



Terms and Conditions of Use of Digitised Theses from Trinity College Library Dublin

Copyright statement

All material supplied by Trinity College Library is protected by copyright (under the Copyright and Related Rights Act, 2000 as amended) and other relevant Intellectual Property Rights. By accessing and using a Digitised Thesis from Trinity College Library you acknowledge that all Intellectual Property Rights in any Works supplied are the sole and exclusive property of the copyright and/or other IPR holder. Specific copyright holders may not be explicitly identified. Use of materials from other sources within a thesis should not be construed as a claim over them.

A non-exclusive, non-transferable licence is hereby granted to those using or reproducing, in whole or in part, the material for valid purposes, providing the copyright owners are acknowledged using the normal conventions. Where specific permission to use material is required, this is identified and such permission must be sought from the copyright holder or agency cited.

Liability statement

By using a Digitised Thesis, I accept that Trinity College Dublin bears no legal responsibility for the accuracy, legality or comprehensiveness of materials contained within the thesis, and that Trinity College Dublin accepts no liability for indirect, consequential, or incidental, damages or losses arising from use of the thesis for whatever reason. Information located in a thesis may be subject to specific use constraints, details of which may not be explicitly described. It is the responsibility of potential and actual users to be aware of such constraints and to abide by them. By making use of material from a digitised thesis, you accept these copyright and disclaimer provisions. Where it is brought to the attention of Trinity College Library that there may be a breach of copyright or other restraint, it is the policy to withdraw or take down access to a thesis while the issue is being resolved.

Access Agreement

By using a Digitised Thesis from Trinity College Library you are bound by the following Terms & Conditions. Please read them carefully.

I have read and I understand the following statement: All material supplied via a Digitised Thesis from Trinity College Library is protected by copyright and other intellectual property rights, and duplication or sale of all or part of any of a thesis is not permitted, except that material may be duplicated by you for your research use or for educational purposes in electronic or print form providing the copyright owners are acknowledged using the normal conventions. You must obtain permission for any other use. Electronic or print copies may not be offered, whether for sale or otherwise to anyone. This copy has been supplied on the understanding that it is copyright material and that no quotation from the thesis may be published without proper acknowledgement.

ELECTRICITY MARKETS AND
RENEWABLES:
EMISSIONS, COSTS AND FUEL DIVERSITY

by

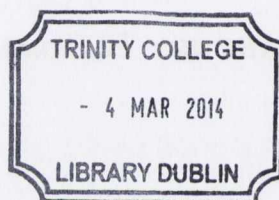
AMY O'MAHONEY B.COMM., M.SC.

Thesis submitted for the degree of
PHILOSOPHIAE DOCTOR
from the
Department of Economics
University of Dublin
Trinity College Dublin, Ireland

Supervisor of Research & Nominating Professor: Prof. Eleanor Denny
Head of School: Prof. Peter Simons



28 March 2013



Thesis 10288

Declaration

I declare that this dissertation has not been submitted as an exercise for the degree of Doctor of Philosophy (Ph.D.) at this or any other university. All research contained herein that is not entirely my own but is based on research that has been carried out jointly with others is duly acknowledged in the text wherever included.

I agree that the library of Trinity College, University of Dublin may lend or copy this thesis upon request. This permission covers only single copies made for study purposes, subject to the normal conditions of acknowledgement.

Abstract

As energy consumption has risen steadily over the past century, so too have emissions, contributing to climate change. Energy consumption is a necessary aspect of economic growth - it is an input into the production of goods and services, the creation of capital stock, and for the development of technological progress. As electricity is a requirement in all households and industries, the price paid for electricity directly affects the monetary and fiscal structure of nations.

While climate change and overconsumption of fossil fuels are not optimal outcomes, the approach governments and policy makers should take to address these issues is not clear cut. The market will not reach sustainable levels of emissions output and fossil fuel consumption without intervention, yet such intervention must be politically and administratively feasible. Thus, any policy alternatives based on reducing emissions output and fossil fuel consumption must be considered within the context of wider policy issues such as competitiveness and consumer welfare. This thesis examines various energy policies under the three objectives of: sustainable cost, emissions reduction and security of supply, discussed in the context of the Irish electricity market.

In order to examine electricity market costs, this dissertation examines if inappropriate bidding behaviour by generators in the Irish electricity market is a driver of high Irish electricity prices. The research finds that generators are bidding ap-

appropriately, with generators bidding the spot price of their inputs correctly in the regression model, and this behaviour remaining constant over the course of the day and varying levels of demand.

A key driver of renewable generation is security of supply, in particular the Irish Government has a target of co-firing biomass in order to utilise indigenous biomass and peat resources. A cost benefit analysis of biomass in Ireland is conducted, and finds that Ireland has only half the necessary resource to meet the 30% biomass cofiring target and as a result imports will be required in large quantities to meet the national target. It is found that in all cofiring scenarios, the estimated total NPVs are negative.

Many renewable generators, such as wind generation, have zero marginal cost and as such may reduce the overall cost of generating electricity. To date much of the literature on analysing the impact of wind generation on electricity prices has focussed on the computationally expensive and highly sophisticated engineering methodology of unit commitment. The third paper in this dissertation considers the impact of wind generation on Irish wholesale electricity prices using an econometric model, and then compares these results to a simulation based model. Results indicate that both models result in costs savings as a result of wind generation on the Irish system. They indicate that the level of these savings is non-trivial, and results in a market dispatch saving of between €93-141 million or 8-11%, and emissions savings of between €24.4-29.3 million.

Finally, this thesis considers the effects of wind and demand on CO₂ emissions from the Republic of Ireland's electricity market in an attempt to compare the effectiveness of two emissions reduction policies. The analysis indicates that wind is less effective than demand reduction in terms of reducing CO₂ emissions. A 1 MW reduction in demand results in approximately a 0.3 tonne reduction in CO₂ emissions per 30 minute period compared to 0.2 tonnes from wind for a 1 MW increase in wind output.

Acknowledgements

I would like to thank everyone who helped and supported me throughout my Ph.D. studies, in particular, special thanks goes to the following people.

First and foremost, I would like to thank my parents, Mary and Derek, for their constant encouragement and infinite support not only over the past four years but for my entire life. These two individuals have guided me throughout the process of writing this thesis as well as everything else I have ever done, and I owe everything that I have accomplished to them.

Next I would like to thank my supervisor, Dr. Eleanor Denny. I wouldn't have been able to complete this thesis without her guidance and encouragement over the past four years, and am extremely grateful for all the advice and direction she has given me. I appreciate all her contributions of time, ideas, and funding to make my Ph.D. experience productive and stimulating.

Dr. Mark O'Malley for his insight and advice, and also for always taking the time to discuss my research with me even though I'm not an engineer.

Dr. Benjamin Hobbs for hosting me in Johns Hopkins, and indeed all the other members of the Systems Group. My time at Hopkins was both insightful and enjoyable and I am very grateful for the opportunity.

Ms. Colette Ding for all her help over the past four years and for keeping things running smoothly.

I gratefully acknowledge the funding sources that made my Ph.D. work possible. I was funded by a Teagasc Walsh Fellowship. I would particularly like to thank Fiona Thorne for detailed discussion and encouragement in the area of biomass and cofiring.

I would also like to thank the students I had the pleasure to work with in both Trinity and the ERC. In particular I would like to thank Cat, Conor, Eamonn, Rob and Sanna for countless hours listening to me talk about my research, but even more for the non academic side of things, especially trips away, parties, and copious amounts of tea.

Finally I'd like to thank Rory for being supportive, kind, and very **very** patient especially during the final stages of this Ph.D. Thank you for everything.

Publications Arising from Thesis

Journal Papers:

1. A. O'Mahoney, F. Thorne, & E. Denny, "A Cost-Benefit Analysis of Generating Electricity from Biomass", *Energy Policy* (*accepted, in press*), March 2013. Also presented at the 26th Annual Conference of the Irish Economics Association, Dublin, Ireland, April 2012.
2. A. O'Mahoney & E. Denny, "Electricity Prices and Generator Behaviour in Gross Pool Electricity Markets", *Energy Policy* (*in review*). Also presented at 17th Spring Meeting of Young Economists, Mannheim, Germany, April 2012.
3. A. O'Mahoney, B. Hobbs, M. O'Malley, & E. Denny, "The Drivers of Power System Emissions: An Econometric Analysis", *Energy Economics* (*in review*). Also to be presented in 51st Meeting of the Euro Working Group on Commodities and Financial Modelling, London, United Kingdom, May 2013.
4. A. O'Mahoney, E. Lannoye, & E. Denny, "Modelling wind generation using empirics and simulation", *The Electricity Journal* (*in preparation*), 2013.

Peer Reviewed Conference Papers:

5. M. Lynch, E. Lannoye, & A. O'Mahoney, "Econometric Analysis of Flexibility Rewards in Electricity Markets", in *9th International Conference of the European Energy Market (EEM'12)*, Florence, Italy, May 2012.
6. A. O'Mahoney & E. Denny, "The Merit Order Effect of Wind Generation in the Irish Electricity Market", in *30th USAEE/IAEE North American Conference*, Washington D.C., USA, October 2011.

Contents

Declaration	i
Abstract	ii
Acknowledgements	iv
Publications Arising from Thesis	vi
List of Figures	xii
List of Tables	xiv
1 Introduction	1
1.1 Energy Consumption and Economic Growth	1
1.1.1 Energy Consumption and Emissions	4
1.1.2 Fossil Fuel Security of Supply	7
1.1.3 Emissions Reduction	7
1.2 Policy Response	9
1.2.1 Cost	10
1.2.2 Emissions Reduction	11
1.2.3 Security of Supply	13

1.3	Outline and Motivation of Thesis	14
1.3.1	Ireland	14
1.4	Thesis Aims and Paper Overviews	17
2	Generator Behaviour in Gross Pool Electricity Markets	20
2.1	Electricity Pool Market as an Auction	25
2.1.1	Gross Pool Electricity Market as a Vickrey Auction	27
2.2	Case Study System: The Irish Electricity Market	29
2.3	Data and Model	32
2.3.1	Demand	32
2.3.2	Supply	33
2.3.3	The Model	35
2.4	Results	36
2.5	Conclusions	40
3	A Cost-Benefit Analysis of Generating Electricity from Biomass	42
3.1	Methods and Data	46
3.2	Case Study - Ireland	47
3.2.1	Energy Crops - Willow & Miscanthus	49
3.2.2	Wood	50
3.2.3	Meat and Bone Meal	50
3.2.4	Potential Imports	51
3.3	Costs	51
3.3.1	Variable Costs Associated with Increased Biomass	51
3.3.2	Capital Costs Associated with Increased Biomass	53
3.4	Benefits	55
3.5	Net Present Values	57
3.6	Discussion	59
3.7	Conclusion	62

4	Modelling the Impact of Wind Generation on Electricity Market Prices using Empirics and Simulation	63
4.1	Merit Order Effect	67
4.2	Irish Electricity System	69
4.3	Methods	71
4.3.1	Regression Model	71
4.3.2	Simulation Model	72
4.3.3	Data	74
4.4	Results & Discussion	74
4.4.1	Regression Model Results	74
4.4.2	Overall Price Reduction Benefit - Econometric Regression Model	78
4.4.3	Average Emissions Savings - Econometric Regression Model .	79
4.4.4	Simulation Results	80
4.4.5	Simulated Prices	80
4.4.6	Simulated Emissions	81
4.5	Discussion	82
4.6	Conclusions	84
5	The Drivers of Power System Emissions: An Econometric Analysis	86
5.1	Electricity Market Emissions	89
5.1.1	Supply Side Approaches	89
5.1.2	Demand Side Approaches	92
5.2	Methodology	93
5.3	Case Study - Ireland	96
5.4	Data	97
5.5	Results	101
5.6	Discussion	104
5.7	Conclusions	107
6	Discussion and Conclusions	109
6.1	Discussion and Conclusions	109

CONTENTS	xi
6.2 Conclusions	114
6.3 Extensions of Work Presented and Future Work	114
References	118

List of Figures

1.1	Energy use (ktoe/capita)	5
1.2	CO ₂ emissions (metric tons/capita)	5
1.3	GDP (constant 2000 US\$/capita)	5
1.4	Change in power generation, 2010-2035	6
1.5	Average Annual Brent Crude Spot Prices	8
1.6	OECD Electricity Consumption by Sector	9
1.7	Energy Policy Measures	10
1.8	2011 Installed Generation Capacity for Ireland in MW	16
1.9	Papers within Energy Policy Pillars	17
2.1	Example of a Gross Pool Market Structure	23
2.2	Merit Order	26
2.3	Average Supply Breakdown in Ireland	31
2.4	Electricity Demand and Price for 1 week Jan '09	32
2.5	Mean Load & Price over 24 hours	38
3.1	CO ₂ emissions of fuels for electricity generation	45
3.2	Current Indigenous Biomass Resources	49
3.3	Cofiring Capital Processes Required	54

3.4	NPV with varying discount rates	58
3.5	NPV with varying Fuel Cost	58
3.6	NPV with varying Carbon Cost	58
4.1	Sample Merit Order Effect	68
4.2	EU Import Dependency	70
4.3	Load & Pool Price end of June 2011	77
4.4	Hourly Wind Savings per MW	78
4.5	Simulated savings from Wind	81
4.6	Estimated savings from Wind	83
4.7	Ireland	85
4.8	ERCOT (Texas)	85
4.9	New South Wales (Australia)	85
5.1	Irish Dispatch example	96
5.2	Load & Load forecast for week beginning 22 nd Oct 2012	100
5.3	Wind & Wind forecast for week beginning 22 nd Oct 2012	100
5.4	Impact of Errors on CO ₂ in Models 2 & 3	106

List of Tables

1.1	2011 National GDP and Energy Consumption	2
1.2	Overview of Selected Studies	3
1.3	Irish Indicators since 2007	15
2.1	End-User Prices in EU 15 countries, € 2008	21
2.2	Capacity by Fuel Type	30
2.3	Summary Statistics	36
2.4	Shadow Price Regression Model	37
2.5	Peak Hour Regression Model	39
3.1	Shares % Electricity Generation Fuel Mix	48
3.2	Biomass Resources	52
3.3	Cost Scenarios Current Indigenous Resources	53
3.4	Capital costs on a per station basis	55
3.5	Cofiring Costs per annum in €	55
3.6	Cofiring Benefits per annum in €	56
4.1	Summary Statistics	75
4.2	Model Results	76
4.3	Simulated Summary Statistics	80

5.1	European Renewable Installations in GW	87
5.2	Summary Statistics	98
5.3	Model Results	102

CHAPTER 1

Introduction

ENERGY policy is a key concern for policy makers worldwide and this thesis examines four distinct elements of energy policy, namely bidding in gross pool electricity markets, biomass cofiring, wind generation and emissions reduction. This introduction section puts these elements in the context of the Irish overall energy policy agenda and highlights some of the challenges facing the sector.

The optimal approach governments and policy makers should take to address energy issues is not always well defined, and must be considered within the context of greater policy issues such as competitiveness and consumer welfare. This thesis examines various energy policies under the three objectives of sustainable cost, emissions reduction and security of supply, discussed in the context of the Irish market.

1.1 Energy Consumption and Economic Growth

Energy consumption has risen steadily over the past century, so too have emissions, contributing to climate change. The stabilisation of greenhouse gas concentrations in the atmosphere is deemed necessary in order to prevent dangerous human activity

based interference with the climate system (IPCC, 2007).

According to IEA (2012b), the international climate goal of limiting global warming to 2 °C is becoming increasingly difficult and costly as time goes by. If no further action to reduce CO₂ emissions is taken by 2017, then all allowable emissions will be locked-in by existing energy infrastructure.

Energy consumption is a necessary contributor to economic growth - it is an input into the production of goods and services, the creation of capital stock, and for the development of technological progress. As electricity is a necessary input into all households and industries, the price paid for electricity directly affects the monetary and fiscal structure of nations (Harris, 2006).

In 2011, the top 5 countries by GDP¹ accounted for 49.4% of global Gross Domestic Product (GDP) (World Bank, 2013), and 48.1% of global energy consumption (BP, 2012), demonstrating the linkage between economic growth and energy consumption. Table 1.1 shows the top five economies in terms of national GDP in US\$ and national energy consumption in million tons of oil equivalent (Mtoe).

Table 1.1: 2011 National GDP and Energy Consumption

Country	GDP	%	Energy Cons.	%
	\$ Billions		Mtoe	
US	14,991.3	21.4	2,269.3	18.5
China	7,318.5	10.5	2,613.2	21.3
Japan	5,867.2	8.4	477.6	3.9
Germany	3,600.8	5.1	306.4	2.5
France	2,773.0	4.0	242.9	2.0
Top 5	34,550.8	49.4	5,909.4	48.1
World Total	69,981.9	100.0	12,274.6	100

Source: World Bank (2013); BP (2012)

Emissions and energy consumption are clearly highly correlated, and as a result reducing energy consumption is a key focus in terms of climate change goals. There is some concern that reducing energy consumption may have a negative im-

¹US, China, Japan, Germany and France (World Bank, 2013)

impact on economic growth, due to its importance in total factor productivity. While correlated, the direction of the causality is debated in the literature, with selected papers presented in Table 1.2. Numerous studies test the causal relationship between energy consumption and economic output in order to determine whether reducing consumption would cause negative impacts in terms of economic growth (Nyamdash and Denny, 2011). The results of this literature are mixed; Akarca and Long II (1979) found unidirectional Granger causality from energy consumption to unemployment using monthly US data from 1973-1979. This long run elasticity was estimated at -1.14, meaning that reducing energy consumption could result in increased total employment.

Table 1.2: Overview of Selected Studies

Country		Model	Short-run	Long-run
Multi-country Studies:				
Asian 10	(Chen <i>et al.</i> , 2007)	Bi-variate	Y→EC	Y→EC
Developed	(Lee and Chang, 2007)	Bi-variate	Y↔EC	-
Developing			Y→EC	-
G-7	(Narayan <i>et al.</i> , 2008)	Bi-variate	Y↔EC	-
Pacific Islands	(Mishra <i>et al.</i> , 2009)	Demand	Y↔EC	Y↔EC
Caribbean	(Francis <i>et al.</i> , 2007)	Bi-variate	Y↔EC	-
Single country studies:				
USA	(Chiou-Wei <i>et al.</i> , 2008)	Bi-variate	Y↔EC	-
	(Lee, 2006)	Bi-variate	Y↔EC	-
Korea	(Oh and Lee, 2004)	Supply	Y←EC	Y↔EC
	(Chiou-Wei <i>et al.</i> , 2008)	Bi-variate	Y↔EC	-
China	(Shiu and Lam, 2004)	Bi-variate	Y↔EC	Y←EC
	(Yuan <i>et al.</i> , 2007)	Bi-variate	Y←EC	Y←EC
Australia	(Narayan <i>et al.</i> , 2008)	Bi-variate	Y←EC	-
	(Narayan and Smyth, 2005)	Supply	Y→EC	Y→EC
India	(Ghosh, 2002)	Bi-variate	Y→EC	-
	(Asafu-Adjaye, 2000)	Demand	Y←EC	Y→EC
Thailand	(Masih and Masih, 1998)	Demand	Y↔EC	Y←EC
	(Asafu-Adjaye, 2000)	Demand	Y↔EC	Y↔EC
Turkey: GNP	(Jobert and Karanfil, 2007)	Bi-variate	Y↔EC	-
Disaggregate level studies:				
USA:SVA	(Zachariadis, 2007)	Bi-variate	Y←EC	Y↔EC
USA:IP	(Thoma, 2004)	Bi-variate	Y→EC	-
Turkey:IVA	(Jobert and Karanfil, 2007)	Bi-variate	Y↔EC	-
	(Karanfil, 2008)	Bi-variate	Y↔EC	Y→EC

Direction of causalities are indicated by →, ← and ↔, and no causality by ↔.

Output (GDP unless specified) by Y, and energy/electricity consumptions by EC. IP-Industrial Production. SVA-Service sector Value Added. IVA-Industrial sector Value Added. Source: Nyamdash and Denny (2011)

Asafu-Adjaye (2000) finds unidirectional Granger causality from energy to income in Indonesia and India in the short-run, and bidirectional Granger causality between energy, income and prices in Thailand and the Philippines. This implies that increased economic output results in increased demand for energy consumption, and vice versa for these two countries under the period of investigation.

Zhang and Cheng (2009) find unidirectional Granger causality from GDP to energy consumption, and from energy consumption to CO₂ emissions using annual data for China from 1960-2007. This result implies that CO₂ emissions and energy consumption are not drivers of economic growth in China. Soytaş and Sari (2009) investigates the linkages between economic growth, energy consumption and economic growth for Turkey using annual data from 1960-2000. Their results find that consumption does not seem to cause income in Turkey in the long run, however they also find Granger causality from carbon emissions to energy consumption, which seems counter intuitive. Other selected studies considering the relationship between economics growth and energy consumption are summarised in Table 1.2, which is adapted from Nyamdash and Denny (2011).

1.1.1 Energy Consumption and Emissions

Figures 1.1, 1.2 and 1.3 present annual trends in energy use, GDP and CO₂ emissions on a per capita basis for the US, China, Japan, Germany and France². These present annual values from 1960 - 2012 to consider these trends over time (World Bank, 2013). The link between energy consumption and CO₂ emissions is clearly visible in the data. While emissions and energy consumption per capita can be seen to fall slightly in recent years for most of the countries, China sees a surge in both. This increase coincides with higher levels of GDP per capita in China.

More recently, the correlation between energy consumption and emissions is seen to weaken, particularly in more developed countries. This decoupling effect, whereby the interdependency between the two variables lessens, means that economic growth can occur without a corresponding increase in emissions. Raupach *et al.* (2007) found

²Full data for Germany was unavailable thus EU values are also included for comparison.

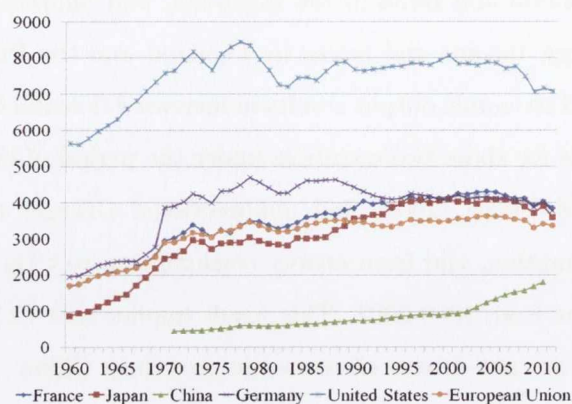


Figure 1.1: Energy use (ktoe/capita)

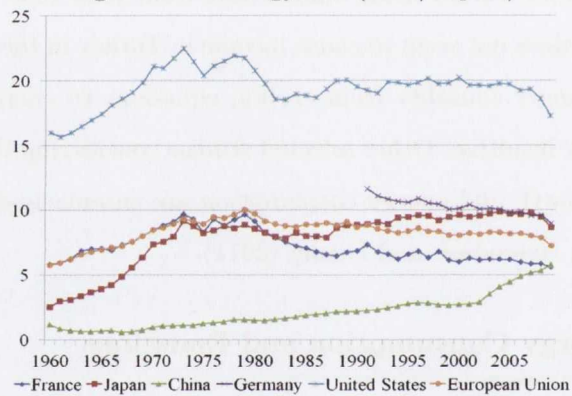


Figure 1.2: CO₂ emissions (metric tons/capita)

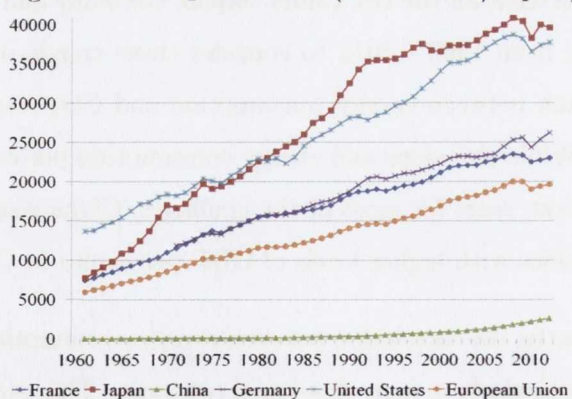


Figure 1.3: GDP (constant 2000 US\$/capita)

a decoupling of energy use and GDP growth in developed regions such as the US, Europe and Japan; however developing and the least developed economies accounted for 73% of global emissions growth. At the same time, they note that these nations account for only 41% of total global emissions.

Modi *et al.* (2005) note that 1.6 billion people currently lack access to electricity. Going forward, most growth in energy demand is likely to come from the developing world (Wolfram *et al.*, 2012). As people in these developing countries become more affluent, they are likely to purchase increasing levels of energy consuming appliances such as refrigerators and vehicles, which will cause their energy consumption to grow significantly (Wolfram *et al.*, 2012). However, despite this demand growth, switching away from biomass and carbon intense fuels, such as coal, in developing nations is unlikely to occur rapidly (Gaye, 2007). The 2012 World Energy Outlook predicts that China and India will continue to increase their demand for coal, and Figure 1.4 presents their estimates for the change in fuel mix for power generation between 2010 and 2035. Less developed regions are less concerned with emissions levels, and justify the use of cheaper, more polluting fuels due to the fact that they are not responsible for any of the historic emissions outputs. Chow (2013) describes it as “they are late to the dinner table so shouldn’t have to evenly split the bill”.

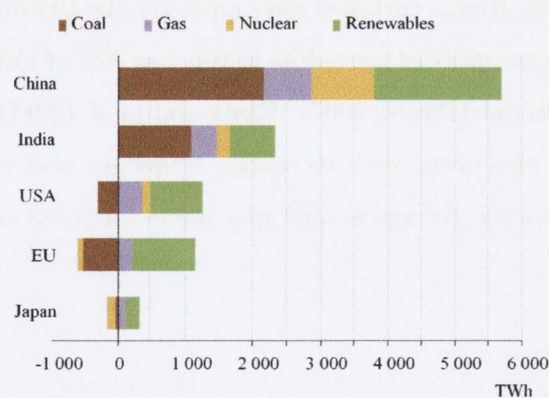


Figure 1.4: Change in power generation, 2010-2035

Source: Chow (2013)

1.1.2 Fossil Fuel Security of Supply

Regardless of the effect on economic growth, the continued consumption of fossil fuels at existing levels is unsustainable. Fossil fuels are a finite resource which are being consumed at a far greater rate than one at which they can regenerate. Based on IEA (2011) figures, global oil demand outstripped global production for five of the fifteen years between 1996-2010, with balances made from existing stores. As these reserves become more dispersed and costly to reach, energy prices will continue to rise. These costs negatively impact on economies - Lutz *et al.* (2012) notes that increased oil prices have a strong influence on the development of individual countries. In particular, they point out that a shortage or price spike will first and strongly affect the transport sector, but through global supply chains will indirectly affect all other sectors as well.

Additionally, there are risks of shortages of fossil fuels due to geopolitical issues. As energy is such an inelastic good, any supply shock to the market results in major price spikes. Fantazzini *et al.* (2011) note that since 2004, global oil production has remained within 5% of maximum production in spite of the historically high oil prices. Alpanda and Peralta-Alva (2010) find that the increased energy prices during the 1973 oil crisis were an important contributor to the US stock market crash of 1973-74. In 2006, Russia curtailed gas supplies to the Ukraine, which had impacts on the availability and price of gas across Europe, as 20% of Europe's natural gas passes through the Ukraine (Pirani, 2007). Fantazzini *et al.* (2011) believes that oil supply shortages may also occur with increasing frequency over the next decade. Figure 1.5 demonstrates the average annual spot prices for Brent crude from 1976-2011 BP (2012).

1.1.3 Emissions Reduction

Emissions reductions are needed in the electricity, heat and transport sectors but the electricity sector tends to be the most effective place to reduce emissions because of its centrally controlled nature with relatively inelastic demand, and as such much

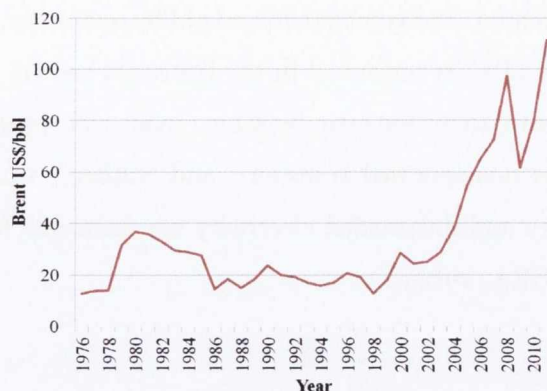


Figure 1.5: Average Annual Brent Crude Spot Prices
Source: BP (2012)

of the focus in CO₂ emissions reduction is in this sector. Electricity as a proportion of energy consumption has risen steadily. The world's demand for electricity is increasing at almost double the rate of total energy consumption (IEA, 2012b). Globally, electric power consumption per capita grew by an average of 2.4% annually between 1971-2010, whereas energy use per capita grew by an average of 0.9% annually over the same period (World Bank, 2013). Electricity is a major expenditure for all households, and is a key input in virtually all production and commercial processes. As electricity has few, if any, substitutes, the wholesale electricity price can directly impact on a country's competitiveness through its cost base and exports. As electricity is a necessary input into all households and industries, the price paid for electricity directly affects the monetary and fiscal structure of nations (Harris, 2006).

Electricity forms a large and increasing share of energy consumption on a global scale, and therefore we focus on this sector for the goal of emissions reduction. Quadrelli and Peterson (2007) found that the bulk of CO₂ emissions from fuel come from the electricity and heat sectors, and thus an improvement in the efficiency or carbon intensity of these sectors could substantially contribute to climate change goals. The electricity sector accounts for 22% of final energy consumption across all OECD countries. Figure 1.6 illustrates where this electricity is consumed across the various sectors. As presented, almost all of electricity generated is consumed between

industry, residential, and commercial and public sector use, in equal amounts. A minor proportion (1%) is consumed in the transport sector, which includes transport in industry and covers domestic aviation, road, rail, pipeline transport, domestic navigation and non-specified transport, and “Other”, which refers to agriculture, fishing, forestry and unspecified electricity use, accounts for 3% of total electricity consumption (IEA, 2012a).

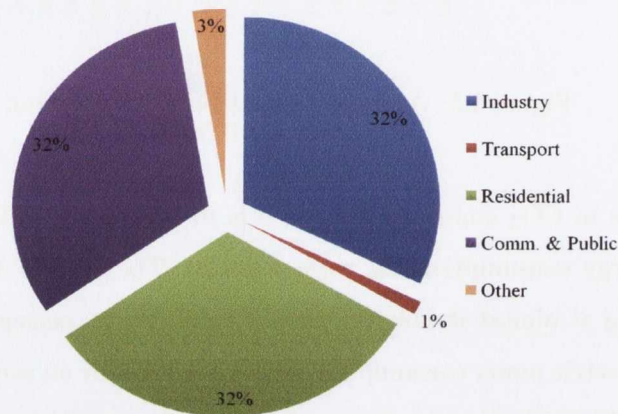


Figure 1.6: OECD Electricity Consumption by Sector
Source: IEA (2012a)

1.2 Policy Response

In the face of scarce resources and externalities in the form of emissions, governments must intervene in order to ensure sustainable future economic growth and to internalise the negative impacts of fossil fuels. A key challenge internationally is the design of future electricity systems which will bring about emissions savings and fuel security at least cost. In the 26 member countries of the International Energy Association (IEA), energy policy aims include diversity, efficiency, and flexibility within the energy sector; the ability to respond promptly and flexibly to energy emergencies; and the environmentally sustainable provision and use of energy (IEA, 1993). Thus, energy policy can be summed up by three main aims: security of sup-

ply, cost competitiveness and emissions reduction. Policy measures that facilitate the meeting of these goals are outlined in Figure 1.7, and each of the three goals are discussed in relation to the electricity sector.

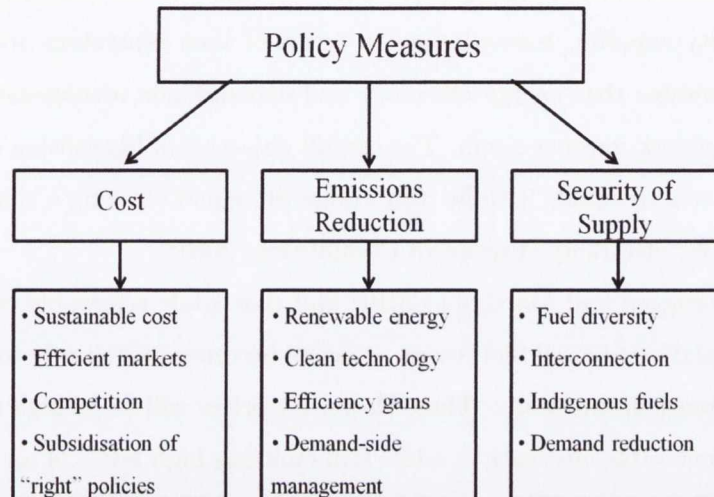


Figure 1.7: Energy Policy Measures

1.2.1 Cost

As energy costs impact upon final consumers through multiple chains, keeping electricity costs at a sustainable level is a key priority. This does not necessarily mean low, as excessively low electricity prices will not promote investment in electricity infrastructure leading to long run security of supply issues. Also, if prices are too low there is no incentive for consumers to reduce demand.

Sustainable pricing has been promoted through increasing electricity market competition. Prior to being consumed, electric power must first be generated, transported across the transmission network, and then distributed to end-users. In most countries historically, all of these operations were carried out by a single firm and thus electricity markets traditionally were a natural monopoly. Consequently, increasing competition and ensuring electricity markets are structured to promote

efficient markets will enhance the potential for cost savings.

In the EU, the Internal Market in Electricity Directive came into force in August 2003. This put forward several measures designed to open up the electricity market to benefit end-users; among these were the right for all consumers to choose their electricity supplier, transparency in terms of how generators are dispatched, and the guarantee that energy efficiency and demand side management are considered in all network improvements. The overall objective of liberalising the EU electricity market was to enable it to be fully competitive and creating a single integrated EU market for electricity (European Commission, 2003).

Verbruggen and Marchohi (2010) find that while renewable energy is currently costly relative to fossil fuel resources, as oil becomes more costly to extract oil prices will increase dramatically. Thus, electricity prices will be as high if not higher than under renewable alternatives while still emitting high levels of air emissions.

This highlights the necessity for the “right” types of policies and subsidies in order to meet cost objectives without affecting the other goals of emissions reduction and security of supply. China’s energy policies to date have focussed largely on low cost objectives, with 70% of their total energy consumption deriving from coal in 2009 (EIA, 2009). This, in turn, has had serious implications for China’s pollution levels - according to IEA (2006) China is home to five of the ten most polluted cities in the world, with Beijing alone having NO_x levels of $90\mu\text{g}$ and SO_2 values of $122\mu\text{g}/\text{m}^3$ (World Bank, 2007)³.

1.2.2 Emissions Reduction

The Kyoto Protocol is an agreement made under the United Nations Framework Convention on Climate Change (Kyoto, 1992) and countries that ratify this protocol committed to reducing their greenhouse gas emissions to around 5.2% below their 1990 levels by 2008-2012. The promotion of carbon pricing as a means of emissions reduction has been promoted primarily through mechanisms such as the EU Emissions Trading Scheme (European Commission, 2009b), Australia’s Clean

³The World Health Organization (WHO) air quality guidelines are annual mean concentrations of $40\mu\text{g}$ for NO_x and daily mean concentrations of $20\mu\text{g}/\text{m}^3$ for SO_2 .

Energy Act (2011), and the US Clean Air Act (2008).

Increasing renewable generation has been supported through mechanisms such as the US Energy Independence and Security Act of 2007 and the EU Renewables Directive (2009/28/EC). This Directive has driven national policies such as the Renewables Obligation Certificate Scheme in the UK (2011) and French and Irish National Renewable Energy Action Plans (2009).

Presently, the main types of renewable generation in use fall into two categories - those that are dispatchable, or available to be operated as the system operator requires them, and those which are non-dispatchable, or variable generators. Dispatchable renewables include biomass, and hydro power. These can be operated in a similar manner to traditional fossil fuel units, and are included in the merit order based on their marginal cost of generation. Variable generation renewables include wind and solar generation, which rely on weather patterns and cannot be dispatched in order to meet demand. These units, while less reliable, have a marginal cost equal to zero, and this has clear cost reduction benefits.

Clean technology options include innovations which reduce or remove flue-gas emissions⁴ from fossil fuel generators of electricity. These include options like scrubbers, which have the potential to remove 95% or more of SO₂ in the flue gases. These are generally most effective in coal stations, which are typically baseload units, which operate at low cost but are not especially flexible. This means that they cannot easily adjust their electricity output, and thus are not particularly complementary to systems requiring high levels of flexibility, such as systems with high levels of variable renewable generation (Adams and OMalley, 2010; NERC, 2009).

Another option for emissions reduction is through efficiency measures, such as consumers switching from standard to more energy efficient goods such as light bulbs and washing machines, or through demand side management (DSM). DSM can include programmes such as time of use pricing, which allows customers to respond to prices and allows the system operator to manage demand more effectively than most existing pricing mechanisms (Yik and Lee, 2005), as presently the majority of con-

⁴CO₂, SO₂ and NO_x

sumers pay a flat rate for the electricity that they consume, thus temporal variations in their demand is a function not of price but of their behavioural patterns.

1.2.3 Security of Supply

Security of supply means that consumers are able to obtain electricity of a defined quality when they need it. Threats to said supply may be as a result of lack of capital investment in transmission networks or generating units, or due to a lack of necessary electricity inputs such as fuel. As fossil fuel resources become more dispersed and are predominantly located in areas of political instability, the promotion of other sources of electricity generation such as renewable becomes increasingly important in order to maintain security of supply.

Ideally, no one fuel will dominate an electricity market, as any shock to its supply could potentially result in electricity blackouts or price surges. This means that maintaining a diversified generating portfolio is necessary in order to ensure long term security and reliability of electricity supply.

Nuclear generation is no longer considered a viable option in many countries, particularly in the wake of the Japanese Fukushima disaster in 2011. In spite of the risks involved with nuclear generated electricity, the costs of nuclear fuel are relatively low and stable (DCENR, 2006), thereby contributing to both the cost and security of supply objectives of energy policy. However, countries such as Germany, Switzerland, and Italy have announced plans to phase out or cancel all their existing and future reactors over safety concerns (EIA, 2011), while countries such as France have also called for a reduction in the share of nuclear electricity in the country's energy mix from 75% presently, to 50% by 2025 (REN21, 2012). Additionally, there currently exists no storage facility in the world for the final disposal of nuclear waste. All current storage units are intermediate storage units.

The use of indigenous fuels also enhances security of supply, as markets become less reliant on imports. Interconnection to other markets allows for increased market integration, which is particularly beneficial for markets which have large penetrations of renewables or indigenous fuels as it allows them to export any excess capacity to

regions without these assets, further enhancing cost-benefits. Interconnection also has the potential to mitigate market power as it increases market liberalisation, reducing the dominance of any single dominant firm (Neuhoff and Newbery, 2005). In March 2010, the European Commission committed €2.3 billion for 12 electricity and 31 gas interconnection projects across Europe, demonstrating their understanding of the importance of security of supply issues.

Consequently, emissions should be reduced by as much as is possible without negatively impacting upon the cost competitiveness or security of supply of electricity.

1.3 Outline and Motivation of Thesis

While climate change and overconsumption of fossil fuels are not optimal outcomes, the approach governments and policy makers should take to address these issues is not clear cut. The market will not reach equilibrium levels of emissions output and fossil fuel consumption without intervention, yet such intervention must be politically and administratively feasible.

Thus, any policy alternatives based on reducing emissions output and fossil fuel consumption must be considered within the context of related policy issues such as competitiveness and consumer welfare. We examine various energy policies under the three objectives of sustainable cost, emissions reduction and security of supply discussed in the context of the Irish market.

1.3.1 Ireland

Ireland is a small, island economy in north west Europe with a population of about 4.5 million. In the ten years prior to the financial crisis of 2007-2008, Ireland had experienced average annual growth of 6.2%, and unemployment levels of only 4.8%. This was largely as a result of high levels of Foreign Direct Investment (FDI), low corporate tax rates and, low European Central Bank interest rates.

However, Ireland was affected more intensely by the global financial crisis than other countries due to its narrow tax base which was highly dependent on the prop-

erty sector for revenue. This ultimately resulted in the EU bailing the Irish government out by €36.7 billion since 2010. Table 1.3 presents growth levels, unemployment and GDP per capita trends in Ireland since the economic downturn. While GDP growth has recovered slightly since its lowest point in 2009, unemployment has fallen steadily and GDP per capita was over 12% lower in 2011 than five years previously.

Table 1.3: Irish Indicators since 2007

Indicator	2007	2008	2009	2010	2011
GDP growth (annual%)	5.18	-2.97	-6.99	-0.43	0.70
Unemployment (% labour force)	4.60	6.00	11.70	13.50	n/a
GDP/capita (US\$ 2000)	31544	30131	27814	27599	27716

Source: World Bank (2013)

In spite of these economic difficulties, Ireland has remained committed to its energy policy goals, and in late 2009 the Irish Government announced a target of 40% of electricity production from renewable sources by 2020. This is part of the Governments overall commitment to achieve a level of 16% of all energy from renewable sources by 2020 (Eirgrid, 2011).

In terms of cost, Irish electricity prices are higher than other EU countries for a variety of reasons. Ireland is an island economy which is not well interconnected to other markets, and as a result cannot benefit from economies of scales to the same extent as other, larger markets. Ireland is also highly import dependent, and as a result is exposed to oil and gas market shocks to a greater extent than markets with large levels of indigenous fuel sources.

Ireland's emissions levels have fallen quite significantly over the past decade, with the emission factors of electricity generated falling by over 45% from a level of 896 CO₂ g/kWh in 1990 to 489 CO₂ g/kWh in 2011 (SEAI, 2012). This is largely due to its level of investment in wind generation, as well as the upgrading of indigenous

peat plants with more efficient stations since 2000, and investing in technologies to reduce emissions in Moneypoint, the nation's only coal station.

Security of Irish electricity supply has been greatly improved through upgrades to the transmission network, alongside greater efficiency and investment in new peat stations and the decision not to decommission Moneypoint coal station. However, Ireland has limited indigenous fuel resources, and its interconnection levels are relatively low - with 2 interconnectors each with a rated capacity of 500MW - or approximately 10% of Ireland's installed capacity in 2011. Ireland is highly dependent on fuel imports; Figure 1.8 presents the Irish Electricity market's installed capacity by fuel type for 2011.

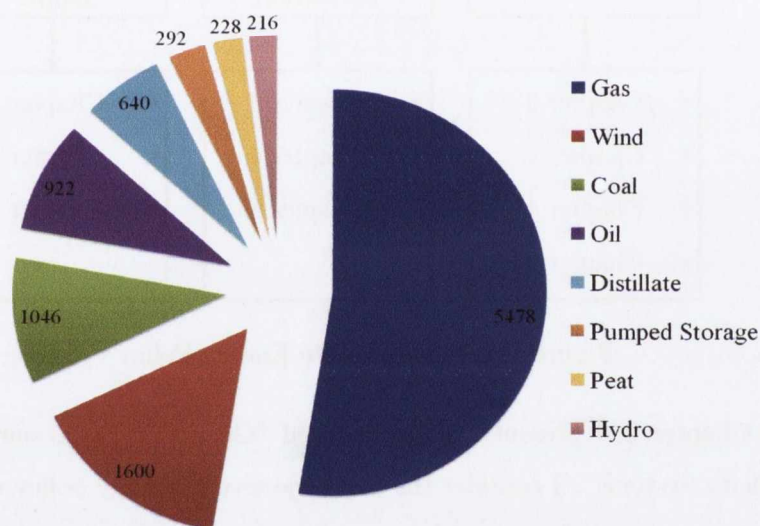


Figure 1.8: 2011 Installed Generation Capacity for Ireland in MW

Source: Eirgrid (2011); SEM (2011)

Ireland imports all coal and oil, and virtually all gas consumed within the Irish market, meaning just peat and wind can be considered indigenous fuel sources. It is important to note that while wind represents the largest installed capacity this represents its maximum export capacity, however wind has a load factor of approximately 29% (Eirgrid, 2013a), which means it is available at roughly 29% of its maximum on average.

1.4 Thesis Aims and Paper Overviews

The aim of this thesis is to consider various policy mechanisms with a view to determine whether they are in line with energy policy goals. Each of the four papers of this thesis are presented in Figure 1.9 in order to illustrate which of the three strands of energy policy that they investigate.

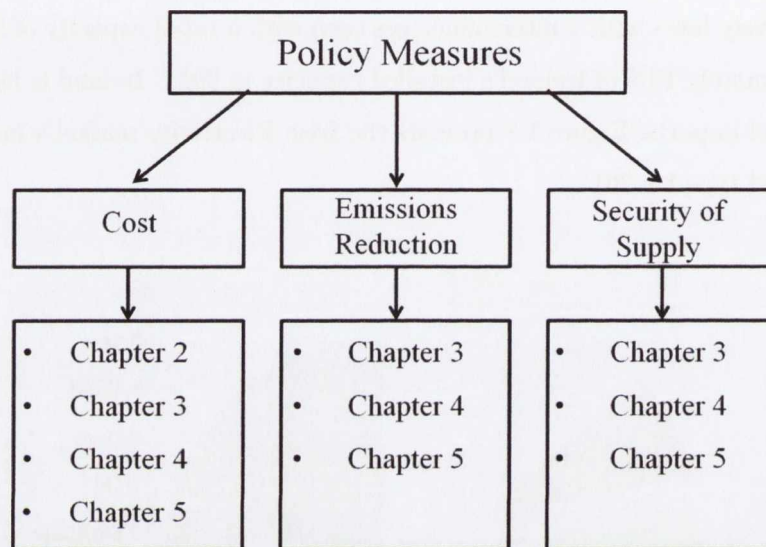


Figure 1.9: Papers within Energy Policy Pillars

In Chapter 2, I present a paper entitled “Generator Behaviour in Gross Pool Electricity Systems”. I consider the cost objective of energy policy within the Irish market. I present a theoretical framework and econometric model in order to consider whether a pool market achieves this goal of increasing competition and reducing electricity prices. We assume that if generators are bidding in accordance with theory and regulatory guidelines, the marginal cost of electricity can be considered to be competitive. Results indicate that the Irish pool system appears to be working efficiently and that generators are bidding their true marginal costs. Thus, the pool element of the market structure does not contribute to the high electricity prices experienced in Ireland. In first identifying whether electricity markets behave in accordance with theory and regulation, we can subsequently ensure that various policy interventions may be fairly compared within the Irish context.

I then consider two methods of fossil fuel reduction in the form of renewable generation policies in Chapters 3 and 4. These papers consider elements of all three energy policy objectives; their impact on cost reductions, emissions reduction and security of supply. Increasing the level of diversity of supply will enhance a system's security of supply, however not all forms of renewable generation are equally beneficial as variable generation sources cannot be relied on for supply at all times equally. For this reason we analyse two different types of renewable generation: biomass which although renewable can be scheduled for operation like any other conventional power station and wind generation which is variable and relatively unpredictable and cannot be 'scheduled' to operate at particular times.

Chapter 3 presents a paper entitled "A Cost-Benefit Analysis of Generating Electricity from Biomass". In this paper, I consider the effect of Biomass using a cost benefit methodology. Cofiring biomass in existing peat stations allows for considerable emission reductions, yet increases station costs through additional capital expenditure, plant modification and O&M costs. Additionally, we estimate the available indigenous biomass resource within Ireland. Due to EU level policies, biomass cannot be considered within the market model presented in Chapter 2 as it does not bid into the market due to its renewable status. Thus, we compare a number of scenarios in an attempt to identify whether existing biomass targets are economically viable and feasible. The results demonstrate that Ireland has only half the necessary resource to meet the national 30% target and that the net cost of doing so is greater than the cost of what is currently being paid for peat, in all of the scenarios considered.

Chapter 4 considers the impact of wind on the Short Run Marginal Cost (SRMC) of electricity, in a paper using the market model developed in Chapter 2 and extending it to identify the price suppression effect of wind on an hourly basis. While wind is also a renewable, it has a priority dispatch status meaning that all wind output must be consumed when it is available. As a result, we can directly identify its price suppression effect in the market on an hourly basis.

In Chapter 5 I compare the effectiveness of two methods of emissions reductions

to consider whether policy options can be considered equally effective in a paper entitled “The Drivers of Power System Emissions: An Econometric Analysis”. Targets have been set for numerous forms of emissions reduction and renewable forms of generation, yet these measures are simply methods of meeting energy policy objectives. The paper contributes to the literature in this area in that it considers the effects of both wind and demand side management on emissions, and it uses actual data rather than a market simulation approach. If these measures are to promote emissions reduction, they should be compared on this basis in order to justify future policies promoting either. Overall, the findings of this paper suggest that wind and load are not equally effective in terms of reducing emissions, and wind in fact only reduces two thirds of CO₂ emissions than that of an equivalent reduction in demand.

Finally, in Chapter 6, I summarise all work and discuss what these results mean in terms of energy policy for Ireland. I also consider potential extensions from the papers as well as outlining certain limitations with the findings in this dissertation.

Generator Behaviour in Gross Pool Electricity Markets

ELECTRICITY is a major expenditure for all households, and is a key input in virtually all production and commercial processes. As electricity has few, if any, substitutes, the wholesale electricity price can directly impact on a country's competitiveness through its cost base and exports. As electricity is a necessary input into all households and industries, the price paid for electricity directly affects the monetary and fiscal structure of nations (Harris, 2006).

In the 26 member countries of the International Energy Association (IEA), energy policy aims include diversity, efficiency, and flexibility within the energy sector; the ability to respond promptly and flexibly to energy emergencies; and the environmentally sustainable provision and use of energy (IEA, 1993). Thus, energy can be summed up by three main aims: security of supply, sustainability, and competition. In recent history, the liberalisation and deregulation of electricity markets has also become common practice internationally in an effort to increase competition and reduce prices.

In the EU, the Internal Market in Electricity Directive came into force in August 2003. This put forward several measures designed to open up the electricity market

to benefit end-users; among these were the right for all consumers to choose their electricity supplier. The overall objective of liberalising the EU electricity market was to enable it to be fully competitive and remove any existing differences between Member States (European Commission, 2003).

While the main driver of liberalisation is a reduction of production costs and prices to end-users, the process of deregulation has proven to be less straight forward than initially considered (Bunn, 2004; Neuhoﬀ and Newbery, 2005). Reasons for this are primarily issues related to the technical limitations of generators, the size of the incumbent, economies of scale, the natural monopoly of networks and the long lead times in building new capacity.

Table 2.1: End-User Prices in EU 15 countries, €2008

Country	Industrial Prices	Domestic Prices	GW Installed
	c/kWh	c/kWh	
Austria	8.82	14.71	20.75
Belgium	n/a	15.21	16.70
Denmark	7.42	22.63	12.50
Finland	5.55	9.87	16.64
France	6.00	9.41	17.62
Germany	n/a	n/a	133.94
Greece	6.43	8.98	14.24
Ireland	10.64	15.29	7.20
Italy	16.59	17.48	97.88
Luxembourg	7.02	12.34	1.64
Netherlands	7.99	13.88	24.83
Portugal	7.52	12.57	15.70
Spain	7.16	12.48	90.19
Sweden	5.45	12.49	33.94
UK	8.37	13.27	85.58

Table 2.1 presents the installed capacity and electricity prices to end-users in the EU 15 countries as of 2009 (Eurostat, 2010; SEAI, 2009b). It shows Ireland, whose electricity market is the focus of this paper, to have the second smallest capacity of countries shown while having some of the highest end-user prices. Italy, on the other hand, has one of the highest installed capacities and still has relatively high end-user prices, which implies market structure may be an important determinant of the costs faced by consumers for the electricity they consume. If this is in fact

the case, then high end-user prices could be reduced through a change in electricity market structure. In this paper we will investigate whether electricity costs are driven by market structure in the Irish context.

Prior to being consumed, electric power must first be generated, transported across the transmission network, and then distributed to end-users. Electricity is generated by converting energy stored in fuels (fossil, nuclear, hydro or other renewables) into electricity in power stations. These stations can be independent or part of larger companies and their sole role is to generate electricity. This is then transported via the electricity infrastructure through, firstly, high voltage/long distance transmission lines and then, low voltage, local area distribution lines. This infrastructure is used for all electricity generated, and as such is generally owned by the state or another monopoly in order to ensure that it is properly maintained and can be accessed by all. In a deregulated environment this infrastructure is operated by independent transmission system operators and distribution system operators to ensure reliable operation and fair access for generation and supply companies (Harris, 2006; Kirschen, 2005). Electricity is then supplied to end-users via a supply company; while in some cases this can be the same company as that generating electricity this is not always the case. Electricity cannot be stored easily, and thus must be generated, transmitted and supplied to the end-user when needed (Weron, 2006).

Methods of liberalising wholesale electricity markets have included structures such as bilateral contracts and gross pool systems. Where bilateral contracts are in operation, generators and suppliers enter into contracts without involvement, interference or facilitation from a third party and as a result there is no official price for electricity as each transaction is set independently by the parties involved (Kirschen, 2005). A pool, similar to an auction, provides a mechanism to systematically determine the equilibrium quantity without relying on direct interactions between consumers and suppliers (Harris, 2006; Kirschen, 2005).

The method of increasing competition within electricity markets which this paper will focus on is the use of mandatory gross pool electricity markets. Where

implemented, participation in such a pool is mandatory, thus ensuring no physical trade of electricity outside of the pool. Each generator bids a price at which it is willing to supply electricity. These bids are then ranked to form a merit order, with electricity demand being met by dispatching units (switching plants on), beginning with the lowest cost unit, until demand is satisfied. Firms are expected to bid based on the prices at which they will cover the variable costs of operating their power plants. These power plants are then ranked based on a merit order, thus making generation costs and network constraints the determining factors for dispatch. The market clearing price is then established by a one-sided auction at the intersection of the supply curve and the forecasted demand for each period (Weron, 2006). In the early 1990s a gross pool system was in operation in England and Wales; however it was later replaced by New Electricity Trading Arrangements (Bunn, 2004; Green and Newbery, 1992; Weron, 2006). Gross pools are currently in operation in Spain, Ireland, and Alberta (Weron, 2006). Figure 2.1 illustrates an example of a gross pool structure.

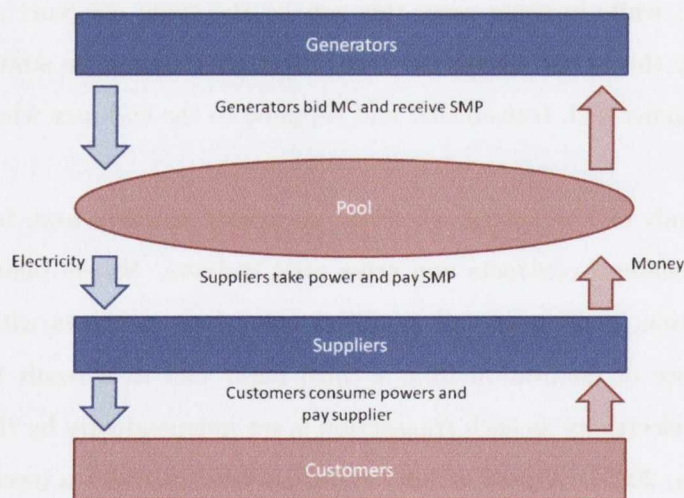


Figure 2.1: Example of a Gross Pool Market Structure

This paper estimates the magnitudes of the main determinants of electricity prices using historical data. While much work has been done in the areas of electricity demand forecasting and price prediction (Bunn, 2000; Conejo *et al.*, 2005; Nogales *et al.*, 2002), little work has been done focusing solely on the effect of the drivers. The majority of studies use simulated as opposed to historical data (Bierbrauer *et al.*, 2005; Knittel and Roberts, 2005). Historical studies allow us to see the true impact of each independent variable over the period in question and may give a more accurate representation than purely simulation-based studies.

Karakatsani and Bunn (2010) use 10 months of half-hourly data from 2001-2002 from the UK market in order to assess the drivers of electricity prices. They found the main causes of volatility to be associated with firm's reactions to market fundamentals, time varying effects and regime switching dynamics. They found evidence of strategic pricing and behavioural influences of generators through learning. An earlier paper by the same authors (2008) focused on the effects of spot price drivers in wholesale electricity markets using linear regression specifications across the 48 trading periods of the day. They found the market to be responding to economic fundamentals and plant operating properties, with learning and emergent financial characteristics, as well as some strategic manipulation of capacity, most effectively exercised by the more flexible plants. Multivariate linear regression was also used by Al-Ghandoor *et al.* (2008) to identify the main drivers behind electricity consumption based on the Jordanian industrial sector. This paper used annual historical data from 1985-2004. One of their main results found that electricity prices had no effect on electricity consumption, and therefore there is no incentive for firms to adopt more efficient technologies or choose less carbon intensive fuels.

This paper will investigate whether gross pool systems are an efficient way to structure electricity markets, given the technical issues and the mixed experience of systems such as the UK to date (Bunn, 2004; Green and Newbery, 1992; Weron, 2006). It will do so by focusing on the interaction of the individual generators and the pool itself. This paper considers the theoretical framework surrounding the operation of an efficient gross pool market; it then tests a gross pool market econo-

metrically to determine if actual market operation produces results consistent with theory and if participants are abiding by market rules.

The remainder of this paper is structured as follows; Section 2.1 outlines the theoretical framework of bidding within a sealed bid second price auction within which we expect generators to operate, and Section 2.2 introduces the Irish electricity market as the case system. Section 2.3 details the model and data used and the results and conclusion are presented in Sections 2.4 and 2.5 respectively.

2.1 Electricity Pool Market as an Auction

According to David and Wen (2000), “Almost all operating electricity markets worldwide employ the sealed bid auction with uniform market prices”. While typically one thinks of buyers auctions, where several bidders attempt to buy a good, electricity markets reflect sellers auctions, where firms bid to supply a good or service. Barriers to entry in the form of capital costs should not affect the short term operation of the market as these costs to the generating firms are often recovered through separate cost recovery or revenue streams. In the long term it is recognised that they do have an impact, but this is not the focus of this research. In the short run, each unit is constrained by the quantity of electricity which it is capable of producing. Participation in the market is determined solely by the price at which they bid into the market. Electricity is an entirely homogenous good; however in most systems, no single unit is large enough to meet demand individually and thereby capture the entire market.

Each firm will have a different marginal cost based on its fuel type, maximum capacity (output) and efficiency. This will result in firms having a diverse range of marginal costs despite producing a homogenous product. This creates a merit order equivalent to each firm’s respective marginal costs, with the pool purchasing the entire output of the lowest cost firms up to the point where demand is met.

While tacit collusion through inflated bids would allow for a collectively more profitable result, each unit is increasing the risk that they will not be dispatched

by pricing themselves out of the market. A unit bidding below marginal cost will increase the likelihood that they will be dispatched, but also increase the probability that the market clearing price will be set below their true marginal cost. Thus, it is expected that bids made by generators will reflect their true marginal cost.

When a generator bids something other than its marginal cost, in an attempt to exploit imperfections in the market and increase its profits, this behaviour is called strategic bidding (David and Wen, 2000). This leads to distorted prices and higher electricity costs for end-users. The electricity market structure under a mandatory gross pool system can be examined as a sealed bid second price auction, where no firm knows exactly what any other firm has bid, and a firm's bid does not affect the price they receive for their electricity, only whether they are dispatched. Electricity is provided by a few major suppliers, with each individual generating unit competing against the others (even those owned by the same company) in order to be "dispatched" and enter into the market, as shown in Figure 2.2.

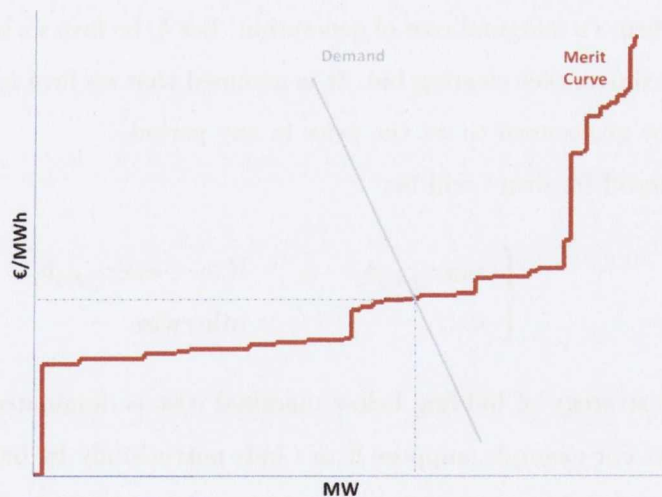


Figure 2.2: Merit Order

We propose to model this as a Vickrey auction. Vickrey (1961) demonstrated that a particular pricing rule makes it a dominant strategy for bidders to report their values truthfully, even when they know that their reported values will be used to allocate goods efficiently¹. If a Vickrey auction is the correct framework for modelling the interaction between generators and electricity pools, then one would expect to find generators are in fact bidding truthfully and efficiently by reporting their true short run marginal costs. The purpose of this paper is to test whether this is the case in the Irish electricity market.

In a Vickrey type auction, bidding one's true marginal cost can be seen to be the dominant strategy for each firm. Bids are sealed, which means it is assumed that no firm has perfect information in relation to the bids of others. It is a second price auction, meaning the bid a firm makes does not necessarily determine the price they receive for the electricity they supply. This is explained in further detail below.

2.1.1 Gross Pool Electricity Market as a Vickrey Auction

Let c_i be firm i 's marginal cost of generation. Let b_i be firm i 's bid price in the pool, and b_j be the market clearing bid. It is assumed that no firm is sufficiently large in order to be guaranteed to set the price in any period.

The payoff for firm i will be:

$$\begin{cases} \max_{(j \neq i)} b_j - c_i & \text{if } b_i < \max_{(j \neq i)} b_j \\ 0 & \text{otherwise} \end{cases}$$

- The strategy of bidding below marginal cost is dominated by bidding truthfully. For example, suppose firm i bids untruthfully by bidding $b_i < c_i$.

If $\max_{(j \neq i)} b_j > c_i$ then firm i would have been dispatched with a truthful bid as well as a bid below marginal cost. The amount of the bid does not alter the payoff therefore both strategies have equal payoffs.

¹This sealed bid, second price auction is considered more appropriate than a uniform-price auction to represent the gross pool electricity market as each generator is capable of bidding multiple units. Under a uniform price auction, this does not lead to bidders bidding their true valuation.

If $\max_{(j \neq i)} b_j < b_i$ then firm i will not be dispatched regardless so both strategies have equal payoffs.

If $c_i > \max_{(j \neq i)} b_j > b_i$ then only the strategy of bidding below marginal cost would win the auction. The payoff for underbidding would be negative as the firm would receive less than their marginal cost for the electricity they supply.

If they had made a truthful bid ($b_i = c_i$) no loss would be made as the firm would simply not be dispatched and its payoff would be 0. Consequently the strategy of bidding below one's true marginal cost is dominated by truthful bidding.

- The strategy of bidding above marginal cost is also dominated by truthful bidding. Assume that firm i bids $b_i > c_i$.

If $\max_{(j \neq i)} b_j < c_i$ then firm i would not be dispatched with a truthful bid or a higher bid, so the strategies have equal payoffs in this situation.

If $\max_{(j \neq i)} b_j > b_i$ then the firm would be dispatched in both cases so the payoffs are once again the same in either case.

If $b_i > \max_{(j \neq i)} b_j > c_i$ then only the strategy of bidding one's true marginal cost would win the auction. The payoff for the truthful strategy will be positive as the firm will receive the market clearing price which is above their true marginal cost, while the payoff for bidding above marginal cost would be zero.

Therefore the strategy of bidding above marginal cost is dominated by the strategy of truthful bidding.

We assume in this model that there is always sufficient excess supply in the market. When this assumption is removed, single units may have market power and reserve pricing may be required (Ausubel and Cramton, 2004; Fabra *et al.*, 2002b). Vickrey auctions are unique in the sense that less efficient suppliers produce only when a rival's capacity is exhausted, meaning that they guarantee productive efficiency independently of the industry capacity and cost configuration (Fabra *et al.*, 2002a).

2.2 Case Study System: The Irish Electricity Market

The Irish electricity market, similar to many others internationally, consisted of a statutory monopoly (ESB in the Republic and Viridian in Northern Ireland) until the market was fully opened to competition in February 2005. These two previously independent systems (of the Republic of Ireland and Northern Ireland) are now combined to create a Single Electricity Market (SEM) for the island of Ireland. In the Irish context, electricity generators receive three types of payment: capacity payments, uplift and the shadow price.

Capacity payments relate to a plant's availability to provide electricity based on maintenance schedules, maximum output and whether or not their supply is needed. These capacity payments are paid in monthly instalments and can be considered payments to assist generators in recovering their fixed costs. They are also justified as a means to encourage investment in generation into the future.

Uplift is a payment through which units can recover their start-up and maintenance costs. When a unit is dispatched in the market, it may be required to switch on from an offline position. Starting up a generating unit almost always leads to early component failure and higher costs (Denny and O'Malley, 2009; Lefton *et al.*, 1997). When the cost of premature component degradation and other impacts are included in the total cost function, it is estimated that the average cost for switching on a single unit can cost as much as €500,000 depending on the type of unit (Grimsrud and Lefton, 1995). This uplift payment enables generators to recover these start-up costs. Uplift is only added to the shadow price if there are generators that do not recover their start-up and no load costs from their infra-marginal rent over a continuous period of operation.

The third payment is called the shadow price and simply refers to the marginal cost of producing electricity in any period². In other words, it is the bid (marginal cost) of the last unit to be dispatched in meeting the demand in any hour.

The System Marginal Price (SMP) comprises the uplift and shadow price ele-

²It should be noted that this price is not a shadow price in the economic sense, in that it is not the value of the Lagrange multiplier at the optimal solution. However, the market documentation refers to the shadow price so for consistency we will continue to use this terminology here.

ments and is paid daily; 83% of the average SMP consists of the shadow price and 17% is from the uplift for the timeframe studied in this paper. This paper focuses exclusively on the appropriateness of the shadow price element of the gross pool market, as this represents the greatest fraction of short run costs, and it most accurately represents the interaction of the generators and the pool itself.

The Irish electricity market is a small, isolated system with a maximum demand of 6488 MW in 2009 and a total installed capacity of 8061MW for the same period. On 1st November 2007 the SEM went live, commencing the trading of wholesale electricity in Ireland and Northern Ireland on an All-Island basis. The SEM consists of a gross mandatory pool market, into which all electricity generated on or imported onto the island of Ireland must be sold, and from which all wholesale electricity for consumption on or export from the island of Ireland must be purchased (SEM-O, 2010). Table 2.2 represents Ireland's installed capacity by fuel type.

Table 2.2: Capacity by Fuel Type

Fuel	MW
Gas	4589
Coal	1331
Oil	805
Hydro	508
Peat	343

Ireland is connected to the Great Britain (GB) system via the Moyle interconnector from Northern Ireland to Scotland, with a maximum import capacity of 400 MW, and export of 80 MW. This means Ireland is essentially self sufficient in its electricity generation. Figure 3.3 below demonstrates the mean proportion of total demand met through conventional supply (which refers to fossil fuel generation), wind, peat and imports over the course of the day.

According to the Market Operator (SEM-O, 2010), conventional generators must bid price and quantity pairs relating to the electricity they can provide for the following day. The price which generators bid is expected to reflect the marginal cost of generating the quantity of electricity specified, and as such is expected to include fuel and carbon prices. While each generator will most likely have hedged fuel costs,

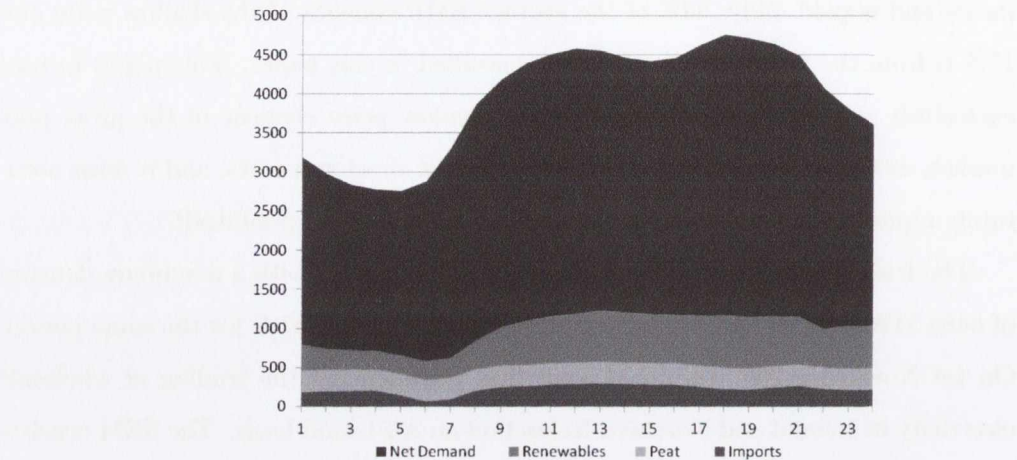


Figure 2.3: Average Supply Breakdown in Ireland

the market rules state that the bids should reflect the opportunity cost of the fuel, meaning the spot price at the time of the bid (CER, 2007).

The marginal unit during each trading period sets the price which all units receive for that period, meaning every other unit that is dispatched receives above the price it bids in at. Generators do not simply receive their bid price as this would act as an incentive to submit bids based not on their marginal cost but their expected value of the breakeven price of electricity (Kirschen, 2005). Due to the set up of the Irish electricity market, it is a prime case study in which to test the effectiveness of a gross pool system based on a Vickrey-style auction. It has little interconnection with other markets, and supply of electricity from all conventional units is required by the Regulator to bid in quantities and prices thus resulting in a Vickrey supply auction set up.

2.3 Data and Model

2.3.1 Demand

Theoretically we expect demand for a good to depend on the price of the good. However, on an hourly basis, demand for electricity is affected exclusively by cycles of activity, as the price final consumers pay for their electricity is fixed³ and is therefore entirely independent of the shadow price (Kirschen, 2005). As demand is independent of the price of electricity in the short run, it can be considered to have zero price elasticity (David and Wen, 2000).

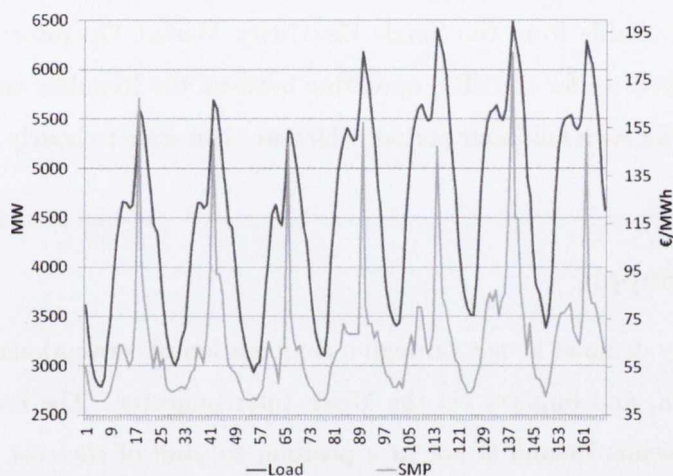


Figure 2.4: Electricity Demand and Price for 1 week Jan '09

While the shadow price does not impact on demand, other factors have an influence on the demand in any hour such as sunshine hours, rainfall, whether it is day or night and daily, monthly and seasonal factors. Social events such as sporting events will also affect demand (Owayedh *et al.*, 2000)⁴. From Figure 2.4 above one can see demand for electricity is highly cyclical with a peak in the evening and minimum

³With the exception of a small number of firms who pay the pool price, however these represent a small fraction of total demand in any hour and can be ignored for the purposes of this study.

⁴Other factors affect the load including losses incurred on the network, the need for reserve, and the amount of electricity required by the generators themselves. These elements are not considered in this study.

during the night.

$$\text{Demand} = f(\text{time, weather, social events}) \quad (2.1)$$

This study attempts to estimate the shadow price using the supply and demand curve. Traditionally, demand would be considered endogenous in such models since it depends on price, however, as mentioned previously, the hourly demand for electricity is independent of the shadow price, thus actual values for demand can be utilised.

Demand in each period must equal supply, as in order to prevent blackouts generators must meet demand and excess supply will result in frequency issues. Demand data is available from the Single Electricity Market Operator (SEM, 2013) - the market operator for the SEM operating between the Republic and Northern Ireland - website for each half hour period, which we then scale to hourly level for all of 2009.

2.3.2 Supply

Electricity demand is met through a combination of conventional supply, renewable generation, and imports via the Moyle interconnector. The low level of interconnection means Ireland is not in a position to avail of the cost efficiencies created in other countries due to economies of scale or the increased liberalisation of the common internal market for electricity (DETI, 2005). While instinctively one would assume imports to be dependent on the shadow price of electricity, or at least the difference between it and the Great Britain price, this is not the case. In fact, Devitt *et al.* (2011) found the wholesale price of electricity to be over €30/MWh higher in Ireland than the UK in 2008, with around half of this attributable to differences in generating technology. There are several reasons for this; mainly in relation to the misalignment of the two markets. For example, the interconnector bids are made in advance of those of the generators; another issue is that the SEM price in any period is not known until Day+4 (SEM Committee, 2009). Imports are not required to bid according to market rules, and as a result both of these should have a negative

impact on the price of electricity in a given period.

Peat and renewables do not participate in the market financially as they are supported separately through a Public Service Obligation (PSO) levy, however they do participate physically in the sense that all electricity is supplied via the pool⁵. This means they have a regulatory mandatory purchase agreement which results in all electricity generated by these units being consumed regardless of their marginal costs. Thus they are not considered as part of the merit order in the operation of the market.

The remainder of demand is met through conventional suppliers which burn fossil fuels in order to generate electricity. These conventional units are the focus of this study, and as a result load net of renewables, peat and interconnector imports is used, leaving demand for conventional supply. As these units must bid their available price and quantity into the market the day prior to generation, the opportunity cost of their fuels should relate to the spot price of the previous day.

We include the daily spot prices for coal, oil, carbon and natural gas into the model. Each of these fuels only bids a single price every 24 hours, therefore the price for each fuel will be identical for 24 successive periods. It is important to note that while all units which use the same fuel will incur the same fuel cost on the spot market, each plant will have a different maximum output and efficiency and this will impact upon the price they bid into the market.

$$TotalSupply_t = ConventionalSupply_t + Renewables_t + Peat_t + Imports_t \quad (2.2)$$

$$TotalSupply_t \equiv TotalDemand_t \quad (2.3)$$

$$NetDemand_t = ConventionalSupply_t - Renewables_t - Peat_t - Imports_t \quad (2.4)$$

$$NetDemand_t \equiv ConventionalSupply_t \quad (2.5)$$

⁵The PSO levy was introduced in January 2003, and relates to the purchase of the output of peat generated electricity, in the interests of security/diversity of supply, and the output of renewable energy generating stations (DETI, 2005). The PSO levy promotes the national policy objectives of ensuring a secure energy supply, the use of indigenous fuels and the use of renewable energy sources in electricity generation. This means if the market clearing price is below the price guaranteed under the PSO, then these generators will be topped up to this levy amount.

2.3.3 The Model

Irish hourly data for 2009 from the SEM is used to identify the main drivers of the shadow price through an inverse supply function regression model. It is expected for the Irish system that the most accurate predictors of the shadow price would be the fuel input prices of oil, gas, coal and carbon price from the day prior to bidding (when bids must be made), and demand and marginal capacity of the day in question.

This is consistent with the guidelines for bidding set out in the market, and is described in the following model:

$$\begin{aligned} ShadowPrice_t = & \alpha + \beta_1 NetDemand_t + \beta_2 NetDemand_t^2 + \beta_3 MarCap_t \\ & + \beta_4 Gas_{(t-24)} + \beta_5 Oil_{(t-24)} + \beta_6 Coal_{(t-24)} + \beta_7 Carbon_{(t-24)} + \epsilon_t \end{aligned} \quad (2.6)$$

Net demand refers to total system demand less demand that is met through renewable and peat output and imports at time t . Gas Coal, Oil and Carbon relate to the daily spot prices of these fuels on the global exchange. These are set and bid into the market in the day ahead and therefore are lagged by 24 periods to account for this.

As demand increases towards total possible supply available, one would expect prices to increase dramatically due to a scarcity premium. In order to see if this is taking place, we include a marginal capacity (*MarCap*) variable in the model, which can be described as $MWOffline/Demand$ - i.e. the number of megawatts which are unavailable for generation as reported by each individual generating unit. This is essentially the difference between the maximum rated number of megawatts a unit is able to supply and their actual availability in a given hour. This is included in the model in order to identify whether a scarcity premium is found to be significant, with a fall in availability resulting in an increase in the price of electricity. Table 2.3 provides summary statistics for all observations of variables included within this study.

In this study we generate a times series multiple regression model. Controls are

Table 2.3: Summary Statistics

Variable	Units	Obs	Mean	Std. Dev.	Min	Max
Shadow Price	€	8682	36.044	12.438	14.485	146.570
Net Demand	MW	8682	2953.656	889.177	276.335	5794.013
MarCap	:	8682	4.313	3.196	0.991	24.701
Gas	€	8682	44.366	6.874	28.157	54.316
Oil	€	8682	34.635	13.274	15.505	77.094
Coal	€	8682	51.173	5.463	44.120	65.040
Carbon	€	8682	13.353	1.542	8.200	15.900

included for each hour of the day, day of the week, month and public holidays as all of these have an effect on the demand for electricity, the availability of wind for generation, and the scheduled maintenance of conventional plant which has an effect on the fuel mix. Figure 2.4 shows the highly cyclical nature of electricity prices. Murray (2009) highlights that while the price is very closely linked to the demand level in power markets; it tends to be stratified as it reflects the different types of plant which are brought into service on a merit order basis.

2.4 Results

Table 2.4 presents the results of the main drivers of shadow price using the fuel prices lagged by 24 hours with robust standard errors in order to see if the fuel spot price set out by the Market Rules can be used to effectively estimate electricity prices. Observations with electricity prices exceeding €150 have been omitted from the model, as prices this high are not due to normal market operation and can instead be attributed to technical issues such as unit failure. Serial correlation is not found to be an issue in either the overall model or in any of the peak hours observed.

The main drivers of the electricity price are found to be net demand, the marginal capacity and the gas price of the previous day. The net demand has a positive effect on the price, as an increase in net demand causes a movement up the merit curve to more expensive generating units, causing the price to increase. This relationship is not linear as both net demand and its square are found to be statistically significant at the 99% level. The marginal capacity (*Marcap*) variable is significant and nega-

tive. This seems reasonable, as more plant becomes available the cost of generation falls, due to the merit order effect. Natural gas is found to be a significant driver of the price in our model; this is most likely due to the fact that just under 60% of Ireland's installed conventional capacity uses natural gas (SEAI, 2009a). This is the only significant fuel type. The other fuels will only be significant at various stages along the supply curve, with only one fuel setting the price at any given point in time. These results can be considered to be in line with both expectations and theory. The high R^2 and would seem to imply that our model is a good predictor of shadow prices, and that firms appear to be behaving appropriately in general, as spot prices are relatively good indicators of the price of electricity.

Table 2.4: Shadow Price Regression Model

VARIABLES	Day Lag
Net Demand	-7.445*** (0.767)
NetDemand ²	1.954*** (0.147)
MarCap	-0.294*** (0.041)
GasLag	0.550*** (0.019)
OilLag	0.066* (0.039)
CoalLag	-0.074 (0.065)
CarbonLag	0.283*** (0.102)
Constant	21.979*** (4.865)
Observations	8,664
R-squared	0.805

Standard errors in parentheses

*** $p < 0.01$, ** $p < 0.05$, * $p < 0.1$

If firms were to bid strategically in order to be dispatched at times of highest prices, it would be most likely to occur in hours when demand is highest. This was found to be the case in the UK in the early 1990's, where portfolios kept certain units offline to drive up the marginal price for the rest of the portfolio. Green and Newbery (1992) found that inefficiencies in the UK market could have been avoided if instead of two unequal thermal generators the industry were subdivided into five equal sized firms.

Looking at Figure 2.5 below, it can be seen that while load increases at a much steeper rate to meet the morning peak, the price increases at a greater rate during peak hours. In order to identify the effect each of the variables in the model has over the course of the day the model is rerun separately for each hour of the day. If firms were to act strategically in peak hours when the demand is highest, we would expect this to be seen in the marginal capacity variable which relates to a potential scarcity premium.

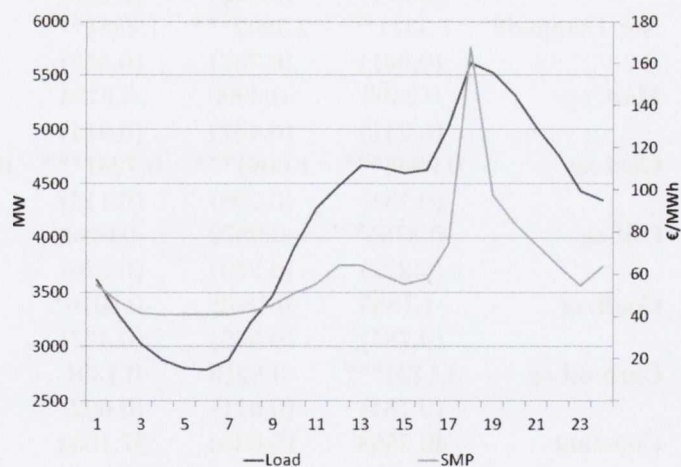


Figure 2.5: Mean Load & Price over 24 hours

Running a separate regression for each hour of the day increases the explanatory power of the model, and also allows the identification of the hours in which each of the fuel prices have the most impact. While daily spot prices are used as opposed to hourly ones for the fuel inputs, this is in line with actual market behaviour whereby plants bid the spot price of the fuel of the previous day, and this value is used continuously for 24 hours.

Table 2.5 demonstrates the results during the peak hours of 5-8pm. The effect of Net Demand is only significant in one peak hours, where it has a positive effect on the shadow price of €3.7033/MW. The square of Net Demand is significant during all peak hours, with its effect varying according to the hour in question. While this may be in part due to inappropriate bidding, it is primarily caused by a shift in the merit order to more expensive generating units, thereby increasing the entire system cost as output increases (as shown in the above merit order in Figure 2.2).

Table 2.5: Peak Hour Regression Model

VARIABLES	5pm	6pm	7pm	8pm
Net Demand	-1.1592 (3.317)	-5.0978 (3.422)	-0.3807 (2.239)	3.7033*** (0.915)
Net Demand ²	1.3311** (0.641)	2.3802*** (0.757)	1.4884*** (0.555)	0.4534* (0.234)
MarCap	0.2493 (0.241)	-0.4990 (0.407)	-0.3194 (0.314)	-0.1354 (0.188)
GasLag	0.9985*** (0.134)	1.0061*** (0.208)	0.7247*** (0.112)	0.4819*** (0.044)
OilLag	-0.3765* (0.222)	-0.0872 (0.229)	-0.0268 (0.226)	0.1081 (0.131)
CoalLag	-1.1885 (0.784)	0.1842 (0.535)	-0.8016* (0.472)	-0.3287 (0.285)
CarbonLag	3.1424*** (0.784)	-0.8215 (0.911)	0.1391 (0.692)	0.4612 (0.299)
Constant	46.3568 (52.615)	15.0354 (40.891)	37.1634 (30.245)	9.7468 (15.985)
Observations	358	359	360	361
R-squared	0.91088	0.86533	0.81271	0.92855

Standard errors in parentheses

*** p<0.01, ** p<0.05, * p<0.1

Marginal Capacity is not found to be a significant driver of the price in any of the peak hours observed, and as a result one cannot conclude that generators are restricting the use of less expensive generating units or behaving inappropriately in any other way based on this sample data. As the same variables are significant in peak hours as during the rest of the day it can be understood that generators are not behaving differently during these hours or bidding differently in these times. Marginal capacity is statistically significant in the overall regression model, this is not the case during peak hours, which is when one would typically expect it to have the greatest effect; however, average hourly demand in 2009 peaked at 4139.65MW at 7pm, while maximum capacity in 2009 was 6130MW. This would imply that there is no great risk in general of the system not being able to meet demand.

The price of gas is highly significant in each of the peak hours, again primarily as a result of the high proportion of gas based generation installed in Ireland. The carbon price is significant at 5pm while the coal price is significant at 7pm, this is most likely explained by fuel switching - different units coming online or going offline at various points along the merit curve.

As mentioned previously, other technical factors will have implications on the operation of power systems and therefore the shadow price. We have not included these technical variables due to lack of data, but they include the need for the system to provide reserve, transmission losses, and units own use of electricity. While the unobserved determinants of the price of generating electricity may be similar from day to day, it is expected that for the most part our seasonality dummies correct for this.

2.5 Conclusions

Overall it would appear that the interaction between generator and the pool in the Irish electricity market is efficient and the shadow price represents the true marginal cost of generation, with generators bidding the spot price of their inputs correctly in the model and the behaviour of the units remaining constant over the course of the day and varying levels of demand. The results of our regression model are in

line with both the theoretical framework outlined in Section 2.1 and Irish regulatory policy on the issue.

One reason why this market structure may be more effective in the Irish context than it has been seen to work elsewhere is due to the small size of the Irish system. Ireland does not have large generators such as nuclear plants, and as a result no single plant sets the market price in general. This makes each unit more likely to set/not set the price increasing competition amongst firms. Another reason is the prescriptive nature of the Irish market; instead of allowing generators to bid their marginal costs arbitrarily they are expected to bid their fuel prices at spot market values rather than their true hedged prices. If interconnection capacity increased, electricity prices overall might be lower, but the conventional units would still operate in the same manner; there would simply be less demand to be met by conventional generation. Any changes to the existing market structure due to changes in regulation or policy could potentially affect the effectiveness of this market.

This work relates exclusively to the Shadow price element of the Irish electricity market, and as a result does not consider whether the uplift element is also being bid appropriately. Based on the results of this work we anticipate that the uplift and capacity payments mechanisms are more likely to be drivers of Ireland's relatively high electricity prices, although the fact that Ireland cannot benefit of the economies of scale seen elsewhere through its small isolated system structure is also presumably a factor. Future work will consider whether generators are in fact bidding their true start up costs in the uplift mechanisms or if this will show elements of strategic behaviour.

A Cost-Benefit Analysis of Generating Electricity from Biomass

A Key challenge internationally is the design of future electricity systems which will bring about emissions reductions and fuel security at least cost. The substitution of conventional energy sources with renewable energy sources offers considerable potential for reducing a nation's carbon emissions and meeting national and international policy targets (DCENR, 2007; European Commission, 2009b). One method of increasing a country's level of renewable generation is by cofiring existing fuel sources with biomass. The potential of cofiring biomass for electricity generation in emissions terms is significant, especially as all forms of biomass are considered by the EU to be carbon neutral, due to the fact that all carbon emitted during combustion has been taken from the atmosphere during their relatively short lifetime (European Commission, 2005).

Biomass can be defined as all the earth's living matter; materials such as wood, plant and animal wastes, which - unlike fossil fuels - were living matter until relatively recently. Biomass is an appealing source of renewable energy for several reasons. The direct benefits associated with cofiring include a reduction in greenhouse gas emissions, not only in terms of a reduction in carbon dioxide (CO₂) but

also methane (CH_4) which also contributes to global warming (De and Assadi, 2009; Sami *et al.*, 2001). As noted by Domac *et al.* (2005), “Millions depend upon bioenergy as their main source of fuel not only for cooking and heating but also more importantly, as a source of employment and incomes”. As all countries have their own biomass supplies, it offers an opportunity to reduce fuel imports and increase fuel mix diversity simultaneously, particularly in those countries without large fossil fuel resources (Domac *et al.*, 2005).

The socio-economic benefits of utilising bioenergy, such as regional economic gain, security of supply and employment gains, can unmistakably be identified as a significant motivation for increasing its share in the total supply of energy (Domac *et al.*, 2005). Biomass, for its part, could significantly reinforce sustainable security of supply, considering that it is a widespread and versatile resource that can be used just as easily for heating, electricity production or as transport fuel. On a global scale, biomass ranks fourth as an energy resource, providing approximately 14% of the world’s energy needs (Bain *et al.*, 1998).

With particular reference to cofiring for electricity generation, using indigenously sourced materials will enable countries to reduce the level of energy which they import and increase their energy mix diversity. With regards to waste residues, such as wood wastes and meat and bone meal (MBM), these residues, if used for cofiring, have the potential to reduce the amount of waste either being sent to landfill or exported, further reducing absolute carbon emissions. However, biomass also poses several challenges; for one it must be sourced responsibly, as transporting vast quantities over larger distances negates any CO_2 mitigation benefits from its combustion. