Strategic Offering in Jointly-Cleared Energy and Balancing Pools with Significant Amounts of Intermittent Generation: an MPEC approach

Thesis for the completion of the MPhil in Economics at

Imperial College London

by

MARIOS VLACHODIMITROPOULOS

March 2017

Department of Management
Imperial College Business School

[Page intentionally left blank]

Declaration of Originality

I, Marios Vlachodimitropoulos, hereby declare that this thesis is my own work and has been exclusively written and submitted for the completion of the MPhil in Economics at Imperial College Business School. All sources of information have been properly cited.

Copyright Declaration

The copyright of this thesis rests with the author and is made available under a Creative Commons Attribution Non-Commercial No Derivatives licence. Researchers are free to copy, distribute or transmit the thesis on the condition that they attribute it, that they do not use it for commercial purposes and that they do not alter, transform or build upon it. For any reuse or redistribution, researchers must make clear to others the licence terms of this work.

[Page intentionally left blank]

Abstract

The large-scale integration of renewable generation has brought about a paradigm shift in power system operations, where the physics of the electricity system and priority dispatch policies imply a diminishing energy role for the conventional plant. Despite their increasingly important role as capacity sources, a consensual reform that compensates generators for offsetting intermittency has yet to be adopted. Dropping utilisation rates and prices may thus prompt firms to behave strategically in order to offset the losses incurred in the energy market.

In this context, we consider the gaming incentives facing dominant firms and present a bi-level optimisation model, which maximises expected profits for the price-making leader, who anticipates the reactions of her price-taking followers in a Stackelberg game. The resulting nonlinear Mathematical Programme with Equilibrium Constraints is reduced into a Mixed Integer Programme, which is linearized by means of disjunctive constraints and solved to global optimality. Key to this work is to derive the optimal bids for the leader and assess the impact of strategic behaviour under uncertainty on locational marginal prices and profits in an energy-only market, which co-optimises energy and balancing operations.

We employ a transmission-constrained dispatch to evaluate our method on a 29-node system for various wind penetration and demand levels and compare results against the competitive benchmark, which is cast as a two-stage stochastic programme with recourse. Results suggest that incumbents have compelling reasons to exploit economic withholding and transmission-related strategies, even under significant amounts of renewable generation. Additional simulations provide for the preliminary understanding of the impact of the parameter of flexibility on the leader's strategy and profits; on-peak withholding causes large price distortions which offset the income erosion following the exposure to a less favourable balancing market, unlike off-peak withholding, where the diminished price-lifting ability connotes lower gains compared to the less flexible system.

[Page intentionally left blank]

Contents

List of Tables

List of Figures

Abbreviations & Acronyms

CAES	Compressed Air Energy Storage
CCGT	Combined Cycle Gas Turbine
CHP	Combined Heat and Power
CO_2	Carbon Dioxide
CSF	Conjectured Supply Function
DA	Day-ahead
DC	Direct Current
EU-ETS	European Union Emissions Trading Scheme
FTR	Financial Transmission Right
IP	Integer Programme
KKT	Karush-Kuhn-Tucker
LCPD	Large Combustion Plant Directive
LMP	Locational Marginal Price
LP	Linear Programme
MCP	Mixed Complementarity Problem
MILP	Mixed Integer Linear Programme
MIP	Mixed Integer Programme
MLCP	Mixed Linear Complementarity Problem
MPCC	Mathematical Programme with Complementarity Constraints
MPEC	Mathematical Programme with Equilibrium Constraints
MPP	Major Power Producer
NCP	Nonlinear Complementarity Problem
NLP	Nonlinear Programming
O&M	Operations & Maintenance
OCGT	Open Cycle Gas Turbine
PDS	Public Distribution System
RT	Real-time
SFE	Supply Function Equilibrium
SO	System Operator
UC	Unit Commitment

[Page intentionally left blank]

Acknowledgements

First and foremost, I would like to thank my supervisor Prof. Richard Green, who has supported the main argument of this thesis. Not only has Prof. Green nurtured my affinity for strategic interactions in electricity markets, together with my aptitude for operations research, he has helped develop a keen ambition for exploring an interdisciplinary research topic at the intersection of renewable generation and market power, and pursue my interest with unconditional faith. Prof. Green has additionally helped navigate through some rough personal moments while at Imperial, thus acting as a genuine source of advice and welfare.

Furthermore, part of the application at Imperial College Business School required the selection and articulation of an original research topic. To this end, my previous engagement with Cambridge Energy Research Associates has sprung my motivation towards research and helped build a concrete proposal.

The subsequent admittance of my research theme notwithstanding, I cannot discount the paramount aspect of funding. I thus wish to express my gratitude to my second supervisor Prof. Goran Strbac and Hubnet's principal investigator Prof. Tim Green, who facilitated this work and honoured me with two EPSRC awards.

[Page intentionally left blank]

1. Introduction

Climate change is undoubtedly one of the most overwhelming problems facing the globe. In addressing the effects of human activities on climate, environmental sustainability concerns prompt policy makers to adopt radical measures. The electricity system will play a crucial role in meeting environmental objectives, as it accounts for the largest contribution in greenhouse gas emissions. The EU energy policy is chiefly driven by the ambition to reach a carbon-free electricity supply by 2050, whereas in the UK, climate aspirations linking to an 85% emissions reduction target by 2030, will stimulate massive investments in intermittent renewables and other low-carbon technologies (CCC, 2012).

Traditional power systems and market rules were designed with the purpose of accommodating carbon-intensive, controllable capacity, while operations have followed demand variations, which have been largely predictable (Papavasiliou, 2011). Needs are changing rapidly however, as the uncontrollably fluctuating nature of renewable generation has greatly affected the way systems and markets operate (Eurelectric, 2011).

In principle, the characteristics of variable generation are discordant with traditional power system operations and call for higher amounts of more responsive and expensive reserves to ensure reliability. Absent a widespread storage technology, conventional stations would have to operate intermittently to cope with the increasingly frequent imbalances (MIT, 2011), incurring an adverse impact on system costs and efficiency. At the same time, reduced operating hours and hence volumes, together with depressed electricity prices, question the viability of existing units and the feasibility of future investments (Baker et al., 2010). Delivering the right mix of flexible capacity to integrate the soaring amounts of variable supplies is hindered in many systems, where non-dispatchable generators are guaranteed priority feed-in and enjoy lucrative subsidies for producing electricity. By contrast, non-subsidised plant rely on market prices for fixed-cost recovery in energy-only markets, however, this ability is restrained during windy periods (Baker et al., 2010).

Demonstrably, the flexibility imperative has influenced all facets of power systems, from day-ahead (DA) and real-time (RT) operations to future capacity expansion in the long-term (MIT, 2011). A new paradigm of power system operations, informed by the requisite to offset intermittency has emerged, but bringing forward the mix that satisfies flexibility standards presents a series of impediments. Where the need for flexibility is growing, controversy surrounds the design which could resolve the integration challenge. Market and transmission rules may well have to change in order to balance the policy trilemma of effecting low-carbon electricity supplies in a competitive and secure way. Suitable price signals and regulations could provide incentives for a more efficient evolution of generation, storage and network capacity.

1.1. Motivation & Contribution

Following the objective for achieving ambitious renewable energy targets, the adoption of generous support mechanisms and the subsequent investments in low-carbon capacity, together with priority dispatch policies, denote a decreasing energy role for the conventional part of generation. Nevertheless, due to the requirement to offset the variability of stochastic generation, system operators (SOs) are prompted to trade electricity in real-time with increasing frequency, effectively relying on the ability of thermal plant to change output on command.

Despite the market-wide acknowledgement of their role as capacity providers, thermal stations have been disadvantaged ensuing the rising amounts of inflexible generation. The amalgamation of these policies suggests an interruptible operational pattern, whose bearing is expressed through pressing economic and technical constraints on the conventional stack. The combination of market rules and arrangements that preserve unequal treatment for different types of plant has not only contributed to the enhanced scheduling complexities as described above but the emerging need for structural intervention to secure the electricity of supply has yet to be addressed in a prompt and consensual way.

This thesis is motivated by the disparate aggregate of objectives surrounding the EU energy policy agenda. Following the large-scale integration of renewable energy sources, we focus on the conventional generation and examine the adoption of strategic behaviour by incumbent firms, as a means for negating energy profit losses. Within this context, we investigate the incentives facing dispatchable plant to exercise market power and insure their dominant position, in electricity markets featuring significant amounts of intermittent generation.

The contributions of this MPhil thesis are as follows:

First, we develop a bi-level complementarity model (Gabriel et al., 2013), which incorporates the objective of a strategic firm to maximise expected profits in the face of uncertain residual demand and prices. We build on the assumption of sequential Stackelberg leadership (Von Stackelberg, 1934) and formulate the complementarity conditions as disjunctive constraints (Fortuny-Amat et al., 1981) in order to recast the nonlinear bi-level Mathematical Programme with Equilibrium Constraints (MPEC) into a single linear Mixed Integer Programme (MIP), which is tractable by commercial solvers (Rosenthal, 2016) and can be solved to global optimality (Floudas, 1995).

An essential feature of our model is the inclusion of the transmission system in order to account for the impact of network effects on the gaming incentives facing the strategist; physical flows are thus modelled by means of a DC linear approximation (Kirschen & Strbac, 2004). Following the advent of powerful branch-and-cut solvers, we implement our technique on a 29-node (and 49-line) network representative of the GB power system and derive the optimal offering for a thermal producer, for various levels of wind penetration and demand. Complementarity modelling is a relatively novel field of research (Gabriel et al., 2013) and so inherent to this work is the aim to aid decision-makers and promote the development of computational tools, devoted to projecting the market outcomes arising from strategic interactions in electricity networks. At the same time, we wish to enrich the list of models and case studies that are available to the academic community.

Second, the coordination of elements from stochastic programming and complementarity modelling has been comparatively unexplored in the electricity markets literature (Gabriel & Fuller, 2010). The primary objective of this work is to encourage research on the market implications of strategic behaviour in low-carbon electricity systems, through the explicit incorporation of supply-side uncertainty, which enters our model in the form of a parsimonious, discrete scenario representation. Effectively, this is one of the first models combining the state-of-the-art in complementarity modelling and wind power integration, to examine the implications of market power in auctions that co-optimise energy and reserves by means of two-stage stochastic programming with recourse (Birge & Louveaux, 2011).

In so doing, we emphasise the ability of the leader to choose the most profitable combination of plant outputs and prices and crystallise the dynamics of arbitrage between the day-ahead and real-time stage. This represents a moderately understudied area of research, due partly to the sequential clearing in some markets and the firm focus on the strategic incentives in the day-ahead stage alone. On the other hand, in response to the recognition of the strong coupling between energy and reserves, we follow the latest research and auction both products jointly, in order to minimise the expected costs for energy delivery and balancing provision (Morales et al., 2014). Subsequently, we determine the impact of strategic offering under uncertainty on locational marginal prices and assess the economic consequences on industry-wide participants, in a market with payment for energy alone, thus staying in line with the most recent advances in the integration of renewables (Morales et al., 2012; Pritchard et al., 2010).

We demonstrate that by applying economic withholding, i.e. by bidding part of her capacity high, the dominant firm extracts larger monopoly profits with declining levels of penetration irrespective of the demand level, while additionally resorting to congestion-seeking behaviour at higher levels of wind power in the winter. Market power is also shown to have a positive effect on collective wind (fringe) profits, which decreases with rising levels of penetration in the winter, however, the induced curtailment can inflict large output and revenue losses for the export-constrained wind fleet. In the summer, the influence of the leader's strategic conduct on wind (fringe) producers exhibits the opposite trend, where their profits are increasingly enhanced with growing amounts of wind power up to the level of 30% penetration, while at 40% penetration they extract competitive (zero) profits.

We further draw on a system featuring higher levels of balancing capability to gain a preliminary understanding of the impact of flexibility on the leader's strategy and profits. Despite the heightened competition in the balancing market - as manifested by the higher (lower) expected balance prices in the high (low) wind scenario - monopoly profits are expected to be higher during high-demand periods, due to the reduced utilisation of higher-cost generation and the formation of higher energy prices. In contrast, the leader stands to win less from the exercise of market power during low-demand periods, where small price distortions cannot offset the profit erosion associated with the switch to a more flexible system. Likewise, fringe competitors can be made better (worse) off by the increase in flexibility in the winter (summer), however, this positive (negative) effect is only expressed at higher levels of penetration. On the other hand, the shift to a more flexible configuration connotes a more favourable balancing environment and thus higher gains for the wind industry as a whole, albeit at higher penetration levels in the winter.

1.2. Overview of the Thesis

This work starts with a review of the literature on large-scale renewable integration in chapter 2 and agues the design that is most likely to result in a more favourable environment for the renewable industry in chapter 3, before presenting our thesis and computational models in chapter 4 and case study in chapter 5.

Specifically, we first briefly discuss the adverse impacts attributed to the irruption of wind power, from the perspective of system operators, generators and market designers in section 2.1. Following the mandate to integrate low-carbon generation with priority and considering the discordant design of restructured power markets, which emphasise on dispatchable generation, we review relevant policies that can help reduce the cost of integrating intermittent generation in section 2.3. The thesis carries on with a short reflection of the main challenges facing the designers of low-carbon markets in Europe in chapter 3; this serves to contextualise the state-of-the-art in renewable integration and justify the adoption of our market setting, in accordance to the latest modelling trends.

Chapters 4 and 5 comprise the cornerstone and original contribution of this work. The bundle of policy asymmetries acts as a starting point that helps to draw the main question of this thesis in section 4.1, while a synopsis of the literature on the exercise of market power and complementarity modelling is presented in sections 4.2 and 4.2.1. Sections 4.3 and 4.3.2 outline the essential characteristics of our electricity market framework and introduce the competitive model used by the system operator to clear the market respectively. Section 4.3.3 draws on the principles of imperfect competition to lay the modelling foundation of our MPEC, which is developed in sections 4.3.4 - 4.3.6; those encompass the formulation of the optimisation problem that maximises strategic profits, the conversion of the bi-level programme into a single, nonlinear MPEC and the linearization process. The performance of our proposed methodology is evaluated in a detailed case study in chapter 5. Crucial modelling assumptions, input data and numerical results are presented in sections 5.1 - 5.3, while important computational aspects are considered in section 5.4.

Chapter 6 concludes this research thesis with a critical discussion of the results, followed by remarks on the weaknesses and considerations for future work in section 6.1.

[Page intentionally left blank]

2. Literature Review

Europe has seen an unprecedented penetration of renewable energy sources. By introducing additional variability into electrical systems, however, these capacity additions pose a new set of challenges to power system planners and operators, and threaten grid stability (Eurelectric, 2011). The lack of economic storage, which essentially requires that power is made available on demand, together with the high share of intermittent renewables, increase the complexity of scheduling operations (Papavasiliou, 2011).

Section 2.1 introduces the abrupt challenges and impacts brought about by the large-scale renewable integration, from a market arrangements perspective. Subsequently, section 2.2 provides a short overview of the evolution of research on the integration of renewables in the last two decades, as well as general cost metrics for the UK electricity industry. Finally, section 2.3 reviews relevant policies that help mitigate the cost of intermittency.

2.1. Adverse Impacts of Intermittency

2.1.1. Investment Uncertainty

The increasing reliance on uncontrollably fluctuating and partially predictable energy sources leads to greater variations in the residual load placed on the thermal generating fleet. In addition to volume risk, this is also expected to increase short- and long-run price volatility and affect the profitability of conventional generators, as their place in the supply stack fluctuates inversely with renewable output (Pöyry, 2014). It also increases the income uncertainty for non-portfolio wind producers, while in concentrated markets the risks facing generators are greater (Green & Vasilakos, 2010). This will make expensive renewable and non-renewable low-carbon projects (such as wind and nuclear) and mid-merit units (such as Combined Cycle Gas Turbines or CCGTs) harder to finance and call for further government support in the form of feed-in tariffs or capacity payments to encourage additions, considering the reduced operating hours to recover capital costs and the lack of belief over the ability of EU's Emissions Trading System to signal correct carbon prices for thermal generation (Baker et al., 2010; Newbery, 2010).

As renewable penetration increases, stations that are cheaper to operate but more expensive to build will run at the margin increasingly, eventually driving average electricity prices down (Green & Léautier, 2015). In energy-only markets, thermal stations would need to be dispatched during peak-load periods when wind output is low to recover investment (Baker et al., 2010), as the reduction in prices during high-wind periods is expected to be significant (EWEA, 2010). Generators will have an incentive to decommission earlier than expected or build a different mix of plant, which is likely to result in more peaking plant that is less expensive to build (Green & Léautier, 2015). Stimulating sufficient investment in low-carbon capacity to achieve climate change goals - especially in the absence of price spikes - will thus be impeded (Baker et al., 2010).

2.1.2. Reserve Requirements

The balancing mechanism gives market participants the opportunity to offset deviations and meet scheduled positions, while system operators bear the responsibility to preserve system reliability and the quality of electricity supply (Ela et al., 2011; Kirschen & Strbac, 2004). The services offered include a number of different operations; for instance, frequency support, voltage support and system restoration, however, a precise distinction between ancillary services is hard to draw, as their provision varies considerably from one market to another (Kirschen & Strbac, 2004).

First and foremost, aggregate generation and demand must be as close as possible at all times to ensure that system frequency is within pre-specified ranges, thereby avoiding electrical faults. System demand, transmission and generation outages vary stochastically and to ensure systems are always in balance and meet security and quality standards, operators must set enough capacity in readiness mode, called reserves (Ela et al., 2011). Reserves are classified according to the timeframe in which they can be brought online and are deployed in reverse response order, i.e. slower reserves supersede faster ones. The reader may refer to Kirschen and Strbac (2004) and Ela et al. (2011) for a detailed description and classification of ancillary services.

The dominating model of ancillary services has been that reserve capacity had to sustain an outage of the largest power station or loss of the major transmission line (Kirschen & Strbac, 2004). Balancing requirements increase under the influence of intermittent renewables such as wind, calling for higher amounts of fast ramping reserves to cope with forecast errors and respond to abrupt supply variations (Eurelectric, 2011). Negative regulation in particular, will become increasingly relevant to integrate the varying output of renewables and retain system stability, as in certain periods excess power will challenge the (safe) operation of the power system (Eurelectric, 2010).

Apart from their short-run balancing role, the term reserves may more loosely relate to the ability of the system to preserve a given level of dependability, i.e. system margin[1] (Gross et al., 2006). The investments in additional, firm capacity to retain reliability during high demand periods are inherent to the widespread deployment of renewables, as generation-load imbalances will be exacerbated more often. Where the capacity credit of wind is low, these costs may partly offset the fuel expenses foregone by thermal generators as a 'MW for MW' capacity policy may be required in certain systems to foster renewable firmness (Eurelectric, 2010).

Gross et al. (2006) point to the higher probability of renewable plant to generate a lower than rated capacity output during on-peak periods compared to controllable plant, to explain why system margins are rendered larger with increasing amounts of renewables. Despite their diminished firmness levels, however, they draw on the statistical derivation of reliability measures to emphasise on the ability of intermittent generators to contribute to system peaks. The authors summarise a range of findings relating to the capacity credit of wind[2] and show it is lower than its average capacity factor[3], standing at the level of 20% - 30% of installed wind power for 20% penetration in the UK.

2.1.3. Imbalance Costs and Inefficiencies

System imbalances will grow in frequency and magnitude with the increasing injections of intermittent supplies and will have to be dealt with in the balancing market. To procure these reserves and preserve stability, the system operator would resort to costly deviations from day-ahead schedules and order some thermal units to part-load operation with higher frequency to be able to respond to abrupt wind drops (Eurelectric, 2010).

Existing practices for offsetting shortfalls in renewable energy supply may prove too costly, however. One profound complication is the rapid decrease of thermal efficiency at part-

[1] The excess firm capacity installed relative to the expectation of peak demand.
[2] In practice, the firm capacity intermittent generators can displace for similar reliability levels.
[3] The power output over a period of time relative to the potential output at nominal capacity over the same time, i.e. the ratio of average output to installed capacity.

load, expressed with a higher heat rate and emissions intensity at the stations' units, which under current dispatch rules are disfavoured for backing up renewables (Eurelectric, 2011). That is, under the absence of economic storage at a large scale, an increasing number of units are deliberately dispatched at less than full output for positive regulation purposes; this essentially stipulates that less inflexible conventional plant provide the capability required to integrate intermittent sources by ramping and cycling more intensely, however (MIT, 2011). This involves significant costs in terms of wear and tear on the plant, and fuel and other start-up costs to restart when the wind drops or demand rises. The need to offset imbalances also connotes that (the expensive) part of the mid-merit and baseload supply stack would have to be displaced (Eurelectric, 2010).

Hindered by the stochastic and unreliable nature of wind power, system operations have become more intricate, rendering the traditional classification of thermal fleet based on the number of operating hours and their capacity factor nebulous, although this is highly influenced by fuel competitiveness. In principle, plant flexibility is being put to the test, and conventional generators are all too often operating intermittently and for fewer hours per year, driving utilisation rates down (Baker et al., 2010). This suboptimal operation impacts overall plant economics, as part of the existing plant will forego significant sales volumes, whereas another will have to exit the market, facing pressing technical and economic constraints (Eurelectric, 2010). Together with the ensuing increase in peaking capacity to manage intermittency, this is expected to increase the slope of the supply curve, considering those stations' interest to raise their bids and compensate for the increased number of start-ups (Eurelectric, 2010).

This loss of profit is more heavily pronounced in high capital, low variable-cost, baseload technologies, as opposed to CCGT plant which are more suitable for load-following operations (MIT, 2011), albeit coal-fired and nuclear plant have been modified to cycle on and off to less than their nominal rating in some markets (e.g. Germany). Where the injection of large volumes of wind power cause spot market prices to drop markedly (or enter negative territory), the financial impact of mandatory part-loading would be even stronger; notwithstanding the reimbursement made to those facilities for the provision of ancillary services, a select few thermal generators might manage to even off this deficit (Eurelectric, 2010). This is especially relevant to peaking gas turbines, as baseload and mid-merit units require high load factors for full economic cost recovery (Eurelectric, 2010).

2.1.4. Negative Prices

EU Directives and Regulations currently mandate a large share in the amount of renewable generation and also provide for the priority dispatch of this generation, severely limiting the circumstances in which it can be constrained off, considering wind plant do not require fuel to generate electricity (Directive, 2009). As the amount of intermittent generation increases, however, there will often be circumstances in which the sum of this generation and the inflexible part of conventional output exceeds the system demand. The risk of oversupply is even higher in systems where wind and demand are negatively correlated, as in the case of West Texas wind power in the Electric Reliability Council of Texas (Baldick, 2012).

The priority dispatch rule would normally compel the system operator to turn off some conventional plant, if they would otherwise have to run below their minimum stable generation levels. While the merit order effect tends to reduce average electricity prices by shifting higher variable cost plant to the right (EWEA, 2010), absorbing large amounts of wind is likely to result in an oversupply which may drive prices to zero or make them negative (Eurelectric, 2010). Load cannot be served from stock and so the ability to make large production adjustments on demand is limited by capability (e.g. start-up and shut-down times, minimum up/down times, minimum stable load and ramping rates) and economic constraints on the conventional generating facilities. Another restriction stems from the need to schedule an increasing number of dispatchable plant in order to facilitate positive and negative regulation. Such inflexibilities may be detrimental for system stability and together with subsidies, which remunerate renewables on the basis of their output and prompt them to pay for the supply of electricity during low-demand, high-wind periods - as in the case of the Renewables Obligation in the UK (Baker et al., 2010) - can be the cause for negative prices (KU Leuven Energy Institute, 2014).

Indeed, the concurrence of low demand with large zero marginal cost supply does cause market prices to drop in competitive markets (Baker et al., 2010). In the case of negative prices, however, some inflexible generators have found that the cost of shutting down and restarting shortly after is higher than the negative bid (Kassakian et al., 2011), i.e. they are willing to pay the buyer of electricity in order to keep their facilities running, thereby avoiding additional operations and maintenance costs. Curbing the priority dispatch rule and lifting the restriction of curtailing renewables, to some extent, would incur lower integration costs compared to accepting high negative prices (Eurelectric, 2010).

2.1.5. Network Congestion

Contrary to the steep growth in renewable generation over the last 15 years, grid expansion has lagged behind (Fink et al., 2009). Power systems were designed to accommodate dispatchable generation, however, the sheer injection of intermittent volumes into the grid has had an unprecedented effect on system operations (Eurelectric, 2011). Large amounts of intermittent wind are often sited remote from load (Stoft et al., 1997) and combined with the increased needs for reserve plant, they increase the risk of congestion (Baker et al., 2010). Where market rules fail to educe enough evidence for congestion-enhancing behaviours, not only are resolution costs unnecessarily increased, over-sizing the grid to fit all generators at once seems to be a plausible, albeit excessively expensive way to even out the adverse impacts of intermittency (Baker et al., 2010).

In the likely event that real-time energy requirements are less than forecast, generators may need to curtail output to meet actual demand. Thermal generators reduce production at profit, on the basis of fuel cost savings incurred by preserving their contracted positions (i.e. no revenue is lost); renewable producers on the other hand, would this way waive access to market income and invariably ask for compensation to retract. In a contingency event, however, where a constrained line prevents excess electricity to be transmitted to other parts of the network, all generators are reimbursed to reduce their output, so as to help relieve congestion (ELEXON, 2015).

Relaxing transmission constraints ensures that larger amounts of (variable) supplies may serve adjacent loads, but doing so by modulating the position of wind generators can be deeply expensive. Shutting down a wind turbine is much less complex; wind farms are thus more likely to be chosen for production cuts, although the compensation they ask in exchange for the (reserved and) unutilised network capacity in the event of congestion or security constraints (e.g. during periods of very high wind or maintenance) is significantly higher than the subsidies waived. Renewable energy opponents might argue that subsidising renewables while paying to have them reduce output or switch off is inefficient, however, the positive externality from the aggregate of investments is manifest through the reduction of technology costs, thereby warranting the support to the technology (Newbery, 2002; Newbery, 2011).

2.2. Quantifying the Impacts of Intermittency

Research on the integration of intermittent renewables has traditionally revolved around reliability and balancing concerns, emphasising on the fuel cost reduction benefits stemming from their operation under the control of a single authority (Gross et al., 2006). The deregulation of the industry in the late '90s, however, and the proliferation of such sources especially during the last decade have shifted the appreciation for the role of renewables. Research has concentrated noticeably less on the merits of renewables as fuel savers, while the changing dynamics of the generation system has motivated the investigation of the adverse impacts of intermittency - especially the increased capital and operational costs for providing security and reserve services (Gross et al., 2006).

More recently, computational advances have facilitated the use of stochastic models, which have increasingly been backed with evidence, to procure more accurate estimates of the balancing costs in systems with high amounts of renewable injections (Gross et al., 2006). Numerous unit commitment based studies have been performed recently, focusing on quantifying the impacts of renewable integration on operating costs, reserve requirements and emissions, for instance by Doherty et al. (2004), Denny and O'Malley (2006), Meibom et al. (2011), Papavasiliou et al. (2011) and Papavasiliou and Oren (2013). Papavasiliou (2011) cites a list of renewable energy integration studies, based on the technical characteristics of the unit commitment model developed.

Gross et al. (2006) give an exhaustive review of the literature on intermittency, including academic research papers, industry and government reports. Typically, the need for additional reserves is determined to be less than 10% of renewable capacity, for deployment levels of up to 20%. For the majority of the reports cited in their work, this corresponds to additional operational expenses of less than £5 per MWh of intermittent generation. UK integration costs stand at the range of £2 - £3 per MWh, whereas total intermittency costs, including capital investments for reliability are between £5 and £8 per MWh of renewable output (Gross et al., 2006). An update to this work, assessing the impacts of high wind penetration in the light of new evidence and renewable energy targets is currently being prepared by Heptonstall et al. (2015).

Druce et al. (2015) highlight the rising trend of integration costs with increasing amounts of low-carbon capacity in a study for the 2030 UK power system and project integration costs for wind and solar that stand £6 - £9 and £13 - £16 per MWh higher than those for nuclear, assuming a technology mix of nuclear, wind, solar, and CCS and decarbonisation targets of 100gr CO_2 and 50 gr CO_2 per KWh respectively. Ilex and Strbac (2002) develop twelve scenarios for renewables development to explore the costs for coping with intermittency in the 2020 UK electricity system. The study reveals that for penetration levels of 20% of gross demand, integration costs stand between £3.21 and £9.31 per addition MWh of renewable output in the Low and High demand case respectively, depending on technology and location. Capacity costs in particular, associated with the provision of security services by open cycle gas turbines (OCGT) and capital costs for reserves outweigh operating balancing costs, thus highlighting the uncertainty underlying the ability of intermittent plant to generate at rated capacity during system peaks (Ilex & Strbac, 2002).

The decreasing capacity value of wind as penetration increases is confirmed by the simulation results, where a fivefold increase in wind capacity from 4 GW to 20 GW, delivers a less than threefold increase in thermal displacement (4 GW compared to 1.5 GW), and the ability of wind and other interruptible technologies to contribute to system peaks is attenuated (Ilex & Strbac, 2002). In other words, the capacity contribution of the marginal installed turbine is significantly smaller than that of the first one. Capital investments in additional firm capacity are thus essential to ensure that reliability is not threatened (Ilex & Strbac, 2002; Gross et al., 2006). These by far exceed all other components; assuming wind is totally unreliable (i.e. zero capacity credit), capacity costs may increase by as much as 50%, based on a 9% generation margin (Ilex & Strbac, 2002).

To appreciate the escalating costs attributed to intermittency, Ilex and Strbac (2002) indicate that the cost of producing an extra MWh of renewable output would increase by 16% on average between the renewable deployment targets of 20% and 30%, depending on the technology mix and plant location, and underscore the significant impact of the latter on the transmission part of costs; in contrast, the influence of demand on unit system costs is insignificant, despite the additional volumes by approximately 8% from the Low to High demand scenario (427 GWh compared to 394 TWh).

2.3. Mitigating Solutions

The long body of literature presented by Gross et al. (2006) is suggestive of the wide array of measures that could help to manage intermittency and most likely, any market design would perform better in certain areas than others (Newbery, 2010). Examples that could help address integration costs and reduce system inflexibility include investments in flexible generation and in storage (Eurelectric, 2011), curbing the priority dispatch rule (Eurelectric, 2010) and adopting a more efficient approach to dispatch (Green, 2008).

2.3.1. Curtailment

The irruption of wind power increases the risk of energy spilling at times when excess inflexible supply challenges the physical properties of the grid or when it is uneconomical to utilise the source. Rising shares of inflexibility, such as high requirements for part-loaded reserves and high minimum generation levels increase the risk of oversupply, thus decreasing the threshold where wind power needs to be discarded (Gross et al., 2006).

Ilex and Strbac (2002) identify one such case in their 30% North Wind scenario, where the system runs out of thermal reserves due to the surplus of intermittent power compared to demand. That is, the residual load is that small or even negative in some extreme cases that only a small number of plant need to be brought online, thus rendering the maintenance of sufficient reserves problematic (Ilex & Strbac, 2002). As a more general indication, 80% of the studies reviewed by Gross et al. (2006) project curtailment levels of up to 7% of renewable output, for deployments close to 20%.

Despite the low order of magnitude implied by the above metrics, energy spilling does reduce system efficiency and results in unnecessary congestion resolution costs and emissions (Gross et al., 2006). Curtailment levels and costs may vary significantly depending on a range of system characteristics, such as the proportion of inflexible plant, the correlation between renewable power with demand and hydropower, and the available transmission capacity to ship supplies to demand centres (Gross et al., 2006).

Fink et al. (2009) manifest the upward trend of wind spilling actions through a number of studies that show how curtailment is applied in different power systems. Given the unprecedented growth of the industry over the last decade, they identify network related issues, either in the form of transmission capacity shortages or constraints during periods where high wind output coincides with low system demand, as the chief limitation to large-scale renewable integration, especially since electricity from sites abound in wind has to be transmitted over long distances to serve the load (Fink et al., 2009).

Burke and O'Malley (2011) determine that non-firm connection of wind generators ensures substantial integration of wind power during transmission constraints. They develop three security-constrained optimal power flow models to investigate the causes of curtailment, under a range of demand profile and gas price parameters, on a power system representative of the Ireland-GB system. Congestion-related curtailment, associated with wind forecast uncertainty and ramping constraints on the thermal generating fleet is particularly responsible at low to medium penetration levels of interruptible volumes (Burke & O'Malley, 2011). At very high penetration levels, however, where available wind may be in excess of demand, curtailment is instructed by the associated need to reserve a sufficient number of generating units in the commitment programme for preserving system stability (Burke & O'Malley, 2011).

In elaborating the over-supply problem induced by renewables, Brandstätt et al. (2011) exploit the paradigm of steep negative prices in the German electricity system to draw on the potential benefits of lifting the ban of curtailing renewables, under a system that mandates electricity purchases from renewable stations with priority and pays them a fixed amount per unit of output. By contrasting the extreme negative levels German power prices can reach, they advocate the adoption of voluntary curtailment agreements (VCAs) to improve market efficiency and foster a more favourable investment environment for renewables, against the existing scheme of potential involuntary curtailment (Brandstätt et al., 2011).

From an economic perspective, negative prices give stations' owners the incentive to operate in a flexible manner, while sending solid signals for investment in the right types of flexible capacity, such as storage facilities and demand side management (Brandstätt et al., 2011). Baseload plant, facing long start-up times would rather bid zero or even pay the system operator to avoid incurring a costly ramp-up or restart in the face of a foreseeable profitable opportunity in a consecutive trading period or due to commitments in the balancing market (Brandstätt et al., 2011). In the same direction, costs would also escalate for system operators, should wind power decrease abruptly, as more expensive plant would have to be called into production (Brandstätt et al., 2011).

Negative prices, however, may also occur during low demand periods, if conventional generators would otherwise have to run below their minimum stable generation levels (MIT, 2011). Observably, with enhanced levels of inflexibility and a rising proportion of interruptible plant, the likelihood of a wind generator becoming marginal during these periods increases. Thermal plant are thus faced with the risk of being forced out of the market, while where peaking units are deployed to counterbalance a shortfall in wind power, system costs increase significantly (Brandstätt et al., 2011).

Brandstätt et al. (2011) maintain that the problem lies with the design of the market which does not provide efficient incentives for integrating large volumes of renewable energy. Wind generators are not exposed to imbalance penalties in Germany and they are thus indifferent of the prospective market outcomes. The combination of the priority rule and the output-based support in the form of fixed feed-in tariffs secure a guaranteed income for renewable stations and contain the ability of the auction mechanism to yield efficient market outcomes (Brandstätt et al., 2011). The incentive facing renewable generators to avoid losing access to production-based subsidies at times of low net demand is corroborated by Baker et al. (2010) in the context of the UK market, where renewable stations are remunerated through the Renewables Obligation scheme.

Demonstrably, negative prices reflect the opportunity cost of not generating for renewable plant, when their income comes from subsidies that are not related to market prices. Extreme negative prices can thus be highly costly to society and even more so during times of network constraints, where the priority of renewables is pronounced more heavily (Brandstätt et al., 2011). One way to improve the efficiency of large-scale integration under a feed-in tariff regime would be to relax the constraint of curtailing renewables (Brandstätt et al., 2011). By incentivising producers to contract for voluntary curtailment with the SO, Brandstätt et al. (2011) contend that they would be remunerated at prices higher than their feed-in tariffs and so energy offers could be used to settle the market efficiently.

The rationale behind this is that SOs would be inclined to organise a tender for VCAs in minimising their costs for bringing renewable energy in the market (Brandstätt et al., 2011). The process would result in the identification of an amount 'δ', which is added to the subsidy and paid to renewable generators for the output not produced (Brandstätt et al., 2011). Clearly, no station would be willing to curtail output for less than their guaranteed subsidy, while a spot price of at most - δ would make curtailing wind power economical, before starting to curb conventional output with a higher than δ opportunity cost (Brandstätt et al., 2011). Under current arrangements, the negative bid expressing the costs incurred for not producing would be cleared after zero marginal cost wind; on the other hand, the proposed scheme restores the merit order and wind plant are curtailed prior to inflexible generation, unless the opportunity cost of the latter is lower than δ (Brandstätt et al., 2011).

Therefore, lifting the ban on curtailing renewable production in a feed-in system is expected to improve efficiency and help avoid undesirably high costs, whilst giving renewable producers incentives for active engagement in the market (Brandstätt et al., 2011). Through the introduction of VCAs, the resulting less negative prices would lessen the indicated need for flexibility, however, the efficiency of investment signals towards flexible capacity is expected to increase (Brandstätt et al., 2011).

Renewable producers stand to benefit by the incorporation of δ, depending on the bids for VCAs (Brandstätt et al., 2011). While curbing priority dispatch is set to reduce their output in the short-term, holding everything else constant, the measure will bring down the integration cost of a given amount of intermittent generation and improve investment conditions, thus leading to an overall gain for the renewable sector. The profit for thermal generators is obvious, as less negative bids will reduce their income loss (Brandstätt et al., 2011). Depending on whether VCAs relieve the intensity of negative prices or amend overall efficiency, end users will be disadvantaged or advantaged, unless cost savings are not transferred to the retail (Brandstätt et al., 2011).

To perceive the additional capacity induced by voluntary curtailment, Brandstätt et al. (2011) cite Nicolosi (2010) data and estimate that the 127.8 GWh of wind energy curtailed in the year 2008-09, during the 71 hours of negative prices where the maximum feed-in was 18 GW, could be offset by the production of 5 MW of additional wind capacity within the span of 20 years, given a capacity factor of 14.84% and a curtailment factor of 10%. Adding more wind has the adverse impact of increasing system inflexibility and so the number of periods associated with the effect of negative prices is likely to increase, however, Brandstätt et al. (2011) trust that the promotion of large-scale storage and demand-side participation programmes will progressively alleviate the problem.

2.3.2. Storage

Preventing the spilling of renewable generation would require investing in flexible assets including storage. Much of the research conducted in the past decade has analysed the economic opportunities of storage, focusing either on the benefits of integrating significant amounts of intermittent generation from a system perspective or the assessment of the value of arbitrage activities due to volatile commodity prices (Tuohy & O'Malley, 2011).

Large-scale pumped storage systems are a good option for dealing with the unpredictability and intermittency of renewable sources, because of their ability to provide the additional load or supply required to balance the system in real time (Black & Strbac, 2006). The uncertainty associated with the prediction of wind adds to the complexity of power system operations and is the principle determinant of supply and demand imbalances in systems with high renewable feed-in (Black & Strbac, 2006). Forecasting error, usually expressed in terms of standard deviation of wind output change for a given horizon can lead to loss of dispatch efficiency, as more reserves must remain online to cope with fluctuations in intermittent supply (Black & Strbac, 2006). As gate closure approaches or as wind power output drops, the uncertainty declines and updated predictions give a better estimate of the wind power output (Black & Strbac, 2006).

To evaluate the contribution of storage in providing capacity and ancillary services, Black and Strbac (2006) simulate three distinct configurations of the generation mix of a GB-sized system in terms of wind capacity, accounting for the different degrees of flexibility namely low, medium and high flexibility. They further consider two cases for reserve provision; the base case where spinning reserve is deployed to manage intermittency and another one, where part of the reserve is standing, pumped storage plant.

The demand profile employed in Black and Strbac (2006) is deterministic, through the use of 6 days representative of the season and day type, while peak and minimum load were set at 57 GW and 18 GW respectively and the hourly wind output was scaled up to meet the requirements of 26 GW in wind capacity. To account for the wind power uncertainty inherent in the unit commitment problem solved at the day-ahead stage, the hourly profile was randomised, however, the economic dispatch that accounts for the real time adjustment of faster units uses this very historical wind output (Black & Strbac, 2006). Typically, the lead time for a CCGT to come online is 4 hours and so in order to incorporate the uncertainty of wind output at this timescale, the requirements for spinning reserve in the base case were set at 3.5 times the wind output forecast error, assuming a normal distribution for wind output fluctuation (Black & Strbac, 2006). The dimension of reliability is not examined in this study, however, 99.7% of imbalances are captured under a reserve level of three standard deviations of wind output uncertainty (Black & Strbac, 2007).

The value of storage is measured by the difference in fuel cost and CO_2 emissions savings when the storage is used as a standing reserve against the base case, for each of the configurations (Black & Strbac, 2006). This is generation system specific, mainly driven by the flexibility of a unit to start-up or shut-down and operate close to technical minimum (Black & Strbac, 2006). Increasing amounts of standing reserve reduce the requirements for partly-loaded spinning reserve in the form of CCGT plant running at lower efficiency, however, at the expense of relatively high marginal cost OCGT plant or relatively low storage efficiencies (Black & Strbac, 2006). Hence, the breakeven point where OCGT costs match the CCGT efficiency deficit would rationalise the utilisation of standing reserve and determine the optimal proportion between offline and online reserve (Black & Strbac, 2007). Aside to minimising balancing costs, reserve distribution can also have a substantial effect on the amounts of absorbed wind power, considering the likely oversupply during low demand periods (Black & Strbac, 2006).

The direct advantages of applying storage-based standing reserve are the reduction in fuel consumption and wind curtailment (Black & Strbac, 2006). First, calling a generating unit in a must-run position to provide downward reserve has a negative effect on its heat rate; doing so for a considerable number of units, significantly affects the efficiency of the system. Second, with less generating units online, the flexibility of the system to respond to an unexpected imbalance is greater, i.e. the system can absorb higher amounts of interruptible volumes and less wind output has to be discarded during hours of excess supply (Black & Strbac, 2006). The third derived advantage of storage is the reduction in carbon emissions, which follow the trend in fuel reductions (Black & Strbac, 2006).

Not surprisingly, the value of storage was found to be significant in systems with a higher degree of inflexibility (Black & Strbac, 2006). With 26 GW of wind capacity and 3 GW of storage, the operating (fuel) cost savings ranged between £213 and £803 per kW of synchronised reserve, assuming a discount rate of 10% over a period of 25 years, translating to a net conventional output reduction of 85 GWh and 10.7 TWh per year, in the high and low flexibility scenario respectively (Black & Strbac, 2006). Likewise, carbon emissions reduction stood at the level of 1.41 million to 5.56 million tonnes per year (Black & Strbac, 2006). The effect on wind energy savings in the form of reduced conventional output credited to storage was more than 10% of wind power generation for low levels of flexibility (Black & Strbac, 2006).

Interestingly, the enhanced charging requirements of 5 GW storage capacity in the high flexibility configuration have the adverse impact of increasing conventional generation by 219 GWh per year, as instructed by the increased need to offset the efficiency losses by charging up the facility (Black & Strbac, 2006). However, the additional volumes imply savings of £99 million in cost and 1.9 million tonnes in carbon emissions per year (Black & Strbac, 2006). The impact of storage size on savings decreases as storage capacity evolves, however, justifying the presence of the facility even in systems with significant amounts of flexible capacity (Black & Strbac, 2006). Running lower amounts of synchronised reserves, as with the case of storage, translates to a substantial increase in system efficiency (Black & Strbac, 2006).

However, the complementarity assumed between spinning and standing reserve in the second case, suggesting that a given amount of storage capacity results in the exact amount of spinning reserve being released is a modelling approximation (Black & Strbac, 2006). In practice, this depends on the energy in store and the operational horizon required by the storage, hence, a proportion of the spinning reserve may be displaced (Black & Strbac, 2006). The extent to which storage justifies itself might be reduced further as competing OCGT plant engage in standing reserve, however, this is a well-illustrated example of the magnitude gains due to storage (Black & Strbac, 2006). Finally, substituting CCGT instead of OCGT plant in the capacity mix leads to a possible underestimation of benefits, associated with the decreased efficiency of OCGT plant and driven by the installed wind capacity (Black & Strbac, 2006).

The rising trend of storage value with decreasing levels of flexibility is also demonstrated in Black and Strbac (2007), where different distributions for spinning and standing reserve are considered. Replacing 2 GW of spinning reserve with 2 GW of OCGT standing reserve in the flexible case results in thermal reduction output of 2,400 MW and the equivalent in additional wind energy absorption, while 800 MW of wind surplus are discarded. If storage is added instead, the 800MW of wind surplus can be kept in store, totalling 3,200 MW in energy savings compared to the all-spinning reserve configuration. The most important feature of storage is that three quarters of wind surplus which would have otherwise been discarded, are directly utilised to serve demand. The system absorbs 93% as opposed to 73% and saves 7% of available wind power, occupying 40% of storage capacity, while conventional (wind) plant meet about 55% (45%) of demand as opposed to 65% (35%).

With 6,950 MW of excess wind power for the same penetration level in the inflexible configuration, substituting 2 GW of CCGT with 2 GW of storage yields a reduction in conventional output by 3,500 MW (or 75% more, compared to the reduction in spinning reserve); 2,000 MW can be used for storage and so wind savings reach 5,500 MW, while 1,450 MW are curtailed. The systems uses 71%, saves 17% and cannot use 12% of available wind output, compared to 42% usage and 58% spilling before the addition of storage, while thermal (wind) stations meet about 66% (34%) of demand compared to 80% (20%). Half the amount of excess wind power is directly utilised by the system, while the remaining is either stored or discarded.

The above metrics confirm benefits are greater in less flexible systems and the relevance of storage size becomes evident, particularly at high penetration levels (Black & Strbac, 2006). Taking the analysis of Black and Strbac (2007) further, it would require a storage device at the size of 2.72 GW to neutralise wind curtailment under the inflexible configuration, while the amount of absorbed power would reach 83%, the remaining would be kept in stock and wind would serve 40% of demand. Assuming a roundtrip efficiency of 70%, 30% of the saved surpluses would be wasted to efficiency losses and about 12% of the initially available wind power could be injected in the system from stock. Although the ability to store surpluses that would otherwise have to be curtailed is central to the value of storage, subjecting larger amounts of wind power to the process of energy conversion makes the parameter of storage efficiency increasingly material (Black & Strbac, 2006).

In a nutshell, zero wind curtailment is a not sufficient to guarantee a high value of a storage device. It takes a much larger device to ensure enough spinning reserve is displaced and increase the wind power infeed. That is, despite the addition of 2.72 GW storage in the above example, 4,900 MW of the 6,950 MW of wind surplus would effectively be dedicated to directly serve demand following the reduction in conventional output, while the stock of 2,050 MW would undergo the energy conversion process. This is why the amount of spillage cannot be used to quantify the contribution of storage to net energy savings (Black & Strbac, 2006; Black & Strbac, 2007). The latter are revealed by the increased levels of wind utilisation due to the reduction in thermal production and the energy delivery potential of the device after the deduction of the conversion losses (Black & Strbac, 2006). More flexible systems make better use of the available wind by directly absorbing larger amounts of excess energy, i.e. the ability of storage to contribute to an inflexible system is constrained as penetration levels increase (Black & Strbac, 2006).

Black and Strbac (2007) also evaluate the relative competitiveness of storage against OCGT in three distinct configurations of standing reserve. The combined OCGT and storage solution performs similarly to the storage-only solution which yields the highest value, while both exceed the OCGT only solution (Black & Strbac, 2007). In addition to the uniquely privileged ability to store wind surpluses (and reduce fuel consumption and emissions), storage devices are capable of providing both positive and negative regulation in contrast to OCGT plant (Black & Strbac, 2007).

In a similar study, Tuohy and O'Malley (2011) examine the benefits of pumped storage in terms of reduction in wind curtailment, in the context of the Irish power system in 2020, which is assumed to be interconnected to GB with a 1,000 MW link. Using a stochastic unit commitment model, the authors evaluate the likely operation of the storage facility and the impact on the system for wind capacity levels ranging between 6 GW and 12 GW or an equivalent of 34% to 68% of net load and compare this to the configuration without storage. Results suggest that curtailment is significant above 9 GW of wind power, providing adequate support for the addition of storage (Tuohy & O'Malley, 2011).

The use of storage is not rationalised until the operating cost savings comprising fuel, start-up and carbon costs incurred by the reduction in wind curtailment outweigh the increase in fuel consumption due to the presence of storage (Tuohy & O'Malley, 2011). This is illustrated in their base case, where replacing 400 MW OCGT and 103 MW CCGT of thermal capacity with the equivalent in storage actually increases the use of baseload plant at the expense of system efficiency. However, with rising levels of wind capacity, the benefits of storage offset the increase in operating costs and the heightened need to reduce curtailment justifies the enhanced utilisation of the device. On the other hand, the impact of carbon prices to cost savings is shown to be insignificant, as gas units usually run at the margin in the Irish market (Tuohy & O'Malley, 2011).

The hourly operation of storage is also modelled, albeit from a system perspective. For wind penetration below 34%, load drives the operation of the unit, as it is more efficient to dedicate wind power to demand compared to storing it and incurring the conversion losses (Tuohy & O'Malley, 2011). With increasing penetration, however, the likelihood that wind power runs at the margin increases and more conventional plant are anyway committed for stability reasons, and the need to capture wind surpluses is the fundamental driver of storage operations (Tuohy & O'Malley, 2011).

This study goes on to consider a wide range of sensitivities in re-evaluation of the results. First, the increased benefits of interconnection with increasing wind output, are shown. As more wind builds in place of thermal capacity, the export activity from Ireland to GB is enhanced and the trading pattern between the two countries starts to become reverse, however, at wind levels above 9.5 GW (Tuohy & O'Malley, 2011). The impact of additional wind on interconnection flows is weakened by the addition of storage and Ireland requires some 10.8 GW for net exports to emerge (Tuohy & O'Malley, 2011). Ireland would thus benefit by either storing national wind surpluses or importing GB power to charge the storage, considering it is generally more expensive than GB (Tuohy & O'Malley, 2011). Evidently, in systems where the connection to neighbouring countries is limited, benefits are greater; with less flexibility in the system if the connection to GB was to be withdrawn, the addition of storage would be justified at 6 GW of wind (Tuohy & O'Malley, 2011)

Second, the impact of plant mix changes is modelled. The authors demonstrate the enhanced system cost savings incurred when storage replaces five OCGT instead of one OCGT and one CCGT plant in the base case, owing to the reduced fuel efficiency of OCGT, which makes the investment in storage worthwhile at lower amounts of wind, however, OCGT capital costs are roughly two times higher than CCGT, negating part of the benefits (Tuohy & O'Malley, 2011). A final strand of this work analyses the sensitivity of storage size on cost savings and system reliability. It is confirmed that a large device is prerequisite to fully replacing conventional plant, especially at high levels of wind penetration (Tuohy & O'Malley, 2011). Deterministic simulations showed that storage sizes of 10 hours (i.e. 500 MW/5 GWh) can maintain similar levels of reliability (i.e. 8 hours per year where demand is not met) to those before replacing thermal plant, whereas at 5 hours the interval where load cannot be met starts to decrease markedly, irrespective of the wind level (Tuohy & O'Malley, 2011). Moreover, it is shown that cost savings due to storage increase slightly with the size of the device, at the expense of higher project costs however (Tuohy & O'Malley, 2011).

The sensitivity of the arbitrage value with respect to energy capacity for a price-taking storage device in PJM is analysed by Sioshansi et al. (2009). Assuming a scheduling commitment of 2 weeks and zero uncertainty in the expectation of electricity prices for all trading periods, a device with 80% efficiency can deliver more than half of its value within 4 hours of operation (i.e. intraday), whereas after 8 hours of discharge, the contribution for each additional hour starts to shrink (Sioshansi et al., 2009). Strbac et al. (2012) also contend the arbitrage value beyond 6 hours of duration to be marginal.

Sioshansi et al. (2009) further illustrate the strong dependence of the arbitrage value on the roundtrip efficiency of the storage. For example, a device with 8 hours of capacity can deliver 75% additional value based on 2006 prices, when its efficiency is raised from 50% to 60% (Sioshansi et al., 2009). With increasing efficiency, storage not only requires less time to charge but it does so by consuming less energy during times where prices are higher, thereby not sacrificing too much arbitrage profit (Sioshansi et al., 2009). A rough calculation advises that the less efficient plant would require 2 hours more to charge for each 6 hours of discharge at full rating. Nonetheless, 90% of the storage theoretical value is seized within 10 hours, regardless of the efficiency parameter (Sioshansi et al., 2009).

Utilising storage to arbitrage electricity prices and maximise wind plant profits has been the topic of intense research, for example by Castronuovo and Peas Lopes (2004) and Garcia-Gonzalez et al. (2008). Castronuovo and Peas Lopes (2004) investigate the optimal daily configuration of a wind farm and a small pumped storage unit in a Monte Carlo simulation study, where time series scenarios are used to describe the uncertainty of wind power output. Storage provides the wind farm with access to larger price differentials, leading to a profit increase compared to the independent operation of the wind park (Castronuovo & Peas Lopes, 2004).

Garcia-Gonzalez et al. (2008) address the problem of the combined daily operation of wind and storage plant by formulating a two-stage stochastic programming model, accounting for the uncertainty of both market prices and wind power output. Their study provides for the optimal bidding and subsequent storage operational profile in the day-ahead market. Where storage is operated as a hedging device against wind power uncertainty, the wind farm enjoys superior flexibility in real-time operations and more closely abides by the schedule declared day-ahead (Garcia-Gonzalez et al., 2008). This in turn minimises the generator's payments for non-compliance, thereby maximising the expected gains from the combined operation (Garcia-Gonzalez et al., 2008). The result is a 2.53% profit increase and a 36% imbalance payments reduction, compared to the independent operation of a 30 MW wind farm and a 10 MW storage. Benefits increase with storage size and for capacities of up to that of the wind farm, non-compliance costs can decline by 50% (Garcia-Gonzalez et al., 2008).

Other constituents have assessed the influence transmission constraints may have on the arbitrage value of storage, including Tuohy and O’Malley (2011). When operated from a system perspective, the GB-IR interconnector competes with storage in providing the flexibility to offset wind variability and reduce curtailment (Tuohy & O’Malley, 2011). However, assuming a scenario for very high wind penetration in GB similar to that seen in Ireland, there would be periods where the ability to reschedule flows intraday is limited and so Irish units and storage would have to fill the gap in flexibility, thereby increasing the arbitrage opportunity for storage (Tuohy & O’Malley, 2011). The increase in storage value under the presence of transmission constraints is also highlighted by Sioshansi et al. (2009), who denote that the use of load-weighted average prices in PJM can yield conservative estimates of the regional variation in annual arbitrage value. The diminished value of storage under the presence of other flexibility enhancing alternatives such as interconnection capacity is observed by Strbac et al. (2012), however, the reduced operating expenditure savings due to lower amounts of reduced curtailment are shown to be offset, to a certain extent, by savings in interconnection capital expenditure.

Storage can also have positive externalities when used as an alternative to transmission for bringing wind energy in the market, provided that the economic benefits are large enough to warrant the application (Sioshansi et al., 2009). Denholm and Sioshansi (2009) raise the question as to whether it is worthwhile to build a smaller network and co-locate storage with wind or whether the revenue loss from the less efficient use of the storage is higher than the transmission cost savings. This investigation is justified, considering that increasing amounts of wind power generated far from major loads mandate a similar trend in transmission expansion; this makes ensuring the maximum utilisation of the existing network vital, before bearing the forbidding costs of building new transmission (Denholm & Sioshansi, 2009). Capturing the transmission value of storage by merging a compressed air energy storage (CAES) and a wind farm at the same site could reduce the amount of transmission required per MWh of wind energy supplied in the market and lead to an improved use of existing transmission assets (Denholm & Sioshansi, 2009).

To optimise the combined operation of the facilities, Denholm and Sioshansi (2009) formulate a mixed integer programme with the objective of maximising aggregated net energy profits. Subsequently, they compare them with those accrued in the uncoupled operation of the plant, with the aim to specify the breakeven cost of transmission, where the decreased network costs are levelled off by the revenue loss incurred when the storage is moved behind (and shares) the same, downsized line with wind (Denholm & Sioshansi, 2009). Effectively, this derives the optimal combination of transmission and storage size, as a function of the transmission cost (Denholm & Sioshansi, 2009).

Pairing the facilities increases the loading and partly compensates for the curtailment induced by the transmission capacity reduction, however, it has a bearing on the arbitrage revenue when transmission constraints are binding (Denholm & Sioshansi, 2009). That is, when located closer to the load, storage takes complete advantage of hourly off- and on-peak price differentials and discharges (charges) at full capacity during high (low) prices, thus maximising its value as an independent asset (Denholm & Sioshansi, 2009). In contrast, as storage assumes its transmission provision role, charging and discharging operations are constrained by the reduced transmission capacity and the level of wind generation respectively, and the device compromises arbitrage revenue in favour of overall efficiency (Denholm & Sioshansi, 2009). On the other hand, selling wind energy is constrained by the downgraded line and supplies free energy to storage when transmission is used up to capacity (Denholm & Sioshansi, 2009).

The suboptimal dispatch of storage in the combined scheme is manifested by the occurrence of high price periods where discharging at full capacity is not stimulated, as opposed to the load-sited case (Denholm & Sioshansi, 2009), due to the concurrence of high wind output. Results suggest those anticipated; for low transmission project costs, downgrading the line is not justified, as the revenue loss from co-locating storage with wind is high (Denholm & Sioshansi, 2009). For network costs above $350 per MW-km in the system of the Electric Reliability Council of Texas, the foregone revenue associated with downsizing the line by 10% becomes smaller than the transmission costs (Denholm & Sioshansi, 2009). Nonetheless, no further reduction is justified for costs up to $850 per MW-km and the optimal transmission and CAES capacity stand at 90% and 5% of the wind plant rating respectively (Denholm & Sioshansi, 2009).

As the topological arrangement decision depends on the change in arbitrage value between the coupled and uncoupled case (Denholm & Sioshansi, 2009), the transmission cost level which guarantees economic locational change, relies on the initial value of storage, i.e. on the fuel mix and prices (Sioshansi et al., 2009). In systems where arbitrage opportunities are smaller, the loss of arbitrage value and hence this threshold would generally be lower (Denholm & Sioshansi, 2009). For instance, in the Midwest system, a cost of $450 per MW-km justifies a network reduction of 20% and a CAES size at 10% the wind plant rating (Denholm & Sioshansi, 2009). Matching the location of storage and wind and downsizing the transmission line are the main drivers of revenue loss, however, the deviations in performance between the wind- and load-sited storage options are expected to decrease, as increased penetration levels start to drive power prices (Denholm & Sioshansi, 2009). In turn, the prospect of increased grid utilisation will promote the interest for CAES, as an alternative to transmission for wind power (Denholm & Sioshansi, 2009).

Rising amounts of storage will tend to flatten the load pattern by shifting an increasing amount of on-peak loads to off-peak periods and result in a similar effect on the price curve (Sioshansi et al., 2009). Storage can thus have a positive impact on efficiency, however, the reduction in arbitrage value will inform investment decisions (Sioshansi et al., 2009). Sioshansi et al. (2009) use a price-taking device to study the drivers of the arbitrage value of storage in PJM; short-term value is mainly influenced by the daily and weekly load patterns and the ability of forecasting techniques to predict prices, while in the long-term this depends on the load and thus fuel costs (Sioshansi et al., 2009). Higher gas prices tend to impact the arbitrage value substantially on the grounds of higher peak prices, however, the arbitrage revenue is a function of both off- and on-peak prices (Sioshansi et al., 2009). Therefore, the future role of storage is prominent in systems with large amounts of low-cost supply such as hydroelectric, coal and nuclear (Sioshansi et al., 2009).

2.3.3. Transmission and Electricity Markets

Other strands have examined a wide spectrum of transmission related issues in assessing the adverse impact of congestion due to the large-scale integration of wind, including investment in additional network capacity and revisiting transmission pricing schemes. For instance, Denny et al. (2010) investigate the mitigation of wind energy variability induced by the increased interconnection levels between Ireland and GB. With 6 GW of installed wind in Ireland and 1,000 MW of interconnection in the base case, increasing the transmission to 2,000 MW does not improve the Irish wind power that is discarded under day-ahead commitment arrangements (Denny et al., 2010). However, the study suggests that the intraday scheduling of flows on the 2,000 MW interconnector would provide extra flexibility to cope with wind forecast uncertainty in either area, as reflected by the increase in net imports by 12.3% compared to the day-ahead horizon, and result in a marked reduction in the usage of peaking plant and intra-day prices in Ireland (Denny et al., 2010).

The intermittent nature of wind power makes the solution of sizing up the network such that maximum wind output is integrated inefficient (Baker et al., 2010). Supply variance in particular, is presented with an upward trend as larger amounts of wind are located in preferred areas, thereby increasing the risk of congestion (Gross et al., 2006). Together with the decreased diversity of output, the negative correlation with peak load connote a capacity credit of wind that is lower in certain parts of the system than others (Gross et al., 2006), so the value of electricity will vary by location. Supplying an additional MW of load in the least-cost way would require the implementation of nodal marginal pricing.

The nodal pricing model has been introduced with the pioneering work of Schweppe et al. (1988). A nodal pricing system promotes dispatch efficiency by explicitly incorporating the opportunity cost of transmission constraints (and the cost of losses) between generators and loads, in the bids of generating units (Green, 1997). This results in a unique price for each origin-destination pair and a schedule which should be optimal in a perfectly competitive market (Green, 1997). At the same time, nodal pricing reflects the spatial value of energy (less any losses) and signals the need for investment in transmission in the long-term, as an alternative to influencing the location of new power stations remote from a constrained area (Green, 1997).

Nodal prices ensure transmission capacity is distributed efficiently and sold to where it is valued the most (Stoft et al., 1997). Unless transmission constraints are binding, the shadow price of transmission is zero, hence, the marginal cost of transporting a MW-worth of power is zero and the electricity price is uniform within the region (Kirschen & Strbac, 2004). Consumers are indifferent as to where an additional MWh of energy is sourced from, i.e. local generators or an adjacent node, as their valuation for the transportation of the energy is nil (Kirschen & Strbac, 2004).

Where congestion constrains the flow between two nodes, however, a single market is divided into separate markets and nodal prices are likely to diverge systematically, signalling rising transmission costs (Kirschen & Strbac, 2004). An exporting generator serving a load at a higher-priced node will be charged an amount equal to the difference in nodal prices multiplied by the flow transferred, for the extra strain inflicted on the powerline (Green, 2008). The obverse would imply that the expensive generator is paid to reduce the flow on the exporting direction by producing more, a practice called counter-trading (Green, 2008). Consequently, the need to avoid exacerbating transmission constraints by utilising less costly stations, gives rise to the opportunity cost of congestion and so more expensive plant have to be dispatched at the import-constrained side of the network (Green, 1997).

Demonstrably, spatial considerations are becoming more intense with more wind and new flow patterns emerging, and albeit the marginal cost of transmission conveys the right information about the cost of utilising the network, where adopting a nodal pricing scheme requires radical interventions, this is most likely to meet political opposition (Green, 2010). Most crucially, generators sited at a region where exporting is stiffened would risk losing revenue, following the application of a nodal pricing system (Green, 2008; Green, 2010). Especially considering the limited dispersion of wind farms and distance from loads, this may impede further development as owners may be discouraged by the increased transmission costs (Stoft et al., 1997) or justify higher, location-sensitive support subsidies to offset the lower prices received (Green, 2010), although wind plant are invariably reimbursed well in excess of the income waived due to the constraints. Other technologies such as solar, whose output often coincides with the system peak will experience a similar effect on transmission charges (Stoft et al., 1997), although costs may be offset by higher production during these periods.

The greater regional variation of prices will increase the relevance of Financial Transmission Rights (FTRs) that hedge locational price differences (Hogan, 1992). FTRs give holders the flexibility to receive a sum equal to the price difference between any two nodes (physically connected or not) for the amount of power transferred (Newbery & Strbac, 2011). For example, a consumer located at a high-priced node, can either opt to import from a cheaper adjacent node and appoint the rights to transmit the energy over its node or buy locally and request its share of the congestion surplus (Kirschen & Strbac, 2004). The amount of energy traded is effectively the same and the value of the FTR reflects the price to be paid for accessing the joining connector (Newbery & Strbac, 2011).

In sum, the efficient allocation and use of transmission capacity could have a pivotal role in reducing the costs of integrating intermittent generation. Enhanced levels of cross-border trading could also foster a more favourable environment for renewables; for instance, where transmission is implicitly auctioned and traded together with energy this ultimately resolves the issue of counter-intuitive trades (Green, 2008). FTRs could thus offset the risk of welfare loss associated with the nomination of physical rights prior to price discovery and make larger amounts of capacity available in the day-ahead coupling (Newbery & Strbac, 2011).

[Page intentionally left blank]

3. Transition to a more Efficient Dispatch

Delivering large amounts of low-carbon electricity in an affordable way is central to the mission of liberalised electricity markets in the 21st century, while providing incentives for timely and efficient investment in generation and transmission to ensure the security of electricity supply is of equal importance. In some European systems, however, the soaring amounts of unpredictable and variable generation have come without substantial reforms, thus revealing the deficiency of existing market designs, while the adverse impacts of the increased balancing requirements and scheduling complexities have been detrimental for the conventional fleet and infrastructure (Eurelectric, 2011).

This issue motivates our thesis, which addresses the optimal offering strategy of thermal generators in pools with wind producers by developing a bi-level optimisation model in section 4.3.4. Before proceeding with the main intent of this work, however, it is essential that critical assumptions of the assumed market format be discussed in more detail. Specifically, central to our proposed technique is the electricity market setup, as demonstrated by the clearing model, which is introduced in section 4.3.2.

With this in mind, the current chapter seeks to contextualise the state-of-the-art in dealing with the integration challenge and thus stipulate the market design that is most likely to result in a more favourable environment for the renewable and the electric power industry as a whole. To this end, we impel the adoption of leading practices from around the world - and in particular the balancing and congestion management arrangements from the US markets - in order to encourage the convergence towards a more efficient operational framework in an EU industry characterised by increasing amounts of inflexible plant. Crucially, this chapter also serves to justify the transition to the employed market design in evaluation of our methodology in chapter 5, where we examine the profit-maximising incentives facing generators in a case study of the UK power market. Needless to say, the suggested construct may readily be utilised within the context of the US markets for similar issues.

3.1. Efficient Balancing Operations

The first set of recommendations is addressed to EU system operators. Notwithstanding the increased awareness about the integral role of capacity markets in future designs, currently employed balancing arrangements encourage practices that increase the amount of part-loaded plant as protection against imbalances, and result chiefly in markets where online production capacity (including reserves) by far exceeds demand for electricity (Baker et al., 2010). In addition, the reliance on ex-ante capacity reservations that don't reflect the actual state of the system close to real-time, fails to promote flexibility (Baker et al., 2010). Within this framework, improved wind forecasts cannot be incorporated in the economic dispatch and the agility to release what seemed to have necessarily been reserved for balancing purposes is limited (Borggrefe & Neuhoff, 2011).

Where intraday markets have been adopted to allow for timely changes in dispatch, the discontinuity between energy and reserves weakens their role in that it diminishes the space for sensible decisions in reaction to improved forecasts; in Germany for example, participants have the incentive to avoid intraday adjustments and exploit the balancing mechanism (Wärtsilä, 2014). This thesis is corroborated by the study of Just and Weber (2015), where static secondary reserve offers during the span of the contracted period of a month, are held responsible for cultivating a wealth of arbitrage opportunities between the spot market and the balancing mechanism in Germany. This suggests that balance prices can be anticipated and participants have the incentive to deviously adjust their declared commitment programmes in either direction, on the grounds of imprecise imbalance calculations (Just & Weber, 2015).

This example illustrates the need for coordination between energy and balancing products to respond to the growing share of intermittent generation is exigent. On the other hand, the increasing currency of balancing services is exemplified in the US market configuration, where energy and reserves are jointly optimised, in acknowledgement of the dual nature of the electricity product (Morales et al., 2014). The thrust of this measure is to provide for the least-cost combination of plant employed for energy and balancing, considering the strong dependence of RT corrections on DA schedules, while well-functioning intraday markets could also help towards the minimisation of the amount of capacity reservations for balancing purposes (Borggrefe & Neuhoff, 2011). Hence our inclination to adopt a more integrated design for our impending study, i.e. in order to optimise dispatch and bring the cost for the activation of short-term reserves down.

In addition, the quest to minimise the heightening proportion of balancing costs, connotes the promotion of a more efficient price discovery. This would decidedly contribute to the creation of a more favourable environment for flexibility, i.e. one where less costly generators are available closer to real-time and which better reflects the actual cost of the supply-demand imbalance. Most certainly, SOs would first seek to resolve deviations once updated forecasts become available, if they would otherwise have to resort to more expensive options. For this to work well, however, they would have to shift the procurement of an increasing amount of balancing resources in the short-term and in a competitive way, while policy makers might have to consider revisiting the rule that shields intermittent plant from imbalance charges and allow the formation of prices that reflect the long-run marginal cost of balancing (Pöyry, 2014).

3.2. Efficient Congestion Management

In addition, because transmission is allocated at day-ahead stage at best in European markets (Neuhoff et al., 2011) the cost for countering the increasingly frequent constraints has started to receive alarming dimensions. Moreover, under traditional allocation processes, SOs are conservative in their allocation of capacity that is made available for international trade in order to ensure their national grid does not get congested and avoid re-scheduling costs (Neuhoff et al., 2011; Neuhoff, 2011). Parallel flows thus have a derating impact on both cross-border flows - thus limiting international competition, and even more so considering the influence exercised by the generation location on the available transfer capacity - as well as domestic adjustments in the balancing market (Neuhoff et al., 2011). Further, EU power markets largely disregard the impact of constraints on the DA dispatch at a national level and resort to costly counter-trading to ensure flow feasibility in real-time (Green, 2008), which raises the incentive to behave in a congestion-seeking way and manipulate the balancing mechanism (Baker et al., 2010).

By contrast, US power markets rely on the explicit incorporation of the transmission requirements within the DA and real-time auctions, and so participants have to bear the costs associated with the delivery of their load obligations at each point into the system (Green, 2008). Not only does this setting diminish the incentive facing exporters (importers) to exploit the constraints (refrain from selling in the energy market) (Green, 2010; Neuhoff et al., 2011), but employing a full representation of the transmission system into the energy and balancing auctions, facilitates the least-cost adjustment to the prevailing wind power conditions and sends appropriate operational (and investment) signals, as well as signals to demand (Green, 2008; Neuhoff et al., 2011).

The second EU structural amendment is thus inspired by the requirement to minimise the cost of dispatch and foster the commitment to harmonising congestion management practices at European scale. Such a co-optimisation suggests the common allocation of existing network capacity at the DA stage and so in practice, SOs would first seek to exploit spare transmission capacity at an international level, before resorting to expensive counter-trading solutions in balancing their systems (Borggrefe & Neuhoff, 2011). Most critically, contrary to more disaggregated designs, the nodal pricing system facilitates the cross-border sharing of intermittent resources by internalising network requirements in the scheduling algorithm (Eurelectric, 2010; Newbery & Strbac, 2011). In addition, where intraday auctions are put into effect, this coordination would enhance the flexibility of transmission by allocating scarce generating capacity just-in-time.

3.2.1. Priority Dispatch for Renewable Generators

Of relevance to the transition to the nodal model are the profound implications of the merit-order effect, which cast reasonable doubts on the efficiency of existing dispatch rules. As the additions of interruptible capacity in biased locations continue, interventions to eliminate distortions relating to the rising spatial granularity of electricity prices appear inevitable (Green, 2008). This suggests the necessity for a more efficient approach to dispatch, however, following the switch to a locational marginal pricing system, developers may be compelled to choose amongst less congested areas or else they will have to forego significant revenue due to high transmission charges or lower prices (Green, 2010).

An alternative would be changes to policy that lead to different operating decisions by renewable generators. For instance, voluntary wind curtailment could be adopted as an economic means for minimising system-wide costs in order to guarantee that electricity from areas abounding in cheap wind power is supplied in the least-cost way; this idea has been put forward to deal with the issue of extreme negative prices in Germany (Brandstätt et al., 2011). If the support to renewable generators was less dependent on their actual output, they would be more willing to curtail generation at times when it was less valuable to the system. Even if the market price still fell to their opportunity cost, this would be a small positive number based on avoided maintenance costs rather than the large negative amount set by the subsidies foregone.

The increasing controversy over the effectiveness of priority dispatch rule notwithstanding, a radical intervention on the status-quo is most likely to meet severe political opposition in its implementation. Therefore, the priority dispatch for the renewable stack will be held intact for the scope of this thesis, however, examining the sensitivity of economically-induced curtailment - especially as technology learning continues to drive capital costs, and by extension the levelised cost of electricity down - represents a field of research to which we aim at contributing with future extensions to our model, depending on the advances on the (political) state of affairs in the electricity industry.

3.2.2. Nodal Prices and FTRs

Despite the merits of the nodal model in getting the prices for congestion right, a second neighbouring issue is whether a change that explicitly includes congestion in marginal costs will be embraced by the spectrum of stakeholders or viewed as inequitable to poorly sited generators. Most notably, nodal prices come with the undesirable attribute of increased price variance (Green, 2008) and an often heavily pronounced revenue redistribution effect (Green, 2007). Observably, the emergence of wind curtailment behind a constrained line, implies zero market income for the dispatched fleet, while also connoting output-based subsidy losses. FTRs can help to hedge against the negative revenue gradient from utilising a line that is prone to congestion (Hogan, 1992), unless this comes at the expense of other participants whose price is expected to increase or with additional political support however, the nodal model might impede the plans for bringing new low-carbon capacity online (Green, 2010). Therefore, much like the priority dispatch rule, the sensitive topic of FTRs represents a standalone area of research and is thus not examined in this thesis.

In conclusion, concerns surrounding the ability of current arrangements to bring forward reliable, low-carbon, electrification at low-cost appear to be justifiable (Newbery, 2011). Resolving the complex of engineering challenges to determine the right fuel mix of generation is far from trivial, however, key to fostering renewable integration in the short-term is to readdress the balancing and congestion management arrangements by facilitating efficient operation and increased aggregation of international resources intraday and possibly down to real-time (Neuhoff, 2011).

[Page intentionally left blank]

4. Energy & Balancing Offering Strategies for a Conventional Producer in Pools with Significant Amounts of Wind

The growing additions of partially predictable and zero marginal cost generation into the electricity system pose significant scheduling complexities for system operators and threaten the economic viability of the conventional fleet. The focus of research has recently been turned on countering market design deficiencies and minimising the cost of integrating variable generation into the grid. Following the crucial acknowledgment of the strong connection between energy and reserves, system operators have been prompted to facilitate the simultaneous trading of these products in a single auction with increasing frequency (Morales et al., 2012; Pritchard et al., 2010).

In this context, we consider the problem of determining the optimal offering strategy for a conventional producer who participates in jointly-cleared electricity and balancing auctions, which feature significant amounts of wind power. The optimisation problem in section 4.3.4 is formulated as a stochastic bi-level model with the objective of maximising profits for the price-maker in the upper-level problem, subject to the equilibrium Karush-Kuhn-Tucker conditions of the least-cost dispatch, performed by the system operator in the lower-level problem. The resulting MPEC of section 4.3.5 is recast as a single-level Mixed Integer Linear Programme (MILP) through the use of disjunctive constraints (Fortuny-Amat et al., 1981) in section 4.3.6 and solved to attain global optimum solutions in a transmission-constrained dispatch.

The impact of strategic behaviour under uncertainty on day-ahead and expected real-time locational marginal prices, system costs and generators' profits is assessed within a settlement scheme that rewards participants for energy delivery alone. Results from a DC power flow model (Kirschen & Strbac, 2004) on a GB representative system for various levels of wind penetration and demand are reported in chapter 5, while additional simulations examine the impact of the parameter of flexibility on strategic profits.

4.1. Background

Directive (2009) currently mandates and provides for the priority dispatch of a large share of renewable generation, severely limiting the circumstances in which it can be constrained off. However, the increased dependence on intermittent generation presents a series of challenges that complicate scheduling operations. Most critically, a number of conventional units would have to be dispatched at part-load to offset abrupt supply variations. A diminishing factor is that some baseload plant cannot make large output adjustments in the short-term[4] and would have to fix their production at the DA schedule to avoid lengthy and costly cycles, while others may have to exit the market if they would otherwise have to run below their minimum stable generation levels (Eurelectric, 2010).

On the other hand, reliable power output estimates of non-dispatchable plant, are difficult to obtain beyond a few hours horizon (Black & Strbac, 2006) and so outcomes are most likely to be suboptimal at the DA stage. As a result, SOs are compelled to trade electricity in RT with increasing frequency and rely on more flexible plant for offsetting production deviations, due to their insignificant lead times and reliable cycling capability. Despite their valuable service to the system, flexible generators stand to lose following the large additions of renewables, inasmuch as the increased ramping and cycling costs are not recompensed by the reduced load factors and prices in the energy market.

Moreover, the sequential auctioning of energy and balancing products helps to buffer the coupling between energy delivery and balancing provision, insofar as it fails to acknowledge the two-dimensional nature of the electricity product (Morales et al., 2012; Pritchard et al., 2010). This restrains the profitability of flexible generators and in turn, the SO's ability to access lower-cost options for offsetting intermittency, especially considering the rising share of balancing costs and their strong dependence on DA schedules (Morales et al., 2014). For what is worse, the fixed character of balancing arrangements, which subscribe to long-term contractual agreements of reserve capacity, lacks the element of competitive pressure and so prices are remotely reflective of the actual imbalance costs.

In the absence of industry-wide consented structural reform that remunerates flexibility explicitly, the capability to deliver energy as needed continues to be undervalued (Borggrefe & Neuhoff, 2011). A determining factor is that offshore and large amounts of onshore wind power still remain above grid parity due to spatial considerations, which most of the EU markets disregard (Green, 2008); by and large, non-dispatchable

[4] Day-ahead commitment decisions are made 12 - 36 hours ahead of actual operations to allow for warm-up and ramping of less responsive conventional generators.

generators are guaranteed priority feed-in and enjoy lucrative subsidies for producing electricity, questioning the efficiency of clearing outcomes and the viability of non-subsidised plant in energy-only markets (Baker et al., 2010).

Generators may thus be prompted to behave strategically in order to offset the revenue erosion following the large scale integration of renewable sources. The question asked in this thesis is whether conventional producers have the incentive to exploit monopoly power in integrated pools that prioritise non-competitive supplies from wind power. Should strategic offering be adopted by flexible producers in the face of contracting income, how will prices and profits change for different amounts of intermittent generation?

4.2. Market Power in Electricity Markets

Drawing upon the definition of Stoft (2002), the exercise of market power is characterised by the ability to raise prices above competitive levels. This specifies that the exercise of market power be profitable, hence the subsequent explicit stipulation that prices depart from competitive levels for a significant period of time, denoting that a cause and causality relationship between high prices and an unusual market conduct may be inferred.

Electricity markets are particularly susceptible to market power exertion, due to their organisation and the intrinsic physical characteristics of the electricity product. For one, storing electricity at a large scale is prohibitively costly and so meeting demand relies on real-time production, however, short-run capacity constraints facing power stations can be the cause for supply shortage (Borenstein, 2002). Second, the physical laws governing network flows render the transportation analogy remote (Oren et al., 1995) and complicate scheduling operations, while failing to preserve grid stability is detrimental. This justifies the presence of a system operator who preserves constant balance between supply and demand and ensures that scheduled flows are below the limits of the transmission links by decreasing and increasing generation upstream and downstream of a constrained line (Green, 2008). Third, inelastic to price demand, as a result of limited exposure to real-time pricing, together with physically constrained supply (near scarcity) raise concerns over the initiative facing strategic generators to suppress competition and increase their profits (Borenstein, 2002).

In the two-decade history of restructured electricity markets, the commitment to eliminate the space for market power abuse has stood firm by regulators and the like. Stalling market power is important for a number of reasons, one of which is associated with preserving the security of supply. The paradox is that, in embracing their mission to retain the intact state of the electricity system, the majority of designs have welcomed or relied on imperfect competition for electricity trading (Bunn & Oliveira, 2003).

For this reason, the ensuing structural changes have propelled the interest for studying strategic interactions between firms and equipped regulators with tools that help detect market power (Twomey et al., 2006). Avoiding to compromise supply is just one of the incentives for curbing market power, however; the exercise of market power can also have far reaching consequences as regards to short-term dispatch schedules and therefore result in overly expensive system operation. Distortive prices can also send inappropriate investment signals and lead to inefficient expansion decisions or give grounds for regulatory interference, with restriction controls that may risk efficiency (Twomey et al., 2006). The need to detect and mitigate market power thus stems from the broader objective to establish effective competition and minimise welfare losses, and maximise productive efficiency (Stoft, 2002).

There is a vast body of empirical and theoretical work pertaining to the exercise, detection and mitigation of market power in the industrial organisation literature; see Stoft (2002) and Kirschen and Strbac (2004) for an introduction to the subject, and Ventosa et al. (2005) for modelling trends. Despite the profound diversity of tools at the disposal of regulators, policy makers have yet to adopt a consensual stance, as to which model best resembles oligopolistic behaviour. Underlying the various approaches, however, is the universal demand for useful insights about the implications following the departure from competitive behaviour, such as the price-effects of market power, the impact on productive efficiency and the strategic interaction of transmission and generating capacity.

Amongst those methods, simulation models for detecting market power are termed under the umbrella equilibrium modelling to describe mathematical entities that aim at finding a future state of the system (e.g. prices, outputs, flows, consumption), where the objectives of different participants are balanced by explicitly considering their behaviour and the induced impact on their rivals' decisions (Neuhoff et al., 2005). A rough categorisation of modelling work may be drawn with respect to the assumed interaction between firms, market mechanisms, network characteristics and computational methods; see Hobbs et al. (2000) and Neuhoff et al. (2005) for a detailed literature and refer to Day et al. (2002) for a theoretical definition and critical review of oligopoly models categorised by strategic interaction, including Cournot, Bertrand, Supply Function Equilibrium (SFE) and Conjectured Function Equilibrium to name but a few.

As far as the strategic instrument is concerned, the primary method for exercising market power is by means of economic withholding (Stoft, 2002). The incumbent firm tampers with the merit-order by which plant come online by ascending marginal cost, in order to drive the electricity price up. In so doing, it reduces part of her generation from the dispatch by bidding it high and collects higher revenue on the scheduled plant. Otherwise, price may directly be abused by means of physical capacity withdrawal, where capacity is made unavailable at any price, termed physical withholding. A third means of exercising market power is by manipulation of transmission-related constraints, in order to curtail competition and create monopoly pockets to increase prices and profits (Twomey et al., 2006).

In the context of large-scale renewable generation, the combination of dropping utilisation rates and electricity prices may enhance the incentives facing dominant firms for capacity misuse. However, the ability to maintain prices above competitive levels by manipulating generating or transmission capacity is not trivial to detect, while the priority dispatch of renewable supplies only adds to the process. Further, the existence of higher (or lower, if a dominant firm seeks to undercut her rivals) prices on its own is not sufficient to support a well-founded argument in favour of market power exercise, because it does not provide conclusive evidence during periods where constraints are binding or plant are down (Harvey & Hogan, 2001). Quite often, allegations for the exercise of market power have been difficult to substantiate and evidence has been called into question, and so the need to equip market designers with sophisticated decision-making tools stands undiminished.

4.2.1. Complementarity Modelling and MPECs

Of recent interest in the electricity markets literature is the study of the market power complications with the use of complementarity modelling and specifically, Mathematical Programming models with Equilibrium Constraints (Gabriel et al., 2013). Unlike Cournot, MPECs are founded on the premise that one dominant firm called the leader, may influence her followers' decisions by using her knowledge of the market demand and an accurate assumption on her rivals' reaction functions (Von Stackelberg, 1934). The terms Mathematical Programming with Equilibrium Constraints and Mathematical Programming with Complementarity Constraints (MPCCs) are used interchangeably to describe bi-level programmes obeying to this sequential type of strategic interaction (Olsson, 2010).

Bi-level programmes represent a special class of optimisation problems, involving decisions at two distinct levels. Intrinsic to their mathematical formulation is their nested structure, which incorporates two mathematical programmes in a single instance to identify the hierarchical relationship governing the interaction of two different entities (Colson et al., 2007). Of the two optimisation objectives, the outer, referred to as the upper-level problem, is solved by the first decision-maker who controls the first set of variables. Once the values of those variables have been revealed, the second decision-maker maximises the inner objective of the bi-level programme by solving a standard optimisation problem and deciding on the variables of the lower-level problem (Saharidis et al., 2013). In the context of market power in electricity markets, this interrelation is typically traced in that the clearing pursued by the SO is embedded within the constraints of the offering strategy concerning the price-maker.

Closely related to the area of bi-level programming is the novel research field of MPECs, which has been motivated by the game theoretic concept of Stackelberg leadership (Olsson, 2010). Observably, the need to formulate Stackelberg games as bi-level programmes stems from the demand to capture the abovementioned hierarchical relationship in a two-level optimisation scheme, pertaining to the conflicting objectives of the first decision-maker (leader) in the upper-level problem and the second decision-maker in the lower-level problem (followers). The objective of such a game is to devise an optimal strategy for the leader, who can (commit to a credible action and) influence the optimal response of her rationally-behaving followers.

Much like bi-level programmes, the computational challenge of MPECs lies in that only those points where the lower-level problem admits an optimal solution are candidates for feasibility in the upper-level problem. This stems from the leader's ability to anticipate the decision of her followers - who seek to optimise their own individual objectives - thus integrating this knowledge into her optimal offering problem. In contrast to bi-level programmes, however, the MPEC formulation of Stackelberg games features a lower-level problem, which comprises a complementarity system or more generally, a variational inequality (Olsson, 2010) to describe a market equilibrium - as opposed to an optimisation problem - arising from the interactions of competing agents (Ralph, 2008). The interested reader may refer to the study of Colson et al. (2007) for an introduction to various subclasses of bi-level programming problems, including MPECs, and a survey on relevant solution methods.

One of the reasons MPECs have surfaced as a central tool in the modelling of restructured electricity markets is, unlike Cournot or Bertrand, their ability to incorporate various market features - such as transmission capacity limits or price caps - and different conjectures about the competition amongst firms in one optimisation problem by means of primal and dual variables (Gabriel et al., 2013). In addition, Cournot and Bertrand models have been criticised for yielding inefficient price levels; demand is fairly inelastic in electricity markets and so firms are insensitive to changes of price or capacity inputs under the Cournot and Bertrand assumption - a modelling weakness that helped spur the motivation for the development of the field of Supply Function Equilibrium, where firms compete by means of offer curves (Klemperer & Meyer, 1989). In the electricity markets context, this suggests the declaration of a (continuous) function, which describes the quantity a firm is willing to supply at different prices. Complementarity modelling does not suffer from drawbacks associated with the simplifications of vertical or horizontal supply conjectures met in Cournot and Bertrand games and can thus provide realistic insights within the context of restructured pools, where the few competing firms submit a generally non-decreasing bid curve (Day et al., 2002).

Nonetheless, much like SFEs, the general MPEC is inherently non-convex, while standard constraint qualifications are not met, and so the very existence of Lagrange multipliers cannot be guaranteed, let alone a local optimum solution may be found at best (Bertsekas, 1999). Under the premise of differentiability and regularity of equality and binding inequality constraints however, first-order (necessary) KKT optimality conditions may be meaningfully formulated, while the existence of a global optimum can be guaranteed, provided that the feasible region corresponds to a convex set (Diwekar, 2008; Floudas, 1995; Gabriel et al., 2013). By contrast, MPECs are tractable by numerical methods and can thus accommodate complex engineering detail, such as re-dispatch and transmission capacity limits in large-scale electricity networks (Day et al., 2002). Sections 4.3.3 on imperfect competition and 5.4 on computational issues, discuss the theory and algorithms of MPECs in more detail.

One of the first studies to consider the Stackelberg conjecture in the electricity literature was conducted by Hobbs et al. (2000), who developed a bi-level constrained optimisation problem to examine the short-term market power effects on a DC linear system. Drawing upon the supply function competition conjecture (Klemperer & Meyer, 1989), the rivals' responses were modelled as insensitive to the leader firm's bidding in the lower-level problem of the optimal dispatch performed by the SO, while the leader firm accurately incorporated their behaviour in choosing her optimal bid function. A penalty interior point algorithm was subsequently developed to estimate an efficient solution to the anyway non-convex bi-level MPEC in a thirty-node system.

Day et al. (2002) introduce an extension to the Cournot model, where a firm may change output in response to changing prices, that is, another type of bid curve game termed

Conjectured Supply Function (CSF). The sophistication of the method lies on the introduction of the general Stackelberg hypothesis, where a firm may anticipate her rivals' collective production (not necessarily accurately, however), through an affine supply function representation that yields different degrees of competitiveness for different parameterisations of their responses (i.e. the CSF itself). Under the assumption of convexity and the subsequent statement of KKT conditions, the emerging Mixed Complementarity Problem (MCP) is used to attain generalised equilibrium on a 13-node system of England and Wales. The reliance on ad-hoc selection of the behavioural parameters is suggestive of the weakness borne by conjectural variation methods, however, unlike the SFE method, the application of CSF is not limited in stylised electricity networks but seems to be extendable in more realistic systems by means of complementarity modelling (Day et al., 2002).

Bautista et al. (2006) extend the work of Day et al. (2002) and construct a Mixed Linear Complementarity Programme that additionally introduces the possibility of conjectured reserve-price responses, following the conjectured supply function competition in DA. The method is used to find equilibrium under various combinations of capacity and spinning reserve limits, with a focus on deriving an expression for the opportunity cost facing constrained generators in Cournot oligopolies, where those products are jointly auctioned. Critically, the study demonstrates the diminishing effect on the arbitrage benefits from the adoption of strategic behaviour in both markets. The complementarity model is applied in a 24-period market, however, much like in Day et al. (2002), plant start-up costs are disregarded to avoid non-convexities associated with the inclusion of binary variables that help model on-off decisions, while the application concerns a small six-node test system.

In contrast to the abovementioned study, Haghighat et al. (2007) are sceptical over the CSF method, for the difficulty pertaining to the estimation of efficient parameters in the absence of marginal cost data. They thus develop a parametrised SFE MPEC to account for the manipulation of the slope and intercept of each firm's bid function in integrated markets for energy and reserves, under a pay-as-bid scheme. The bulk of experiments conducted are similar to those in Bautista et al. (2006), including a multi-period model, while an explicit formula for the optimal offering of the strategic firms is additionally derived. The paper underlines the incentives facing firms to raise both energy and reserve prices under binding constraints such as capacity (and ramping) limits and determines the relation of the marginal contribution of the generating capacity to the reserve price and scheduled quantity. Nonetheless, much like Bautista et al. (2006), Haghighat et al. (2007) adopt a deterministic security metric for the quantification of reserves and test their model on a similarly small system, while a similar approach is adopted with respect to (non-convexities arising from) the inclusion of binary on-off decision variables.

Bakirtzis et al. (2007) develop a single-period MPEC for a producer participating in the spot energy market, under the presence of uncertain demand and fringe plant outages. They subsequently use the binary expansion method applied in Pereira et al. (2005) to convert their MPEC into an MILP that is solvable by off-the-shelf optimisation packages. They further compare the optimal step-wise offering strategy with that obtained by Nonlinear Programming (NLP) solvers and conclude the overall superiority of the integer formulation, which is manifest through the inability of NLP techniques to attain global optimum solutions and accommodate on-off variables. However, their method is limited to the investigation of the gaming space in the DA market and their application is restricted to a small, ten-unit system, which lacks the intricacies of the transmission network.

Ruiz and Conejo (2009) develop a 24-period transmission-constrained MPEC to determine the optimal offering of a leader in pools, where uncertainty surrounding the demand-side bids and rivals' offers is explicitly incorporated in the form of eight equiprobable scenarios and inter-temporal constraints are accounted in the generators' ramping limits. The resulting MIP is applied on the DC linear IEEE Reliability Test System (Grigg et al., 1999), after disposing of the nonlinearity associated with the KKT conditions by means of disjunctive constraints, however, the strategic behaviour relates to energy delivery arrangements alone.

Gabriel and Leuthold (2010) solve the MILP-recast MPEC in a DC linear network-constrained dispatch and make use of disjunctive constraints and indicator binary variables to negate the nonlinearity associated with the complementarity constraints and $price \cdot output$ products in the objective function respectively. Assuming the 'TRUE' status (i.e. 1) of an indicator variable, a discrete generation level is enforced on the associated strategic plant. The technique is repeatedly applied on a fifteen-node model representative of the Western European system to calculate prices and profits for one dominant utility each time. Despite the requirements for binary variables that control the level of output can be overwhelming, considering those grow with the number of plant and amount of committed capacity, the authors report reasonable computational times. Moreover, the advantage of narrowing down a plant's operational envelope to a number of discrete levels more than justifies the computational hurdle, as it corresponds to a realistic and ever desirable attribute from an operational and modelling perspective.

4.3. Problem Formulation

In this work, we derive the optimal offering strategy of a conventional producer participating in coordinated energy and balancing, transmission-constrained auctions. Our proposition rests on the sequential Stackelberg hypothesis (Von Stackelberg, 1934), where the strategic leader firm anticipates the reaction of the naive fringe, which for the purpose of this work behave in a competitive fashion. The motive of this thesis springs from the disparate EU renewable energy agenda and hence, gaining economic and policy insights is of primary consideration. The emerging oligopoly structure following the EU-wide liberalisation initiative of the '90s justifies such an investigation within the context of a Stackelberg leader-follower type game, considering the few and in some markets one remaining dominant firm (Gabriel & Leuthold, 2010). We thus focus on combining the state-of-the-art in renewable integration and complementarity modelling in order to study the market power effects of conventional generation in low-carbon electricity markets.

Considering the increasing role of balancing markets ensuing the large-scale integration of renewable generation, it would be distortive to omit the incentives facing generators in auctions, where energy and reserves are jointly cleared to minimise system costs. In addition, low-carbon systems feature significant amounts of weather-reliant generation at biased locations and are thus particularly vulnerable to bottlenecks. Hence, the thrust of adopting a nodal pricing system for clearing the market is to facilitate the emerging need for investigating apart from economic withholding, transmission-related strategies which seek to exacerbate the constraints and create monopoly pockets (Twomey et al., 2006).

The auction model featuring joint provision of energy and reserves, integrated with locational marginal pricing is indeed the American one, and has been advocated for its transparency and for increasing the efficiency of balancing and congestion management arrangements. This makes it particularly suitable for the study of strategic interactions within the context of renewable integration; chapter 3 argues the state-of-the-art in low-carbon systems and impels the convergence of EU designs to the US standards in order to help meet policy objectives.

