval in the first test. Examples of pairings in which seasonality is found to be a significant regressor are NBP M1 against the other gas hubs' month-ahead prices, and FR Base against DE Base. During summer, season of low gas demand for the UK and low power demand for France, the spread between the pairs of prices are lower than they are during winter (see Table 14 for a complete list).

The significance of estimate for the regression coefficient β is assessed for all 240 tests, it was found that except for the pair FR Base and Henry Hub, the regression coefficient has been found to be significant at 95% confidence level for all pairs. The adjusted R^2 of all tests is shown in Table 15. It can be seen that the adjusted R^2 is the highest for the group of NW European power prices (0.89 to 1). Group 2 NW gas prices were found also to be good regressors for English and Dutch power prices (R^2 adjust from 0.68 to 0.82). However, they are weaker in the explanation of variation of French and German power prices (R^2 adjusted from 0.29 to 0.42). Regression of these power prices series against Coal ARA, on the other hand, provide a much higher adjusted R^2 (0.73 and 0.89).

R^2 adjusted varies widely for pairs within group 1 and pairs within group 3 (0.39 to 0.96). Within group 1, the highest correlation is found between German import and Brent prices (R^2 adjusted = 0.83), while the lowest if found between German import and Henry Hub prices (R^2 adjusted = 0.09). Within group 3, relatively high correlation is identified between the Dutch power price and all other power price series (R2 adjusted = 0.68 to 0.79). German and French prices appear to be closely correlated (R^2 adjusted = 0.82 to 0.87), while their respective correlation with the UK power series is much lower (R^2 adjusted = 0.24 to 0.49).

The Brent spot prices series holds moderate explanatory power over the variation in all other series except for that of Henry Hub. Compared to other global energy commodities, the German import price, when used as regressor to explain variation in NW European gas prices, show higher adjusted R^2 (0.71-0.80). Henry Hub gas prices is consistently the worst regressor for all other energy prices (R^2 adjusted from 0.02 to 0.24). Symmetrically, its variation is also the least well explained for by other prices series (R^2 adjusted from 0.02 to 0.24).

At this stage, correlation is expected for some price series, but spurious regression (non-stationary residuals) is also expected to come from regression of non-stationary time series. Further analysis of the stationarity of regression residuals is required to ascertain whether cointegration – the correction of short-term deviation toward a long-term equilibrium – exists between the pairs tested. The ADF test, using critical value tables from MacKinnon (1991), is conducted for the residuals from the 240 bivariate regressions, and the results from this test is summarized in Table 17. As expected, not all pairs of prices which are significantly correlated have stationary regression residuals.

In order to establish a cointegrating relationship between a pair of variables, the residuals from bivariate regression needs to be stationary. The variables are said to be deterministically cointegrated if the residuals are stationary and without deterministic trends. If the residuals have non-zero deterministic trends, then the variables are said to be stochastically cointegrated (Maddala & Kim, 1998). Stochastic cointegration can be found between series which experience structural changes in the underlying long-run equilibrium between them, while deterministic cointegration cannot. Therefore, different type of stationarity identified in residuals are distinguished in Table 17. The pairs that are labelled "determ" and "both" meet the requirement for deterministic cointegration, since their residuals rejected the unit root null hypothesis without a deterministic trend term in the test model, while those that are labelled "stoch" meet the requirement for stochastic cointegration.

It is observed that the pairwise residual stationarity states displayed in Table 17 are much less symmetrical than the adjusted R^2 values in Table 15. This shows that the assumption of exogenous variable matters in the determination of cointegration relationship; in other words, they are sometimes one-way relationships. For example: when regressing against German import price as the independent variable, a cointegration relationship can be established between DE Base and the average gas import price, while the opposite cannot be established.

Table 14: Pairwise regression with significant seasonality[9]

	Brent	Coal ARA	Japan LNG	Henry Hub	German import	TTF DAH	TTF M1	ZEE DAH	ZEE M1	NBP DAH	NBP M1	UK Base	UK APX	NL Base	FR Base	DE Base
Brent					3						4					
Coal ARA															3	3
Japan LNG																
Henry Hub																
German import	2															
TTF DAH										2	5					
TTF M1											6					
ZEE DAH										3	4					
ZEE M1											6					
NBP DAH						2		3								
NBP M1	4					6	6	4	6							
UK Base																
UK APX																
NL Base															2	
FR Base	3	4												3		4
DE Base		4													5	

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[9] The values shown are the number of months that qualify as important exogenous variables (12 months were used).

Table 15: Adjusted R-squared for pairwise regression between all series

	Brent	Coal ARA	Japan LNG	Henry Hub	German import	TTF DAH	TTF M1	ZEE DAH	ZEE M1	NBP DAH	NBP M1	UK Base	UK APX	NL Base	FR Base	DE Base
Brent	NA	0.51	0.58	0.22	0.83	0.59	0.66	0.59	0.65	0.52	0.62	0.42	0.47	0.56	0.25	0.45
Coal ARA	0.51	NA	0.15	0.11	0.49	0.28	0.36	0.27	0.34	0.21	0.28	0.33	0.34	0.63	0.63	0.89
Japan LNG	0.58	0.15	NA	0.12	0.58	0.38	0.42	0.39	0.42	0.35	0.39	0.14	0.18	0.19	0.06	0.10
Henry Hub	0.22	0.11	0.12	NA	0.09	0.14	0.16	0.14	0.16	0.13	0.15	0.24	0.24	0.21		0.08
German import	0.83	0.49	0.58	0.09	NA	0.77	0.80	0.76	0.79	0.71	0.74	0.48	0.52	0.63	0.35	0.42
TTF DAH	0.59	0.28	0.38	0.14	0.77	NA	0.95	1.00	0.95	0.98	0.96	0.80	0.82	0.75	0.39	0.30
TTF M1	0.66	0.36	0.42	0.16	0.80	0.95	NA	0.94	1.00	0.89	0.99	0.74	0.76	0.77	0.41	0.37
ZEE DAH	0.59	0.27	0.39	0.14	0.76	1.00	0.94	NA	0.95	0.99	0.96	0.80	0.82	0.74	0.39	0.29
ZEE M1	0.65	0.34	0.42	0.16	0.79	0.95	1.00	0.94	NA	0.90	0.99	0.74	0.76	0.76	0.40	0.36
NBP DAH	0.52	0.21	0.35	0.13	0.71	0.98	0.89	0.99	0.90	NA	0.93	0.80	0.80	0.68	0.39	0.24
NBP M1	0.63	0.28	0.39	0.15	0.74	0.96	0.99	0.96	0.99	0.93	NA	0.74	0.74	0.72	0.42	0.31
UK Base	0.42	0.33	0.14	0.24	0.48	0.80	0.74	0.80	0.74	0.80	0.72	NA	0.96	0.79	0.49	0.39
UK APX	0.47	0.34	0.18	0.24	0.52	0.82	0.76	0.82	0.76	0.80	0.73	0.96	NA	0.79	0.46	0.39
NL Base	0.56	0.63	0.19	0.21	0.63	0.75	0.77	0.74	0.76	0.68	0.72	0.79	0.79	NA	0.68	0.69
FR Base	0.45	0.73	0.06		0.35	0.39	0.41	0.39	0.40	0.39	0.42	0.49	0.46	0.76	NA	0.87
DE Base	0.45	0.89	0.10	0.08	0.42	0.30	0.37	0.29	0.36	0.24	0.31	0.39	0.39	0.69	0.82	NA

Table 16: Regression coefficient for the independent variable in pairwise regression

	Brent	Coal ARA	Japan LNG	Henry Hub	German import	TTF DAH	TTF M1	ZEE DAH	ZEE M1	NBP DAH	NBP M1	UK Base	UK APX	NL Base	FR Base	DE Base
Brent	NA	3.27	1.22	2.44	2.14	2.07	2.30	2.04	2.28	1.88	2.26	1.18	1.22	0.96	0.59	0.74
Coal ARA	0.16	NA	0.14	0.40	0.36	0.32	0.36	0.31	0.35	0.27	0.32	0.23	0.23	0.22	0.25	0.23
Japan LNG	0.48	1.15	NA	1.18	1.12	1.05	1.12	1.05	1.11	0.98	1.07	0.44	0.49	0.36	0.20	0.23
Henry Hub	0.09	0.32	0.12	NA	0.15	0.21	0.23	0.21	0.22	0.19	0.21	0.18	0.18	0.12		0.07
German import	0.40	1.38	0.53	0.73	NA	1.01	1.05	1.00	1.04	0.95	1.00	0.54	0.55	0.44	0.30	0.31
TTF DAH	0.29	0.92	0.37	0.76	0.76	NA	0.99	0.99	0.98	0.98	1.00	0.60	0.60	0.41	0.27	0.23
TTF M1	0.31	1.01	0.38	0.79	0.76	0.96	NA	0.94	0.99	0.90	1.00	0.57	0.56	0.41	0.27	0.25
ZEE DAH	0.29	0.91	0.38	0.76	0.77	1.01	1.00	NA	0.99	0.99	1.01	0.61	0.60	0.42	0.27	0.23
ZEE M1	0.31	0.99	0.39	0.79	0.77	0.97	1.01	0.95	NA	0.91	1.01	0.58	0.57	0.41	0.27	0.25
NBP DAH	0.28	0.82	0.37	0.74	0.75	1.00	0.99	1.00	0.98	NA	1.00	0.62	0.61	0.41	0.28	0.21
NBP M1	0.30	0.91	0.38	0.77	0.75	0.97	0.99	0.95	0.98	0.94	NA	0.58	0.57	0.41	0.28	0.23
UK Base	0.37	1.48	0.34	1.42	0.90	1.33	1.30	1.32	1.29	1.29	1.28	NA	0.96	0.63	0.45	0.38
UK APX	0.39	1.52	0.40	1.46	0.95	1.38	1.35	1.36	1.33	1.32	1.34	1.00	NA	0.64	0.45	0.39
NL Base	0.59	2.84	0.56	1.87	1.45	1.83	1.88	1.79	1.84	1.69	1.79	1.26	1.23	NA	0.89	0.71
FR Base	0.48	2.83	0.39		1.21	1.48	1.53	1.45	1.51	1.43	1.53	1.11	1.05	0.83	NA	0.76
DE Base	0.62	3.91	0.49	1.44	1.40	1.37	1.55	1.33	1.49	1.18	1.39	1.04	1.02	0.97	1.12	NA

Table 17: Cointegration according to pairwise residual stationarity at 95% confidence level

	Brent	Coal ARA	Japan LNG	Henry Hub	German import	TTF DAH	TTF M1	ZEE DAH	ZEE M1	NBP DAH	NBP M1	UK Base	UK APX	NL Base	FR Base	DE Base
Brent			stoch	stoch			stoch		stoch							
Coal ARA			stoch			determ	determ	determ	determ	determ	determ	determ	determ		both	both
Japan LNG																
Henry Hub																
German import								determ	determ	determ				stoch		
TTF DAH							determ	both	determ	both	determ					
TTF M1						determ		determ	determ	determ	determ		stoch			
ZEE DAH						both	determ		determ	determ	determ					
ZEE M1						determ	determ	determ		determ			stoch			
NBP DAH						determ	determ	determ	determ		determ					
NBP M1						determ		determ		stoch						
UK Base						stoch	determ	stoch	determ	stoch	stoch		determ	determ		
UK APX					determ	stoch	both		both		determ	determ		both		
NL Base					both	both	determ	both	determ	both	determ	both	both			
FR Base	determ	both	determ		both	determ	both	determ	both	determ	both	determ		determ		both
DE Base		both			determ										both	

4.4.2.2 Estimation of error correction mechanisms

As the second step of the Engle-Granger procedure, bivariate ECMs are estimated for the same 240 pairs. The error correction term should be found to be significant in the pairs that have stationary regression residuals. Two ECMs are used, with the inclusion/exclusion of a deterministic trend γt as the only difference:

$$\Delta Y_t = \xi_0 + \kappa \hat{z}_{y,t-1} + \theta \Delta X_{t-1} + \phi \Delta Y_{t-1} \tag{4.17}$$

$$\Delta Y_t = \xi_0 + \gamma t + \kappa \hat{z}_{y,t-1} + \theta \Delta X_{t-1} + \phi \Delta Y_{t-1} \tag{4.18}$$

ΔY_t: first difference of Y_t

ξ_0: constant

γ: coefficient for deterministic trend

κ: coefficient for the error correction term

$\hat{z}_{y,t-1}$: lagged residual for $Y(X)$

ΔX_{t-1}: lagged first difference of X

ΔY_{t-1}: lagged first difference of Y

Given the previous definition of stochastic and deterministic cointegration, it is expected that the pairs which are determined to be deterministically stationary will have a significant and negative κ testing through Equation (4.17), while those which are determined to be stochastically stationary will have a significant and negative κ testing through Equation (4.18). The results from the ECM estimation are summarized in Table 18.

The higher adjusted R^2 of the two possible ECMs for all pairs with significant ECMs is shown in Table 19. These values indicate how much of the short-term variation in a given series is explained by the three or four independent variables used in the ECM regression. The explanatory power of ECMs over the short-term dynamics of the variables is overall moderate. It can be seen then that the ECMs can explain up to 39% of short-term variation for the German import, using its own history, the history of NBP M1, and the deviation of German import from its long-run equilibrium with NBP M1. On the other hand, ECMs, although found to be significant, can only explain 3% of the short-term variation in NL Base using its deviation from an equilibrium with Brent as an exogenous factor.

The coefficients of the error correction terms for all pairs with significant ECMs are shown in Table 20. When both regression models show significant error correction, the coefficient of the model with the higher R^2 adjusted is chosen. These coefficients describe the speed of adjustment of one series with respect to its deviation from its long-term relationship with the independent series. The closer to zero the coefficient is, the slower the adjustment process.

Table 18: Cointegration according to ECM estimation at 95% confidence level

	Brent	Coal ARA	Japan LNG	Henry Hub	German import	TTF DAH	TTF M1	ZEE DAH	ZEE M1	NBP DAH	NBP M1	UK Base	UK APX	NL Base	FR Base	DE Base
Brent				stoch	both	stoch	stoch									
Coal ARA				stoch												
Japan LNG	both			stoch	both	both	both	stoch	both	stoch	stoch	stoch	stoch	stoch		
Henry Hub	both						both		both		both	both	both	both		
German import						stoch	stoch	stoch	stoch		stoch			stoch	stoch	
TTF DAH					both											
TTF M1					both											
ZEE DAH					determ											
ZEE M1			stoch		both											
NBP DAH	both				both		both		both							
NBP M1			stoch		both											
UK Base	both	both	stoch		both	both	both	both	both	both	both			both		both
UK APX	both	both	stoch		both	both	both	both	both	both	both			both		
NL Base	both															
FR Base	both	both	both	both	both	both	both	both	both	both	both	both	both	both		both
DE Base	both	both	stoch	stoch												

Table 19: Adjusted R-squared for bivariate ECMs

	Brent	Coal ARA	Japan LNG	Henry Hub	German import	TTF DAH	TTF M1	ZEE DAH	ZEE M1	NBP DAH	NBP M1	UK Base	UK APX	NL Base	FR Base	DE Base
Brent				0.14	0.13	0.20	0.18									
Coal ARA				0.14												
Japan LNG	0.34			0.25	0.25	0.22	0.26	0.23	0.26	0.22	0.25	0.22	0.23	0.21		
Henry Hub	0.05						0.08		0.08		0.07	0.12	0.13	0.06		
German import						0.20	0.39	0.19	0.37		0.39			0.17	0.13	
TTF DAH					0.06											
TTF M1					0.15											
ZEE DAH					0.06											
ZEE M1			0.11		0.16											
NBP DAH	0.07				0.08		0.11		0.11							
NBP M1			0.16		0.18											
UK Base	0.12	0.06	0.04		0.11	0.06	0.13	0.07	0.13	0.05	0.10			0.14		0.06
UK APX	0.15	0.06	0.06		0.13	0.12	0.18	0.11	0.18	0.09	0.17			0.17		
NL Base	0.03															
FR Base	0.11	0.21	0.23	0.25	0.21	0.15	0.20	0.15	0.20	0.14	0.19	0.12	0.13	0.13		0.14
DE Base	0.09	0.15	0.05	0.16												

Table 20: Coefficient of error correction term for significant ECMs

	Brent	Coal ARA	Japan LNG	Henry Hub	German import	TTF DAH	TTF M1	ZEE DAH	ZEE M1	NBP DAH	NBP M1	UK Base	UK APX	NL Base	FR Base	DE Base
Brent				-0.13	-0.22	-0.12	-0.13									
Coal ARA				-0.20												
Japan LNG	-0.21			-0.10	-0.16	-0.11	-0.11	-0.11	-0.11	-0.11	-0.11	-0.10	-0.10	-0.09		
Henry Hub	-0.15						-0.14		-0.14		-0.14	-0.15	-0.15	-0.15		
German import						-0.15	-0.18	-0.15	-0.17		-0.16			-0.12	-0.08	
TTF DAH					-0.26											
TTF M1					-0.32											
ZEE DAH					-0.26											
ZEE M1			-0.14		-0.31											
NBP DAH	-0.17				-0.28		-0.48		-0.51							
NBP M1			-0.15		-0.29											
UK Base	-0.30	-0.26	-0.25		-0.35	-0.45	-0.50	-0.43	-0.49	-0.42	-0.43			-0.67		-0.25
UK APX	-0.35	-0.25	-0.25		-0.40	-0.59	-0.61	-0.57	-0.59	-0.53	-0.61			-0.73		
NL Base	-0.20															
FR Base	-0.46	-0.64	-0.47	-0.51	-0.47	-0.44	-0.48	-0.44	-0.48	-0.43	-0.48	-0.47	-0.45	-0.54		-0.78
DE Base	-0.16	-0.64	-0.23	-0.45												

4.5 Discussion

Before comparing the cointegration test results to the hypothesized relationships, the findings from the two steps of the Engle-Granger procedure are consolidated.

4.5.1 Consolidation of results

The results from the assessment of residual stationarity and the estimation of ECMs for a given pair might not both find evidence for cointegration. Thus, before discussion of correspondence with the original hypothesis, the results obtained from the two steps are consolidated. Depending on results from the test of residual stationary and the results on error correction model significance, there are four possible outcomes for any given pair tested.

1. No evidence for cointegration under both tests (blank);
2. Stationary regression residuals only ("stat");
3. Significant and negative error correction coefficient only ("EC");
4. Stationary regression residuals AND significant and negative error correction coefficient ("both").

The final outcome for all pairs are determined through the superposition of results from Table 17 and Table 18. It is shown in Table 21. Only results of the type "both" meet the full definition of cointegration: that of a common trend maintained by an error correction mechanism. Pairs of price series of the type "stat" could have had stationary residuals due to correlation in their short-term shocks, even when error correction is absent. Pairs of price series of the type "EC" could have non-stationary residuals due to the high impact of short-term influences, on the independent variable and/or on the dependent variable, which cannot be fully eliminated through the error correction mechanism that exists.

Table 21: Consolidated results of the Engle-Granger procedure

	Brent	Coal ARA	Japan LNG	Henry Hub	German import	TTF DAH	TTF M1	ZEE DAH	ZEE M1	NBP DAH	NBP M1	UK Base	UK APX	NL Base	FR Base	DE Base
Brent			stat	both	EC	EC	both		stat							
Coal ARA			stat	EC		stat	stat	stat	stat	stat	stat	stat	stat		stat	stat
Japan LNG	EC			EC	EC	EC	EC	EC	EC	EC	EC	EC	EC	EC		
Henry Hub	EC						EC		EC		EC	EC	EC	EC		
German import						EC	both	both	both		EC		stat	EC	EC	
TTF DAH					EC		stat	stat	stat	stat	stat					
TTF M1					EC	stat		stat	stat	stat	stat		stat			
ZEE DAH					EC	stat	stat		stat	stat	stat					
ZEE M1			EC		EC	stat	stat	stat		stat			stat			
NBP DAH	EC				EC	stat	both	stat	both		stat					
NBP M1			EC		EC	stat		stat		stat						
UK Base	EC	EC	EC		EC	both	both	both	both	both	both		stat	both		EC
UK APX	EC	EC	EC		both	both	both	EC	both	EC	both	stat		both		
NL Base	EC				stat	stat	stat	stat	stat	stat	stat	stat	stat			
FR Base	both	both	both	EC	both	both	both	both	both	both	both	both	EC	both		both
DE Base	EC	both	EC	EC	stat										stat	

4.5.2 Comparison with hypothesis

Due to the large number of relationships to be compared, the discussion is divided using the following grouping:

A. Pairs that are hypothesized to be cointegrated, and the hypothesis is supported by empirical evidence;
B. Pairs that are hypothesized to be cointegrated, and the hypothesis is rejected by empirical evidence;
C. Pairs that are not hypothesized to be cointegrated, and there is no empirical evidence for cointegration;
D. Pairs that are not hypothesized to be cointegrated, and there is empirical evidence for cointegration.

Group C is not discussed, as the results are an expected absence of cointegration. Group A is surveyed but not extensively, as the results are an expected presence of cointegration. The core of the discussion is based on group B, containing the set of hypothesized but rejected cointegration relationships. Group D, non-hypothesized but statistically significant cointegration relationships, is also discussed. But, it should be noted that statistically spurious relationships are possible in this category and the results are mentioned as points of interest for future studies.

The initial hypothesis for relationships among all variables, when communicated in the pairwise form, can be represented as Table 22. They are compared with the final outcome of tests in Table 21, yielding Table 23 which displays whether relationship between two given price series fall into category A, B, C, or D. Note that only results of type "both" from Table 21 is considered to qualify as full cointegration. "EC" and "stat" type results are considered insufficient to support the hypothesis of cointegration, for they are partial evidence for cointegration.

Table 23 shows that only five pairs of hypothesized relationships are supported by empirical evidence. A greater number of hypothesized relationships are rejected ("B"), and a large number of non-hypothesized, possibly spurious, relationships are suggested by statistical evidence.

Table 22: Hypothesized relationships among price series

	Brent	Coal ARA	Japan LNG	Henry Hub	German import	TTF DAH	TTF M1	ZEE DAH	ZEE M1	NBP DAH	NBP M1	UK Base	UK APX	NL Base	FR Base	DE Base
Brent																
Coal ARA																
Japan LNG	Yes															
Henry Hub	Maybe															
German import	Yes															
TTF DAH					Maybe		Yes	Yes	Yes	Yes	Yes					
TTF M1					Maybe				Yes		Yes					
ZEE DAH					Maybe	Yes	Yes		Yes	Yes	Yes					
ZEE M1					Maybe		Yes				Yes					
NBP DAH					Maybe	Yes	Yes	Yes	Yes		Yes					
NBP M1					Maybe		Yes		Yes							
UK Base										Yes				Maybe		
UK APX										Yes		Yes				
NL Base						Yes						Maybe				Yes
FR Base																Yes
DE Base														Yes	Yes	

Table 23: Correspondence between the hypothesis and test results

	Brent	Coal ARA	Japan LNG	Henry Hub	German import	TTF DAH	TTF M1	ZEE DAH	ZEE M1	NBP DAH	NBP M1	UK Base	UK APX	NL Base	FR Base	DE Base
Brent	C	C	C	D	C	C	D	C	C	C	C	C	C	C	C	C
Coal ARA	C	C	C	C	C	C	C	C	C	C	C	C	C	C	C	C
Japan LNG	B	C	C	C	C	C	C	C	C	C	C	C	C	C	C	C
Henry Hub	B	C	C	C	C	C	C	C	C	C	C	C	C	C	C	C
German import	B	C	C	C	C	C	D	D	D	C	C	C	C	C	C	C
TTF DAH	C	C	C	C	B	C	B	B	B	B	B	C	C	C	C	C
TTF M1	C	C	C	C	B	C	C	C	B	C	B	C	C	C	C	C
ZEE DAH	C	C	C	C	B	B	B	C	B	B	B	C	C	C	C	C
ZEE M1	C	C	C	C	B	C	B	C	C	C	B	C	C	C	C	C
NBP DAH	C	C	C	C	B	B	A	B	A	C	B	C	C	C	C	C
NBP M1	C	C	C	C	B	C	B	C	B	C	C	C	C	C	C	C
UK Base	C	C	C	C	C	D	D	D	D	A	D	C	C	A	C	C
UK APX	C	C	C	C	D	D	D	C	D	B	D	B	C	D	C	C
NL Base	C	C	C	C	C	B	C	C	C	C	C	B	C	C	C	B
FR Base	D	D	D	C	D	D	D	D	D	D	D	D	C	D	C	A
DE Base	C	D	C	C	C	C	C	C	C	C	C	C	C	B	B	C

4.5.2.1 Proven hypothesized relationships (A)

The key parameters from the long-term regression (regression between levels) and short-term ECM regression (regression between difference and residual from first regression) are summarized in Table 24. The results for category A relationships confirm the initial hypothesized dependence of the spot UK gas price (NBP DAH) on forward gas prices in continental NW Europe. The long-term equilibrium between the NBP DAH and the regional gas forward prices explains the majority of the long-term trend in NBP DAH. Deviation of the UK spot from the European forward prices is also driving a limited part of its month-to-month change, and it reacts fastest toward deviation from ZEE M1, incrementally more slowly toward TTF M1.

The results also confirm the initial hypothesized dependence of the UK power prices on the UK spot gas prices. However, month-to-month change in the average price of baseload power is only driven by a limited extent by its deviation from its long-term equilibrium with NBP DAH. And, given the residual of the UK Base-NBP DAH regression is trend stationary (as indicated by the label “stoch” for stochastic cointegration implied by trend stationary residual), there possibly has been a change in the long-term equilibrium between spot gas and day-ahead power prices in the UK during the 2011-2015 period. Figure 27 suggests that there has been a gradual tightening of the long-term equilibrium position of the two, seen as the fall in magnitude of residuals. This can be interpreted as a narrowing spark spread. Of the two confirmed cointegrated power price pairs, the FR Base-DE Base pair is cointegrated more tightly than the UK Base-NL Base pair: more of the long-term variation in FR Base is explained by the level of DE Base; it also adjusts faster towards its equilibrium value with DE Base when there is a deviation.

Table 24: Key parameters for proven hypothesized relationships

Dep. variable	Indep. variable	Residual	ECM	LT R2 adjusted	LT reg. coeff.	ECM R2 adjusted	ECM reg. coeff.
NBP DAH	**TTF M1**	determ	both	0.89	0.99	0.11	-0.48
NBP DAH	**ZEE M1**	determ	both	0.90	0.98	0.11	-0.51
UK Base	**NBP DAH**	stoch	both	0.80	1.29	0.05	-0.42
UK Base	**NL Base**	determ	both	0.79	0.63	0.14	-0.67
FR Base	**DE Base**	both	both	0.87	0.76	0.14	-0.78

In this group, the long-term equilibrium between variables explains a large portion of the variation in the price level of the dependent variable (R^2 adjusted between 0.90 to 0.79). The long-term relationship between the first two pairs (NBP DAH vs. the two month-ahead prices of different NW European hubs) have regression coefficients very close to or equal to one: if the month-ahead prices of TTF/ZEE change by one unit, then the NBP DAH prices will also change by one unit. This is expected since the underlying commodity is the same: natural gas.

The regression coefficients for the effect of NBP DAH and NL Base on UK base are very different: NBP DAH price changes lead to larger changes (1.29 unit change in UK Base/unit change in NBP DAH), while NL Base price changes lead to smaller changes (0.63 unit change in UK Base/unit change in NL Base). This is because the effect of changes in gas price on the power price is magnified, given the consumption of one energy unit of gas generates less than one unit of electricity.

Of all ECMs between pairs, the two error correction mechanisms between the electricity prices explains more of the dependent variable's change from one month to another (R^2 adjusted = 0.14), while the one between UK Base toward NBP DAH explains the least (R^2 adjusted = 0.05). In other words, only 5% of variation in month-to-month change of UK Base can by explained changes in NBP DAH, but 14% can be explained through its relative deviation from NL Base prices. Finally, the regression coefficient for the error terms in ECMs represent the speed of adjustment. It can be seen that the adjustment is fastest for the FR Base-DE Base pair, and the slowest for the inter-commodity adjustment of UK Base toward NBP DAH.

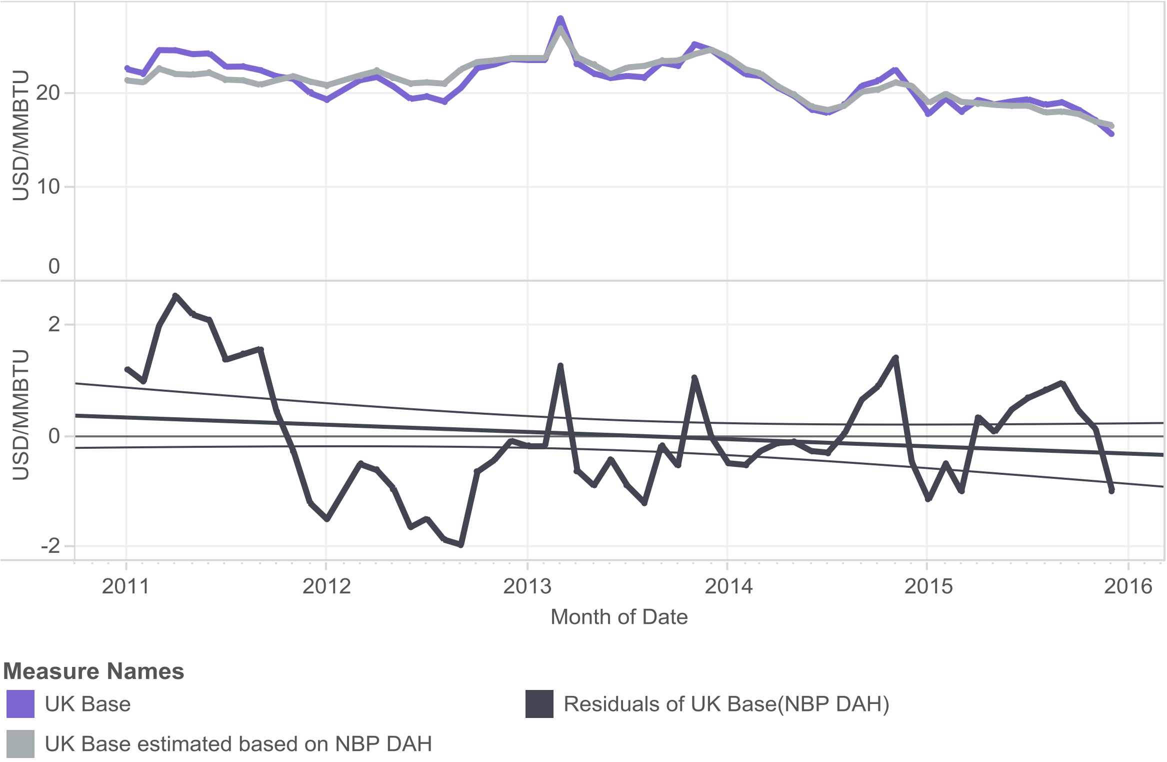

Figure 27: Comparison of UK Base prices with their estimated values based on NBP DAH

4.5.2.2 Non-proven hypothesized relationships (B)

The greatest number of non-proven hypothesized relationships are found between Group 2 pairs: except for the NBP DAH-TTF M1, NBP DAH-ZEE M1 pair established in the previous section, none of the remaining gas price pairs are found to have met the full definition of cointegration (See Table 23 and Table 25). Other than that, expected cointegration of Group 1 global energy commodity prices with Brent is not proven, and cointegration of Group 2 NW European gas prices with German import gas prices is not established. Within Group 3, several electricity prices hypothesized to be cointegrated have not been found to be so, and, finally, some of the hypothesized cointegration between power and gas prices – UK APX-NBP DAH, NL Base-TTF DAH – have not been established. This section examines the results from the two statistical tests in detail to understand what empirical evidence prevented the conclusion of cointegration.

4.5.2.2.1 Between NW European gas hub prices

It could be seen that most Group 2 pairs, even when they do not show significant error correction mechanisms between them, do have stationary regression residuals. In other words, they have moved along each other, maintaining the same relative paths in the absence of error correction between pairs, from one month to another. As an example, the residuals of ZEE M1 against TTF M1 are plotted in Figure 28. It can be seen that ZEE M1 almost never deviates from its long-term equilibrium with TTF M1 (which is almost exact parity); when it does, the monthly average's deviation is less than 0.2 $/MMBTU.

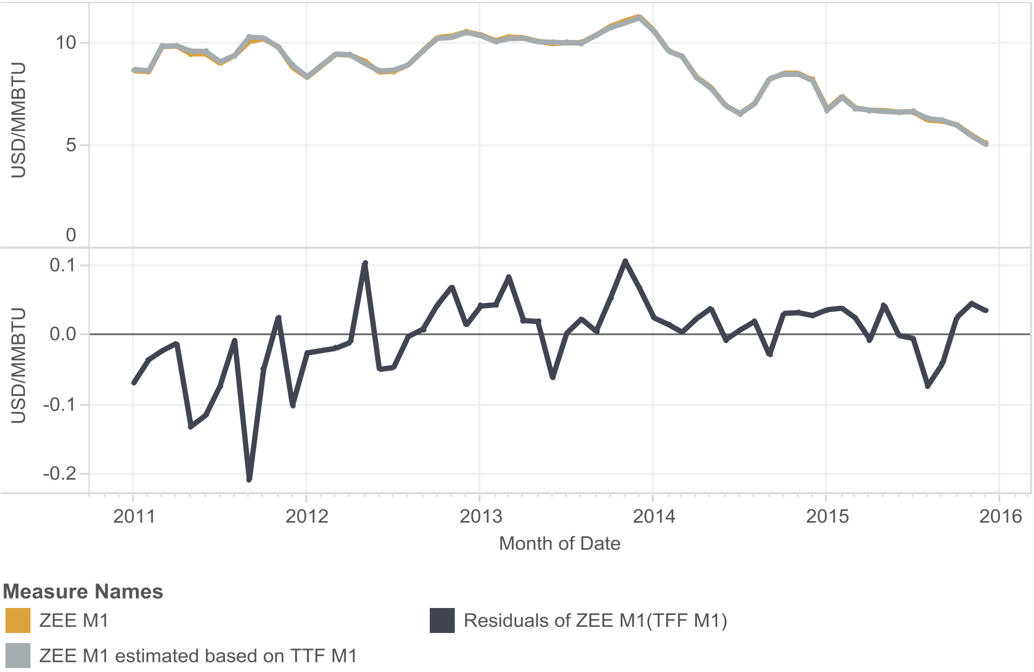

Figure 28: Comparison of ZEE M1 prices with their estimated values based on TTF M1

Table 25: Key parameters for non-proven hypothesized relationships

Dep. variable	Indep. Variable	Category	Type	LT R2 adjusted	LT reg. coefficient	ECM R2 adjusted	ECM reg. coefficient
Japan LNG	**Brent**	EC	both	0.58	0.48	0.34	-0.21
Henry Hub	**Brent**	EC	both	0.22	0.09	0.05	-0.15
German import	**Brent**			0.83	0.40		
ZEE DAH	**TTF DAH**	stat	both	1.00	1.01		
NBP DAH	**TTF DAH**	stat	determ	0.98	1.00		
TTF DAH	**TTF M1**	stat	determ	0.95	0.99		
ZEE DAH	**TTF M1**	stat	determ	0.94	1.00		
ZEE M1	**TTF M1**	stat	determ	1.00	1.01		
NBP M1	**TTF M1**			0.99	0.99		
TTF DAH	**ZEE DAH**	stat	both	1.00	0.99		
NBP DAH	**ZEE DAH**	stat	determ	0.99	1.00		
TTF DAH	**ZEE M1**	stat	determ	0.95	0.98		
TTF M1	**ZEE M1**	stat	determ	1.00	0.99		
ZEE DAH	**ZEE M1**	stat	determ	0.95	0.99		
NBP M1	**ZEE M1**			0.99	0.98		
TTF DAH	**NBP DAH**	stat	both	0.98	0.98		
ZEE DAH	**NBP DAH**	stat	determ	0.99	0.99		
TTF DAH	**NBP M1**	stat	determ	0.96	1.00		
TTF M1	**NBP M1**	stat	determ	0.99	1.00		
ZEE DAH	**NBP M1**	stat	determ	0.96	1.01		
ZEE M1	**NBP M1**			0.99	1.01		
NBP DAH	**NBP M1**	stat	determ	0.93	1.00		
UK APX	**UK Base**	stat	determ	0.96	1.00		
NL Base	**UK Base**	stat	both	0.79	1.26		
NL Base	**DE Base**			0.69	0.71		
DE Base	**NL Base**			0.69	0.97		
DE Base	**FR Base**	stat	both	0.82	1.12	The	
TTF DAH	**German import**	EC	both	0.77	0.76	0.06	-0.26
TTF M1	**German import**	EC	both	0.80	0.76	0.15	-0.32
ZEE DAH	**German import**	EC	determ	0.76	0.77	0.06	-0.26
ZEE M1	**German import**	EC	both	0.79	0.77	0.16	-0.31
NBP DAH	**German import**	EC	both	0.71	0.75	0.08	-0.28
NBP M1	**German import**	EC	both	0.74	0.75	0.18	-0.29
NL Base	**TTF DAH**	stat	both	0.75	1.83		
UK APX	**NBP DAH**	EC	both	0.80	1.32	0.09	-0.53

The question remains: how could these pairs of price series maintain the same long-term trends so closely, without having active error correction mechanisms between them? A possible explanation is that the price series are subject to the same exogenous short-term influences, so their monthly average change in the same way. If so, then ΔX_t should be significantly and positively correlated with ΔY_t . Also, it is possible then that, given the monthly step, error correction could occur in the same period rather than in the next period. It is not possible to statistically differentiate the two cases using data with monthly resolution. Because, if the second case is true, then the deviation from equilibrium will have been corrected within a month, which appears as if ΔY_t is concomitant with ΔX_t. Put differently, when assessing correlation between differences in variable in the same period, it is not possible to distinguish whether they are correlated through immediate error-correction or common exogenous influences.

Adding a contemporaneous term ΔX_t to the previous ECM equations used allows us to determine the combined effect of the previous two possibilities. If the error correction occurs within a month and/or if short-term changes in Y_t are caused by the same exogenous factors as those that induce changes in X_t, the added term should prove to be a significant regressor.

$$\Delta Y_t = \xi_0 + \kappa R_{y,t-1} + \lambda \Delta X_t + \theta \Delta X_{t-1} + \phi \Delta Y_{t-1} \tag{4.19}$$

$$\Delta Y_t = \xi_0 + \gamma t + \kappa R_{y,t-1} + \lambda \Delta X_t + \theta \Delta X_{t-1} + \phi \Delta Y_{t-1} \tag{4.20}$$

ECM regression results for the new model show that the term ΔX_t is a more important regressor than ΔX_{t-1} and $R_{y,t-1}$ for all pairs within Group 2 (not all ΔX_{t-1} terms are significant, and all other regressors have smaller coefficients, meaning that ΔY_t reacts more significantly to ΔX_t than ΔX_{t-1} and $R_{y,t-1}$). This suggests that either one or both of the suggestions above could be the case: that error-correction mechanisms for Group 2 pairs occur within the same month (therefore full cointegration can be established), and/or that Group 2 pairs are subject to similar external influences that cause them to change at same time. To reach a more nuanced conclusion requires cointegration analysis with price data at a finer resolution.

The value of estimate λ is shown for all pairs in Group 2, all of them are significant at 95% confidence level (Table 26). In general, the change in month-ahead prices on day-ahead prices is stronger ($\lambda = 0.86 - 0.92$) than the opposite ($\lambda = 0.55 - 0.79$). The impact of TTF prices and ZEE on NBP prices ($\lambda = 0.76 - 1.10$) is larger than the opposite ($\lambda = 0.55 - 0.92$). This seems to suggest that month-ahead prices Granger cause day-ahead prices, and that TTF/ZEE prices (more closely coupled) Granger cause NBP prices.

Table 26: The effect of short-term change in independent variable on the change in contemporaneous dependent variable

		Independent variable					
		TTF DAH	**TTF M1**	**ZEE DAH**	**ZEE M1**	**NBP DAH**	**NBP M1**
Dependent variable	**TTF DAH**	NA	0.92	0.96	0.91	0.81	0.86
	TTF M1	0.75	NA	0.71	0.99	0.55	0.91
	ZEE DAH	1.03	0.92	NA	0.93	0.85	0.88
	ZEE M1	0.77	1.00	0.73	NA	0.58	0.92
	NBP DAH	1.10	0.88	1.09	0.89	NA	0.89
	NBP M1	0.79	1.02	0.76	1.00	0.62	NA

Other than the absence of significant error correction mechanisms, several pairs involving NBP has also shown non-stationary regression residuals. The residuals for the NBP M1-TTF M1 and NBP M1-ZEE M1 regressions are visually examined in Figure 29. It can be observed that the key departure from stationarity is the deviation of NBP M1 on August 2011.

This relative depressed NBP M1 price can be attributed to the planned maintenance shutdowns on the Bacton-Zeebrugge Interconnector in September 2011, which prevented gas from being exported from the UK to continental Europe (Petrovich, 2013, p. 29). Subsequent maintenance of the Interconnector pipeline has had led NBP M1 to negative deviation from its equilibrium position, but not to the same extent and not consistently. However, the maintenance shutdowns were found to be as significant as in 2011 in previous years (2008-2010) (van Alem, 2013). This suggests a change in the effect of pipeline maintenance on the deviation of prices between NBP and the continental gas hubs, in between the periods 2008-2011 and 2012-2015. The month August 2011 is thus considered an outlier, a one-off event during the study period. Regression residuals are found to be stationary after removing this outlier.

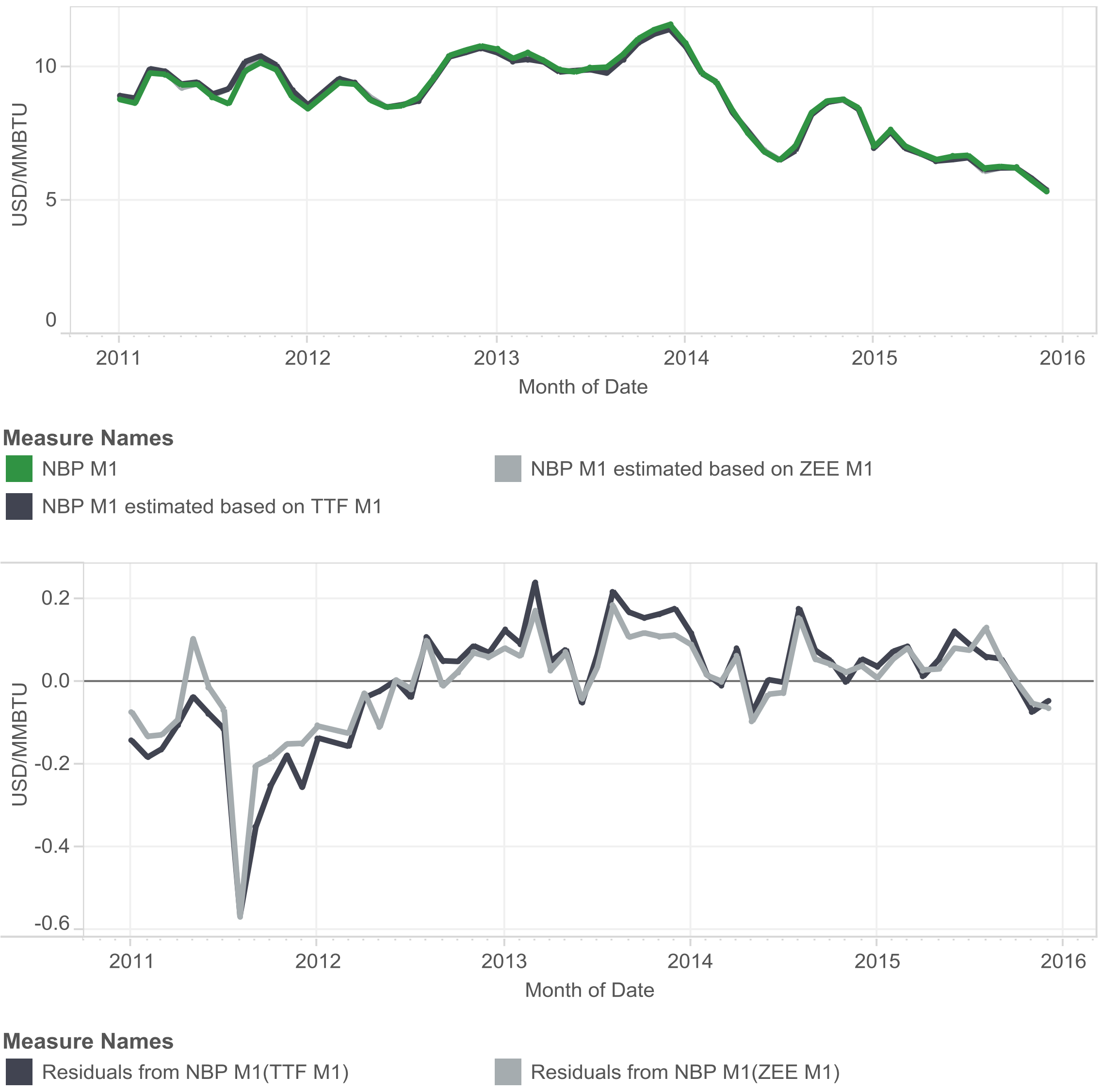

Figure 29: NBP M1 prices and its estimated values based on ZEE M1 and TTF M1

4.5.2.2.2 Global energy commodities Vs. Brent

The hypothesized relationships between Japan LNG, Henry Hub (possible but less probable cointegration was hypothesized), and German import are not found for the study period 2011-2015.

For the first two pairs, error correction mechanisms are statistically significant, but the residuals from regression are not stationary (Table 25). Therefore, it could be that the short-term influences that drive the month-to-month change of Japan LNG and Henry Hub are more significant than their long-term equilibrium with Brent. The non-stationary regression residuals (difference between actual Japan LNG/ Henry Hub prices and their estimated values based on Brent) are visually inspected in Figure 30 and Figure 31.

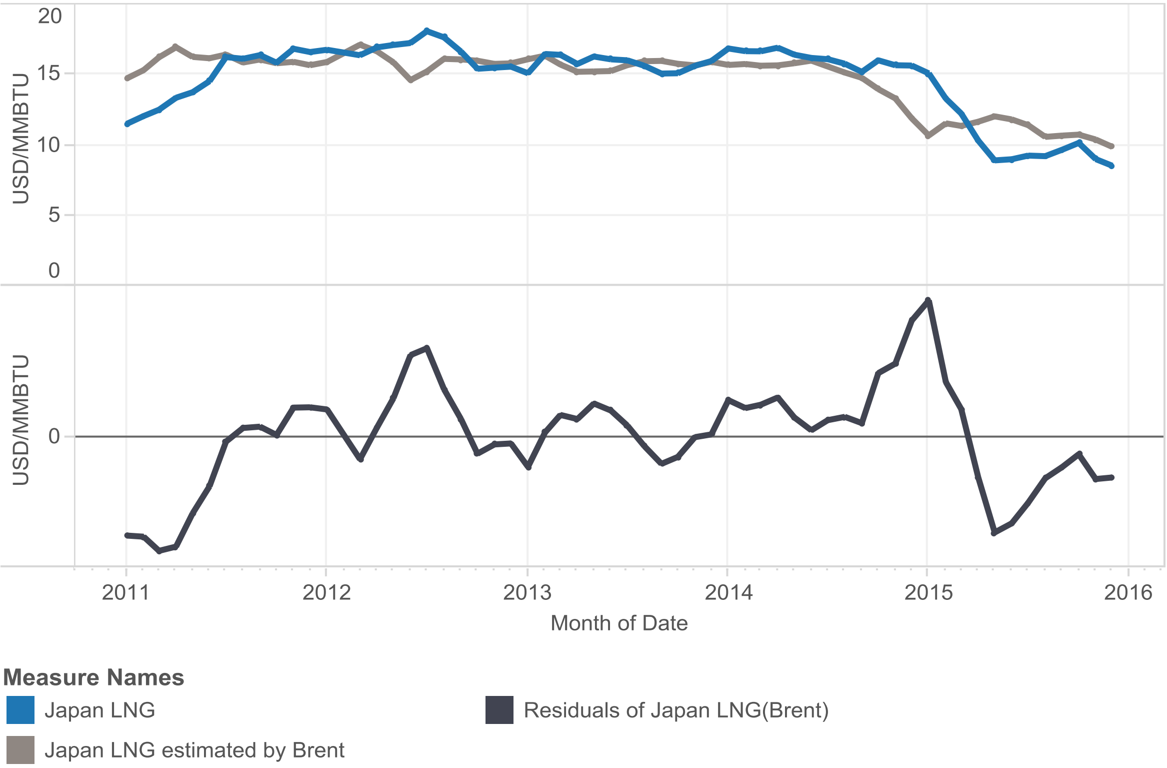

Figure 30: Comparison of Japan LNG prices with their estimated values based on Brent

It can be seen that the realized value of Japan LNG actually tracks the Brent-estimated value quite closely; however, the realized value lags the estimated value by about four months. This matches observations made elsewhere (Rogers, 2015, p. 3). This calls for an adjustment in the standard regression model used to estimate long-term relationships (Equation (4.16)). The revised equation incorporates five lagged terms of the independent variable:

$$Y_{i,t} = \mu + \sum_{n=1}^{6} \beta_n X_{j,t+1-n} + \psi D_t \tag{4.21}$$

It is found that the price of Brent lagged by one period is also a significant regressor. The residuals of the corrected regression model are tested again by the ADF test, and they are found to be stationary. Therefore, after taking into account the lagged nature of the long-term equilibrium between Japan LNG and Brent, they do prove to be cointegrated.

The residuals of the Henry Hub-Brent pair show important period of divergence of Henry Hub from its equilibrium position with respect to Brent during the 2011-2015 period. This is consistent with the view that changes in Henry Hub prices are determined by domestic supply and demand forces; these market forces are greater than the maintenance of a certain equilibrium with respect to crude oil prices.

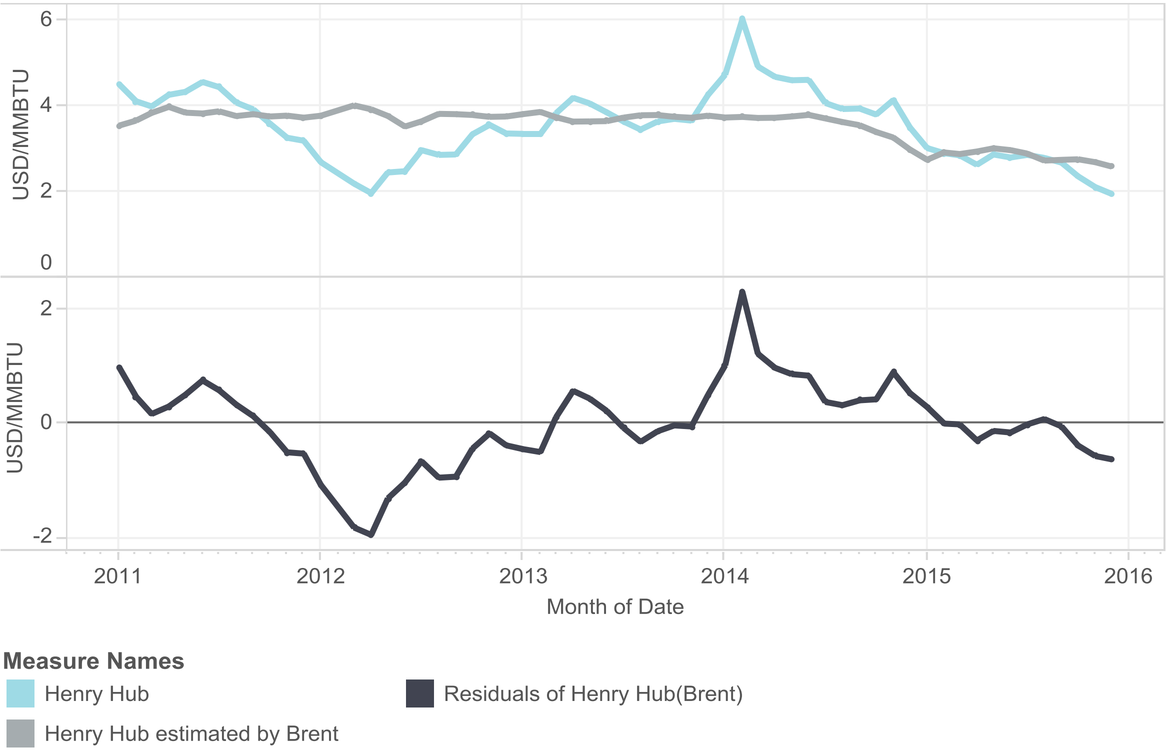

Figure 31: Comparison of Henry Hub gas prices with their estimated values based on Brent

As for German import, neither a stationary residual nor a significant error correction term toward Brent was found through the Engle-Granger procedure. However, there is statistical evidence that the German average import gas price is cointegrated with TTF M1, ZEE DAH, and ZEE M1, which were not hypothesized relationships. Therefore, the residuals of the German import – Brent pair are compared with that of German import -TTF M1, to evaluate crude oil and NW European hubs' respective impact on German import price levels.

It can be seen that the actual German import price is roughly bracketed between the two estimates (Figure 32). Up to March 2012, the estimates based on Brent are closer to the actual values of German import prices, but the estimates based on TTF M1 are closer for the period mid-2012 to late 2014. Since the fall of crude oil prices, the estimates based on crude oil, interestingly, are more accurate once more. These findings imply that for the bulk of the study period, the NW European hub prices either drive or forecasts German import prices. The traditional connection between German import prices and crude oil prices is, at least temporarily, inactive.

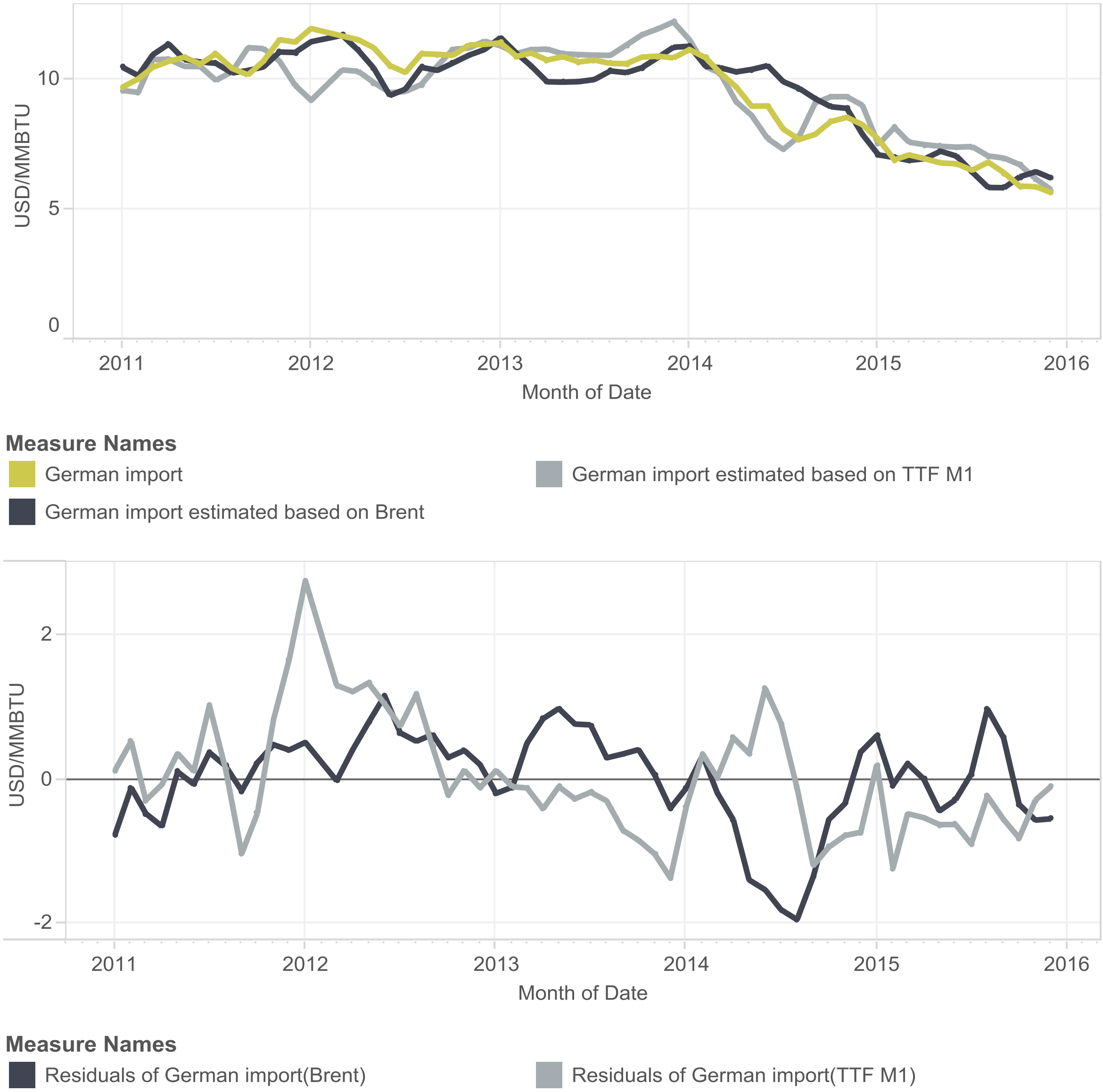

Figure 32: Comparison of German import prices and its estimated values based on Brent and TTF M1

4.5.2.2.3 NW European gas hubs prices Vs. German import

The expected cointegration relationships between NW European gas hub prices and German import prices are not found, but unexpected cointegration in the opposite direction is detected, as discussed above. More precisely, significant error correction was found between all hub prices toward the German import price; but, the residuals of these pairwise regressions are not stationary. This suggests that short-term exogenous effects on hub prices are more important than their error correction mechanism toward their long-term equilibrium with German import.

The residuals of TTF M1-German import are illustrated in Figure 33. It can be seen that between November 2011 to September 2012, TTF M1 is below its equilibrium position with respect to

German import, while from October 2012 to January 2014, it is above said equilibrium position. A similar cycle, but of shorter duration, took place during 2014. These deviations from equilibrium are statistically long-stationary and driven by events other than German import prices. Therefore, it can be said that, during the 2011-2015 period, NW European hub prices are not cointegrated with the German import price. But, since 2015, the residuals have been decreasing. If the trend is maintained into the future, it could suggest that the upcoming period is one in which hub prices are cointegrated with the German import price once more.

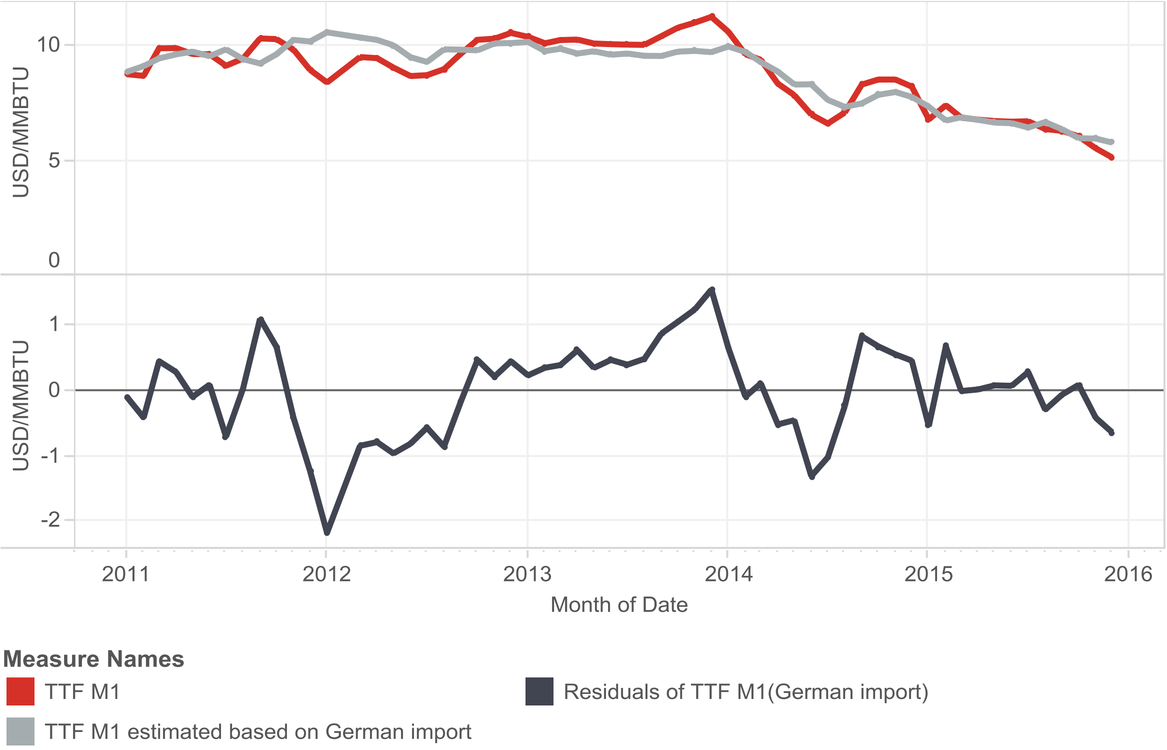

Figure 33: Comparison of TTF M1 prices with their estimated values based on German import

4.5.2.2.4 Between NW European power prices

Given that a lot of information about electricity prices (varying by the hour) is lost by aggregating them via the monthly average values, conclusions about relationships between electricity prices are less certain than those about gas prices (varying by the day).

Unexpectedly, the UK APX Market Price Index is not cointegrated with the UK Base (OTC day-ahead prices). Although their residuals are stationary, but there is no statistically significant error correction mechanism from UK APX toward its equilibrium position with respect to UK Base. This is a case similar to that of lack of error correction between gas hub price pairs. Therefore, a similar follow-up hypothesis is investigated: the error-correction mechanism could be taking place within a month rather than between month, or contemporaneous external short-term effects are dominant. Equation (4.19) and (4.20) are used for short-term ECM regression. The ΔX_t term is found to be a significant and important regressor, therefore the proposed possibility cannot be rejected.

On another hand, no error correction mechanisms can be found between NL Base – UK Base, and DE Base – FR Base pairs, while cointegration in the opposite direction has been established. This suggests that NL Base Granger cause UK Base (the Netherlands is a price-setting net exporter), and DE Base Granger cause FR Base (France is a price-taking net exporter).

Between the NL Base – DE Base pair, the regression residuals are reported to be non-stationary (Figure 34). It can be seen that the major deviation from the equilibrium position occurred during the year 2013, the year during which the use of coal in power generation in Germany peaked since its previous local maximum in 1990. Despite their interconnections and trade of electricity in both directions, the prices of electricity in the Netherlands and Germany are not cointegrated during the 2011-2015 period.

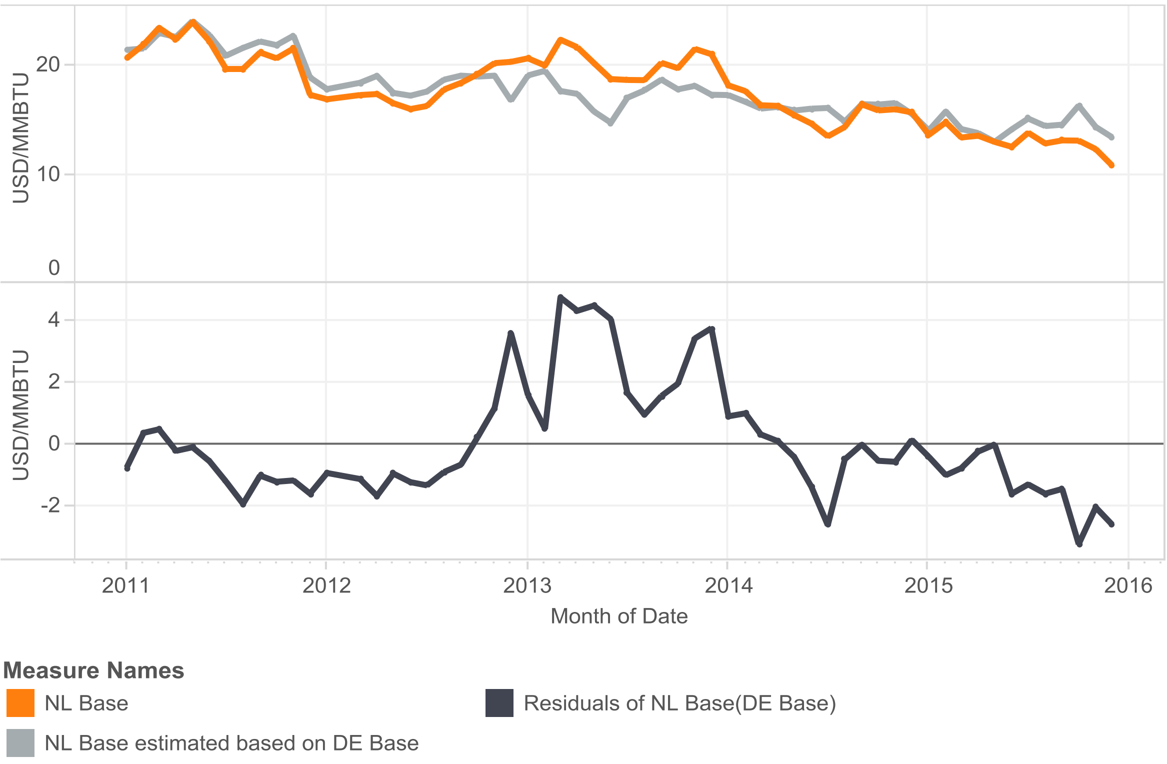

Figure 34: Comparison of NL Base prices with their estimated values based on DE Base

4.5.2.2.5 Between NW European gas and power prices

The last pairs of expected relationships not found via statistical tests are NL Base – TTF DAH and UK APX – NBP DAH. Between the first pair, the residuals are stationary, but there is no significant error correction mechanism. Between the second pair, there is significant error correction, but the residuals are non-stationary (Table 25).

In the case of NL Base and TTF DAH, the absence of month-to-month error correction and the existence of stationary residuals could be due to 1) within month error correction and 2) concomitant external short-term influences. Using the method described above, the contemporaneous ΔX_t term is added to the ECM regression models, and it is found to be significant and very important. Therefore, the two scenarios cannot be rejected.

In the case of UK APX and NBP DAH, the non-stationary residuals are compared to the (statistically stationary) residuals of the UK Base – NBP DAH pair (Figure 35). The price levels of UK Base and UK APX are also plotted.

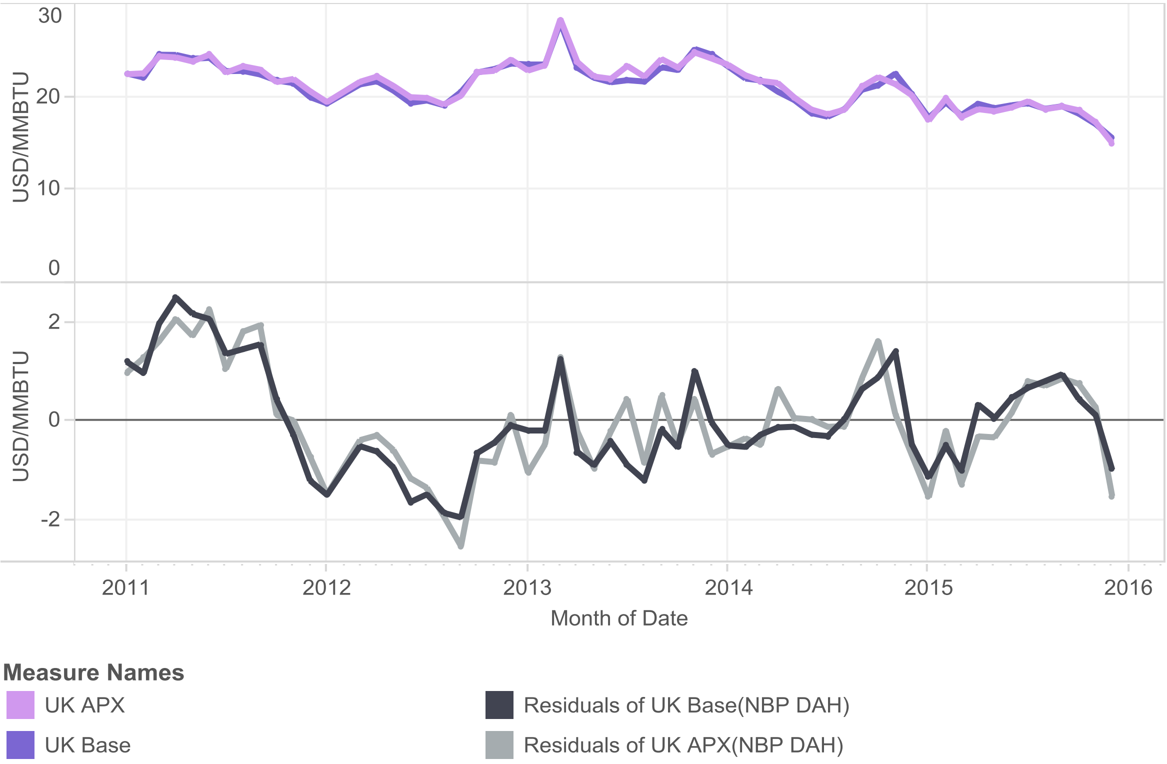

Figure 35: Comparison of the residuals of UK APX and UK Base relative to their estimated values based on NBP DAH

It can be seen that UK APX and UK Base in general follow the same trend, but UK APX experiences more spikes (due to intraday supply and demand balance of power in the UK). The same can be said of their residuals relative to the estimated values based on regression against NBP DAH. Therefore, it can be said that the error correction mechanism between UK APX and NBP DAH cannot maintain stationary residuals mainly due to the short-term exogenous influences that UK APX experiences due to other shorter-term market forces in the power sector.

4.5.2.2.6 Proven non-hypothesized relationships (D)

Apart from non-proven hypothesized relationships, there are also a large number of statistically significant but non-hypothesized cointegrated pairs (Table 27). It should be repeated that statistical relationships found without prior knowledge in the form of a hypothesis is prone to spurious findings, therefore, these results are included for completeness but should not be taken to be the key findings of this study.

The non-hypothesized cointegration between German import and NW European hug gas prices (instead of German import and Brent), which have backing in market fundamentals, has already been discussed. The non-hypothesized cointegration of DE Base with Coal ARA suggests that coal-fired power generation is the marginal unit setting price in the German power market during 2011-2015. Unexpectedly, not only the UK day-ahead power price is cointegrated with UK spot gas price, it is also cointegrated with all other North-western European hub gas prices. The same can be said about UK APX, cointegrated with all hub gas prices except for ZEE DAH and NBP DAH. The UK APX market price index has also been shown to be statistically cointegrated with NL Base and German import. Brent, expected to be free from the influence of other price series included in this study, is found to be not so: the tests suggesting that it is cointegrated with Henry Hub and TTF M1. Finally, the French power price series has shown non-hypothesized cointegration with all other price series except for that of Henry Hub and the UK APX. It should be remembered that being a trend stationary series, the cointegration shown is likely to be spurious.

Table 27: Key parameters for proven non-hypothesized relationships

Dep. variable	Indep. variable	Residual	ECM	LT R^2 adjusted	LT reg. coeff.	ECM R^2 adjusted	ECM reg. coeff.
Brent	**Henry Hub**	stoch	stoch	0.22	2.44	0.14	-0.13
FR Base	**UK Base**	determ	both	0.49	1.11	0.12	-0.47
FR Base	**NL Base**	determ	both	0.76	0.83	0.13	-0.54
UK APX	**NL Base**	both	both	0.79	0.64	0.17	-0.73
Brent	**TTF M1**	stoch	stoch	0.66	2.30	0.18	-0.13
German import	**TTF M1**	determ	stoch	0.80	1.05	0.39	-0.18
German import	**ZEE DAH**	determ	stoch	0.76	1.00	0.19	-0.15
German import	**ZEE M1**	determ	stoch	0.79	1.04	0.37	-0.17
UK Base	**TTF DAH**	stoch	both	0.80	1.33	0.06	-0.45
UK Base	**TTF M1**	determ	both	0.74	1.30	0.13	-0.50
UK Base	**ZEE DAH**	stoch	both	0.80	1.32	0.07	-0.43
UK Base	**ZEE M1**	determ	both	0.74	1.29	0.13	-0.49
UK Base	**NBP M1**	stoch	both	0.72	1.28	0.10	-0.43
UK APX	**TTF DAH**	stoch	both	0.82	1.38	0.12	-0.59
UK APX	**TTF M1**	both	both	0.76	1.35	0.18	-0.61
UK APX	**ZEE M1**	both	both	0.76	1.33	0.18	-0.59
UK APX	**NBP M1**	determ	both	0.73	1.34	0.17	-0.61
FR Base	**TTF DAH**	determ	both	0.39	1.48	0.15	-0.44
FR Base	**TTF M1**	both	both	0.41	1.53	0.20	-0.48
FR Base	**ZEE DAH**	determ	both	0.39	1.45	0.15	-0.44
FR Base	**ZEE M1**	both	both	0.40	1.51	0.20	-0.48
FR Base	**NBP DAH**	determ	both	0.39	1.43	0.14	-0.43
FR Base	**NBP M1**	both	both	0.42	1.53	0.19	-0.48
UK APX	**German import**	determ	both	0.52	0.95	0.13	-0.40
FR Base	**German import**	both	both	0.35	1.21	0.21	-0.47
FR Base	**Brent**	determ	both	0.45	0.48	0.11	-0.46
FR Base	**Coal ARA**	both	both	0.73	2.83	0.21	-0.64
FR Base	**Japan LNG**	determ	both	0.06	0.39	0.23	-0.47
DE Base	**Coal ARA**	both	both	0.89	3.91	0.15	-0.64

4.5.3 Revised relationships between price series

Given the discussion above, the original hypothesis about relationships among price series is revised to reflect the empirical findings. Figure 36 shows the revised diagram. The key findings of this cointegration study are the following (the order in which the series are mentioned is important, with the dependent variable mentioned first):

Group 1

- Rejected cointegration of Henry Hub with Brent;
- Rejected cointegration of German import with Brent;
- Confirmed cointegration of Japan LNG with Brent after accounting for lag;

Group 2

- Confirmed cointegration of NBP DAH with ZEE M1 and TTFM1;
- Suggested cointegration between all North-western European gas hub prices, with ZEE/TTF Granger causing NBP and M1 prices Granger causing DAH prices, but cointegration needs to be tested again with more fine grained data;

Group 3

- Confirmed cointegration of UK Base with NL Base;
- Rejected cointegration of NL base with UK Base;
- Confirmed cointegration of FR Base with DE Base;
- Rejected cointegration of DE Base with FR Base;
- Rejected cointegration of NL Base with DE Base;
- Rejected cointegration of DE Base with NL Base;
- Suggested cointegration of UK APX with UK Base, but cointegration needs to be tested again with more fine grained data;

Between groups:

- Confirmed cointegration of UK Base with NBP DAH;
- Suggested cointegration of NL Base with TTF DAH, but cointegration needs to be tested again with more fine grained data;
- Rejected cointegration of UK APX with spot gas prices, possibly due to exogenous power market influences in the intraday market;
- Rejected cointegration of NW European hub gas prices with German import, possibly due to regional supply and demand market forces;
- Suggested cointegration of German import with NW European hub gas prices, possibly due to hub-indexing of newly signed contracts between Russia and its customers;
- Suggested cointegration of DE Base with Coal ARA, possibly due to the use of coal-fired power as the marginal generation technology in Germany.

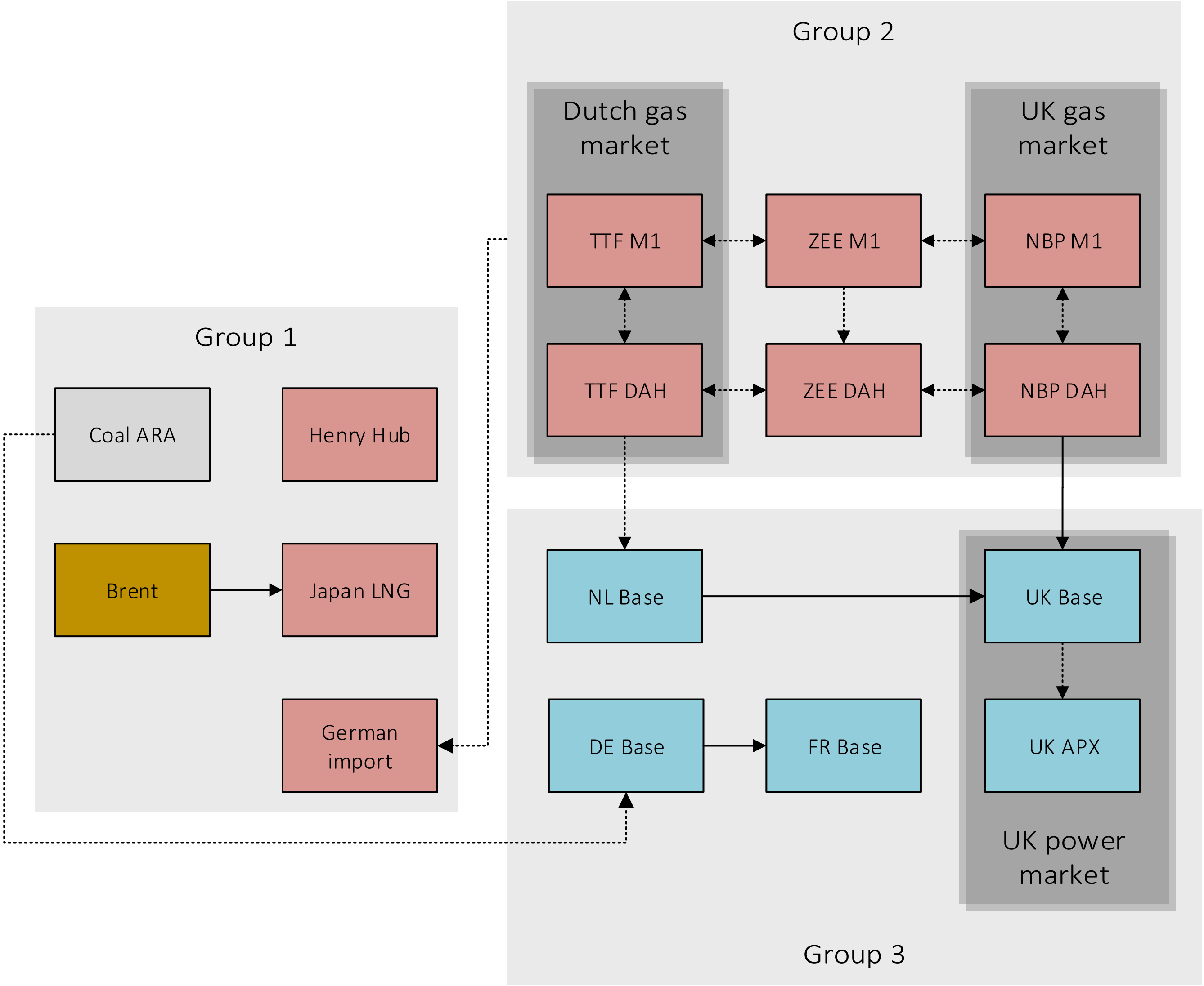

Figure 36: Revised hypothesized relationships among price series studied based on empirical findings

The implications of these findings for the modelling of UK power and gas market modelling is more obvious if the relationships between energy price series are reframed in terms of the UK market. Figure 37 shows that the UK gas and power markets are affected by the prices of gas in NW European hubs and the price of electricity exported by the Netherlands. Although the direction of causality for correlation for gas prices couldn't be ascertained due to the use of monthly data, it is found that the impact of month-ahead price changes on day-ahead price changes is larger than the opposite, and the impact of TTF/ZEE prices changes on NBP price changes is larger than the opposite. For UK power prices, it is more clear that UK gas prices (and the NW European gas prices, via cointegration with UK gas prices) as well as the (gas-fired) Dutch electricity export drive the day-ahead power prices. Therefore, a model of the UK energy markets consistent with empirical findings will need to incorporate the effect of these exogenous prices on the market clearing process.

It is also important to understand the possible range of uncertainty that is associated with these key exogenous variables. Figure 37 also shows how the Dutch electricity prices and the gas prices at NW European hubs could be influenced: The Dutch power price, like the UK one, is driven by natural gas price in NW Europe, since they affect its own market fundamentals. The price of power in France, not yet setting prices in the UK, is driven by the price of power in Germany, which is in turn driven by the price of coal. As for the NW hub gas prices, they irregularly correct toward German import and do not maintain a stable long-term equilibrium position with the German import prices, deviating upward and downward depending on region-wide supply and demand forces. Therefore, the uncertainty within NW European hub prices for gas lies in the uncertainty of regional demand and its balance with flexible supplies, a process that is influenced by the price of gas imported from Russia, which is in turn increasingly influenced by the hub prices themselves.

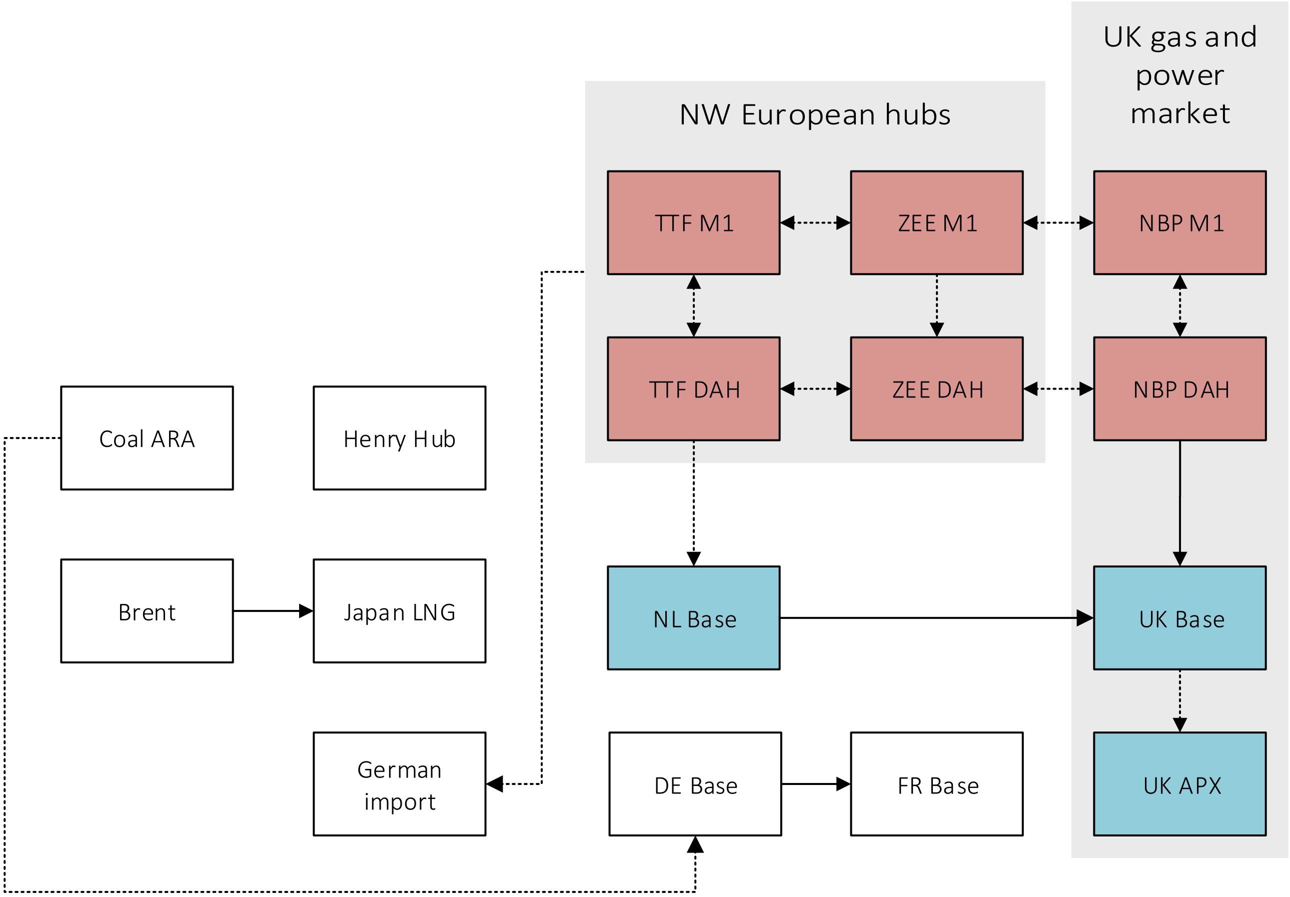

Figure 37: Price relationships of importance to UK gas and power markets

5 Model development

Based on the UK case study, the SD simulation model that formally represents key interdependencies between gas and power sectors' investment decision is developed. It is a set of self-consistent causal beliefs, represented explicitly through mathematical equations, that allows the effects of exogenous inputs to be explored. The model presented below should be seen as the first working prototype in a lineage of future models. The wider than usual scope of the system modelled required a trade-off with the representational accuracy of individual causal links within the system. However, simplifying assumptions, whenever adopted, are announced explicitly and open to challenge and future amendment. In this section, the simulation model developed is presented in the following order: first, the causal loop diagram illustrating the modelling scope is presented and the feedback loops identified to be important are described. Then, the detailed mathematical formulation of the model is presented in sub-sections.

5.1 Model scope

The overall model structure adopted is illustrated in Figure 38. Following SD conventions, causal relationships between variables are traced through arrows. The five key causal loops that can be traced are indicated via blue loop symbols. Key exogenous variables, uncertain variables which are not specified by the model, but fed to it as an input, are labelled in red. And, grey boxes indicate that causal links leading to and departing from these boxes are processed by an underlying sub-model.

Reading of the causal loop diagram is guided by the causal loops that it includes. But, before that, the sub-models need to be introduced to facilitate the reading of causal loops.

The sub-model **gas market** is the mathematical representation of the ensemble of relationships between gas demand, gas supply, gas storage, and the various constraints to which they are subjected to. The price of natural gas in the UK is determined by the gas market sub-model, as a function of interplay of these variables and constraints. Similarly, the sub-model **power market** is the mathematical representation of the relationships between power demand, power supply, and other constraints to which they are subjected to. The price of electricity in the UK is determined by the power market sub-model, as a function of the variables and constraints in place. The two sectorial **forecast** sub-models represent the set of mathematical relationships that allow inference of future revenue and cost projections based on current information. The **investment** sub-models represent set of mathematical relationships that are meant to capture the investment decision-making process of sector agents based on forecasted cost/revenue and other capital budgeting parameters.

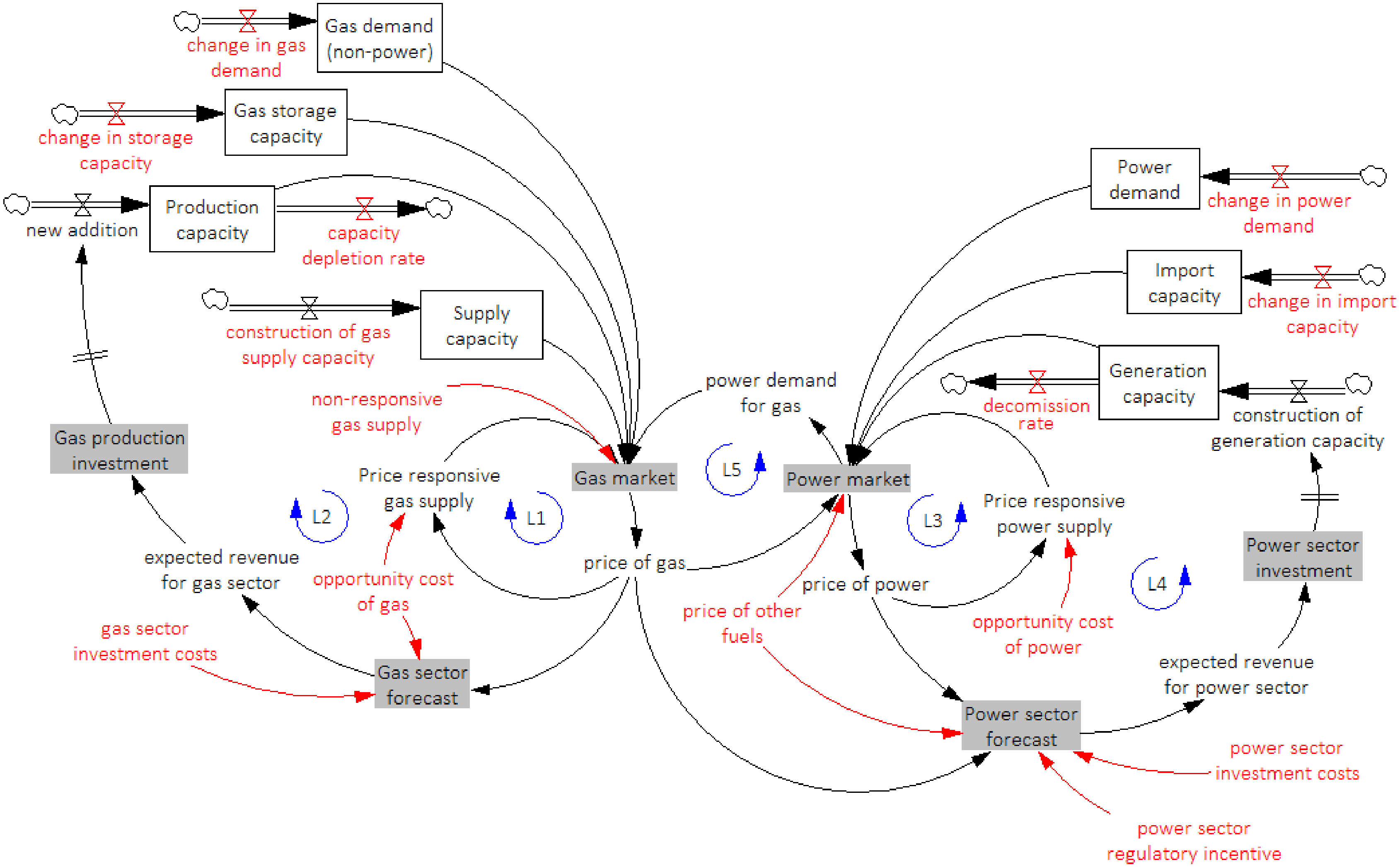

Figure 38: Causal loop diagram of the overall model

The boundary of the model is delineated by what is considered exogenous. The current choice of boundary reflects knowledge gained during the case study: two particular segments of the gas-to-power supply chain are plagued with uncertainties (domestic gas production and power generation), while other segments are relatively static. Therefore, generation capacity investment and domestic production investment are represented endogenously, while the other segments are represented exogenously (gas storage capacity, gas supply/import, (non-power) gas demand, power demand, power import capacity).

Of the remaining exogenous variables, some are not specified endogenously, because they are not (uniquely) determined by influences of agents within the UK's gas and power sectors, but are important to outcome in the UK: price of coal, investment costs of generation technology or gas import infrastructure, price-responsiveness and opportunity cost of flexible gas supply, for example. Others are intentionally kept out of model boundary because they are policy decision variables, which are altered to represent different energy policy decision made by the UK government: decommission rate of existing power generation capacity and the investment incentive for power generation capacity are the most important examples.

The key feedback loops that can be traced in Figure 38 are numbered and described briefly.

- **L1: Price responsive gas supply**

  This feedback loop corresponds to the interaction between price-responsive (flexible) gas supply[10] and market price. If the market price is high, it will attract additional supply at the new increased price level, which alleviates the supply/demand imbalance at the origin of high price and stops the price from increasing. If the market price is low, then tranches of supply that are price responsive might decrease/stop flow, preventing prices from falling. In other words, this is a balancing loop, in which price spikes or dips are corrected by the market action that they incentivise. Through price, the short-term supply/demand balance is regulated.

- **L2: Availability of gas production capacity**

  This feedback loop describes the interaction between gas production capacity and current/expected market condition. Given production investment decision is followed by a development lag and the recovery of investment via production is a long-term project, investment decisions are made with forecasted information. If the future market price in the UK is *expected* to be high, based on existing market

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[10] This represents some but not all of gas supply. In the UK, it is in the form of flexible import from Belgium via the IUK and flexible LNG import, storage injection/withdrawal, and pipeline long-term contract swing volumes.

condition, so that future gas production in the country is *expected* to be profitable after considering exploration and production costs, then gas producers will be incentivised to invest in more production capacity through exploration and development. Provided all other conditions remain equal, once the newly developed production capacity comes online, providing more supplies to the market, then the price of gas is supposed to fall, followed by a fall in the *expectation* of high prices, removing the incentive for further production investments. Thus, this balancing loop regulates the long-term production capacity relative to demand via price.

- **L3: Price responsive power supply**

  This feedback loop is analogous to L1, but it is applied in the power sector. If the market price for electricity is high (indicating to supply/demand imbalance), then power supply tranches with higher costs will be activated, meeting the outstanding demand and preventing the price from further escalation. Correspondingly, if the market price for electricity is low, then power supply tranches with higher costs will not generate, removing the outstanding supply and preventing the price from further fall. Like L1, this balancing feedback loop regulates the short-term supply/demand balance via price.

- **L4: Availability of power generation capacity**

  This feedback loop is analogous to L2. It describes the interaction between power generation investment and current/expected market conditions. As in L2, delays exist between investment and the end of economic lifetime of the investment brought online, so investment decisions are made using forecast rather than current information. If the *expected* revenue from power generation is high so that, after considering the *expected* costs required, the investment considered remains profitable, then power generators will be incentivised to invest in new generation capacity. This continues until a change in the market price, which then percolates into investor expectations, that it is no longer profitable to do so since there is no longer a supply shortage. Notice how the current gas price and its forecast is also an input into the power generation investment decision.

L5 is a balancing feedback loop that involves both gas and power markets. In doing so, it complicates the dynamics of the overall system, because previously unconnected feedback loops in the two sectors are now connected.

- **L5: Price responsiveness of power sector gas demand**

  This feedback loop describes the interaction between the supply/demand balance of the gas and power markets. If the price of gas increases, due to imbalance between gas supply and demand, this will affect the cost of gas-fired generation and their bids in the power market, leading to a decreased use of gas and increased use of generation with lower costs (if available). If all other things remain equal, then this decreased gas demand of the power sector should help restore balance in the gas market. In other words, the gas demand of the power sector is price-sensitive and will respond to changes in gas price, provided power sector supply/demand balance can be maintained.

All feedback loops described above involve either the power market or the gas market, and sometimes both. This illustrates the key role of markets as feedback mechanisms in the short and long-term self-regulation of the gas and power sectors.

5.2 Model specification

Individually, the logic of each causal loop is relatively easy to understand, and their effect can be predicted if they are studied in isolation. However, when all five loops are simultaneously in action, and a non-negligible number of exogenous variables is acting on the system, as in reality, the dynamics of the system become considerably more complex and non-longer tractable through back-of-envelope type calculations. This calls for the use of a simulation model, which is able to automatically track the state of all variables contained in the causal loop diagram, their inter-relationships, and the constraints that some of them are subject to (if any). The simulation model derives possible trajectories for the behaviour of the system, given different initial condition and exogenous input values/pathways. In this section, the mathematical representation of the five feedback loops above is presented and justified.

As shown in Figure 38, the system under study is represented by a series of sub-models, which contain the detailed formulation of relationships between sub-model inputs and outputs: gas/power markets, gas/power sector investment decisions, and gas/power sector forecasting. Therefore, the model specification is delineated according to these divisions. The remaining elements in the causal loop diagram are the stocks of infrastructure, cash, and demand. How they are tracked within the simulation model is described at the end of this section.

5.2.1 Gas and power markets

The gas and power markets are the most important sub-models of the overall simulation model. As mentioned above, they are the nexus through which all feedback loops intersect, and L1, L3, and L5 take place either within the gas and power market sub-models or between them, without involving other sub-models. Adequate mathematical representation of the gas and power markets requires the following:

- Gas market
    - To differentiate between sources of gas supply that are price-responsive (flexible) and those that are not, and to propose a mechanism through which price-responsive supply interacts with market price (L1)
    - To differentiate between non-power sector and power sector gas demand, assuming only the latter is price-responsive, and to propose a mechanism through which power sector gas demand interacts with the gas market price (L5)
- Power market
    - To differentiate between generation technologies that are price-responsive (flexible) and those that are not, and to propose a mechanism through which price-responsive generation interacts with market price (L3)
    - To differentiate between generation technology with exogenous cost and gas-fired generation, given that power-sector gas use could potentially influence the price of gas, and to propose a mechanism through endogenous price of gas is communicated to the power market (L5).

Previous SD modelling work typically models the power market through the intersection of demand (in the form of load duration curves) with the merit order supply curve of cumulative generation capacity. The gas market is under-represented in the SD literature, and the price-formation process is often assumed to be simply a function of the relative reserve-demand ratio or a function of the ratio of demand to supply.

In this newly developed model, the relationship between gas/power supply, demand, and market price is represented in more details compared to previous SD models. The gas market is formulated as a market clearing process with monthly resolution, where market participants (producers/shippers/suppliers) behave competitively given existing contractual and infrastructural constraints; the market outcome is one in which inter-temporal arbitrage via storage and inter-market arbitrage via flexible import/export is used to minimize the overall cost to meet gas demand (L1). The power market is formulated as a market clearing process with hourly resolution, where generators behave competitively given existing technology and infrastructural constraints; the market outcome is one in which the operation of different generation assets is optimized to minimize the overall cost to meet power demand (L3). Intertemporal arbitrage and inter-market arbitrage for the power sector also exists in the form of pumped hydro storage and flexible imports/exports through interconnectors. They represent a small percentage of the overall power supply available (1% and 8% of overall supply respectively, compared to up to 10% and 30% estimated for the gas sector).

5.2.1.1 Gas market

In order to specify the source of gas used to meet demand and the market price, given supply availability and infrastructure constraints, it is assumed that the UK gas market operates as a perfectly competitive market, once the boundary of the competitive marketplace is known (in the form of long-term contract terms, availability and opportunity cost of import). This means that it is assumed that the market outcome is one in which the total operational cost of supplying gas is minimized. The total operation cost is the difference between supply costs from domestic and import sources and the potential revenue from export.

The model takes inputs of gas demand and the opportunity cost of imported gas at monthly resolution, because the greatest variation in the UK gas demand occurs within a year due to the important seasonal effect of gas used for heating. The gas demand is disaggregated into that from the power sector, and that from the other sectors. The former is generated endogenously within the overall model, through the power market sub-model, while the latter is specified exogenously.

The model outputs gas supplied by different sources: UKCS, Norway, the Netherlands, Belgium, and LNG, as well as the to/from storage flows. Export to Belgium is also allowed. The optimization model dispatches the least expensive supply of gas to meet monthly demand, as long as these contractual and technical constraints are met:

1. Storage infrastructure constraints in the form of maximum injection, withdrawal, and working gas capacity;
2. End-of-year storage requirement (at least a given fraction of total storage capacity is filled);
3. Long-term contract constraints in the form of annual contract quantity, monthly minimum uptake, and annual take-or-pay volume;
4. Import/export infrastructure constraint.

The non-price responsive portion of gas supply is captured by the long-term contract constraints (take-or-pay volume that will be taken regardless of price).

The market price of gas is taken to be the marginal cost of the supply source that is needed to meet an additional unit of demand. In the gas sector, the marginal cost of flexible imported supply is its opportunity cost, the price that it could fetch in an alternative market; the marginal cost of gas sourced through long-term contracts in the UK are indexed to the hub price, therefore they are linked to the marginal cost of flexible imported supply.

All parameters except for power sector gas demand, the annual contract quantity for natural gas from the UKCS, and the (hub-indexed) long-term contract prices are specified exogenously. The power sector gas demand is fetched from the power market sub-model, the annual contract quantity for the UKCS from the gas production capacity tracking sub-model, and the (hub-indexed) long-term contract prices are determined within the gas market sub-model. In order to determine the price of long-term contract gas indexed to the hub, a convergence algorithm with the following logic is used:

1. In the first iteration, the price of long-term contract p_m^{LTC} is set to the price of the interconnected NW European hub $p_{m,BG}$, because NW European gas hub prices are assumed to be the same unless local supply/demand imbalance arises;
2. Given the above, the optimization model is run and the NBP hub price p_m^{NBP} is set to be the dual variable of the demand balance constraint, in other words the marginal cost of meeting demand, assuming a fully competitive market;
3. The optimization model is solved again after re-setting the price of long-term contracts $p_m^{LTC} = p_m^{NBP}$, until there is no more difference between the resulting NBP hub price and the price of long-term contracts used.

Indexes

m	months of the year
t	source of supply or destination for export
c	commercial arrangement
k	type of storage

Parameters

D_m^{NP}	non-power sector gas demand in month m, Bcm
D_m^{P}	power sector gas demand in month m, Bcm
η_k^{GS}	efficiency for gas storage [gas stored per gas used]
$\bar{H}_k$	net maximum storage capacity, Bcm
$H_{0,k}$	gas in storage at beginning of year, Bcm
$H_{f,k}^{RELATIVE}$	gas in storage at end of year, Bcm
$\bar{J}_k$	injectability limit, Bcm/month
$\bar{W}_k$	withdrawability limit, Bcm/month
ACQ_t	annual contract volume for long-term contract, Bcm
ToP_t	annual take-or-pay volume for long-term contract, % of ACQ_t
$m_{\min,t}$	minimum monthly denomination for long-term contract, % of ACQ
$\bar{Q}_t$	infrastructure constraint from supply source t, Bcm/month

v	calorific value, MMBTU/Bcm
$\Delta p_t^{GAS}\left(\Delta S_t\right)$	price premium needed for import ΔS_t , \$/MMBTU
$\Delta q_t^{GAS}\left(\Delta E_t\right)$	price discount needed for export ΔE_t , \$/MMBTU
$p_{m,t}$	opportunity cost in market t for month m, \$/MMBTU]
p_m^{LTC}	price charged for long-term contract, \$/MMBTU

Variables

C_t^{SUPPLY}	cost of supply from t, \$
R_t^{EXPORT}	revenue from exporting to t, \$
$S_{m,t}$	supply procured from t in month m, Bcm
$J_{m,k}$	injection of gas into storage in month m, Bcm/month
$W_{m,k}$	withdrawal of gas into storage in month m, Bcm/month
$H_{m,k}$	gas in storage in month m, Bcm
$E_{m,t}$	export to t under c in month m, Bcm/month ($E_{m,t,LTC}=0$, $E_{m,t\neq BG,flex}=0$)
p_m^{NBP}	price at NBP in month m, \$/MMBTU

Objective function

$$\min\Big(\sum_t C_t^{SUPPLY}-R_t^{EXPORT}\Big) \qquad (5.1)$$

Constraints

$$C_t^{SUPPLY1}=\sum_m p^{LTC}S_{m,t}v \qquad \forall t\in LTC \qquad (5.2)$$

$$C_t^{SUPPLY2}=\sum_m\left(p_{m,t}+\Delta p_t^{GAS}\right)S_{m,t}v \qquad \forall t\in flex \qquad (5.3)$$

$$R_t^{EXPORT}=\sum_m\left(p_{m,t}+\Delta q_t^{GAS}\right)E_{m,t}v \qquad \forall t=BG \qquad (5.4)$$

$$\sum_t\left(S_{m,t}-E_{m,t}\right)-\sum_k\left(I_{m,k}-W_{m,k}\right)\geq D_m \qquad \forall m \qquad (5.5)$$

$$H_{m,k}=H_{m-1,k}+\eta_k^{GS}\,\mathrm{I}_{m,k}-W_{m,k} \qquad \forall m,k \qquad (5.6)$$

$$H_{12,k}=H_{f,k}^{RELATIVE}\bar{H}_k \qquad \forall k \qquad (5.7)$$

$$\sum_m S_{m,t\in LTC}\leq ACQ_t \qquad t\in LTC \qquad (5.8)$$

$$\sum_m S_{m,t\in LTC}\geq ToP_t^A ACQ_t \qquad t\in LTC \qquad (5.9)$$

$$m_{\min,t}ACQ_t\leq S_{m,t} \qquad \forall m,t\in LTC \qquad (5.10)$$

$$\sum_{c} S_{m,t} + E_{m,t} \leq Q_t \qquad \forall m,t \qquad (5.11)$$

$$0 \leq H_{m,c} \leq \bar{H}_c \qquad \forall m \qquad (5.12)$$

$$0 \leq J_{m,c} < \bar{J}_c \qquad \forall m \qquad (5.13)$$

$$0 \leq W_{m,c} \leq \bar{W}_c \qquad \forall m \qquad (5.14)$$

$$E_{m,t} = 0 \qquad \forall t \neq BG \qquad (5.15)$$

5.2.1.2 Power market

In order to specify dispatched generation and the market price of power, given import/generation capacity and upstream costs, it is assumed that the UK power market operates as a perfectly competitive market, one in which the total operational cost of generation is minimized as an outcome. The total operational cost consists of fuel consumption costs (from normal operation and generator start-up), fixed operational cost, carbon emission cost, import procurement cost, and the cost for not complying with the renewable obligation level. Therefore, the power market is represented by an optimization model with hourly resolution that minimizes the total operational cost.

The model outputs generation and import at hourly resolution, because electricity demand (and increasingly supply, through intermittent generation) exhibits important variation within hourly timescales. Not all other input variables are available/change at such high frequency. The price of generation fuels, carbon price, the opportunity cost of import electricity is fed to the model as monthly data. They are mapped to hourly values by assigning certain hours of the year to a given month. Ideally, the opportunity cost of import electricity should also be hourly, given the supply/demand in the interconnected markets changes also on an hourly basis.

To differentiate between generation technologies that are price-responsive and those that are not, the power market sub-model makes use of the concept of "effective demand", sometimes also called residual demand. It is the difference between actual national demand and generation that is considered to be non-flexible: wind, solar, and non-pumped storage hydro generation. The flexible generation technologies – nuclear, coal, gas, co-firing, biomass, and pumped storage – along with import capacity are dispatched according to the total operational cost minimization principle to meet the effective demand. However, in their operation, the flexible generation technologies are subject to a number of constraints other than meeting the hourly effective demand:

1. Pumped hydro infrastructure constraint
2. Renewable obligation constraint
3. Generation capacity (maximum and minimum stable load) constraint
4. Ramp up/down constraint
5. Interconnector capacity constraint

The least expensive generation unit/import source is dispatched as long as none of the constraint is violated; otherwise, a more expensive generation technology/import source may be dispatched (the least expensive among those that meet the constraint).

The market price of power is taken to be the marginal cost of the generation technology or import source that is needed to meet an additional unit of demand. In the power sector, the marginal cost of domestic generation is its variable cost (except for pumped hydro, whose marginal cost is its opportunity cost, the price that it could have fetched being used at another time). The marginal cost of flexible power import from interconnected markets is their opportunity cost, the price that could have been fetched if power was supplied to the alternative market.

Operations in the power market are constrained by underlying energy policies such as the renewable obligation scheme. Renewable obligation certificates are issued to eligible renewable electricity generators for the electricity that they generate, according to the banding they are assigned: 1 MWh of electricity might be awarded a number of certificates that is different. If power suppliers, who buy electricity in the wholesale market, do not collect the target number of renewable obligation certificates set by the government, then they would have to pay for the non-collected amount at the pay-out price, also set by the government. This is the equivalent of establishing a market for renewable obligation certificates.

The RO market is represented as embedded within the power wholesale market through the renewable obligation constraint: the power market sub-model dispatches generation so that the RO obligation is met at the lowest cost, with paying the buy-out price as an option of meeting this constraint. Given that renewable obligation certificates are awarded to non-price responsive generation such as solar and wind, which are not dispatched in the power market sub-model, the number of certificates that are already available from their generation is deducted from the overall target. In the case that generation from biomass and co-firing generators is a more economical way of meeting the renewable obligation constraint than paying the pay-out price, those generators are dispatched.

All parameters other than the effective demand, the price of natural gas, the number of (clustered) generation units available, and the RO target met by non-dispatchable RE production are specified exogenously. The price of natural gas is fetched from the gas market sub-model; the number of generation units available is obtained from the generation capacity tracking sub-model. The effective hourly demand and the RO target met by non-dispatchable RE generation are determined by the power demand profile generator sub-model.

Indexes

h	hour of the year
m	months of the year
g	generation type
t	source of import

Parameters

D_h	effective demand of hour h, MW
η^{PS}	efficiency of pumping for pumped storage
$\overline{PS}^{G}$	maximum pumped storage generation capacity, MW
$\overline{PS}^{P}$	maximum pumped storage pumping capacity, MW
R_0	pumped storage reservoir initial level, MWh
$R_{\max}$	maximum reservoir level for pumped storage, MWh
$\bar{P}_g$	maximum generation of a single unit of generator type g, MW
$\underline{P}_g$	minimum generation of a single unit of generator type g, MW
$\Delta P_{\max,g}^{UP}$	maximum ramp up speed, MW/h
$\Delta P_{\max,g}^{DOWN}$	maximum ramp down speed, MW/h
$\bar{I}_t$	maximum interconnector capacity for import source t, MW
γ_g	fuel consumption of generator type g for a cold start-up, MWht
η_g	fuel efficiency of generator type g, MWhe/MWht
$E_g^{CO_2}$	carbon emission associated with fuel use of generator type g, ton CO_2/MWht
$C_m^{CO_2}$	carbon price in month m, \$/ton CO_2
C_g^{OM}	variable operation and maintenance cost for generator type g, \$/MWhe
n_g	number of identical units clustered within type g
B_g	renewable obligation banding for different technologies, certificate/MWhe
RO	overall annual RO target level, RO certificates
RO^{ND}	RO target met by non-dispatchable RE production, RO certificates
P^{BUYOUT}	buyout price established for year, \$/RO certificate
$\Delta p_t^{POWER}\left(I_t\right)$	expected premium/discount for import/export from market t, \$/MWh
$f_{m,g}$	price of fuel for generator type g in month m, \$/MWht
$a_{m,t}$	average monthly price in market t, \$/ MWh

Variables

C_g^{FUEL}	cost of fuel consumed during production and start-ups, \$
C_g^{OTHER}	other cost of power generation (emission and variable O&M), \$
C_t^{IMPORT}	cost of importing power, \$
C^{RO}	cost of RO buy-out, \$
$P_{h,g}$	generation of generator type g during hour h, MW
$I_{h,t}$	import from source t, MW
PS_h^G	generation from pumped storage, MW
PS_h^P	pumping demand for pumped storage, MW
R_h	reservoir level, MWh
Q^{BUYOUT}	quantity of buy-out exercised, MWh
$u_{h,g}$	commitment status of g during month m, sub-period s
$y_{h,g}$	start-up decision of g during hour h
$z_{h,g}$	shut-down decision of g during hour h

Objective function

$$Min\left\{\sum_g\left(C_g^{FUEL}+C_g^{OTHER}\right)+\sum_t C_t^{IMPORT}+C^{RO}\right\} \tag{5.16}$$

Constraints

$$C_g^{FUEL}=\sum_m f_{m,g}\left(\sum_{h\in m}P_{h,g}/\eta_g+y_{h,g}\gamma_g\right) \qquad \forall g \tag{5.17}$$

$$C_g^{OTHER}=\sum_m\sum_{h\in m}P_{g,h}\left(C_m^{CO_2}E_g^{CO_2}/\eta_g+C_g^{OM}\right) \qquad \forall g \tag{5.18}$$

$$C_t^{IMPORT}=\sum_h I_{t,h}\left(a_{m,t}+\Delta p_t^{POWER}\right) \qquad \forall t \tag{5.19}$$

$$C^{RO}=Q^{BUYOUT}P^{BUYOUT} \tag{5.20}$$

$$\sum_g P_{h,g}+\sum_t I_{h,t}+PS_h^G-PS_h^P\geq D_h \qquad \forall h \tag{5.21}$$

$$R_h=R_{h-1}+\eta_{PS}PS^P-PS^G \qquad \forall h \tag{5.22}$$

$$R_h\leq\bar{R} \qquad \forall h \tag{5.23}$$

$$PS_h^G\leq\overline{PS}^G \qquad \forall h \tag{5.24}$$

$$PS_h^P\leq\overline{PS}^P \qquad \forall h \tag{5.25}$$

$$\sum_{h} P_{h,g} B_g + Q^{BUYOUT} \geq RO - RO^{ND} \qquad (5.26)$$

$$P_{h,g} \leq u_{s,g} \overline{P}_g \qquad \forall s,h,g \qquad (5.27)$$

$$P_{h,g} \geq u_{s,g} \underline{P}_g \qquad \forall s,h,g \qquad (5.28)$$

$$I_{h,t} \leq \overline{I}_t \qquad \forall h,t \qquad (5.29)$$

$$u_{s,g} - u_{s-1,g} = y_{s,g} - z_{s,g} \qquad \forall s,g \qquad (5.30)$$

5.2.1.3 Interaction between gas and power markets

In terms of the feedback loop operating between the gas and power markets (L5), the two markets are connected via the iterative convergence algorithm illustrated below:

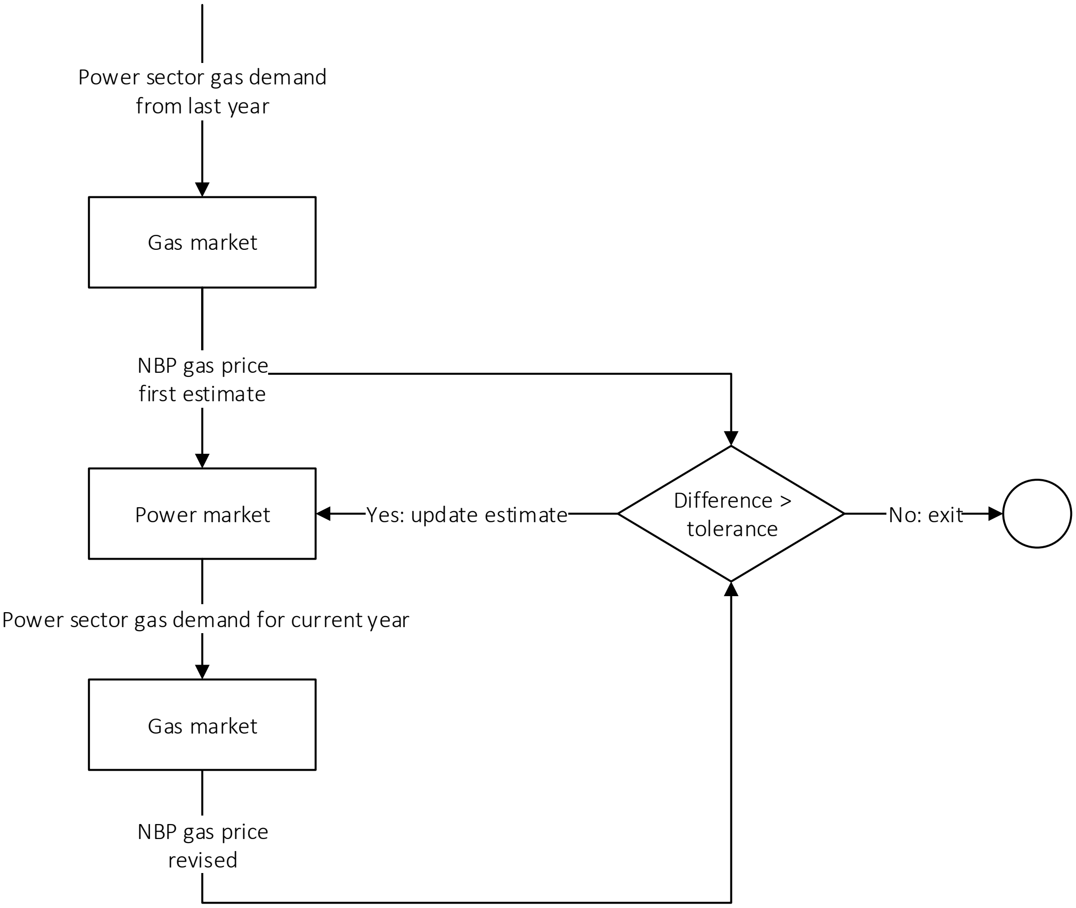

Figure 39: Convergence algorithm between power and gas market sub-models

A first estimate for the market price of gas is determined using the gas market sub-model with power sector gas demand from the previous year, along with other input to the gas market sub-model for the current year. This first price estimate is then fed to the power market sub-model, and the gas demand of the power sector of the current year is determined. While other things remain equal, the gas market sub-model is re-run using the current year's gas demand from the power sector, and a revised gas price is determined. If the difference between the first estimate of gas price and the revised price is smaller than a pre-set tolerance value, the gas and power markets' gas demand and supply is considered to be at equilibrium. If not, the process is repeated, with the revised gas price replacing the first estimate. At equilibrium, the power sector's gas demand for the current year has adjusted to one which is consistent with the current supply and demand situation in the gas market. The representation of power-gas market interaction implicitly assumes that equilibrium between the power and gas markets is achieved immediately within the same year.

In the case that the estimates for gas market price and the revised values are not converging (operationally, this is determined as when three iterations fail to further decrease the difference between the estimates and the revised values), an additional constraint is introduced into the power market sub-model, to limit the magnitude by which power sector gas demand can change from one iteration to the other.

$$0.9D_m^P \leq \sum_{h\in m} \frac{P_{h,gas}}{\eta_{gas}} \frac{3.412MMBTU}{MWh} \frac{Bcm}{37636000MMBTU} \leq 1.1D_m^P \tag{5.31}$$

Here, D_m^P is the power sector gas demand from the previous iteration in Bcm per month, and $P_{h,gas}$ is gas-fired power generation in the current iteration in MWh per month.

5.2.2 Forecasting

The forecasting sub-models are used to convert the output of market sub-models (market price and market shares) and current exogenous variables to expectations that can be processed by the investment decision sub-models, for example expected revenue/costs for given investments. They are the first linkages in loops L2 and L4.

In this thesis, when projecting future values for current variables, an established System Dynamics function developed by Sterman (2000) is used. The TREND function espouses the bounded rationality hypothesis (BRH) to represent expectation formation, instead of the rational expectation hypothesis (REH). Because, the latter assumes that forecasters hold a complete knowledge of the system that they are trying to forecast and form expectations independent of past states, but Sterman (1987, 1988, 2000) has shown that the forecast of many economic variables – energy demand and inflation, for example – can be explained and well replicated by considering only backward-looking rules. Therefore, it is believed that actual forecasting in the real world is a process that can be better described by the BRH rather than the REH; adaptation of rational expectation behaviour by learning might be very slow or unwarranted at all (Olsina et al., 2006).

The function developed by Sterman is extended to yield the forecast of a certain variable given a number of parameters and initial values provided:

$$x_y = TREND\left(TPPC, THRC, TPT, TREND_0, PPC_0, RC_0, x, y\right) \tag{5.32}$$

$$\Delta PPC = \frac{x - PPC_0}{TPPC} \tag{5.33}$$

$$PPC = PPC_0 + \Delta PPC \tag{5.34}$$

$$\Delta RC = \frac{PPC_0 - RC_0}{THRC} \tag{5.35}$$

$$RC = RC_0 + \Delta RC \tag{5.36}$$

$$ITREND = \frac{\left(PPC - RC\right)/RC}{THRC} \tag{5.37}$$

$$\Delta TREND = \frac{ITREND - TREND_0}{TPT} \tag{5.38}$$

$$TREND = TREND_0 + \Delta TREND \tag{5.39}$$

$TPPC$	time to perceive present condition, in time period units
$THRC$	time horizon for reference condition, in time period units
TPT	time to perceive trend, in time period units
$ITREND$	indicated trend
$TREND$	trend perceived
PPC	perceived present condition
RC	reference condition used
y	time horizon for forecast
x	variable value for current year
x_y	forecast of variable over horizon y

When the model is first initialized, the initial value for $TREND_0$ needs to be provided, after which the other initial values are determined as below:

$$PPC_0 = \frac{x_0}{1 + TPPC \times TREND_0} \tag{5.40}$$

$$RC_0 = \frac{PPC_0}{1 + THRC \times TREND_0} \tag{5.41}$$

Here, x_0 is the initial input value.

Once a first loop of the model has been completed, subsequent of values of $TREND_0$, PPC_0 , and RC_0 are taken from the previous run.

Depending on the nature of the variable to be forecasted, two modes are enabled for forecasting with trend perceived, the output of the TREND function. In the first mode, there is ground to believe that the variable being forecasted can grow/decline without constraint, so that the current trend can be extrapolated into the future without constraint.

$$x_y = PPC\left(1+TREND\times TPPC\right)\left(1+TREND\right)^y \qquad (5.42)$$

In the second mode, there is ground to believe that the variable being forecasted is subject to constraint that will slow down its growth/decline, therefore the current growth cannot be extrapolated into the future. Thus, for the forecast, the current trend is scaled down gradually to reach zero by year THRC from the present. Forecast of the variable for years which are in the future beyond the THRC assumed to be constant at the level achieved when y = THRC.

$$x_y = PPC\left(1+TREND\times TPPC\right)\left(1+TREND\right) \qquad \forall y=1 \qquad (5.43)$$

$$x_y = x_{y-1}\left(1+TREND-TREND\left(y-1\right)/THRC\right) \qquad \forall y\le THRC+1 \qquad (5.44)$$

$$x_y = x_{y-1} \qquad \forall y > THRC+1 \qquad (5.45)$$

The use of TREND in forecasting in both modes is illustrated by Figure 40 and Figure 41. In both cases, the forecast is adjusted in time as more current information becomes available. In the unconstrained case, exponential growth leads to very high forecasted value in the case of positive perceived trend, especially in the later years. In the constrained case, the expectation of stabilization of current trend in the future leads to stationary values for forecasts rather than explosive ones.

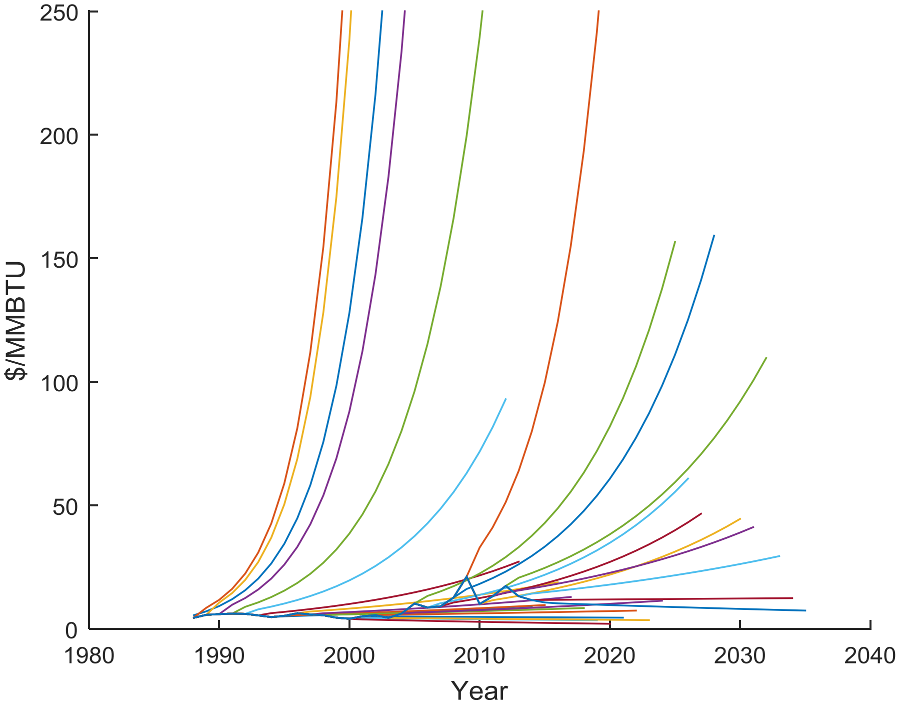

Figure 40: Coal price and forecast of coal price generated under unconstrained mode for 1987-2015

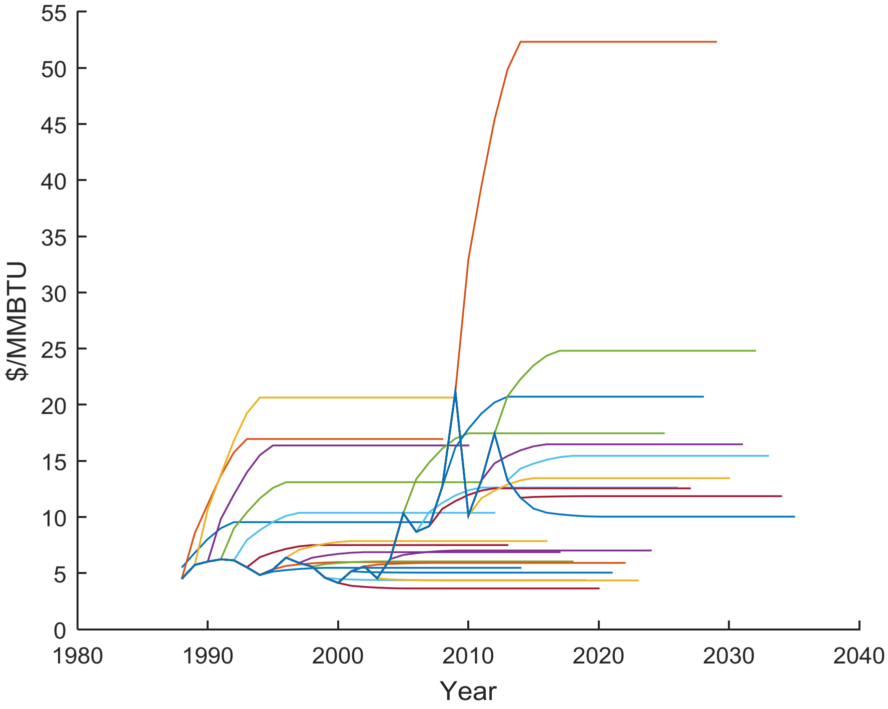

Figure 41: Coal price and forecast of coal price generated under constrained mode for 1987-2015

5.2.2.1 Gas sector forecasting

The variables that need to be forecasted for the gas sector's development decisions are the expected NBP price, the expected unit operating cost, and the production profile of a reservoir of a given size in the first fifteen years of its production life.

For the first two variables, the TREND function described above is used to extrapolate from current values under the constrained mode. Constrained expectation formation mode is selected for both variables, because it is believed that price and cost expectations are constrained: investors do not believe that they will rise exponentially for the forecast period.

As for the production profile of a reservoir of a given size, historic production profiles of UKCS reservoirs have been studied, and correlation between four parameters of a production profile and the corresponding reservoir size is tested[11].

1. Peak year as a function of reservoir size;
2. Number of years in plateau as a function of reservoir size;
3. Relative maximum production as a function of reservoir size;
4. Post-plateau decline rate as a function of reservoir size.

Based on the statistical correlation obtained from historical data, if the reservoir size is available, its relative production profile can be calculated. The actual production profiles of two UKCS fields are shown in Figure 42 to illustrate the typical shapes of production profiles.

In general, larger fields peak later during their production life, their plateau period lasts longer, their decline rate is lower, but their relative maximum production (Maximum production/reservoir size) is lower than smaller reservoirs. The relative production profiles for 20 hypothetical reservoirs with sizes ranging from 1 Bcm to 20 Bcm are calculated using the historical correlations and shown in Figure 43. The lighter is the blue, the smaller is the reservoir size.

For the two fields displayed in Figure 42, their relative production profile forecasted based only on the reservoir size, using historical correlations, are shown alongside their actual (normalized) production profiles (Figure 44). The comparison shows that the forecasted production profiles do capture the essence of production profiles of these fields.

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[11] Since the actual reservoir size is not available among DECC data, the reserve that can be recovered through each reservoir is estimated by extending its production profile assuming constant decline rate, and summing all possible production until the production rate is zero.

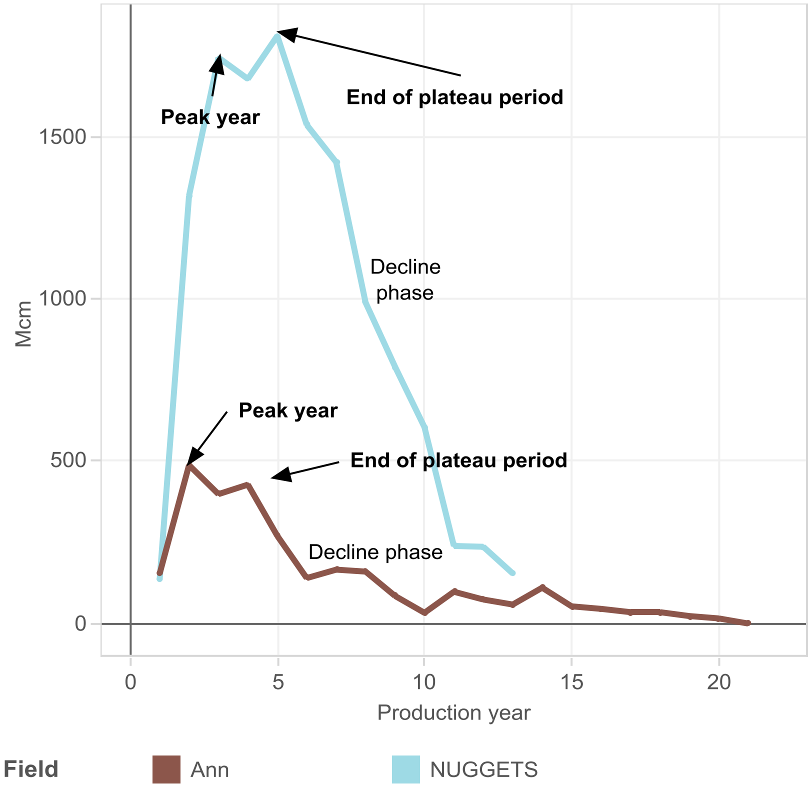

Figure 42: Production profiles for two UKCS fields (Based on data from DECC)

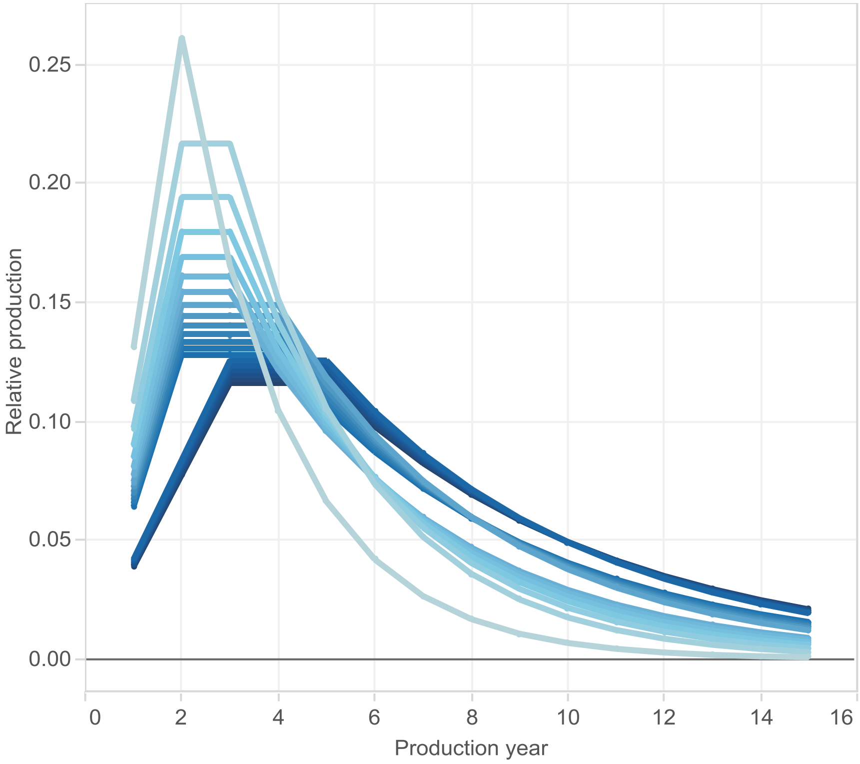

Figure 43: Illustrative relative production profiles

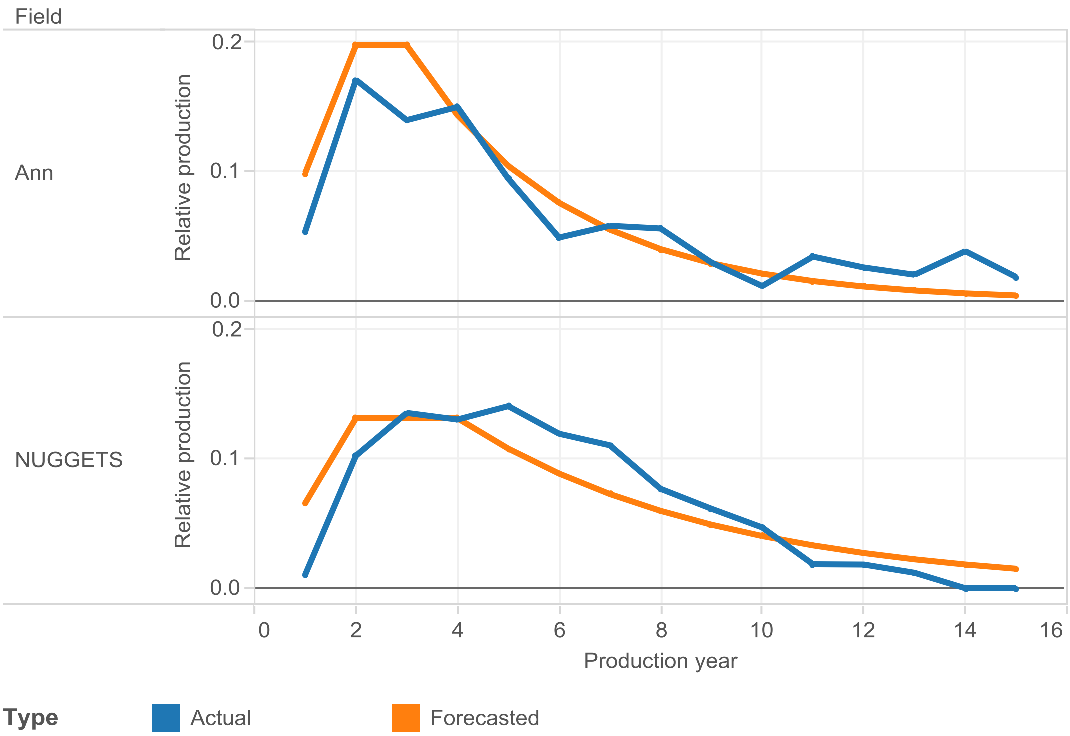

Figure 44: Comparison of production profile forecasts and actual production

5.2.2.2 Power sector forecasting

Of the inputs to the power investment model, expected operating profit from technology g in year y needs to be forecasted, as current information cannot be used directly. The operating profit is the profit that generation owners collect based on their market operations, which is subject to several types of price uncertainties: power price uncertainty, fuel price uncertainty, and carbon price uncertainty. The price at which Renewable Obligation certificates can be sold, underpinned by the Buyout Price set by the government, is also a possible source of change in the industry's operating revenue.

In forecasting the operating revenue of new capacity of different generation technologies, the following expression is used:

$$P^{OP}_{g,y} = \theta_g \sum_h P^{OP}_{g,y,h} \tag{5.46}$$

$$\begin{cases} P^{OP}_{g,y,h} = \max\left\{\pi_{h,y} + R^{RO}_{g,y} - C^{VAR}_{g,y}, 0\right\}, RE^{MECH} = RO \\ P^{OP}_{g,y,h} = \max\left\{\left(P^{STRIKE}_{g,y} - \pi_{h,y}\right) + \left(\pi_{h,y} - C^{VAR}_{g,y}\right), 0\right\}, RE^{MECH} = CFD \end{cases} \tag{5.47}$$

$P_{g,y}^{OP}$	expected operating profit of g in year y, $/MW
θ_g	availability factor of g, % time available in a year
$P_{g,y,h}^{OP}$	expected hourly operating profit of g in year y, $/MW
$\pi_{h,y}$	expected price of power for hour h of year y, $/MWh
$R_{g,y}^{RO}$	expected revenue from sales of RO certificate, $/MWh
$P_{g,y}^{STRIKE}$	expected strike price for contract for difference, $/MWh
$C_{g,y}^{VAR}$	average variable cost of technology g in year y, $/MWh
h	hour in a year

This way of determining operating profit takes into account the price-responsiveness of generation technologies: the integral of the difference between the possible revenue and costs is taken only for hours during which the revenue (from sales of power and regulatory mechanisms) is larger or equal to the variable generation cost of technology g. Because, in the opposite case, the technology will not be dispatched and will not incur the variable cost. The integral of profit from all eligible hours yields the operating profit that can be expected from 1 MW of capacity that is always available, therefore it needs to be adjusted using the availability factor, which reflects unforeseen outages or scheduled maintenance.

In the UK, there are two regulatory mechanisms that are used to incentivise investment in renewable generation: renewable obligations (ROs) and contracts for difference (CFDs). Only one of them is assumed to be in place in any given year, and the expected revenues under the scheme in place is calculated.

The expected revenue from sales of RO certificate is formulated as below:

$$R_{g,y}^{RO} = B_g P_y^{BUYOUT} \qquad (5.48)$$

B_g	banding of technology g, RO certificate/MWh generated
P_y^{BUYOUT}	buy-out price for a RO certificate in year y, $/RO certificate

It is assumed that the price at which generators can sell RO certificate is the buy-out price, the price that a supplier has to pay the government per certificate if its quota is not met.

For generators eligible for the Contract for Difference, they will receive the difference between the strike price and the price of electricity sold, if the latter is lower than the strike price. On the other hand, if the price of electricity is higher than the strike price, they will need to pay out the difference between the price of power and the strike price (See Equation (5.47)). This has the effect of guaranteeing revenue at the strike price.

The variable cost of technology g in year y is determined using the following expression:

$$C_{g,y}^{VAR} = f_{g,y} / \eta_g + C_g^{OM} + C_y^{CO_2} E_g^{CO_2} / \eta_g \qquad (5.49)$$

$f_{g,y}$	expected fuel cost for g in year y, \$/MWht
η_g	fuel efficiency of g, MWhe/MWht
C_g^{OM}	variable operating and maintenance cost for g, \$/MWhe
$C_y^{CO_2}$	expected carbon cost for year y, \$/ton CO_2
$E_g^{CO_2}$	carbon emission associated with fuel use of g, ton CO_2/MWht

Given the procedure presented above, five variables need to be forecasted, so that the expected operating profit for each technology can be determined: $\pi_{h,y}$, P_y^{BUYOUT}, $P_{g,y}^{STRIKE}$, $f_{g,y}$ and $C_y^{CO_2}$. They are forecasted using the TREND function described at the beginning of this section, using these variables' current values as inputs. The constrained expectation formation mode is selected for all.

For the forecasting of the hourly price duration for future years, the shape of the current year's price distribution is taken to be the same, only the annual average is forecasted. Then all values of the current price distribution are adjusted according to the forecasted annual average price of power:

$$\pi_{h,y} = \pi_{h,0} \bar{\pi}_y / \bar{\pi}_0 \qquad (5.50)$$

$\pi_{h,0}$	hourly price for hour h in current year
$\bar{\pi}_y$	forecast of annual average power price for year y, \$/MWh
$\bar{\pi}_0$	annual average power price for current year, \$/MWh

For co-firing and biomass, given that they are based on conversion from existing coal generation units, the expected operating profit needs to take into consideration the opportunity cost of performing the conversion. Therefore, their operating profit forecast is the difference between of their operating profits after conversion and their operating profits before conversion (i.e. the operating profits of coal power plants).

5.2.3 Investment decisions

Together, with the forecasting sub-models, the investment decision models for UKCS gas production and for power generation complete the remaining causal loops: L2 and L4. They describe how the gas and power industries make long-term capital allocation decisions based on market signals. Adequate mathematical representation of the investment decisions need to specify what projects are developed, given a given set of market outlook, investor preferences and capital availability.

The investment decision sub-models allocate funds available to different power generation/gas production projects to maximized the net present value of investments based on discounted cash flow analysis. Unlike SD work in literature which overwhelmingly use a modeller specified scaling factor/function to relate the expected profitability (IRR over hurdle rate) to a specific amount of investment, this thesis proposes the use of linear programming optimization functions to allocate investment funds available to different technologies or different reservoirs, given their different revenue and cost expectations. Another key distinguishing characteristic of the investment decision models used is the endogenous nature of capital availability. Instead of imposing an exogenously specified upper limit for investment, the capital available for investment is determined as a fraction of industry cash flow, which is calculated endogenously for each year.

Because the goal of this thesis is to investigate the long-term investment at the industry level, instead investigating the distribution of income/investment within the industry, an industry-level aggregation of companies' investments is judged to be reasonable. The investment decisions are not differentiated by firms. In other words, it is assumed that all firms considering investment in the upstream power or gas sectors have access to and use the same forecasted information, similar discount rates, and have similar capital reallocation strategy.

5.2.3.1 UKCS gas development

The UKCS gas development decision specifies, for the next year, which reservoirs are developed among the portfolio of reservoir available, given gas market price forecasts, costs, and total fund available. The gas producers are represented as profit maximizing agents who select projects on the basis of NPV maximization. The NPV of a developed reservoir is the difference between the present value of expected sales, operating expenses, and depreciation of the initial investment. If the NPV for a given reservoir development is negative or zero, then the investment will not take place. In the case that there is no reservoir available for investment, investment will also not take place. If the NPVs for the development of multiple reservoirs are positive, then they are selected in the order of decreasing NPV while the total investment cap is not met.

The portfolio of reservoir available for development are represented in terms of the reserves that they contain, and the production profiles that are possible from these reservoirs. The production profiles are derived using historical correlations between (estimated) UKCS reservoir size and their actual production. They are expressed in relative terms (normalized using reserve size). The exact procedure has been described in the sub-section on forecasting. As a key simplification, no distinction is made between the different types of reserves (proven, probable, and possible). This is common in bottom-up oil/gas production models (Jakobsson, Söderbergh, Snowden, & Aleklett, 2014). Each year, all reservoir in the portfolio is examined for development, including those that are discovered in previous years but have not been developed. Due to data availability, reservoirs are not differentiated in terms of development cost and operating cost; instead, a UKCS-wide value is used.

In determining the expected revenues, it is assumed that all incremental production resulting from the UKCS, after deducting the producers' own consumption, can be sold at the expected hub price. Among the expected costs, the operating cost is forecasted, while the development cost is depreciated as a function of reservoir depletion: the overall development cost is attributed to each year based on the proportion of total production occurring in each year. This allows the investment decision model to deal with potential investment with different lifetimes: If a reservoir is not depleted completely by year 15, then only the fraction of development costs that is proportional to production within these years will have been depreciated.

All parameters except for expected NBP price, relative production profile of reservoir b in year y, undeveloped reserves available in reservoir b, expected unit operating cost, and cap for development investment are specified exogenously. The expected NBP price, expected unit operating cost, and production profile of reservoir b in year y are obtained from the gas sector forecasting sub-model. The undeveloped reserves available in reservoir b is obtained from the gas reserve and production capacity tracking sub-models. Finally, the cap for development investment is obtained from the gas sector cash flow tracking sub-model.

Index

y	year in consideration
b	index of reservoir within portfolio

Parameters

P_y^{NBP}	expected NBP price in year y, $/MMBTU
η^{UKCS}	efficiency of gas production, Bcm marketed/ Bcm produced
v	calorific value, 37636000 MMBTU/Bcm
$Q_{y,b}^{RELATIVE}$	relative production profile, Bcm produced/Bcm reserve developed
C_y^P	expected unit operating cost, $/Bcm
C^D	current development cost of reserves, $/Bcm
$\bar{C}^{DEV}$	cap for development investment for current year, $
$\bar{E}_b$	undeveloped reserves available in field b, Bcm
T	tax rate effective for UKCS gas producers
F_y^{GAS}	discount factor used by UKCS gas producers for year y

Variables

NPV_b	net present value of field b, $
F_y	discount factor to convert cash flow in year y to present value

$R_{y,b}$	revenue from sales of production from field b in year y, \$
$C_{y,b}^{op}$	operating cost of field b in year y, \$
$A_{y,b}$	depreciation of development cost of field b in year y, \$
$Q_{y,b}$	production of gas from field b in year y, Bcm
C_b^{dev}	development cost for field b, \$
E_b	new reserves developed for production, Bcm
n_b	development status of field

Objective function

$$Max\sum_b NPV_b \tag{5.51}$$

Constraints

$$NPV_b = \sum_y F_y^{GAS}\left[R_{y,b} - C_{y,b}^{op} - A_{y,b}\right](1-T) \qquad \forall b \tag{5.52}$$

$$R_{y,b} = P_y^{NBP}\eta^{UKCS} v Q_{y,b} \qquad \forall y,b \tag{5.53}$$

$$Q_{y,b} = Q_{y,b}^{RELATIVE} n_b \bar{E}_b \qquad \forall y,b \tag{5.54}$$

$$C_{y,b}^{op} = C_y^P Q_{y,b} \qquad \forall y,b \tag{5.55}$$

$$A_{y,b} = C_b^{dev} Q_{y,b}^{RELATIVE} \qquad \forall y,b \tag{5.56}$$

$$C_b^{dev} = n_b \bar{E}_b C^D \qquad \forall b \tag{5.57}$$

$$n_b \geq 1 \qquad \forall b \tag{5.58}$$

$$\sum_b C_b^{dev} \leq \bar{C}^{DEV} \tag{5.59}$$

5.2.3.2 Power generation investment

The power generation investment decision sub-model specifies, for the next year, investments in different generation technologies, once revenues forecasts, costs, and investment fund availability are known. The power generators are represented as profit maximizing agents who select projects on the basis of NPV maximization. The NPV of a generation investment is the difference between the present value of expected operating profits (net of variable operating cost), fixed costs, and depreciation of the initial investment. If the NPV for investments in a technology is negative, or the remaining investment funds cannot support a typical size project, then the investment will not take place. If the NPVs for investment in more than one type of generation technology are positive, then investment in these technologies occur the order of decreasing NPV while the total investment cap is not met.

It is assumed that investments in different generation technologies can only take place in incremental sizes that are multiple of typical project sizes. Economies of scale in project sizes is neglected, by using a constant investment cost regardless of the capacity commissioned. The investment costs of different generation capacities are depreciated linearly over their economic lifetime. This allows the investment decision model to deal with potential investment with different lifetimes. By the end of year 15, for generation technologies with an economic life time of 25 years and 40 years, for example, 15/25 and 15/40 of total investment costs will have been depreciated, therefore generation projects with longer economic lifetimes are not unduly penalized.

The expected revenues and costs for co-firing and biomass generation technologies included are based on plant conversion from existing coal power plants. An upper limit is set on the number of coal plants that can be shut-down for conversion to co-firing or full biomass firing in each year.

All parameters, except for the expected operating profit for each technology in future years and the cap on total investment in the industry, are specified exogenously. The details about the determination of expected operating profit can be found in the sub-section on forecasting. The cap on total investment is determined in the power sector cash flow tracking sub-model.

Index

y	year in consideration	/1*15/
g	type of generation	/Nuclear, Coal, Gas, Co-firing, Biomass, OSW, OFW, PV/

Parameters

$P_{g,y}^{OP}$	expected operating profit from technology g in year y, \$/MW
θ_g	available factor for technology g, MW available/MW
$P_y^{CAPACITY}$	current capacity price awarded to new capacity, \$/MW available
C_g^F	fixed cost for technology g in each year, \$/MW
C_g^I	investment cost for technology g, \$/MW
T_g^C	construction time required for technology g, year
T_g^L	economic lifetime of technology g, year
$X_{0,g}$	capacity basis for fixed cost in year 0, MW
$\bar{C}^{INV}$	cap on total investment in the industry in a year
$d\underline{X}_g$	standard size for incremental investment in g, MW
$F_{g,y}^{POWER}$	discount factor for technology g in year y, $1/(1+d_g)^y$
$\bar{n}^{CONVERSION}$	maximum number of units converted from coal plans

Variables

C_g^{inv}	investment made for technology g in upcoming year, $
n_g	units of g accepted for investment
$X_{g,y}$	capacity of technology g in year y, MW
$dX_{g,y}$	capacity to come online from investment in year y, MW
$A_{g,y}$	annual depreciation for investment in year y, $

Objective function

$$Max \sum_y \sum_g F_{g,y} \left[\left(P_{g,y}^{OP} + \theta_g P_y^{CAPACITY} - C_{F,g} \right) X_{g,y} - A_{g,y} \right] \qquad (5.60)$$

Constraints

$$X_{g,y} = X_{g,y-1} + dX_{g,y} \qquad \forall g, y \qquad (5.61)$$

$$dX_{g,T_{Cg}} = n_g d\underline{X}_g \qquad \forall g \qquad (5.62)$$

$$C_g^{inv} = n_g d\underline{X}_g C_g^I \qquad \forall g \qquad (5.63)$$

$$\sum_g C_g^{inv} \le \bar{C}^{INV} \qquad (5.64)$$

$$A_{g,y} = C_g^{inv} / \left(T_g^C + T_g^L \right) \qquad \forall g, y \le \left(T_g^C + T_g^L \right) \qquad (5.65)$$

$$A_{g,y} = 0 \qquad \forall g, y > \left(T_g^C + T_g^L \right) \qquad (5.66)$$

$$n_{Cofiring} + n_{Biomass} \le \bar{n}^{CONVERSION} \qquad (5.67)$$

5.2.4 Infrastructure stocks

The infrastructure stocks are sub-models that track the change in infrastructure from one year to another, based on initial condition and change that took place during the last year (both endogenous commissioning and exogenous decommissioning/depletion of capacity). They are the intermediates between investment decision sub-models and the market sub-models, completing loops L2 and L4.

5.2.4.1 Gas reserve tracking

In order for the UKCS gas development sub-model to make temporally consistent decisions, the stock of already discovered reserves in the form of a portfolio of reservoirs that are available for development need to be tracked.

The exploration process is modelled separately from the gas development decision, because it is considered a pre-requisite for development decision making. It is also an activity that has much less certain outcomes, where probability needs to be taken into account. In this thesis, it is assumed that the gas producing companies decide their exploration efforts based on their annual cash flow. Then, the outcome of the exploration wells is determined based on probability distributions derived from historical results.

A historical correlation has been found between the cash flow of the UKCS gas producers and the number of exploration wells drilled. This relationship is used to specify the number of exploration wells drilled in the same year. At the same time, there is a cap on how much can be spent on exploration, which is a fixed proportion of the industry cash flow (as with development investment), as future rising costs of exploration might limit the total numbers of exploration wells that can be drilled, despite the historical correlation.

$$dN_y^E = \min\left(\bar{C}_y^{EXP} / C_y^E \, , dN_y^E\left(CF_y^{UKCS} \right) \right) \tag{5.68}$$

dN_y^E	number of exploration wells drilled in current year
$\bar{C}_y^{EXP}$	UKCS exploration investment cap for current year, \$
C_y^E	cost per exploration well in current year, \$
CF_y^{UKCS}	annual operating cash flow of UKCS gas producers, \$

The tracking of reserves discovered is made up of two steps: first, reserves that have been earmarked for development based on investment decision of last year is removed from the inventory; secondly, current year's addition to reserves is determined from exploration efforts. The updated inventory of undeveloped reserve at the end of these two steps is passed onto the gas production development decision sub-model, for a new round of assessment.

For the first step, the development decision is fetched as the lagged output of the gas production development sub-model.

$$E_{b,y}^D = E_{b,y-1}^D - dE_{b,y}^D \qquad \forall b \le N_{y-1}^E \tag{5.69}$$

$$dE_{b,y}^D = dn_{b,y-1} E_{b,y-1}^D \tag{5.70}$$

b	index of exploration well drilled
y	year of simulation
N_{y-1}^E	cumulative number of exploration wells drilled by the end of last year
$E_{b,y}^D$	inventory of undeveloped reserve for well n for current year, Bcm
$E_{b,y-1}^D$	inventory of undeveloped reserve for well n from last year, Bcm
$dE_{b,y}^D$	reserves earmarked for development in year y, Bcm
$dn_{b,y-1}$	development decision for reserve associated with well b made last year

For the second step, once the number of newly drilled exploration wells is known the outcome of these efforts is determined as the product of drilling success and reservoir size.

$$E^{D}_{b,y} = p^{S}_{b,y} E^{F}_{b,y} \qquad \forall N^{E}_{0} < b \le N^{E} + dN^{E} \qquad (5.71)$$

$$N^{E}_{y} = N^{E}_{y-1} + dN^{E}_{y} \qquad (5.72)$$

$p^{S}_{b,y}$ drilling success of well n in current year

$E^{F}_{b,y}$ discovered reservoir size for well n in current year, Bcm

Drilling success is sampled randomly from a binomial distribution $B(1,s)$ where s is the success probability, and reservoir size is sampled randomly from a lognormal distribution $\ln \mathrm{N}\left(\bar{E},\sigma^{2}\right)$, where $\bar{E}$ is the average size of reservoir discovered, and σ the standard deviation for size of reservoir discovered. The seed of the random number generator is specified for each year, so the random sampling process is repeatable.

5.2.4.2 Gas production capacity tracking

The maximum production capacity available from the UKCS, dependent on the commissioning of newly developed reservoirs and the depletion of already producing reservoirs, needs to be tracked across simulation time periods, for it interacts with the gas market sub-model in articulating the final gas market price and the shares of different supplies. The tracking of developed production capacity is made up of three steps: first, reserves that have been developed in the last year is added to the production stack; secondly, gross production capacity available from the cumulated production stack is determined. Finally, the net production capacity available from the UKCS is passed on to the gas market sub-model, and set to be the annual contract quantity for UK-sourced gas. This assumes that all production from the UKCS is sold under long-term contracts, with an annual contract quantity that is adjusted to reflect the production capacity of the UKCS fields.

For the first step, the newly added reserves are taken to be the lagged output of the reserve tracking sub-model, so that any reservoir is commissioned two years after a development decision has been made concerning it. The reserves commissioned in years before the simulation starts, which are still producing ($E^{P}_{b,y'<y}$), are specified exogenously.

$$E^{P}_{b,y'} = dE^{D}_{b,y'-1} \qquad \forall y' \ge y \qquad (5.73)$$

$E^{P}_{b,y'}$ reserves associated with well b which is commissioned in year y', Bcm

y' commissioning year

y year in simulation

A reservoir's achievable production capacity in any year is simplified to be a function of time since its commissioning year and its size. If the size of reservoir is known, then the four parameters of its production profile is specified using the historical correlations, previously presented in the sub-section on gas sector forecasting. However, technological improvement or unexpected deterioration is allowed through the addition of an exogenous term to modify the decline rate based on historical correlation. The modifier is applied to all reservoirs equally; it does not differentiate between field-specific improvement/deterioration. Then, its gross production capacity in any year following commissioning can be derived from these four parameters.

The net production available in each simulation year is the difference between gross production possible from all reservoirs active and the producers' own production, which depends on the gross production rate.

$$Y_b^{PEAK} = f\left(E_{b,y}^{P}\right) \tag{5.74}$$

$$Y_b^{PLATEAU} = g\left(E_{b,y}^{P}\right) \tag{5.75}$$

$$Q_b^{MAX} = h\left(E_{b,y}^{P}\right) \tag{5.76}$$

$$\tau_b = j\left(E_{b,y}^{P}, d\tau_y\right) \tag{5.77}$$

$$Q_{b,y}^{GROSS} = \frac{y-y'}{Y_b^{PEAK}} Q_b^{MAX} \qquad \forall y-y' \le Y_b^{PEAK} \tag{5.78}$$

$$Q_{b,y}^{GROSS} = Q_{b,y-1}^{GROSS} \qquad \forall y-y' < Y_b^{PEAK} + Y_b^{PLATEAU} \tag{5.79}$$

$$Q_{b,y}^{GROSS} = Q_{b,y-1}^{GROSS}\left(1-\tau_b\right) \qquad \forall y-y' \ge Y_b^{PEAK} + Y_b^{PLATEAU} \tag{5.80}$$

$$Q_y^{NET} = \sum_b Q_{b,y}^{GROSS} - Q_y^{OWN-USE} \tag{5.81}$$

Y_b^{PEAK}	peaking year for reservoir b
$Y_b^{PLATEAU}$	number of years in plateau for b
Q_b^{MAX}	maximum production rate for b
τ_b	decline rate post-plateau for b
$d\tau_y$	decline rate modifier for year y
$Q_{b,y}^{GROSS}$	gross production rate of reserve associated with b in year y, Bcm
Q_y^{NET}	net production rate of all reservoirs in year y, Bcm
$Q_y^{OWN-USE}$	UKCS producers' own use of gas, Bcm

5.2.4.3 Power generation capacity tracking

The generation capacity available in the power sector needs to be tracked across simulation time periods. It is dependent on the commissioning of newly developed generation projects and the decommissioning of existing generation capacity. In this sub-model, generation capacity that has reached the end of the development pipeline is added to the generation stack, decommissioned capacity, if any, is removed from the generation stack. After that, the generation capacity available in the form of number of generation units available, clustered by generation technology, is passed on to the power market sub-model.

$$n_{g,y} = n_{g,y-1} + dn_{g,y} - \delta n_{g,y} \qquad (5.82)$$

$n_{g,y}$ number of generation units of type g in year y

$dn_{g,y}$ newly commissioned generation units of type g in year y

$\delta n_{g,y}$ decommissioned generation units of type g in year y

Currently, the decommissioned generation units in each year is specified exogenously: the decommissioning decision is not within the modelling scope. And, production capacity earmarked for decommissioning is removed from the production stack immediately.

In order to track the investment decision that comes online with a delay of non-uniform construction time, a queue of capacity under construction is set up. Once an investment decision has been made, the capacity is sent to the queue with a length that corresponds to its construction time. The queue is update annually, advancing all projects in queues by one position, those which have reached the first position in the queue is commissioned. Every year, new investment decisions are also added to the queue.

$$dn_{g,y} = q_{g,y,1} \qquad (5.83)$$

$$q_{g,y,T} = dq_{g,y,T^C+1} + q_{g,y-1,T+1} \qquad (5.84)$$

T construction time tracking index

$q_{g,y,1}$ generation projects which have finished construction

$q_{g,y,T}$ queue of generation projects under construction

dq_{g,y,T^c+1} newly added generation investments to the construction queue

5.2.4.4 Tracking of exogenous capacity changes

Other infrastructure stocks which need to be tracked are gas storage capacity, gas import capacity, and power import capacity. Being out of the scope of this thesis, investments and decommissioning of these infrastructure are not represented endogenously. However, exogenously specified changes are accommodated. The change in these capacities can be specified by the model user. They may be changed as part of a sensitivity or scenario analysis.

$$\bar{Q}_{t,y} = \bar{Q}_{t,y-1} + d\bar{Q}_{t,y} \qquad (5.85)$$

$$\bar{I}_{t,y} = \bar{I}_{t,y-1} + d\bar{I}_{t,y} \qquad (5.86)$$

$\bar{Q}_{t,y}$	Gas supply infrastructure capacity from/to t in year y, Bcm/month
$d\bar{Q}_{t,y}$	Change in gas supply infrastructure capacity from/to t in year y, Bcm/month
$\bar{I}_{t,y}$	Power interconnector capacity from/to t in year y, MW
$d\bar{I}_{t,y}$	Change in power interconnector infrastructure capacity from/to t in year y, MW

The case of gas storage is slightly different: gas storage capacity has three important parameters, other than the working gas volume (the maximum capacity of gas that can be stored), there is also the injectability limit and the withdrawability limit. They are functions of the nature of the storage reservoir (depleted gas field, solution-mined salt caverns, or LNG peak shaving facilities) and its capacity, to a less extent. In this thesis, the injectability and withdrawability limit of newly added storage capacity is derived from the type and capacity of reservoir capacity added. They are not specified by the model-user directly.

$$\bar{H}_{k,y} = \bar{H}_{k,y-1} + d\bar{H}_{k,y} \qquad (5.87)$$

$$\bar{W}_{k,y} = f\left(\bar{H}_{k,y}\right) \qquad (5.88)$$

$$\bar{J}_{k,y} = g\left(\bar{H}_{k,y}\right) \qquad (5.89)$$

$\bar{H}_{k,y}$	maximum working gas storage capacity, Bcm
$d\bar{H}_{k,y}$	change in maximum working gas storage capacity, Bcm
$\bar{W}_{k,y}$	withdrawability limit, Bcm/month
$\bar{J}_{k,y}$	injectability limit, Bcm/month

5.2.5 Cash flow

In addition to the infrastructure stocks, which are tracked to connect investment decisions to markets, industry cash flows are also tracked to relate market outcome with investment, in addition to market price and market shares. This is the equivalent of assuming that the industry's access to capital is affected by its financial performance. For this thesis, it is assumed that the capital that can be accessed by an industry for investment is a linear function of its operating cash flow: a fixed percentage of the operating cash flow sets the threshold for investment in the same year can be specified by the model-user.

$$\bar{C}^{EXP} = \varepsilon CF^{UKCS} \tag{5.90}$$

$$\bar{C}^{DEV} = \delta CF^{UKCS} \tag{5.91}$$

$$\bar{C}^{INV} = \mu CF \tag{5.92}$$

$\bar{C}^{EXP}$	UKCS exploration investment cap, \$
$\bar{C}^{DEV}$	UKCS development investment cap, \$
$\bar{C}^{INV}$	UK Power generation investment cap, \$
CF^{UKCS}	annual operating cash flow of UKCS gas producers, \$
CF	annual operating cash flow of UK power generators, \$

ε, δ, μ are exogenously specified constants

5.2.5.1 UKCS gas production cash flow

The operating cash flow of the UKCS gas producers is the difference between the total operating revenue of gas producers and their operating costs.

$$CF^{UKCS} = R^{UKCS} - C^{OP,UKCS} \tag{5.93}$$

R^{UKCS}	annual revenue for UKCS gas producers, \$
$C^{OP,UKCS}$	annual operating costs for UKCS gas producers, \$

For any simulation year, the total revenue of gas producers is the product of the gas supplied by the UKCS and the gas market price at which they are supplied, while their operating costs are calculated as the product of unit operating cost and the quantity of gas supplied. Given the granularity of data available, the unit operating cost is assumed to include variable as well as fixed operating cost.

$$R^{UKCS} = \sum_m S_{m,UK} v p_m^{NBP} \tag{5.94}$$

$$C^{OP,UKCS} = \sum_m S_{m,UK} C^P \tag{5.95}$$

$S_{m,UK}$	gas supplied by the UKCS in month m of year, Bcm/month
v	calorific value, MMBTU/Bcm

p_m^{NBP} gas market price for month m of year, $/MMBTU

C^P unit operating cost for current year, $/Bcm

5.2.5.2 Power generation cash flow

The operating cash flow of the UK power generators is the difference between the total operating revenues of power generators and their operating costs.

$$CF = R - C^{OP} \tag{5.96}$$

CF annual revenue for UK power generators, $

C^{OP} annual operating costs for UK power generators, $

Compared to the gas sector, the determination of the operating cash flow for the power generation sector is more complicated, because the total revenue of the power generation segment consists of multiple sources of market and regulatory income. All generation capacity receives the market price for their production. In addition, those that are eligible to special regulatory schemes receive additional regulatory revenue. Current generating capacity can be registered under either the RO or the CfD scheme, depending on the regulatory mechanism in place when the investment is made. The capacity generating under these schemes are tracked in aggregate and separately in the power generation capacity tracking sub-model. In the determination of revenues and costs, it is assumed that the share of generation for generators registered under different schemes is proportional to their share in the total generation capacity.

$$R = R^{RO} + R^{RO,market} + R^{CFD} + R^{CFD,market} + R^{CAPACITY} \tag{5.97}$$

R^{RO} annual regulatory income from RO, $

$R^{RO,market}$ annual market income of capacity under RO, $

R^{CFD} annual regulatory income from CfD, $

$R^{CFD,market}$ annual market income of capacity under CfD, $

$R^{CAPACITY}$ annual income from capacity payments, $

The generators' market income is determined as the product of their hourly generation and the corresponding hourly market price.

$$R^{RO,market} = \sum_g \sum_h P_{h,g} \pi_h \frac{n_g^{RO}}{n_g^{RO} + n_g^{CFD}} \tag{5.98}$$

$$R^{CFD,market} = \sum_g \sum_h P_{h,g} \pi_h \frac{n_g^{CFD}}{n_g^{RO} + n_g^{CFD}} \tag{5.99}$$

$P_{h,g}$ power generated by technology g in hour h, MWh

π_h	power market price for hour h, \$/MWh
n_g^{RO}	units of technology g registered under RO
n_g^{CFD}	units of technology g registered under CfD

For generation capacity under the RO scheme, the regulatory revenue come from the sales of renewable obligation certificates assigned to the eligible generation. For generation under the CfD scheme, the regulatory revenue is the difference between the enforced strike price and the market price for the eligible generation. The revenue from capacity payment is the product of a universal capacity price (if it is in place) and the availability factor of different type of technologies.

$$R^{RO} = \sum_g \sum_h P_{h,g} B_g P^{BUYOUT} \frac{n_g^{RO}}{n_g^{RO} + n_g^{CFD}} \tag{5.100}$$

$$R^{CFD} = \sum_g R_g^{CFD} \tag{5.101}$$

$$R_g^{CFD} = \sum_h \left(P_g^{STRIKE} - \pi_h \right) P_{h,g} \frac{n_g^{CFD}}{n_g^{RO} + n_g^{CFD}} \qquad \forall P_g^{STRIKE} > 0 \tag{5.102}$$

$$R_g^{CFD} = 0 \qquad \forall P_g^{STRIKE} = 0 \tag{5.103}$$

$$R^{CAPACITY} = \theta_g P^{CAPACITY} n_g d\underline{X}_g \tag{5.104}$$

B_g	RO banding for technology g, RO certificates/MWh
P^{BUYOUT}	buy-out price for RO certificates, \$/RO certificate
P_g^{STRIKE}	strike price for technology g under CfD, \$/MWh
θ_g	availability factor of technology g, MW available/MW installed
$P^{CAPACITY}$	capacity payment, \$/MW available
n_g	number of units installed of technology g
$d\underline{X}_g$	standard size for incremental investment in g, MW

The total cost of the power generation segment consists of costs passed on from the market sub-model: fuel costs, start-up costs, emission costs and variable operating costs. In addition, fixed operating costs are also included.

$$C^{OP} = \sum_g C_g^{FUEL} + C_g^{OTHER} + C_g^F n_g d\underline{X}g \tag{5.105}$$

C_g^{FUEL}	cost of fuel consumed during production and start-ups, \$
C_g^{OTHER}	other cost of power generation (emission and variable O&M), \$

C_g^F	fixed operating cost for g, $/MW installed

5.2.6 Demand profiles

The demand profile generators are sub-models that translate hypothesized demand trends to demand profiles which can be fed to the market sub-models. Through the use of deterministic hourly or monthly templates, the demand profile generators are able to convert average annual trends to hourly/monthly demands or embedded generation.

5.2.6.1 Non-power sector gas demand

The monthly values of non-power sector gas demand for the simulation period 2011-2030 is generated taking into consideration potentially different trends in its four components: local distribution zones (LDZ) demand, industrial demand, exports to Ireland, and (direct offshore) exports to the Netherlands from select fields.

$$D_m^{NP} = D_m^{LDZ} + D_m^{IND} + D_m^{ExIRL} + D_m^{ExNL} \qquad (5.106)$$

The four monthly demand series are obtained by multiplying an annual template with monthly resolution with an annual trend. The year on which the annual template is based on is 2012: the historic monthly series for LDZ demand, industrial demand, export to Ireland and to the Netherlands are de-trended by dividing them by their 12-month moving average (Figure 45).

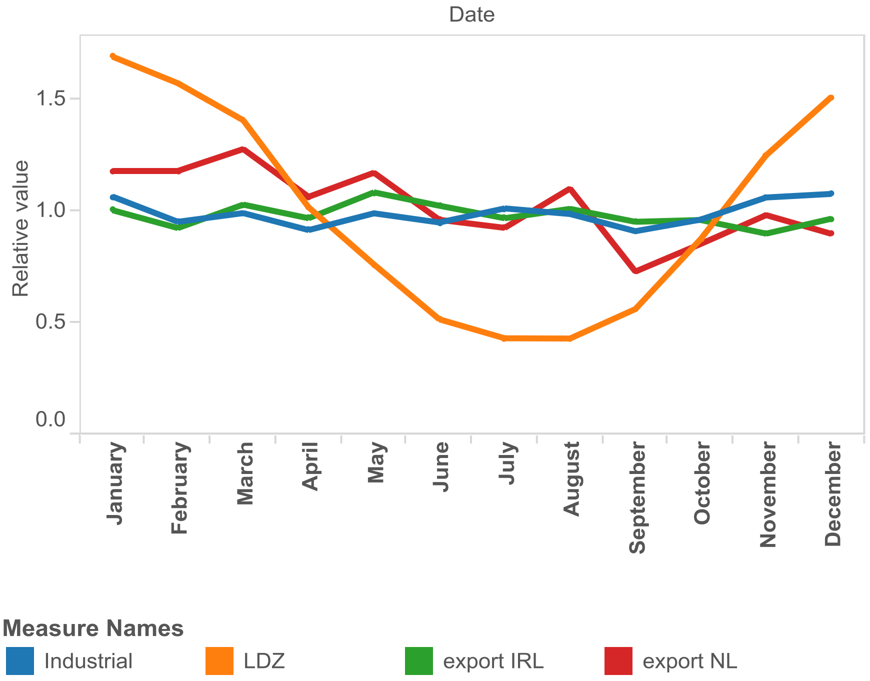

Figure 45: Monthly templates used for non-power sector gas demand profile generation

The annual trend values four these four types of demand are specified exogenously and interpolated between years, so that the trend at each month is:

$$T_{m,y} = \bar{T}_{y-1} + \frac{\left(\bar{T}_y - \bar{T}_{y-1}\right)}{12} m \qquad (5.107)$$

$T_{m,y}$	annual trend in year y for month m, Bcm/month
$\bar{T}_{y-1}$	annual average trend for year y-1, Bcm/month
$\bar{T}_y$	annual average trend for year y, Bcm/month
m	month of year (out of 12)

5.2.6.2 Effective power demand

The effective power demand D_h, the demand that needs to be met in the power market sub-model, is partially endogenously specified in the model. The effective demand is the difference between total power demand in the UK and the available generation from non-price responsive sources (non-dispatchable, intermittent RE generation).

$$D_h = D_h^{TOTAL} - (P_h^{EWIND} + P_h^{ESOLAR} + P_h^{WIND} + P_h^{PV} + P_h^{HYDRO}) \qquad (5.108)$$

D_h^{TOTAL}	total hourly demand in the UK, MW
P_h^{EWIND}	embedded hourly wind generation, MW
P_h^{ESOLAR}	embedded hourly solar generation, MW
P_h^{WIND}	hourly transmission grid wind generation, MW
P_h^{PV}	hourly transmission grid PV generation, MW
P_h^{HYDRO}	hourly (non-pumped storage) hydro generation, MW

For all hourly demand/generation series except for P_h^{HYDRO}, the final values are calculated by multiplying an annual template with hourly resolution with an annual trend. The year on which the annual template is based on is 2012: the hourly series for total demand, embedded wind, embedded solar, and wind in 2012 are de-trended by dividing them by their 8760-hour moving average (for total demand), or by dividing them by their estimated installed capacity (solar and wind) (Figure 46).

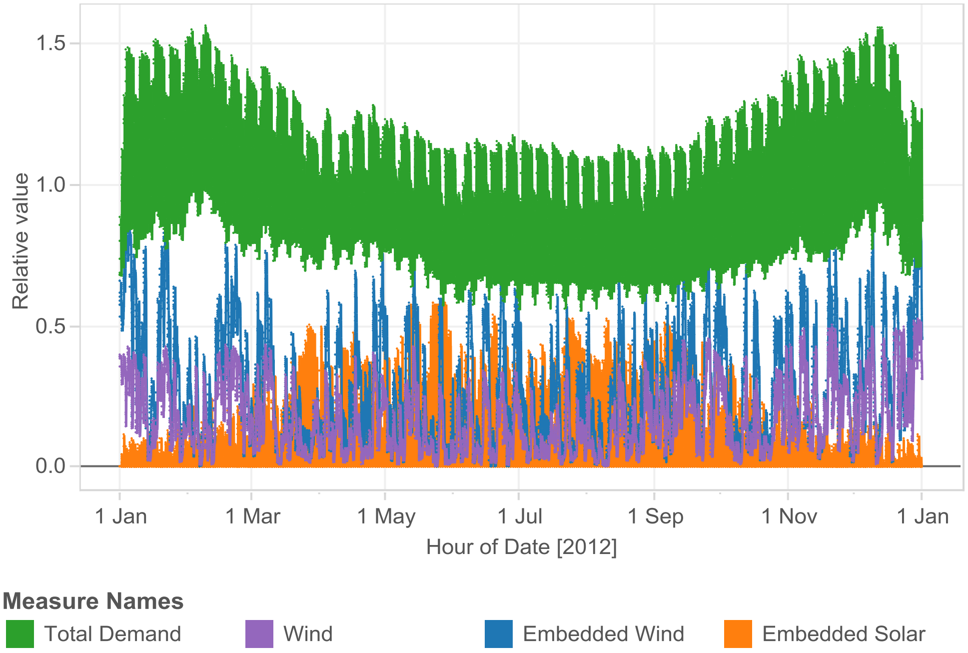

Figure 46: Hourly templates used for power demand profile generation

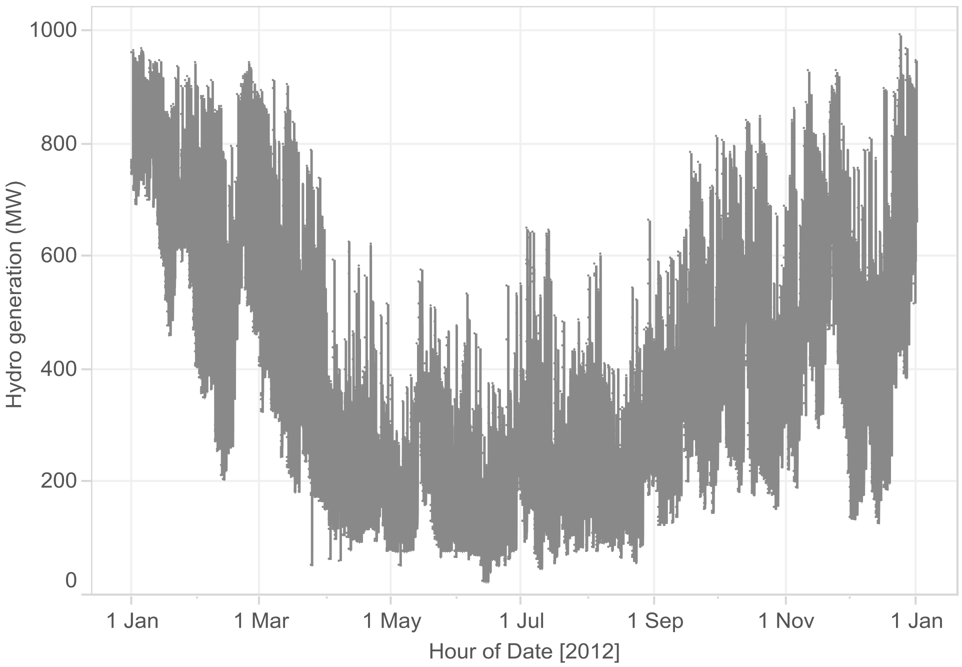

Figure 47: Hourly values for non-pumped storage hydro generation

The annual trend to which they are multiplied are interpolated between years, so that the trend at each hour is:

$$T_{h,y} = \bar{T}_{y-1} + \frac{\left(\bar{T}_y - \bar{T}_{y-1}\right)}{8760} h \qquad (5.109)$$

$T_{h,y}$	trend/installed capacity in year y for hour h, MW
$\bar{T}_{y-1}$	annual average trend/capacity for year y-1, MW
$\bar{T}_y$	annual average trend/capacity installed for year y, MW
h	hour of year (out of 8760)

The average annual trend/installed capacity for total demand, embedded wind, and embedded solar generation is specified exogenously. However, the installed capacity of transmission-connected wind and photovoltaic systems is generated endogenously by the model (passed on from the investment and then capacity tracking sub-models). Given that the potential for investment in hydro generation is limited in the UK, the generation of non-pumped storage hydro is assumed to remain constant over future years, at its 2012 values (Figure 47). Similarly, the technical capacity of pumped storage is assumed to remain constant until 2030, not subject to new investment. Similarly, the technical capacity of pumped storage is assumed to remain constant until 2030, not subject to new investment.

Since the hourly series of non-dispatchable RE demand is generated within this sub-model, the number of renewable obligation certificates which are fulfilled through them are also calculated here. The renewable obligation banding differentiates between on-shore and off-shore wind, yet the hourly generation of wind is only estimated as a whole, not disaggregated by their location. Here, the onshore and offshore hourly wind generations are estimated assuming the following relationship stands:

$$P_h^{WIND} = \frac{n_{OSW}}{n_{OSW} + n_{OFW}} \theta_{OSW} P_h^{OSW} + \frac{n_{OFW}}{n_{OSW} + n_{OFW}} \theta_{OFW} P_h^{OFW} \qquad (5.110)$$

$$P_h^{OSW} = P_h^{WIND} \frac{\theta_{OSW}}{\theta_{OSW} + \theta_{OFW}\, n_{OFW} / n_{OSW}} \qquad (5.111)$$

$$P_h^{OSW} = P_h^{WIND} \frac{\theta_{OFW}}{\theta_{OFW} + \theta_{OSW}\, n_{OSW} / n_{OFW}} \qquad (5.112)$$

$$RO^{ND} = \sum_h P_h^{OSW} B_{OSW} + \sum_h P_h^{OFW} B_{OFW} + \sum_h P_h^{PV} B_{PV} \qquad (5.113)$$

OSW index for on-shore wind
OFW index for off-shore wind
P_h^{OSW} hourly generation from on-shore wind

P_h^{OFW}	hourly generation from off-shore wind
RO^{ND}	RO target met by non-dispatchable RE production, RO certificates
B_g	RO banding for technology g
θ_g	availability for technology g
n_g	number of units installed of technology g

6 Model validation

In order to assess whether the proposed model captures the main dynamics of the UK's power and gas sector in terms of power and gas prices, as well as the investment in new power generation/gas production capacity, a 20-year base case scenario is constructed, consisting of historical pathways of exogenous variables (for the first five years 2011-2015) and their most likely pathway (2016-2030), as estimated by the author. The base case scenario is fed to the simulation model in order to assess its output. The first five years' output of the model is compared to the historical behaviour of the system. Then, the results for the remaining years are evaluated in terms of interpretability: whether the model output for the less immediate future is consistent with the set of causal hypothesis used to formulate the model.

The direct comparison of model output with historical system behaviour is limited due to the unavailability of historical data, but it still can yield important insight on the dynamics of the UK's gas and power sector in making long-term investment decisions. Because, by comparing the two, deficiency in the assumptions laid down in the mathematical formal model can be identified. This allows for explicit correction of mental models that have been the basis for model development (Figure 48).

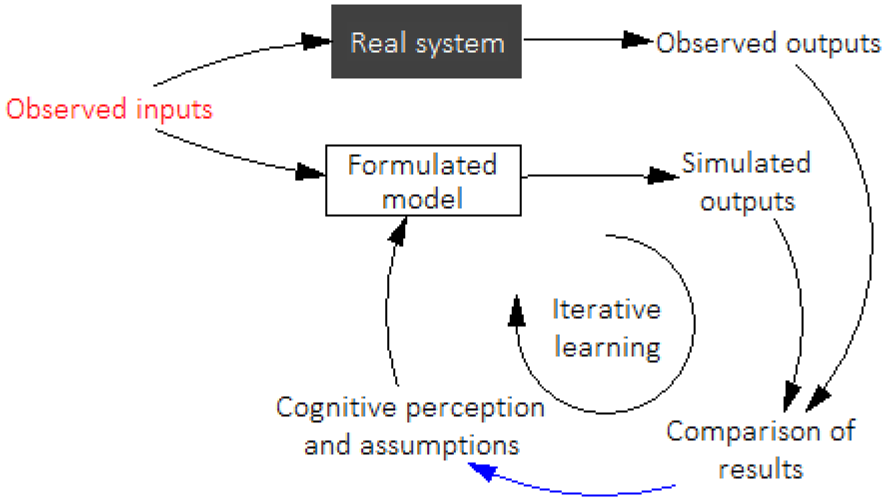

Figure 48: Causal loop diagram for model validation

In the following section, the base case scenario, consisting of historical values of key exogenous inputs and their guesstimated future pathways, are presented, followed by the presentation of main simulation results. Then, the results from the SD simulation are discussed through a comparison to observed historical behaviour (for the first five years), and an analysis relating model outputs to the inputs used for the remaining years (interpretability check). Finally, the future work that is still needed to make the best use of the simulation model that has been developed is outlined, incorporating deficiencies outlined during the model validation phase.

6.1 Base case scenario

In this section, the exogenous values used for the base case scenario is delineated in a structure that mirrors the chapter on model development. Given the large number of exogenous variables that need to be accounted for, a complete list is included in the Appendix, referring each exogenous variable to the sub-model in which it is used, which is also the sub-section in which they are introduced in the following description.

6.1.1 Gas and power markets

In the gas and power markets, the exogenous variables used fall into four types: those that describe the evolution of future demand, those that describe the evolution of non-endogenous supply (the opportunity cost of imports/export) or the operating costs of endogenous supply (carbon and fuel prices), those that describe market-based policies (renewable obligation), and technical constraints that limit market operations (storage efficiency, ramping speeds, etc.).

6.1.1.1 Gas market

The annual average trends used for years 2011-2030 for all four categories of demand are shown in Figure 49. The values for 2011 to 2015 is actual values, while the rest is based on assumptions that:

1. LDZ demand will decrease by 9% by 2030 from its 2015 value, due to increasing efficiency improvements in gas usage;
2. The trends for industrial, export to Ireland, export to the Netherlands are extrapolated from their trends during 2011-2015, which leads to a decrease of 16%, 11%, and an increase of 9% relative to their 2015 values.

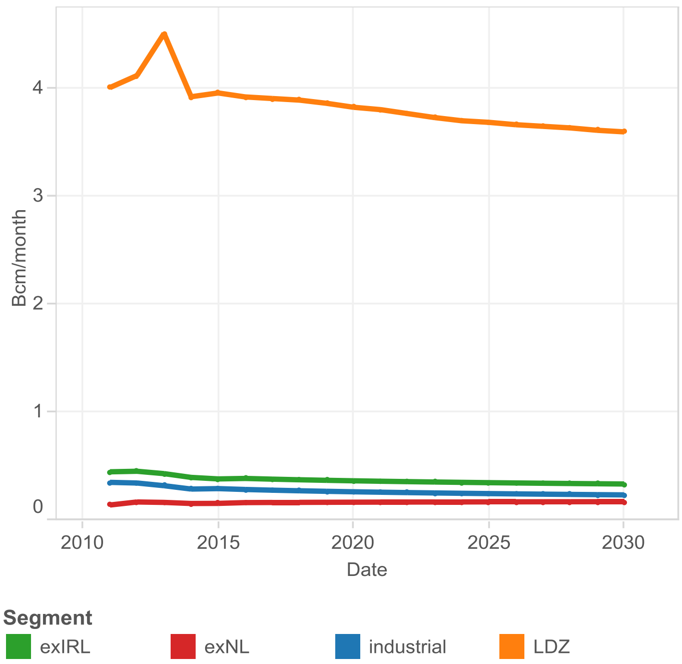

Figure 49: Average annual trends for non-power sector gas demand in the UK

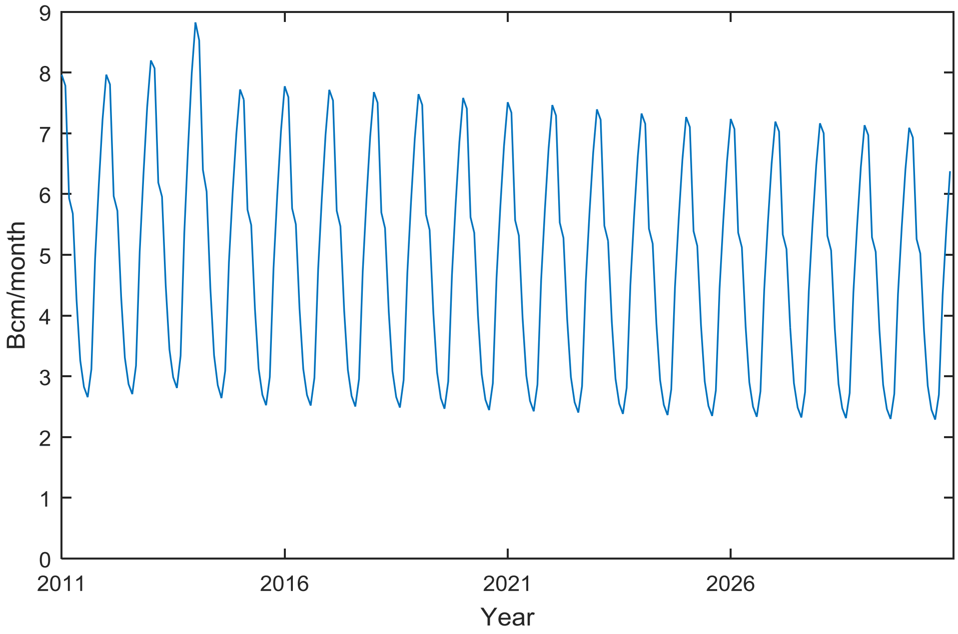

Figure 50: Monthly non-power sector gas demand for the UK

The monthly non-power sector gas demand for the UK thus derived for the simulation based on the procedure above is shown in Figure 50. Their annual sums, ranging from 62 Bcm in 2011 to 54 Bcm in 2030, is consistent with the scenarios developed by industry observers (Honoré, 2014; National Grid, 2015c).

The exogenous variables that deal with the supply situation in the UK gas market can be divided into two parts: those that describe the terms of future long-term contracts with Norway and the Netherlands (Table 28), and those that describe the opportunity cost of importing/exporting flexible gas from continental Europe and the global LNG market (Figure 51 to Figure 53).

In terms of future long-term contracts, the future annual quantity of UKCS production is generated endogenously within the model, updated annually to be the expected annual production capacity of the UKCS for that year, as computed by the gas production capacity tracking sub-model.

It is assumed that the long-term contract(s) with Norway can be renewed in its current form until 2020, the year in which Norwegian production (of which almost all is exported) is expected to peak in 2020 (Norwegian Petroleum Directorate, 2013). After that, it is assumed that the ACQ for import from Norway gradually decreases, falling to about 80% of its peak value by 2030.

The long-term contract of the UK for gas import from the Netherlands is coming to an end in 2016. It is assumed that the contract is not renewed, because the Netherlands is seen to struggle meeting its own gas demand, after placing a production cap on the Groningen field due to the risk of small earthquakes (Reuters, 2016). However, starting from 2016, flexible import from the Netherlands is assumed to be available, if the UK market price for gas is high enough to provide the price premium needed to attract gas supply from the Dutch market.

The take-or-pay volume for all long-term contract is estimated to be 85% of the annual contract quantity, while the monthly minimum denomination for each source of gas is estimated from historical data between 2011-2015. The minimum denominations, expressed in terms of a percentage of the annual contract volume, is assumed to remain constant throughout the life of the contract.

Table 28: Base case scenario for long-term contract parameters

	ACQ (Bcm/year)			ToP (% ACQ)			m_{min} (% ACQ)		
Year	UK	Norway	Netherlands	UK	Norway	Netherlands	UK	Norway	Netherlands
2011	endo.	27	8	85%	85%	85%	5.8%	3.7%	2.5%
2012	endo.	27	8	85%	85%	85%	5.8%	3.7%	2.5%
2013	endo.	27	8	85%	85%	85%	5.8%	3.7%	2.5%
2014	endo.	27	8	85%	85%	85%	5.8%	3.7%	2.5%
2015	endo.	27	8	85%	85%	85%	5.8%	3.7%	2.5%
2016	endo.	27	0	85%	85%	0%	5.8%	3.7%	0.0%
2017	endo.	27	0	85%	85%	0%	5.8%	3.7%	0.0%
2018	endo.	27	0	85%	85%	0%	5.8%	3.7%	0.0%
2019	endo.	27	0	85%	85%	0%	5.8%	3.7%	0.0%
2020	endo.	27	0	85%	85%	0%	5.8%	3.7%	0.0%
2021	endo.	26.5	0	85%	85%	0%	5.8%	3.7%	0.0%
2022	endo.	26	0	85%	85%	0%	5.8%	3.7%	0.0%
2023	endo.	25.5	0	85%	85%	0%	5.8%	3.7%	0.0%
2024	endo.	25	0	85%	85%	0%	5.8%	3.7%	0.0%
2025	endo.	24.5	0	85%	85%	0%	5.8%	3.7%	0.0%
2026	endo.	24	0	85%	85%	0%	5.8%	3.7%	0.0%
2027	endo.	23.5	0	85%	85%	0%	5.8%	3.7%	0.0%
2028	endo.	23	0	85%	85%	0%	5.8%	3.7%	0.0%
2029	endo.	22.5	0	85%	85%	0%	5.8%	3.7%	0.0%
2030	endo.	22	0	85%	85%	0%	5.8%	3.7%	0.0%

In terms of the opportunity cost of importing/exporting flexible gas from continental Europe and the global LNG market, the price premium needed relative to alternative markets to import a certain quantity of gas is assumed to be a linear function of the quantity of gas sourced. The price premium required relative to the Dutch, Belgian, and the Asian LNG market price is estimated based on historical data between 2011 and 2015 (Figure 51). For flexible imports from Netherlands and Belgium, about a $0.50 and $0.70 mark-up above the TTF and ZEE price is required for the UK to import gas from these two markets at 100% pipeline capacity. As for LNG, the UK market price does not need to be above the Japan LNG spot price, but it needs to be less than $5 lower than the Japan LNG spot price to attract LNG supply. And, extrapolating from historical trend, a UK market price of less than $3.4 is needed to attract LNG supply at its full import capacity. For the base case scenario, it is assumed that these price premium functions remain stable for the entire simulation period.

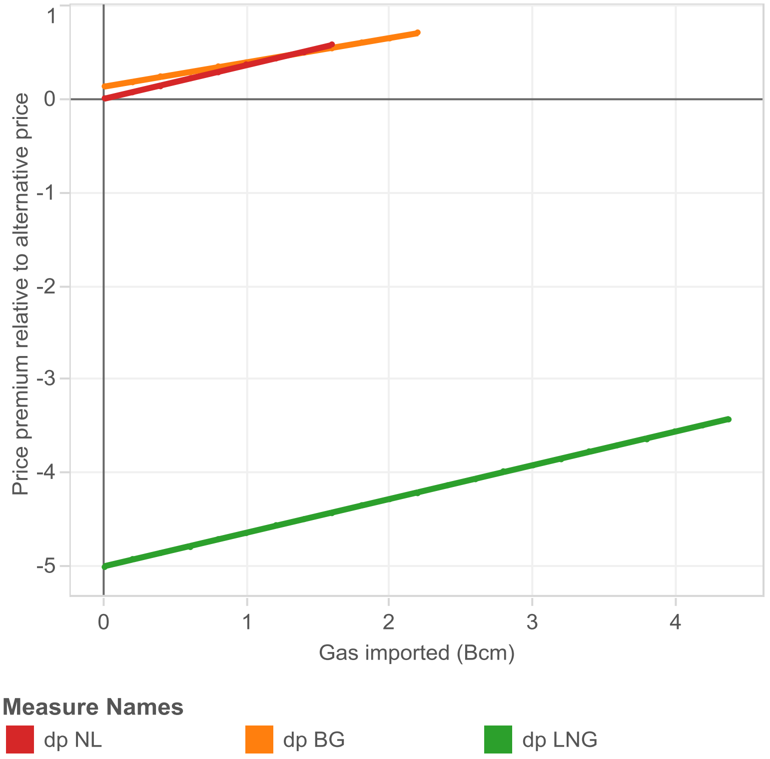

Figure 51: Price premium required relative to alternative price for flexible gas import

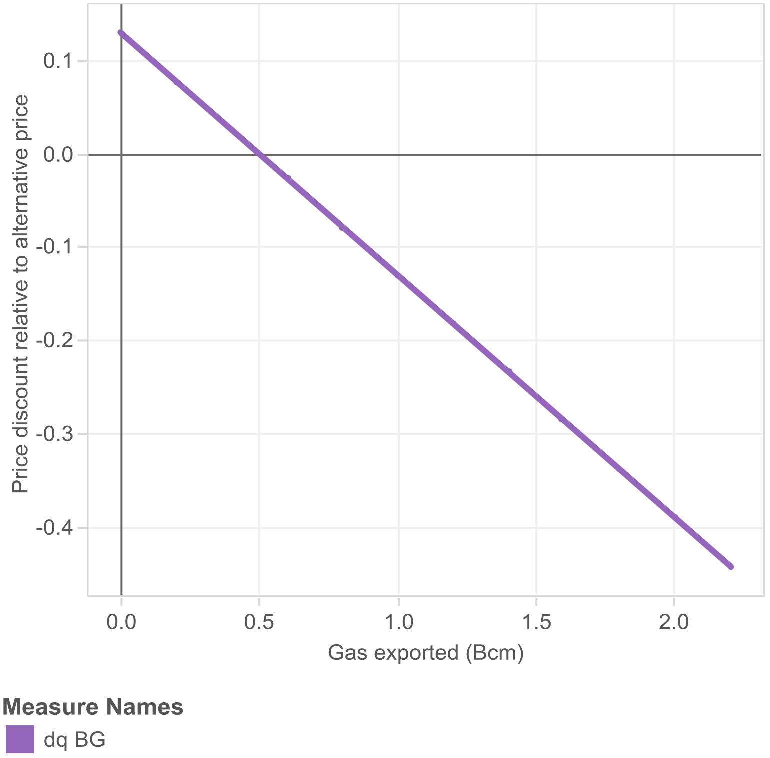

Figure 52: Price discount required relative to alternative price for flexible gas export

Given the Interconnector pipeline is bidirectional, gas export from the UK is also possible, when the UK market price is at a discount relative to the ZEE price. The price discount needed for different quantity of export is estimated using historical data. It is found that a low amount of gas is exported to Belgium, even when the NBP-ZEE spread is positive, possibly due to the presence of the GB commodity charge which outweighs a low spread (Ofgem, 2013). A price discount of about $0.40 is required for export to occur at full pipeline capacity[12].

The price of flexible import/export from the Netherlands, Belgium, and the global LNG market is dependent on the combined effect of the price premium/discount required **and** the underlying market price in alternative markets. More specifically, the TTF, the ZEE, and the Japan spot market prices. Therefore, the base case scenario also needs to include possible pathways for natural gas prices in these markets for the entire simulation period.

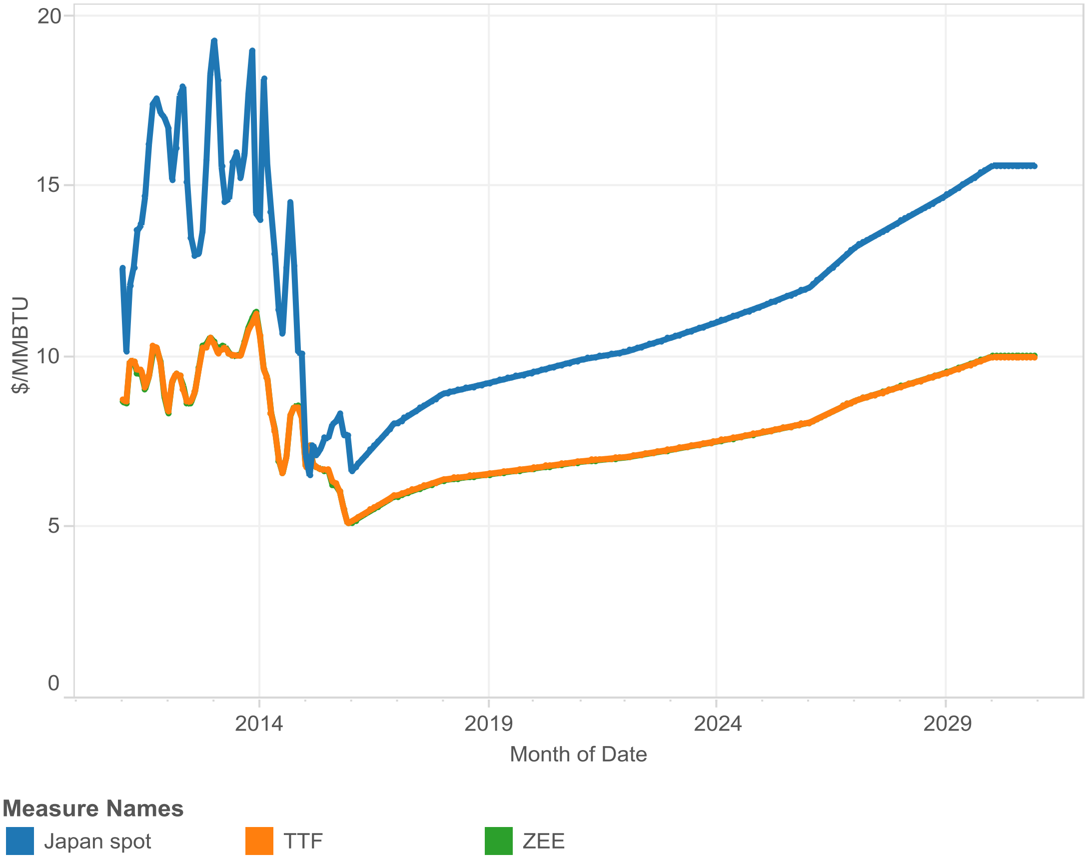

Figure 53: Base case scenario for gas prices in alternative markets

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[12] The difference in pipeline capacity in import and export mode is neglected to simplify model representation.

It is assumed that, following in the fall in Japan LNG spot prices in 2014-2015 due to softening Asian demand, the global LNG market gradually tightens again to reach price levels seen during 2011-2013, at $15/MMBTU. Similarly, North-western European gas market is assumed to follow the same trend, with prices falling in 2014-2015 in tandem with the Japan LNG spot prices, then returning to their early 2010s level by 2030. The ZEE and TTF markets are assumed to remain almost perfectly integrated, without significant price difference. It should be noted that these values are not forecasts, but one of the possible envelopes for future uncertainty that is used for simulation. Other sets of possible price pathways for these markets can be and should be tested using the simulation model.

Remaining exogenous variables used for the gas market involve the operations of gas storage and the physical properties of gas.

In the gas market sub-model, the cost of storage is not represented as transactional (the fees shippers pay to storage operators), instead, the system cost of storage is represented as the consumption of gas by storage operators (mainly used for compressing gas before injection or for liquefaction). The efficiency of the three different types of storage available, also the gas in storage inventory in these storage reservoirs at the start of simulation, are shown in Table 29. Finally, it is assumed that the seasonal storage reservoirs (depleted gas reservoirs and salt caverns) need to be at least 60% full at the end of each year. This specification is made to remediate the fact that the gas market representation does not allow inter-year optimization: it is possible that, the optimizing gas market in year y depletes all gas in storage to serve the demand in year y, disregarding the gas demand in the early months in year y+1.

Table 29: Base case scenario for gas storage operation parameters

	Depleted gas reservoirs	Salt caverns	LNG peak shaving
Storage efficiency	0.98	0.98	0.90
Initial inventory (Bcm)	3.20	0.58	0.07
Inventory at end of year (% capacity)	60%	60%	0%

Since gas price is expressed per its energy content, while gas flow rate is usually expressed in volumetric terms, the calorific value of natural gas supplied/traded needs to be known to convert between these two sets of units. For this thesis, the calorific value of natural gas is assumed to be 37636 MMBTU/Mcm, a value derived from historical gas statistics from the DECC.

6.1.1.2 Power market

The average annual trends/installed capacity for total demand, embedded wind, and embedded solar generation used for the base case scenario are shown in Figure 54.

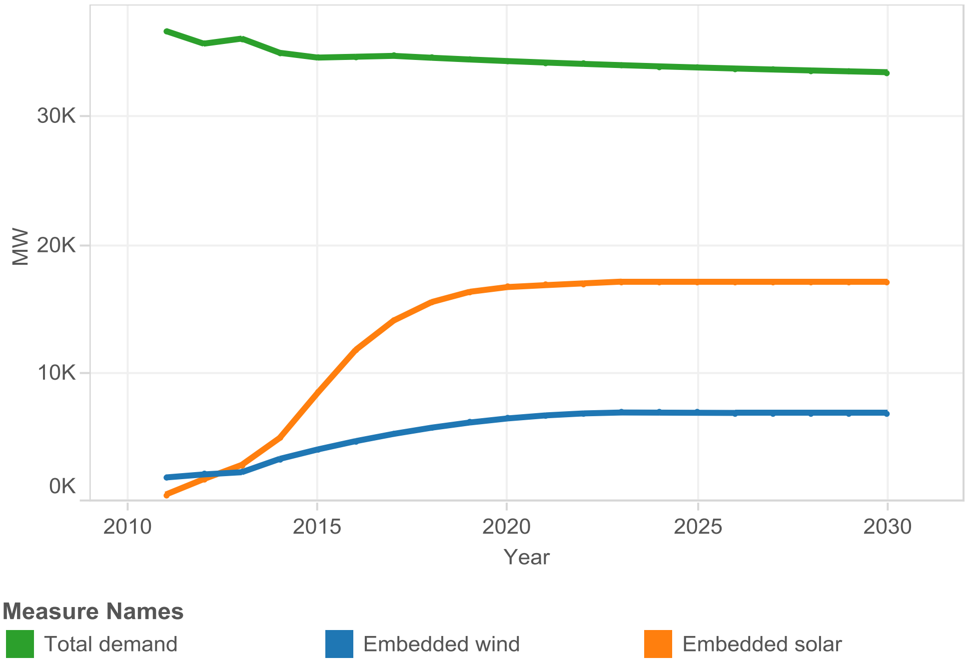

Figure 54: Average annual trends for total power demand and embedded generation in the UK

As for other data used for the base case scenario, the values for year 2011-2015 is actual data, while the values for year 2016 and 2030 are assumptions made by the author. It is assumed that the average annual trend for total power demand in the UK decreases marginally between 2015 and 2030 by 3% in total, from 34.6GW to 33.5 GW. Given the peak relative demand is 1.56 times the average annual trend, this corresponds to a peak demand of 52 GW in year 2030, which is consistent with National Grid's forecast of about 50 GW(National Grid, 2015a). It is assumed that the installed capacity of embedded solar generation plateaus around 2020 at 17 GW. This is a more aggressive estimate than that projected by DECC (12 GW by 2020), but is likely given the important exponential growth in embedded solar capacity in the past few years. Finally, extrapolating from recent trends, it is assumed that the capacity of embedded wind generation will reach about 7 GW by 2020, after which it will also plateau. The stabilizing trends for embedded generation is assumed, because it is expected that more favourable investment opportunities will have been exhausted by 2020; also, given the growth in embedded generation (especially solar) that outpaced government expectation, DECC has lowered the tariffs that subsidize embedded generation (the

Feed-in-Tariff scheme), therefore the growth for embedded generation is perceived to be more limited post 2020 (DECC, 2015f).

One of the most important components of power generation's upstream cost is the cost of fuel used. The price of fuel used for all thermal generators, except for the price of natural gas, is specified exogenously (Figure 55). It is assumed that the price of fuel for nuclear generators and biomass generators grow steadily at the rate of 1% per year. It is assumed that the downward trend for coal price comes to an end in 2016, then slowly trends upward again to reach its 2012 level by the late 2020s. This is consistent with the central long-term coal price projection published by the UK government in 2015 (DECC, 2015c). The fuel for co-fired generation is assumed to be a 50:50 blend of coal with biomass, therefore its price is the average of the two individual fuels.

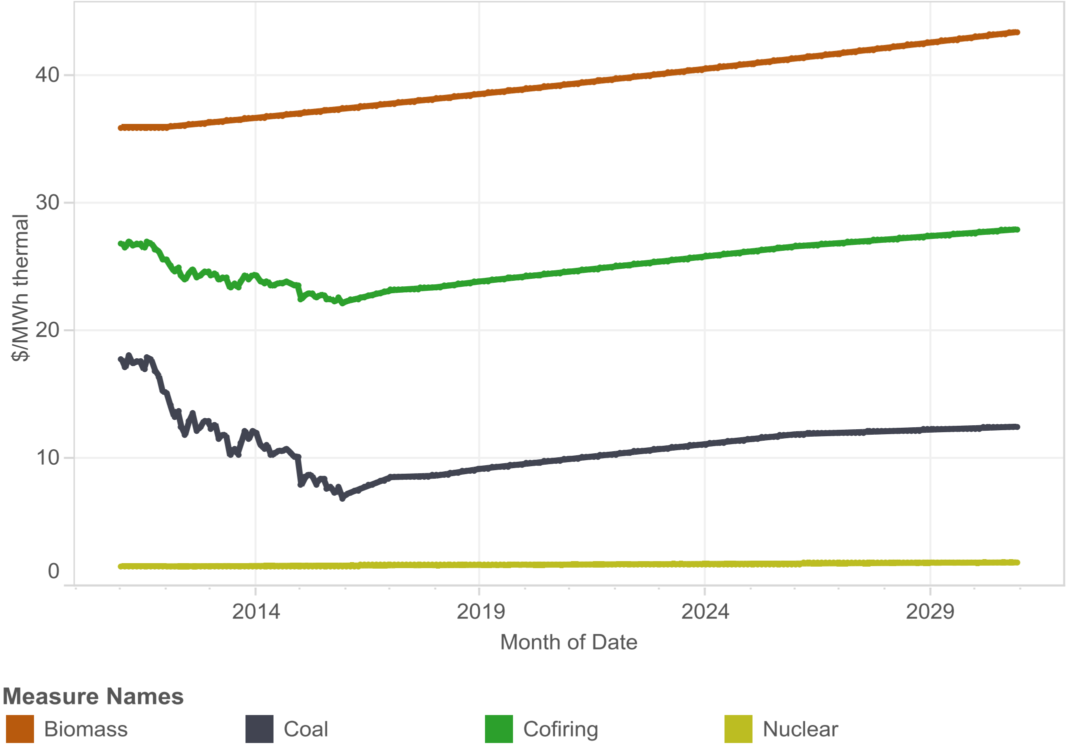

Figure 55: Base case scenario for generation fuel prices

Another import component of power generation upstream cost is the carbon price, the price that generators need to pay for carbon emissions associated with power generation. For UK power generators, who are involved in the European Union Emissions Trading System (ETS), the price of carbon they need to pay is the traded price of the ETS carbon credit, and, since 2013, a UK-specific carbon price floor (CPF), designed to reinforce the price of carbon to further decarbonisation (Figure 56). The traded price of ETS is dependent on the supply and demand of carbon credits within Europe. Given that the European Commission is intent upon reducing its carbon emission relative to 1990 by

40%, and that learning-by-doing will have occurred through the previous phases, it is assumed that the ETS carbon cap will be set in a way so that the phase 4 ETS credit price post-2020 is significantly higher than historical values, reaching \$60/ton CO_2 by 2030. (Schjølset, 2014). On the other hand, the UK CPF has been frozen at its 2015 levels until 2020. Given that its original purpose is to uphold the unstable ETS price, it is assumed that by the time the CPF level is re-evaluate post-2020, due to the improved performance of the phase 4 ETS, the UK CPF will not be increased. Instead, it will be maintained at the existing level until 2030.

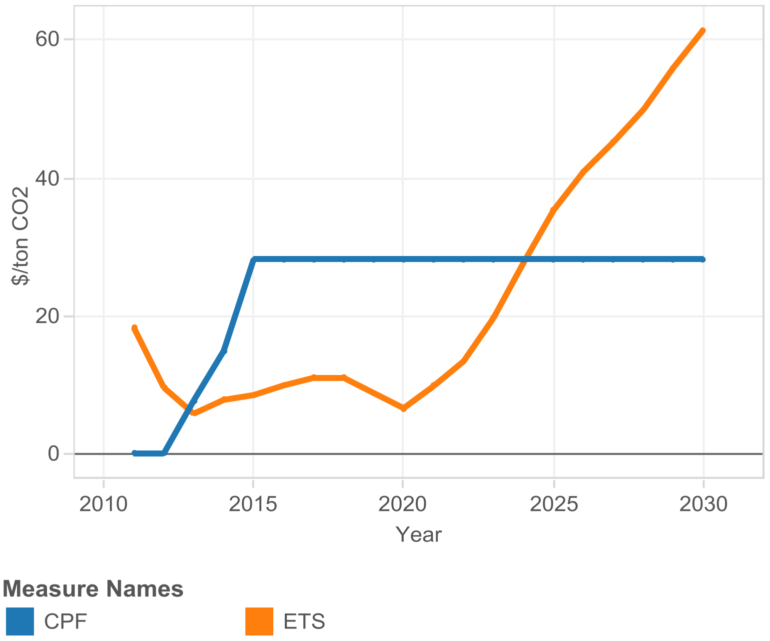

Figure 56: Base case scenario for European and UK carbon price

These combined assumptions yield the monthly carbon prices in Figure 57. Note that the annual average price of ETS is interpolated to specify the monthly value, whereas the CPF is updated every April.

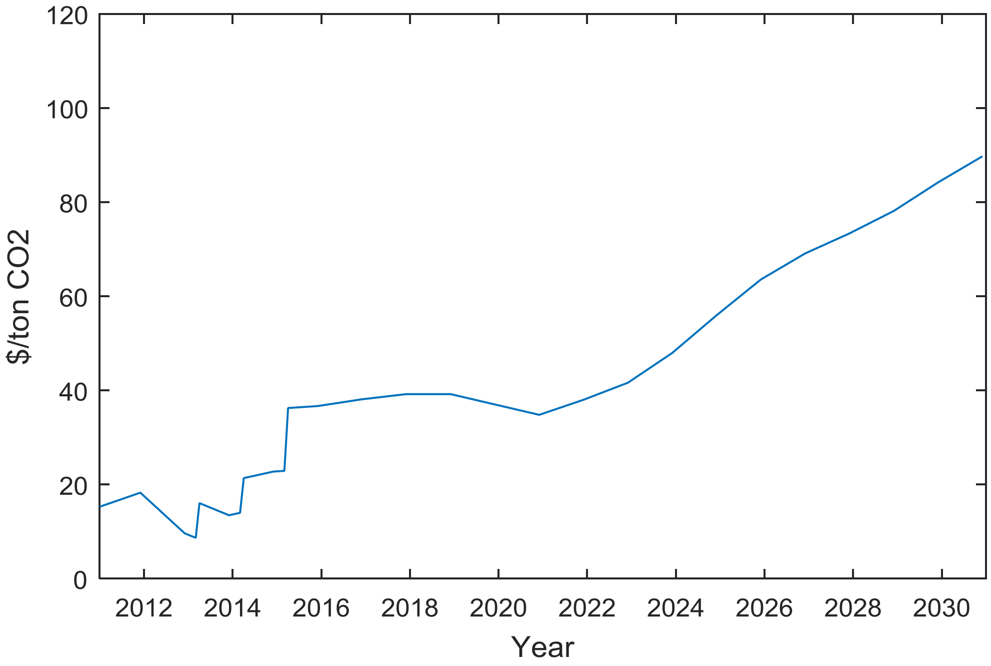

Figure 57: Monthly carbon price for UK power generators

As for the representation of price-responsive power import/export from France and the Netherlands, like for the gas market, these sources of supply are represented in terms of the price premium/discount needed to import/export a quantity of power, and the underlying price in the competing power market. The price premiums required to import electricity from France and the Netherlands are estimated based on historical data from 2011-2015, and assumed to be constant for all years of simulation. They are shown in Figure 58. The price discounts required for exports are shown in the same figure (negative price premium vs. negative import). The estimated relationship indicates that the UK market price for power needs to be $29 higher than the French market price, in order to import electricity from France at the maximum capacity of the IFA interconnector. For imports from the Netherlands at full capacity of BritNed, a price premium of ~$17 is needed. As for power flow in the opposite direction, price discounts of $27 and $17 are required, for exports to France and the Netherlands at full capacity.

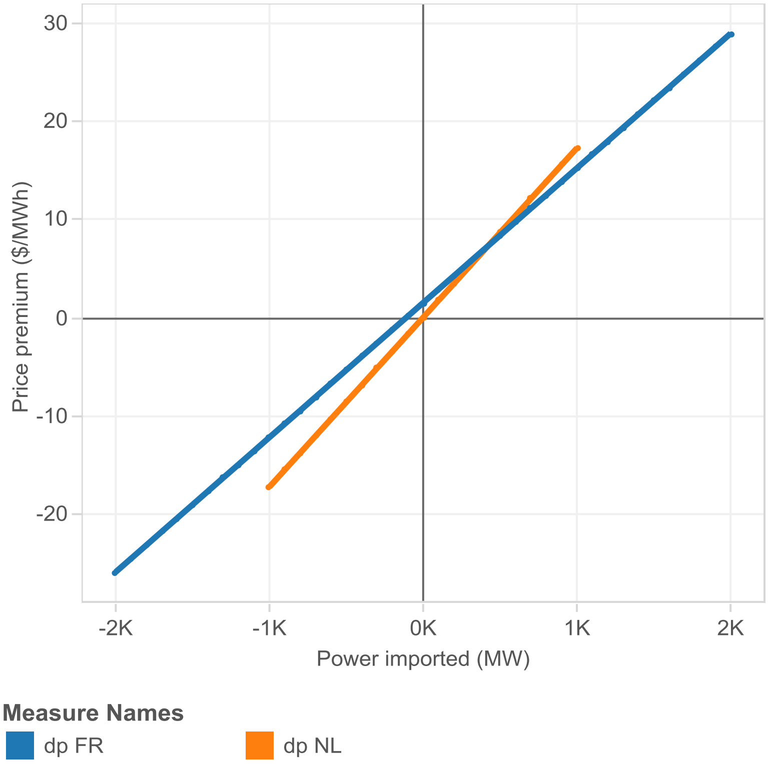

Figure 58: Price premium required relative to alternative price for flexible power import

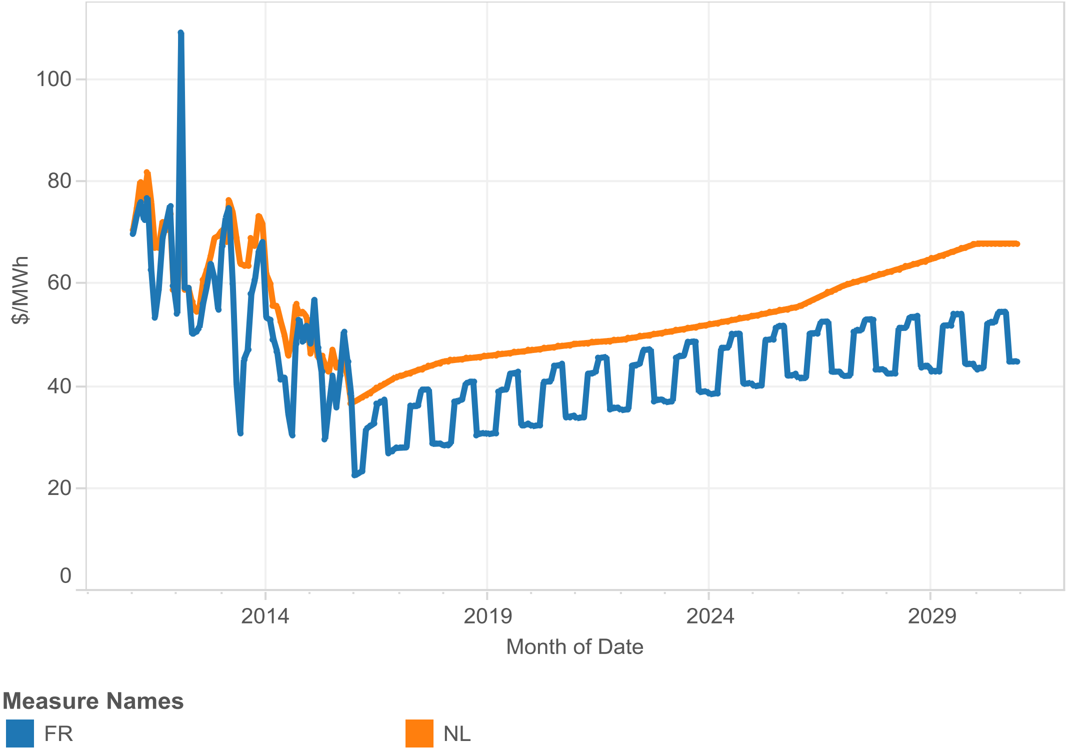

Figure 59: Base case scenario for power prices in alternative markets

As with the gas market, the underlying market prices of electricity in France and the Netherlands need to be provided to the model. For this base case scenario, it is assumed that the price of power in the Netherlands retains its historical long-term relationship with gas price in North-western Europe, as found in the cointegration study, therefore it increases in a way that is consistent with the rebound in TTF/ZEE gas price assumed for the previous section. For the price of power in France, which is found to vary seasonally around the German power price, underpinned by the price of coal in the cointegration study, it is assumed that these cointegration relationships also remain, so that the projected French power price is consistent with the price of coal assumed for the previous section.

Concerning the parameters related to the renewable obligation, the banding of renewable obligation for different technologies, the buyout price, and the annual RO target level used for the base case scenario are shown below (Figure 60 & Figure 61).

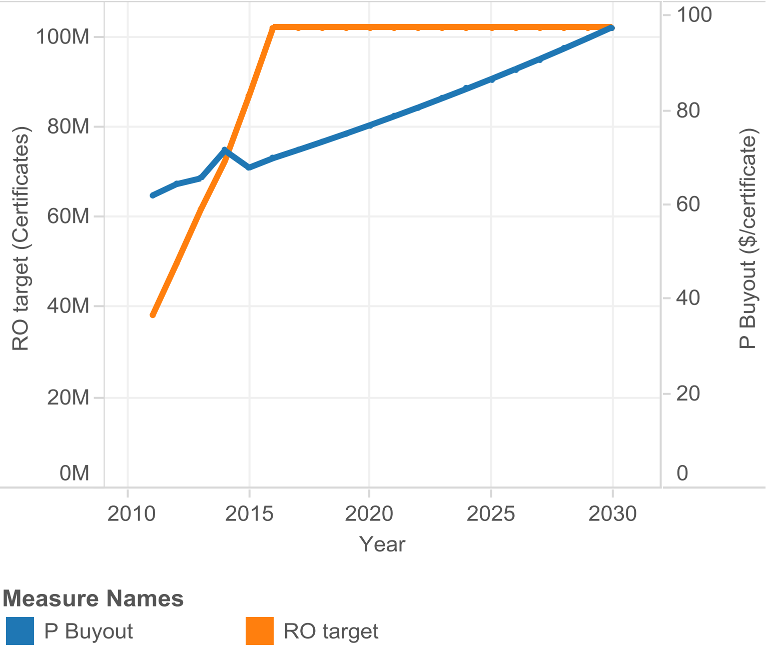

Figure 60: Base case scenario for pay-out price and RO target

In Figure 60, year 2011 to 2015 show historical data, the kink in pay-out price for 2014 comes from the sudden change in GBP/USD exchange rate. It is assumed that the RO target becomes fixed starting from 2016, since the RO scheme is assumed to become closed to new generation capacity starting from 2017. This means that the supply of RO certificates can no longer increase, in consequence the target level (i.e. the RO demand stipulated by the government) also can no longer increase. On the other hand, the pay-out price is assumed to continue to increase at the inflation linked rate (2.4% per year) from 2016 to 2020.

In Figure 61, year 2011 to 2016 show historical data. The actual banding has very narrowly defined types of technology (e.g.: co-firing of energy crops with CHP, co-firing of relevant energy crops low range, co-firing of regular bio-liquid + CHP, etc.). The RO banding represented here is a simplified version, sampling only five technologies (nuclear, coal, and gas are not eligible and do not receive RO certificates). The banding for co-firing is assumed to be that of co-firing mid-range, the one for biomass is assumed to be that of full unit conversion, and the banding for PV is assumed to be that of PV – building mounted. It is assumed that, due to the closure of RO to new generation in 2017, the banding is no longer revised post-2016.

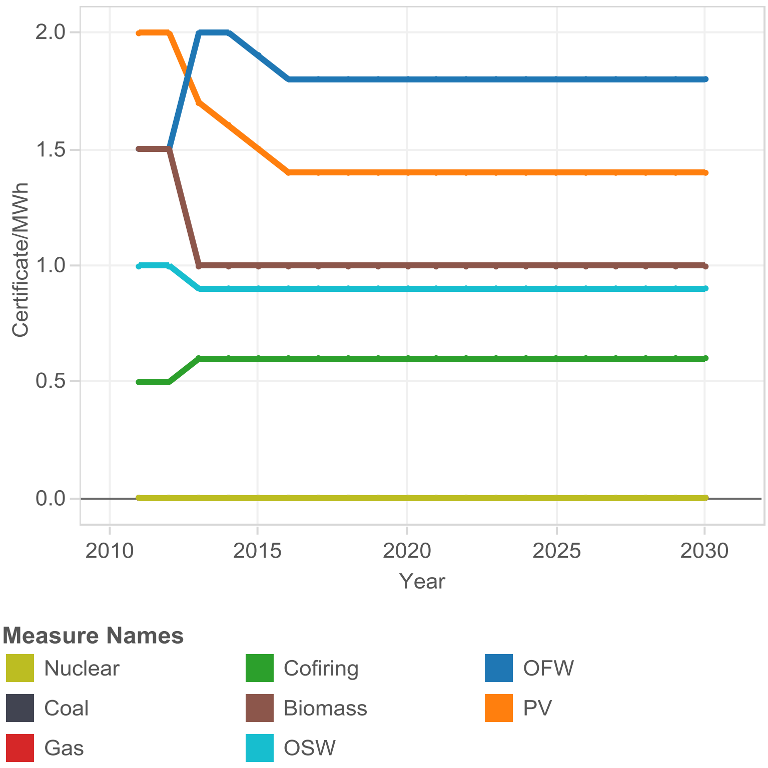

Figure 61: Base case scenario for RO banding

The variable operating and maintenance cost of different generation technologies is assumed to remain constant over the simulation period, along with other generation technology parameters (Table 30). The parameters circumscribing the operations of pumped storage are also assumed to stay constant throughout the simulation period (Table 31).

Table 30: Base case scenario for generator parameters

	Nuclear	Coal	Gas	Co-firing	Biomass	OSW	OFW	PV
Variable operation and maintenance cost ($/MWhe)	5	3	0	4	4	0	0	0
Fuel efficiency of generator (MWhe/MWht)	0.38	0.36	0.47	0.36	0.36	NA	NA	NA
Fuel consumption for a cold start-up (MWht)	0	3000	80	3000	3000	NA	NA	NA
Carbon emission associated (ton CO_2/MWh)	0	0.33	0.18	0.165	0	0	0	0
Maximum generation of a single unit (MW)	1000	600	400	600	600	NA	NA	NA
Minimum generation of a single unit (MW)	950	400	100	400	400	NA	NA	NA
Maximum ramp down speed (MW/h)	50	300	600	300	300	NA	NA	NA
Maximum ramp up speed (MW/h)	50	300	600	300	300	NA	NA	NA

Table 31: Base case scenario for pumped storage operation parameters

Parameter	Value
Efficiency of pumping for pumped storage	0.85
Maximum pumped storage generation capacity (MW)	2300
Minimum pumped storage generation capacity (MW)	2000
Initial level of pumped storage reservoir (MWh)	0
Maximum reservoir level for pumped storage (MWh)	30000

6.1.2 Forecasting

In order to use the TREND function to model expectation formation, the initial perceived trend value for the forecasted parameters need to be specified. The perceived trends will then evolve as per the process described in the forecasting section of the Model development chapter. The values used in Table 32 are based on the pre-2011 long-term trend of the corresponding price/cost series.

Table 32: Initial perceived trends used for forecasting

Initial trend perceived	Value
UK carbon price	-30%
UKCS production cost	10%
Nuclear fuel price	1%
Coal price	2%
Gas price	-10%
Co-firing fuel price	-3%
Biomass price	1%
RO buyout price	2%
Average power price	-2%
Average gas price	2%
CfD strike price	0%

The use of TREND function also requires the specification of the forecasting process through the following parameters: time to perceive present condition (TPPC), time horizon for reference condition (THRC), and time to perceive trend (TPT). It is assumed that the forecasting process of gas and power sector investors have no lag in perceiving the present value and the change in trend, so TPPC and TPT are set to 1. In other words, the condition of the price/cost series forecasted is perceived within the same year, and the trend indicated by this present condition is perceived and incorporated into long-term trend forecasting within the same year. The time horizon for reference condition, the historical period that forecasters consider to be relevant in the forecasting process, is set to be 5 years.

Another exogenous variable that is used by the forecasting sub-models is the renewable support scheme that is in place for different years of the simulation period, since it determines which expression is used to forecast the expected operating profit for potential generation investment. It is assumed that between 2011 and 2016, new generation investments are eligible for the RO scheme, while starting from 2017, the CfD scheme is enforced. This is a simplification of reality, as between 2014 and 2017, generators are eligible to choose between the two schemes. The technology-specific strike prices that are associated with the CfD scheme are shown in Figure 62. It is assumed that the strike prices remain constant from 2017, when they are launched, into 2030, as the purpose of CfDs is to guarantee price stability.

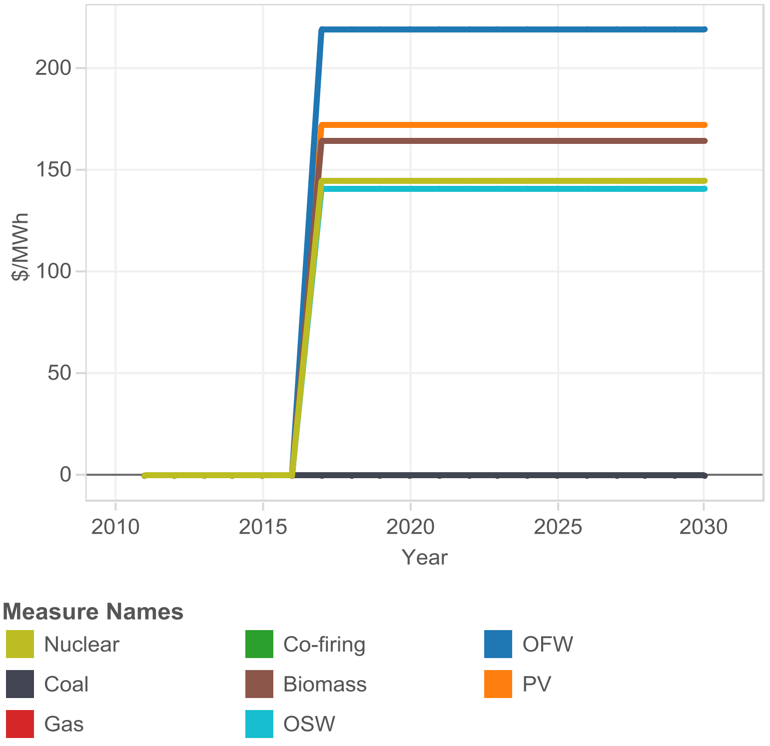

Figure 62: Base case scenario for CfD strike prices

6.1.3 Investment decisions

In the investment decision sub-models, the exogenous variables used fall into three types: variables that describe the evolution of costs/revenue beyond those involved in/derived from market operations; variables that described the profitability expectation of gas producers or power generators; and variables that characterize the potential investments.

6.1.3.1 UKCS gas development

The exogenous variables that affect costs/revenues involved in UKCS gas development decisions are the development cost of gas, the (forecasted) operating cost of gas, and the tax rate that is applicable to UKCS gas producers. Given that not all production from the UKCS is marketed, the percentage of gas that needs to be used by producers to sustain production also affects the prospective revenue of developed gas fields.

For the base case scenario, the UKCS gas development cost and operating cost assumed are shown in Figure 63. The operating cost includes both fixed and variable operating costs. It is very challenging to obtain estimates for the gas production related costs, because the public reporting of UKCS costs do not distinguish between oil and gas exploration, development, or production. Consequently, the figures presented here for historical years (2011 to 2015) are the average development and operating cost for UKCS petroleum development/production. It would benefit from future investigation. Given a historical relationship between oil price and petroleum development/production costs is known – increased demand for upstream drilling services is believed to be a cause (Toews & Naumov, 2015)– for the period 2016-2030, it is assumed that the production and development costs temporarily falls due to the fall in oil price, then recovers to its peak level in 2013-2014 by 2030.

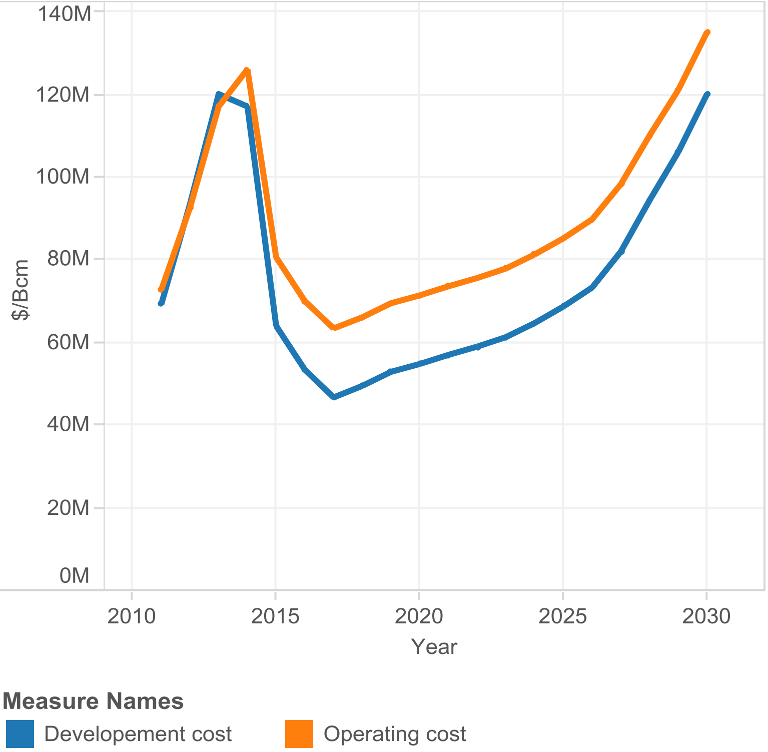

Figure 63: Base case scenario for UKCS development and production costs

The tax rate that are applicable to UKCS gas producers is dependent on the fiscal regime of the UK government for petroleum production. Although the marginal tax rate applied to UKCS fields increased importantly in 2011 (in addition to the corporation tax charged at 30% of profits, the supplementary charge increased from 20% to 32%[13]). In 2015, the supplementary charge is decreased by 2%. Although the government recognizes that UKCS new projects are increasingly marginal and that the overall tax burden will need to fall as the basin matures (see HM Treasury (2014)), for this base case scenario, it is assumed that the 60% tax rate is maintained beyond 2015 until 2030.

UKCS gas producers consume part of the gross production from the fields in their own operations. There is a strong historical correlation between the amount of gas used by producers and the gross production. As gross production decreases, the producers' own consumption also increases. From the historical correlation, it is found that, for any incremental unit of gross production, 0.04 unit is expected to be used in production activities. For the base case scenario, this relationship is assumed to remain in place.

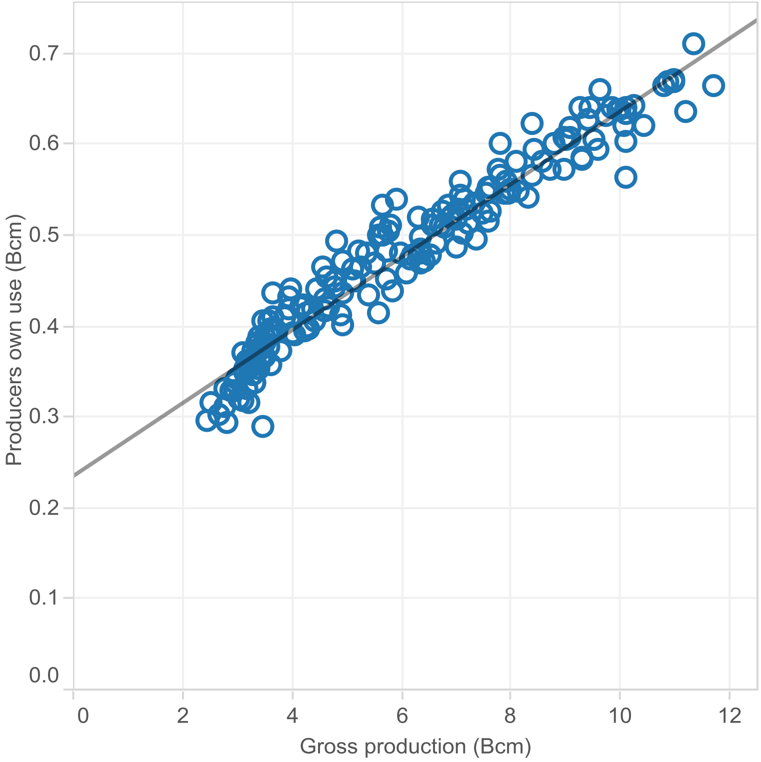

Figure 64: Historical correlation between UKCS producers gas for own use and gross production (Based on data from DECC)

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[13] The petroleum revenue tax which are charged at 50% on profits from fields with development approval granted prior to March 1993 are ignored to simplify model representation, since they do not affect new field development decisions.

As for the UKCS producers' profit expectation, a post-tax discount rate of 10% is used and assumed to remain constant throughout the simulation period. The discount factor used for each of the fifteen years considered in the gas development DCF is calculated based on this figure.

6.1.3.2 Power generation investment

The exogenous variables that affect costs/revenues involved in the UK power generation investment decisions are the fixed operating costs, the investment costs, and the capacity payment that might be awarded to capacity generators outside of the wholesale power market. For the base case scenario, the fixed operating costs and the investment costs of different generation technologies are assumed to remain constant throughout the simulation period of 2011-2030. They are presented alongside other parameters of different generation technologies that constraint the investment decision, all assumed to be constant over the simulation period Table 33.

Table 33: Base case scenario generation technology investment parameters

	Nuclear	Coal	Gas	Co-firing	Biomass	OSW	OFW	PV
Fixed operating cost(k$/MW)	128	94	35	15	64	63	130	35
Unit investment cost (k$/MW)	6500	3470	940	190	625	2500	3750	1530
Standard size of unit (MW)	1000	600	400	600	600	5	5	1
Construction time required (years)	8	5	3	1	1	2	3	3
Economic lifetime (years)	60	25	25	20	20	24	22	25
Availability factor	0.82	0.88	0.89	0.88	0.88	0.25	0.35	0.1

The capacity payment that is available to generators in each year is currently represented as an exogenous parameter. It is assumed to be a payment that is available to all generation capacity after derating through their respective availability factor. The capacity payments are assumed to be announced four years before they are implemented, accounting for lead time required for investment in new capacity. The following payments are assumed for the simulation period, but in a follow-up study, the capacity payment is the result of the capacity auction which should be incorporated as part of the exogenous model. For year 2010 to 2015, the values shown in Figure 65 are actual data (no capacity payment announced prior to 2013); for post-2016 announcements, it is assumed the capacity payment achieved remains low at $25/MWh.

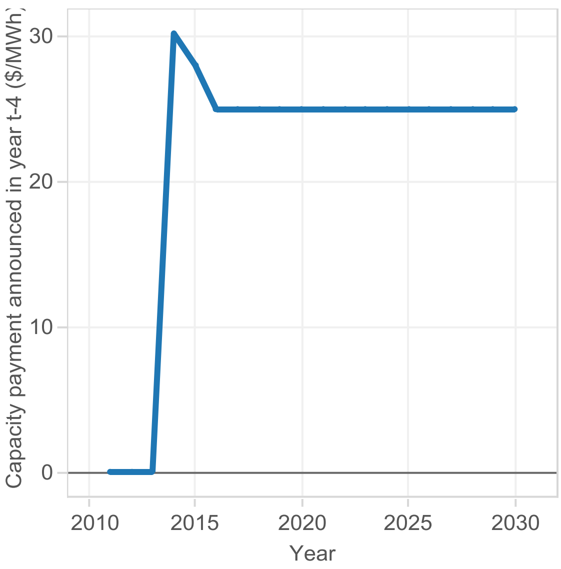

Figure 65: Base case scenario for capacity payment

As for the UK power generators' profit expectation, a discount rate of 10% is used and assumed to remain constant throughout the simulation period. The discount factor used for each of the fifteen years considered in the power investment DCF is calculated based on this figure. It is assumed that power generators do not distinguish between generation technologies through technology-specific discount rates.

6.1.4 Infrastructure stocks

In the infrastructure stock tracking sub-models, the exogenous variables used fall into two categories: the initial condition of the infrastructure stock in question, at the beginning of simulation, and the exogenously specified changes to infrastructure capacity.

6.1.4.1 Gas reserve

Due to the unavailability of information in the public domain on 1) the discovered yet undeveloped reserves available to UKCS gas producers by the end of 2010, and 2) the pipeline of reserves that are under development by the end of 2010, for the base case scenario, it is assumed that these quantities are negligible. In other words, the base case scenario values for $dE_{b,0}^{D}$ and $E_{b,0}^{D}$ are assumed to be zero. In the subsequent (endogenous) determination of reserves discovered following exploration efforts, the parameters used are summarized in Table 34. The exploration prospects that they describe are assumed to remain constant during the simulation period. It is possible that the mean size of discovery will decrease as cumulative exploration efforts increase, but historical experience has shown that such decline rate is quite modest, for the most important decline has already occurred for this mature basin (Kemp & Stephen, 2006). The cost per exploration well of exploration well is assumed to evolve with the same trend as that assumed for gas production and development costs.

Table 34: Base case scenario values for gas reserve exploration

Parameter	Value
Success probability of exploration drilling	20%
Average size of reservoir discovered (Bcm)	3
Size std. dev. of reservoir discovered (Bcm)	1.5

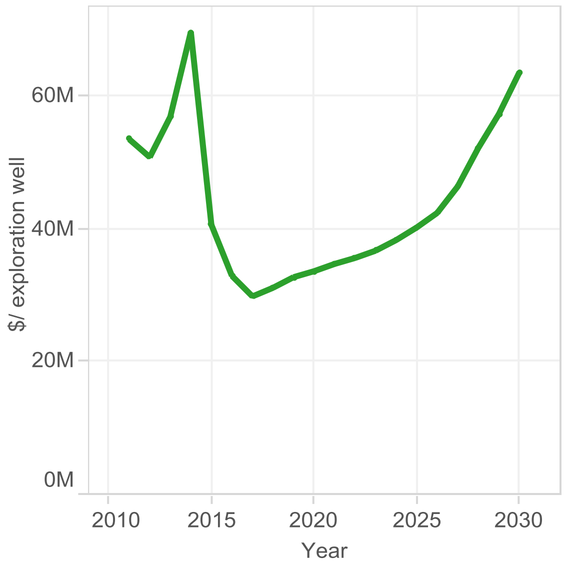

Figure 66: Base case scenario for UKCS exploration cost

6.1.4.2 Gas production

The reserves associated with fields that are commissioned before the start of the simulation, estimated based on historical production profiles, are shown in Figure 67. The producers' own use of gas produced is determined as a function of the maximum production capacity of the same year, using the historical correlation illustrated in Figure 64. It is assumed that there is no change in technology/operating procedures that leads to a change in field depletion rate. In other words, the base case scenario of the decline rate modifier is assumed to be zero.

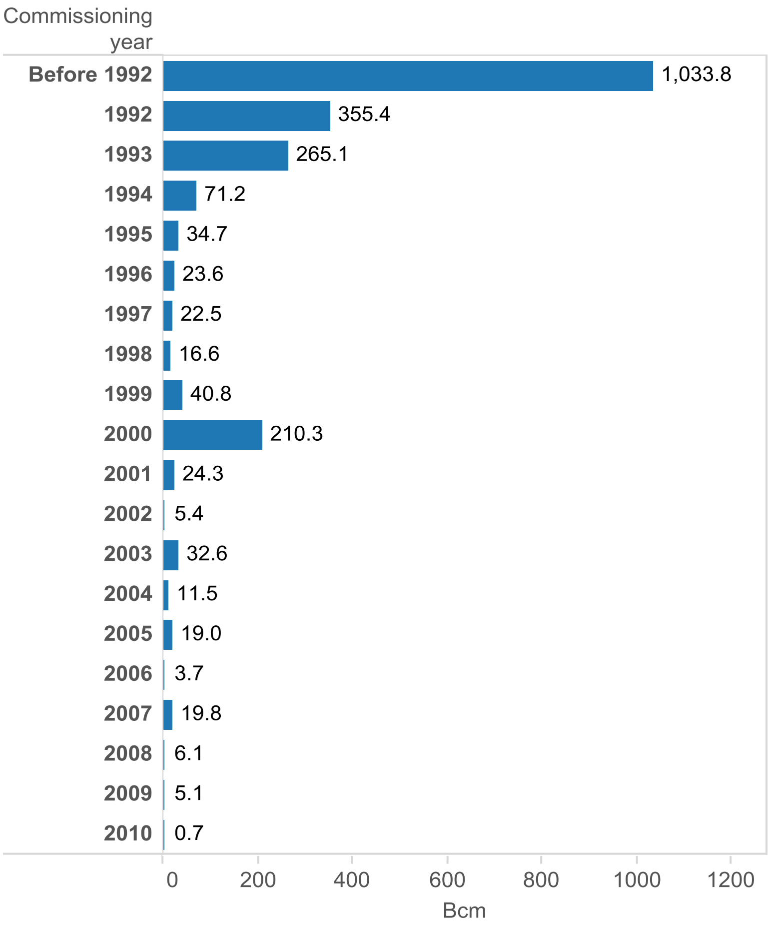

Figure 67: UKCS reserves commissioned before start of simulation

6.1.4.3 Power generation

Due to the non-availability of data in the public domain, the queue of generation projects under construction at the start of construction $q_{g,0,T}$, its initial inflow (newly added generation investment to the queue $dq_{g,0,T^C+1}$), and initial outflow (newly commissioned generation units at start of simulation $dn_{g,0}$) are assumed to be zero. The initial number of generation units available and the corresponding initial generation capacity used in the base case scenario, based on actual installed capacity at the end of 2010, are shown in Table 17.

Table 35: Base case scenario initial generation capacity

	Nuclear	Coal	Gas	Co-firing	Biomass	OSW	OFW	PV
Initial number of gen. units	10	38	79	0	0	742	264	0
Initial generation capacity (MW)	10000	22800	31600	0	0	3710	1320	0

Given that generation units are tracked separately, based on the renewable support scheme in place in the year in which investment decision is made, initial values need to be provided for the initial generation capacity under the RO scheme and the CfD scheme. For the base case, it is assumed that all generation capacity (that is eligible) is registered under the RO, whereas the CfD, not yet implemented, has no generation capacity associated with it.

An important exogenous variable involved in power generation capacity tracking is the decommissioned generation units during the simulation period. Nuclear and coal power plants are the only types that expected to be decommissioned due to exogenous causes (Table 36). The nuclear fleet of the UK is coming toward the end of its technical lifetime, and decommissioning of at least half of its capacity is expected by 2030. As for coal power plants, the combined effect of the Large Combustion Plant Directive and the government's pledge to close all unabated coal generation by 2025 inform the base case scenario's decommissioning assumptions.

Table 36: Base case scenario for decommissioned generation units

Year	Nuclear	Coal
2011		
2012	1	3
2013		2
2014		4
2015		6
2016		4
2017		4
2018		4
2019		3
2020		3
2021		3
2022		2
2023	2	
2024	2	
2025		
2026		
2027		
2028		
2029		
2030		

6.1.4.4 Exogenous capacity

Gas storage capacity in the UK has been largely static since liberalization. At the beginning of simulation period (end 2010), the working capacities for depleted gas fields, salt caverns, and LNG peaking shaving are, respectively, 3.195 Bcm, 0.580 Bcm, and 0.069 Bcm. From 2011 to 2015, only one salt cavern is commissioned (addition of 0.2 Bcm for Holford in 2013), storage capacity of the depleted gas fields and LNG peak-shaving type has remained the same (DECC, 2015a). It is assumed that the storage capacity remains constant beyond 2015 until 2030.

The import/export capacity for natural gas in the UK has also remained unchanged for the period 2011-2015, with the following configuration (Figure 68). It is assumed that the import/export infrastructure remains constant beyond 2015 until 2030.

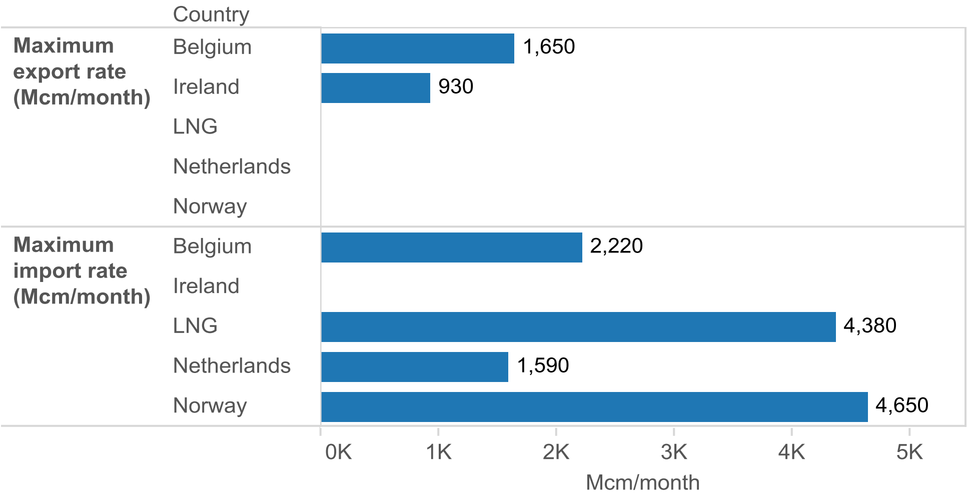

Figure 68: Natural gas import/export capacity for 2011-2015 (Based on data from DECC, 2015a)

At the beginning of the simulation period, the UK only had one interconnector, IFA with France at 2000 MW; in 2011, BritNed was commissioned with a 1000 MW capacity. For the base case scenario, it is assumed that the interconnector capacities remain constant at these levels until 2030. This is a simplifying assumption that should be revisited in other scenarios, as several interconnectors between the UK and other power markets are currently being evaluated (National Grid, 2015b).

6.1.5 Cash flow

The fractions of gas and power sector operating cash flow that are used to fund investment in gas exploration, gas development, and power generation investment are assumed to remain constant throughout the simulation period. They are 10%, 75%, and 60% for the base case scenario, respectively.

6.2 Simulation results

The key results from the simulation of the base case scenario are presented in the order listed, first for the gas sector, then for the power sector:

1. Shares of supplies dispatched to meet demand (including imports and flow from storage);
2. Shares of demand (including exports and flow to storage);
3. Market price;
4. Measures for annual investment.

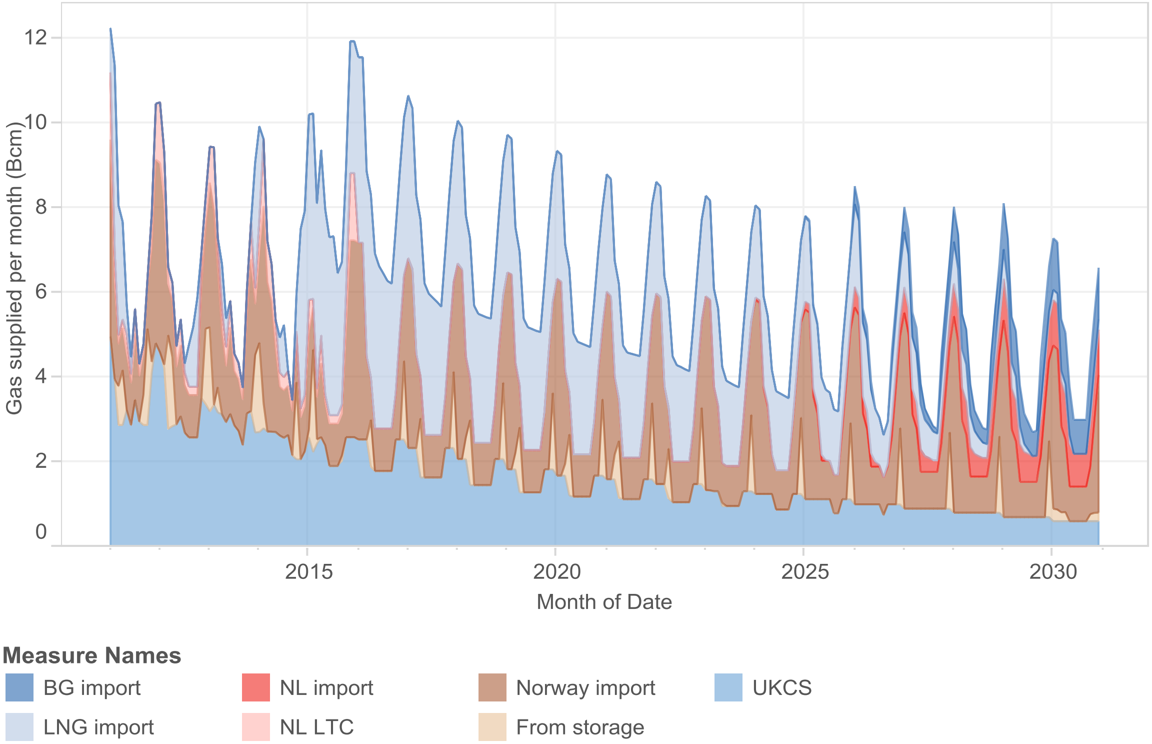

Figure 69: Breakdown of UK gas supply for 2011-2030 under the base case scenario

Examining Figure 69 and Figure 70 gives us an overview of the UK gas market under the base case scenario. In this case, UK's gas demand temporarily increases between 2015-2021 which is met by shipment of LNG. The increase in gas demand consists of increased demand of the power sector and increased export to Belgium. In summary, under the base case scenario assumption of abundant supplies of LNG up to 2025 (implied in Figure 53), the UK acts as a transit market for LNG. However, as the LNG market tightens post-2025, imports from Belgium and the Netherlands become essential for meeting the UK gas demand. Beyond 2020, the use of gas for power generation decreases significantly.

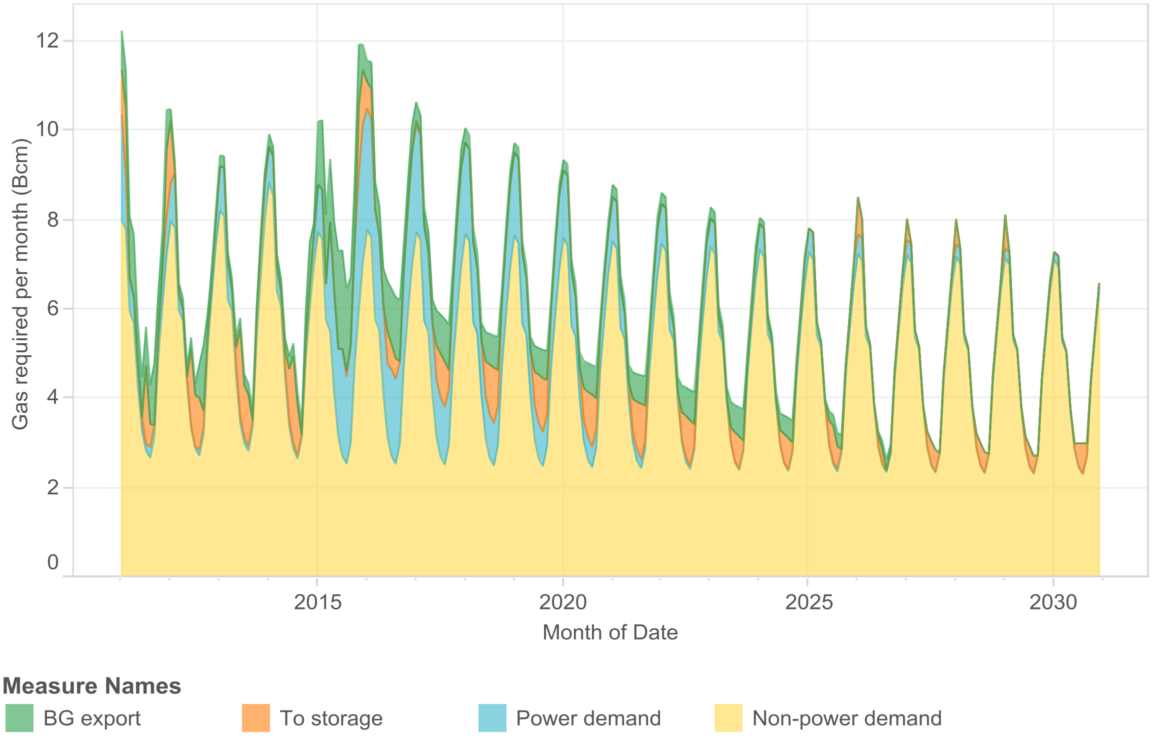

Figure 70: Breakdown of UK gas demand for 2011-2030 under the base case scenario

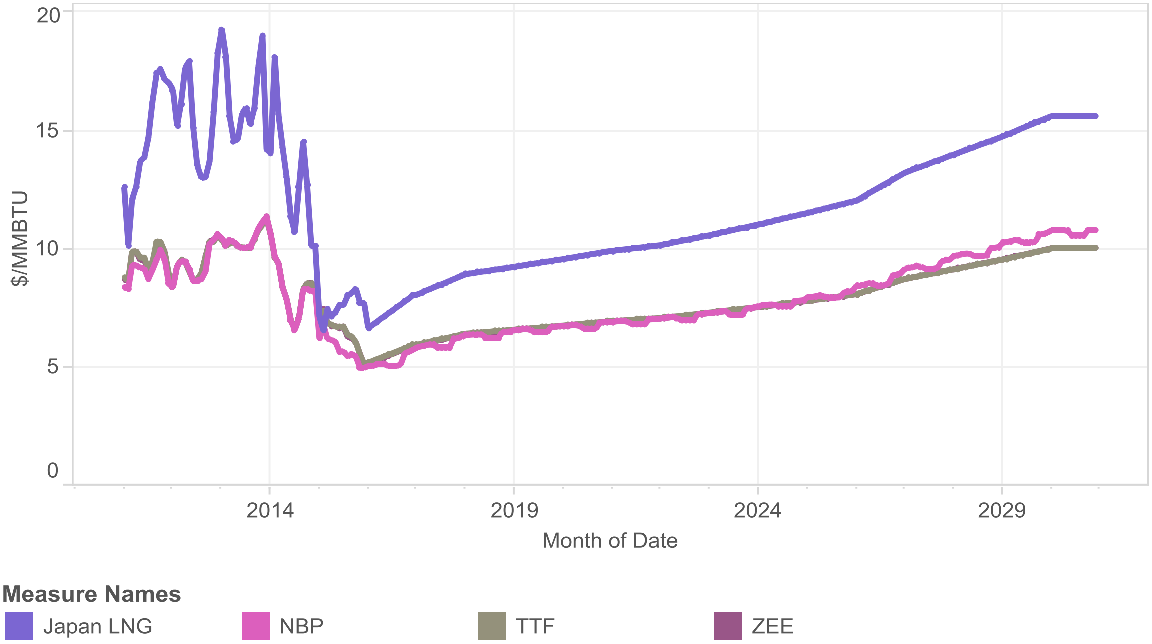

Figure 71: UK market price of gas under the base case scenario

Figure 71 shows that the UK market price for gas is anchored to that of the North-western European hubs. When LNG is being exported from the UK to continental Europe, between 2015 to 2025, the UK market price is consistently lower than ZEE/TTF; when pipeline gas from Europe is being imported in great quantity to meet UK demand (post 2025), the NBP price is higher than ZEE/TTF price to attract import. During both periods, NBP exhibits a seasonal pattern relative to the continental prices due to the seasonality of UK demand: lower during the summer and higher during the heating season.

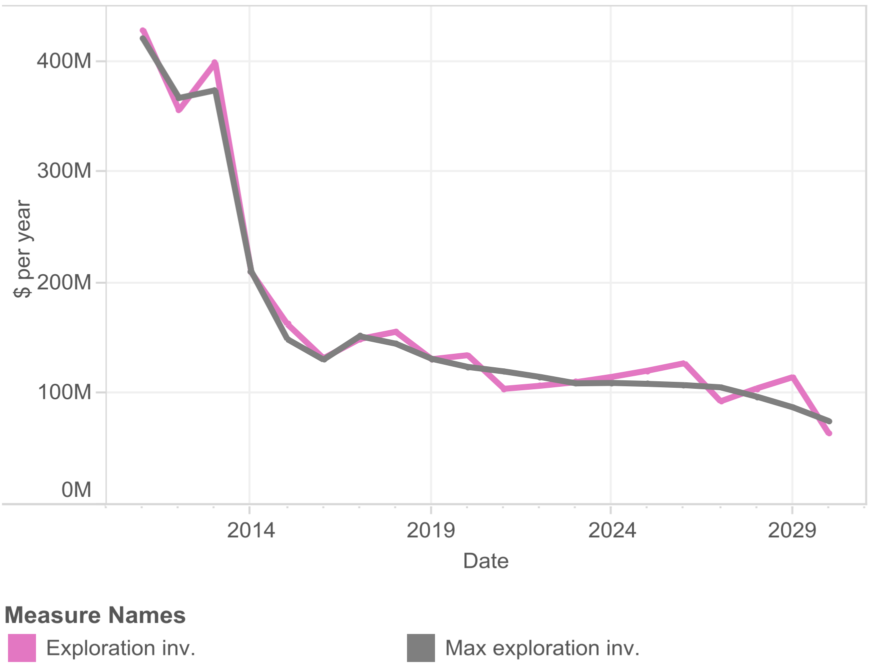

Figure 72: Maximum UKCS exploration investment cap and simulated exploration investment

Under the conditions assumed by the base case scenario, the numbers of exploration wells drilled in the UKCS will decrease over time due to falling gas producer income (declining production despite rise in NBP price) (see Figure 72). The limited extent of exploration and the small size of average discoveries constraint the reserves that can be discovered and subsequently developed (Figure 73). The lack of prospects to be developed is the constraint to the addition of new capacity to UKCS production, instead of lack of development fund. Because, as Figure 74 shows, the development fund cap set is never reached.

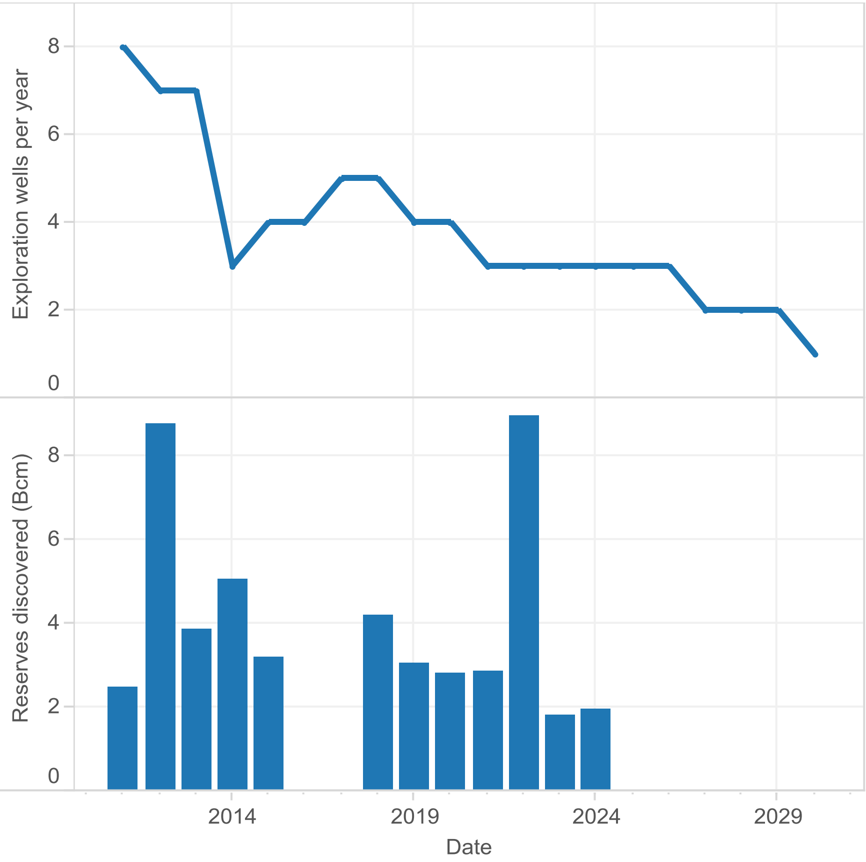

Figure 73: Exploration outcome in the UKCS under the base case scenario

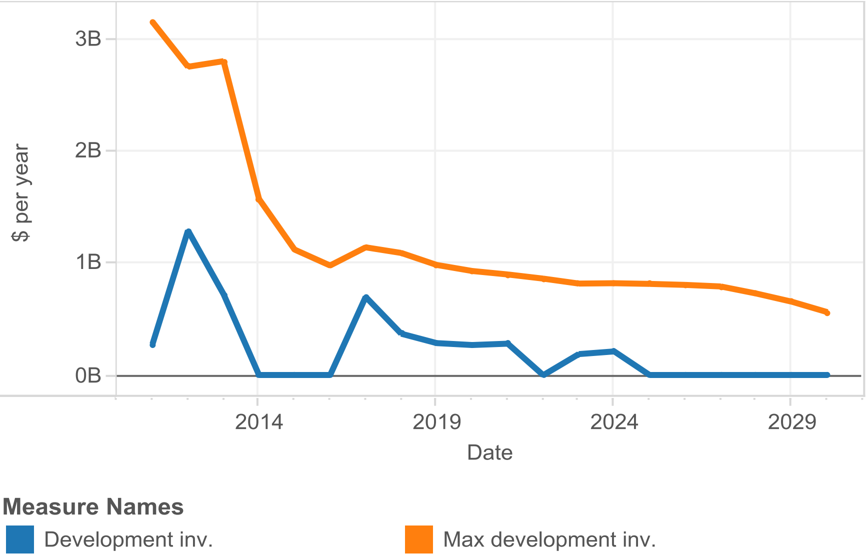

Figure 74: Maximum UKCS development investment cap and simulated development investment

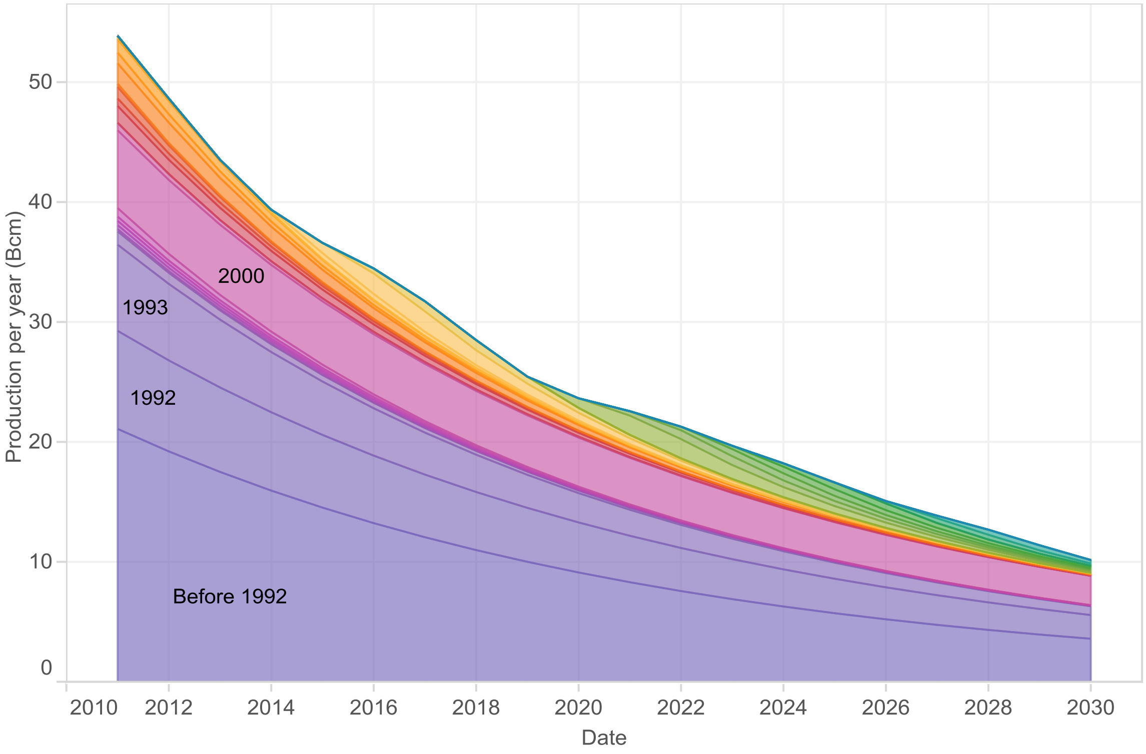

Figure 75: UKCS production capacity under the base case scenario

Given the above, limited new capacity can be added to UKCS production. Newly developed reserves do not reverse the declining trend of production capacity, it only slows down its decline. By 2030, the majority of still producing fields are slow-declining, large reservoirs that are commissioned before 2000 (Figure 75).

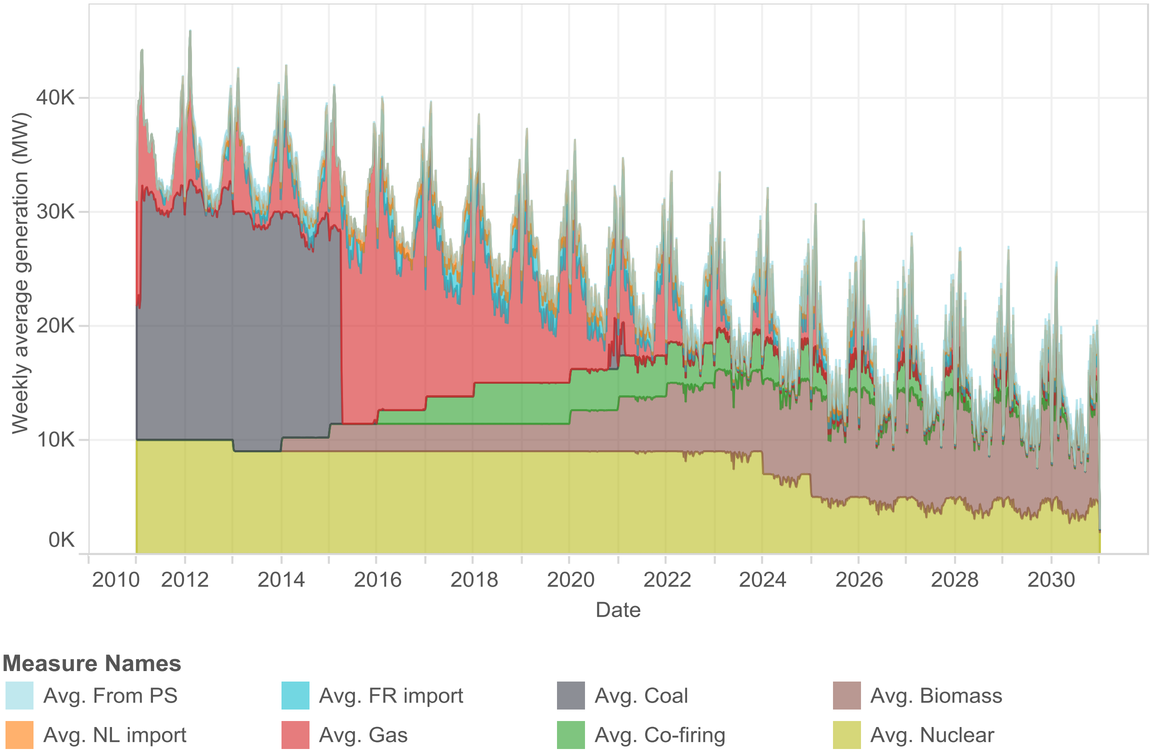

Figure 76: Breakdown of weekly average generation for 2011-2030 under the base case scenario

Given the power market is modelled at hourly resolution, there are 20x8760 = 175200 data points for each type of generation, if the original results were to be plotted at the same resolution. To increase legibility and ease of interpretation, the weekly averages of hourly data are plotted to show the breakdown of generation and demand for the power market.

Figure 76 shows that, after fuel-switching from coal to gas occurred in 2015, due to lowered price of gas induced by plentiful LNG supplies in the global market, coal generation never really recovers. Generation from biomass units gradually come to dominate dispatch able generation, surpassing gas and coal generation toward the second half of 2020s. Generation from co-firing and gas generating units decreases importantly after 2020, because of the important increase in carbon price, assumed under the base case scenario.

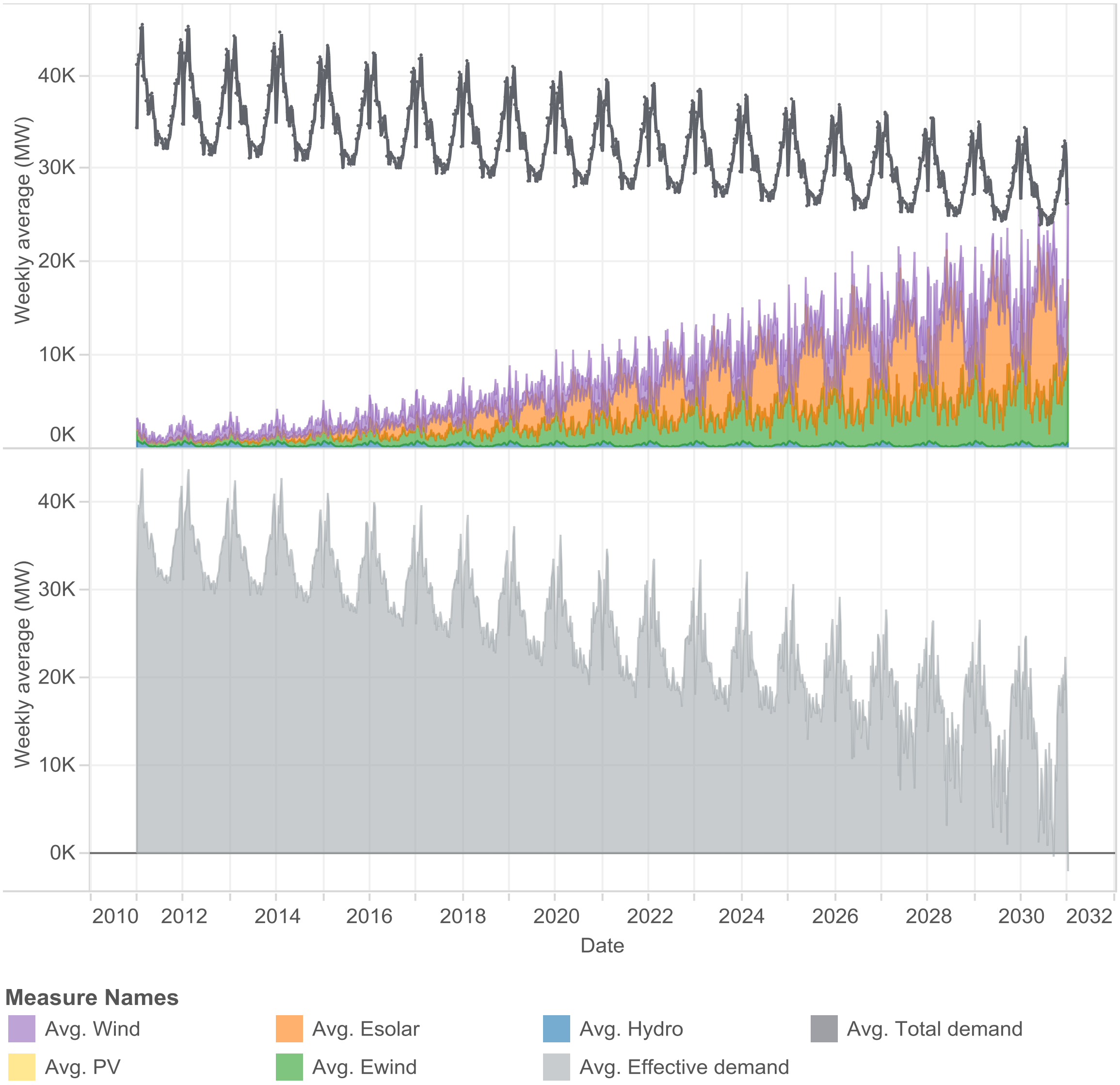

Figure 77: Breakdown of effective demand for 2011-2030 under the base case scenario

The demand met by dispatchable generators in Figure 76 decreases by half between 2011 and 2030. This is not due to a significant fall in overall power demand, but caused by the increase in embedded generation and grid-connected intermittent generation such as solar and wind. Between 2011 and 2030, under the assumptions made for the base scenario, embedded and grid-connected non-dispatchable generation increases to cause “fraying” of the effective demand: the demand that is to be met by dispatchable generators decreases and becomes increasingly volatile (Figure 77). If plotted on an hourly basis, it can be seen that there are cases of “negative demand” during which non-dispatchable generation produces more than the total demand of the grid. This is concealed in the presentation of weekly averages. For this reason, UK’s power export to France and the Netherlands, negligible before 2020, increases, to absorb this excess of renewable generation (Figure 78).

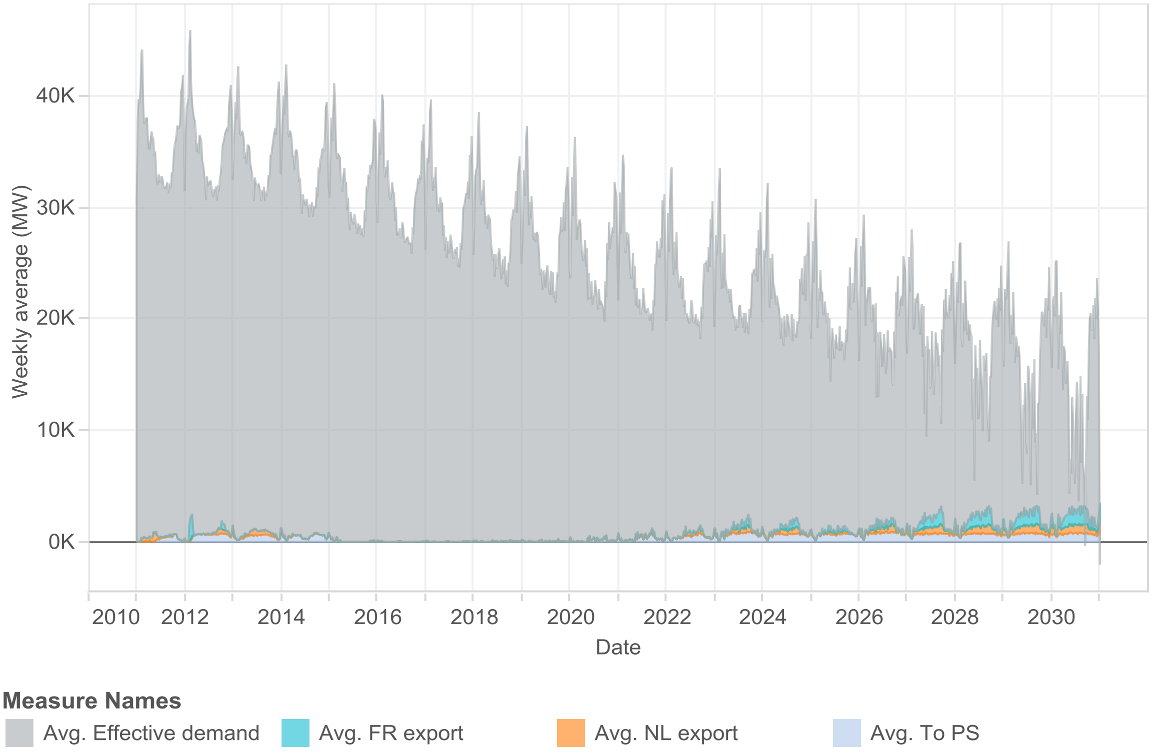

Figure 78: Breakdown of UK power demand for 2011-2030 under the base case scenario

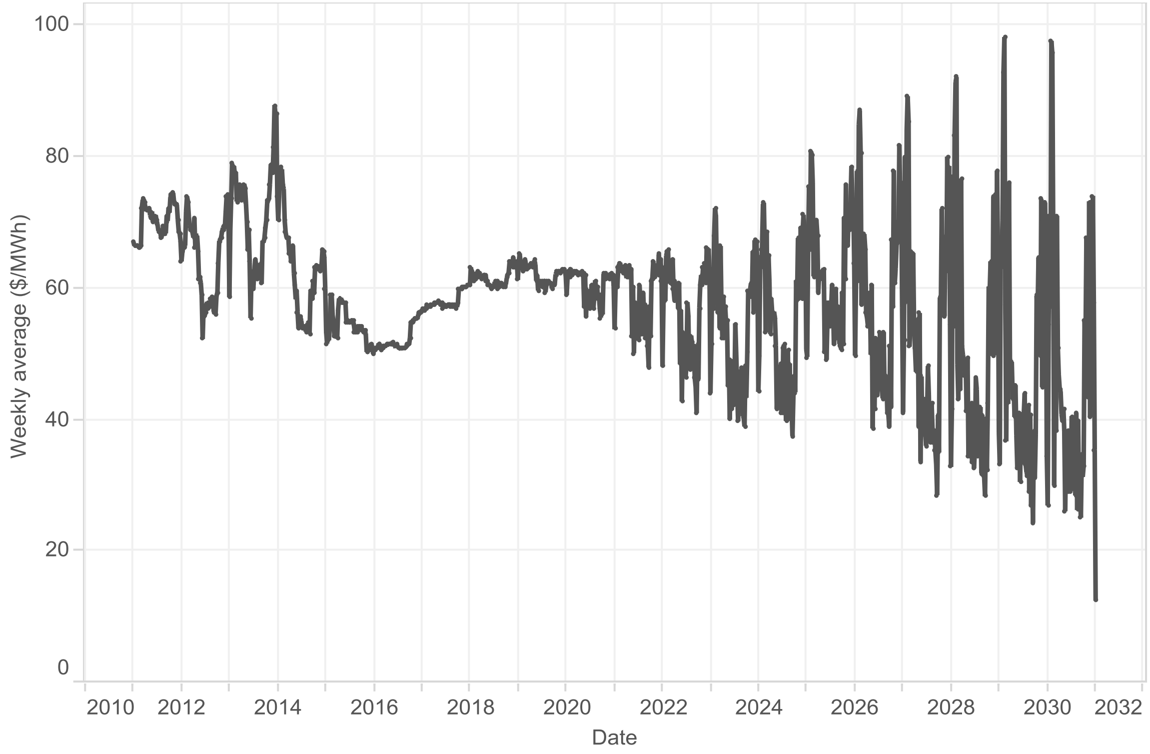

Figure 79: Weekly average UK market price of power under the base case scenario

The volatility in effective demand is reflected on the market price of power. After 2020, the marginal cost of meeting an additional unit of demand (assumed to be the market price of power in a competitive market) is increasingly dynamic. The monthly average of the power price is compared to the French and Dutch market prices assumed for the base case scenario in Figure 80. The UK power market price moves broadly in line with the two other price series until 2020, after which discount relative to the two other markets is needed due to the necessity to export excess renewable generation.

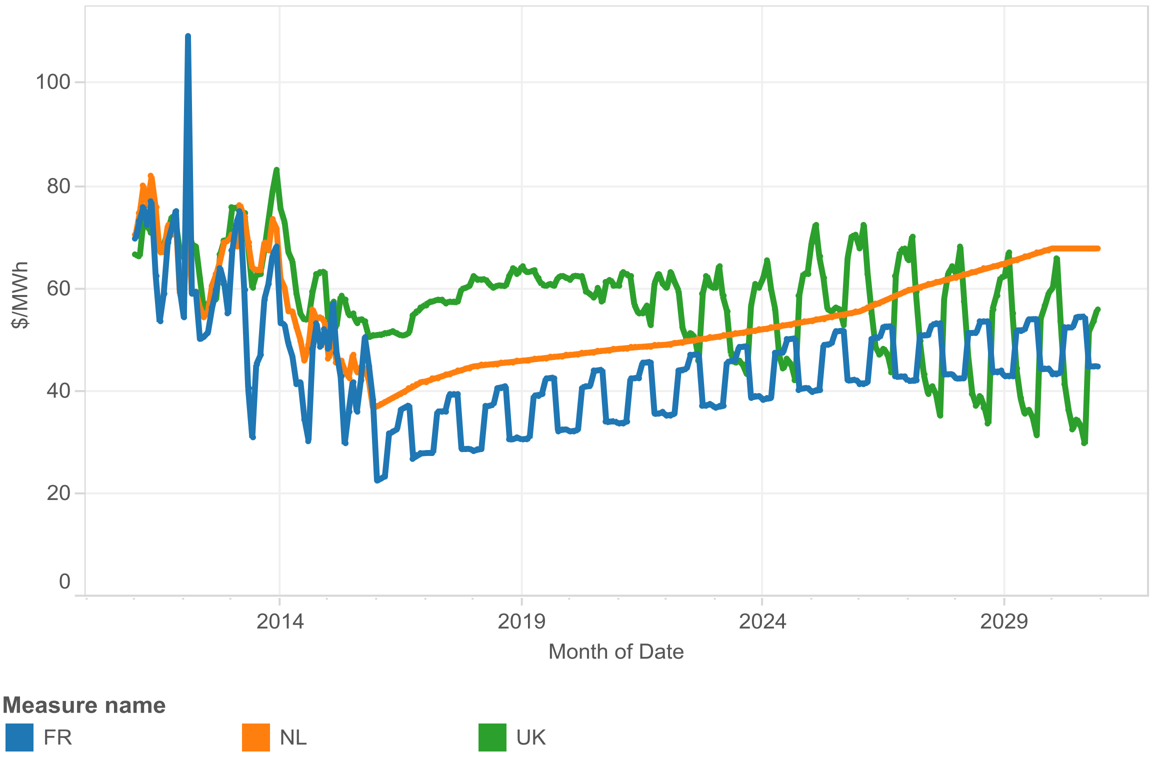

Figure 80: Comparison of monthly average UK, FR and NL power prices

In terms of generation investment in the UK's power sector: investment in converting coal generation plants to co-firing ones are made until the renewable support scheme no longer supports it (transitioning from RO to CfD), while the conversion of coal generation plants to biomass ones continue until there are no more coal generation units remaining. Investment in PV, on-shore, and off-shore wind is continuously made, provided that the renewable support scheme operates as assumed in the base case scenario (Figure 81).

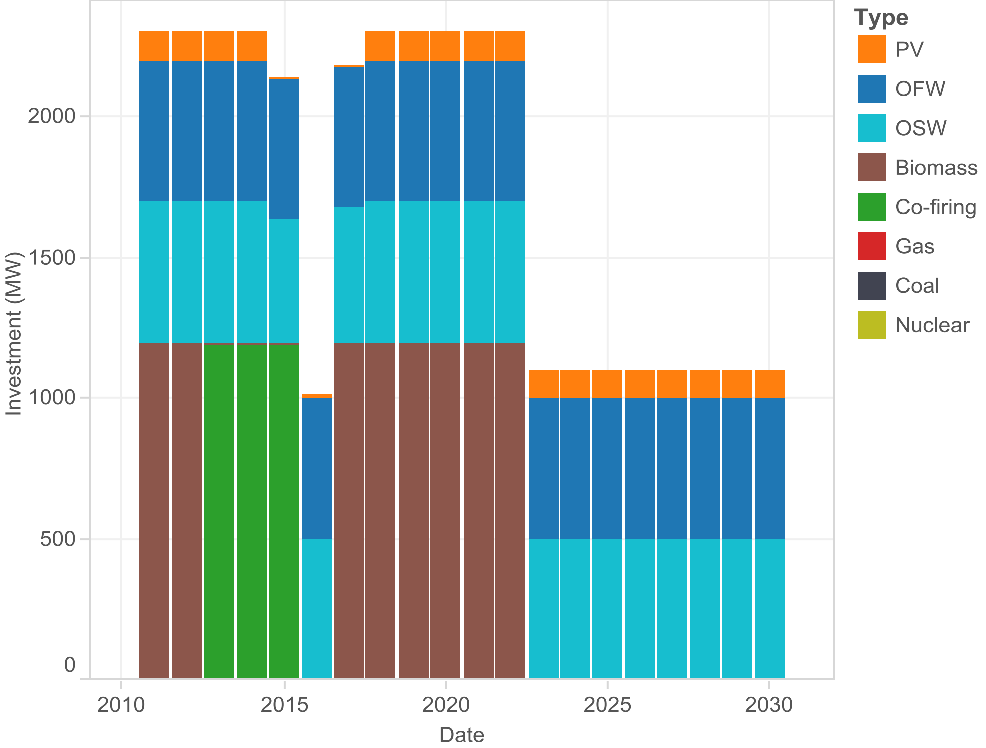

Figure 81: Investment made in each year under base case scenario

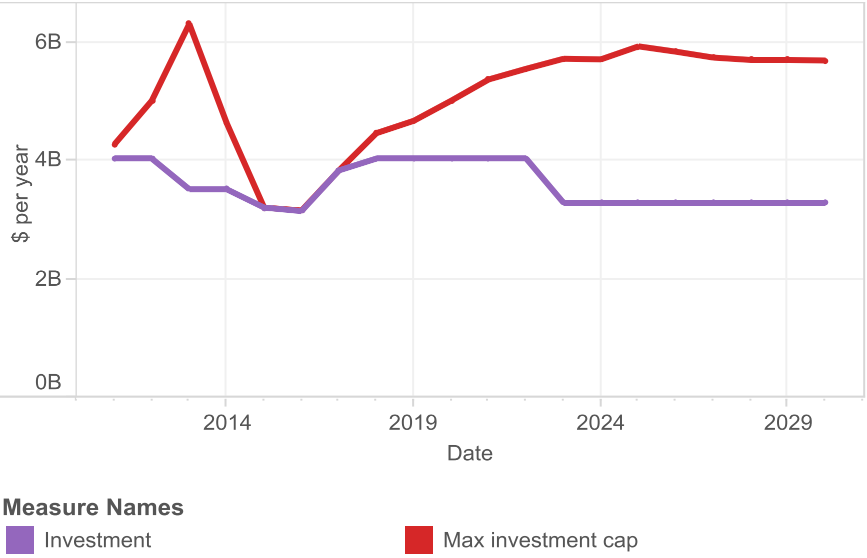

Figure 82: Maximum UK generation investment cap and simulated generation investment

Between 2015 to 2017, investment is constrained by industry cash flow (Figure 82). The decrease in generator operating profit, or more specifically coal units' operating profits, is caused by a fall in power price (induced by a fall in the price of gas, which is marginal generating unit that sets the price during that period) and the subsequent fuel-switching from coal to gas. The sector's operating profit improves as more renewable power generating capacity comes online and start collecting revenue (Figure 83). The pay-out of capacity payment starting in 2018 is also believed to have helped alleviate the investment capital constraint by contributing to industry revenue.

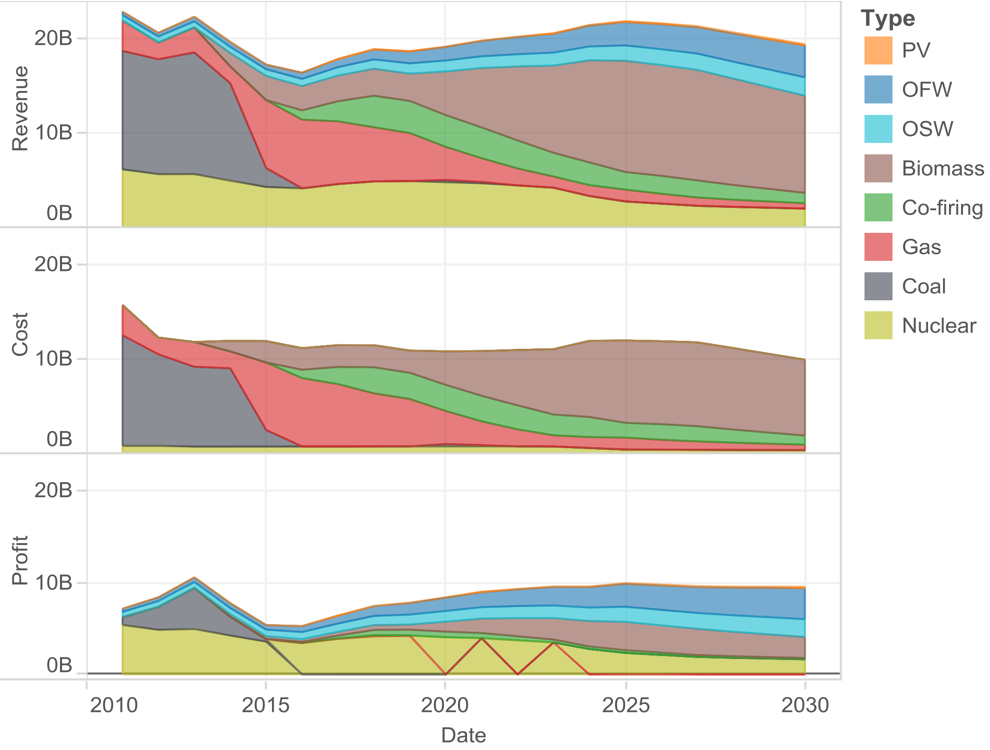

Figure 83: Breakdown of generators' revenue, cost, and profit by technology

The evolution of the installed generation capacity for the UK is shown in Figure 84. All coal capacity is either converted into co-firing/biomass or decommissioned by 2023. The overall installed capacity remains the same, although its composition has changed: in 2011, renewable energy generators (co-firing, biomass, PV, and wind) capacity constituted less than 10% of the total installed capacity, while they represent nearly 50% of installed capacity in 2030. It is believed that no investment in nuclear generating capacity is made, because the minimum investment required ($6.5 billion) is above the assumed industry investment cap (60% of operating profit).

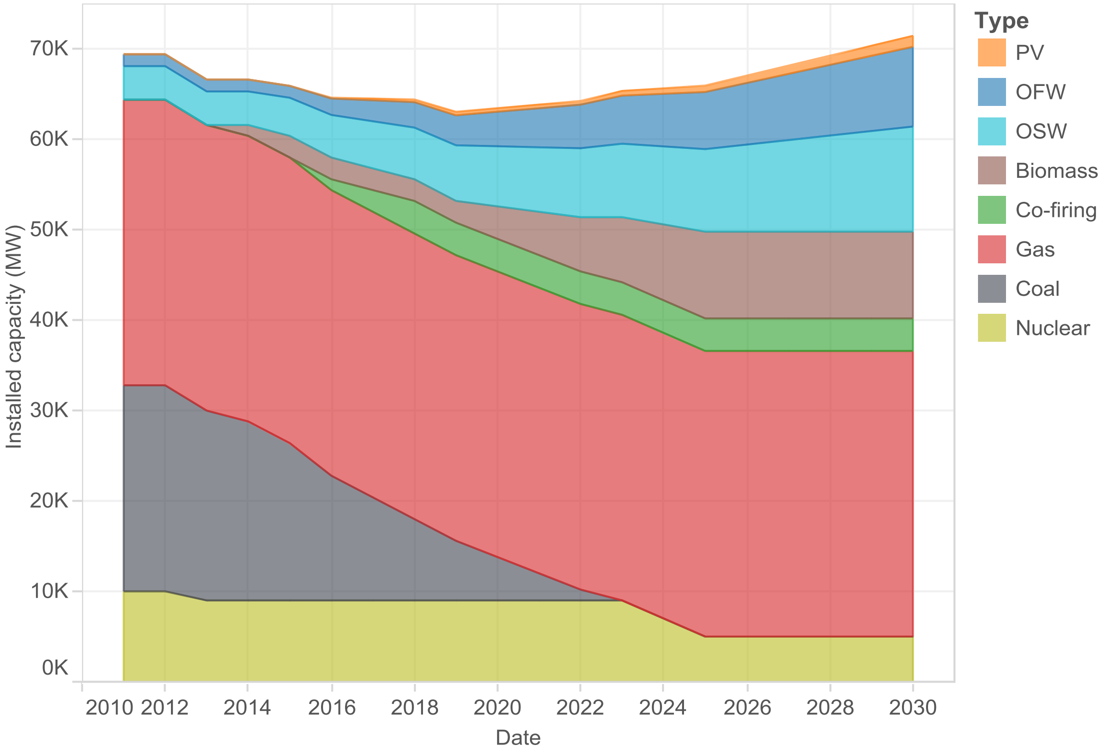

Figure 84: Evolution of installed generation capacity for 2011-2030 under the base case scenario

6.3 Discussion

The historical outcome for the UK gas and power markets between 2011 and 2015 are shown in Figure 85 to Figure 90. In general, an overall survey of the historical results and the simulation results shows that the simulation model captured the key features of the UK gas and power markets. The simulated gas and power market prices, when regressed against the actual prices, have a R^2 of 0.97 and 0.78, respectively. Nevertheless, the historical period for which data is available displays limited change in dynamic; it is also short relative to the simulation period of 20 years, therefore continued evaluation of the model against updated data will be beneficial.

It should be emphasized that the simulation model is to be used to infer internally consistent dynamics based on exogenous scenario, and not to be used as a forecast tool. Therefore, differences in the exact levels of variables are considered acceptable as long as the overall trend displayed is meaningful. The most important departures of the simulated trends from historical conditions are observed and discussed below.

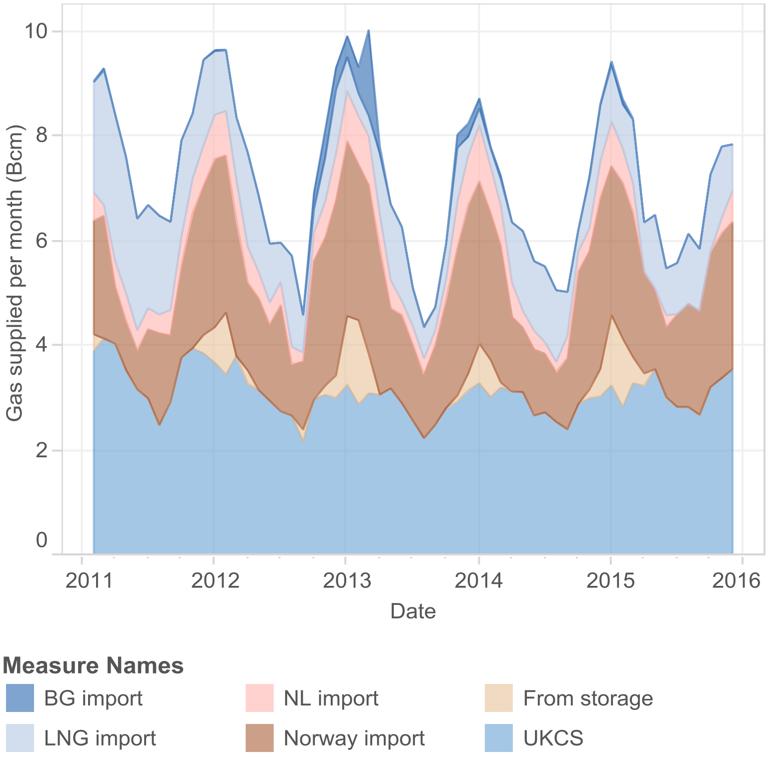

Figure 85: Breakdown of historical UK gas supply for 2011-2015

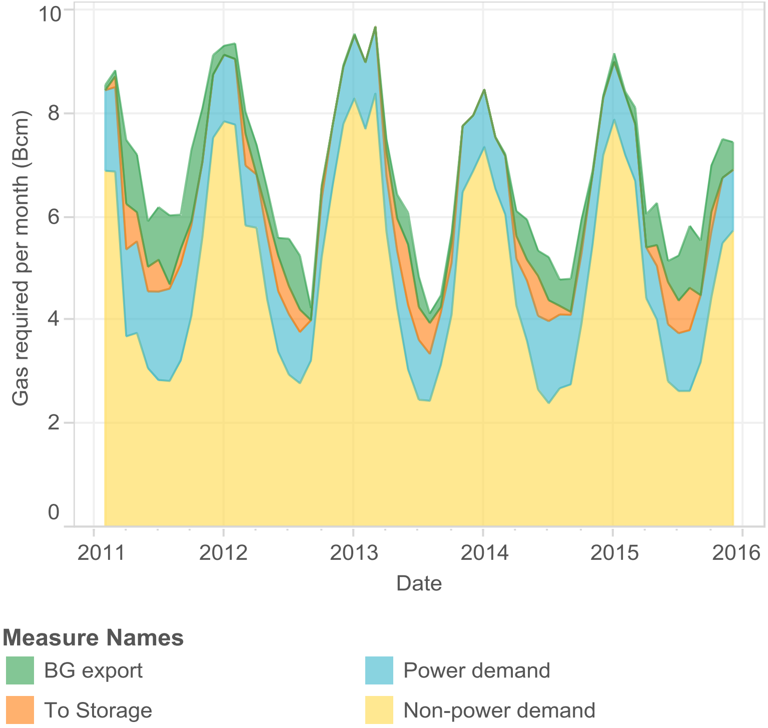

Figure 86: Breakdown of historical UK gas demand for 2011-2015

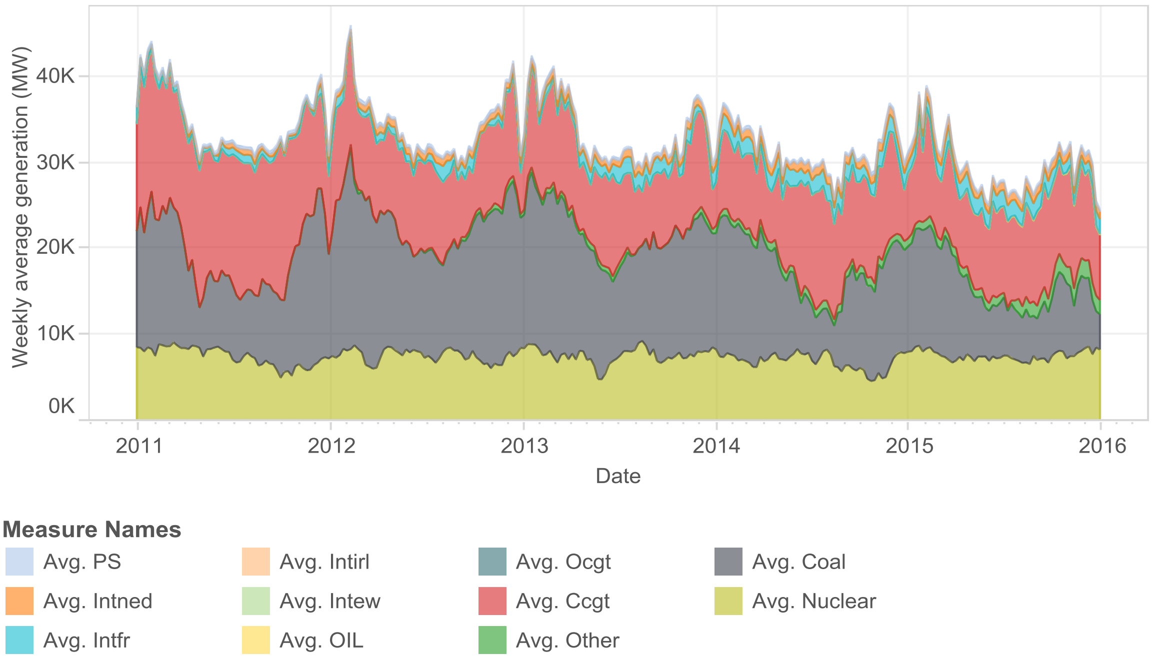

Figure 87: Breakdown of historical UK power supply for 2011-2015

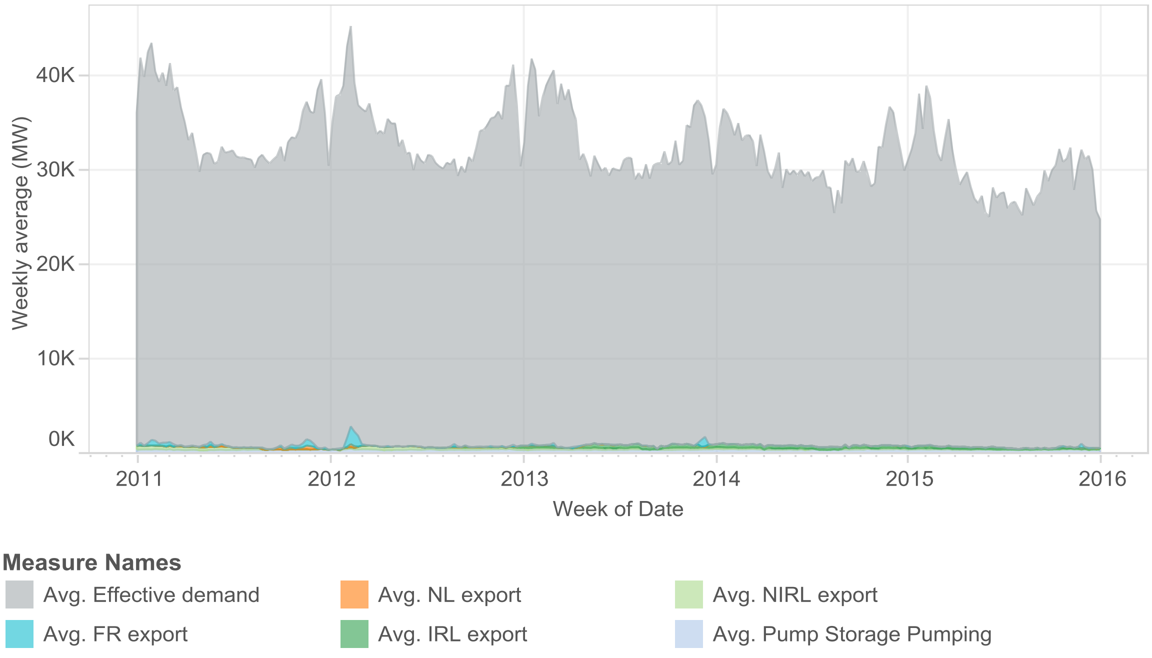

Figure 88: Breakdown of historical UK power demand for 2011-2015

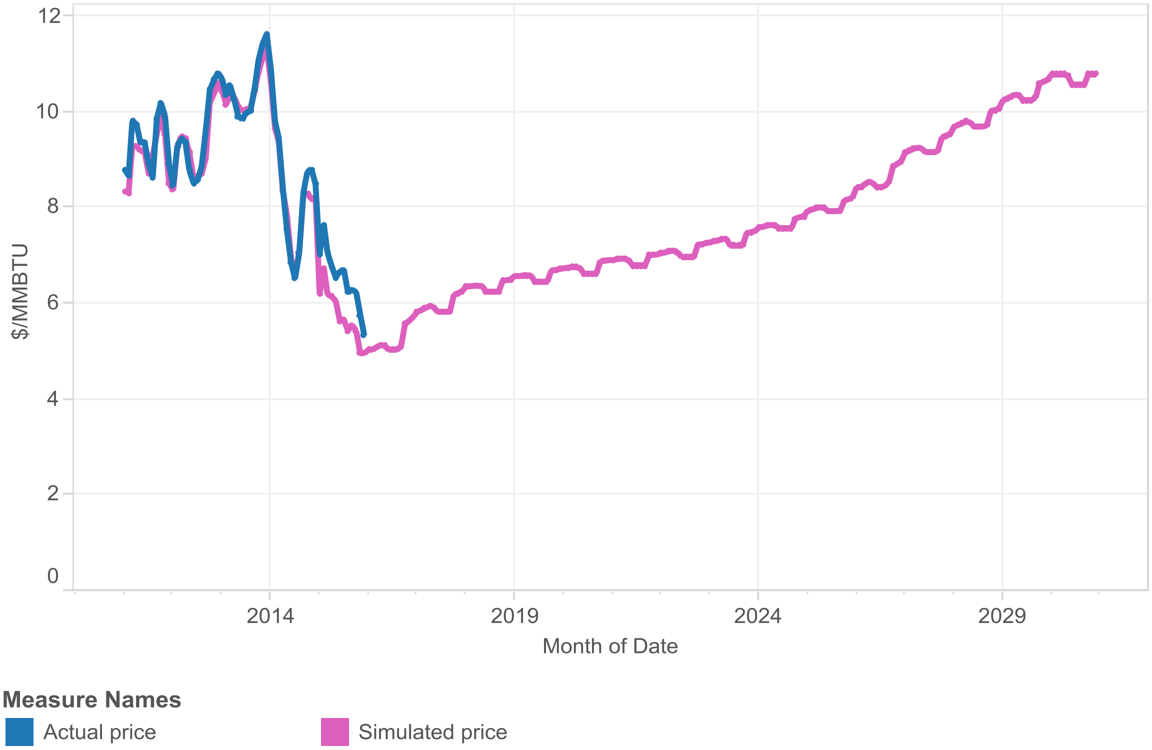

Figure 89: Comparison of actual and simulated UK gas price

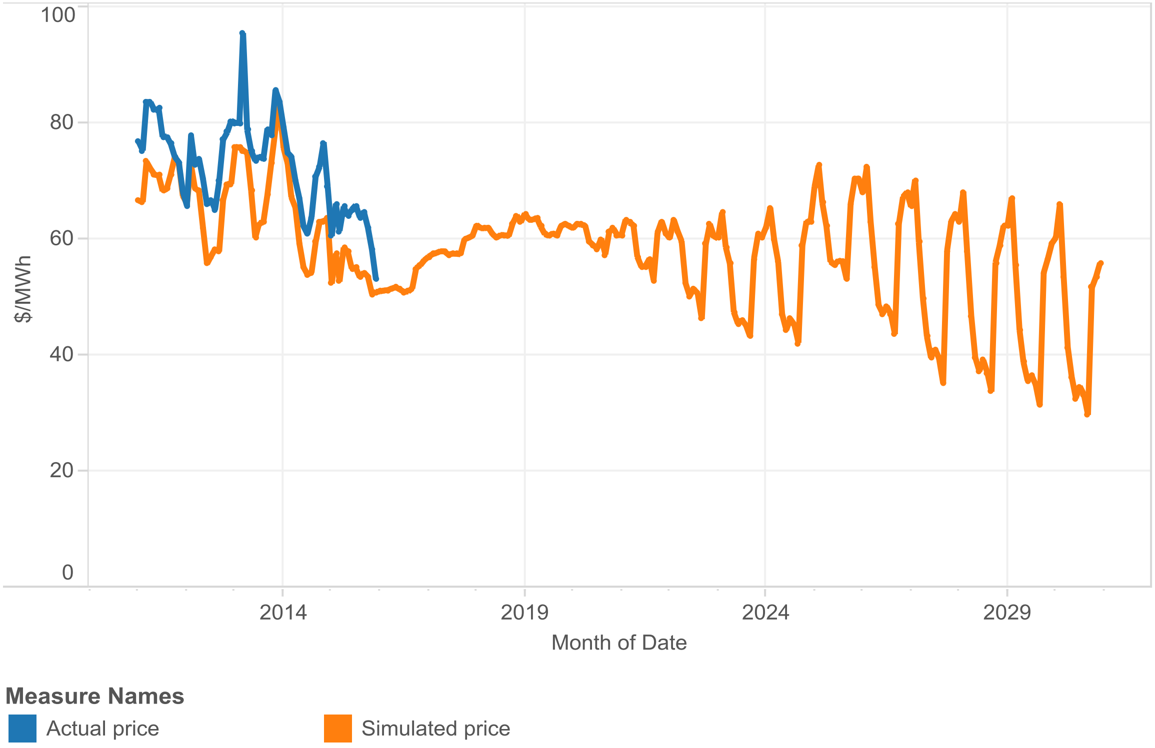

Figure 90: Comparison of actual and simulated UK power price

For the gas market, the main difference between the simulated case and the historical results is that LNG import did not increase as rapidly as expected, once the global LNG market became over-supplied, as implied by the fall in the Japan LNG spot price. In other words, LNG supply is not as price-responsive as assumed in the base case scenario. Literature suggests that LNG arbitrage might not occur as much as might have been expected, given a certain price differential between two regions, because of the transactional cost that is involved in re-routing the LNG cargo (Chyong & Kazmin, 2016). Time and logistical accommodation is required for LNG producers to respond to any shortfalls of demand or new market opportunities. This is also the reason why the simulated gas price has fallen more than the actual price in 2015: since the LNG import has not been as forthcoming as in the simulation, the reliance on pipeline gas imported from continental Europe has kept the UK gas price up.

Another key departure of historical results from the simulated results, one that straddles the two markets, is the fact that gas-fired power generation (and consequently the gas demand of the power sector) is higher than that determined by the power market model, given known upstream fuel and operating costs of different generation technologies (compare Figure 87 with Figure 76, and Figure 86 with Figure 70). This could be explained if some of the gas-fired generation capacity has lower operating costs than that specified (possibly in the form of higher thermal efficiency), so dispatch occurs even when the simulation does not expect it. Or, if some of the gas-fired generation capacity has long-term gas procurement contracts with take-or-pay clauses, so that they bid to generate electricity regardless of the market price of gas.

In the power market, an important difference between the historical results and the simulated results is that generation from biomass (currently reported under the catch-all term “other”) in 2014-2015 did not reach the level proposed by the simulation model. This warrants more investigation in the history and current status of biomass generation projects in the UK. It is believed that the lack of a clear regulatory signal prior to 2012 could have delayed the time by which investment in co-firing/biomass plants from converted coal units began. If this is the case, the increasing biomass generation should be observed in the near term as the plants which reached final investment decision since 2012 come online.

Another difference between the simulation results and historical data is the gap between the simulated and actual price of power. The historical price of power in the UK (OTC M1 baseload used as reference) is consistently higher than the price determined through the simulation. This suggests that gas generators bid not at their marginal cost, but at a price level that incorporate a mark-up over their marginal cost. Investigation of the determinants of this gap would also improve understanding of the UK power market.

How did power sector developments affect gas demand?

The increase in carbon price since 2010, the continuous decrease of effective demand due to increase in non-dispatchable generation, and the investment in biomass-fired generating capacity, supported by regulatory schemes, squeezed power sector gas demand so that it is only 4% of its peak value in 2017 by 2030.

How did uncertain upstream fuel costs (such as the cost of natural gas) affect the outcome of regulatory measures in the power sector?

The fall in natural gas price in late 2014 encouraged the fuel-switching from coal to gas, which accelerated the phase out of coal-fired generation capacity. After that, the price of gas no longer consistently set the price of power. As the effective demand of power becomes increasingly volatile, so does the marginal cost of meeting demand.

How does the joint performance of gas and power industries compare against overall UK energy policy goals? What are the implications?

Security

For the gas sector, by the end of simulation period, in 2030, the UK imports 85% of its natural gas, compared to 47% at the start of the simulation period. Depending on the difference in price/availability, import from Continental Europe through pipelines and import of LNG cargoes are both used to meet the UK's gas demand. The balancing loop L2, through which UKCS producers respond to market price with exploration and development investment is not active because of several reasons:

- Given the available channels for import, the price of natural gas in the UK is driven by the marginal import that is needed to balance supply with demand. This means that a decline in UKCS production does not drive up the market price for gas unilaterally. In fact, a glut in the global or North-western gas markets is able of driving down the UK market price for gas despite reduced UKCS production. Therefore, UKCS producers are not incentivised to greatly increase their production capacity despite decline;
- The decline of production, on the other hand, reduces the revenue that UKCS gas producers collect from the gas market. This, combined with the inflation in gas exploration, development, and production costs are tied in-part to the price of oil, limit the extent of exploration that actually occurs in the UKCS.
- Finally, the average size of reservoirs discoveries is small due to the maturity of the basin, so the already reduced exploration efforts do not yield discoveries of a size that is large enough to reverse the declining trend of UKCS production.

It is found that the core constraint in capacity addition to UKCS production is the drilling of exploration wells and the small size of reserves discovered, therefore policy measures that will encourage and improve exploration efforts are expected to delay the decline of UK's domestic production capacity.

Sustainability

For the power sector, if power sector investors make decision in the manner specified in the simulation model, then the UK should be able to generate more than 90% of its electricity through low-carbon sources (nuclear, biomass, hydro, wind, and solar), due to the decommissioning/conversion of coal and nuclear capacity and the commissioning of renewable generating units.

The key driver in this balancing loop (L4) is not the potential market revenue of new generating capacity, but the guaranteed regulatory revenue that is set by the government through a growing number of complex regulatory schemes. The market revenue of carbon-intensive generating capacity is negatively impacted by the significant upward change in the ETS carbon price post-2020.

The fall in the revenue of conventional generation first slows down investment in the generation sector due to funding constraint. But, as growing (regulatory) revenues are collected by newly commissioned renewable generating capacity, investment constraint is resolved. The large size of the minimum investment required for new nuclear generation capacity relative to the operating cash flow of the power producers is a constraint in new nuclear investment.

Affordability

It is found that the UK's market price for gas is tied to the price of gas elsewhere (especially those in North-western Europe). As for the market price of power, volatility of the wholesale market price is expected to increase as intermittent non-dispatchable generation "unravels" demand. As import and export become important tools for managing excess/shortfall of generation, the UK's market price of power is expected to be tied in general trend to those of countries with which it trades electricity. In so far as its affordability concerns the wholesale prices of power and gas, the UK government has relatively little control over the final outcome, given the evolution of the prices are influence by global energy market developments. The retail price of power needs to be assessed separately, for the consumers' energy bills contain the cost of renewable support schemes such as the RO, CfD, and FIT (not modelled since embedded generation is made exogenous) in addition to the wholesale price of power.

6.4 Future work

The future work that is recommended with respect to this thesis is viewed from to different perspectives: work that is needed to address issues raised concerning model validity and work that is needed to address the uncertainty of exogenous variables.

In terms of work needed to improve model validity, the four differences between the simulation results and the historical results between 2011 and 2015 need to be further investigated:

1. The delayed/absent increase in LNG import following the softening of Asian demand and subsequent loosening of the global LNG market;
2. The persistent gas fired-generation between 2011-2014 that appears to be non-price responsive, dispatched although the relative gas and coal prices, along with other assumed parameters for generating technologies, suggest that coal should be dispatched instead;
3. The delayed uptake of biomass/co-firing generation;
4. The difference between the realized price of power in the UK and the simulated one (the marginal cost of the marginal generating unit, which is gas for the period 2011-2015.

Once these discrepancies between simulation results and actual system behaviour are better understood, it should be decided how the current model can be amended to incorporate the causal relationships behind these discrepancies.

In terms of work needed to address the uncertainty of exogenous inputs, further simulation trials with the model in the form of sensitivity analysis (change in individual input) and scenario analysis (change in set of inputs) is necessary. The base case scenario used in this thesis is only meant to be a demonstration of the capability of the simulation model proposed. It is not meant to be a forecast of the future, but an illustration of one of the possible pathways. A short list exogenous inputs, considered important to the dynamics of the simulation results, is proposed for further testing:

- UKCS exploration efforts relative to operating profit and the maximum fraction of gas cash flow used for exploration;
- UKCS fiscal regime (tax rate applicable to producers);
- Prices of gas in alternative markets of import (ZEE, TTF, and Japan LNG spot);
- Strike prices for CfD scheme;
- ETS carbon price and the UK carbon price floor;
- Price of power in alternative markets of import (FR and NL).

It is also possible to expand the scope of the model to include elements which are currently specified exogenously.

For the power sector, investment decisions (and the subsequent commissioning) are generated endogenously within the model, but all decommissioning decisions are specified exogenously. Following the model development exercise, it is found that such exogenous representation of decommissioning decision might not be appropriate. It is assumed that only coal and nuclear units are decommissioned due to non-market decisions (regulatory ban and technical lifetime constraint). But, as the share of gas-fired generation greatly reduced after 2020, in the base case scenario, it is not appropriate to assume that all the gas-fired generation capacity will stay online throughout the simulation period. Instead, parallel to investment decisions, the decommissioning decisions of existing units made by generators should be endogenously modelled to internalize the interaction between existing capacity and newly added capacity. Decommissioning in the gas sector, currently only implicitly represented in the model in the form of decline of UKCS production capacity, might need to be formally incorporated as an activity, as decommissioning cost is expected to rise as the number of fields reaching the end of their productive life increases. This could further deter exploration activities in the region since decommissioning cost consumes more of the operating profit available, before it can be reallocated in capital investments.

Some of the regulatory cost/revenue of power generators (ETS carbon price, capacity payment, CfD strike price) is not set administratively. Instead, a competitive mechanism, typically in the form of an auction of fixed allocation of carbon credits/capacity/budget, is used to determine the price level. These procedures could be internally represented to elucidate potential interaction between their price levels and UK power/gas sectors.

Another direction for the expansion of model scope is in the inclusion of more national energy system, thereby endogenising the price formation process in alternative markets such as France, the Netherlands, and the global LNG market.

7 Conclusions

This thesis was set out to explore the interdependencies between long-term investment decisions of the UK's power and gas industries. The interdependencies between these two network industries have been growing during the past two decades along many dimensions: physical, commercial, and regulatory. An emerging body of research focused on gas and power interdependencies has developed, as a consequence of rising interdependencies. Because, technical, commercial, and regulatory decisions made with narrow scope, without considering potential interaction between the two industries, might cause unwanted consequences or fail to take advantage of opportunities.

The challenge of gas and power interdependency research dwells in its multidisciplinary nature and broad scope. The gas and power industries are complex socio-technical systems, with structural similarities and significant differences in their technical, commercial, and political aspects. Therefore, research involving both requires a multidisciplinary perspective and multidisciplinary tools.

This thesis contributes to the nascent body of research on gas and power interdependencies through its multi-method approach, which allows for the gradual identification and evaluation of long-term interdependencies between power and gas industries in the UK. From qualitative to quantitative, from general to specific, the four methods used offer different lenses through which to view gas and power interdependencies: a literature review of research traditions in long-term investments in power and gas sectors, a case study that dissects the UK's gas-to-power supply chain segment-by -segment, an econometric study that test for cointegration between gas and power prices series, and a System Dynamics simulation model that allows for quantitative testing of uncertain scenarios.

Although these four studies can be viewed independently, they have benefitted from being conducted in proximity. The findings of the more general studies have been able to inform the research methodology of subsequent, more specific studies.

The first study, the methodological review, has identified seven lines of inquiries active in gas and power research on long-term investments. It found that gas sector researchers most commonly investigate *the evolution of supply and demand*, through qualitative approaches such as strategic driver analysis/scenario analysis, and quantitative approaches such as optimization and equilibrium models, simulation models, and econometric analysis. On the other hand, power sector researchers most commonly investigate *the design of regulatory frameworks*, largely through simulation models, but also through the presentation of frameworks of considerations, stylized examples, or case studies. At the end of the methodological study, the exploratory research objective of this thesis – to explore the physical and informational interdependencies of UK gas and power sectors' investment decisions – is re-articulated in terms of the most active lines of inquiries within power and gas long-term investment research. Also, System Dynamics modelling is selected for the study of interdependent dynamics of power and gas sector investments, but it is also recognized that additional tools are needed to address the weaknesses of SD modelling: model formulation is highly dependent on modeller's domain knowledge; as a result of the SD approach's focus on endogenous dynamics, uncertainty and correlation in exogenous variables are not specifically addressed.

To provide a qualitative understanding of the UK's power and gas sectors, essential before any mathematical formalization can be attempted, a holistic case study that analyses the UK's gas-to-power supply chain systematically is conducted. Beyond a review of historical development of gas and power use in the UK, the case study covers the maturity of the gas and power infrastructure, the coordination mechanism adopted by industry agents, the government's policy agenda and how it may influence the industry's self-regulating decisions. The case study found that in the UK's gas to power supply chain, mainly coordinated through the market mechanism, uncertainties plague two particular segments: domestic gas production and power generation. The regulatory actions carried out by the government to achieve is sustainability and security goals, mainly targeting the power generation segment, exposes power and gas sector agents to regulatory uncertainty. These insights are used in the SD modelling study to make decisions about the appropriate model scope: the model focuses on endogenous gas production and power generation investment decisions, with investments in other segments are represented exogenously.

To provide empirical evidence on the nature of relationships between the UK's power and gas prices and those of markets to which the UK is connected to (some of the most important exogenous variables), an econometric study using the two step Engle-Granger procedure is carried out on 16 energy commodity price series across various geographic regions. The cointegration study found that the UK's gas prices are cointegrated with the North-western European gas hub's prices, and that the UK's power prices are cointegrated with the Dutch electricity price. It also found that the Dutch power price is driven by the North-western European gas prices, which have experience a transitioning relationships with the German import price during 2011-2015. These finding are incorporated in to the SD modelling study, informing the way market price formation is represented in the model and the set-up of consistent exogenous price scenarios. However, the cointegration study also found that price data with resolution higher than that used (monthly) is necessary to provide more definitive conclusions about cointegration between some of the series, especially for the power price series.

Finally, the SD simulation model developed is based on interconnected market, forecasting, and investment decision sub-models that form five key causal loops. These loops capture short-term and long-term self-regulation in the gas and power sectors and between these sectors. A base case scenario of exogenous inputs is developed based on 2011-2015 historical data and the author's best estimates for 2016-2030. The resulting simulation results are evaluated through comparison to historical outcome for 2011-2015 and interpretation of the results for the future years. The validation of the SD model found that the simulation captured key features of the UK gas and power markets and sector investment decisions, but four important deviations exist:

1. Historical LNG supply was as price-responsive as assumed in the simulation model;
2. Historical gas-fired power generation is higher than that determined by the power market sub-model when provided with historical costs;
3. Actual of biomass generation is more slowly than that proposed by the simulation model;
4. The actual price of power in the UK is consistently higher than that determined by the power market sub-model.

It is recommended that future work following this thesis explore these areas to improve the simulation model's representation of reality. Further simulation trials in the form of sensitivity analysis and scenario analysis are considered essential to make the best use of the model. Expansion of the model scope to endogenously represent decommissioning decisions, regulatory auctions, and interconnected energy systems is also recommended.

8 Appendix

Name	Description	Unit	Uncertainty	Sector	Sub-model
$a_{t,y}$	average monthly price in market t	\$/MWh	High	Power	Power market
$ACQ_{t,y}$	Annual contract volume for long-term contract	Bcm	Medium	Gas	Gas market
$B_{g,y}$	renewable obligation banding for different technologies	cert/MWhe	Low	Power	Power market
$C^{CO_2}_{m,y}$	carbon price in month m	\$/ton CO2	High	Power	Power market
C^{E}_{y}	cost per exploration well in year y	\$	Medium	Gas	Infrastructure stock
C^{D}_{y}	current development cost of reserves	\$/Bcm	High	Gas	Gas development
C^{F}_{g}	fixed cost for technology g	\$/MW	Low	Power	Power investment
C^{I}	investment cost for technology g	\$/MW	Medium	Power	Power investment
C^{OM}_{g}	variable operation and maintenance cost for g	\$/MWhe	Low	Power	Power market
C^{P}_{y}	operating cost for UKCS gas production	\$/Bcm	High	Gas	Gas development
$D_{h,y}$	effective demand of hour h	MW	Medium	Power	Power market
d^{GAS}	discount rate used by UKCS gas producers		Medium	Gas	Gas development
D^{NP}_{m}	non-power sector gas demand in month m	Bcm	Medium	Gas	Gas market
d^{POWER}	discount rate used by UK power generators		Medium	Power	Power investment
$dE^{D}_{b,0}$	reserves earmarked for development at start of simulation	Bcm	Medium	Gas	Infrastructure stock
δ	fraction of gas cash flow used for development		High	Gas	Cash flow
$\delta n_{g,y}$	decommissioned generation units of type g in year y		High	Power	Infrastructure stock
$\Delta P^{UP}_{\max,g}$	maximum ramp down speed	MW/h	Low	Power	Power market
$\Delta P^{UP}_{\max,g}$	maximum ramp up speed	MW/h	Low	Power	Power market
$d\bar{H}_{k,y}$	change in maximum working gas storage capacity	Bcm	Medium	Gas	Infrastructure stock

Name	Description	Unit	Uncertainty	Sector	Sub-model
$d\bar{I}_{t,y}$	change in power interconnector capacity	MW	High	Power	Infrastructure stock
$dn_{g,0}$	newly commissioned generation units at start of simulation		Medium	Power	Infrastructure stock
Δp_t^{GAS}	price premium needed for import	\$/MMBTU	High	Gas	Gas market
Δp_t^{POWER}	price premium/discount needed for import/export from market t	\$/MWhe	High	Power	Power market
Δq_t^{GAS}	price discount needed for export	\$/MMBTU	High	Gas	Gas market
$dq_{g,0,T^C+1}$	newly added generation investment to the construction queue at start of simulation		High	Power	Infrastructure stock
$d\bar{Q}_{t,y}$	change in gas supply infrastructure capacity	Bcm/month	Low	Gas	Infrastructure stock
$d\tau_y$	decline rate modifier		Medium	Gas	Infrastructure stock
$d\underline{X}_g$	standard size for incremental investment in g	MW	Low	Power	Power investment
$\bar{E}$	average size of reservoir discovered	Bcm	Medium	Gas	Infrastructure stock
$E_g^{CO_2}$	carbon emission associated with fuel use of g	ton CO2/MWht	Low	Power	Power market
$E_{b,0}^D$	inventory of undeveloped reserve at beginning of simulation	Bcm	Medium	Gas	Infrastructure stock
$E_{b,y'<y}^P$	Reserves associated commissioned before simulation starts	Bcm	Medium	Gas	Infrastructure stock
ε	fraction of gas cash flow used for exploration		High	Gas	Cash flow
η_g	fuel efficiency of generator type g		Low	Power	Power market
η_k^{GS}	efficiency for gas storage		Low	Gas	Gas market
η^{PS}	efficiency of pumping for pumped storage		Low	Power	Power market
η^{UKCS}	efficiency for UKCS gas production		Medium	Gas	Gas development
$f_{m,g,y}$	price of fuel	\$/MWht	High	Power	Power market
F_y^{GAS}	discount factor used by UKCS gas producers for year y		Medium	Gas	Gas development
$F_{g,y}^{POWER}$	discount factor used by UK power generators		Medium	Power	Power investment

Name	Description	Unit	Uncertainty	Sector	Sub-model
γ_g	fuel consumption of generator type g for a cold start-up	MWht	Medium	Power	Power market
$H_{0,k}$	gas in storage at beginning of year	Bcm	Low	Gas	Gas market
$H_{f,k}^{RELATIVE}$	gas in storage at end of year		Low	Gas	Gas market
$\bar{H}_{k,0}$	initial maximum working gas storage capacity	Bcm	Low	Gas	Infrastructure stock
$\bar{\mathrm{I}}_{t,0}$	initial power interconnector infrastructure capacity	MW	Low	Power	Infrastructure stock
$m_{\min,t,y}$	minimum monthly denomination	% of ACQ	Medium	Gas	Gas market
μ	fraction of power cash flow used for investment		High	Power	Cash flow
$n_{g,0}^{CFD}$	units of technology registered under CfD	MW	Low	Power	Infrastructure stock
$n_{g,0}^{RO}$	units of technology registered under RO	MW	Medium	Power	Infrastructure stock
$n_{g,0}$	number of generation units at start of simulation		Low	Power	Infrastructure stock
$p_{m,t,y}$ **p**	opportunity cost in market t	$/MMBTU	High	Gas	Gas market
P_y^{BUYOUT}	buyout price for year y	$/certificate	Low	Power	Power market
$P_y^{CAPACITY}$	capacity price for year y	$/MW	High	Power	Power investment
$P_{g,y}^{STRIKE}$	strike price for year y	$/MWh	Medium	Power	Forecasting
$\bar{P}_g$	maximum generation of a single unit of generator type g	MW	Low	Power	Power market
$\underline{P}_g$	minimum generation of a single unit of generator type g	MW	Low	Power	Power market
$\overline{PS}^G$	maximum pumped storage generation capacity	MW	Low	Power	Power market
$\overline{PS}^G$	maximum pumped storage pumping capacity	MW	Low	Power	Power market
$Q_y^{OWN-USE}$	UKCS producers' own use of gas	Bcm	Low	Gas	Infrastructure stock
$q_{g,0,T}$	queue of generation projects under construction at start of simulation		High	Power	Infrastructure stock
$\bar{Q}_{t,0}$	initial gas supply infrastructure	Bcm/month	Low	Gas	Infrastructure stock

Name	Description	Unit	Uncertainty	Sector	Sub-model
R_0	initial level of pumped storage reservoir	MWh	Low	Power	Power market
RE_y^{MECH}	renewable support scheme in place in year y		Low	Power	Forecasting
$\bar{R}$	maximum reservoir level for pumped storage	MWh	Low	Power	Power market
RO_y	overall annual RO target level	certificates	Medium	Power	Power market
s	success probability of exploration drilling		Medium	Gas	Infrastructure stock
σ	standard deviation for size of reservoir discovered	Bcm	Medium	Gas	Infrastructure stock
T	tax rate effective for UKCS gas producers		Medium	Gas	Gas development
T_g^C	construction time required for technology g	year	Low	Power	Power investment
T_g^L	economic lifetime of technology g	year	Low	Power	Power investment
θ_g	availability factor for technology g		Low	Power	Power investment
$THRC$	Time horizon for reference condition	year	Medium	NA	Forecasting
TOP_t	annual take-or pay volume for long-term contract	% of ACQ	Low	Gas	Gas market
$TPPC$	Time to perceive present condition	year	Medium	NA	Forecasting
TPT	Time to perceive trend	year	Medium	NA	Forecasting
$TREND_0^{C^{CO_2}}$	initial trend perceived for UK carbon price		Medium	Power	Forecasting
$TREND_0^{C^P}$	initial trend perceived for UKCS production cost		Medium	Gas	Forecasting
$TREND_0^{f_g}$	initial trend perceived for fuel price		Medium	Power	Forecasting
$TREND_0^{P^{BUYOUT}}$	initial trend perceived for RO buyout price		Low	Power	Forecasting
$TREND_0^{\bar{\pi}}$	initial trend perceived for average power price		Medium	Power	Forecasting
$TREND_0^{\bar{p}^{NBP}}$	initial trend perceived for average gas price		Medium	Gas	Forecasting
$TREND_0^{P_g^{STRIKE}}$	initial trend perceived for CfD strike price		Medium	Power	Forecasting
v	calorific value	MMBTU/Bcm	Low	Gas	Gas market

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