To the best of our knowledge, the attempt to model a price-making (conventional) flexible generator in a system that accommodates significant amounts of intermittent generation is novel. To this end, we develop a stochastic bi-level MPEC to derive the offering strategy of a single dominant firm that participates in the DA and RT markets. In determining her profit-maximising output, the leader firm solves an optimisation problem, which includes an accurate conjecture of her rivals' responses and moves first in order to influence those and set the price, while followers believe the market price is outside their control. The leader thus seeks to maximise profits in the upper-level, subject to the equilibrium Karush-Kuhn-Tucker conditions of the least-cost dispatch performed by the SO in the lower-level problem, which is modelled as a two-stage stochastic programme with recourse (Birge & Louveaux, 2011) in a DC linear network, according to the standard practices in power system economics (Kirschen & Strbac, 2004). The leader's decision variables include bid prices (outputs) in the upper-level (lower-level) problem in the DA and balancing markets. We apply the Fortuny-Amat et al. (1981) linearization and use the Strong Duality Theorem (Luenberger & Ye, 1984) to recast the non-convex MPEC into an MILP that is readily solvable with off-the-shelf commercial optimisation packages and can guarantee global optimum solutions (Rosenthal, 2016).

4.3.1. Notation

Sets & Indices

Ω: set of dual variables

K: set of thermal generators

O: set of strategic thermal generators

C: set of competitive thermal generators

J: set of loads

I: set of wind generators

N: set of buses

Λ: set of transmission lines

S: set of scenarios

X_n^K: set of thermal generators at bus n

X_n^O: set of strategic generators at bus n

X_n^C: set of competitive generators at bus n

X_n^J: set of loads at bus n

X_n^I: set of wind generators at bus n

$a(l)$: bus of line l from a to b

$b(l)$: bus of line l from a to b

Parameters

C_k: production cost of thermal generator k

$C_{k,u}$: positive regulation cost of thermal generator k

$C_{k,d}$: negative regulation cost of thermal generator k

π_s: probability of scenario s

P_k^{max}: capacity of thermal generator k

P_k^{min}: technical minimum of thermal generator k

$R_{k,u}^{max}$: maximum positive reserve offer of thermal generator k

$R_{k,d}^{max}$: maximum negative reserve offer of thermal generator k

L_j: power consumption by load j

Vsp: value of curtailed wind

$vLOL$: voluntary demand reduction price

$W_{i,s}$: production of wind generator i under scenario s

W_i^{max}: maximum power offer of wind generator i

T_l^{max}: transmission capacity of line l from a to b

Ψ_l: reactance of transmission line l from a to b

Decision variables

$\hat{C}_k$: production cost offer of strategic generator k

$\hat{C}_{k,u}$: positive regulation cost offer of strategic generator k

$\hat{C}_{k,d}$: negative regulation cost offer of strategic generator k

P_k: dispatched power output of thermal generator k

$P_{k,u,s}$: positive regulation of thermal generator k under scenario s

$P_{k,d,s}$: negative regulation of thermal generator k under scenario s

W_i^d: dispatched power output of wind generator i

$W_{i,s}^{sp}$: curtailment of wind generator i under scenario s

$L_{j,s}^{sh}$: shedding of load j under scenario s

θ_n^0: voltage angle at bus n at the DA stage

$\theta_{n,s}$: voltage angle at bus n under scenario s

Dual variables

λ_n: DA generation-demand balance at node n

$\mu_{n,s}$: RT generation-demand balance at node n under scenario s

ρ_l^{min}: DA transmission capacity of line l in the direction b to a

ρ_l^{max}: DA transmission capacity of line l in the direction a to b

$\rho_{l,s}^{min}$: RT transmission capacity of line l in the direction b to a under scenario s

$\rho_{l,s}^{max}$: RT transmission capacity of line l in the direction a to b under scenario s

$e_{k,s}^{min}$: lower power and reserve capability of generator k under scenario s

$e_{k,s}^{max}$: upper power and reserve capability of generator k under scenario s

$\bar{z}_{k,s}^{min}$: lower positive reserve capability of generator k under scenario s

$\bar{z}_{k,s}^{max}$: upper positive reserve capability of generator k under scenario s

$\underline{z}_{k,s}^{min}$: lower negative reserve capability of generator k under scenario s

$\underline{z}_{k,s}^{max}$: upper negative reserve capability of generator k under scenario s

ξ_k^{min}: lower power output of generator k

ξ_k^{max}: upper power output of generator k

$h_{i,s}^{min}$: lower curtailment of wind generator i under scenario s

$h_{i,s}^{max}$: upper curtailment of wind generator i under scenario s

p_i^{min}: lower power output of wind generator i

p_i^{max}: upper power output of wind generator i

$q_{j,s}^{min}$: lower shedding of load j under scenario s

$q_{j,s}^{max}$: upper shedding of load j under scenario s

g: DA slack bus equality

g_s: RT slack bus equality under scenario s

Binary variables

δ_l^1: binary variable for the DA transmission capacity of line l in the direction b to a

δ_l^2: binary variable for the DA transmission capacity of line l in the direction a to b

$\delta_{l,s}^3$: binary variable for the RT transmission capacity of line l in the direction b to a under scenario s

$\delta_{l,s}^4$: binary variable for the RT transmission capacity of line l in the direction a to b under scenario s

δ_k^5: binary variable for the lower power output of generator k

δ_k^6: binary variable for the upper power output of generator k

$\delta_{k,s}^7$: binary variable for the lower power and reserve capability of generator k under scenario s

$\delta_{k,s}^8$: binary variable for the upper power and reserve capability of generator k under scenario s

$\delta_{k,s}^9$: binary variable for the lower positive reserve capability of generator k under scenario s

$\delta_{k,s}^{10}$: binary variable for the upper positive reserve capability of generator k under scenario s

$\delta_{k,s}^{11}$: binary variable for the lower negative reserve capability of generator k under scenario s

$\delta_{k,s}^{12}$: binary variable for the upper negative reserve capability of generator k under scenario s

$\delta_{i,s}^{13}$: binary variable for the lower curtailment of wind generator i under scenario s

$\delta_{i,s}^{14}$: binary variable for the upper curtailment of wind generator i under scenario s

δ_{i}^{15}: binary variable for the lower power output of wind generator i

δ_{i}^{16}: binary variable for the upper power output of wind generator i

$\delta_{j,s}^{17}$: binary variable for the lower shedding of load j under scenario s

$\delta_{j,s}^{18}$: binary variable for the upper shedding of load j under scenario s

4.3.2. Stochastic Market Clearing

We consider a mandatory pool where conventional generators submit supply offers to meet demand at each trading hour of the next day, i.e. 12 - 36 ahead of actual operations. Typically, these take the form a non-decreasing function of price, whereas demand bidding may as well be represented via a downward sloping linear curve. The SO seeks to maximise social welfare and clears the DA market to determine the optimal dispatch and the Locational Marginal Price (LMP) at each bus (Morales et al., 2014). Critically, scheduling decisions are made on the basis of the information submitted by market participants, i.e. the SO does not respond to actual costs but rather cost offers submitted by producers, which can coincide when firms behave in a competitive fashion. We also provide for the priority dispatch of zero marginal cost generation to reflect the inexpensive utilisation by the SO. Given the scheduling uncertainty attributed to intermittent generation, we adopt a single, energy-only market where energy and balancing operations are jointly optimised at the DA stage (Morales et al., 2012; Pritchard et al., 2010). The DA market thus also serves to schedule the available reserve capacity for offsetting real-time imbalances and so requirements are derivatively inferred from the expected deployment at the balancing stage of the optimal dispatch (Morales et al., 2014).

The market-clearing process is thus modelled as a two-stage stochastic programme with recourse (Birge & Louveaux, 2011), to allow for explicit consideration of the potential impact of DA commitment decisions on expected real-time actions and costs. The resulting optimal schedule determines a first-stage decision and a set of second-stage or recourse decisions for each uncertain realisation (Barroso & Conejo, 2006); the former model the energy and reserve dispatch based on day-ahead forecasts of stochastic production, while the latter correspond to real-time operations (Ruiz et al., 2009). Observably, derived pool (day-ahead) prices are accordingly influenced by the projected impact of real-time decisions, i.e. by the expected impact of marginal load variations on balancing costs (Morales et al., 2012).

The stochastic unit commitment (4.3.2) is described below:

$$min_{\{P_k,P_{k,u,s},P_{k,d,s},\theta_n^0,\theta_{n,s}^0,W_i^d,W_{i,s}^{sp},L_{j,s}^{sh}\}}$$

$$\sum_{k\in K} C_k \cdot P_k + \sum_{s\in S} \pi_s \cdot \left(\sum_{k\in K} \left(C_{k,u} \cdot P_{k,u,s} - C_{k,d} \cdot P_{k,d,s} \right) + \sum_{i\in I} Vsp \cdot W_{i,s}^{sp} + \sum_{j\in J} vLOL \cdot L_{j,s}^{sh} \right) \tag{4.3.2a}$$

$s.t.$

$$\sum_{k\in X_n^K} P_k + \sum_{i\in X_n^I} W_i^d - \sum_{j\in X_n^J} L_j = \sum_{l\in \Lambda|a(l)=n} \frac{\theta_{a(l)}^o - \theta_{b(l)}^o}{\Psi_l}, \qquad (\lambda_n), \forall\, n \in N \tag{4.3.2b}$$

$$\sum_{k\in X_n^K} (P_{k,u,s} - P_{k,d,s}) + \sum_{i\in X_n^I} (W_{i,s} - W_i^d - W_{i,s}^{sp})$$

$$+ \sum_{j\in X_n^J} L_j^{sh} = \sum_{l\in \Lambda|a(l)=n} \frac{\theta_{a(l),s} - \theta_{a(l)}^o - \theta_{b(l),s} + \theta_{b(l)}^o}{\Psi_l}, (\mu_{n,s}), \forall n \in N, s \in S \tag{4.3.2c}$$

$$-T_l^{max} \le \frac{\theta_{a(l)}^0 - \theta_{b(l)}^0}{\Psi_l} \le T_l^{max}, \qquad (\rho_l^{min}, \rho_l^{max}), \qquad \forall\, l \in \Lambda \tag{4.3.2d}$$

$$-T_l^{max} \le \frac{\theta_{a(l),s} - \theta_{b(l),s}}{\Psi_l} \le T_l^{max}, \qquad (\rho_{l,s}^{min}, \rho_{l,s}^{max}), \qquad \forall\, l \in \Lambda, s \in S \tag{4.3.2e}$$

$$P_k^{min} \le P_k - P_{k,d,s}, \quad (e_{k,s}^{min}),\ \forall\, k \in K, s \in S \tag{4.3.2f}$$

$$P_k + P_{k,u,s} \le P_k^{max}, \quad (e_{k,s}^{max}),\ \forall\, k \in K, s \in S \tag{4.3.2g}$$

$$0 \le P_{k,u,s} \le R_{k,u}^{max}, \quad (\overline{z}_{k,s}^{min}, \overline{z}_{k,s}^{max}),\ \forall\, k \in K, s \in S \tag{4.3.2h}$$

$$0 \le P_{k,d,s} \le R_{k,d}^{max}, \quad (\underline{z}_{k,s}^{min}, \underline{z}_{k,s}^{max}),\ \forall\, k \in K, s \in S \tag{4.3.2i}$$

$$P_k^{min} \le P_k \le P_k^{max}, \quad (\xi_k^{min}, \xi_k^{max}),\ \forall\, k \in K \tag{4.3.2j}$$

$$0 \le W_i^d \le W_i^{max}, \quad (p_i^{min}, p_i^{max}),\ \forall\, i \in I \tag{4.3.2k}$$

$$0 \le W_{i,s}^{sp} \le W_{i,s}, \quad (h_{i,s}^{min}, h_{i,s}^{max}),\ \forall\, i \in I, s \in S \tag{4.3.2l}$$

$$0 \leq L_{j,s}^{sh} \leq L_j, \quad (q_{j,s}^{min}, q_{j,s}^{max}), \quad \forall j \in J, s \in S \tag{4.3.2m}$$

$$\theta_1^0 = 0, \quad (g) \tag{4.3.2n}$$

$$\theta_{1,s} = 0, \quad (g_s), \forall s \in S \tag{4.3.2o}$$

Objective function $(4.3.2a)$ represents the expected cost incurred by the SO from the operation of a competitive market in which all generators offer their output at their true marginal cost C_k, $C_{k,u}$, $C_{k,d}$, hence the minimisation objective; this comprises energy delivery costs and scenario dependent costs for positive and negative regulation, as well as the cost for curtailing wind power and shedding load in RT operations. Equations $(4.3.2b)$ enforce the power balance equation on scheduled quantities at each node at the DA stage. In order to offset any RT imbalances due to wind power uncertainty, equations $(4.3.2c)$ ditto the above argument for each scenario by means of reserve deployment or load shedding. The next group of constraints $(4.3.2d)$ and $(4.3.2e)$ limit the amount of power flow between any two nodes at the thermal capacity of their connecting line. Constraints $(4.3.2f)$ and $(4.3.2g)$ capture the coupling between energy delivery at the DA and balancing provision at the RT stage, while the amount of positive and negative regulation is constrained by the stations' maximum positive and negative reserve offers in $(4.3.2h)$ and $(4.3.2i)$. The DA commitment of thermal and wind power plant is bounded by their capacity and maximum offer in constraints $(4.3.2j)$ and $(4.3.2k)$ respectively. Constraints $(4.3.2l)$ indicate that the amount of wind curtailment at each scenario and plant cannot exceed their actual production. Similarly, the load that is shed cannot be higher than the load requirement at any bus and scenario in $(4.3.2m)$. The reference node n_1 for the DA and RT stages is set by $(4.3.2n)$ and $(4.3.2o)$.

4.3.3. Imperfect Competition

A conventional producer decides to trade strategically with the aim to optimise her profits from selling energy and reserves. As such, the firm's decision making shall be informed by her stations' agility to exploit the complementarity between those products - by committing part of the capacity reserved at day-ahead stage, in the real-time market - and the extent to which not engaging in this inter-temporal arbitrage presents a sizeable opportunity cost for the strategic producer (Morales et al., 2012).

From a microeconomic perspective, a firm can either decide to act as a price-taker, acknowledging that the market price is beyond its control or act strategically by anticipating the effect its behaviour has on the price outcome. At equilibrium, the former assumption of perfect competition implies that the firm would offer an output at the level where its marginal cost equates the price (and the price would be equal to the marginal, as well as the average revenue), as defined by the intersection of supply and demand at the market level. In the short-run, as long as this price is higher than its average (total) variable cost, the firm would satisfy the condition for profit maximisation - and make profits over and above all its costs - and sell all units of output at the market price, while the demand curve facing the competitive firm would be horizontal, i.e. her output decisions would have no bearing on the market price or equivalently, any extra unit sold would incur a marginal revenue equal to the equilibrium price (Pindyck & Rubinfeld, 2005).

Should a firm decide to act strategically, however, it would have to weigh her rivals' likely responses before adopting a monopolistic behaviour over her residual demand curve. Imperfect competition theory suggests that this is downward-sloping, i.e. the strategic firm cannot choose both the price and output controls and so, she might have to forego large shares to other competitors if she were to raise prices or incur significant revenue losses if a cut in price were to be matched by competition (Pindyck & Rubinfeld, 2005). That is, the few large directly competing firms comprising the oligopoly may well observe each other's actions and deter efforts to acquire further amounts of monopoly power. The firm's output decision thus depends on the competition with her peers and so, producers cannot discount the potential impact of their behaviour (actions) on the behaviour of the other oligopolistic firms (reactions).

The influence such strategic reciprocity may subsequently exert on the combined output and hence market price, could be anticipated insofar as the rival firms' optimal production decisions can be conjectured by their reaction functions in the Cournot model (Cournot, 1838). Competing firms would need to derive the curve that bears their own profit-maximising level of production as a function of price, i.e. first determine their residual demand curve after their peers' output has been fixed (i.e. guessed) and then act as monopolists on their residual demand curve by choosing output where marginal cost equals marginal revenue (Pindyck & Rubinfeld, 2005). The Nash equilibrium outputs of the Cournot game would lie at the intersection of the different reaction curves and the price would be determined at a market level. In such a game, all firms-followers are better off at equilibrium and thus not willing to depart from this state individually. Not surprisingly, the

Cournot equilibrium is more favourable than the perfectly competitive outcome, where firms extract normal profits (in the long-run).

Another type of Nash game arises when firms compete strategically over price in a Bertrand game, considering their rivals' price is fixed and beyond their control (Bertrand, 1883). Once its price decision has been determined, a firm is prepared to supply all demand, assuming it has enough capacity to do so. Compared to Cournot, Bertrand games can yield considerably different outcomes, especially when residual demand is not known with certainty, otherwise firms remain indifferent as to the dimension of competition, be it the price or quantity (Klemperer & Meyer, 1989). Crucially, for a market as small as a duopoly facing the same marginal cost of production, the sole Bertrand equilibrium is equivalent to the competitive equilibrium, considering consumers' incentive to purchase from the firm that offers he lowest price and firms' interest to avoid losses. The former connotes that the duopoly may not raise the price above marginal cost, given the incentive of any firm to undercut her rival and deduct her market share, and the latter that neither firm would want to offer below marginal cost (Besanko & Braeutigam, 2011). That is, there is no profit-maximising strategy that a firm could unilaterally follow and the rival could not forestall and so, both firms end up charging the competitive price. In contrast, Cournot competition would require a very large number of firms to match the competitive equilibrium (Nicholson & Snyder, 2008).

An alternative formulation of non-cooperative oligopoly is that of the Stackelberg leadership model (Von Stackelberg, 1934). Unlike Cournot competition where firms take each other's output as fixed and choose quantities simultaneously - i.e. a firm assumes her opponents' strategy remains unchanged with her actions at equilibrium - a Stackelberg model is founded on the premise that, in addition to her knowledge of the inverse demand, an incumbent can manipulate her followers' decisions, having a sophisticated perception of their reaction curves (Besanko & Braeutigam, 2011). Essentially, the leader moves first and chooses her profit-maximising output (which is larger than Cournot output) on her competitors' reaction curve (Nicholson & Snyder, 2008). Assuming those are acting in a profit-maximising way, this stimulates their best response at the next stage, and so the sequential mode of the game holds a crucial advantage for the leader, who manages to influence the price in order to improve net income.

As long as the firm commits to a credible Stackelberg leader's action that is ex-ante set to induce a Stackelberg follower's response - assuming the follower observes the quantity chosen by the leader, i.e. under the assumption of perfect information and enough commitment power - whose decision-making is informed by economic reason, the latter is expected to restrict output, thus securing larger profits for the leader (Nicholson & Snyder, 2008). Compared to the Cournot profit, the leader is invariably better off with the Stackelberg solution, whereas followers can be worse off; on the other hand, efficiency losses are smaller in the Stackelberg oligopoly, as output is larger and price is lower compared to Cournot (Nicholson & Snyder, 2008). However, if the strategy to extract profits beyond Cournot by leading in a Stackelberg game is multilaterally exercised, the derived outcome would represent a Stackelberg disequilibrium (Wetzstein, 2013).

In this work, the strategic producer acts as a leader in a Stackelberg game, whose potential solution, much as in Cournot, represents a Nash Equilibrium under imperfect competition in which followers are doing the best they can, subject to the actions of other agents, and so have no interest to alter their decisions. In practice, such instances may arise when a dominant utility has the ability to correctly foresee her followers' bids; this provides the agent with a strong incentive to influence prices and maximise profits. Correspondingly, the remaining inferior firms may consider the market price is beyond their control and, for the purpose of this thesis, behave in a price-taking fashion.

4.3.4. Producer's Problem

The proposed optimisation model employs a stochastic bi-level programme (Colson et al., 2007) that seeks to derive the optimal offering strategy for a thermal producer in the upper-level problem, whose output is constrained by the market clearing algorithm in the lower-level problem. This sequential structure is an instance of a Stackelberg game (Von Stackelberg, 1934) where the leader firm maximises her profits under the assumption that the followers exhibit a rational behaviour in response to her actions (Hobbs et al., 2000). While the original Stackelberg game is one of choosing quantities, however, we consider the extended leader-follower version of price competition, where a single strategic agent chooses bids first and the competitive fringe price at marginal cost (Gabriel et al., 2013).

The bi-level formulation $(4.3.4)$ follows below:

$$max_{\{\hat{C}_k,\hat{C}_{k,u},\hat{C}_{k,d}\}\cup\{P_k,P_{k,u,s},P_{k,d,s},\theta_n^0,\theta_{n,s}^0,W_i^d,W_{i,s}^{sp},L_{j,s}^{sh}\}\cup\Omega}$$

$$\sum_{k\in O}\Bigg(\lambda_{n:k\in \mathrm{X}_\mathrm{n}^O}\cdot P_k - C_k\cdot P_k + \sum_{s\in S}\left(\mu_{n:k\in \mathrm{X}_\mathrm{n}^O,s}\cdot P_{k,u,s} - \pi_s\cdot C_k\cdot P_{k,u,s}\right) - \sum_{s\in S}\left(\mu_{n:k\in \mathrm{X}_\mathrm{n}^O,s}\cdot P_{k,d,s} - \pi_s\cdot C_k\cdot P_{k,d,s}\right)\Bigg) \qquad (4.3.4a)$$

$s.t.$

$$min_{\{P_k, P_{k,u,s}, P_{k,d,s}, \theta_n^0, \theta_{n,s}^0, W_i^d, W_{i,s}^{sp}, L_{j,s}^{sh}\}}$$

$$\sum_{k \in O} \left(\hat{C}_k \cdot P_k + \hat{C}_{k,u} \cdot \sum_{s \in S} \pi_s \cdot P_{k,u,s} - \hat{C}_{k,d} \cdot \sum_{s \in S} \pi_s \cdot P_{k,d,s} \right)$$
$$+ \sum_{k \in C} \left(C_k \cdot P_k + C_{k,u} \cdot \sum_{s \in S} \pi_s \cdot P_{k,u,s} - C_{k,d} \cdot \sum_{s \in S} \pi_s \cdot P_{k,d,s} \right)$$
$$+ \sum_{s \in S} \pi_s \cdot \left(\sum_{i \in I} Vsp \cdot W_{i,s}^{sp} + \sum_{j \in J} vLOL \cdot L_{j,s}^{sh} \right) \qquad (4.3.4b)$$

$s.t.$

$$constraints\ (4.3.2b) - (4.3.2o) \qquad (4.3.4c)$$

A hierarchic categorisation renders the strategic firm's problem $(4.3.4a)$ the upper-level optimisation problem, whereas the lower-level problem $(4.3.4b) - (4.3.4c)$ is that of obtaining equilibrium in the electricity market, which was presented in section 4.3.2. However, in contrast to the competitive benchmark where the actual costs C_k, $C_{k,u}$, $C_{k,d}$ facing plant were communicated to the SO by all market participants, i.e. the SO cleared the market on the basis of true information submitted to it, competitive behaviour is hereby adopted by fringe producers alone, whereas bid declarations $\hat{C}_k$, $\hat{C}_{k,u}$, $\hat{C}_{k,d}$ generally deviate from actual costs for the oligopolistic firm.

The optimisation variables are arranged in two subsets, corresponding to the price offers relevant to the upper-level problem $\{\hat{C}_k, \hat{C}_{k,u}, \hat{C}_{k,d}\}$ and those of the lower-level problem $\{P_k, P_{k,u,s}, P_{k,d,s}, \theta_n^0, \theta_{n,s}^0, W_i^d, W_{i,s}^{sp}, L_{j,s}^{sh}\}$. The dual variables are indicated in parentheses at the right hand side of the associated constraints $(4.3.4c)$ and are clustered in the set $\Omega = \{\lambda_n, \mu_{n,s}, \rho_l^{min}, \rho_l^{max}, \rho_{l,s}^{min}, \rho_{l,s}^{max}, e_{k,s}^{min}, e_{k,s}^{max}, \overline{z}_{k,s}^{min}, \overline{z}_{k,s}^{max}, \underline{z}_{k,s}^{min}, \underline{z}_{k,s}^{max}, \xi_k^{min}, \xi_k^{max}, h_{i,s}^{min}, h_{i,s}^{max}, p_i^{min}, p_i^{max}, q_{j,s}^{min}, q_{j,s}^{max}, g, g_s\}$.

Objective function $(4.3.4a)$ maximises the expected profit for the leader; this includes revenue earned in the energy and balancing markets minus actual costs C_k, $C_{k,u}$, $C_{k,d}$ incurred, subject to the least-cost dispatch pursued by the SO. In particular, the product $\lambda_n \cdot P_k$ (£) stands for the revenue extracted by generator k in the DA market, where λ_n ($\frac{£}{MWh}$) represents the dual variable of the balance constraint $(4.3.2b)$, i.e. the energy price at node n, and P_k (MW) the scheduled power for one period (hour). Products

$\sum_{s \in S} \mu_{n,s} \cdot P_{k,u,s}$ and $-\sum_{s \in S} \mu_{n,s} \cdot P_{k,\mathrm{d},s}$ correspond to the expected revenue received and charges incurred due to positive $P_{k,u,s}$ and negative $P_{k,d,s}$ regulation, where $\mu_{n,s}$ ($\frac{£}{MWh}$) is the dual variable of the real-time balance constraint $(4.3.2c)$ at node n under scenario s, i.e. positive (negative) balancing is paid (charged) at the dual value of the balance constraint divided by the probability of occurrence for each scenario. On the other hand, objective function $(4.3.4b)$ minimises system operating costs, with the first and second three terms consisting of the strategist's and her rivals' energy and balancing costs, as perceived by the SO.

Observably, the SO's decisions in the lower-level problem are influenced by the optimisation variables of the upper-level problem and so the former represents a Generalised Nash Equilibrium (Gabriel et al., 2013), where the followers' reactions are dependent in a predictable way on the leader's actions (Day et al., 2002). That is, bids $\hat{C}_k$, $\hat{C}_{k,u}$, $\hat{C}_{k,d}$ are variables in the optimal offering problem facing the leader; however, represent known parameters in the clearing problem facing the SO, much like the actual costs C_k, $C_{k,u}$, $C_{k,d}$ communicated by the fringe. On the other hand, apart from the values of her own decision variables, i.e. her bid offers, the strategic firm's profit additionally depends on the primal and dual variables of the lower-level problem, i.e. in practice, on her sold quantities and the LMPs. The bi-level structure highlights the interrelation of the strategic firm's and the SO's decisions; it is through the lower-level problem that the leader firm has a precise anticipation of her followers' reactions, and thus pre-positions herself to induce a behaviour that is optimal for her and the rationally-behaving, price-taking follower firms. The bi-level model $(4.3.4)$ cannot be tackled as it stands, however, if transformed into a single mathematical programme, can be tractable by commercial solvers (Rosenthal, 2016) and this is the topic of the next section.

4.3.5. MPEC Formulation

Central to obtaining the conditions for optimality in the context of constrained optimisation, is to formulate the Lagrangian function and transform the original problem into an unconstrained one (Floudas, 1995). In the context of the bi-level structure $(4.3.4a) - (4.3.4c)$ of the previous section, the constraining lower-level problem $(4.3.4c)$ is linear (and thus convex) and may be replaced by its first-order sufficient KKT conditions (Gabriel et al., 2013); this helps to recast the original problem as a single optimisation problem, i.e. a

Mathematical Programme with Equilibrium Constraints, which can be tackled with optimisation solvers (Rosenthal, 2016).

To formulate the KKT conditions, we first consider the Lagrangian function $(4.3.5a)$ of the lower-level problem:

$$L(x,y,u,v) = g(x,y) + u^T \cdot w(x,y) + v^T \cdot z(x,y) \tag{4.3.5a}$$

where $x = (x_1, x_2, \dots x_\beta) \in X \subseteq \mathbb{R}^\beta$ and $y = (y_1, y_2, \dots y_\gamma) \in Y \subseteq \mathbb{R}^\gamma$ stand for the optimisation variable vector of the upper-level and lower-level problem respectively. Functions g, w and z satisfying continuity and differentiability requirements, represent the objective function, and the equality and $\leq$ type inequality constraints of the lower-level problem, while $u^T = (u_1, u_2, \dots, u_m)$ and $v^T = (v_1, v_2, \dots, v_r)$ correspond to the Lagrange multiplier vectors associated with the equality and inequality constraints, respectively (Floudas, 1995).

In turn, the stationary points of the constrained lower-level problem are determined by obtaining the first-order KKT conditions $(4.3.5b) - (4.3.5f)$ of the unconstrained Lagrangian function $(4.3.5a)$:

$$\nabla_y g(x,y) + u^T \cdot \nabla_y w(x,y) + v^T \cdot \nabla_y z(x,y) = 0 \tag{4.3.5b}$$

$$w(x,y) = 0 \tag{4.3.5c}$$

$$z(x,y) \leq 0 \tag{4.3.5d}$$

$$v^T \cdot z(x,y) = 0 \tag{4.3.5e}$$

$$v \geq 0 \tag{4.3.5f}$$

Constraints $(4.3.5b)$ are derived by differentiating $(4.3.5a)$ with respect to each decision variable in the lower-level problem's optimisation vector y and indicate that the gradient of the auxiliary function $L(x,y,u,v)$ at an optimal solution y^* should be zero (Gabriel et al., 2013). Differentiating with respect to the equality and inequality multipliers u and v pertaining to the lower-level problem yields $(4.3.5c)$ and $(4.3.5d)$; observably, the latter impose the equality and inequality constraints of the lower-level problem. Constraints $(4.3.5e)$ suggest that the inner product of each of the Lagrangian multipliers with their associated inequality is zero; this connotes that the Lagrangian multiplier or the shadow value of the inactive (non-binding) resource constraints is zero at the optimal solution y^* (Floudas, 1995). Constraints of the type $(4.3.5f)$ show that each of the Lagrangian multipliers v would have to be non-negative; on the other hand, the multiplier vector u, associated with the equality constraints is free of sign. Finally, complementarity conditions $(4.2.5d)-(4.2.5f)$ may collectively be written as

$$0 \leq -z(x,y) \perp v \geq 0 \qquad (4.3.5g)$$

where the operator $\perp$ denotes complementarity, i.e. the inner product of the elements at the left and right of the operator is zero.

We are now ready to devise the strategic producer's MPEC $(4.3.5h)-(4.3.5an)$:

$$max_{\{\hat{C}_k,\hat{C}_{k,u},\hat{C}_{k,d}\}\cup\{P_k,P_{k,u,s},P_{k,d,s},\theta_n^0,\theta_{n,s}^0,W_i^d,W_{i,s}^{sp},L_{j,s}^{sh}\}\cup\Omega}$$

$$\sum_{k\in O}\left(\lambda_{n:k\in \mathrm{X}_\mathrm{n}^O}\cdot P_k - C_k\cdot P_k + \sum_{s\in S}\left(\mu_{n:k\in \mathrm{X}_\mathrm{n}^O,s}\cdot P_{k,u,s} - \pi_s\cdot C_k\cdot P_{k,u,s}\right)\right.$$
$$\left. - \sum_{s\in S}\left(\mu_{n:k\in \mathrm{X}_\mathrm{n}^O,s}\cdot P_{k,d,s} - \pi_s\cdot C_k\cdot P_{k,d,s}\right)\right) \qquad (4.3.5h)$$

$s.t.$

$$constraints\ (4.3.2b)-(4.3.2c)\ and\ (4.3.2n)-(4.3.2o) \qquad (4.3.5i)$$

$$\hat{C}_k - \lambda_{n:k\in \mathrm{X}_\mathrm{n}^O} - \xi_k^{min} + \xi_k^{max} + \sum_{s\in S}\left(e_{k,s}^{max} - e_{k,s}^{min}\right) = 0, \qquad \forall\, k\in \mathrm{O} \qquad (4.3.5j)$$

$$C_k - \lambda_{n:k\in \mathrm{X}_\mathrm{n}^C} - \xi_k^{min} + \xi_k^{max} + \sum_{s\in S}\left(e_{k,s}^{max} - e_{k,s}^{min}\right) = 0, \qquad \forall\, k\in \mathrm{C} \qquad (4.3.5k)$$

$$\pi_s\cdot\hat{C}_{k,u} - \mu_{n:k\in \mathrm{X}_\mathrm{n}^O,s} + e_{k,s}^{max} + \bar{z}_{k,s}^{max} - \bar{z}_{k,s}^{min} = 0,\ \ \forall\, k\in O, s\in S \qquad (4.3.5l)$$

$$\pi_s\cdot C_{k,u} - \mu_{n:k\in \mathrm{X}_\mathrm{n}^C,s} + e_{k,s}^{max} + \bar{z}_{k,s}^{max} - \bar{z}_{k,s}^{min} = 0,\ \forall\, k\in C, s\in S \qquad (4.3.5m)$$

$$-\pi_s\cdot\hat{C}_{k,d} + \mu_{n:k\in \mathrm{X}_\mathrm{n}^O,s} + e_{k,s}^{min} + \underline{z}_{k,s}^{max} - \underline{z}_{k,s}^{min} = 0,\ \ \forall\, k\in \mathrm{O}, s\in S \qquad (4.3.5n)$$

$$-\pi_s\cdot C_{k,d} + \mu_{n:k\in \mathrm{X}_\mathrm{n}^C,s} + e_{k,s}^{min} + \underline{z}_{k,s}^{max} - \underline{z}_{k,s}^{min} = 0,\ \forall\, k\in \mathrm{C}, s\in S \qquad (4.3.5o)$$

$$\sum_{l\in\Lambda|a(l)=n_1}\frac{\lambda_{a(l)} - \lambda_{b(l)} - \rho_l^{min} + \rho_l^{max}}{\Psi_l} - \sum_{s\in S}\sum_{l\in\Lambda|a(l)=n_1}\frac{\mu_{a(l),s} - \mu_{b(l),s}}{\Psi_l} + g = 0, \qquad (4.3.5p)$$

$$\sum_{l\in\Lambda|a(l)=n}\frac{\lambda_{a(l)} - \lambda_{b(l)} - \rho_l^{min} + \rho_l^{max}}{\Psi_l} - \sum_{s\in S}\sum_{l\in\Lambda|a(l)=n}\frac{\mu_{a(l),s} - \mu_{b(l),s}}{\Psi_l} = 0\,, \forall\, n\in N\backslash\{n_1\}$$

$$(4.3.5q)$$

$$\sum_{l\in\Lambda|a(l)=n_1}\frac{\mu_{a(l),s}-\mu_{b(l),s}-\rho_{l,s}^{min}+\rho_{l,s}^{max}}{\Psi_l}+g_s=0,\qquad\forall\, s\in S \tag{4.3.5r}$$

$$\sum_{l\in\Lambda|a(l)=n}\frac{\mu_{a(l),s}-\mu_{b(l),s}-\rho_{l,s}^{min}+\rho_{l,s}^{max}}{\Psi_l}=0,\qquad\forall\, n\in N\backslash\{n_1\}, s\in S \tag{4.3.5s}$$

$$-\lambda_{n:i\in X_n^I}+p_i^{max}-p_i^{min}+\sum_{s\epsilon S}\mu_{n,s}=0,\qquad\forall i\in I \tag{4.3.5t}$$

$$\pi_s\cdot Vsp+\mu_{n:i\in X_n^I,s}+h_{i,s}^{max}-h_{i,s}^{min}=0,\qquad\forall\, i\in I, s\in S \tag{4.3.5u}$$

$$\pi_s\cdot vLOL-\mu_{n:i\in X_n^J,s}+q_{j,s}^{max}-q_{j,s}^{min}=0,\qquad\forall\, j\in J, s\in S \tag{4.3.5v}$$

$$0\le\frac{\theta_{\alpha(l)}^{o}-\theta_{b(l)}^{o}}{\Psi_l}+T_l^{max}\perp\rho_l^{min}\ge 0,\qquad\forall\, l\in\Lambda \tag{4.3.5w}$$

$$0\le T_l^{max}-\frac{\theta_{\alpha(l)}^{o}-\theta_{b(l)}^{o}}{\Psi_l}\perp\rho_l^{max}\ge 0,\qquad\forall\, l\in\Lambda \tag{4.3.5x}$$

$$0\le\frac{\theta_{a(l),s}-\theta_{b(l),s}}{\Psi_l}+T_l^{max}\perp\rho_{l,s}^{min}\quad\ge 0,\qquad\forall\, l\in\Lambda, s\in S \tag{4.3.5y}$$

$$0\le T_l^{max}-\frac{\theta_{a(l),s}-\theta_{b(l),s}}{\Psi_l}\perp\rho_{l,s}^{max}\ge 0,\qquad\forall\, l\in\Lambda, s\in S \tag{4.3.5z}$$

$$0\le P_k-P_k^{min}\perp\xi_k^{min}\ge 0,\qquad\forall k\in K \tag{4.3.5aa}$$

$$0\le P_k^{max}-P_k\perp\xi_k^{max}\ge 0,\qquad\forall k\in K \tag{4.3.5ab}$$

$$0\le P_k-P_{k,d,s}-P_k^{min}\perp e_{k,s}^{min}\ge 0,\qquad\forall\, k\in K, s\in S \tag{4.3.5ac}$$

$$0\le P_k^{max}-P_k-P_{k,u,s}\perp e_{k,s}^{max}\ge 0,\qquad\forall\, k\in K, s\in S \tag{4.3.5ad}$$

$$0\le P_{k,u,s}\perp\overline{z}_{k,s}^{min}\ge 0\,,\qquad\forall\, k\in K, s\in S \tag{4.3.5ae}$$

$$0\le R_{k,u}^{max}-P_{k,u,s}\perp\overline{z}_{k,s}^{max}\ge 0,\ \ \forall\, k\in K, s\in S \tag{4.3.5af}$$

$$0\le P_{k,d,s}\perp\underline{z}_{k,s}^{min}\ge 0,\qquad\forall\, k\in K, s\in S \tag{4.3.5ag}$$

$$0\le R_{k,d}^{max}-P_{k,d,s}\perp\underline{z}_{k,s}^{max}\ge 0,\ \forall\, k\in K, s\in S \tag{4.3.5ah}$$

$$0\le W_{i,s}^{sp}\perp h_{i,s}^{min}\ge 0,\ \forall\, i\in I,\ s\in S \tag{4.3.5ai}$$

$$0 \leq W_{i,s} - W_{i,s}^{sp} \perp h_{i,s}^{max} \geq 0, \ \forall\, i \in I, s \in S \tag{4.3.5aj}$$

$$0 \leq W_i^d \perp p_i^{min} \geq 0, \ \forall i \in I \tag{4.3.5ak}$$

$$0 \leq W_i^{max} - W_i^d \perp p_i^{max} \geq 0, \qquad \forall\, i \in I \tag{4.3.5al}$$

$$0 \leq L_{j,s}^{sh} \perp q_{j,s}^{min} \geq 0, \ \forall\, j \in J, s \in S \tag{4.3.5am}$$

$$0 \leq \ L_j - L_{j,s}^{sh} \ \perp q_{j,s}^{max}, \ \forall\, j \in J, s \in S \tag{4.3.5an}$$

Constraints $(4.3.5i)$ of type $(4.3.5c)$ are derived by taking the first derivative of the Lagrangian function with respect to the dual variables $\lambda_n, \mu_{n,s}, g, g_s$. Constraints $(4.3.5j)$ – $(4.3.5v)$ of type $(4.3.5b)$ are derived by differentiating with respect to each of the lower-level problem's decision variables $P_k, P_{k,u,s}, P_{k,d,s}, \theta_n^0, \theta_{n,s}^0, W_i^d, W_{i,s}^{sp}, L_{j,s}^{sh}$ and have been written separately for the strategic firm and the competitive fringe. On the other hand, to obtain the complementarity conditions $(4.3.5w) - (4.2.5an)$ of type $(4.3.5g)$, we differentiate the Lagrangian function with respect to the remaining dual variables $\rho_l^{min}, \rho_l^{max}, \rho_{l,s}^{min}, \rho_{l,s}^{max}, \xi_k^{min}, \xi_k^{max}, e_{k,s}^{min}, e_{k,s}^{max}, \overline{z}_{k,s}^{min}, \overline{z}_{k,s}^{max}, \underline{z}_{k,s}^{min}, \underline{z}_{k,s}^{max}, h_{i,s}^{min}, h_{i,s}^{max}, p_i^{min}, p_i^{max}$ $q_{j,s}^{min}, q_{j,s}^{max}$.

4.3.6. Linearization

The resulting mathematical programme $(4.3.5h) - (4.3.5an)$ is single-level, continuous and nonlinear, due to the complementarity constraints $(4.3.5w) - (4.3.5an)$ and the objective function $(4.3.5h)$. To eliminate nonlinearity we first employ the Fortuny-Amat et al. (1981) linearization; in so doing, we introduce a binary variable δ and a sufficiently large number M associated with each of the $(4.3.5g)$ type complementarity constraints, which are in turn formed into the set of constraints $(4.3.6a) - (4.3.6b)$:

$$0 \leq -z(x, y) \leq M \cdot \delta \tag{4.3.6\alpha}$$

$$0 \leq v \leq M \cdot (1 - \delta) \tag{4.3.6b}$$

Subsequently, we use the Strong Duality Theorem (Luenberger & Ye, 1984) and perform exact algebraic transformations of some KKT conditions to convert the problem into a Mixed Integer Linear Programme that is readily solvable by commercial solvers (Rosenthal, 2016).

Specifically, we start by integrating the disjunctive constraints $(4.3.6\alpha) - (4.3.6b)$ into the producer's MPEC, which is shaped into $(4.3.6c) - (4.3.6an)$:

$$max_{\{\hat{C}_k,\hat{C}_{k,u},\hat{C}_{k,d}\}\cup\left\{P_k,P_{k,u,s},P_{k,d,s},\theta_n^o,\theta_{n,s}^o,W_i^d,W_{i,s}^{sp},L_{j,s}^{sh}\right\}\cup\Omega}$$

$$\sum_{k\in O}\left(\lambda_{n:k\in X_n^O}\cdot P_k - C_k\cdot P_k + \sum_{s\in S}\left(\mu_{n:k\in X_n^O,s}\cdot P_{k,u,s} - \pi_s\cdot C_k\cdot P_{k,u,s}\right)\right.$$
$$\left. - \sum_{s\in S}\left(\mu_{n:k\in X_n^O,s}\cdot P_{k,d,s} - \pi_s\cdot C_k\cdot P_{k,d,s}\right)\right) \tag{4.3.6c}$$

$s.t.$

$$constraints\ (4.3.5i) - (4.3.5v) \tag{4.3.6d}$$

$$0 \le \frac{\theta_{a(l)}^o - \theta_{b(l)}^o}{\Psi_l} + T_l^{max} \le M_1\cdot\delta_l^1, \qquad \forall\, l\in\Lambda \tag{4.3.6e}$$

$$0 \le \rho_l^{min} \le M_1\cdot(1-\delta_l^1), \qquad \forall\, l\in\Lambda \tag{4.3.6f}$$

$$0 \le T_l^{max} - \frac{\theta_{a(l)}^o - \theta_{b(l)}^o}{\Psi_l} \le M_2\cdot\delta_l^2, \qquad \forall\, l\in\Lambda \tag{4.3.6g}$$

$$0 \le \rho_l^{max} \le M_2\cdot(1-\delta_l^2), \qquad \forall\, l\in\Lambda \tag{4.3.6h}$$

$$0 \le \frac{\theta_{a(l),s} - \theta_{b(l),s}}{\Psi_l} + T_l^{max} \le M_3\cdot\delta_{l,s}^3, \qquad \forall\, l\in\Lambda, s\in S \tag{4.3.6i}$$

$$0 \le \rho_{l,s}^{min} \le M_3\cdot\left(1-\delta_{l,s}^3\right), \qquad \forall\ l\in\Lambda, s\in S \tag{4.3.6j}$$

$$0 \le T_l^{max} - \frac{\theta_{a(l),s} - \theta_{b(l),s}}{\Psi_l} \le M_4\cdot\delta_{l,s}^4, \qquad \forall\, l\in\Lambda, s\in S \tag{4.3.6k}$$

$$0 \le \rho_{l,s}^{max} \le M_4\cdot\left(1-\delta_{l,s}^4\right), \qquad \forall\, l\in\Lambda, s\in S \tag{4.3.6l}$$

$$0 \le P_k - P_k^{min} \le M_5\cdot\delta_k^5, \qquad \forall\, k\in K \tag{4.3.6m}$$

$$0 \le \xi_k^{min} \le M_5\cdot\left(1-\delta_k^5\right), \qquad \forall\, k\in K \tag{4.3.6n}$$

$$0 \le P_k^{max} - P_k \le M_6\cdot\delta_k^6, \qquad \forall\, k\in K \tag{4.3.6o}$$

$$0 \le \xi_k^{max} \le M_6\cdot\left(1-\delta_k^6\right), \qquad \forall\, k\in K \tag{4.3.6p}$$

$$0 \le P_k - P_{k,d,s} - P_k^{min} \le M_7\cdot\delta_{k,s}^7, \qquad \forall\, k\in K, s\in S \tag{4.3.6q}$$

$$0 \le e_{k,s}^{min} \le M_7\cdot\left(1-\delta_{k,s}^7\right), \qquad \forall\, k\in K, s\in S \tag{4.3.6r}$$

$$0 \leq P_k^{max} - P_k - P_{k,u,s} \leq M_8 \cdot \delta_{k,s}^8, \qquad \forall\, k \in K, s \in S \tag{4.3.6s}$$

$$0 \leq e_{k,s}^{max} \leq M_8 \cdot \left(1 - \delta_{k,s}^8\right), \qquad \forall\, k \in K, s \in S \tag{4.3.6t}$$

$$0 \leq P_{k,u,s} \leq M_9 \cdot \delta_{k,s}^9, \qquad \forall\, k \in K, s \in S \tag{4.3.6u}$$

$$0 \leq \overline{z}_{k,s}^{min} \leq M_9 \cdot \left(1 - \delta_{k,s}^9\right), \qquad \forall\, k \in K, s \in S \tag{4.3.6v}$$

$$0 \leq R_{k,u}^{max} - P_{k,u,s} \leq M_{10} \cdot \delta_{k,s}^{10}, \;\; \forall k \in K, s \in S \tag{4.3.6w}$$

$$0 \leq \overline{z}_{k,s}^{max} \leq M_{10} \cdot \left(1 - \delta_{k,s}^{10}\right), \qquad \forall\, k \in K, s \in S \tag{4.3.6x}$$

$$0 \leq P_{k,d,s} \leq M_{11} \cdot \delta_{k,s}^{11}, \qquad \forall\, k \in K, s \in S \tag{4.3.6y}$$

$$0 \leq \underline{z}_{k,s}^{min} \leq M_{11} \cdot \left(1 - \delta_{k,s}^{11}\right), \qquad \forall\, k \in K, s \in S \tag{4.3.6z}$$

$$0 \leq R_{k,d}^{max} - P_{k,d,s} \leq M_{12} \cdot \delta_{k,s}^{12}, \; \forall\, k \in K, \; s \in S \tag{4.3.6aa}$$

$$0 \leq \underline{z}_{k,s}^{max} \leq M_{12} \cdot \left(1 - \delta_{k,s}^{12}\right), \qquad \forall\, k \in K, s \in S \tag{4.3.6ab}$$

$$0 \leq W_{i,s}^{sp} \leq M_{13} \cdot \delta_{i,s}^{13}, \qquad \forall\, i \in I, s \in S \tag{4.3.6ac}$$

$$0 \leq h_{i,s}^{min} \leq M_{13} \cdot \left(1 - \delta_{i,s}^{13}\right), \qquad \forall\, i \in I, s \in S \tag{4.3.6ad}$$

$$0 \leq W_{i,s} - W_{i,s}^{sp} \leq M_{14} \cdot \delta_{i,s}^{14}, \; \forall\, i \in I, s \in S \tag{4.3.6ae}$$

$$0 \leq h_{i,s}^{max} \leq M_{14} \cdot \left(1 - \delta_{i,s}^{14}\right), \qquad \forall\, i \in I, s \in S \tag{4.3.6af}$$

$$0 \leq W_i^d \leq M_{15} \cdot \delta_i^{15}, \; \forall i \in I \tag{4.3.6ag}$$

$$0 \leq p_i^{min} \leq M_{15} \cdot \left(1 - \delta_i^{15}\right), \qquad \forall i \in I \tag{4.3.6ah}$$

$$0 \leq W_i^{max} - W_i^d \leq M_{16} \cdot \delta_i^{16}, \qquad \forall\, i \in I \tag{4.3.6ai}$$

$$0 \leq p_i^{max} \leq M_{16} \cdot \left(1 - \delta_i^{16}\right), \qquad \forall\, i \in I \tag{4.3.6aj}$$

$$0 \leq L_{j,s}^{sh} \leq M_{17} \cdot \delta_{j,s}^{17}, \; \forall\, j \in J, s \in S \tag{4.3.6ak}$$

$$0 \leq q_{j,s}^{min} \leq M_{17} \cdot \left(1 - \delta_{j,s}^{17}\right), \qquad \forall\, j \in J, s \in S \tag{4.3.6al}$$

$$0 \leq L_j - L_{j,s}^{sh} \leq M_{18} \cdot \delta_{j,s}^{18}, \; \forall \, j \in J, \; s \in S \tag{4.3.6am}$$

$$0 \leq q_{j,s}^{max} \leq M_{18} \cdot \left(1 - \delta_{j,s}^{18}\right), \qquad \forall \, j \in J, s \in S \tag{4.3.6an}$$

Notice that $(4.3.6c) - (4.3.6an)$ is still a nonlinear problem, due to the objective function $(4.3.6c)$. To dispose of the nonlinear revenue terms of the strategic producer $\lambda_n \cdot P_k$ in the DA and $\mu_{n,s} \cdot P_{k,u,s}$ and $-\mu_{n,s} \cdot P_{k,d,s}$ in the RT market, we start by multiplying equations $(4.3.5j), (4.3.5l)$ and $(4.3.5n)$ with P_k, $P_{k,u,s}$ and $P_{k,d,s}$ respectively. We then get $(4.3.6ao)$, $(4.3.6ap)$ and $(4.3.6aq)$ as per below:

$$\hat{C}_k \cdot P_k - \lambda_{n:k \in \mathrm{X}_\mathrm{n}^O} \cdot P_k - \xi_k^{min} \cdot P_k + \xi_k^{max} \cdot P_k + \sum_{s \in S} e_{k,s}^{max} \cdot P_k - \sum_{s \in S} e_{k,s}^{min} \cdot P_k = 0$$
$$, \forall \, k \in O \tag{4.3.6ao}$$

$$\pi_s \cdot \hat{C}_{k,u} \cdot P_{k,u,s} - \mu_{n:k \in \mathrm{X}_\mathrm{n}^O, s} \cdot P_{k,u,s} + e_{k,s}^{max} \cdot P_{k,u,s} + \bar{z}_{k,s}^{max} \cdot P_{k,u,s} - \bar{z}_{k,s}^{min} \cdot P_{k,u,s} = 0$$
$$, \forall \, k \in O, s \in S \tag{4.3.6ap}$$

$$-\pi_s \cdot \hat{C}_{k,d} \cdot P_{k,d,s} + \mu_{n:k \in \mathrm{X}_\mathrm{n}^O, s} \cdot P_{k,d,s} + e_{k,s}^{min} \cdot P_{k,d,s} + \underline{z}_{k,s}^{max} \cdot P_{k,d,s} - \underline{z}_{k,s}^{min} \cdot P_{k,d,s} = 0$$
$$, \forall \, k \in O, s \in S \tag{4.3.6aq}$$

Observably, the nonlinearity relating to equations $(4.3.6ao) - (4.3.6aq)$ is due partly to the nonlinearity introduced by the previous algebraic transformation, i.e. the terms representing products of the decision variables $P_k, P_{k,u,s}$ and $P_{k,d,s}$ with the dual variables λ_n and $\mu_{n,s}$. Our aim is to re-write those equations to obtain a linear expression of the strategic revenue, included in the MPEC's objective function $(4.3.6c)$.

We begin with equations $(4.3.6ao)$ which include nonlinear product terms of the type $\xi_k^{min} \cdot P_k$, $\xi_k^{max} \cdot P_k$ and $e_{k,s}^{max} \cdot P_k$, $e_{k,s}^{min} \cdot P_k$; complementarity conditions $(4.3.5aa)$ and $(4.3.5ab)$ help transform the terms $\xi_k^{min} \cdot P_k$ and $\xi_k^{max} \cdot P_k$ into their equivalent linear expression, as per $(4.3.6ar)$ and $(4.3.6as)$:

$$\left(P_k - P_k^{min}\right) \cdot \xi_k^{min} = 0 \Leftrightarrow P_k \cdot \xi_k^{min} = P_k^{min} \cdot \xi_k^{min}, \forall \, k \in O \tag{4.3.6ar}$$

$$\left(P_k^{max} - P_k\right) \cdot \xi_k^{max} = 0 \Leftrightarrow P_k^{max} \cdot \xi_k^{max} = P_k \cdot \xi_k^{max}, \forall \, k \in O \tag{4.3.6as}$$

Further, as regards to terms $e_{k,s}^{min} \cdot P_k$ and $e_{k,s}^{max} \cdot P_k$, we re-write conditions $(4.3.5ac)$ and $(4.3.5ad)$ as $(4.3.6at)$ and $(4.3.6au)$ respectively:

$$\left(P_k - P_{k,d,s} - P_k^{min}\right) \cdot e_{k,s}^{min} = 0 \Leftrightarrow e_{k,s}^{min} \cdot P_k = e_{k,s}^{min} \cdot \left(P_k^{min} + P_{k,d,s}\right)$$
$$, \forall \, k \in O, s \in S \tag{4.3.6at}$$

$$\left(P_k^{max} - P_k - P_{k,u,s}\right) \cdot e_{k,s}^{max} = 0 \Leftrightarrow e_{k,s}^{max} \cdot P_k = e_{k,s}^{max} \cdot \left(P_k^{max} - P_{k,u,s}\right),$$

$$, \forall\, k \in O, s \in S \qquad (4.3.6au)$$

Solving $(4.3.6ao)$ for $\lambda_n \cdot P_k$ and substituting the nonlinear terms with the help of $(4.3.6ar) - (4.3.6au)$ yields $(4.3.6av)$:

$$\lambda_{n:k\in \mathrm{X}_{\mathrm{n}}^{O}} \cdot P_k = \hat{C}_k \cdot P_k - P_k^{min} \cdot \xi_k^{min} + P_k^{max} \cdot \xi_k^{max}$$

$$+ \sum_{s\in S} e_{k,s}^{max} \cdot \left(P_k^{max} - P_{k,u,s}\right) - \sum_{s\in S} e_{k,s}^{min} \cdot \left(P_k^{min} + P_{k,d,s}\right), \forall k \in O \qquad (4.3.6av)$$

The linearization process continues by performing similar algebraic transformations to equations $(4.3.6ap)$. Inequalities $(4.3.5ae)$ and $(4.3.5af)$ yield $(4.3.6aw)$ and $(4.3.6ax)$:

$$P_{k,u,s} \cdot \overline{z}_{k,s}^{min} = 0\,, \qquad \forall\, k \in O, s \in S \qquad (4.3.6aw)$$

$$\left(R_{k,u}^{max} - P_{k,u,s}\right) \cdot \overline{z}_{k,s}^{max} = 0 \Leftrightarrow R_k^{umax} \cdot \overline{z}_{k,s}^{max} = P_{k,u,s} \cdot \overline{z}_{k,s}^{max}, \qquad \forall\, k \in O, s \in S \qquad (4.3.6ax)$$

and so the sum of equations $(4.3.6ap)$ pertaining to each strategic plant over all scenarios, with $\sum_{s\in S} \mu_{n,s} \cdot P_{k,u,s}$ at the left-hand side, is written in $(4.3.6ay)$:

$$\sum_{s\in S} \mu_{n:k\in \mathrm{X}_{\mathrm{n}}^{O},s} \cdot P_{k,u,s} = \hat{C}_{k,u} \cdot \sum_{s\in S} \pi_s \cdot P_{k,u,s} + \sum_{s\in S} e_{k,s}^{max} \cdot P_{k,u,s} + \sum_{s\in S} \overline{z}_{k,s}^{max} \cdot R_{k,u}^{max}, \forall\, k \in O$$

$$(4.3.6ay)$$

Finally, we focus on equations $(4.3.6aq)$. Similar to the above, conditions $(4.3.5ag)$ and $(4.3.5ah)$ help eliminate part of the nonlinearity inherent to equations $(4.3.6aq)$, due to $(4.3.6az)$ and $(4.3.6ba)$:

$$P_{k,d,s} \cdot \underline{z}_{k,s}^{min} = 0, \qquad \forall\, k \in O, s \in S \qquad (4.3.6az)$$

$$\left(R_{k,d}^{max} - P_{k,d,s}\right) \cdot \underline{z}_{k,s}^{max} = 0 \Leftrightarrow R_{k,d}^{max} \cdot \underline{z}_{k,s}^{max} = P_{k,d,s} \cdot \underline{z}_{k,s}^{max}, \ \forall\, k \in O, s \in S \qquad (4.3.6ba)$$

Equation $(4.3.6bb)$ providing the sum of equations $(4.3.6aq)$ relevant to each of the strategist's stations over all scenarios, is written with respect to the term $-\sum_{s\in S} \mu_{n,s} \cdot P_{k,d,s}$:

$$-\sum_{s\in S} \mu_{n:k\in \mathrm{X}_{\mathrm{n}}^{O},s} \cdot P_{k,d,s} = -\hat{C}_{k,d} \cdot \sum_{s\in S} \pi_s \cdot P_{k,d,s} + \sum_{s\in S} e_{k,s}^{min} \cdot P_{k,d,s} + \sum_{s\in S} \underline{z}_{k,s}^{max} \cdot R_{k,d}^{max}, \forall k \in O$$

$$(4.3.6bb)$$

Having solved equations $(4.3.6ao) - (4.3.6aq)$ for the nonlinear revenue terms $\lambda_n \cdot P_k$, $\sum_{s\in S} \mu_{n,s} \cdot P_{k,u,s}$ and $-\sum_{s\in S} \mu_{n,s} \cdot P_{k,d,s}$, we add the derived equations $(4.3.6av)$, $(4.3.6ay)$ and $(4.3.6bb)$ to receive $(4.3.6bc)$:

$$\lambda_{n:k\in \mathrm{X}_{\mathrm{n}}^{O}} \cdot P_k + \sum_{s\in S} \mu_{n:k\in \mathrm{X}_{\mathrm{n}}^{O},s} \cdot P_{k,u,s} - \sum_{s\in S} \mu_{n:k\in \mathrm{X}_{\mathrm{n}}^{O},s} \cdot P_{k,d,s} =$$

$$\hat{C}_k \cdot P_k - P_k^{min} \cdot \xi_k^{min} + P_k^{max} \cdot \xi_k^{max} + \sum_{s\in S} \left(e_{k,s}^{max} \cdot P_k^{max} - e_{k,s}^{min} \cdot P_k^{min}\right)$$

$$+\hat{C}_{k,u} \cdot \sum_{s\in S} \pi_s \cdot P_{k,u,s} + \sum_{s\in S} \overline{z}_{k,s}^{max} \cdot R_{k,u}^{max} - \hat{C}_{k,d} \cdot \sum_{s\in S} \pi_s \cdot P_{k,d,s} + \sum_{s\in S} \underline{z}_{k,s}^{max} \cdot R_{k,d}^{max}$$

$$,\forall k \in O \qquad (4.3.6bc)$$

We observe that nonlinearity persists in $(4.3.6bc)$ due to terms involving products of variables, i.e. $\hat{C}_k \cdot P_k$, $\hat{C}_{k,u} \cdot \sum_{s\in S} \pi_s \cdot P_{k,u,s}$ and $-\hat{C}_{k,d} \cdot \sum_{s\in S} \pi_s \cdot P_{k,d,s}$. In turn, we use the Strong Duality Theorem (Luenberger & Ye, 1984), where the existence of an optimal solution in the primal problem can guarantee the admittance of an optimal and equal solution for the dual, i.e.

$$c^T \cdot y = \zeta^T \cdot b \qquad (4.3.6bd)$$

where c and ζ stand for the objective function coefficient and dual variable vectors, y is the decision variable vector and b the right-hand side parameter vector of the constraints. We thus formulate the objective function $(4.3.6be)$ of the dual of the lower-level problem $(4.3.4b) - (4.3.4c)$, in an effort to linearize the right-hand side of equations $(4.3.6bc)$ and subsequently cast the MPEC's objective function $(4.3.6c)$ into its linear counterpart:

$$max_{\{\Omega\}}$$

$$\sum_{k\in K} \left(P_k^{min} \cdot \xi_k^{min} - P_k^{max} \cdot \xi_k^{max}\right)$$

$$+\sum_{s\in S} \sum_{k\in K} \left(P_k^{min} \cdot e_{k,s}^{min} - P_k^{max} \cdot e_{k,s}^{max}\right) - \sum_{s\in S} \sum_{k\in K} \left(R_{k,u}^{max} \cdot \overline{z}_{k,s}^{max} + R_{k,d}^{max} \cdot \underline{z}_{k,s}^{max}\right)$$

$$-\sum_{l\in \Lambda} T_l^{max} \cdot \left(\rho_l^{min} + \rho_l^{max}\right) - \sum_{s\in S} \sum_{l\in \Lambda} T_l^{max} \cdot \left(\rho_{l,s}^{min} + \rho_{l,s}^{max}\right)$$

$$-\sum_{s\in S} \sum_{i\in I} W_{i,s} \cdot h_{i,s}^{max} - \sum_{i\in I} W_i^{max} \cdot p_i^{max} - \sum_{s\in S} \sum_{n\in N} \sum_{i\in X_n^I} W_{i,s} \cdot \mu_{n,s}$$

$$-\sum_{s\in S} \sum_{j\in J} L_j \cdot q_{j,s}^{max} + \sum_{n\in N} \sum_{j\in X_n^J} L_j \cdot \lambda_n \qquad (4.3.6be)$$

Following $(4.3.6bd)$, we equate objective functions $(4.3.6be)$ of the dual and $(4.3.4b)$ of the primal and solve for the strategic firm's cost, as perceived by the SO:

$$\sum_{k\in O}\left(\hat{C}_k\cdot P_k+\hat{C}_{k,u}\cdot\sum_{s\in S}\pi_s\cdot P_{k,u,s}-\hat{C}_{k,d}\cdot\sum_{s\in S}\pi_s\cdot P_{k,d,s}\right)=$$

$$-\sum_{k\in C}\left(C_k\cdot P_k+C_{k,u}\cdot\sum_{s\in S}\pi_s\cdot P_{k,u,s}-C_{k,d}\cdot\sum_{s\in S}\pi_s\cdot P_{k,d,s}\right)$$

$$-\sum_{s\in S}\pi_s\cdot\left(\sum_{i\in I}Vsp\cdot W_{i,s}^{sp}+\sum_{j\in J}vLOL\cdot L_{j,s}^{sh}\right)$$

$$+\sum_{k\in K}\left(P_k^{min}\cdot\xi_k^{min}-P_k^{max}\cdot\xi_k^{max}\right)$$

$$+\sum_{s\in S}\sum_{k\in K}\left(P_k^{min}\cdot e_{k,s}^{min}-P_k^{max}\cdot e_{k,s}^{max}\right)-\sum_{s\in S}\sum_{k\in K}\left(R_{k,u}^{max}\cdot\overline{z}_{k,s}^{max}+R_{k,d}^{max}\cdot\underline{z}_{k,s}^{max}\right)$$

$$-\sum_{l\in\Lambda}T_l^{max}\cdot\left(\rho_l^{min}+\ \rho_l^{max}\right)-\sum_{s\in S}\sum_{l\in\Lambda}T_l^{max}\cdot\left(\rho_{l,s}^{min}+\rho_{l,s}^{max}\right)$$

$$-\sum_{s\in S}\sum_{i\in I}W_{i,s}\cdot h_{i,s}^{max}-\sum_{i\in I}W_i^{max}\cdot p_i^{max}-\sum_{s\in S}\sum_{n\in N}\sum_{i\in X_n^I}W_{i,s}\cdot\mu_{n,s}$$

$$-\sum_{s\in S}\sum_{j\in J}L_j\cdot q_{j,s}^{max}+\sum_{n\in N}\sum_{j\in X_n^J}L_j\cdot\lambda_n \qquad (4.3.6bf)$$

Equation $(4.3.6bf)$ is a linear formulation of the strategic firm's cost as perceived by the SO and is replaced into the equation that is derived from the summation of $(4.3.6bc)$ over all strategic plant, thus providing a linear expression of her strategic income in $(4.3.6bg)$:

$$\sum_{k\in O}\left(\lambda_{n:k\in \mathrm{X}_{\mathrm{n}}^{O}}\cdot P_k+\sum_{s\in S}\mu_{n:k\in \mathrm{X}_{\mathrm{n}}^{O},s}\cdot P_{k,u,s}-\sum_{s\in S}\mu_{n:k\in \mathrm{X}_{\mathrm{n}}^{O},s}\cdot P_{k,d,s}\right)=$$

$$\sum_{k\in O}\left(-P_k^{min}\cdot\xi_k^{min}+P_k^{max}\cdot\xi_k^{max}\right)$$

$$+\sum_{s\in S}\sum_{k\in O}\left(P_k^{max}\cdot e_{k,s}^{max}-P_k^{min}\cdot e_{k,s}^{min}\right)+\sum_{s\in S}\sum_{k\in O}\left(R_{k,u}^{max}\cdot\overline{z}_{k,s}^{max}+R_{k,d}^{max}\cdot\underline{z}_{k,s}^{max}\right)$$

$$-\sum_{k\in C}\left(C_k\cdot P_k+C_{k,u}\cdot\sum_{s\in S}\pi_s\cdot P_{k,u,s}-C_{k,d}\cdot\sum_{s\in S}\pi_s\cdot P_{k,d,s}\right)$$

$$-\sum_{s\in S}\pi_s\cdot\left(\sum_{i\in I}Vsp\cdot W_{i,s}^{sp}+\sum_{j\in J}vLOL\cdot L_{j,s}^{sh}\right)$$

$$+\sum_{k\in K}\left(P_k^{min}\cdot\xi_k^{min}-P_k^{max}\cdot\xi_k^{max}\right)$$

$$+\sum_{s\in S}\sum_{k\in K}\left(P_k^{min}\cdot e_{k,s}^{min}-P_k^{max}\cdot e_{k,s}^{max}\right)-\sum_{s\in S}\sum_{k\in K}\left(R_{k,u}^{max}\cdot \overline{z}_{k,s}^{max}+R_{k,d}^{max}\cdot \underline{z}_{k,s}^{max}\right)$$

$$-\sum_{l\in \Lambda}T_l^{max}\cdot\left(\rho_l^{min}+\ \rho_l^{max}\right)-\sum_{s\in S}\sum_{l\in \Lambda}T_l^{max}\cdot\left(\rho_{l,s}^{min}+\rho_{l,s}^{max}\right)$$

$$-\sum_{s\in S}\sum_{i\in I}W_{i,s}\cdot h_{i,s}^{max}-\sum_{i\in I}W_i^{max}\cdot p_i^{max}-\sum_{s\in S}\sum_{n\in N}\sum_{i\in X_n^I}W_{i,s}\cdot\mu_{n,s}$$

$$-\sum_{s\in S}\sum_{j\in J}L_j\cdot q_{j,s}^{max}+\sum_{n\in N}\sum_{j\in X_n^J}L_j\cdot\lambda_n \qquad (4.3.6bg)$$

Equation $(4.3.6bg)$ represents a linear expression of the strategic firm’s revenue. Effectively, the leader’s objective function $(4.3.6c)$ comprises linear terms alone and the producer’s MPEC may be coded as an MILP in commercial solvers.

5. Case Study

The resulting model of section 4.3.6 is implemented in GAMS, using the CPLEX 12.6 solver (Rosenthal, 2016). We employ a transmission-constrained dispatch model for the GB power system to evaluate the proposed scheme and explore the impact of wind power uncertainty on day-ahead and expected balance prices, costs incurred by the system and profits made by producers. The strategic equilibrium is compared against the outcome derived by solving the market, where price-taking behaviour is assumed for all participants.

The proposed framework is shown to benefit the strategic firm increasingly with declining amounts of wind power for both demand levels. In winter, the expected profit increase ranges between 88% and 937% in the models with 15% and 5% penetration as a share of demand, while in summer, strategic gains are between 2% and 37% for the models with 40% and 10% penetration. Wind and thermal fringe producers also stand to benefit from the price-making conduct of the dominant utility, albeit decreasingly with rising levels of wind in the winter; on the other hand, wind and fringe generators are increasingly better off in the summer up to the level of 30% penetration, while extracting competitive and zero profits respectively at 40% penetration. Results from the strategic equilibrium additionally suggest the loss of market income incurred by individual wind plant sited at export-constrained nodes, as well as changes in the fuel mix of generation.

The leader's strategy is summarised as taking advantage of her overwhelming size in order to raise energy and balance prices and extract monopoly profits. This is facilitated by means of economic withholding, i.e. by bidding part of her capacity high, the firm alters the merit-order of plant and compels the utilisation of higher-cost generation in recompense. At higher levels of wind penetration, decreased residual demand levels prompt the strategist to exacerbate the constraints, in pursuit of larger monopoly pockets.

The method was complementarily tested on a more flexible configuration of the GB system to examine the impact of balancing capability on the leader's strategy and profits. The stations' enhanced ability for RT output adjustments was reflected on the lower balancing premiums, i.e. firms were willing to pay (receive) more (less) to cut back (stand up) in RT. Profits were found to be higher (lower) by as much as 1.9% (3.7%) in the winter (summer) MPEC with 10% (30%) penetration, suggesting the increased (decreased) incentives for strategic behaviour in more flexible systems during higher (lower) levels of demand.

5.1. Model Assumptions

The main assumptions adopted in our model are summarised for clarity below:

1) Due to the highly non-convex nature of MPECs, the stations' bids are simplified to express the minimum revenue per MW of power at a specific location in one period, that is, a single block for energy delivery, and positive and negative balancing.

2) To keep the models manageable and results easier to interpret, a price cap of £300 per MWh in the DA market is introduced, despite the remote resemblance to the GB power market provisions. The threshold where demand is voluntarily willing to shed load is similarly set to £200 per MWh to allow for direct comparisons of the opportunity cost facing the SO (and the leader) in consideration of the balancing value to demand.

3) We consider thermal units alone, i.e. disregard hydroelectric units to avoid the enforcement of additional trading complexities pertaining to hydro injections; this may well represent a period where the system is short in mandatory hydro generation. Incidentally, hydro generation stood at just 1.3% of transmission demand in 2014, hence, there is no need to adjust demand so that it corresponds to load levels net of hydro production.

4) Our experiments rest on the assumption that all stations other than nuclear and CHP are balance responsible.

5) We shall occupy ourselves with manually effected reserves alone, throughout the study considered. This is suggestive of their ability to ramp-up in replacement of automatically activated secondary regulating sources, under the presence of persisting energy imbalances. To this end, the differentiation between faster and slower generators feeds through into the maximum balancing capability and the premium asked for positive and negative re-dispatch.

6) As analysed in section 3.1, the energy and reserve markets are cleared simultaneously. Moreover, reserve requirements are determined indirectly through the clearing mechanism. That is, in the presence of stochastic generation, the anticipated balancing action at the second stage provides an ex-post estimate of the reserve needs that is readily referenced against the actual valuation of consumption (Morales et al., 2014), thus abiding by the latest research on the integration of renewables.

7) We consider zero reserve capacity costs; instead, we impose a price premium to reflect the value of electricity exchanged at the balancing stage, staying in line with the energy-only character of the settlement scheme (Morales et al., 2012).

8) We follow a single-price imbalance settlement, where positive (negative) balancing is paid (charged) at the dual value of the balance constraint divided by the probability of

occurrence for each scenario. The same price is received (paid) by wind plant for a production surplus (shortfall) in RT.

9) Demand for electricity is considered to be insensitive to price changes in the short-term, i.e. completely inelastic up to the voluntary load shedding price $vLOL$; if the price reaches this level, the consumers are willing to shed as much demand as necessary to balance generation.

10) The only source of uncertainty is with regards to wind power production, which feeds through into the output required from dispatchable producers and expected balance prices. Wind power uncertainty enters the model through an explicit probabilistic representation in the form of scenarios. To facilitate a critical review of the market power exercise and subsequent price-formation, we use a parsimonious two non-equiprobable set describing the high and low wind power states of the system, with probability 60% and 40% respectively. Moreover, we consider wind power output to grow in the same proportion at all nodes for each of the penetration levels examined; details about the wind power scenarios for each of the subsequent simulations may be found in Appendix A. This work is not occupied with the independent field of complex scenario generation and reduction techniques; the interested reader may refer to the study of Dupačová et al. (2003) for a review of such aspects.

11) Wind is conceived as a zero marginal cost energy source; as such, the resource may be spilled at zero cost by the SO. In addition, both the competitive unit commitment models as well as the MPECs, are solved with the upper bound of DA wind dispatch, set at the high wind scenario prediction in (4.3.21).

12) The objective of the SO is to minimise expected system costs, comprising day-ahead energy and expected real-time balancing costs, which for this purpose, are explicitly incorporated in the objective function, as analysed in section 4.3.2.

13) We employ a DC linear approximation to explicitly model the flows in the GB transmission network. Losses and reactive power considerations are ignored, remaining in line with common market clearing practices (Kirschen & Strbac, 2004).

14) For reasons analysed in section 3.2, we employ a nodal marginal pricing system; the network topology is thus explicitly taken into account during the dispatch to reflect the spatial granularity of electricity.

15) Inter-temporal constraints (e.g. ramping limits) are ignored on the grounds of simplicity. Instead, we focus on a single-period auction, however, our method may well be extended to incorporate multi-period auctions.

16) Sophisticated features such as minimum power output levels are omitted, in an effort to steer clear from the likelihood of arriving at no equilibrium and intractable running times, due to the highly non-convex nature of MPECs.
17) The goals of the competing firms are conflicting; there is a leader, which has a precise anticipation of her rivals' bids and adopts a price-making behaviour in the energy and balancing markets, while they are acting as price-taking followers.
18) Despite being typical within long-term simulation models, CO_2 emissions constraints are not taken into account, as we focus on the short-term implications of market power.

5.2. Input Data & System Description

We test our MPEC on a 29-node and 49-line network, representative of the high-voltage GB transmission system that spans the geography of Scotland, England and Wales, which accommodates 79 conventional and 11 wind plant dispersed across the system. The topology of the GB electricity network, showing the location of the main power stations (including Northern Ireland) at the end of May 2015 is presented in Figure 1 (DUKES, 2015), while our 29-node grid, representative of the GB system is depicted on Figure 2.[5] The physical links comprising the GB transmission system are introduced in Table 1. A reactance of 0.13 is assumed for all transmission lines.

DUKES (2015) features an electricity production breakdown between incumbent electricity generation companies called Major Power Producers (MPPs) and Other Generators, whose primary business is not power generation, including auto-generators and (some) renewables. Electricity on the high-voltage Public Distribution System (PDS) is mainly supplied by MPPs, while the remainder consists of international imports and transfers from Other Generators that are connected to the low-voltage distribution network - typically referred to as embedded generation. PDS's share of GB's power demand stood at the level of 94% in 2014; MPPs, and net imports and transfers covered about 88.3% and 10.5% of PDS's demand respectively (DUKES, 2015).

[5] We would like to thank Prof. Keith Bell from the University of Strathclyde, who provided us with demand and transmission data and the reduced GB power system, as well as preliminary data for GB's generating capacity.

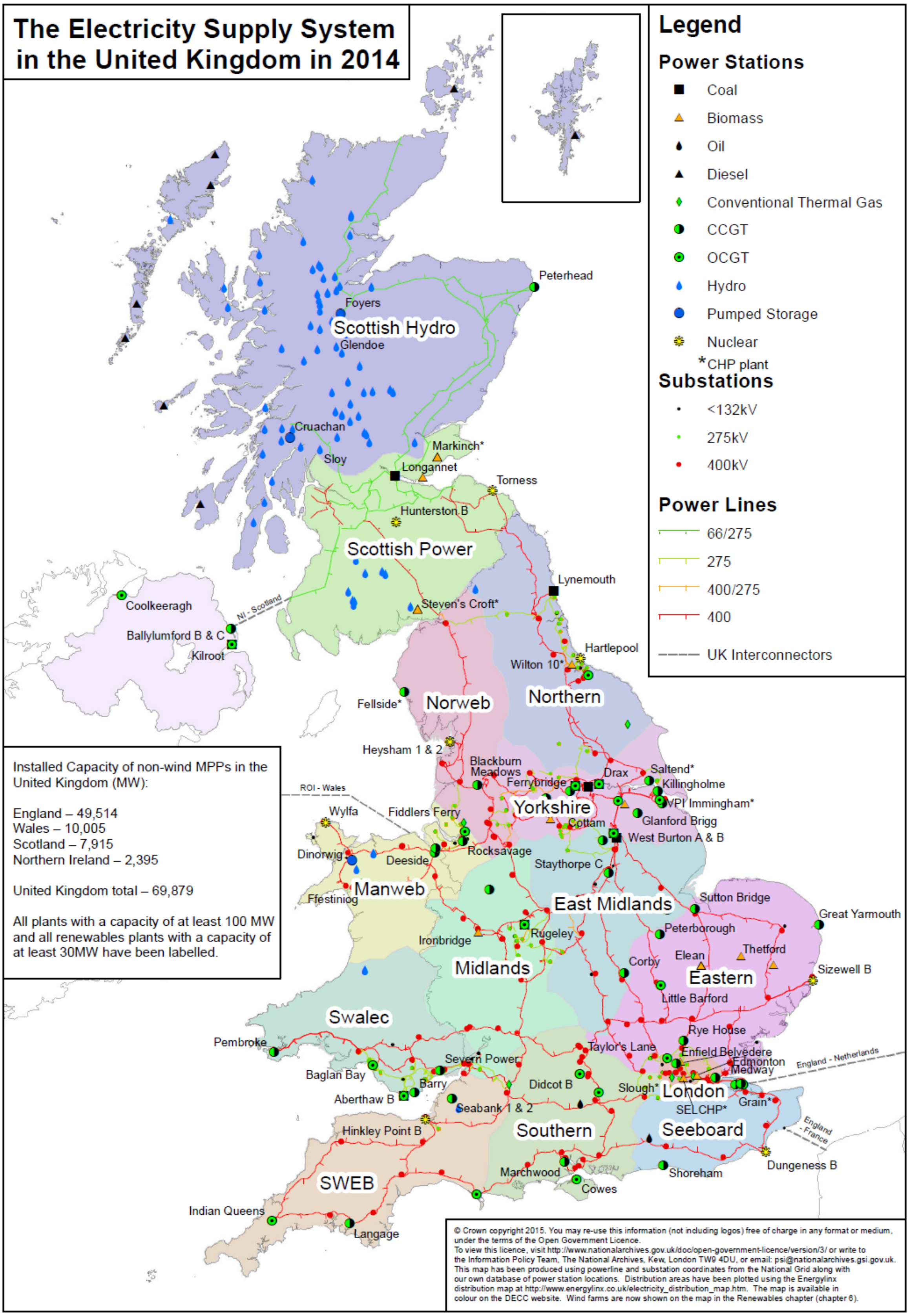

Figure 1: UK Electricity transmission system and main power stations as of June 2015. Source: DUKES (2015).

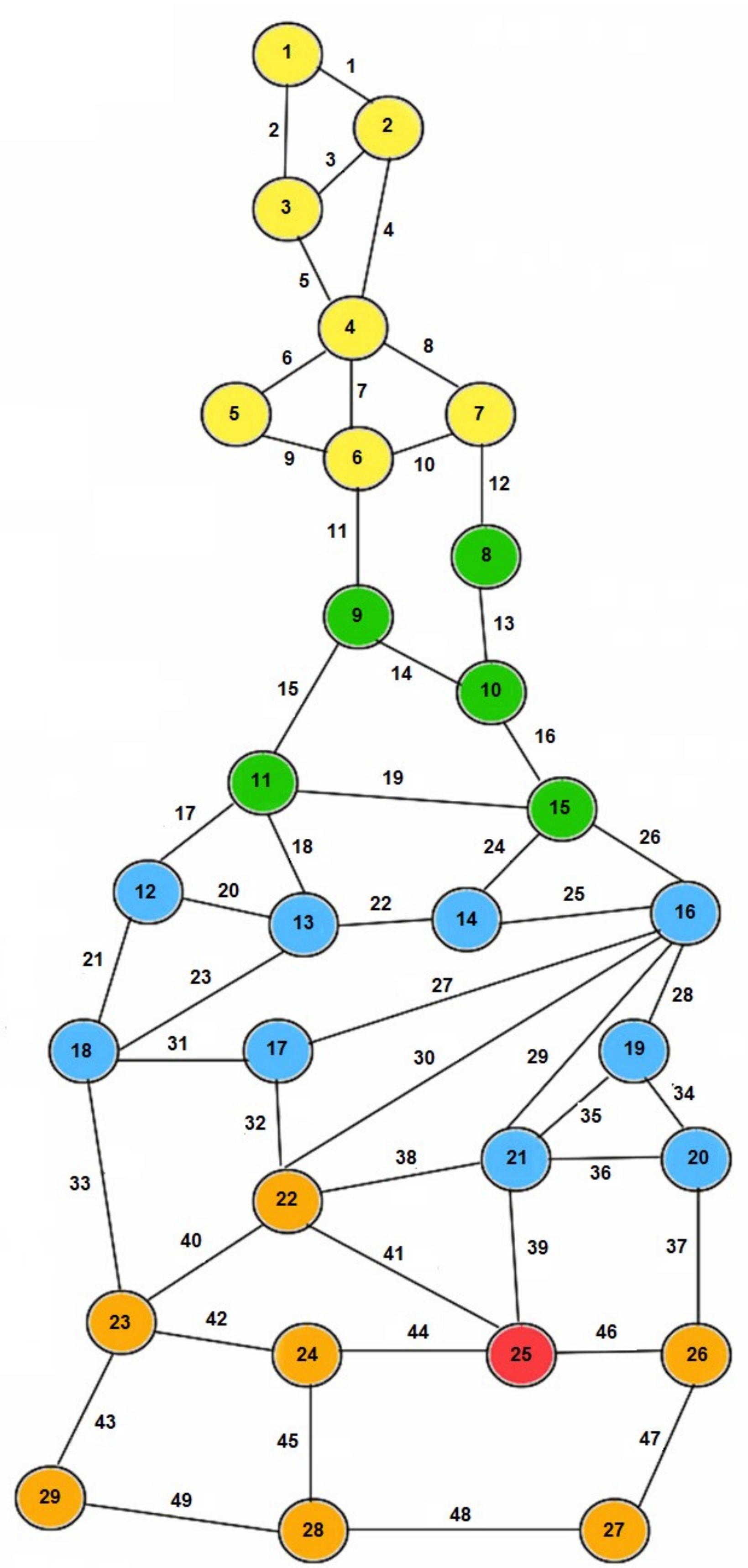

Figure 2: Nodal representation of the GB power system.

Line	Start node	End node	Thermal capacity (MW)
l_1	n_1	n_2	1,050
l_2	n_1	n_3	264
l_3	n_2	n_3	652
l_4	n_2	n_4	1,520
l_5	n_3	n_4	1,296
l_6	n_4	n_5	2,000
l_7	n_4	n_6	2,620
l_8	n_4	n_7	2,180
l_9	n_5	n_6	2,780
l_{10}	n_6	n_7	1,900
l_{11}	n_6	n_9	4,200
l_{12}	n_7	n_8	4,680
l_{13}	n_8	n_{10}	6,140
l_{14}	n_9	n_{10}	1,605
l_{15}	n_9	n_{11}	2,780
l_{16}	n_{10}	n_{15}	8,460
l_{17}	n_{11}	n_{12}	6,640
l_{18}	n_{11}	n_{13}	4,380
l_{19}	n_{11}	n_{15}	5,040
l_{20}	n_{12}	n_{13}	6,200
l_{21}	n_{12}	n_{18}	4,800
l_{22}	n_{13}	n_{14}	2,080
l_{23}	n_{13}	n_{18}	4,800
l_{24}	n_{14}	n_{15}	10,000
l_{25}	n_{14}	n_{16}	3,205
l_{26}	n_{15}	n_{16}	8,310
l_{27}	n_{16}	n_{17}	4,040
l_{28}	n_{16}	n_{19}	6,560
l_{29}	n_{16}	n_{21}	8,600
l_{30}	n_{16}	n_{22}	5,560
l_{31}	n_{17}	n_{18}	3,960
l_{32}	n_{17}	n_{22}	5,810
l_{33}	n_{18}	n_{23}	4,200
l_{34}	n_{19}	n_{20}	4,560
l_{35}	n_{19}	n_{21}	3,180
l_{36}	n_{20}	n_{21}	4,560
l_{37}	n_{20}	n_{26}	4,560
l_{38}	n_{21}	n_{22}	4,200
l_{39}	n_{21}	n_{25}	4,560
l_{40}	n_{22}	n_{23}	4,560
l_{41}	n_{22}	n_{25}	6,550
l_{42}	n_{23}	n_{24}	7,180
l_{43}	n_{23}	n_{29}	4,020
l_{44}	n_{24}	n_{25}	2,480
l_{45}	n_{24}	n_{28}	4,420
l_{46}	n_{25}	n_{26}	12,500
l_{47}	n_{26}	n_{27}	6,200
l_{48}	n_{27}	n_{28}	6,140
l_{49}	n_{28}	n_{29}	4,560

Table 1: GB transmission (PDS) data.

The ownership shares by firm are presented in Table 2, while Table 3 showcases a complementary breakdown by fuel type. Technical data for all 79 conventional plant and their location on the grid are listed in Table 74 in Appendix A. Installed capacities are based on DUKES (2015) and have been adjusted to exclude large chunks of (mainly coal-fired) capacity decommissioned in early 2016, as part of the opted-out fleet's obligation against the Large Combustion Plant Directive (LCPD) to shut down by the end of 2015 or once 20,000 hours of operation have been completed between 2008 and 2015 (Directive, 2001). In contrast, a number of aged coal-fired units, having secured peak availability contracts, are expected to run during the winter alone, as part of the GB capacity market or National Grid's supplementary balancing reserve (Evans, 2016).

Firm	Installed capacity (MW)	Shares (%)
EDF	15,129	25.3
RWE	11,185	18.7
E.ON	8,281	13.9
SSE	6,033	10.1
Drax	3,945	6.6
Centrica	3,505	5.9
Intergen	2,490	4.2
Scottish Power	1,999	3.3
Engie	2,911	4.9
Others	4,283	7.2
Total	59,761	100.0

Table 2: MPPs' thermal capacity shares by firm. Source: DUKES (2015).

Firm	Fuel type								Total
	CCGT	Coal	Nuclear	CHP	Oil	OCGT	Biomass	CHP - biomass	
EDF	2,151	4,020	8,918			40			15,129
RWE	6,562	1,586		153	2,406	413		65	11,185
E.ON	3,245	2,000		1,365	1,355	233		83	8,281
SSE	3,944	1,961				93		35	6,033
Drax		2,580				75	1,290		3,945
Centrica	2,455					1,050			3,505
Intergen	2,490								2,490
Scottish Power	1,999								1,999
Engie	515	1,006		1,200		190			2,911
Others	1,771	775		1,607		92	38		4,283
Total	25,132	13,928	8,918	4,325	3,761	2,186	1,328	183	59,761

Table 3: MPPs' and GB PDS thermal capacity mix. Installed capacity figures in MW. Source: DUKES (2015).

Furthermore, installed capacities represent gross maximum rated output figures, hence, a 10% derating to account for the self-consumption at the stations is applied to conduct our simulations. Observably, by providing for a more realistic representation of system capacity, fringe competition decreases and the price-lifting potential of the dominant utility is strengthened. Table 4 elaborates on the declared re-dispatch capability as a percentage of the capacity a plant is capable of committing in real-time, based on Papaefthymiou et al. (2014).[6] This puts forward the idea of flexibility that is predicated on the following fast-ramping capability hierarchy: OCGTs, Oil, CCGTs, coal-fired and biomass-fired plant. Due to their intrinsic design that is specifically intended for baseload operation, GB nuclear stations are currently regarded as inflexible and are not utilised for offsetting large real-time stochastic production deviations through ramping and cycling.

Fuel type	**Re-dispatch capability (% capacity)**	
	Positive	**Negative**
Biomass	20	20
CCGT	30	30
CHP		
CHP - biomass		
Coal	20	20
Nuclear		
OCGT	100	
Oil	100	

Table 4: Positive and negative re-dispatch capability, as a percentage of installed capacity.

Combined Heat and Power (CHP) schemes are considered to be primarily driven by their heat load requirements and do not participate in the balancing market, neither are considered as must-run, for the ability providing modern hot water storage accumulators to decouple the scheme from the electricity market and serve heat by discharging when prices are low.[7] For the purpose of this study, MPPs' CHP plant operate on natural gas-fuelled CCGTs, considering that three quarters of CHP electrical capacity and three quarters of electricity generated in 2014 came from natural gas, with 67% of those supplies fuelling CCGT stations (DUKES, 2015). A fraction of 'good-quality' CHPs running on various biomass and other renewable fuel types, are considered to operate on wood pellet-fired boilers that drive steam turbine generators. On a similar note, the handful of dedicated biomass units are assumed to utilise wood pellet fuel for electricity production.

Wind plant capacities and location on the PDS are summarised in Table 5. This encompasses wind capacity that is directly connected to the transmission system and excludes renewable generation connected to the distribution network (DUKES, 2015). Table 75 in Appendix A provides the nodal analogy of the wind power stations' location on

[6] Re-dispatch capabilities shown in Table 74 in Appendix A are adjusted accordingly, following the derating.
[7] This provides CHPs with the incentive to adapt operations to market prices and shut down during low-demand periods.

our test grid. A derating factor of 10% is applied for wind power plant, accounting for the electricity consumption of various auxiliary equipment at the generating site. Wind profits are examined at an industrial level; this allows for aggregating wind capacity at a nodal level and so no distinction is drawn between different wind energy companies.

Region	Installed Capacity (MW)
East	1,090.0
East Midlands	26.0
North West	997.0
Scotland	4,439.4
South East	1,313.0
Wales	576.0
Yorkshire and the Humber	68.0
Total	8,509.4

Table 5: PDS wind power capacity per GB country and region. Source: DUKES (2015).

Type	Production cost	Balancing premium (%)		Balancing cost	
		Positive	Negative	Positive	Negative
Nuclear	8.00				
Coal	30.00	50.00	- 25.00	45.00	- 22.50
CHP biomass	32.00				
CHP	36.00				
Biomass	47.00	60.00	- 30.00	75.20	- 32.90
CCGT	50.00	25.00	- 12.50	62.50	- 43.75
OCGT	60.00	10.00		66.00	
Oil	100.00			100.00	

Table 6: Production and balancing costs as perceived by the SO for different types of plant. Costs in £ per MWh.

With respect to thermal plant costs, data appearing on Table 6 comprise of fuel, carbon and O&M variable costs; to this end, fuel prices, thermal efficiencies and emissions intensities are based on DUKES (2015) and projections for O&M costs are extracted from DECC (2013). Heat and power efficiencies for CHP installations are derived from Mott MacDonald (2010). Indispensable to calculating the CHP bidding price in the spot market is the revenue stream attributed to the sales of heat, which is founded on a 90% boiler efficiency premise for all CHP installations. By substituting the heat production process at the boiler with that at the engine, the bidding price of electricity in the spot market is brought to a level between that of coal and biomass. In the absence of prevailing statistics on costs for wood pellet power generation, a hypothesis of £80 per tonne with a gross heat content of 17 GJ per tonne and 36% efficiency is adopted. This is in line with the assumptions of CCC (2011), finds of E4Tech (2010) and Argus (2016). Assumptions for the premiums on the electricity traded in RT are also enclosed in Table 6. A carbon price of £5 per tonne is used to calculate the carbon emissions cost for fossil fuel generation.

Node	Demand	
	Winter	Summer
n_1	306.9	102.3
n_2	645.3	215.1
n_3	55.8	18.6
n_4	387.9	129.3
n_5	181.8	60.6
n_6	2,010.6	670.2
n_7	2,019.6	673.2
n_8	173.7	57.9
n_9	199.8	66.6
n_{10}	1,574.1	524.7
n_{11}	285.3	95.1
n_{12}	702.9	234.3
n_{13}	2,301.3	767.1
n_{14}	3,078.9	1,026.3
n_{15}	1,436.4	478.8
n_{16}	1,379.7	459.9
n_{17}	2,253.6	751.2
n_{18}	2,191.5	730.5
n_{19}	2,159.1	719.7
n_{20}	1,161.9	387.3
n_{21}	2,035.8	678.6
n_{22}	6,390.0	2,130.0
n_{23}	2,192.4	730.8
n_{24}	2,662.2	887.4
n_{25}	8,764.2	2,921.4
n_{26}	1,190.7	396.9
n_{27}	1,176.3	392.1
n_{28}	2,201.4	733.8
n_{29}	1,666.8	555.6
Total	52,785.9	17,595.3

Table 7: Winter and summer nodal demand data for the GB PDS.

Two levels of demand are examined; high and low demand, corresponding to the winter and summer demand levels on the PDS respectively. For high demand models in particular, a moderating factor of 7% is applied to account for the impact of imports and transfers from the distribution system during the winter in anticipation of a tight system margin. Seven different tests are carried out altogether; three for winter and four for summer demand, standing for different levels of wind penetration defined as the mean wind power output (across the two wind scenarios) as a percentage of winter or summer demand. We initially solve the problem where all firms behave competitively, i.e. the SO's unit commitment that constitutes the benchmark against which output, prices and profits derived from solving the MPEC - i.e. the problem where an incumbent firm assumes the leader's role and the rest are followers in a Stackelberg game - are compared, for various penetration levels.

High demand models feature RWE as the leader - who chooses price and output in order to maximise profits - followed by the naive fringe, who behave in a competitive way. By bidding her significant capacity of mid-merit CCGT and peaking OCGT plant, and one coal station high, RWE prompts the commitment of more expensive capacity and lifts prices, thus extracting higher revenue with her dispatched fleet. On the other hand, EDF commits to a credible leadership action in low demand models, for the large shares of inexpensive baseload nuclear and two coal stations in her portfolio. Observably, by withholding her capacity during the winter, EDF would have gained access to insurmountable levels of market power, owing more than a quarter of GB's installed capacity.

5.3. Numerical Results

5.3.1. Winter demand

I. 5% Wind Power Penetration

We start by presenting results for winter demand, where RWE behaves strategically with ten of her plant, i.e. one coal, four CCGT and five OCGT stations, while bidding oil-fired and CHP facilities at marginal cost. This situation is of special interest to the GB market, considering the government's undiminished commitment to coal phase-out and the ensuing adequacy risk during winter peaks. At such high demand levels, the incentive facing large firms to increase profits is enhanced as wind power subsides, as revealed by the marked price distortion of £150 per MWh at 5% penetration due to RWE's bidding.

In the absence of binding transmission constraints, the cost of transporting a MW-worth of power is zero and the market price is uniform across the network in both the competitive and strategic equilibria. In the competitive case, DA and expected high wind scenario balance prices correspond to the marginal station's offer for energy and down-regulation respectively, i.e. plant would receive the CCGT variable cost of £50 per unit of output in the DA market, while the system is expected to save £43.75, for each unit of withdrawn thermal output due to an additional MWh of wind, with 60% probability in RT.

Node	Competitive			Strategic		
	DA	RT High	Low	DA	RT High	Low
n_1	50.00	43.75	59.375	200.00	200.00	200.00
n_2	50.00	43.75	59.375	200.00	200.00	200.00
n_3	50.00	43.75	59.375	200.00	200.00	200.00
n_4	50.00	43.75	59.375	200.00	200.00	200.00
n_5	50.00	43.75	59.375	200.00	200.00	200.00
n_6	50.00	43.75	59.375	200.00	200.00	200.00
n_7	50.00	43.75	59.375	200.00	200.00	200.00
n_8	50.00	43.75	59.375	200.00	200.00	200.00
n_9	50.00	43.75	59.375	200.00	200.00	200.00
n_{10}	50.00	43.75	59.375	200.00	200.00	200.00
n_{11}	50.00	43.75	59.375	200.00	200.00	200.00
n_{12}	50.00	43.75	59.375	200.00	200.00	200.00
n_{13}	50.00	43.75	59.375	200.00	200.00	200.00
n_{14}	50.00	43.75	59.375	200.00	200.00	200.00
n_{15}	50.00	43.75	59.375	200.00	200.00	200.00
n_{16}	50.00	43.75	59.375	200.00	200.00	200.00
n_{17}	50.00	43.75	59.375	200.00	200.00	200.00
n_{18}	50.00	43.75	59.375	200.00	200.00	200.00
n_{19}	50.00	43.75	59.375	200.00	200.00	200.00
n_{20}	50.00	43.75	59.375	200.00	200.00	200.00
n_{21}	50.00	43.75	59.375	200.00	200.00	200.00
n_{22}	50.00	43.75	59.375	200.00	200.00	200.00
n_{23}	50.00	43.75	59.375	200.00	200.00	200.00
n_{24}	50.00	43.75	59.375	200.00	200.00	200.00
n_{25}	50.00	43.75	59.375	200.00	200.00	200.00
n_{26}	50.00	43.75	59.375	200.00	200.00	200.00
n_{27}	50.00	43.75	59.375	200.00	200.00	200.00
n_{28}	50.00	43.75	59.375	200.00	200.00	200.00
n_{29}	50.00	43.75	59.375	200.00	200.00	200.00

Table 8: DA and expected RT prices for the competitive and strategic winter cases, at 5% penetration. Prices in £ per MWh.

Coming up with the predicted balance price for the low wind scenario is less intuitive, considering it does not correspond to any of the offers for re-dispatch in Table 9. That is because, in contrast to a deterministic simulation, the stochastic programming framework minimises the expected cost over all scenarios (Birge & Louveaux, 2011), i.e. the expected cost of all possible realisations is taken into account when deriving the optimal schedule, as explained in section 5.1. The expected impact of RT decisions on costs feeds through into the DA stage and so schedules and by extension prices, are expected to be different to those derived from a deterministic clearing (Morales et al., 2012). Observably, in the stochastic context, the expected value of balance prices is reflected on the DA price, i.e. $0.6 \cdot \frac{£}{MWh} 43.75 + 0.4 \cdot \frac{£}{MWh} 59.375 = \frac{£}{MWh} 50$. Therefore, serving an uncertain load increase in the low wind scenario in the least-cost way, may be thought of as injecting 1 thermal MWh in DA and procuring 1 MWh of negative regulation in the high wind scenario, at a cost of $C_k \cdot P_k - \pi_s \cdot C_{k,d} \cdot P_{k,d,s} = \left(\frac{£}{MWh} 50 - 0.6 \cdot \frac{£}{MWh} 43.75\right) \cdot 1\ MWh = £23.75$, as per $(4.3.2a)$, hence the balance price of £59.375 per MWh in the low wind scenario.[8,9]

Type	Competitive			Strategic		
	DA	RT Positive	RT Negative	DA	RT Positive	RT Negative
$Coal_1$	30.00	45.00	22.50	200.00	200.00	200.00
$CCGT_1$	50.00	62.50	43.75	200.00	200.00	200.00
$CCGT_2$	50.00	62.50	43.75	200.00	200.00	200.00
$CCGT_3$	50.00	62.50	43.75	200.00	200.00	200.00
$CCGT_4$	50.00	62.50	43.75	200.00	200.00	200.00
$OCGT_1$	60.00	66.00		300.00	200.00	
$OCGT_2$	60.00	66.00		300.00	200.00	
$OCGT_3$	60.00	66.00		300.00	200.00	
$OCGT_4$	60.00	66.00		300.00	200.00	
$OCGT_5$	60.00	66.00		300.00	200.00	

Table 9: RWE bids by price-making plant and stage for the competitive and strategic winter cases, at 5% penetration. Bids in £ per MWh.

To help understand the motive driving the SO's and RWE's decisions, we work out the costs as perceived by the SO and profits to RWE, from a MWh-worth of down- and up-regulation respectively. Our worked example involves a CCGT plant that is dispatched with a MWh in the DA market at a cost of £50 in the competitive configuration and provides down-regulation services at £43.75 per MWh. Regulation costs are distributed according to the assigned probabilities between the two scenarios; in the high wind scenario with 60% probability, the SO stands the marginal CCGT down to make room for 1 MWh of zero variable cost wind, thus incurring variable cost savings of £26.25 in expectation. Similarly, a MWh of thermal output introduced in the low wind scenario with 40% probability of occurrence would cost the SO £25, according to Table 10. Nonetheless, balancing actions may be taken in any direction at any scenario, considering the leader's attempt to game the balancing market in the strategic equilibrium. The costs for a MWh-worth of positive regulation in the high and negative regulation in the low scenario are computed likewise and are presented for completeness in Table 76 in Appendix B.

[8] The shadow value is divided by the probability of occurrence to determine the balance price, as noted in section 5.1, i.e. $\frac{£}{MWh}\frac{23.75}{0.4} = \frac{£}{MWh} 59.375$.

[9] Balancing prices for the actual realisation of any scenario may be attained by fixing the first-stage variables to their optimal values and solving the real-time stage of the problem (Morales et al., 2012), e.g. the low-wind scenario realisation yields £62.50 per MWh, i.e. the up-regulation cost of CCGT.

Type	Competitive			Strategic		
	DA	RT High wind	Low wind	DA	RT High wind	Low wind
Coal	30.00	- 13.50	18.00	200.00	- 120.00	80.00
Biomass	47.00	-19.74	30.08	47.00	- 19.74	30.08
CCGT	50.00	- 26.25	25.00	200.00	- 120.00	80.00
OCGT				200.00		80.00
Oil				100.00		40.00

Table 10: DA and expected RT unit (i.e. for 1 MWh of added output in the low wind and 1 MWh of subtracted output in the high wind scenario) costs, as perceived by the SO by plant type (active in the RT market) and scenario, for the competitive and strategic winter cases, at 5% penetration. Costs in £ per MWh.

Demonstrably, the SO's re-dispatch decisions depend on the relative costs of different plant in the DA and RT stage. For example, coal and CCGT have a net expected cost of £16.50 and £23.75 for 1 MWh of energy in the DA market, followed by 1 MWh of negative regulation in the high wind scenario; on the other hand, infra-marginal coal is by £20 per MWh cheaper in DA compared to CCGT. This makes marginally running CCGT-fired generation the best candidate for negative regulation in the competitive equilibrium. This implies that balancing decisions are in principle governed by a non-decreasing marginal cost order for standing plant down during windy periods, considering RT generation is costlier than output produced DA, for the increased maintenance costs due to part-loaded operation in readiness of re-dispatch (Kirschen & Strbac, 2004). Together with the assigned scenario probabilities, the asymmetry in regulation costs imply that calling a CCGT to produce 1 MWh in RT is less preferable, compared to producing it in DA and constraining it in the high wind scenario, i.e. the first action is cheaper by £1.25 in expectation. In response to its cost-minimisation objective for offsetting wind variability, the SO would thus seek to over-commit than to under-commit thermal plant.

Type	Competitive			Strategic		
	DA	RT High wind	Low wind	DA	RT High wind	Low wind
Coal	20.00	- 8.25	11.75	170.00	- 102.00	68.00
Biomass	3.00	1.95	4.95	153.00	- 91.80	61.20
CCGT	0.00	3.75	3.75	150.00	- 90.00	60.00
OCGT				140.00		56.00
Oil				100.00		40.00

Table 11: DA and expected RT unit (i.e. for 1 MWh of added output in the low wind and 1 MWh of subtracted output in the high wind scenario) profits by plant type (active in the RT market) and scenario, for the competitive and strategic winter cases, at 5% penetration. Costs in £ per MWh.

On the profits side, the station would be charged (paid) the balance price at its node if it were to buy back (increase) output in RT and incur profits from the difference between the price and the cost of changing output. The CCGT would pay £43.75 to curtail a MWh in the high wind scenario sold for £50 in DA, and so the station's expected profit would be $(\pi_s \cdot C_k \cdot P_{k,d,s} - \mu_{n,s} \cdot P_{k,d,s}) = \left(0.6 \cdot \frac{£}{MWh} 50 - \frac{£}{MWh} 26.25\right) \cdot 1\ MWh = £3.75$, on the basis of avoided variable costs. In response to a call for standing up in the low wind scenario, the CCGT would collect the balance price of £59.375 per MWh and so, the expected profit would be $(\mu_{n,s} \cdot P_{k,u,s} - \pi_s \cdot C_k \cdot P_{k,u,s}) = \left(\frac{£}{MWh} 23.75 - 0.4 \cdot \frac{£}{MWh} 50\right) \cdot 1\ MWh = £3.75$ per MWh, according to Table 11. Therefore, in exchange for relaxing or increasing production CCGTs facilitate cost-recovery, while profits foregone before the realisation of the stochastic parameters are compensated by the recourse actions adopted at the second stage (Morales et al., 2014). The profits for a MWh-worth of positive (negative) regulation in the high (low) scenario are presented for completeness in Table 77 in Appendix B.

System costs	Competitive	Strategic	Absolute change	Relative change (%)
Energy	1,723,130	2,186,424	463,294	26.9
Positive re-dispatch		60,604	60,604	
Negative re-dispatch	- 35,456	- 268,294	- 232,838	- 656.7
Total	1,687,674	1,978,734	291,060	17.2

Table 12: Energy and expected re-dispatch costs as perceived by the SO for the competitive and strategic winter cases, at 5% penetration. Costs in £.

Turning our focus on the strategic equilibrium, the impact on system costs is expressed through a 17% or some £291k increase, while load payments increase by 300% as shown in Table 78 in Appendix B. As far as the dynamics of arbitrage between DA and RT is concerned, RWE's withholding with a diverse mix of plant that spans the supply stack (i.e. from coal to OCGT) prompts the SO to exhaust the fringe output at this very stage, considering RWE's DA mark-up atop her coal- and gas-fired generation. The sheer magnitude of contracted supply in DA not only does it act as a device for driving DA electricity prices as high as possible, it additionally helps develop the market forces that curtail competition for access to the otherwise coveted RT product, thus helping RWE control the RT price formation process.

That is, the abnormally high RT bid of £200 per MWh for negative regulation in Table 9 makes the SO as discouraged for reducing low-cost fringe output as it is physically constrained for increasing it - the interested reader may refer to Table 79 in Appendix B for the fringe's output breakdown by plant type. This translates to expected savings of £120 per MWh in the high wind scenario; by comparison, curbing a fringe CCGT MWh would save £26.25 according to Table 10. On the other hand, the cost of committing a fringe CCGT in DA is by £150 per MWh lower and so the fringe are committed at capacity in DA, while the RT market succumbs to RWE. As a result, seemingly much to her disadvantage, RWE stations are penalised for re-purchasing their output, for the balance price by far exceeds their marginal cost of generation. Such a situation is unavoidable, considering a MW of load could be shed voluntarily instead, should a lower down-regulation bid be placed by the incumbent. Bids for energy and balancing are remotely detached in integrated markets and so the SO would have to decide whether to curtail a CCGT MWh in the high wind scenario at a net cost of $\frac{£}{MWh}(200-0.6\cdot 200)\cdot 1\,MWh = £80$ or to curtail a MW of load at a cost of $0.4\cdot\frac{£}{MWh}200\cdot 1\,MWh = £80$ in the low wind scenario. Observing the opportunity cost of voluntary load shedding informs that, should RWE seek to submit a lower down-regulation bid, her DA bid shall be moderated accordingly.

Therefore, RWE cannot help but forego just more than 64% of her price-making stations' DA profit in calculated RT losses, for her strategy is informed by the interest to run the leftmost and middle parts of her stack - first coal and then CCGTs - (almost) just as much to deliver the least-cost combination of negative and positive re-dispatch needs of the system. Observably, the firm's overwhelming size allows her to influence her rivals' decisions and opt for the most profitable schedule by capturing the complementarity between the DA and RT stage. This has a profoundly distorting effect on the sequence of clearing decisions and justifies the transfer of 228 MWh of wind power in RT and the increased negative re-dispatch by the same amount in the strategic equilibrium.

Type	**Competitive**		**Strategic**		**Absolute change**		**Relative change (%)**
	DA	**RT**	**DA**	**RT**	**DA**	**RT**	
RWE	7,529.4	- 140.4	3,949.2	- 1,038.4	- 3,580.2	- 898.0	- 60.6
Fringe	39,910.2	- 670.1	43,718.4		3,808.2	670.1	11.4
Wind	1,651.3	810.4	1,423.3	1,038.4	- 228.0	228.0	
Industry	49,090.9		49,090.9				

Table 13: Industry-wide output levels by fuel type and stage, for the competitive and strategic winter cases, at 5% penetration. Outputs in MWh.

The shift in the fuel mix of generation is further marked by the sizeable decrease in the utilisation of coal and CCGT stations in the GB wholesale market, by some 1.2 GWh (or 9.5%) and 3.8 GWh (or 18.2%) respectively, and the subsequent swing towards the use of less efficient OCGT and oil-fired generation by 5 GWh combined. The incumbent's ability to manipulate industry-wide production levels (and ultimately prices) is suggestive of the tight supply from CCGT facilities, which run at the margin, with an overall load factor of 92% in the competitive equilibrium. That is, the combination of low wind and high demand conditions, enables RWE to hold back some 6.6 GWh of her low-cost generation, namely 1.2 GWh of her baseload and 5.5 GWh of her mid-merit product and dispatch some 2.2 GWh of expensive oil-fired generation, which translates to a production reduction of 4.5 GWh or 61% of her competitive output. In the emerging equilibrium, RWE supplies her profit-maximising output of 2.9 GWh, which corresponds to just less than 6% of system demand, while fringe firms contribute a combined 89% and wind 5% of demand.

Type	Competitive	Strategic	Load factor (%)		Fuel shares (%)	
			Competitive	Strategic	Competitive	Strategic
Nuclear	8,026.2	8,026.2	100.0	100.0	16.3	16.3
Coal	12,535.2	11,345.1	100.0	90.5	25.5	23.1
CHP	4,057.2	4,057.2	100.0	100.0	8.3	8.3
Biomass	1,195.2	1,195.2	100.0	100.0	2.4	2.4
CCGT	20,815.4	17,024.9	92.0	75.3	42.4	34.7
OCGT		1,595.7		81.1		3.3
Oil		3,384.9		100.0		6.9
Wind	2,461.7	2,461.7	32.1	32.1	5.0	5.0
Total	49,090.9	49,090.9			100.0	100.0

Table 14: GB fuel mix of generation for the competitive and strategic winter cases, at 5% penetration. Outputs in MWh. Load factor utilises the sum of generation in both DA and RT stages. Fuel shares as a percentage of demand.

Type	Competitive	Strategic	Change		Load factor (%)	
			Absolute	Relative (%)	Competitive	Strategic
Coal	1,427.4	237.3	- 1,190.1	- 83.4	100.0	16.6
CHP	196.2	196.2			100.0	100.0
CCGT	5,765.4	311.9	- 5,453.5	- 94.6	97.6	5.3
OCGT						
Oil		2,165.4	2,165.4			100.0
RWE	7,389.0	2,910.8	- 4,478.3	- 60.6		

Table 15: RWE fuel mix of generation for the competitive and strategic winter cases, at 5% penetration. Outputs in MWh. Load factor utilises the sum of generation in both DA and RT stages. Relative change with reference to competitive output.

Specifically, by arbitraging between her baseload and CCGT stations in DA and RT operations, RWE manages to extract maximum expected profits; the coal plant gains £170 per MWh in DA, while incurring combined RT losses of £34 per MWh by re-dispatching down in the high and up in the low wind scenario, as per Table 11. On the other hand, CCGTs give away £90 of their £150 per MWh of DA profit by providing down-regulation in the high scenario, while $CCGT_4$ is re-dispatched further down in the low scenario, thus accepting extra RT losses at £60 per MWh, according to Table 77.[10] Attending to such unfavourable down-regulation needs might prove an expensive way to help establish her strategy, however, it is this level of withholding that secures supernormal profits for RWE.

[10] Observably, negative regulation is less penalising in the low compared to the high wind scenario under strategic offering at 5% penetration, for the balance prices are equal in the two scenarios.

Type	Max rating	Re-dispatch capability		Competitive			Strategic		
		Positive	Negative	DA	RT High	RT Low	DA	RT High	RT Low
Coal	1,427.4	285.5	285.5	1,427.4			294.4	- 285.5	285.5
CHP_1	137.7			137.7			137.7		
CHP_2	58.5			58.5			58.5		
$CCGT_1$	1,594.8	478.4	478.4	1,594.8					
$CCGT_2$	1,026.0	307.8	307.8	1,026.0			307.8	- 307.8	
$CCGT_3$	1,323.0	396.9	396.9	1,323.0	- 233.9		396.9	- 396.9	
$CCGT_4$	1,962.0	588.6	588.6	1,962.0			588.6	- 588.6	- 513.6
$OCGT_1$	90.0	90.0							
$OCGT_2$	126.0	126.0							
$OCGT_3$	45.9	45.9							
$OCGT_4$	15.3	15.3							
$OCGT_5$	94.5	94.5							
Oil_1	1,233.0	1,233.0					1,233.0		
Oil_2	932.4	932.4					932.4		
RWE	10,066.5	4,594.3	2,057.2	7,529.4	- 233.9		3,949.2	- 1,578.8	- 228.1

Table 16: RWE maximum rating, re-dispatch capability and output levels by plant and stage, for the competitive and strategic winter cases, at 5% penetration. Maximum rating refers to a 10% derating of installed capacity. Capability figures in MW, outputs in MWh.

Type	Competitive		Strategic		Absolute change		Relative change (%)
	DA	RT	DA	RT	DA	RT	
RWE	31,529	877	492,978	- 156,907	461,449	- 157,784	937
Fringe	617,321	4,188	7,098,149		6,480,828	- 4,188	1,042
Wind	82,565	35,456	284,664	207,683	202,099	172,227	317
Industry	731,415	40,521	7,875,791	50,776	7,144,376	10,255	927

Table 17: Expected industry-wide profits by stage, for the competitive and strategic winter cases, at 5% penetration. Profits in £.

In effect, the surge in market price pays dividends for the strategic firm, which manages to cement her status owing to a sheer nine-fold increase in profit. This is largely attributed to her substantial amounts of oil-fired generation, which account for just less than 75% of RWE's commitment in the strategic equilibrium. In the grand scheme of things, oil-fired generation yields a profit of 64%, while price-making stations bring in 26% of total profit. Benefits to the fringe may generally be larger, considering the cost incurred for the exercise of market power and the market-wide price increase (Stoft, 2002). Due largely to the expansion of mid-merit CCGT-fired generation by a net 11% that compensates for 37% of the supply withheld by the leader, conventional followers extract a tenfold collective profit increase, whereas wind generators manage to quadruple their profits.

Sensitivity analysis: flexibility

An additional simulation was conducted to gain a preliminary understanding of the influence of balancing capability (i.e. flexibility) on the gaming incentives facing the leader, as reflected by the profits made by the dominant firm and others. To this end, the proposed method was applied in a revised version of the 29-node system, featuring higher levels of flexibility at the coal, biomass and CCGT fleets. In particular, the re-dispatch capability of coal and biomass (CCGT) plant rose from 20% (30%) to 40% of installed capacity and remained unchanged for the rest of the plant types. Balancing premiums have accordingly been adjusted to reflect the cheaper utilisation of the abovementioned resources in RT.

Type	Balancing premium (%)		Balancing cost	
	Positive	Negative	Positive	Negative
Nuclear				
Coal	30.00	- 15.00	39.00	- 25.50
CHP biomass				
CHP				
Biomass	40.00	- 20.00	65.80	- 37.60
CCGT	15.00	- 7.50	57.50	- 46.25
OCGT	10.00		66.00	
Oil			100.00	

Table 18: Balancing costs as perceived by the SO for different types of plant in the flexible configuration. Costs in £ per MWh.

The ensuing enhanced competition in the RT market is reflected on the re-dispatch costs of the competitive solution, which are by 5.71% or £2,026 lower in expectation, in the flexible configuration. Competitive DA prices remain unaltered, however, expected balance prices do change, to mirror the gains stemming from a system that more easily - and hence cheaply - adopts to unforeseen production deviations in RT. This justifies the formation of prices, which are by £2.50 and £3.75 higher and lower in the high and low wind scenario respectively, and so DA prices are unaffected considering their mean.

System costs	Competitive	Strategic	Absolute change	Relative change (%)
Energy	1,723,130	1,984,860	261,730	15.2
Positive re-dispatch		62,389	62,389	
Negative re-dispatch	- 37,482	- 68,515	- 31,033	- 82.8
Total	1,685,648	1,978,734	293,086	17.4

Table 19: Energy and expected re-dispatch costs as perceived by the SO for the competitive and strategic winter cases, at 5% penetration in the flexible configuration. Costs in £.

Expected total costs and load payments do not differ in the strategic equilibrium, corroborating the similarly distortive order of clearing decisions induced by the (unaltered) bidding of the leader, while the impact on prices also stands undiminished. Although identical with respect to fundamentals, the difference in strategy compared to the less flexible system is condensed on the incumbent's portfolio distribution between the DA and RT horizon; that is, the firm opts for a higher production with her coal and lower with her CCGT plant. The thrust of this tactic is to secure maximum firm-wide profits by taking advantage of the additional flexibility at her most profitable station. Moreover, the impact on the GB fuel mix of generation is expressed through the shift of coal's (CCGT's) share of demand from 23.1% to 23.6% (34.7% to 34.2%) in the flexible system. Observably, deviations are borne by the strategic firm, while the fringe are dispatched at capacity in DA, much like in the less flexible system. The interested reader may refer to Table 80 in Appendix B for the fringe's output breakdown by plant type in the flexible configuration.

Node	Competitive			Strategic		
	DA	RT		DA	RT	
		High	Low		High	Low
n_1	50.00	46.25	55.625	200.00	200.00	200.00
n_2	50.00	46.25	55.625	200.00	200.00	200.00
n_3	50.00	46.25	55.625	200.00	200.00	200.00
n_4	50.00	46.25	55.625	200.00	200.00	200.00
n_5	50.00	46.25	55.625	200.00	200.00	200.00
n_6	50.00	46.25	55.625	200.00	200.00	200.00
n_7	50.00	46.25	55.625	200.00	200.00	200.00
n_8	50.00	46.25	55.625	200.00	200.00	200.00
n_9	50.00	46.25	55.625	200.00	200.00	200.00
n_{10}	50.00	46.25	55.625	200.00	200.00	200.00
n_{11}	50.00	46.25	55.625	200.00	200.00	200.00
n_{12}	50.00	46.25	55.625	200.00	200.00	200.00
n_{13}	50.00	46.25	55.625	200.00	200.00	200.00
n_{14}	50.00	46.25	55.625	200.00	200.00	200.00
n_{15}	50.00	46.25	55.625	200.00	200.00	200.00
n_{16}	50.00	46.25	55.625	200.00	200.00	200.00
n_{17}	50.00	46.25	55.625	200.00	200.00	200.00
n_{18}	50.00	46.25	55.625	200.00	200.00	200.00
n_{19}	50.00	46.25	55.625	200.00	200.00	200.00
n_{20}	50.00	46.25	55.625	200.00	200.00	200.00
n_{21}	50.00	46.25	55.625	200.00	200.00	200.00
n_{22}	50.00	46.25	55.625	200.00	200.00	200.00
n_{23}	50.00	46.25	55.625	200.00	200.00	200.00
n_{24}	50.00	46.25	55.625	200.00	200.00	200.00
n_{25}	50.00	46.25	55.625	200.00	200.00	200.00
n_{26}	50.00	46.25	55.625	200.00	200.00	200.00
n_{27}	50.00	46.25	55.625	200.00	200.00	200.00
n_{28}	50.00	46.25	55.625	200.00	200.00	200.00
n_{29}	50.00	46.25	55.625	200.00	200.00	200.00

Table 20: DA and expected RT prices for the competitive and strategic winter cases, at 5% penetration in the flexible configuration. Prices in £ per MWh.

Type	Competitive	Strategic	Load factor (%)		Fuel shares (%)	
			Competitive	Strategic	Competitive	Strategic
Nuclear	8,026.2	8,026.2	100.0	100.0	16.3	16.3
Coal	12,535.2	11,573.5	100.0	92.3	25.5	23.6
CHP	4,057.2	4,057.2	100.0	100.0	8.3	8.3
Biomass	1,195.2	1,195.2	100.0	100.0	2.4	2.4
CCGT	20,815.4	16,796.5	92.0	74.3	42.4	34.2
OCGT		1,595.7		81.1		3.3
Oil		3,384.9		100.0		6.9
Wind	2,461.7	2,461.7	32.1	32.1	5.0	5.0
Total	49,090.9	49,090.9			100.0	100.0

Table 21: GB fuel mix of generation for the competitive and strategic winter cases, at 5% penetration in the flexible configuration. Outputs in MWh. Load factor utilises the sum of generation in both DA and RT stages. Fuel shares as a percentage of demand.

Type	Max rating	Re-dispatch capability		Competitive			Strategic		
		Positive	Negative	DA	RT		DA	RT	
					High	Low		High	Low
Coal	1,427.4	571.0	571.0	1,427.4			579.8	- 571.0	571.0
CHP$_1$	137.7			137.7			137.7		
CHP$_2$	58.5			58.5			58.5		
CCGT$_1$	1,594.8	637.9	637.9	1,594.8					
CCGT$_2$	1,026.0	410.4	410.4	1,026.0					208.8
CCGT$_3$	1,323.0	529.2	529.2	1,323.0					
CCGT$_4$	1,962.0	784.8	784.8	1,962.0					
OCGT$_1$	90.0	90.0							
OCGT$_2$	126.0	126.0							
OCGT$_3$	45.9	45.9							
OCGT$_4$	15.3	15.3							
OCGT$_5$	94.5	94.5							
Oil$_1$	1,233.0	1,233.0					1,233.0		
Oil$_2$	932.4	932.4					932.4		
RWE	10,066.5	4,594.3	2,057.2	7,529.4			2,941.4	- 571.0	779.7

Table 22: RWE maximum rating, re-dispatch capability and output levels by plant and stage, for the competitive and strategic winter cases, at 5% penetration in the flexible configuration. Maximum rating refers to a 10% derating of installed capacity. Capability figures in MW, outputs in MWh.[11]

Specifically, RWE's stance is typified by the provision of balancing services by some - 571 MWh with her coal plant in the high and 780 MWh with her coal and CCGT$_2$ plant in the low wind scenario. Expected balancing needs are thus lower overall, connoting the increased DA commitment of wind power in the flexible system; the latter is indicative of the leader's ability to manipulate the DA and RT dispatch and determine her best response (i.e. net output) in pursuit of her profit-maximising objective. Moreover, RWE produces some 97% more at her coal station in DA, and uses her enhanced capability to help offset

[11] GAMS results are exported to Excel where table entries are independently rounded, and so totals may at times deviate from the sum of their constituents.

wind variability by selling unprofitable negative regulation services. However, RWE compromises less profit, since it buys back lower-cost generation, whereas more than 81% of her negative regulation was provided by CCGT plant in the less flexible setting.

Type	Competitive	Strategic	Change		Load factor (%)	
			Absolute	Relative (%)	Competitive	Strategic
Coal	1,427.4	465.7	- 961.7	- 67.4	100.0	32.6
CHP	196.2	196.2			100.0	100.0
CCGT	5,905.8	83.5	- 5,822.3	- 98.6	100.0	1.4
OCGT						
Oil		2,165.4	2,165.4			100.0
RWE	7,529.4	2,910.8	- 4,618.6	- 61.3		

Table 23: RWE fuel mix of generation for the competitive and strategic winter cases, at 5% penetration in the flexible configuration. Outputs in MWh. Load factor utilises the sum of generation in both DA and RT stages. Relative change with reference to competitive output.

Type	Competitive		Strategic		Absolute change		Relative change (%)
	DA	RT	DA	RT	DA	RT	
RWE	7,529.4		2,941.3	- 30.6	- 4,588.1	- 30.6	- 61.3
Fringe	39,910.2	- 810.4	43,718.4		3,808.2	810.4	11.8
Wind	1,651.3	810.4	2,431.1	30.6	779.8	-779.8	
Industry	49,090.9		49,090.9				

Table 24: Industry-wide output levels by fuel type and stage, for the competitive and strategic winter cases, at 5% penetration in the flexible configuration. Outputs in MWh.

In effect, the net profit-maximising output is unchanged between the two strategic equilibria, however, RWE extracts additional £4,568 or 1.36% by means of higher amounts of lower-cost production. On the other hand, the net output and profits to wind and fringe producers stand unaffected compared to the less flexible system. In absolute terms, RWE’s strategy is likely to be more rewarding in the flexible setting, nonetheless, gaming incentives also depend on competitive profits, which are generally different between the two systems; for example, consider the ability of a more flexible system to deliver the same balancing needs with fewer and hence, a different set of plant. Collective thermal (wind) profits, however, are lower (higher) in the competitive equilibrium, i.e. the flexible system implies a less (more) rewarding environment for thermal (wind) operations.

Type	Competitive		Strategic		Absolute change		Relative change (%)
	DA	RT	DA	RT	DA	RT	
RWE	31,529		347,515	- 6,876	315,986	- 6,876	980
Fringe	617,321	3,039	7,098,149		6,480,828	- 3,039	1,044
Wind	82,565	37,482	486,228	6,119	403,663	- 31,363	310
Industry	731,415	40,521	7,931,892	- 757	7,200,477	- 41,278	927

Table 25: Expected industry-wide profits by stage, for the competitive and strategic winter cases, at 5% penetration in the flexible configuration. Profits in £.

II. 10% Wind Power Penetration

Next, the focus of our research is turned on the model with 10% penetration as a share of winter demand. For starters, the competitive aspect of the problem is identical to the former in terms of prices[12], revealing the marginally running CCGT-fired capacity that is in excess by some 4.3 GW or 19%, due to the 2.5 GWh of heightened wind power generation. This helps reduce the utilisation of higher variable cost CCGT plant by the same amount and net system costs by 7% compared to the model with 5% penetration.

Type	Competitive	Strategic	Load factor (%)		Fuel shares (%)	
			Competitive	Strategic	Competitive	Strategic
Nuclear	8,026.2	8,026.2	100.0	100.0	16.3	16.3
Coal	12,535.2	11,939.5	100.0	95.2	25.5	24.3
CHP	4,057.2	4,057.2	100.0	100.0	8.3	8.3
Biomass	1,195.2	1,195.2	100.0	100.0	2.4	2.4
CCGT	18,353.6	17,480.7	81.1	77.3	37.4	35.6
OCGT		1,595.7		81.1		3.3
Oil						
Wind	4,923.5	4,796.4	64.3	62.6	10.0	9.8
Total	49,090.9	49,090.9			100.0	100.0

Table 26: GB fuel mix of generation for the competitive and strategic winter cases, at 10% penetration. Outputs in MWh. Load factor utilises the sum of generation in both DA and RT stages. Fuel shares as a percentage of demand.

Moreover, re-dispatch requirements stand at the level of - 1.6 GWh compared to that of - 0.8 GWh, signalling a twofold increase in balancing activity. As far as the commitment of wind power is concerned, the SO schedules the minimum prediction in DA and offsets variability by means of reducing output from thermal stations in the high wind scenario, similarly to the competitive case with 5% penetration.

System costs	Competitive	Strategic	Absolute change	Relative change (%)
Energy	1,640,585	1,634,047	- 6,538	- 0.4
Positive re-dispatch		82,289	82,289	
Negative re-dispatch	- 70,930	- 25,983	44,947	63.4
Total	1,569,655	1,690,353	120,698	7.7

Table 27: Energy and expected re-dispatch costs as perceived by the SO for the competitive and strategic winter cases, at 10% penetration. Costs in £.

However, substantial evidence to the contrary surfaces with respect to the strategic equilibrium. For one, owing to the expansion of zero marginal cost wind by 2.3 GWh which bears an output reduction of 1.2 GWh to fringe competitors, RWE is faced with a leftward-

[12] This is suggestive of the overwhelming size of the CCGT stack, which is the backbone of the GB system with some 25 GW of installed capacity, hence the difficulty in achieving lower prices in the short-run.

shifted residual demand curve and opts for a profit-maximising output of 1.8 GWh or 1.1 GWh (5.7 GWh) less, compared to the strategic (competitive) model with 5% (10%) penetration. In addition, RWE's bidding is considerably lower, conferring the complete slack (utilisation) of fringe oil-fired (OCGT) capacity at this level of net demand; DA and positive regulation bids are directly compared against the marginal cost of oil at £100 per MWh, while bids for negative regulation are constrained by the opportunity cost of oil-fired generation, which may alternatively be turned on in the low wind scenario.[13]

Type	Competitive	Strategic	Change		Load factor (%)	
			Absolute	Relative (%)	Competitive	Strategic
Coal	1,427.4	831.7	- 595.7	- 41.7	100.0	58.3
CHP	196.2	196.2			100.0	100.0
CCGT	5,905.8	767.7	- 5,138.1	- 87.0	100.0	13.0
OCGT						
Oil						
RWE	7,529.4	1,795.6	- 5,733.8	- 76.2		

Table 28: RWE fuel mix of generation for the competitive and strategic winter cases, at 10% penetration. Outputs in MWh. Load factor utilises the sum of generation in both DA and RT stages. Relative change with reference to competitive output**.**

Type	Competitive			Strategic		
	DA	RT		DA	RT	
		Positive	Negative		Positive	Negative
$Coal_1$	30.00	45.00	22.50	100.00	100.00	100.00
$CCGT_1$	50.00	62.50	43.75	100.00	100.00	100.00
$CCGT_2$	50.00	62.50	43.75	100.00	100.00	100.00
$CCGT_3$	50.00	62.50	43.75	100.00	100.00	100.00
$CCGT_4$	50.00	62.50	43.75	100.00	100.00	100.00
$OCGT_1$	60.00	66.00		100.00	2,600.00	
$OCGT_2$	60.00	66.00		100.00	2,600.00	
$OCGT_3$	60.00	66.00		100.00	2,600.00	
$OCGT_4$	60.00	66.00		100.00	2,600.00	
$OCGT_5$	60.00	66.00		100.00	2,600.00	

Table 29: RWE bids by price-making plant and stage for the competitive and strategic winter cases, at 10% penetration. Bids in £ per MWh.

Second, the price formation abides by the incumbent's bids, and so prices are declarative of the marginal activity provided by RWE's facilities. In contrast to the previous penetration, however, those additionally reflect the physical limitation of the transmission system; that is, network effects are gaining currency with rising amounts of wind, as attested by the differential persisting in the northernmost nodes of the GB system. In effect, prices diverge and become locational marginal prices, thus revealing the opportunity cost of not utilising

[13] The net cost for reducing RWE output in the high wind scenario is $\frac{£}{MWh}(100 - 0.6 \cdot 100) = \frac{£}{MWh}40$, i.e. equal to the opportunity cost of oil-fired generation in the low wind scenario $\frac{£}{MWh}0.4 \cdot 100 = \frac{£}{MWh}40$.

cheaper imports in substitution of more expensive local resources. The agent for market separation is the bottleneck of line l_2 in DA and the high wind scenario, while the latter is also responsible for the curtailment of 127 MWh or 2.6% of average system-wide wind.

Node	**Competitive**			**Strategic**		
	DA	**RT**		**DA**	**RT**	
		High	**Low**		**High**	**Low**
n_1	50.00	43.75	59.375	40.00		100.00
n_2	50.00	43.75	59.375	85.00	75.00	100.00
n_3	50.00	43.75	59.375	115.00	125.00	100.00
n_4	50.00	43.75	59.375	100.00	100.00	100.00
n_5	50.00	43.75	59.375	100.00	100.00	100.00
n_6	50.00	43.75	59.375	100.00	100.00	100.00
n_7	50.00	43.75	59.375	100.00	100.00	100.00
n_8	50.00	43.75	59.375	100.00	100.00	100.00
n_9	50.00	43.75	59.375	100.00	100.00	100.00
n_{10}	50.00	43.75	59.375	100.00	100.00	100.00
n_{11}	50.00	43.75	59.375	100.00	100.00	100.00
n_{12}	50.00	43.75	59.375	100.00	100.00	100.00
n_{13}	50.00	43.75	59.375	100.00	100.00	100.00
n_{14}	50.00	43.75	59.375	100.00	100.00	100.00
n_{15}	50.00	43.75	59.375	100.00	100.00	100.00
n_{16}	50.00	43.75	59.375	100.00	100.00	100.00
n_{17}	50.00	43.75	59.375	100.00	100.00	100.00
n_{18}	50.00	43.75	59.375	100.00	100.00	100.00
n_{19}	50.00	43.75	59.375	100.00	100.00	100.00
n_{20}	50.00	43.75	59.375	100.00	100.00	100.00
n_{21}	50.00	43.75	59.375	100.00	100.00	100.00
n_{22}	50.00	43.75	59.375	100.00	100.00	100.00
n_{23}	50.00	43.75	59.375	100.00	100.00	100.00
n_{24}	50.00	43.75	59.375	100.00	100.00	100.00
n_{25}	50.00	43.75	59.375	100.00	100.00	100.00
n_{26}	50.00	43.75	59.375	100.00	100.00	100.00
n_{27}	50.00	43.75	59.375	100.00	100.00	100.00
n_{28}	50.00	43.75	59.375	100.00	100.00	100.00
n_{29}	50.00	43.75	59.375	100.00	100.00	100.00

Table 30: DA and expected RT prices for the competitive and strategic winter cases, at 10% penetration. Prices in £ per MWh.

Line	**Competitive**			**Strategic**			**Absolute change**		**Relative change (%)**
	DA	**RT**		**DA**	**RT**		**DA**	**RT**	
		High	**Low**		**High**	**Low**			
l_2	100.0	- 10.2	- 71.5	100.0		- 36.3		20.2	30.9

Table 31: DA utilisation and expected RT change of the line connecting nodes n_1 and n_3 for the competitive and strategic winter cases, at 10% penetration. Figures in % of line capacities.

Therefore, contrary to the competitive equilibrium, where non-binding congestion emerges at the DA stage, the strategic equilibrium underlines the leader's ability to choose plant outputs, in a way that seeks to game the re-dispatch process and manipulate system-wide power flows. It is by taking advantage of her dispersion and anticipating the subsequent impact of her behaviour on the network (following Kirchhoff's Voltage Law) that the leader manages to influence rival production and congest line l_2 downstream of node n_1 in the high wind scenario. In other words, the rigorously devised combination of plant outputs gives rise to artificial DA supply needs, which cause system-wide production deviations and alter the direction of flows in the network. These incite the SO to commit all running fringe plant at capacity[14] as shown in Table 81 in Appendix C and over-commit system-wide wind by 2 GWh in the DA schedule.

Type	Competitive		Strategic		Absolute change		Relative change (%)
	DA	RT	DA	RT	DA	RT	
RWE	7,529.4		1,232.6	563.1	- 6,296.8	563.1	- 76.2
Fringe	38,259.3	- 1,621.3	42,498.9		4,239.6	1,621.3	16.0
Wind	3,302.2	1,621.3	5,359.4	- 563.0	2,057.2	- 2,184.3	- 2.6
Industry	49,090.9		49,090.9				

Table 32: Industry-wide output levels by fuel type and stage, for the competitive and strategic winter cases, at 10% penetration. Outputs in MWh.

Understandably, the leader is able to gain access to higher monopoly levels by causing market separation and inducing higher prices at those nodes with significant capacity advantage over the competition, thus motivating the fringe to increase output at marginal cost. This is different to the exercise of market power by means of economic withholding, inasmuch as the strategist withholds output to create import constraints, which block competition and help raise prices (Borenstein et al., 2000). Following the induced curtailment, the average balance price is expected at £96.55 per MWh in the high scenario, exerting a similar pressure on the DA market, which clears at £97.93 per MWh.

On the strategic outputs and profits front, RWE's coal plant runs out of negative-regulation capability in the high scenario, connoting real-time damages of £4k, however, helping the incumbent secure net profits of £109k. Observably, unlike the MPEC with 5% penetration, where price-making stations were dispatched (almost) just as much to offset variability, RWE's profit-maximising objective drives the loading of the coal-fired plant to 58% compared to 17%, thus affording 46% (53%) of RWE's output (profit). On the other hand, CCGTs operate for regulation purposes, albeit at 13% compared to 5% load factor, due to the higher down-regulation needs in the MPEC with 5% penetration. RWE's conduct has a positive bearing on fringe (wind) plant, which increase profits by 332% (86%), while load payments double, as shown in Table 82 in Appendix C. To avoid repetition, the strategic

[14] This also applies to the sole, fringe CCGT, station located at node n_2, i.e. at the end-node of line l_1, parallel to the constrained path n_1-n_3.

simulation of the flexible system is omitted from the following, however, the interested reader may refer to Appendix C for results about prices, outputs and profits.

Type	Max rating	Re-dispatch capability		Competitive			Strategic		
		Positive	Negative	DA	RT High	RT Low	DA	RT High	RT Low
Coal	1,427.4	285.5	285.5	1,427.4			888.8	- 285.5	285.5
CHP_1	137.7			137.7			137.7		
CHP_2	58.5			58.5			58.5		
$CCGT_1$	1,594.8	478.4	478.4	1,594.8					478.4
$CCGT_2$	1,026.0	307.8	307.8	1,026.0					307.8
$CCGT_3$	1,323.0	396.9	396.9	1,323.0			147.6	- 147.6	396.9
$CCGT_4$	1,962.0	588.6	588.6	1,962.0					588.6
$OCGT_1$	90.0	90.0							
$OCGT_2$	126.0	126.0							
$OCGT_3$	45.9	45.9							
$OCGT_4$	15.3	15.3							
$OCGT_5$	94.5	94.5							
Oil_1	1,233.0	1,233.0							
Oil_2	932.4	932.4							
RWE	10,066.5	4,594.3	2,057.2	7,529.4			1,232.6	- 433.1	2,057.2

Table 33: RWE maximum rating, re-dispatch capability and output levels by plant and stage, for the competitive and strategic winter cases, at 10% penetration. Maximum rating refers to a 10% derating of installed capacity. Capability figures in MW, outputs in MWh.

Type	Competitive		Strategic		Absolute change		Relative change (%)
	DA	RT	DA	RT	DA	RT	
RWE	31,529		82,385	27,011	50,856	27,011	247
Fringe	617,321	10,133	2,710,379		2,093,058	- 10,133	332
Wind	165,110.0	70,931.4	494,843	- 56,301	329,733	- 127,233	86
Industry	813,960	81,064	3,258,939	- 629	2,444,979	- 81,693	264

Table 34: Expected industry-wide profits by stage, for the competitive and strategic winter cases, at 10% penetration. Figures in £.

III. 15% Wind Power Penetration

Next, the focus of research is shifted towards the case where RWE adopts a strategic behaviour under the presence of significant wind power supplies at 15% penetration level as a share of winter demand, corresponding to 7.4 GWh of mean wind power. First, as far as the competitive equilibrium is concerned, prices remain largely at the levels they did in their peer models of 5% and 10% penetration while reflecting the lump of CCGT spare capacity of 29% or 6.5 GW. Most critically, our attention is distinctly drawn by the presence of transmission constraints in DA and the high wind scenario, as manifest through the market separation at the northern border of the system.

System costs	Competitive	Strategic	Absolute change	Relative change (%)
Energy	1,558,020	1,541,329	- 16,691	- 1.1
Positive re-dispatch		59,463	59,463	
Negative re-dispatch	- 96,026	- 97,138	- 1,112	- 1.2
Total	1,461,994	1,503,654	41,660	2.8

Table 35: Energy and expected re-dispatch costs as perceived by the SO for the competitive and strategic winter cases, at 15% penetration. Costs in £.

Type	Competitive	Strategic	Change		Load factor (%)	
			Absolute	Relative (%)	Competitive	Strategic
Coal	1,427.4	1,427.4			100.0	100.0
CHP	196.2	196.2			100.0	100.0
CCGT	5,310.6	93.7	- 5,216.9	- 98.2	89.9	1.6
OCGT						
Oil						
RWE	6,934.2	1,717.3	- 5,216.9	- 75.2		

Table 36: RWE fuel mix of generation for the competitive and strategic winter cases, at 15% penetration. Outputs in MWh. Load factor utilises the sum of generation in both DA and RT stages. Relative change with reference to competitive output.

Specifically, expected high wind scenario and DA prices are by £1.51 and £0.91 per MWh lower, while low wind scenario prices stand unaffected compared to the cases with 5% and 10% penetration. Following the 4.7 GWh increase in mean wind power, negative balancing requirements delivered by part-loaded CCGT plant have mounted to 2.2 GWh, an increase by a factor of 2.7 compared to the model with 5% penetration which feeds through into RT costs in the exact proportion. In response to their mandate to integrate wind with priority, the SO has curbed production at the CCGT stack by 23% or 4.7 GWh compared to the same standards, conferring net system cost savings of 13%.

In elaboration of the MPEC, the resulting price formation yields £96.66 and £42.24 per MWh for the low and high wind scenarios, and £64.01 per MWh of energy; this drives the 32% increase in expected load payments, as shown in Table 86 in Appendix D. The deviation at this level of wind power, is condensed on RWE's restrained price-lifting ability - which explains the 100% load factor of her coal plant - due to the combination of the largely under-utilised network and the fringe oil fleet that is in abundance. In addition, fringe CCGT stations located outside the constraints are dispatched at capacity in DA and provide negative regulation in the high wind scenario,[15,16] while OCGT stations are upward-constrained in the low wind scenario, as shown in Table 87 in Appendix D.

[15] On the other hand, the fringe CCGT at node n_2 runs at the margin with 524 MWh in DA, and is downward-constrained (upward-constrained) in the high (low) scenario with 318.6 MWh.
[16] Observably, down-regulation is profitable for CCGTs at this level of high wind scenario balance prices.

Node	Competitive			Strategic		
	DA	RT High	Low	DA	RT High	Low
n_1	23.750		59.375	1.25		3.125
n_2	43.437	32.812	59.375	50.00	32.812	75.783
n_3	56.562	54.687	59.375	82.50	54.687	124.220
n_4	50.000	43.750	59.375	66.25	43.750	100.000
n_5	50.000	43.750	59.375	66.25	43.750	100.000
n_6	50.000	43.750	59.375	66.25	43.750	100.000
n_7	50.000	43.750	59.375	66.25	43.750	100.000
n_8	50.000	43.750	59.375	66.25	43.750	100.000
n_9	50.000	43.750	59.375	66.25	43.750	100.000
n_{10}	50.000	43.750	59.375	66.25	43.750	100.000
n_{11}	50.000	43.750	59.375	66.25	43.750	100.000
n_{12}	50.000	43.750	59.375	66.25	43.750	100.000
n_{13}	50.000	43.750	59.375	66.25	43.750	100.000
n_{14}	50.000	43.750	59.375	66.25	43.750	100.000
n_{15}	50.000	43.750	59.375	66.25	43.750	100.000
n_{16}	50.000	43.750	59.375	66.25	43.750	100.000
n_{17}	50.000	43.750	59.375	66.25	43.750	100.000
n_{18}	50.000	43.750	59.375	66.25	43.750	100.000
n_{19}	50.000	43.750	59.375	66.25	43.750	100.000
n_{20}	50.000	43.750	59.375	66.25	43.750	100.000
n_{21}	50.000	43.750	59.375	66.25	43.750	100.000
n_{22}	50.000	43.750	59.375	66.25	43.750	100.000
n_{23}	50.000	43.750	59.375	66.25	43.750	100.000
n_{24}	50.000	43.750	59.375	66.25	43.750	100.000
n_{25}	50.000	43.750	59.375	66.25	43.750	100.000
n_{26}	50.000	43.750	59.375	66.25	43.750	100.000
n_{27}	50.000	43.750	59.375	66.25	43.750	100.000
n_{28}	50.000	43.750	59.375	66.25	43.750	100.000
n_{29}	50.000	43.750	59.375	66.25	43.750	100.000

Table 37: DA and expected RT prices for the competitive and strategic winter cases, at 15% penetration. Figures in £ per MWh.

RWE's bidding pattern is shaped accordingly; the opportunity cost of not starting a fringe oil-fired station in RT caps the bids for up-regulation at £100 per MWh. DA bids are likewise influenced by this very opportunity cost, insofar as the SO may call a rival oil-fired plant with 40% probability in the low wind scenario, as an alternative to scheduling an increment of price-making output in DA and curtailing it with 60% probability in the high wind scenario. Further, accepted bids for down-regulation cannot be lower than the willingness of the rival marginal CCGT to buy back output at £43.75 per MWh, hence the accepted energy bids of £66.25 per MWh for RWE.[17] Nonetheless, $CCGT_4$ is willing to cut back at

[17] Formally, $\frac{£}{MWh}(66.25 - 0.6 \cdot 43.75) = 0.4 \cdot \frac{£}{MWh} 100 = \frac{£}{MWh} 40$, i.e. the abovementioned actions cost £40 per MWh in expectation.

£100 per MWh, i.e. incur a seeming extra loss and pay 50% more than her presumed DA cost in RT, however, enables RWE to game the balancing market in the low wind scenario.

Type	Competitive			Strategic		
	DA	RT Positive	RT Negative	DA	RT Positive	RT Negative
Coal$_1$	30.00	45.00	22.50	66.25	100.00	43.75
CCGT$_1$	50.00	62.50	43.75	66.25	100.00	43.75
CCGT$_2$	50.00	62.50	43.75	66.25	100.00	43.75
CCGT$_3$	50.00	62.50	43.75	66.25	100.00	43.75
CCGT$_4$	50.00	62.50	43.75	66.25	100.00	100.00
OCGT$_1$	60.00	66.00		66.25	3,710.42	
OCGT$_2$	60.00	66.00		66.25	3,710.42	
OCGT$_3$	60.00	66.00		66.25	3,710.42	
OCGT$_4$	60.00	66.00		300.00	3,710.42	
OCGT$_5$	60.00	66.00		66.25	3,710.42	

Table 38: RWE bids by price-making plant and stage for the competitive and strategic winter cases, at 15% penetration. Figures in £ per MWh.

Line	Competitive			Strategic			Absolute change		Relative change (%)
	DA	RT High	RT Low	DA	RT High	RT Low	DA	RT	
l_2	100.0		- 24.8	100.0				9.9	11.0

Table 39: DA utilisation and expected RT change of the line connecting nodes n_1 and n_3 for the competitive and strategic winter cases, at 15% penetration. Figures in % of line capacities.

Type	Competitive	Strategic	Load factor (%)		Fuel shares (%)	
			Competitive	Strategic	Competitive	Strategic
Nuclear	8,026.2	8,026.2	100.0	100.0	16.3	16.3
Coal	12,535.2	12,535.2	100.0	100.0	25.5	25.5
CHP	4,057.2	4,057.2	100.0	100.0	8.3	8.3
Biomass	1,195.2	1,195.2	100.0	100.0	2.4	2.4
CCGT	16,128.7	15,521.2	71.3	68.6	32.9	31.6
OCGT		638.3		32.4		1.3
Oil						
Wind	7,148.4	7,117.6	93.3	92.9	14.6	14.5
Total	49,090.9	49,090.9			100.0	100.0

Table 40: GB fuel mix of generation for the competitive and strategic winter cases, at 15% penetration. Outputs in MWh. Load factor utilises the sum of generation in both DA and RT stages. Fuel shares as a percentage of demand.

Similar to the MPEC with 10% penetration, RWE's strategy combines elements of economic withholding with local market power exercise, and so the concerted effort for exacerbating the constraints is transferable here; RWE's tactic to find herself at the import-constrained zone is founded on her incentive to isolate part of the market and capture supernormal profits by generating at a substantial mark-up to her cost. Observably, RWE's price-making behaviour creates a flow pattern that curtails some 31 MWh more in expectation compared to the competitive schedule and drives wind power's share to 14.5% of demand, while additionally causing market separation in the low wind scenario.

Type	Max rating	Re-dispatch capability		Competitive			Strategic		
		Positive	Negative	DA	RT High	RT Low	DA	RT High	RT Low
Coal	1,427.4	285.5	285.5	1,427.4			1,427.4		
CHP_1	137.7			137.7			137.7		
CHP_2	58.5			58.5			58.5		
$CCGT_1$	1,594.8	478.4	478.4	1,594.8					234.3
$CCGT_2$	1,026.0	307.8	307.8	1,026.0					
$CCGT_3$	1,323.0	396.9	396.9	1007.0					
$CCGT_4$	1,962.0	588.6	588.6	1,962.0	- 465.4		588.6	- 588.6	- 588.6
$OCGT_1$	90.0	90.0							
$OCGT_2$	126.0	126.0							
$OCGT_3$	45.9	45.9							
$OCGT_4$	15.3	15.3							
$OCGT_5$	94.5	94.5							
Oil_1	1,233.0	1,233.0							
Oil_2	932.4	932.4							
RWE	10,066.5	4,594.3	2,057.2	7,213.4	- 465.4		2,212.2	- 588.6	- 354.3

Table 41: RWE maximum rating, re-dispatch capability and output levels by plant and stage, for the competitive and strategic winter cases, at 15% penetration. Maximum rating refers to a 10% derating of installed capacity. Capability figures in MW, output figures in MWh.

Type	Competitive		Strategic		Absolute change		Relative change (%)
	DA	RT	DA	RT	DA	RT	
RWE	7,213.4	- 279.2	2,212.2	- 494.9	- 5,001.2	- 215.7	- 75.2
Fringe	36,923.9	- 1,915.7	40,365.2	- 109.2	3,441.3	1,806.5	15.0
Wind	4,953.5	2,194.9	6,513.5	604.1	1,560.0	- 1,590.8	- 0.4
Industry	49,090.9		49,090.9				

Table 42: Industry-wide output levels by fuel type and stage, for the competitive and strategic winter cases, at 15% penetration. Outputs in MWh.

Of critical importance to circumvent competition is the behaviour of $CCGT_4$, which assumes a zero profit position and compels the SO for commitment.[18] Specifically, by reducing output in the low wind scenario, $CCGT_4$ helps to exhaust the fringe OCGT fleet and set the price at the marginal cost of oil plant; $CCGT_1$ subsequently sells balancing services at a considerable premium, while the DA price formation helps the upward-constrained coal station to deliver 83% of profits. As a result, RWE extracts 88% higher profit compared to the competitive equilibrium by withholding 5.2 GWh of her competitive product and producing 1.2 GWh less, compared to the MPEC with 5% penetration.

[18] Operating $CCGT_4$ incurs negative costs to the SO, i.e. the SO avoids $\frac{£}{MWh}(100 - 66.25) = \frac{£}{MWh} 33.75$.

Type	Competitive		Strategic		Absolute change		Relative change (%)
	DA	RT	DA	RT	DA	RT	
RWE	31,529	1,745	67,477	- 4,879	35,948	- 6,624	88
Fringe	615,230	14,064	1,264,740	36,376	649,510	22,312	107
Wind	224,816	93,936	378,252	- 7,674	153,437	- 101,610	16
Industry	871,574	109,745	1,710,470	23,823	838,895	- 85,922	77

Table 43: Expected industry-wide profits by stage, for the competitive and strategic winter cases, at 15% penetration. Figures in £.

In sum, propelled by the incentive to drive high pool prices, the leader's strategy is directed towards exhausting the operating thermal fringe fleet, while wind power commitment in the energy market may be higher or lower, depending on the amount of DA withholding. Key to obtaining the best firm-wide output is to opt for the most profitable production allocation between the DA and RT horizon; this could be achieved either through more DA production and subsequently higher negative regulation (or less positive regulation, if less than profit-maximising output has been committed) or through the reverse, which implies less production in DA followed by less retraction (or more positive regulation) in RT.

At low levels of penetration, the reduced competition in the RT market suggests an environment which is more likely to succumb to one dominant provider of balancing services to any direction. This is manifest through the shift of balancing needs from high and negative in the high wind scenario of the competitive equilibrium to a combination of positive and negative in the low and high wind scenario of the strategic equilibrium. Critically, the enhanced merit-order effect at higher levels of penetration, reduces the space for strategic behaviour and the expectation of monopoly profits. The weakened ability to raise prices prompts the firm to commit her coal-fired plant up to capacity, while also necessitating CCGT output reductions in RT in order to influence balance prices in the MPEC with 15% penetration. Effectively, the strategist withholds considerably less compared to the expanding renewable generation, i.e. 3% as a share of the wind infeed increase from 10% to 15% penetration, signalling the greater reliance on quantities as opposed to prices for maximising profits.

Increasingly, the incentive to exacerbate the constraints serves as a benchmark for profitable access to larger residual demand levels, following the deliberate price decrease at some nodes. Therefore, while increasing amounts of concentrated variable generation and hence uncertainty, have a moderating effect on participants' outputs and profits under price-taking behaviour, a dominant firm could take advantage of the transmission's disposition to constraints in a profitable fashion. Following the firm's strategic conduct, financial damages to those generators located inside the constraints could spike by as much as 95%, due to a combination of higher curtailment and dropping prices.[19]

Sensitivity analysis: flexibility

This section summarises the implications of exercising market power in the more flexible system, at the level of 15% of wind penetration. Much like in the model with 5% penetration, where competitive re-dispatch costs were by 5.71% lower compared to the less flexible system, the heightened competition in the balancing market is here responsible for the same share of expected balancing cost savings, i.e. 5.71% or £5,487.

System costs	Competitive	Strategic	Absolute change	Relative change (%)
Energy	1,558,020	1,628,096	70,077	4.5
Positive re-dispatch		51,897	51,897	
Negative re-dispatch	- 101,513	- 220,129	- 118,616	- 116.8
Total	1,456,507	1,459,864	3,357	0.2

Table 44: Energy and expected re-dispatch costs as perceived by the SO for the competitive and strategic winter cases, at 15% penetration in the flexible configuration. Costs in £.

This is not surprising, considering that at this level of demand, both systems employ the same type of plant for the procurement of the same amount of negative balancing services in the competitive equilibrium, while energy delivery costs are unaltered, connoting the fuel mix of generation, which stands unaffected. Therefore, key to the formation of system costs is the CCGT cost for negative regulation, which is lower by £2.50 per MWh (or 5.71%) in the flexible setting. With the average price-lowering effect of congestion in mind, high wind scenario prices are expected to be higher by £2.41 (or 5.71%), while low wind scenario prices are expected to be £3.75 per MWh (or 6.32%) lower,[20] and so the expected impact on DA prices through their mean is - £0.05 per MWh (or - 0.11%).

Turning to the strategic equilibrium, prices reveal the emergence of congestion in all DA and RT stages, while much like in the MPEC of the less flexible system and by virtue of her distortive bidding, RWE procures negative regulation services and sets the price in the low wind scenario, as shown in Table 88 in Appendix D. This comes with system-wide scheduling alterations; most critically, the exhaustion of all fringe OCGTs (CCGTs located outside the constraints) in RT (DA), as shown in Table 89 in Appendix D and the system-wide over-commitment of wind power.[21] The induced congestion in the low wind scenario denotes additional curtailment of 0.7 MWh compared to the competitive programme and

[19] Renewable plant could thus also forego income connected to production-based subsidies.
[20] Another way to think of this is that the average off-peak (peak) price is higher (lower) in the less flexible system.
[21] On the other hand, the fringe CCGT at node n_2 is scheduled just as much to offset wind variability with 424.8 MWh in DA, and is downward-constrained (upward-constrained) in the high (low) scenario.

inflicts a diminishing force on the DA price at the export-constrained node n_1. In comparison to the MPEC of the less flexible system, overall curtailment is lower by some 30 MWh and wind utilisation reaches 96.8% as opposed to 96.4% of demand.

Node	Competitive			Strategic		
	DA	RT High	RT Low	DA	RT High	RT Low
n_1	22.250		55.625			
n_2	43.062	34.688	55.625	50.000	34.687	72.970
n_3	56.937	57.813	55.625	83.333	57.812	121.615
n_4	50.000	46.250	55.625	66.667	46.250	97.293
n_5	50.000	46.250	55.625	66.667	46.250	97.293
n_6	50.000	46.250	55.625	66.667	46.250	97.293
n_7	50.000	46.250	55.625	66.667	46.250	97.293
n_8	50.000	46.250	55.625	66.667	46.250	97.293
n_9	50.000	46.250	55.625	66.667	46.250	97.293
n_{10}	50.000	46.250	55.625	66.667	46.250	97.293
n_{11}	50.000	46.250	55.625	66.667	46.250	97.293
n_{12}	50.000	46.250	55.625	66.667	46.250	97.293
n_{13}	50.000	46.250	55.625	66.667	46.250	97.293
n_{14}	50.000	46.250	55.625	66.667	46.250	97.293
n_{15}	50.000	46.250	55.625	66.667	46.250	97.293
n_{16}	50.000	46.250	55.625	66.667	46.250	97.293
n_{17}	50.000	46.250	55.625	66.667	46.250	97.293
n_{18}	50.000	46.250	55.625	66.667	46.250	97.293
n_{19}	50.000	46.250	55.625	66.667	46.250	97.293
n_{20}	50.000	46.250	55.625	66.667	46.250	97.293
n_{21}	50.000	46.250	55.625	66.667	46.250	97.293
n_{22}	50.000	46.250	55.625	66.667	46.250	97.293
n_{23}	50.000	46.250	55.625	66.667	46.250	97.293
n_{24}	50.000	46.250	55.625	66.667	46.250	97.293
n_{25}	50.000	46.250	55.625	66.667	46.250	97.293
n_{26}	50.000	46.250	55.625	66.667	46.250	97.293
n_{27}	50.000	46.250	55.625	66.667	46.250	97.293
n_{28}	50.000	46.250	55.625	66.667	46.250	97.293
n_{29}	50.000	46.250	55.625	66.667	46.250	97.293

Table 45: DA and expected RT prices for the competitive and strategic winter cases, at 15% penetration in the flexible configuration. Figures in £ per MWh.

Line	Competitive			Strategic			Absolute change		Relative change (%)
	DA	RT High	RT Low	DA	RT High	RT Low	DA	RT	
l_2	100.0		- 39.9	100.0				16.0	19.0

Table 46: DA utilisation and expected RT change of the line connecting nodes n_1 and n_3 for the competitive and strategic winter cases, at 15% penetration in the flexible configuration. Figures in % of line capacities.

Observably, RWE's abusive behaviour is conflicting with the properties of the network, which poses restrictions on the accepted regulation bids, further than those due to the opportunity cost of oil-fired capacity, i.e. £97.292 is lower than £100 per MWh. Specifically, the presence of the marginal CCGT at node n_2 limits the access to higher monopoly profits, and so the leader cannot increase her share by inducing congestion (in the low wind scenario) without decreasing her bids. On the other hand, bids for down-regulation cannot be lower than the fringe CCGT cost at £46.25 per MWh and so pool prices are restrained through the expected value of balance prices to £66.667 per MWh, however, are higher than those in the less flexible system.

Type	**Competitive**			**Strategic**		
	DA	**RT Positive**	**RT Negative**	**DA**	**RT Positive**	**RT Negative**
$Coal_1$	30.00	39.00	25.50	66.667	3,712.917	- 2,953.750
$CCGT_1$	50.00	57.50	46.25	66.667	97.292	97.292
$CCGT_2$	50.00	57.50	46.25	66.667	97.292	46.250
$CCGT_3$	50.00	57.50	46.25	66.667	97.292	97.292
$CCGT_4$	50.00	57.50	46.25	66.667	97.292	97.292
$OCGT_1$	60.00	66.00		300.000	3,712.917	
$OCGT_2$	60.00	66.00		66.667	3,712.917	
$OCGT_3$	60.00	66.00		300.000	3,712.917	
$OCGT_4$	60.00	66.00		66.667	3,712.917	
$OCGT_5$	60.00	66.00		300.000	97.292	

Table 47: RWE bids by price-making plant and stage for the competitive and strategic winter cases, at 15% penetration in the flexible configuration. Figures in £ per MWh.

Unlike the previously elaborated flexible case at 5% penetration, RWE may not further shift CCGT production to her coal plant in order to maximise profits, as coal is committed at capacity in DA at this level of wind power. Therefore, in contrast to the MPEC with 5% (as well as the 10%) penetration, where prices remained the same for different flexibility levels, the merit-order effect by which those are falling due to the addition of zero marginal cost generation makes balancing cost differentials more relevant. This phenomenon is critical to the formation of less favourable expected balance prices in the flexible system, where conventional stations ask for (pay) less (more) to re-dispatch up (down). In particular, the average off-peak (i.e. the expected high wind scenario) price is higher by £2.41 as in the competitive models; on the other hand, the lower average peak (i.e. the expected low wind scenario) price notwithstanding, the differential is not as large as in the competitive models, standing at - £2.72 as opposed to - £3.75 per MWh, and so the energy market of the flexible system is more expensive by £0.36 per MWh on average.

Type	**Competitive**	**Strategic**	**Load factor (%)**	**Fuel shares (%)**

			Competitive	Strategic	Competitive	Strategic
Nuclear	8,026.2	8,026.2	100.0	100.0	16.3	16.3
Coal	12,535.2	12,535.2	100.0	100.0	25.5	25.5
CHP	4,057.2	4,057.2	100.0	100.0	8.3	8.3
Biomass	1,195.2	1,195.2	100.0	100.0	2.4	2.4
CCGT	16,128.7	15,491.1	71.3	68.5	32.9	31.6
OCGT		638.3		32.4		1.3
Oil						
Wind	7,148.4	7,147.7	93.3	93.3	14.6	14.6
Total	49,090.9	49,090.9			100.0	100.0

Table 48: GB fuel mix of generation for the competitive and strategic winter cases, at 15% penetration in the flexible configuration. Outputs in MWh. Load factor utilises the sum of generation in both DA and RT stages. Fuel shares as a percentage of demand.

Type	Competitive	Strategic	Change		Load factor (%)	
			Absolute	Relative (%)	Competitive	Strategic
Coal	1,427.4	1,427.4			100.0	100.0
CHP	196.2	196.2			100.0	100.0
CCGT	4,959.3	91.6	- 4,867.7	- 98.2	84.0	1.6
OCGT						
Oil						
RWE	6,582.9	1,715.2	- 4,867.7	- 73.9		

Table 49: RWE fuel mix of generation for the competitive and strategic winter cases, at 15% penetration in the flexible configuration. Outputs in MWh. Load factor utilises the sum of generation in both DA and RT stages. Relative change with reference to competitive output.

In response to the reduced curtailment by 30 MWh and the increase in pool prices, the leader's profit-maximising output is correspondingly lowered by 2 MWh; on the other hand, fringe generators curb production by 28 MWh, while thermal production deviations are borne by the CCGT fleet, as indicated by the GB or RWE fuel mix of generation. The aggregation of those effects is manifest through a profit increase of £324 or 0.52% for the leader, compared to the strategic equilibrium of the less flexible system. By contrast to the 5% and 10% cases, where outputs and profits of other participants were unaltered between systems of different flexibility, fringe (wind) profits are higher by 14k or 1.08% (£6k or 1.62%) for wind penetration at the level of 15%. The collective benefits for the wind power industry notwithstanding, independent wind producers sited behind the constraints would forego their entire market profit following the exercise of market power. Finally, the impact on efficiency losses, is expressed through an increase in load payments by 0.6% compared to the less flexible configuration, as shown in Table 90 in Appendix D.

Type	Competitive		Strategic		Absolute change		Relative change (%)
	DA	RT	DA	RT	DA	RT	
RWE	31,529	3,549	91,122	- 28,200	59,593	- 31,749	79
Fringe	617,321	4,681	1,281,354	33,827	664,033	29,145	111

Wind	221,299	101,516	293,674	82,908	72,375	- 18,608	17
Industry	870,149	109,746	1,666,150	88,535	796,001	- 21,212	79

Table 50: Expected industry-wide profits by stage, for the competitive and strategic winter cases, at 15% penetration in the flexible configuration. Figures in £.

Type	Competitive		Strategic		Absolute change		Relative change (%)
	DA	RT	DA	RT	DA	RT	
RWE	7,529.4	- 946.5	3,575.5	- 1,860.3	- 3,953.9	- 913.8	- 73.9
Fringe	36,608.0	- 1,248.4	40,266.0	- 38.0	3,658.0	1,210.4	13.8
Wind	4,953.5	2,194.9	5,249.4	1,898.3	295.9	- 296.6	
Industry	49,090.9		49,090.9				

Table 51: Industry-wide output levels by fuel type and stage, for the competitive and strategic winter cases, at 15% penetration in the flexible configuration. Outputs in MWh.

In conclusion, the switch to a more flexible setting at such high levels of stochastic generation helps pronounce a balancing market that is more penalising for the thermal stack, i.e. one where charges (payments) for down-regulation (up-regulation) in the high (low) wind scenario are higher (lower). Therefore, not only are incentives for the exercise of market power - as a share of competitive profits - diminished with increasing penetration levels, the relative benefits of misbehaving in more flexible systems are reduced at very high levels of intermittent supplies. The latter is a result of the heightened competition in the RT market - both in terms of balancing capability, as well as costs - and the presence of marginal generators which cannot be outdone by network effects, thus posing restrictions on balancing bids. Observably, the expected negative impact is not fully passed onto peak prices under strategic conduct - reflecting the larger gaming space during lower-wind periods - nonetheless, physical laws act as a market power reduction device, following the leader's offering in the more flexible system.

In contrast to higher net demand levels, where higher balancing capabilities and unaltered prices (and profit-maximising outputs) necessitated shifting operations to lower-cost plant in pursuit of higher profits, RWE's baseload station runs at capacity in both strategic equilibria. The resulting DA price formation is thus key to rationalising the lower net profit-maximising output in the flexible system. The financial impact is expressed through higher gains for the leader, while fringe (wind) producers also improve their position by producing (curtailing) less. This paradigm is appreciably different to that seen at lower levels of wind, where the transition to higher levels of flexibility acted to the asymmetric benefit of the strategist. Moreover, the corollary inferred previously is confirmed; positive (negative) regulation becomes more relevant following a lesser (higher) than profit-maximising output in DA, hence the higher DA production and subsequently higher down-regulation activity of the leader in the flexible configuration.

5.3.2. Summer demand

In contrast to the previous section, we here below examine the strategic behaviour borne by less flexible generators. While peak-load scarcity serves as an ideal opportunity for those possessing to exercise monopoly power, intrinsic to low-demand periods is the emphasis on quantities in order to maximise profits. In response to their mission for enhancing competition, liberalised markets often adopt measures that mitigate the firms' dominating status by requiring them to sell some of their assets; in effect, generators become net buyers of electricity and are prompted to emphasise on forward contracting to deliver their load obligations (Stoft, 2002). This substantially reduces the space for abuse and if considered within the context of low-demand periods, explains why much of the incentive for the exercise of market power is eliminated.

However, exploring the complexities surrounding the challenging task of meeting high balancing requirements during low-demand periods, is gaining currency. The incentive to exacerbate the constraints, which could be greater during off-peak periods where generating options are limited, additionally motivates this investigation (Cardell et al., 1997). As such, we repeat our analysis with respect to the incentives facing large firms to increase profits during those stressing to the system low-demand, high-wind periods. Specifically, we run simulations ranging from 10% (1.8 GWh) to 40% penetration (7 GWh) with 10% increments, however, due to similarities between models, only 30% results, featuring 5.3 GWh of mean wind power are presented in the following in detail, while prices, outputs and profits for the rest of the models are presented in Appendix E for completeness. Summer models feature EDF as the Stackelberg leader who pursues her profit-maximising objective against the price-taking competitive fringe. To this end, two coal and seven nuclear plant assume a price-making role; due to her substantial baseload generation and virtually without competitors at the nuclear part of the stack, EDF's establishment is marked by her ability to raise pool prices close to the marginal cost of CHP for electricity generation, for wind penetration levels up to 30%.

I. 30% Wind Power Penetration

The attributes pertaining to the expedient employed by the incumbent firm are similar to those identified in the strategic winter cases. That is, EDF bids part of her generation at higher than marginal cost levels to ensure the merit-order by which stations are deployed is altered, causing market prices to rise. Nonetheless, considering the substantially lower slope of the supply stack at lower loads, EDF's price-lifting ability is restrained by the cost of CHP generation at £36 per MWh that is in abundance, as shown in Table 103 in Appendix E. This helps to appreciate the motive for the considerably higher - compared to winter simulations - profit-maximising output and hence, lesser withholding.[22]

System costs	Competitive	Strategic	Absolute change	Relative change (%)
Energy	221,576	- 1,592,872	- 1,814,448	- 818.9
Positive re-dispatch	14,079	19,978	5,899	41.9
Negative re-dispatch	- 24,752	- 48,545	- 23,793	- 96.1
Total	210,903	- 1,621,439	- 1,832,342	- 868.8

Table 52: Energy and expected re-dispatch costs as perceived by the SO for the competitive and strategic summer cases, at 30% penetration. Costs in £.

To derive the expected balance prices for the high wind scenario, it is helpful to observe the price formation outside the constraints, as well as bear in mind that the handful of currently dispatched set of plant is rendered downward-constrained, as shown in Table 104 in Appendix E. This justifies the nonzero positive regulation requirements, implied by the breakdown of competitive costs. The system has actually transitioned to (departs from) a downward-inadequate position at the 20% (40%)[23] penetration level; within these ranges, the SO would be compelled to make changes in the DA schedule for bringing high wind scenario predictions into the market. That is, during periods where negative capability is scarce, the SO would adopt a higher wind commitment at the DA stage at the expense of an equal amount of higher up-regulation services in the low wind scenario.[24] Therefore, serving a MW-worth of load in the high scenario, may be thought of as increasing the coal-fired supply by 1 MWh in DA and reducing the procurement of up-regulation services by 1 MWh in the low scenario, at the cost of $\frac{£}{MWh}(30 - 0.4 \cdot 45) = \frac{£}{MWh}12$, hence the expected balance price of £20 per MWh.

[22] Comparing the average winter and summer pool price for roughly the same amount of wind power, additionally helps to understand the accentuated on-peak merit-order effect; competitive prices drop by £10 (£6) per MWh in the winter (summer) model with 10% (30%) penetration, compared to the zero wind case.
[23] This is due to the congestion at line l_2, which mandates large amounts of wind curtailment at node n_1.
[24] The second-best option would be to start CCGT plant and integrate wind by means of down-regulation.

Node	Competitive			Strategic		
	DA	RT High	Low	DA	RT High	Low
n_1	18.00		45.00	23.75		59.375
n_2	27.00	15.00	45.00	32.75	15.00	59.375
n_3	33.00	25.00	45.00	38.75	25.00	59.375
n_4	30.00	20.00	45.00	35.75	20.00	59.375
n_5	30.00	20.00	45.00	35.75	20.00	59.375
n_6	30.00	20.00	45.00	35.75	20.00	59.375
n_7	30.00	20.00	45.00	35.75	20.00	59.375
n_8	30.00	20.00	45.00	35.75	20.00	59.375
n_9	30.00	20.00	45.00	35.75	20.00	59.375
n_{10}	30.00	20.00	45.00	35.75	20.00	59.375
n_{11}	30.00	20.00	45.00	35.75	20.00	59.375
n_{12}	30.00	20.00	45.00	35.75	20.00	59.375
n_{13}	30.00	20.00	45.00	35.75	20.00	59.375
n_{14}	30.00	20.00	45.00	35.75	20.00	59.375
n_{15}	30.00	20.00	45.00	35.75	20.00	59.375
n_{16}	30.00	20.00	45.00	35.75	20.00	59.375
n_{17}	30.00	20.00	45.00	35.75	20.00	59.375
n_{18}	30.00	20.00	45.00	35.75	20.00	59.375
n_{19}	30.00	20.00	45.00	35.75	20.00	59.375
n_{20}	30.00	20.00	45.00	35.75	20.00	59.375
n_{21}	30.00	20.00	45.00	35.75	20.00	59.375
n_{22}	30.00	20.00	45.00	35.75	20.00	59.375
n_{23}	30.00	20.00	45.00	35.75	20.00	59.375
n_{24}	30.00	20.00	45.00	35.75	20.00	59.375
n_{25}	30.00	20.00	45.00	35.75	20.00	59.375
n_{26}	30.00	20.00	45.00	35.75	20.00	59.375
n_{27}	30.00	20.00	45.00	35.75	20.00	59.375
n_{28}	30.00	20.00	45.00	35.75	20.00	59.375
n_{29}	30.00	20.00	45.00	35.75	20.00	59.375

Table 53: DA and expected RT prices for the competitive and strategic summer cases, at 30% penetration. Prices in £ per MWh.

Hence, in contrast to winter models, where down-regulating capability by means of CCGT plant was only reduced at very high wind penetrations, high wind scenario balance prices do not generally correspond to a station's down-regulation cost in summer demand models. The reliance on more optimistic anticipations of intermittent generation in DA schedules following the inadequacy, justifies the DA wind power commitment, which is higher than the minimum prediction in the competitive model with 30% penetration. As well as explains why high wind scenario prices outside the constraints are lower by £2.5 per MWh compared to the competitive model with 10% penetration, as shown in Table 91 in Appendix E; on the other hand, low wind scenario prices corresponding to the up-regulation cost of coal at 30% penetration are higher by £3.75.[25]

In turn, DA prices clear at an average £29.586 per MWh, when all firms behave competitively in the model with 30% penetration. Observably, the diminishing impact of congestion and curtailment on average prices is more heavily pronounced during low, as opposed to high-demand periods, considering that for roughly the same amount of wind power, the winter model with 10% penetration has not exerted the moderating force on prices noticed in the summer model with 30% penetration. Hence, in the absence of higher demand to absorb the remaining surpluses, the summer model with 30% penetration discards 282 MWh of wind power at node n_1 in the high wind scenario.

Type	**Competitive**			**Strategic**		
	DA	**RT Positive**	**RT Negative**	**DA**	**RT Positive**	**RT Negative**
$Nuclear_1$	8.00			35.75		
$Nuclear_2$	8.00			- 300.00		
$Nuclear_3$	8.00			- 300.00		
$Nuclear_4$	8.00			35.75		
$Nuclear_5$	8.00			- 300.00		
$Nuclear_6$	8.00			- 300.00		
$Nuclear_7$	8.00			- 300.00		
$Coal_1$	30.00	45.00	22.50	35.75	59.375	59.375
$Coal_2$	30.00	45.00	22.50	35.75	59.375	59.375

Table 54: EDF bids by price-making plant and stage for the competitive and strategic summer cases, at 30% penetration. Bids in £ per MWh.

Turning the focus on the MPEC, we examine the leader's bids and generating pattern in order to understand the formation of strategic prices. Specifically, EDF's bids of £59.375 per MWh for negative regulation with her coal stations are revealing of the willingness to buy back output sold for £35.75 per MWh in DA. $Coal_1$ thus sustains some negative regulation losses in order to render the fringe coal upward-constrained in the low wind scenario, as shown in Table 104 in Appendix E. This is to ensure that the price is set at the highest level possible, given the opportunity cost of calling a fringe CCGT in DA and standing it down in the high wind scenario at the cost of $\frac{£}{MWh}(50 - 0.6 \cdot 43.75) = \frac{£}{MWh}23.75$, hence the accepted regulation bids of £59.375 per MWh. As a result, balance prices are expected at £19.31 in the high and £59.375 per MWh in the low wind scenario, yielding a mean DA price of £35.336 per MWh in the strategic equilibrium.

[25] The lowering of high scenario balance prices is not attributed to the merit-order effect, but to the system's inability to cope with low demand levels, while DA price differences are due to the congestion at line l_2.

Type	Max rating	Re-dispatch capability		Competitive				Strategic	
		Positive	Negative	DA	RT		DA	RT	
					High	Low		High	Low
Nuclear$_1$	868.5			868.5			868.5		
Nuclear$_2$	1,066.5			1,066.5			1,066.5		
Nuclear$_3$	2,146.5			2,146.5			2,146.5		
Nuclear$_4$	1,078.2			1,078.2			995.9		
Nuclear$_5$	945.0			945.0			945.0		
Nuclear$_6$	859.5			859.5			859.5		
Nuclear$_7$	1,062.0			1,062.0			1,062.0		
Coal$_1$	1,810.8	362.2	362.2	362.2	- 362.2	317.7	362.2	- 362.2	- 327.7
Coal$_2$	1,807.2	361.4	361.4	361.4	- 361.4		361.4	- 361.4	
CCGT$_1$	737.1	221.1	221.1						
CCGT$_2$	1,198.8	359.6	359.6						
OCGT	36.0	36.0							
EDF	13,616.1	1,340.4	1,304.4	8,749.8	- 723.6	317.7	8,667.5	- 723.6	- 327.7

Table 55: EDF maximum rating, re-dispatch capability and output levels by plant and stage, for the competitive and strategic summer cases, at 30% penetration. Maximum rating refers to a 10% derating of installed capacity. Capability figures in MW, output figures in MWh.

In deconstructing the leader's strategy, the congestion spurred in DA and the high wind scenario confirm the recurrent combination of economic withholding with transmission-related strategies for high levels of wind penetration, as shown in Table 105 in Appendix E. Further, the amount of DA and RT wind schedule is unaltered between the competitive and strategic equilibria, however, this should be not regarded as an indication of reduced ability to game the re-dispatch. Had the leader chosen a lower coal-fired energy output, the scheduling of wind power would have increased, subsequently reducing the provision of down-regulation or even increasing the up-regulation services offered by the leader, if less than profit-maximising output had been committed. That is, the leader may determine her best net output by producing less in DA or more and compensate for any deviations in RT according to the corollary inferred for the winter MPECs; on the other hand, the output of fringe plant stands unaffected, considering the leader's interest to raise prices.[26]

Type	Competitive		Strategic		Absolute change		Relative change (%)
	DA	RT	DA	RT	DA	RT	
EDF	8,749.8	- 307.1	8,667.5	- 565.3	- 82.3	- 258.2	- 4.0
Fringe	4,522.0	- 480.2	4,604.2	- 222.0	82.3	258.2	8.4
Wind	4,323.5	787.2	4,323.5	787.2			
Industry	17,595.3		17,595.3				

Table 56: Industry-wide output levels by fuel type and stage, for the competitive and strategic summer cases, at 30% penetration. Outputs in MWh.

[26] Even if the leader withheld all coal output in DA, EDF would still be able to set the price by means of strictly positive regulation in the low wind scenario.

In the resulting profit-maximising schedule, EDF increases profits by 23% and withholds just 4% of her competitive product, which underscores the strong dependence on output for optimising profits, given her diminished price-lifting ability at the level of 5.1 GWh of absorbed wind. Observably, EDF maximises profits by withholding both coal and nuclear generation; a more naive strategy which sets the output of her most profitable nuclear fleet at 100% would result in a smaller price distortion, and thus lower gains from the exercise of market power, despite her expanding coal generation. The opportunity cost of not extracting large baseload profits explains the negative bids at her nuclear stations - which are responsible for 98% of her profit - and the expected net profits to the SO; load payments, however, are higher by 19%, as reported in Table 106 in Appendix E.

Type	Competitive	Strategic	Change		Load factor (%)	
			Absolute	Relative (%)	Competitive	Strategic
Nuclear	8,026.2	7,943.9	- 82.3	- 1.0	100.0	99.0
Coal	416.5	158.3	- 258.2	- 62.0	11.5	4.4
EDF	8,442.7	8,102.3	- 340.5	- 4.0		

Table 57: EDF fuel mix of generation for the competitive and strategic summer cases, at 30% penetration. Outputs in MWh. Load factor utilises the sum of generation in both DA and RT stages. Relative change with reference to competitive output.

Type	Competitive		Strategic		Absolute change		Relative change (%)
	DA	RT	DA	RT	DA	RT	
EDF	176,576	6,248	224,605	491	48,028	- 5,757	23
Fringe		9,446	26,145	10,255	26,145	10,255	385
Wind	121,553	7,923	146,414	3,426	24,860	- 4,497	16
Industry	298,130	23,617	397,163	23,617	99,034		31

Table 58: Expected industry-wide profits by stage, for the competitive and strategic summer cases, at 30% penetration. Profits in £.

In conclusion, similar to the winter strategic studies, exerting market power is gainful for the leader and monopoly profits are reduced with increasing amounts of wind power; in the MPEC with 30% penetration, the leader gains 8% less compared to that with 10% penetration, due largely to a combination of lower DA prices by £0.25 per MWh at her nodes and production by 20%, as revealed by Table 93 in Appendix E. Nonetheless, the argument for the exercise of monopoly power with higher amounts of intermittent generation could be reversed, considering the incentive to exploit the constraints and the anyway low prices and coal stations' volatile loading and profits, ranging between 417 MWh (30% penetration) and 3,255 MWh (10% penetration), and £1.6k (40% penetration) and £6.2k (30% penetration) in the competitive equilibrium. On the other hand, nuclear profits are absolutely unaffected by windy conditions during low demand periods, standing at the level of £177k, across all wind power penetration levels.

On the other hand, in contrast to winter MPECs, fringe producers witness an increase in profits with rising amounts of wind by as much as 35% - despite the reduced net production by 23% - in the MPEC with 30% compared to that with 10% penetration. This is due largely to the formation of a more favourable (to thermal producers) balancing market ensuing the downward-inadequacy, and the increased RT activity induced by the leader's strategy which aims at exhausting the fringe coal positive capability in order to lift prices. Wind plant are also better off by 170% in the MPEC with 30% compared to that with 10% penetration.

Sensitivity analysis: flexibility

The impact of flexibility was examined at the side of these simulations. Unlike winter MPECs, where absolute benefits to the strategist grow with flexibility, summer models exhibit the opposite trend and EDF profits are invariably lower for all penetration levels in the flexible configuration. This is somehow expected, considering the less favourable balancing environment is readily pronounced in all summer MPECs; in contrast, this required considerably high penetration at the level of 15% in winter. In principle, the enhanced flexibility could help to offset the exposure to the RT market, depending on the level of DA prices; in practice, however, nuclear plant run close to capacity to compensate for the small price distortion following the exercise of market power, thus narrowing down the space for more profitable operations compared to the less flexible configuration.

System costs	Competitive	Strategic	Absolute change	Relative change (%)
Energy	245,041	- 1,586,274	- 1,831,315	- 747.4
Positive re-dispatch		5,810	5,810	
Negative re-dispatch	- 40,019	- 35,725	4,294	10.7
Total	205,022	- 1,616,189	- 1,821,211	- 888.3

Table 59: Energy and expected re-dispatch costs as perceived by the SO for the competitive and strategic summer cases, at 30% penetration in the flexible configuration. Costs in £.

For starters, in contrast to the less flexible system, the enhanced capability is sufficient to support renewable integration by means of coal down-regulation in the competitive equilibrium. This drives the higher utilisation of coal in the DA schedule and the dispatched fringe plant are rendered upward-constrained as shown in Table 107 in Appendix E, while high (low) wind scenario prices clear at £24.62 (£36.75) per MWh. Due to the lower balancing premium, the average balance price is thus expected to be higher (lower) by £5.31 (£8.25) per MWh in the high (low) scenario, compared to the less flexible system.

Node	Competitive			Strategic		
	DA	RT High	Low	DA	RT High	Low
n_1	14.700		36.75	20.700		51.75
n_2	26.175	19.125	36.75	32.175	19.125	51.75
n_3	33.825	31.875	36.75	39.825	31.875	51.75
n_4	30.000	25.500	36.75	36.000	25.500	51.75
n_5	30.000	25.500	36.75	36.000	25.500	51.75
n_6	30.000	25.500	36.75	36.000	25.500	51.75
n_7	30.000	25.500	36.75	36.000	25.500	51.75
n_8	30.000	25.500	36.75	36.000	25.500	51.75
n_9	30.000	25.500	36.75	36.000	25.500	51.75
n_{10}	30.000	25.500	36.75	36.000	25.500	51.75
n_{11}	30.000	25.500	36.75	36.000	25.500	51.75
n_{12}	30.000	25.500	36.75	36.000	25.500	51.75
n_{13}	30.000	25.500	36.75	36.000	25.500	51.75
n_{14}	30.000	25.500	36.75	36.000	25.500	51.75
n_{15}	30.000	25.500	36.75	36.000	25.500	51.75
n_{16}	30.000	25.500	36.75	36.000	25.500	51.75
n_{17}	30.000	25.500	36.75	36.000	25.500	51.75
n_{18}	30.000	25.500	36.75	36.000	25.500	51.75
n_{19}	30.000	25.500	36.75	36.000	25.500	51.75
n_{20}	30.000	25.500	36.75	36.000	25.500	51.75
n_{21}	30.000	25.500	36.75	36.000	25.500	51.75
n_{22}	30.000	25.500	36.75	36.000	25.500	51.75
n_{23}	30.000	25.500	36.75	36.000	25.500	51.75
n_{24}	30.000	25.500	36.75	36.000	25.500	51.75
n_{25}	30.000	25.500	36.75	36.000	25.500	51.75
n_{26}	30.000	25.500	36.75	36.000	25.500	51.75
n_{27}	30.000	25.500	36.75	36.000	25.500	51.75
n_{28}	30.000	25.500	36.75	36.000	25.500	51.75
n_{29}	30.000	25.500	36.75	36.000	25.500	51.75

Table 60: DA and expected RT prices for the competitive and strategic summer cases, at 30% penetration in the flexible configuration. Figures in £ per MWh.

Turning to the strategic equilibrium, negative regulation bids are shaped at the cost of unconstrained coal for down-regulation at £25.5 per MWh, while the abovementioned upward-inadequacy and the coupling between the DA and RT stage prompts the leader to choose bids for energy and up-regulation at £36 and £51.75 per MWh, considering the opportunity cost of standing up CHP plant and reducing coal output in the high scenario.[27] Observably, the alleviating price-effect of a more competitive RT market feeds through into the low wind scenario to a lesser extent under strategic offering, and expected balance prices are by £7.63 per MWh lower. Despite forming a cheaper DA market by £0.11 per

[27] Formally, $\frac{£}{MWh}(36 - 0.6 \cdot 25.5) = \frac{£}{MWh}20.7$, hence the expected balance price of £51.75 per MWh in the low scenario.

MWh in the competitive case, the average DA price is thus higher under the influence of market power in the flexible system, clearing at £35.472 per MWh.

Type	Competitive			Strategic		
	DA	RT		DA	RT	
		Positive	Negative		Positive	Negative
$Nuclear_1$	8.00			36.0		
$Nuclear_2$	8.00			- 300.0		
$Nuclear_3$	8.00			- 300.0		
$Nuclear_4$	8.00			- 300.0		
$Nuclear_5$	8.00			- 300.0		
$Nuclear_6$	8.00			- 300.0		
$Nuclear_7$	8.00			36.0		
$Coal_1$	30.00	45.00	22.50	36.0	51.75	25.50
$Coal_2$	30.00	45.00	22.50	36.0	51.75	25.50

Table 61: EDF bids by price-making plant and stage for the competitive and strategic summer cases, at 30% penetration in the flexible configuration. Bids in £ per MWh.

As a result, EDF withholds 4.9% of her competitive output, while the strategic price formation supports the leader's output distribution between the DA and RT horizon; this is marked by the incentive to offset the exposure to the balancing market, which is less favourable compared to the less flexible system. By comparison, EDF sets a lower profit-maximising output by 284 MWh in exchange for the additional DA premium of £0.25 per MWh at the nodes accommodating her capacity. Compared to the competitive equilibrium, profits are increased on account of her nuclear, which retract by 555 MWh to 93.1% loading and bring 97% of profits; on the other hand, coal plant expand by 156 MWh to a 9.6% load factor, while procuring less (more) negative (positive) regulation compared to the strategic equilibrium of the less flexible system. Despite the profit increase attributed to the adoption of price-making behaviour by 22%, the higher DA price by £0.14 per MWh is not sufficient to allow for higher strategic profits, compared to the less flexible system.

Type	Competitive	Strategic	Change		Load factor (%)	
			Absolute	Relative (%)	Competitive	Strategic
Nuclear	8,026.2	7,471.1	- 555.1	- 6.9	100.0	93.1
Coal	191.3	347.5	156.1	81.6	5.3	9.6
EDF	8,217.5	7,818.6	- 398.9	- 4.9		

Table 62: EDF fuel mix of generation for the competitive and strategic summer cases, at 30% penetration in the flexible configuration. Outputs in MWh. Load factor utilises the sum of generation in both DA and RT stages. Relative change with reference to competitive output.

Type	Max rating	Re-dispatch capability		Competitive			Strategic		
		Positive	Negative	DA	RT		DA	RT	
					High	Low		High	Low
$Nuclear_1$	868.5			868.5			313.4		
$Nuclear_2$	1,066.5			1,066.5			1,066.5		
$Nuclear_3$	2,146.5			2,146.5			2,146.5		
$Nuclear_4$	1,078.2			1,078.2			1,078.2		
$Nuclear_5$	945.0			945.0			945.0		
$Nuclear_6$	859.5			859.5			859.5		
$Nuclear_7$	1,062.0			1,062.0			1,062.0		
$Coal_1$	1,810.8	724.3	724.3	478.3	- 478.3		588.0	- 588.0	280.7
$Coal_2$	1,807.2	722.9	722.9						
$CCGT_1$	737.1	294.8	294.8						
$CCGT_2$	1,198.8	479.5	479.5						
OCGT	36.0	36.0							
EDF	13,616.1	1,340.4	1,304.4	8,504.5	- 478.3		8,059.1	- 588.0	280.7

Table 63: EDF maximum rating, re-dispatch capability and output levels by plant and stage, for the competitive and strategic summer cases, at 30% penetration in the flexible configuration. Maximum rating refers to a 10% derating of installed capacity. Capability figures in MW, output figures in MWh.

Type	Competitive		Strategic		Absolute change		Relative change (%)
	DA	RT	DA	RT	DA	RT	
EDF	8,504.5	- 287.0	8,059.1	- 240.5	- 445.4	46.4	- 4.9
Fringe	5,549.4	- 1,282.4	5,714.1	- 1,048.2	164.7	234.2	9.3
Wind	3,541.4	1,569.3	3,822.1	1,288.6	280.7	- 280.7	
Industry	17,595.3		17,595.3				

Table 64: Industry-wide output levels by fuel type and stage, for the competitive and strategic summer cases, at 30% penetration in the flexible configuration. Outputs in MWh.

Type	Competitive		Strategic		Absolute change		Relative change (%)
	DA	RT	DA	RT	DA	RT	
EDF	176,576	1,291	212,720	4,029	36,143	2,738	22
Fringe		5,771	33,955	4,717	33,955	- 1,054	570
Wind	95,847	40,018	137,594	19,519	41,748	- 20,498	16
Industry	272,423	47,080	384,269	28,266	111,846	- 18,814	29

Table 65: Expected industry-wide profits by stage, for the competitive and strategic summer cases, at 30% penetration in the flexible configuration. Figures in £.

In conclusion, growing amounts of wind generation can help the leader enjoy higher prices in more flexible systems, however, determine a considerably smaller profit-maximising output by 3.5% at 30% penetration as a share of summer demand. In contrast to winter MPECs, the access to larger monopoly profits is readily inhibited with rising flexibility levels; the leader's profit-maximising objective drives further reductions of low-cost (nuclear) output and the induced price distortion cannot compensate for the heightened competition in the balancing market. This is not to say the strategy is suboptimal; on the contrary, assuming a nuclear output at the level of 99% loading as in the less flexible system, the price-lifting at the marginal cost of CHP would be unattainable. This would necessitate a disproportionate output increase from her coal stations and result in substantially lower monopoly profits. Following the foregone nuclear profits from the exercise of market power, strategic gains are by 3.7% lower than those accrued in the less flexible setting.[28]

Similarly, fringe competitors are worse off by the exercise of market power in the more flexible system by 15.6%, despite the higher output by 6.5%; the large difference is attributed to the inherent inadequacy of the less flexible configuration at 30% penetration. On the other hand, wind plant are scheduled with lower output in DA following the flexible system's unconstrained negative capability and thus do not enjoy the full benefits of a more expensive energy market. Nonetheless, the flexible system helps to form a more rewarding balancing environment for the wind industry and profits are higher across all penetration levels.[29] The asymmetric benefits from the exercise of economic withholding are also testified by the higher (lower) payments made to wind (thermal) producers compared to the less flexible case by 4.9% (1.1%), as shown in Table 108 in Appendix E. In fact, amongst all MPECs examined, those with 30% penetration presented the steepest profit (loss) increase for the renewable (thermal) stack between the two systems.[30]

5.4. Computational Issues

For starters, the determination of the optimal offering for the incumbent firm was founded on the premise of linear cost expression for the problem facing the SO. To contextualise, the leader firm seeks to exploit her profit-maximising strategy in the upper-level problem, subject to the market equilibrium attained in the lower-level problem of the MPEC. This is a special instance of hierarchical optimisation, i.e. a bi-level structure, which features an optimisation problem that is constrained by another optimisation problem (Colson et al., 2007). MPECs are acclaimed for their flexibility, in that the stationary points of the lower-level problem may be formulated as KKT conditions and are thus seemingly tractable by nonlinear programming techniques (Ralph, 2008).

[28] Strategic profits are invariably lower in the flexible system, however, increasingly up to 30% penetration. At 40%, the exercise of market power does not change prices and profit differences are due to RT activity.
[29] Wind (fringe) profits are increasingly higher (lower) up to 30% penetration; at 40%, the gains to participants not exercising market power are diminished in both systems and wind (fringe) producers extract competitive (zero) profits.
[30] Much like the winter MPECs with 5% and 10% penetration, fringe firms operate in DA alone in the summer models with 10% and 40% penetration; they are thus not exposed to the RT market and their profits are unaltered between the two systems.

However, for KKT necessary optimality conditions to be relevant, the differentiability and regularity of binding constraints must be satisfied (Bertsekas, 1999). Even then, however, their sufficiency cannot be guaranteed, considering the feasible region of an MPEC corresponds to a generally non-convex set (Diwekar, 2008; Gabriel et al., 2013). This is due to the orthogonality constraints $(4.3.5g)$ that describe the disjunctive behaviour of the inequality constraints z and their Lagrangian multipliers v, requiring that their inner product is zero. On the other hand, nonlinear programming techniques rely on the desirable property of convexity to tackle optimisation problems, for which they can secure global optimality, assuming the problem is not infeasible. That is, NLP solvers largely focus on meeting first-order conditions and finding stationary points (Ralph, 2008) and so the very existence of meaningful multipliers cannot be guaranteed, considering that constraint qualifications do not generally hold for MPECs, while whether an optimal solution is global or local cannot be justified within efficient computational times (Ralph, 2008), as they run the risk of getting trapped around the area of the local optimum (Williams, 2013).

Observably, dealing with the modelling challenge of MPECs is far from trivial. A common, albeit computationally demanding approach for affording a global optimum in generally non-convex problems is by means of integer programming (Williams, 2013). In the context of our MPEC, the first step towards sidestepping non-convexity was made by adopting a linear cost function in the lower-level problem. The subsequent formulation of the orthogonality KKT conditions of the lower-level problem notwithstanding, the emerging non-convexity was eliminated by means of disjunctive constraints through the Fortuny-Amat et al. (1981) linearization.

The drawbacks associated with the employment of integer programming to resolve nonlinearity, come exactly from the utilisation of the disjunctive constraints. First, due to the combinatorial nature of integer programmes, the number of integer variables substantially influences their computational tractability and so, the introduction of too many complementarity constraints in the MPEC and in turn, too many 0-1 binary variables δ in the MIP, can render the problem computationally intractable (Hillier & Lieberman, 2001).[31] The detailed transmission representation, in particular, consists a formidable modelling challenge (Day et al., 2002); in our model, this required the inclusion of two binary variables per line at the DA stage, and two for each line and scenario at the RT stage.[32] Nonetheless, the sophisticated representation of the grid is paramount to explore the incentives facing conventional generators to entrench their position in the market.

[31] In contrast, the number of (effective) constraints is more important for tackling linear programmes.
[32] The number of decision and dual variables increases linearly with the number of scenarios, however, their impact on computational efficiency is far less important in integer programming (Hillier & Lieberman, 2001).

Exploring the interaction between generating patterns and network phenomena is even more important, considering the scope of our investigation, which lies at the intersection of wind power integration and the exercise of market power.

Adding to the complexities, the computational efficiency of the integer formulation is highly sensitive to the selection of M-constants for the disjunctive constraints (Gabriel et al., 2013). In the absence of a standardised formula to obtain M, choosing appropriate values relies on the modeller's aptitude, i.e. it is model specific. Too big a value and the model may run in 'trickle flow', as the perverse interrelation between larger and smaller parameters will cause CPLEX to run into numerical issues. Too small constants and the algorithm may cut out optimal solutions. Evidently, the order of magnitude between different variables is important and so the modeller should steer clear from approaches that give rise to improperly scaled models (Rosenthal, 2016). The ad-hoc determination of M constants also suggests that computational times may vary significantly between models and indicates the potential multiplicity of equilibria (Gabriel et al., 2013), whose study exceeds the scope of this thesis.

The aim is to come up with values of M that are small, but not so small that they restrain the feasible region. Fortuitously, the problem itself may provide useful information with respect to the selection of appropriate bounds for the primal variables in $(4.3.6a)$. These relate to physical quantities such as power generation and re-dispatch limits, whose upper bound may be derived from the dataset (Gabriel & Leuthold, 2010). Selecting upper bounds for the dual variables $(4.3.6b)$ can be more complex, however, bearing in mind that those correspond to the shadow values of the resource constraints can be helpful; see the works of Gabriel and Leuthold (2010) and Ruiz and Conejo (2009) for a discussion on the issue.

Another source of nonlinearity stems from terms involving products between unknown variables, i.e. bilinear $price \cdot output$ terms, which are embedded in the MPEC's objective function $(4.3.6c)$. To derive a linear objective function, we started by performing exact algebraic transformations of some KKT conditions and made use of the complementarity conditions $(4.3.5j)$, $(4.3.5l)$ and $(4.3.5n)$, however, nonlinearity persisted in the leader's revenue expression $(4.3.6bc)$ by means of bilinear $offer \cdot output$ terms. Following the use of the Strong Duality Theorem (Luenberger & Ye, 1984), we were able to substitute those and derive a linear formulation for the leader's income in $(4.3.6bg)$ and by extension, a linear objective function for the original MPEC. There is no general method to guarantee that the linearization will be successful, however, enjoying the benefits of working with linear problems justifies the effort (Gabriel et al., 2013).

In effect, the nonlinear bi-level optimisation problem was transformed into a linear MIP which is much easier to solve, compared to the MPEC. This is largely attributed to the 1980's algorithmic breakthrough in the fields of MIP and its linear programming modelling platform, as well as recent advances in computing technology, which have driven a paradigm shift in the modelling of integer programmes (Bixby et al., 2000). The advent of cutting plane routines in particular, which combine traditional branch-and-bound[33] linear programming techniques with cutting plane capabilities[34] have made them indispensable for addressing this class of problem. By cutting (i.e. reducing) the feasible set of the LP relaxation, the cutting plane algorithm identifies the formulation which yields the best polyhedron in the real coordinate space that omits no solutions for the integer programme, while the extreme points of the resulting convex hull are candidates for the LP and hence the IP optimum (Wolsey, 1998).

As a result, the MIP formulation - and its application in real power systems - has been gaining currency (Carrion & Arroyo, 2006; Streiffert et al., 2005) and so MPECs have been made tractable by commercial solvers, such as GAMS-CPLEX (Rosenthal, 2016). In contrast to NLP, MIP solvers provide primal and dual bounds, which stand for the value of the actual solution and a threshold that assures that no better solution exists. These correspond to the best feasible (i.e. the one discovered so far) and best possible integer solution of the problem which, with time are improved and converge when the model has been solved to global optimality (Rosenthal, 2016). As far as near-optimum solutions are concerned, unlike NLP, MIP solvers can guarantee an error on the estimate of the objective function, as discussed in the next (Gabriel et al., 2013).

The 1,704 discrete variables for the winter (RWE leader) and 1,634 for the summer (EDF leader) MPECs notwithstanding, all models were solved with option OptCR set to zero, i.e. CPLEX was instructed to stop only after the relative optimality gap for the integer solution was zero, i.e. when the primal and dual bounds converged. Formally, OptCR asks CPLEX to stop after the relative optimality criterion of the MIP problem - given by the formula $(|BP - BF|)/(1.0e - 10 + |BF|) < OptCR$, where BP and BF stand for the best possible integer solution and the objective function value of the best integer solution

[33] Integer linear programmes rely on relaxing part of the integer stipulation and applying the simplex (or dual simplex) method to attain optimal solutions. The most common algorithm for attacking discrete optimisation problems is the linear programming branch-and-bound, which applies an implicit enumeration of all integer solutions. The method eliminates parts of the feasible region that either contain solutions which are non-integer or yield an objective function value which is worse than the incumbent (Hillier & Lieberman, 2001).

[34] Those rely on generating valid inequalities to the LP relaxation of the integer programme, until the resulting optimal solution is integer. They thus do not subdivide the feasible region like branch-and-bound techniques, but focus on sequentially improving a single LP instead (Bradley et al., 1977).

discovered so far - is smaller than the assigned value (Rosenthal, 2016). Finally, all models were solved on an Intel Core i5-3337U 1.8 GHz with 6 GB of RAM.

Penetration (% demand)	Execution time			Number of variables		
	Competitive	Strategic		Competitive	Strategic	
		Less flexible	Flexible		Discrete	Continuous
5 (winter)	0.031	459.516	938.094	793	1,704	4,162
10 (winter)	0.031	2,231.438	1,451.187	793	1,704	4,162
15 (winter)	0.031	403.234	51.453	793	1,704	4,162
10 (summer)	0.015	7,825.204	1,234.578	758	1,634	1,634
20 (summer)	0.015	173.125	44.953	758	1,634	1,634
30 (summer)	0.015	98.563	219.485	758	1,634	1,634
40 (summer)	0.015	50.391	53.047	758	1,634	1,634

Table 66: Execution times and number of variables for the competitive and strategic cases in both flexibility configurations, for various demand and penetration levels. Times in seconds.

Observably, computational times for the competitive models were insignificant, considering the LP formulation (i.e. no discrete variables) of the problem. On the other hand, despite the size of the MPECs, CPLEX managed to find solutions within a minute and reported execution times were very reasonable for the majority of the MPECs, standing below 16 minutes. This is attributed to the appropriateness of the selection of M constants, which helped formulate computationally efficient models.

However, one computational issue relates to the time required to converge to the global optimal in some models, where although solutions were found within a minute, completion times reached up to 37 minutes; a similar symptom has also been reported by Gabriel and Leuthold (2010). With respect to the selection of M constants, repeated simulations helped to weigh the impact on profits and outputs. We inferred that larger M constants have no bearing on the results but may need considerably larger horizons to find an optimal solution; on the other hand, smaller M values can limit the space of feasible solutions and the optimal values were observed to change, however not dramatically.

In closing, the nature of the multi-stage Stackelberg game entails much larger mathematical and coding rigor, as the number of variables and constraints grow substantially compared to optimisation models (Gabriel et al., 2013). That is due to the bi-level character of MPECs, which requires the inclusion of dual variables and expressions containing the derivative for each decision variable of the lower-level problem (Gabriel et al., 2013). Effectively, the leader solves a single optimisation problem, which incorporates the reactions of her followers to her decisions through the statement of the KKT conditions, hence the larger size of the MPEC. It is thus by modelling the equilibrium constraints as a complementarity system, that the vast computational hurdle is introduced (Luo et al., 1996;

Ralph, 2008); this requires that the linear independence constraint qualification is met (Diwekar, 2008) in order to secure the very existence of finitely many Lagrange multipliers (Bertsekas, 1999). Unfortunately, unless the complementarity impediments can be avoided by solving an optimisation (as opposed to a complementarity) problem, the convenient property of regularity for the binding constraints cannot be guaranteed, while the desire for global optimality may require a trade-off between computational accuracy and time (Gabriel et al., 2013).

6. Conclusion

The rapid introduction of renewable generation has come with a paradigm shift in power system operations, where thermal generators are insistently underutilised in the energy market, while on the other hand, their role for offsetting variability in real-time operations gains currency. This leaves conventional generators exposed to revenue erosion risk, due to the combination of lower prices and reduced sales in the DA market, while a reform that explicitly rewards them for their increasingly frequent intermittent operation is yet to be implemented.

In response to the SOs' mandate to absorb wind with priority, large conventional generators are likely to adopt a price-making behaviour in order to offset their loss of income in the DA market. Within this context, we considered the strategic behaviour of a dominant firm in nodal markets that accommodate significant amounts of wind power and auction energy and balancing markets jointly in order to minimise expected costs, thus following the state-of-the-art in renewable integration (Morales et al., 2012; Pritchard et al., 2010).

The decision-making problem facing the strategic producer was modelled by means of complementarity, using a Mathematical Programme with Equilibrium Constraints. The objective to maximise expected profits in the face of uncertain residual demand and prices builds on the Stackelberg hypothesis, where the leader firm precisely anticipates the reactions of her price-taking followers in a sequential game of price competition. The proposed stochastic bi-level optimisation model seeks to derive the optimal offering strategy for the leader in the upper-level problem, subject to the cost minimisation pursued by the SO in the lower-level problem, which determines the production level of each plant and prices. The resulting nonlinear MPEC was recast as a single linear MIP through the use of disjunctive constraints and solved to global optimality for various wind penetration and demand levels, using GAMS CPLEX 12.6.

To assess the implications of strategic bidding on locational marginal prices and profits of market-wide participants, we employed a DC linear approximation in a transmission-constrained, 29-node test network of GB. Results suggest that incumbent firms have compelling incentives to behave strategically and exploit economic-withholding and transmission-related strategies - while the impact on industry-wide participants is found to be invariably positive - still under substantial amounts of stochastic generation. Nonetheless, the ability to lift prices is weakened and monopoly profits decrease with growing levels of wind power, i.e. the residual load facing thermal plant is diminished and the incumbent's bidding is restrained by the opportunity cost of fringe unconstrained capacity. Additionally, the firm's strategy typifies her ability to exploit the arbitrage opportunities embedded between the DA and RT market and determine the amount of balancing needs at either direction, i.e. the leader may opt for her profit-maximising output by producing less in DA or more and compensate any deviations in RT, which in low-wind periods can result in a dominant provider of balancing capability.

The degree of economic withholding and subsequent price distortion also differs markedly between the two demand levels. In contrast to high-demand periods, where the leader's ability to profitably raise prices above competitive levels is substantial, the reliance on quantities is shown to be considerably higher in low-demand periods. Critically, during summer periods of low net demand, the system is rendered downward-inadequate and the formation of a less penalising balancing market helps fringe firms extract larger gains with rising levels of penetration.

A second strand of this work conducted a preliminary investigation of the impact of flexibility on generators' profits. Despite the higher competition for balancing services, the incentive to exercise market power can be greater in more flexible systems during high-demand periods, while low-demand periods exhibit the opposite trend. In winter, the lower balancing premium asked by competitive firms has no bearing on the offering strategy at low wind penetrations; however, the leader wins more by taking advantage of the additional capability at her lower-cost plant. At higher penetrations, the emerging RT competition produces a balancing market, which is less favourable to thermal producers, thus limiting the leader's monopoly power. Despite her lower profit-maximising output, the higher induced pool price distortion is not offsetting to the damaging RT profit gradient and the leader firm starts to benefit less following the switch to a more flexible setting, whereas wind (fringe) plant increase profits by curtailing less (by retracting).

On the other hand, the impact of a less favourable RT market is readily pronounced during low-demand periods, while at higher penetrations the strategist is compelled to further reductions of nuclear generation to maximise expected profits. However, the combination of the larger induced price distortion and foregone nuclear profits following the exercise of market power, does not compensate for the impact of a less convenient RT market and the leader stands to profit less compared to the flexible configuration, while wind (fringe) producers are increasingly better (worse) off.

6.1. Scope for Further Research

Market power is inherently difficult to substantiate, while large additions of stochastic generation render such efforts even more complex. The modelling extensions for the problem at hand are thus likely to be numerous, however, the most prominent are summarised below, as an appeal for future research.

For starters, one modelling limitation refers to the adoption of a parsimonious scenario set, as well as the premise of proportionate wind output increase at all nodes for growing penetration levels, which helped to promote a critical review of our test results, in evaluation of our methodology. Therefore, a finer representation of the wind power uncertainty through the use of a larger number of scenarios and corresponding reduction techniques is vital, as it would provide for a more realistic description of the prevailing system conditions; those are critical for determining the leader's output and so this is likely to mitigate her ability to game the DA and balancing markets, considering the impact of constraints is more pronounced in the northern part of the GB system in this study.

Towards this direction, the implementation of ramping limits and other inter-temporal constraints would help to extend the scope of our method to multi-period auctions. For this to work well, however, the modelling of nonzero minimum power output levels is considered necessary - especially within the context of high-wind, low-demand conditions - albeit challenging for the formulation and tractability of the subsequent MPEC, due to the introduction of additional non-convexity associated with the modelling of on-off decisions. The inclusion of the abovementioned spectrum of modelling elements is likely to result in equilibria which are different to those derived from our static Stackelberg model and so this stands for a second area of improvements.

Of special interest within the context of renewable integration, our future research shall focus on the incorporation of storage in the MPEC, in order to facilitate a preliminary understanding of the strategic role of storage providers in the GB system and Europe. Their critical role as hedging devices against wind imbalances has been extensively analysed in section 2.3.2, however, our intention would be to enrich this work with insights pertaining to the market performance under the presence of price-making storage facilities. This would help to investigate the relative merits of decentralised storage in addressing the costs associated with the uncertainty of renewable output; this will also mandate the quantification of carbon and other emissions in order to account for the environmental impact of storage and weigh the likely benefits against conventional forms of generation. Simultaneously, we aim at looking into the arbitrage space for the decentralised model, as growing amounts of storage are added in the capacity mix.

By extension, we wish to touch on the wider issue of flexibility and investigate the wind power threshold where the expected gains to the strategist are saturated for different degrees of system flexibility, an issue which was only implied in this work. The end objective would be to assess the role of balancing capability as a market power mitigation device. For instance, modelling the relationship between the critical technical parameters and associated costs for re-dispatch - which were assumed to differ only amongst different fuel-type plant - could help to define the amount of ramping requirements that secures adequate margin for the mitigation of market power for various levels of penetration and minimises the balancing costs for those firms behaving in a competitive fashion.

References

Argus (2016) *Argus Biomass Markets.* Report Number: Issue 16-014. [Online] Available from: http://www.argusmedia.com/~/media/files/pdfs/samples/argus-biomass.pdf/?la=en [Accessed 13th May 2016].

Baker, P. E., Mitchell, C. & Woodman, B. (2010) *Electricity Market Design for a Low-carbon Future.* The UK Energy Research Centre. Report Number: UKERC/WP/ESM/2005/004. [Online] Available from: www.ukerc.ac.uk/asset/E73E19C1-8DF3-4463-8F80867F8938150C/ [Accessed 2nd October 2015].

Bakirtzis, A. G., Ziogos, N. P., Tellidou, A. C. & Bakirtzis, G. A. (2007) Electricity producer offering strategies in day-ahead energy market with step-wise offers. *IEEE Transactions on Power Systems,* 22 (4), 1804-1818.

Baldick, R. (2012) Wind and energy markets: a case study of Texas. *Systems Journal, IEEE,* 6 (1), 27-34.

Barroso, L. A. & Conejo, A. J. (2006) Decision making under uncertainty in electricity markets. *IEEE Power Engineering Society General Meeting, 2006, Montreal, QC, Canada*, p. 3.

Bautista, G., Quintana, V. H. & Aguado, J. A. (2006) An oligopolistic model of an integrated market for energy and spinning reserve. *IEEE Transactions on Power Systems,* 21 (1), 132-142.

Bertrand, J. (1883) Review of Walras's 'Théorie mathématique de la richesse sociale' and Cournot's 'Recherches sur les principes mathematiques de la theorie des richesses'. *Journal de Savants,* 67 499-508.

Bertsekas, D. P. (1999) *Nonlinear programming.* 2nd ed. Belmont, Massachusetts, Athena scientific.

Besanko, D. & Braeutigam, R. R. (2011) *Microeconomics.* 4th ed. Hoboken, NJ, John Wiley & Sons.

Birge, J. R. & Louveaux, F. (2011) *Introduction to stochastic programming.* Springer Series in Operations Research and Financial Engineering. New York, NY, Springer.

Bixby, E. R., Fenelon, M., Gu, Z., Rothberg, E. & Wunderling, R. (2000) MIP: Theory and Practice — Closing the Gap. In: Powell, M. J. D. & Scholtes, S. (eds.) *System Modelling and Optimization: Methods, Theory and Applications. 19th IFIP TC7 Conference on System Modelling and Optimization July 12–16, 1999, Cambridge, UK.* Boston, MA: Springer US, pp. 19-49.

Black, M. & Strbac, G. (2006) Value of storage in providing balancing services for electricity generation systems with high wind penetration. *Journal of Power Sources,* 162 (2), 949-953.

Black, M. & Strbac, G. (2007) Value of Bulk Energy Storage for Managing Wind Power Fluctuations. *Energy Conversion, IEEE Transactions on,* 22 (1), 197-205.

Borenstein, S. (2002) The trouble with electricity markets: understanding California's restructuring disaster. *The Journal of Economic Perspectives,* 16 (1), 191-211.

Borenstein, S., Bushnell, J. & Stoft, S. (2000) The Competitive Effects of Transmission Capacity in a Deregulated Electricity Industry. *The RAND Journal of Economics,* 31 (2), 294-325.

Borggrefe, F. & Neuhoff, K. (2011) *Balancing and intraday market design: Options for wind integration.* Climate Policy Initiative / DIW Berlin. [Online] Available from: www.diw.de/documents/publikationen/73/diw_01.c.387225.de/dp1162.pdf [Accessed 21st September 2015].

Bradley, S., Hax, A. & Magnanti, T. (1977) *Applied mathematical programming.* Reading, MA, Addison-Wesley Publishing Company.

Brandstätt, C., Brunekreeft, G. & Jahnke, K. (2011) How to deal with negative power price spikes?—Flexible voluntary curtailment agreements for large-scale integration of wind. *Energy Policy,* 39 (6), 3732-3740.

Bunn, D. W. & Oliveira, F. S. (2003) Evaluating individual market power in electricity markets via agent-based simulation. *Annals of Operations Research,* 121 (1-4), 57-77.

Burke, D. J. & O'Malley, M. J. (2011) Factors Influencing Wind Energy Curtailment. *Sustainable Energy, IEEE Transactions on,* 2 (2), 185-193.

Cardell, J. B., Hitt, C. C. & Hogan, W. W. (1997) Market power and strategic interaction in electricity networks. *Resource and energy economics,* 19 (1), 109-137.

Carrion, M. & Arroyo, J. M. (2006) A computationally efficient mixed-integer linear formulation for the thermal unit commitment problem. *Power Systems, IEEE Transactions on,* 21 (3), 1371-1378.

Castronuovo, E. D. & Peas Lopes, J. A. (2004) On the optimization of the daily operation of a wind-hydro power plant. *Power Systems, IEEE Transactions on,* 19 (3), 1599-1606.

CCC (2011) *Technical Paper 4: Biomass in Power Generation.* Committee on Climate Change. [Online] Available from: https://www.theccc.org.uk/archive/aws2/Bioenergy/1463%20CCC_Bio-TP4_power_FINALwithBkMks.pdf [Accessed 13th May 2016].

CCC (2012) *The 2050 target - achieving an 80% reduction including emissions from international aviation and shipping.* [Online] Available from: https://www.theccc.org.uk/archive/aws/IA&S/CCC_IAS_Tech-Rep_2050Target_April2012.pdf [Accessed 2nd January 2016].

Colson, B., Marcotte, P. & Savard, G. (2007) An overview of bilevel optimization. *Annals of Operations Research,* 153 (1), 235-256.

Cournot, A. A. (1838) *Researches Into the Mathematical Principles of the Theory of Wealth.* [English translation (1927) by Nathaniel T. Bacon] New York, NY, Macmillan.

Day, C. J., Hobbs, B. F. & Jong-Shi, P. (2002) Oligopolistic competition in power networks: a conjectured supply function approach. *IEEE Transactions on Power Systems,* 17 (3), 597-607.

DECC (2013) *Electricity Generation Costs 2013.* [Online] Available from: https://www.gov.uk/government/publications/electricity-generation-costs-december-2013 [Accessed 18th October 2015].

Denholm, P. & Sioshansi, R. (2009) The value of compressed air energy storage with wind in transmission-constrained electric power systems. *Energy Policy,* 37 (8), 3149-3158.

Denny, E. & O'Malley, M. (2006) Wind generation, power system operation, and emissions reduction. *Power Systems, IEEE Transactions on,* 21 (1), 341-347.

Denny, E., Tuohy, A., Meibom, P., Keane, A., Flynn, D., Mullane, A. & O'Malley, M. (2010) The impact of increased interconnection on electricity systems with large penetrations of wind generation: A case study of Ireland and Great Britain. *Energy Policy,* 38 (11), 6946-6954.

Directive, E. C. (2001) 80/EC of the European Parliament and of the Council of 23 October 2001 on the limitation of emissions of certain pollutants into the air from large combustion plants. *Official Journal of the European Union,* L 309, 1–21.

Directive, E. C. (2009) 28/EC of the European Parliament and of the Council of 23 April 2009 on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77/EC and 2003/30/EC. *Official Journal of the European Union,* L 140, 16–62.

Diwekar, U. (2008) *Introduction to applied optimization.* Springer Optimization and Its Applications 7393. 2nd ed. New York, NY, Springer Science & Business Media.

Doherty, R., Denny, E. & O'Malley, M. (2004) System operation with a significant wind power penetration. *IEEE Power Engineering Society General Meeting*, 6-10 June 2004, pp. 1002-1007 Vol.1.

Druce, R., Carmel, A., Borkowski, K., Strbac, G. & Aunedi, M. (2015) *System Integration Costs for Alternative Low Carbon Generation Technologies – Policy Implications.* [Online] Available from: https://www.theccc.org.uk/wp-content/uploads/2015/10/NERA-Final-Report-21-Oct-2015.pdf [Accessed 19th December 2015].

DUKES (2015) *Digest of United Kingdom Energy Statistics 2015.* [Online] Available from: https://www.gov.uk/government/statistics/digest-of-united-kingdom-energy-statistics-dukes-2015-printed-version [Accessed 22nd May 2016].

Dupačová, J., Gröwe-Kuska, N. & Römisch, W. (2003) Scenario reduction in stochastic programming. *Mathematical programming,* 95 (3), 493-511.

E4Tech (2010) *Biomass Prices in the Heat and Electricity Sectors in the UK.* Report Number: URN 10D/546. [Online] Available from: http://www.e4tech.com/wp-content/uploads/2016/01/100201Biomass_prices.pdf [Accessed 8th June 2016].

Ela, E., Milligan, M. & Kirby, B. (2011) *Operating Reserves and Variable Generation.* National Renewable Energy Laboratory. Report Number: Report Number: NREL/TP-

5500-51978. [Online] Available from: http://www.nrel.gov/docs/fy11osti/51978.pdf [Accessed 3rd August 2015].

ELEXON (2015) *The Electricity Trading Arrangements: A Beginner's Guide.* [Online] Available from: www.elexon.co.uk/wp-content/uploads/2015/10/beginners_guide_to_trading_arrangements_v5.0.pdf [Accessed 12th December 2016].

Eurelectric (2010) *Integrating Intermittent Renewable Sources Into The EU Electricity System by 2020: Challenges And Solutions.* [Online] Available from: http://www.eurelectric.org/media/45254/res_integration_paper_final-2010-030-0492-01-e.pdf

Eurelectric (2011) *Flexible Generation: Backing Up Renewables.* [Online] Available from: http://www.eurelectric.org/media/61388/flexibility_report_final-2011-102-0003-01-e.pdf [Accessed 28th June 2015].

Evans, S. (2016) *Countdown to 2025: Tracking the UK coal phase out* [Online]. Available: http://www.carbonbrief.org/countdown-to-2025-tracking-the-uk-coal-phase-out [Accessed 2nd May 2016].

EWEA (2010) *Wind Energy and Electricity Prices: Exploring the 'merit order effect'.* European Wind Energy Association. [Online] Available from: http://www.ewea.org/fileadmin/files/library/publications/reports/MeritOrder.pdf [Accessed 8th January 2015].

Fink, S., Mudd, C., Porter, K. & Morgenstern, B. (2009) *Wind Energy Curtailment: Case Studies.* Exeter Associates. Report Number: Report Number: NREL/SR-550-46716. [Online] Available from: http://www.nrel.gov/docs/fy10osti/46716.pdf [Accessed 19th August 2015].

Floudas, C. A. (1995) *Nonlinear and mixed-integer optimization: fundamentals and applications.* Series: Topics in Chemical Engineering. New York, NY, Oxford University Press.

Fortuny-Amat, J., xe & McCarl, B. (1981) A Representation and Economic Interpretation of a Two-Level Programming Problem. *The Journal of the Operational Research Society,* 32 (9), 783-792.

Gabriel, S. A., Conejo, A. J., Fuller, J. D., Hobbs, B. F. & Ruiz, C. (2013) *Complementarity modeling in energy markets.* International Series in Operaions Research & Management Science 6161. New York, Springer.

Gabriel, S. A. & Fuller, J. (2010) A Benders decomposition method for solving stochastic complementarity problems with an application in energy. *Computational economics,* 35 (4), 301-329.

Gabriel, S. A. & Leuthold, F. U. (2010) Solving discretely-constrained MPEC problems with applications in electric power markets. *Energy Economics,* 32 (1), 3-14.

Garcia-Gonzalez, J., de la Muela, R. M. R., Santos, L. M. & Gonzalez, A. M. (2008) Stochastic Joint Optimization of Wind Generation and Pumped-Storage Units in an Electricity Market. *Power Systems, IEEE Transactions on,* 23 (2), 460-468.

Green, R. (1997) Electricity transmission pricing: an international comparison. *Utilities Policy,* 6 (3), 177-184.

Green, R. (2007) Nodal pricing of electricity: how much does it cost to get it wrong? *Journal of Regulatory Economics,* 31 (2), 125-149.

Green, R. (2010) Are the British electricity trading and transmission arrangements future-proof? *Utilities Policy,* 18 (4), 186-194.

Green, R. & Vasilakos, N. (2010) Market behaviour with large amounts of intermittent generation. *Energy Policy,* 38 (7), 3211-3220.

Green, R. J. (2008) Electricity wholesale markets: designs now and in a low-carbon future. *The Energy Journal,* 29 (Special Issue), 95-124.

Green, R. J. & Léautier, T. O. (2015) Do costs fall faster than revenues? Dynamics of renewables entry into electricity markets. *Toulouse School of Economics Working Paper,* No. TSE-591.

Grigg, C., Wong, P., Albrecht, P., Allan, R., Bhavaraju, M., Billinton, R., Chen, Q., Fong, C., Haddad, S. & Kuruganty, S. (1999) The IEEE reliability test system-1996. A report prepared by the reliability test system task force of the application of probability methods subcommittee. *IEEE Transactions on power systems,* 14 (3), 1010-1020.

Gross, R., Philip, H., Anderson, D., Green, T., Leach, M. & Skea, J. (2006) *The cost and impacts of intermittency: An assesment on the evidence on the costs and impacts of intermittent generation on the British electricity network.* The UK Energy Research Centre. [Online] Available from: http://www.uwig.org/0604_Intermittency_report_final.pdf [Accessed 4th February 2015].

Haghighat, H., Seifi, H. & Kian, A. R. (2007) Gaming analysis in joint energy and spinning reserve markets. *IEEE Transactions on Power Systems,* 22 (4), 2074-2085.

Harvey, S. M. & Hogan, W. W. (2001) *Market power and withholding.* [Online] Available from: https://www.hks.harvard.edu/fs/whogan/Market%20Power%20&%20Withholding%20Harvey-Hogan%2012-20-01.pdf [Accessed 2nd May 2016].

Heptonstall, P., Gross, R. & Steiner, F. (2015) *UKERC Technology and Policy Assessment: Intermittency II Project.* The UK Energy Research Centre. [Online] Available from: http://www.ukerc.ac.uk/programmes/technology-and-policy-assessment/the-costs-and-impacts-of-intermittency-ii.html [Accessed 2nd January 2016].

Hillier, F. & Lieberman, G. (2001) *Introduction to Operations Research.* 7th ed. New York, NY, McGraw Hill.

Hobbs, B. F., Metzler, C. B. & Pang, J. S. (2000) Strategic gaming analysis for electric power systems: an MPEC approach. *IEEE Transactions on Power Systems,* 15 (2), 638-645.

Hogan, W. W. (1992) Contract networks for electric power transmission. *Journal of Regulatory Economics,* 4 (3), 211-242.

Ilex & Strbac, G. (2002) *Quantifying the System Costs of Additional Renewables in 2020.* [Online] Available from: http://webarchive.nationalarchives.gov.uk/+/http:/www.berr.gov.uk/files/file21352.pdf [Accessed 22nd March 2015].

Just, S. & Weber, C. (2015) Strategic Behavior in the German Balancing Energy Mechanism: Incentives, Evidence, Costs and Solutions. *Journal of Regulatory Economics,* 48 (2), 218-243.

Kassakian, J., Schmalensee, R., Desgroseilliers, G., Heidel, T., Afridi, K., Farid, A., Grochow, J., Hogan, W., Jacoby, H. & Kirtley, J. (2011) *The Future of the Electricity Grid:*

An Interdisciplinary MIT Study. [Online] Available from: https://energy.mit.edu/wp-content/uploads/2011/12/MITEI-The-Future-of-the-Electric-Grid.pdf [Accessed 12th April 2016].

Kirschen, D. S. & Strbac, G. (2004) *Fundamentals of power system economics.* Chichester, John Wiley & Sons.

Klemperer, P. D. & Meyer, M. A. (1989) Supply Function Equilibria in Oligopoly under Uncertainty. *Econometrica,* 57 (6), 1243-1277.

KU Leuven Energy Institute (2014) *Negative electricity market prices.* Report Number: EI-Fact Sheet 2014 - 01. [Online] Available from: http://set.kuleuven.be/ei/images/negative-electricity-market-prices [Accessed 18th June 2015].

Luenberger, D. G. & Ye, Y. (1984) *Linear and nonlinear programming.* International Series in Operations Research & Management Science 6161. 4th ed. Cham, Springer.

Luo, Z.-Q., Pang, J.-S. & Ralph, D. (1996) *Mathematical Programs with Equilibrium Constraints.* Cambridge University Press.

Meibom, P., Barth, R., Hasche, B., Brand, H., Weber, C. & O'Malley, M. (2011) Stochastic Optimization Model to Study the Operational Impacts of High Wind Penetrations in Ireland. *Power Systems, IEEE Transactions on,* 26 (3), 1367-1379.

MIT (2011) *Managing Large-Scale Penetration of Intermittent Renewables.* [Online] Available from: https://energy.mit.edu/wp-content/uploads/2012/03/MITEI-RP-2011-001.pdf [Accessed 16th November 2015].

Morales, J. M., Conejo, A. J., Liu, K. & Zhong, J. (2012) Pricing electricity in pools with wind producers. *Power Systems, IEEE Transactions on,* 27 (3), 1366-1376.

Morales, M. J., Conejo, J. A., Madsen, H., Pinson, P. & Zugno, M. (2014) *Integrating renewables in electricity markets: Operational problems.* International Series in Operations Research & Management Science 6161. New York, Springer.

Mott MacDonald, A. M. (2010) *UK electricity generation costs update.* [Online] Available from: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/65716/71-uk-electricity-generation-costs-update-.pdf [Accessed 3rd May 2016].

Neuhoff, K. (2011) *Europe's Challenge: A Smart Power Market at the Centre of a Smart Grid.* Climate Policy Initiative / DIW Berlin. [Online] Available from:

http://climatepolicyinitiative.org/wp-content/uploads/2011/12/Smart-Power-Market-Project-Overview.pdf [Accessed 1st December 2015].

Neuhoff, K., Barquin, J., Boots, M. G., Ehrenmann, A., Hobbs, B. F., Rijkers, F. A. & Vazquez, M. (2005) Network-constrained Cournot models of liberalized electricity markets: the devil is in the details. *Energy Economics,* 27 (3), 495-525.

Neuhoff, K., Hobbs, B. F. & Newbery, D. M. (2011) *Congestion management in European power networks: criteria to assess the available options.* [Online] Available from: http://climatepolicyinitiative.org/wp-content/uploads/2011/12/Congestion-Management-Paper.pdf [Accessed 5th September 2015].

Newbery, D. (2010) Market design for a large share of wind power. *Energy Policy,* 38 (7), 3131-3134.

Newbery, D. (2011) Reforming competitive electricity markets to meet environmental targets. *Cambridge Working Paper in Economics,* No. 1154.

Newbery, D. & Strbac, G. (2011) *Physical and financial capacity rights for cross-border trade.* Directorate-General Energy European Commission. Report Number: R01071. [Online] Available from: https://ec.europa.eu/energy/sites/ener/files/documents/2012_transmission.pdf [Accessed 25th December 2015].

Newbery, D. M. (2002) Regulatory challenges to European electricity liberalisation. *Swedish Economic Policy Review,* 9 (2), 9-44.

Nicholson, W. & Snyder, C. (2008) *Microeconomic theory.* 10th ed. Mason, OH, Thomson South-Western.

Nicolosi, M. (2010) Wind power integration and power system flexibility–An empirical analysis of extreme events in Germany under the new negative price regime. *Energy Policy,* 38 (11), 7257-7268.

Olsson, D. (2010) *The linear complementarity problem: Methods and applications.* [Online] Available from: https://www.math.kth.se/optsyst/grundutbildning/kurser/SF2827/olsson.pdf [Accessed 7th June 2016].

Oren, S. S., Spiller, P. T., Varaiya, P. & Wu, F. (1995) Nodal prices and transmission rights: A critical appraisal. *The Electricity Journal,* 8 (3), 24-35.

Papaefthymiou, G., Grave, K. & Dragoon, K. (2014) *Flexibility options in electricity systems.* Ecofys. [Online] Available from: http://www.ecofys.com/files/files/ecofys-eci-2014-flexibility-options-in-electricity-systems.pdf [Accessed 15th June 2016].

Papavasiliou, A. 2011. *Coupling Renewable Energy Supply With Deferrable Demand.* Doctor of Philosophy, University of California, Berkeley.

Papavasiliou, A. & Oren, S. S. (2013) Multiarea Stochastic Unit Commitment for High Wind Penetration in a Transmission Constrained Network. *Operations Research,* 61 (3), 578-592.

Papavasiliou, A., Oren, S. S. & O'Neill, R. P. (2011) Reserve Requirements for Wind Power Integration: A Scenario-Based Stochastic Programming Framework. *Power Systems, IEEE Transactions on,* 26 (4), 2197-2206.

Pereira, M. V., Granville, S., Fampa, M. H., Dix, R. & Barroso, L. A. (2005) Strategic bidding under uncertainty: a binary expansion approach. *IEEE Transactions on Power Systems,* 20 (1), 180-188.

Pindyck, R. S. & Rubinfeld, D. L. (2005) *Microeconomics.* 7th ed. New Jersey, Prentice Hall.

Pöyry (2014) *Revealing the value of flexibility: How can flexible capability be rewarded in the electricity markets of the future?* [Online] Available from: http://www.poyry.com/sites/default/files/imce/files/revealing_the_value_of_flexibility_public_report_v1_0.pdf [Accessed 16th April 2016].

Pritchard, G., Zakeri, G. & Philpott, A. (2010) A Single-Settlement, Energy-Only Electric Power Market for Unpredictable and Intermittent Participants. *Operations Research,* 58 (4), 1210-1219.

Ralph, D. (2008) Mathematical Programs with Complementarity Constraints in Traffic and Telecommunications Networks. *Philosophical Transactions of the Royal Society A: Mathematical, Physical and Engineering Sciences,* 366 (1872), 1973-1987.

Rosenthal, R. (2016) *GAMS—A User's Guide 2016.* GAMS Development Corporation, Washington, DC, USA. [Online] Available from: http://www.gams.com/help/topic/gams.doc/userguides/GAMSUsersGuide.pdf [Accessed 8th May 2016].

Ruiz, C. & Conejo, A. J. (2009) Pool strategy of a producer with endogenous formation of locational marginal prices. *IEEE Transactions on Power Systems,* 24 (4), 1855-1866.

Ruiz, P. A., Philbrick, C. R., Zak, E., Cheung, K. W. & Sauer, P. W. (2009) Uncertainty Management in the Unit Commitment Problem. *Power Systems, IEEE Transactions on,* 24 (2), 642-651.

Saharidis, K. D. G., Conejo, J. A. & Kozanidis, G. (2013) Exact Solution Methodologies for Linear and (Mixed) Integer Bilevel Programming. In: Talbi, E.-G. (ed.) *Metaheuristics for Bi-level Optimization.* Studies in Computational Intelligence 482 Heidelberg: Springer, pp. 221-245.

Schweppe, F., Caramanis, M., Tabors, R. & Bohn, R. (1988) *Spot Pricing of Electricity.* International Series in Engineering and Computer Science. Boston, Kluwer Academic Publishers.

Sioshansi, R., Denholm, P., Jenkin, T. & Weiss, J. (2009) Estimating the value of electricity storage in PJM: Arbitrage and some welfare effects. *Energy Economics,* 31 (2), 269-277.

Stoft, S. (2002) *Power system economics : Designing markets for electricity.* New York, NY, Wiley-Interscience.

Stoft, S., Webber, C. & Wiser, R. (1997) *Transmission Pricing and Renewables: Issues, Options, and Recommendations.* Environmental Energy Technologies Division, Ernest Orlando Lawrence Berkeley National Laboratory, University of California. Report Number: LBNL-39845, UC-1321. [Online] Available from: http://emp.lbl.gov/sites/all/files/REPORT%20lbnl%20-%2039845.pdf [Accessed 9th May 2015].

Strbac, G., Aunedi, M., Pudjianto, D., Djapic, P., Teng, F., Sturt, A., Jackravut, D., Sansom, R., Yufit, V. & Brandon, N. (2012) *Strategic assessment of the role and value of energy storage systems in the UK low carbon energy future.* [Online] Available from: http://www.carbontrust.com/media/129310/energy-storage-systems-role-value-strategic-assessment.pdf [Accessed 1st October 2015].

Streiffert, D., Philbrick, R. & Ott, A. (2005) A mixed integer programming solution for market clearing and reliability analysis. *Power Engineering Society General Meeting, 2005. IEEE*, 12-16 June 2005, 2724-2731 Vol. 3.

Tuohy, A. & O'Malley, M. (2011) Pumped storage in systems with very high wind penetration. *Energy Policy,* 39 (4), 1965-1974.

Twomey, P., Green, R. J., Neuhoff, K. & Newbery, D. (2006) *A Review of the Monitoring of Market Power: The Possible Roles of TSOs in Monitoring for Market Power Issues in Congested Transmission Systems.* [Online] Available from: http://www.econ.cam.ac.uk/electricity/publications/wp/ep71.pdf [Accessed 3rd March 2016].

Ventosa, M., Baıllo, A., Ramos, A. & Rivier, M. (2005) Electricity market modeling trends. *Energy policy,* 33 (7), 897-913.

Von Stackelberg, H. (1934) *Marktform und Gleichgewicht (Market structure and equilibrium).* Vienna, J. Springer.

Wärtsilä (2014) *Delivering flexibility in the German electricity markets: are current arrangements fit for purpose?* [Online] Available from: http://cdn.wartsila.com/docs/default-source/Power-Plants-documents/downloads/White-papers/europe/flexibility-and-german-electricity-markets---wartsila-study.pdf?sfvrsn=4 [Accessed 6th June 2016].

Wetzstein, M. E. (2013) *Microeconomic theory: concepts and connections.* 2nd ed. New York, NY, Routledge.

Williams, H. P. (2013) *Model building in mathematical programming.* 5th ed. Chichester, John Wiley & Sons.

Wolsey, L. A. (1998) *Integer programming.* Wiley-Interscience Series in Discrete Mathematics and Optimization. New York, Wiley.

Appendix A

Node	Wind power output	
	High	Low
n_1	538.7	296.3
n_3	361.4	198.8
n_5	142.5	78.4
n_6	452.6	249.0
n_8	70.9	39.0
n_{11}	351.7	193.5
n_{13}	203.2	111.8
n_{16}	24.0	13.2
n_{19}	9.2	5.0
n_{20}	384.6	211.5
n_{26}	463.2	254.8
Total	3,002.1	1,651.2

Table 67: Wind power output prediction by node and scenario, at 5% winter penetration. Outputs in MWh.

Node	Wind power output	
	High	Low
n_1	1,077.5	592.6
n_3	722.8	397.5
n_5	285.1	156.8
n_6	905.3	497.9
n_8	141.8	78.0
n_{11}	703.5	386.9
n_{13}	406.4	223.5
n_{16}	48.0	26.4
n_{19}	18.3	10.1
n_{20}	769.1	423.0
n_{26}	926.5	509.5
Total	6,004.2	3,302.3

Table 68: Wind power output prediction by node and scenario, at 10% winter penetration. Outputs in MWh.

Node	Wind power output	
	High	Low
n_1	1,616.2	888.9
n_3	1,084.2	596.3
n_5	427.6	235.2
n_6	1,357.9	746.9
n_8	212.7	117.0
n_{11}	1,055.2	580.4
n_{13}	609.6	335.3
n_{16}	72.0	39.6
n_{19}	27.5	15.1
n_{20}	1,153.7	634.5
n_{26}	1,389.7	764.3
Total	9,006.3	4,953.5

Table 69: Wind power output prediction by node and scenario, at 15% winter penetration. Outputs in MWh.

Node	Wind power output	
	High	Low
n_1	384.8	211.6
n_3	258.1	142.0
n_5	101.8	56.0
n_6	323.3	177.8
n_8	50.7	27.9
n_{11}	251.2	138.2
n_{13}	145.2	79.8
n_{16}	17.1	9.4
n_{19}	6.6	3.6
n_{20}	274.7	151.1
n_{26}	330.9	182.0
Total	2,144.4	1,179.4

Table 70: Wind power output prediction by node and scenario, at 10% summer penetration. Outputs in MWh.

Node	Wind power output	
	High	Low
n_1	770.4	423.7
n_3	516.8	284.2
n_5	203.8	112.1
n_6	647.3	356.0
n_8	101.4	55.8
n_{11}	503.0	276.6
n_{13}	290.6	159.8
n_{16}	34.3	18.9
n_{19}	13.1	7.2
n_{20}	549.9	302.5
n_{26}	662.4	364.3
Total	4,293.0	2,361.2

Table 71: Wind power output prediction by node and scenario, at 20% summer penetration. Outputs in MWh.

Node	Wind power output	
	High	Low
n_1	1,155.5	635.5
n_3	775.2	426.3
n_5	305.7	168.1
n_6	970.9	534.0
n_8	152.1	83.7
n_{11}	754.4	414.9
n_{13}	435.9	239.7
n_{16}	51.5	28.3
n_{19}	19.7	10.8
n_{20}	824.8	453.6
n_{26}	993.6	546.5
Total	6,439.1	3,541.5

Table 72: Wind power output prediction by node and scenario, at 30% summer penetration. Outputs in MWh.

Node	Wind power output	
	High	Low
n_1	1,374.3	1,095.3
n_3	922.0	734.8
n_5	363.6	289.8
n_6	1,154.7	920.3
n_8	180.9	144.2
n_{11}	897.3	715.1
n_{13}	518.4	413.2
n_{16}	61.2	48.8
n_{19}	23.4	18.6
n_{20}	981.0	781.8
n_{26}	1,181.7	941.8
Total	7,658.5	6,103.6

Table 73: Wind power output prediction by node and scenario, at 40% summer penetration. Outputs in MWh.

Firm	Fuel type	Installed capacity (MW)	Re-dispatch capability (MW)		Node
			Positive	Negative	
SSE	CCGT	1,180.0	354.0	354.0	n_2
E.ON	CHP - biomass	50.0			n_6
EDF	Nuclear	965.0			n_6
Grangemouth	CHP	145.0			n_7
RWE	CHP - biomass	65.0			n_7
EDF	Nuclear	1,185.0			n_8
EDF	Nuclear	2,385.0			n_{11}
NDA	CHP	180.0			n_{11}
Scottish Power	CCGT	59.0	17.7	17.7	n_{11}
E.ON	CCGT	1,436.0	430.8	430.8	n_{13}
Engie	CCGT	515.0	154.5	154.5	n_{13}
Intergen	CCGT	810.0	243.0	243.0	n_{13}
SSE	Coal	1,961.0	392.2	392.2	n_{13}
SSE	OCGT	34.0	34.0		n_{13}
Drax	Biomass	1,290.0	258.0	258.0	n_{14}
Drax	Coal	2,580.0	516.0	516.0	n_{14}
Drax	OCGT	75.0	75.0		n_{14}
E.ON	CHP - biomass	33.0			n_{14}
Eggborough	Coal	775.0	155.0	155.0	n_{14}
SSE	OCGT	34.0	34.0		n_{14}
EDF	Nuclear	1,180.0			n_{15}
Sembcorps	Biomass	38.0	7.6	7.6	n_{15}
Sembcorps	CHP	42.0			n_{15}
Sembcorps	OCGT	42.0	42.0		n_{15}
Centrica	CCGT	1,310.0	393.0	393.0	n_{16}
Centrica	OCGT	150.0	150.0		n_{16}
Centrica	OCGT	665.0	665.0		n_{16}
E.ON	CCGT	395.0	118.5	118.5	n_{16}
E.ON	CCGT	1,006.0	301.8	301.8	n_{16}

EDF	CCGT	1,332.0	399.6	399.6	n_{16}
EDF	Coal	2,008.0	401.6	401.6	n_{16}
EDF	Coal	2,012.0	402.4	402.4	n_{16}
EDF	OCGT	40.0	40.0		n_{16}
Engie	CHP	1,200.0			n_{16}
Immingham	CHP	1,240.0			n_{16}
SSE	OCGT	25.0	25.0		n_{16}
RWE	CCGT	1,772.0	531.6	531.6	n_{19}
EDF	Nuclear	1,198.0			n_{20}
RWE	CCGT	1,140.0	342.0	342.0	n_{20}
RWE	OCGT	17.0	17.0		n_{20}
Centrica	CCGT	905.0	271.5	271.5	n_{21}
EDF	CCGT	819.0	245.7	245.7	n_{21}
Intergen	CCGT	880.0	264.0	264.0	n_{21}
RWE	CCGT	1,470.0	441.0	441.0	n_{21}
Corby	CCGT	401.0	120.3	120.3	n_{22}
E.ON	Coal	2,000.0	400.0	400.0	n_{22}
E.ON	OCGT	34.0	34.0		n_{22}
Engie	Coal	1,006.0	201.2	201.2	n_{22}
Engie	OCGT	50.0	50.0		n_{22}
Baglan Bay	CCGT	520.0	156.0	156.0	n_{23}
Centrica	CCGT	240.0	72.0	72.0	n_{23}
Centrica	OCGT	235.0	235.0		n_{23}
RWE	Coal	1,586.0	317.2	317.2	n_{23}
RWE	OCGT	51.0	51.0		n_{23}
Severn Power	CCGT	850.0	255.0	255.0	n_{23}
RWE	CCGT	2,180.0	654.0	654.0	n_{24}
RWE	OCGT	100.0	100.0		n_{24}
SSE	CCGT	1,222.0	366.6	366.6	n_{24}
E.ON	CCGT	408.0	122.4	122.4	n_{25}
E.ON	CHP	1,365.0			n_{25}
E.ON	OCGT	55.0	55.0		n_{25}
E.ON	OCGT	144.0	144.0		n_{25}
RWE	OCGT	105.0	105.0		n_{25}
RWE	Oil	1,370.0	1370.0		n_{25}
Scottish Power	CCGT	715.0	214.5	214.5	n_{25}
SSE	CHP - biomass	35.0			n_{25}
E.ON	Oil	1,355.0	1355.0		n_{26}
Intergen	CCGT	800.0	240.0	240.0	n_{26}
Scottish Power	CCGT	805.0	241.5	241.5	n_{26}
SSE	CCGT	700.0	210.0	210.0	n_{26}
EDF	Nuclear	1,050.0			n_{27}
RWE	CHP	153.0			n_{27}
Scottish Power	CCGT	420.0	126.0	126.0	n_{27}
BP	OCGT	50.0	50.0		n_{28}
RWE	OCGT	140.0	140.0		n_{28}
RWE	Oil	1,036.0	1036.0		n_{28}
SSE	CCGT	842.0	252.6	252.6	n_{28}

EDF	Nuclear	955.0			n_{29}
Engie	OCGT	140.0	140.0		n_{29}
Thermal		59,761.0	16,537.8	10,590.8	

Table 74: MPPs installed capacity and re-dispatch capability per plant and location.

Node	**Installed Capacity (MW)**
n_1	1,527.0
n_3	1,024.4
n_5	404.0
n_6	1,283.0
n_8	201.0
n_{11}	997.0
n_{13}	576.0
n_{16}	68.0
n_{19}	26.0
n_{20}	1,090.0
n_{26}	1,313.0
Total	8,509.4

Table 75: PDS wind power capacity per node on the test GB system.

Appendix B

Type	Competitive			Strategic		
	DA	RT High wind	Low wind	DA	RT High wind	Low wind
Coal	30.00	27.00	- 9.00	200.00	120.00	- 80.00
Biomass	47.00	45.12	- 13.16	47.00	45.12	- 13.16
CCGT	50.00	37.50	- 17.50	200.00	120.00	- 80.00
OCGT				200.00	120.00	
Oil				100.00	60.00	

Table 76: Counter-intuitive DA and expected RT unit (i.e. for 1 MWh of added output in the high wind and 1 MWh of subtracted output in the low wind scenario) costs, as perceived by the SO by plant type (active in the RT market) and scenario, for the competitive and strategic winter cases, at 5% penetration. Costs in £ per MWh.

Balancing actions may be taken in any direction at any scenario, i.e. re-dispatch up in the high and re-dispatch down in the low wind scenario, especially considering RWE's attempt to manipulate the re-dispatch process. We work out the 'counter-intuitive' costs for the competitive configuration, while strategic costs are computed likewise and shown in Table 76. In the low wind scenario with 40% probability of occurrence, the SO may reduce 1 MWh of CCGT output that was committed in DA, to save $\pi_s \cdot C_{k,d} \cdot P_{k,d,s} = 0.4 \cdot \frac{£}{MWh} 43.75 \cdot 1\ MWh = £\ 17.50$ in expectation. Observably, this is counter-intuitive, in the absence of costless wind to recompense in the competitive case. By the same token, a MWh of CCGT output introduced in the RT market would cost the SO £37.50 in the high wind scenario, which is also counter-intuitive in the competitive benchmark.

Type	Competitive			Strategic		
	DA	RT High wind	Low wind	DA	RT High wind	Low wind
Coal	20.00	8.25	- 11.75	170.00	102.00	- 68.00
Biomass	3.00	- 1.95	- 4.95	153.00	91.80	- 61.20
CCGT	0.00	- 3.75	- 3.75	150.00	90.00	- 60.00
OCGT				140.00	84.00	
Oil				100.00	60.00	

Table 77: Counter-intuitive DA and expected RT unit (i.e. for 1 MWh of added output in the high wind and 1 MWh of subtracted output in the low wind scenario) profits, as perceived by the SO by plant type (active in the RT market) and scenario, for the competitive and strategic winter cases, at 5% penetration. Costs in £ per MWh.

Profits for the counter-intuitive positions are shaped accordingly, as shown in Table 77. Expected RT profits for 1 MWh of up-regulation in the high wind scenario would add up to $\left(\mu_{n,s} \cdot P_{k,u,s} - \pi_s \cdot C_k \cdot P_{k,u,s}\right) = \left(\frac{£}{MWh} 26.25 - 0.6 \cdot \frac{£}{MWh} 50\right) \cdot 1\ MWh = -£3.75$ per MWh, i.e. the CCGT would incur losses in the competitive equilibrium. Re-dispatching down by 1 MWh in the low scenario yields an identical expectation of RT profits of - £3.75 per MWh.

Load payments	**Competitive**		**Strategic**		**Absolute change**		**Relative change (%)**
	DA	**RT**	**DA**	**RT**	**DA**	**RT**	
Thermal	2,371,979	- 35,456	9,533,513	- 207,680	7,161,534	- 172,224	299
Wind	82,565	35,456	284,664	207,683	202,099	172,227	317
Congestion							
Total	2,454,544		9,818,180		7,363,636		300

Table 78: Energy and expected re-dispatch payments to thermal and wind producers for the competitive and strategic winter cases, at 5% penetration. Payments in £.

Type	**Max rating**	**Re-dispatch capability**		**Competitive**			**Strategic**		
		Positive	**Negative**	**DA**	**RT**		**DA**	**RT**	
					High	**Low**		**High**	**Low**
Nuclear	8,026.2			8,026.2			8,026.2		
Coal	11,107.8	2,221.6	2,221.6	11,107.8			11,107.8		
CHP	3,861.0			3,861.0			3,861.0		
Biomass	1,195.2	239.0	239.0	1,195.2			1,195.2		
CCGT	16,713.0	5,013.9	5,013.9	15,720.0	- 1,116.8		16,713.0		
OCGT	1,595.7	1,595.7					1,595.7		
Oil	1,219.5	1,219.5					1,219.5		
Fringe	43,718.4	10,289.7	7,474.5	39,910.2	- 1,116.8		43,718.4		

Table 79: Fringe maximum rating, re-dispatch capability and output levels by plant type and stage, for the competitive and strategic winter cases, at 5% penetration. Maximum rating refers to a 10% derating of installed capacity. Capability figures in MW, outputs in MWh.

Type	**Max rating**	**Re-dispatch capability**		**Competitive**			**Strategic**		
		Positive	**Negative**	**DA**	**RT**		**DA**	**RT**	
					High	**Low**		**High**	**Low**
Nuclear	8,026.2			8,026.2			8,026.2		
Coal	11,107.8	4,443.1	4,443.1	11,107.8			11,107.8		
CHP	3,861.0			3,861.0			3,861.0		
Biomass	1,195.2	478.1	478.1	1,195.2			1,195.2		
CCGT	16,713.0	6,685.2	6,685.2	15,720.0	- 1,350.7		16,713.0		
OCGT	1,595.7	1,595.7					1,595.7		
Oil	1,219.5	1,219.5					1,219.5		
Fringe	43,718.4	14,421.6	11,606.4	39,910.2	- 1,350.7		43,718.4		

Table 80: Fringe maximum rating, re-dispatch capability and output levels by plant type and stage, for the competitive and strategic winter cases, at 5% penetration in the flexible configuration. Maximum rating refers to a 10% derating of installed capacity. Capability figures in MW, outputs in MWh.

Appendix C

Type	Max rating	Re-dispatch capability		Competitive			Strategic		
		Positive	Negative	DA	RT High	RT Low	DA	RT High	RT Low
Nuclear	8,026.2			8,026.2			8,026.2		
Coal	11,107.8	2,221.6	2,221.6	11,107.8			11,107.8		
CHP	3,861.0			3,861.0			3,861.0		
Biomass	1,195.2	239.0	239.0	1,195.2			1,195.2		
CCGT	16,713.0	5,013.9	5,013.9	14,069.1	- 2,702.1		16,713.0		
OCGT	1,595.7	1,595.7					1,595.7		
Oil	1,219.5	1,219.5							
Fringe	43,718.4	10,289.7	7,474.5	38,259.3	- 2,702.1		42,498.9		

Table 81: Fringe maximum rating, re-dispatch capability and output levels by plant type and stage, for the competitive and strategic winter cases, at 10% penetration. Maximum rating refers to a 10% derating of installed capacity. Capability figures in MW, outputs in MWh.

Load payments	Competitive		Strategic		Absolute change		Relative change (%)
	DA	RT	DA	RT	DA	RT	
Thermal	2,289,434	- 70,930	4,357,217	56,305	2,067,782	127,236	99
Wind	165,110	70,931	494,843	- 56,301	329,733	- 127,233	86
Congestion			31,676		31,676		
Total	2,454,544		4,883,740		2,429,196		99

Table 82: Energy and expected re-dispatch payments to thermal and wind producers for the competitive and strategic winter cases, at 10% penetration. Payments in £.

Node	Competitive			Strategic		
	DA	RT High	RT Low	DA	RT High	RT Low
n_1	50.00	46.25	55.625	40.00		100.00
n_2	50.00	46.25	55.625	85.00	75.00	100.00
n_3	50.00	46.25	55.625	115.00	125.00	100.00
n_4	50.00	46.25	55.625	100.00	100.00	100.00
n_5	50.00	46.25	55.625	100.00	100.00	100.00
n_6	50.00	46.25	55.625	100.00	100.00	100.00
n_7	50.00	46.25	55.625	100.00	100.00	100.00
n_8	50.00	46.25	55.625	100.00	100.00	100.00
n_9	50.00	46.25	55.625	100.00	100.00	100.00
n_{10}	50.00	46.25	55.625	100.00	100.00	100.00
n_{11}	50.00	46.25	55.625	100.00	100.00	100.00
n_{12}	50.00	46.25	55.625	100.00	100.00	100.00
n_{13}	50.00	46.25	55.625	100.00	100.00	100.00
n_{14}	50.00	46.25	55.625	100.00	100.00	100.00
n_{15}	50.00	46.25	55.625	100.00	100.00	100.00
n_{16}	50.00	46.25	55.625	100.00	100.00	100.00
n_{17}	50.00	46.25	55.625	100.00	100.00	100.00
n_{18}	50.00	46.25	55.625	100.00	100.00	100.00
n_{19}	50.00	46.25	55.625	100.00	100.00	100.00
n_{20}	50.00	46.25	55.625	100.00	100.00	100.00
n_{21}	50.00	46.25	55.625	100.00	100.00	100.00
n_{22}	50.00	46.25	55.625	100.00	100.00	100.00
n_{23}	50.00	46.25	55.625	100.00	100.00	100.00
n_{24}	50.00	46.25	55.625	100.00	100.00	100.00
n_{25}	50.00	46.25	55.625	100.00	100.00	100.00
n_{26}	50.00	46.25	55.625	100.00	100.00	100.00
n_{27}	50.00	46.25	55.625	100.00	100.00	100.00
n_{28}	50.00	46.25	55.625	100.00	100.00	100.00
n_{29}	50.00	46.25	55.625	100.00	100.00	100.00

Table 83: DA and expected RT prices for the competitive and strategic summer cases, at 10% penetration in the flexible configuration. Prices in £ per MWh.

Type	Competitive		Strategic		Absolute change		Relative change (%)
	DA	RT	DA	RT	DA	RT	
RWE	7,529.4	- 185.5	2,837.5	- 1,041.9	- 4,691.9	-856.4	- 75.5
Fringe	38,259.3	- 1,435.8	42,498.9		4,239.6	1,435.8	15.4
Wind	3,302.2	1,621.3	3,754.5	1,041.9	452.3	- 579.4	- 2.6
Industry	49,090.9		49,090.9				

Table 84: Industry-wide output levels by fuel type and stage, for the competitive and strategic winter cases, at 10% penetration in the flexible configuration. Outputs in MWh.

Type	Competitive		Strategic		Absolute change		Relative change (%)
	DA	RT	DA	RT	DA	RT	
RWE	31,529	696	161,986	- 50,571	130,457	- 51,267	246
Fringe	617,321	5,384	2,710,379		2,093,058	- 5,384	335
Wind	165,110	74,984	378,093	60,450	212,983	- 14,535	83
Industry	813,960	81,064	3,250,457	9,878	2,436,498	- 71,186	246

Table 85: Expected industry-wide profits by stage, for the competitive and strategic winter cases, at 10% penetration in the flexible configuration. Figures in £.

[Page intentionally left blank]

Appendix D

Load payments	Competitive		Strategic		Absolute change		Relative change (%)
	DA	RT	DA	RT	DA	RT	
Thermal	2,204,778	- 93,935	2,812,238	7,676	607,460	101,611	34
Wind	224,815	93,937	378,252	- 7,674	153,437	- 101,610	16
Congestion	13,858		34,318		20,460		148
Total	2,443,454		3,224,810		781,356		32

Table 86: Energy and expected re-dispatch payments to thermal and wind producers for the competitive and strategic winter cases, at 15% penetration. Payments in £.

Type	Max rating	Re-dispatch capability		Competitive			Strategic		
		Positive	Negative	DA	RT High	RT Low	DA	RT High	RT Low
Nuclear	8,026.2			8,026.2			8,026.2		
Coal	11,107.8	2,221.6	2,221.6	11,107.8			11,107.8		
CHP	3,861.0			3,861.0			3,861.0		
Biomass	1,195.2	239.0	239.0	1,195.2			1,195.2		
CCGT	16,713.0	5,013.9	5,013.9	12,733.7	- 3,192.8		16,175.0	- 1,458.2	318.6
OCGT	1,595.7	1,595.7							1,595.7
Oil	1,219.5	1,219.5							
Fringe	43,718.4	10,289.7	7,474.5	36,923.9	- 3,192.8		40,365.2	- 1,458.2	1,914.3

Table 87: Fringe maximum rating, re-dispatch capability and output levels by plant type and stage, for the competitive and strategic winter cases, at 15% penetration. Maximum rating refers to a 10% derating of installed capacity. Capability figures in MW, outputs in MWh.

Type	Max rating	Re-dispatch capability		Competitive			Strategic		
		Positive	Negative	DA	RT High	Low	DA	RT High	Low
Coal	1,427.4	571.0	285.5	1,427.4			1,427.4		
CHP_1	137.7			137.7			137.7		
CHP_2	58.5			58.5			58.5		
$CCGT_1$	1,594.8	637.9	637.9	1,594.8	- 637.9		637.9	- 637.9	- 637.9
$CCGT_2$	1,026.0	410.4	410.4	1,026.0	- 410.4				
$CCGT_3$	1,323.0	529.2	529.2	1323.0	- 529.2		529.2	- 529.2	- 529.2
$CCGT_4$	1,962.0	784.8	784.8	1,962.0			784.8	- 784.8	- 555.8
$OCGT_1$	90.0	90.0							
$OCGT_2$	126.0	126.0							
$OCGT_3$	45.9	45.9							
$OCGT_4$	15.3	15.3							
$OCGT_5$	94.5	94.5							
Oil_1	1,233.0	1,233.0							
Oil_2	932.4	932.4							
RWE	10,066.5	4,594.3	2,057.2	7,529.4	-1,577.5		3,575.5	- 1,951.9	-1,722.9

Table 88: RWE maximum rating, re-dispatch capability and output levels by plant and stage, for the competitive and strategic winter cases, at 15% penetration in the flexible configuration. Maximum rating refers to a 10% derating of installed capacity. Capability figures in MW, output figures in MWh.

Type	Max rating	Re-dispatch capability		Competitive			Strategic		
		Positive	Negative	DA	RT High	Low	DA	RT High	Low
Nuclear	8,026.2			8,026.2			8,026.2		
Coal	11,107.8	4,443.1	4,443.1	11,107.8			11,107.8		
CHP	3,861.0			3,861.0			3,861.0		
Biomass	1,195.2	478.1	478.1	1,195.2			1,195.2		
CCGT	16,713.0	6,685.2	6,685.2	12,417.8	- 2,080.6		16,075.8	- 1,410.8	424.8
OCGT	1,595.7	1,595.7							1,595.7
Oil	1,219.5	1,219.5							
Fringe	43,718.4	14,421.6	11,606.4	36,608.0	- 2,080.6		40,266.0	- 1,410.8	2,020.5

Table 89: Fringe maximum rating, re-dispatch capability and output levels by plant type and stage, for the competitive and strategic winter cases, at 15% penetration in the flexible configuration. Maximum rating refers to a 10% derating of installed capacity. Capability figures in MW, outputs in MWh.

Load payments	Competitive		Strategic		Absolute change		Relative change (%)
	DA	RT	DA	RT	DA	RT	
Thermal	2,206,869	- 101,513	2,915,702	- 82,906	708,833	18,607	35
Wind	221,299	101,516	293,674	82,908	72,375	- 18,608	17
Congestion	14,649		35,198		20,549		140
Total	2,442,820		3,244,577		801,756		33

Table 90: Energy and expected re-dispatch payments to thermal and wind producers for the competitive and strategic winter cases, at 15% penetration in the flexible configuration. Payments in £.

Appendix E

Node	Competitive			Strategic		
	DA	RT High	Low	DA	RT High	Low
n_1	30.00	22.50	41.25	36.00	22.50	56.25
n_2	30.00	22.50	41.25	36.00	22.50	56.25
n_3	30.00	22.50	41.25	36.00	22.50	56.25
n_4	30.00	22.50	41.25	36.00	22.50	56.25
n_5	30.00	22.50	41.25	36.00	22.50	56.25
n_6	30.00	22.50	41.25	36.00	22.50	56.25
n_7	30.00	22.50	41.25	36.00	22.50	56.25
n_8	30.00	22.50	41.25	36.00	22.50	56.25
n_9	30.00	22.50	41.25	36.00	22.50	56.25
n_{10}	30.00	22.50	41.25	36.00	22.50	56.25
n_{11}	30.00	22.50	41.25	36.00	22.50	56.25
n_{12}	30.00	22.50	41.25	36.00	22.50	56.25
n_{13}	30.00	22.50	41.25	36.00	22.50	56.25
n_{14}	30.00	22.50	41.25	36.00	22.50	56.25
n_{15}	30.00	22.50	41.25	36.00	22.50	56.25
n_{16}	30.00	22.50	41.25	36.00	22.50	56.25
n_{17}	30.00	22.50	41.25	36.00	22.50	56.25
n_{18}	30.00	22.50	41.25	36.00	22.50	56.25
n_{19}	30.00	22.50	41.25	36.00	22.50	56.25
n_{20}	30.00	22.50	41.25	36.00	22.50	56.25
n_{21}	30.00	22.50	41.25	36.00	22.50	56.25
n_{22}	30.00	22.50	41.25	36.00	22.50	56.25
n_{23}	30.00	22.50	41.25	36.00	22.50	56.25
n_{24}	30.00	22.50	41.25	36.00	22.50	56.25
n_{25}	30.00	22.50	41.25	36.00	22.50	56.25
n_{26}	30.00	22.50	41.25	36.00	22.50	56.25
n_{27}	30.00	22.50	41.25	36.00	22.50	56.25
n_{28}	30.00	22.50	41.25	36.00	22.50	56.25
n_{29}	30.00	22.50	41.25	36.00	22.50	56.25

Table 91: DA and expected RT prices for the competitive and strategic summer cases, at 10% penetration. Prices in £ per MWh.

Type	Competitive		Strategic		Absolute change		Relative change (%)
	DA	RT	DA	RT	DA	RT	
EDF	11,644.2	- 363.0	10,339.6	- 216.8	- 1,304.6	146.2	- 10.3
Fringe	4,771.7	- 216.0	5,714.1		942.4	216.0	25.4
Wind	1,179.4	579.0	1,541.6	216.8	362.2	- 362.2	
Industry	17,595.3		17,595.3				

Table 92: Industry-wide output levels by fuel type and stage, for the competitive and strategic summer cases, at 10% penetration. Outputs in MWh.

Type	Competitive		Strategic		Absolute change		Relative change (%)
	DA	RT	DA	RT	DA	RT	
EDF	176,576	2,722	238,614	6,515	62,038	3,793	37
Fringe		1,620	33,955		33,955	- 1,620	1,996
Wind	35,382	13,027	55,496	- 11	20,114	- 13,038	15
Industry	211,958	17,370	328,066	6,505	116,107	- 10,865	46

Table 93: Expected industry-wide profits by stage, for the competitive and strategic summer cases, at 10% penetration. Figures in £.

Node	Competitive			Strategic		
	DA	RT High	RT Low	DA	RT High	RT Low
n_1	30.00	25.50	36.75	36.00	25.50	51.75
n_2	30.00	25.50	36.75	36.00	25.50	51.75
n_3	30.00	25.50	36.75	36.00	25.50	51.75
n_4	30.00	25.50	36.75	36.00	25.50	51.75
n_5	30.00	25.50	36.75	36.00	25.50	51.75
n_6	30.00	25.50	36.75	36.00	25.50	51.75
n_7	30.00	25.50	36.75	36.00	25.50	51.75
n_8	30.00	25.50	36.75	36.00	25.50	51.75
n_9	30.00	25.50	36.75	36.00	25.50	51.75
n_{10}	30.00	25.50	36.75	36.00	25.50	51.75
n_{11}	30.00	25.50	36.75	36.00	25.50	51.75
n_{12}	30.00	25.50	36.75	36.00	25.50	51.75
n_{13}	30.00	25.50	36.75	36.00	25.50	51.75
n_{14}	30.00	25.50	36.75	36.00	25.50	51.75
n_{15}	30.00	25.50	36.75	36.00	25.50	51.75
n_{16}	30.00	25.50	36.75	36.00	25.50	51.75
n_{17}	30.00	25.50	36.75	36.00	25.50	51.75
n_{18}	30.00	25.50	36.75	36.00	25.50	51.75
n_{19}	30.00	25.50	36.75	36.00	25.50	51.75
n_{20}	30.00	25.50	36.75	36.00	25.50	51.75
n_{21}	30.00	25.50	36.75	36.00	25.50	51.75
n_{22}	30.00	25.50	36.75	36.00	25.50	51.75
n_{23}	30.00	25.50	36.75	36.00	25.50	51.75
n_{24}	30.00	25.50	36.75	36.00	25.50	51.75
n_{25}	30.00	25.50	36.75	36.00	25.50	51.75
n_{26}	30.00	25.50	36.75	36.00	25.50	51.75
n_{27}	30.00	25.50	36.75	36.00	25.50	51.75
n_{28}	30.00	25.50	36.75	36.00	25.50	51.75
n_{29}	30.00	25.50	36.75	36.00	25.50	51.75

Table 94: DA and expected RT prices for the competitive and strategic summer cases, at 10% penetration in the flexible configuration. Prices in £ per MWh.

Type	Competitive		Strategic		Absolute change		Relative change (%)
	DA	RT	DA	RT	DA	RT	
EDF	11,644.2		11,184.0	- 1,061.2	- 460.2	- 1,061.2	- 13.1
Fringe	4,771.7	- 579.0	5,714.1		942.4	579.0	36.3
Wind	1,179.4	579.0	697.2	1,061.2	- 482.2	482.2	
Industry	17,595.3		17,595.3				

Table 95: Industry-wide output levels by fuel type and stage, for the competitive and strategic summer cases, at 10% penetration in the flexible configuration. Outputs in MWh.

Type	Competitive		Strategic		Absolute change		Relative change (%)
	DA	RT	DA	RT	DA	RT	
EDF	176,576.4		243,680.4	- 287.7	67,104.0	- 287.7	38
Fringe		2,605.5	33,955.2		33,955.2	- 2,605.5	1,203
Wind	35,382.0	14,764.1	25,099.2	32,123.3	- 10,282.8	17,359.2	14
Industry	211,958.4	17,369.6	302,734.8	31,835.6	90,776.4	14,466.0	46

Table 96: Expected industry-wide profits by stage, for the competitive and strategic summer cases, at 10% penetration in the flexible configuration. Figures in £.

Node	Competitive			Strategic		
	DA	RT		DA	RT	
		High	Low		High	Low
n_{1}	30.00	20.00	45.00	36.00	22.50	56.25
n_{2}	30.00	20.00	45.00	36.00	22.50	56.25
n_{3}	30.00	20.00	45.00	36.00	22.50	56.25
n_{4}	30.00	20.00	45.00	36.00	22.50	56.25
n_{5}	30.00	20.00	45.00	36.00	22.50	56.25
n_{6}	30.00	20.00	45.00	36.00	22.50	56.25
n_{7}	30.00	20.00	45.00	36.00	22.50	56.25
n_{8}	30.00	20.00	45.00	36.00	22.50	56.25
n_{9}	30.00	20.00	45.00	36.00	22.50	56.25
n_{10}	30.00	20.00	45.00	36.00	22.50	56.25
n_{11}	30.00	20.00	45.00	36.00	22.50	56.25
n_{12}	30.00	20.00	45.00	36.00	22.50	56.25
n_{13}	30.00	20.00	45.00	36.00	22.50	56.25
n_{14}	30.00	20.00	45.00	36.00	22.50	56.25
n_{15}	30.00	20.00	45.00	36.00	22.50	56.25
n_{16}	30.00	20.00	45.00	36.00	22.50	56.25
n_{17}	30.00	20.00	45.00	36.00	22.50	56.25
n_{18}	30.00	20.00	45.00	36.00	22.50	56.25
n_{19}	30.00	20.00	45.00	36.00	22.50	56.25
n_{20}	30.00	20.00	45.00	36.00	22.50	56.25
n_{21}	30.00	20.00	45.00	36.00	22.50	56.25
n_{22}	30.00	20.00	45.00	36.00	22.50	56.25
n_{23}	30.00	20.00	45.00	36.00	22.50	56.25
n_{24}	30.00	20.00	45.00	36.00	22.50	56.25
n_{25}	30.00	20.00	45.00	36.00	22.50	56.25
n_{26}	30.00	20.00	45.00	36.00	22.50	56.25
n_{27}	30.00	20.00	45.00	36.00	22.50	56.25
n_{28}	30.00	20.00	45.00	36.00	22.50	56.25
n_{29}	30.00	20.00	45.00	36.00	22.50	56.25

Table 97: DA and expected RT prices for the competitive and strategic summer cases, at 20% penetration. Prices in £ per MWh.

Type	Competitive		Strategic		Absolute change		Relative change (%)
	DA	RT	DA	RT	DA	RT	
EDF	11,644.2	- 434.2	8,796.5	- 144.7	- 2,847.7	289.4	- 22.8
Fringe	3,491.6	- 626.6	5,714.1	- 290.8			89.3
Wind	2,459.5	1,060.8	3,084.7	435.6	625.2	- 625.2	
Industry	17,595.3		17,595.3				

Table 98: Industry-wide output levels by fuel type and stage, for the competitive and strategic summer cases, at 20% penetration. Outputs in MWh.

Type	Competitive		Strategic		Absolute change		Relative change (%)
	DA	RT	DA	RT	DA	RT	
EDF	176,576	4,342	229,355	10,854	52,779	6,512	33
Fringe		7,250	33,955	2,181	33,955	- 5,069	398
Wind	73,786	20,232	111,049	33	37,264	- 20,199	18
Industry	250,362	31,823	374,360	13,068	123,998	- 18,755	37

Table 99: Expected industry-wide profits by stage, for the competitive and strategic summer cases, at 20% penetration. Figures in £.

Node	Competitive			Strategic		
	DA	RT High	RT Low	DA	RT High	RT Low
n_1	30.00	25.50	36.75	36.00	25.50	51.75
n_2	30.00	25.50	36.75	36.00	25.50	51.75
n_3	30.00	25.50	36.75	36.00	25.50	51.75
n_4	30.00	25.50	36.75	36.00	25.50	51.75
n_5	30.00	25.50	36.75	36.00	25.50	51.75
n_6	30.00	25.50	36.75	36.00	25.50	51.75
n_7	30.00	25.50	36.75	36.00	25.50	51.75
n_8	30.00	25.50	36.75	36.00	25.50	51.75
n_9	30.00	25.50	36.75	36.00	25.50	51.75
n_{10}	30.00	25.50	36.75	36.00	25.50	51.75
n_{11}	30.00	25.50	36.75	36.00	25.50	51.75
n_{12}	30.00	25.50	36.75	36.00	25.50	51.75
n_{13}	30.00	25.50	36.75	36.00	25.50	51.75
n_{14}	30.00	25.50	36.75	36.00	25.50	51.75
n_{15}	30.00	25.50	36.75	36.00	25.50	51.75
n_{16}	30.00	25.50	36.75	36.00	25.50	51.75
n_{17}	30.00	25.50	36.75	36.00	25.50	51.75
n_{18}	30.00	25.50	36.75	36.00	25.50	51.75
n_{19}	30.00	25.50	36.75	36.00	25.50	51.75
n_{20}	30.00	25.50	36.75	36.00	25.50	51.75
n_{21}	30.00	25.50	36.75	36.00	25.50	51.75
n_{22}	30.00	25.50	36.75	36.00	25.50	51.75
n_{23}	30.00	25.50	36.75	36.00	25.50	51.75
n_{24}	30.00	25.50	36.75	36.00	25.50	51.75
n_{25}	30.00	25.50	36.75	36.00	25.50	51.75
n_{26}	30.00	25.50	36.75	36.00	25.50	51.75
n_{27}	30.00	25.50	36.75	36.00	25.50	51.75
n_{28}	30.00	25.50	36.75	36.00	25.50	51.75
n_{29}	30.00	25.50	36.75	36.00	25.50	51.75

Table 100: DA and expected RT prices for the competitive and strategic summer cases, at 20% penetration in the flexible configuration. Prices in £ per MWh.

Type	Competitive		Strategic		Absolute change		Relative change (%)
	DA	RT	DA	RT	DA	RT	
EDF	10,324.6	- 727.1	8,614.2	9.6	- 1,710.4	736.7	- 10.1
Fringe	4,909.6	- 432.0	5,714.1	- 262.8	804.5	169.2	21.7
Wind	2,361.1	1,159.2	3,267.0	253.3	905.9	- 905.9	
Industry	17,595.3		17,595.3				

Table 101: Industry-wide output levels by fuel type and stage, for the competitive and strategic summer cases, at 20% penetration in the flexible configuration. Outputs in MWh.

Type	Competitive		Strategic		Absolute change		Relative change (%)
	DA	RT	DA	RT	DA	RT	
EDF	176,576.4	3,272.1	228,261.6	9,468.9	51,685.2	6,196.8	32
Fringe		1,944.0	33,955.2	1,182.6	33,955.2	- 761.4	1,708
Wind	70,833.0	29,559.4	117,612.0	- 3,052.6	46,779.0	- 32,612.0	14
Industry	247,409.4	34,775.6	379,828.8	7,598.9	132,419.4	- 27,176.6	37

Table 102: Expected industry-wide profits by stage, for the competitive and strategic summer cases, at 20% penetration in the flexible configuration. Figures in £.

Type	Competitive	Strategic	Load factor (%)		Fuel shares (%)	
			Competitive	Strategic	Competitive	Strategic
Nuclear	8,026.2	7,943.9	100.0	99.0	45.6	45.1
Coal	4,458.3	4,375.9	48.6	47.7	25.3	24.9
CHP		164.7		4.1		0.9
Biomass						
CCGT						
OCGT						
Oil						
Wind	5,110.7	5,110.7	66.7	66.7	29.0	29.0
Total	17,595.2	17,595.2			100.0	100.0

Table 103: GB fuel mix of generation for the competitive and strategic summer cases, at 30% penetration. Outputs in MWh. Load factor utilises the sum of generation in both DA and RT stages. Fuel shares as a percentage of demand.

Type	Max rating	Re-dispatch capability		Competitive			Strategic		
		Positive	Negative	DA	RT		DA	RT	
					High	Low		High	Low
Coal	5,549.4	1,109.9	1,109.9	4,522.0	- 1,109.9	464.4	4,439.5	- 1,109.9	1,109.9
CHP	4,057.2						164.7		
Biomass	1,195.2	239.0	239.0						
CCGT	20,682.9	6,204.9	6,204.9						
OCGT	1,931.4	1,931.4							
Fringe	4,057.2	9,485.2	7,553.8	4,522.0	- 1,109.9	464.4	4,604.2	- 1,109.9	1,109.9

Table 104: Fringe maximum rating, re-dispatch capability and output levels by plant type and stage, for the competitive and strategic summer cases, at 30% penetration. Maximum rating refers to a 10% derating of installed capacity. Capability figures in MW, outputs in MWh.

Line	Competitive			Strategic			Absolute change		Relative change (%)
	DA	RT		DA	RT		DA	RT	
		High	Low		High	Low			
l_2	100.0		- 28.5	100.0		- 28.5			

Table 105: DA utilisation and expected RT change of the line connecting nodes n_1 and n_3 for the competitive and strategic summer cases, at 30% penetration. Figures in % of line capacities

Load payments	Competitive		Strategic		Absolute change		Relative change (%)
	DA	RT	DA	RT	DA	RT	
Thermal	398,153	- 7,923	474,465	- 3,426	76,313	4,497	21
Wind	121,553	7,923	146,414	3,426	24,860	- 4,497	16
Congestion	6,336		6,336				
Total	526,042		627,215		101,173		19

Table 106: Energy and expected re-dispatch payments to thermal and wind producers for the competitive and strategic summer cases, at 30% penetration. Payments in £.

Type	Max rating	Re-dispatch capability		Competitive			Strategic		
		Positive	Negative	DA	RT High	RT Low	DA	RT High	RT Low
Coal	5,549.4	2,219.8	2,219.8	5,549.4	- 2,137.3		5,549.4	- 1,747.0	
CHP	4,057.2						164.7		
Biomass	1,195.2	478.1	478.1						
CCGT	20,682.9	8,273.2	8,273.2						
OCGT	1,931.4	1,931.4							
Fringe	33,436.1	12,902.4	10,971.1	5,549.4	- 2 ,137.3		5,714.1	- 1,747.0	

Table 107: Fringe maximum rating, re-dispatch capability and output levels by plant type and stage, for the competitive and strategic summer cases, at 30% penetration in the flexible configuration. Maximum rating refers to a 10% derating of installed capacity. Capability figures in MW, outputs in MWh.

Load payments	Competitive		Strategic		Absolute change		Relative change (%)
	DA	RT	DA	RT	DA	RT	
Thermal	421,617	- 40,019	495,836	- 29,915	74,219	10,104	22
Wind	95,847	40,018	137,594	19,519	41,748	- 20,498	16
Congestion	8,080		8,079				
Total	525,542		631,114		105,572		20

Table 108: Energy and expected re-dispatch payments to thermal and wind producers for the competitive and strategic summer cases, at 30% penetration in the flexible configuration. Payments in £.

Line	Competitive			Strategic			Absolute change		Relative change (%)
	DA	RT High	RT Low	DA	RT High	RT Low	DA	RT	
l_2	88.6		- 28.5	88.6		- 28.5			

Table 109: DA utilisation and expected RT change of the line connecting nodes n_1 and n_3 for the competitive and strategic summer cases, at 30% penetration in the flexible configuration. Figures in % of line capacities

Node	Competitive			Strategic		
	DA	RT High	RT Low	DA	RT High	RT Low
n_1						
n_2	22.50	16.875	30.938	22.50	16.875	30.938
n_3	37.50	28.125	51.563	37.50	28.125	51.563
n_4	30.00	22.500	41.250	30.00	22.500	41.250
n_5	30.00	22.500	41.250	30.00	22.500	41.250
n_6	30.00	22.500	41.250	30.00	22.500	41.250
n_7	30.00	22.500	41.250	30.00	22.500	41.250
n_8	30.00	22.500	41.250	30.00	22.500	41.250
n_9	30.00	22.500	41.250	30.00	22.500	41.250
n_{10}	30.00	22.500	41.250	30.00	22.500	41.250
n_{11}	30.00	22.500	41.250	30.00	22.500	41.250
n_{12}	30.00	22.500	41.250	30.00	22.500	41.250
n_{13}	30.00	22.500	41.250	30.00	22.500	41.250
n_{14}	30.00	22.500	41.250	30.00	22.500	41.250
n_{15}	30.00	22.500	41.250	30.00	22.500	41.250
n_{16}	30.00	22.500	41.250	30.00	22.500	41.250
n_{17}	30.00	22.500	41.250	30.00	22.500	41.250
n_{18}	30.00	22.500	41.250	30.00	22.500	41.250
n_{19}	30.00	22.500	41.250	30.00	22.500	41.250
n_{20}	30.00	22.500	41.250	30.00	22.500	41.250
n_{21}	30.00	22.500	41.250	30.00	22.500	41.250
n_{22}	30.00	22.500	41.250	30.00	22.500	41.250
n_{23}	30.00	22.500	41.250	30.00	22.500	41.250
n_{24}	30.00	22.500	41.250	30.00	22.500	41.250
n_{25}	30.00	22.500	41.250	30.00	22.500	41.250
n_{26}	30.00	22.500	41.250	30.00	22.500	41.250
n_{27}	30.00	22.500	41.250	30.00	22.500	41.250
n_{28}	30.00	22.500	41.250	30.00	22.500	41.250
n_{29}	30.00	22.500	41.250	30.00	22.500	41.250

Table 110: DA and expected RT prices for the competitive and strategic summer cases, at 40% penetration. Prices in £ per MWh.

Type	Competitive		Strategic		Absolute change		Relative change (%)
	DA	RT	DA	RT	DA	RT	
EDF	9,621.4	- 217.3	8,749.8	- 194.6	- 871.6	22.7	- 9.0
Fringe	2,102.4	- 576.3	2,375.0		272.6	576.3	55.6
Wind	5,871.5	793.5	6,470.5	194.5	599.0	- 599.0	
Industry	17,595.3		17,595.3				

Table 111: Industry-wide output levels by fuel type and stage, for the competitive and strategic summer cases, at 40% penetration. Outputs in MWh.

Type	Competitive		Strategic		Absolute change		Relative change (%)
	DA	RT	DA	RT	DA	RT	
EDF	176,576	1,630	176,576	5,952		4,322	2
Fringe		4,322				- 4,322	- 100
Wind	155,763	17,854	173,733	- 116	17,970	- 17,970	
Industry	332,339	23,805	350,309	5,835	17,970	- 17,970	

Table 112: Expected industry-wide profits by stage, for the competitive and strategic summer cases, at 40% penetration. Figures in £.

Node	Competitive			Strategic		
	DA	RT		DA	RT	
		High	Low		High	Low
n_1						
n_2	22.50	19.125	27.563	22.50	19.125	27.563
n_3	37.50	31.875	45.938	37.50	31.875	45.938
n_4	30.00	25.500	36.750	30.00	25.500	36.750
n_5	30.00	25.500	36.750	30.00	25.500	36.750
n_6	30.00	25.500	36.750	30.00	25.500	36.750
n_7	30.00	25.500	36.750	30.00	25.500	36.750
n_8	30.00	25.500	36.750	30.00	25.500	36.750
n_9	30.00	25.500	36.750	30.00	25.500	36.750
n_{10}	30.00	25.500	36.750	30.00	25.500	36.750
n_{11}	30.00	25.500	36.750	30.00	25.500	36.750
n_{12}	30.00	25.500	36.750	30.00	25.500	36.750
n_{13}	30.00	25.500	36.750	30.00	25.500	36.750
n_{14}	30.00	25.500	36.750	30.00	25.500	36.750
n_{15}	30.00	25.500	36.750	30.00	25.500	36.750
n_{16}	30.00	25.500	36.750	30.00	25.500	36.750
n_{17}	30.00	25.500	36.750	30.00	25.500	36.750
n_{18}	30.00	25.500	36.750	30.00	25.500	36.750
n_{19}	30.00	25.500	36.750	30.00	25.500	36.750
n_{20}	30.00	25.500	36.750	30.00	25.500	36.750
n_{21}	30.00	25.500	36.750	30.00	25.500	36.750
n_{22}	30.00	25.500	36.750	30.00	25.500	36.750
n_{23}	30.00	25.500	36.750	30.00	25.500	36.750
n_{24}	30.00	25.500	36.750	30.00	25.500	36.750
n_{25}	30.00	25.500	36.750	30.00	25.500	36.750
n_{26}	30.00	25.500	36.750	30.00	25.500	36.750
n_{27}	30.00	25.500	36.750	30.00	25.500	36.750
n_{28}	30.00	25.500	36.750	30.00	25.500	36.750
n_{29}	30.00	25.500	36.750	30.00	25.500	36.750

Table 113: DA and expected RT prices for the competitive and strategic summer cases, at 40% penetration in the flexible configuration. Prices in £ per MWh.

Type	Competitive		Strategic		Absolute change		Relative change (%)
	DA	RT	DA	RT	DA	RT	
EDF	8,026.2		9,511.1	- 380.9	1,484.9	- 380.9	13.8
Fringe	3,697.6	- 793.6	1,800.0		- 1,897.6	793.6	- 38.0
Wind	5,871.5	793.5	6,284.2	380.8	412.7	- 412.7	
Industry	17,595.3		17,595.3				

Table 114: Industry-wide output levels by fuel type and stage, for the competitive and strategic summer cases, at 40% penetration in the flexible configuration. Outputs in MWh.

Type	Competitive		Strategic		Absolute change		Relative change (%)
	DA	RT	DA	RT	DA	RT	
EDF	176,576.4		176,576.4	3,571.0		3,571.0	2
Fringe		3,571.0				- 3,571.0	- 100
Wind	155,763.0	20,234.2	195,441.0	- 19,443.8	39,678.0	- 39,678.0	
Industry	332,339.4	23,805.2	372,017.4	- 15,872.8	39,678.0	- 39,678.0	

Table 115: Expected industry-wide profits by stage, for the competitive and strategic summer cases, at 40% penetration in the flexible configuration. Figures in £.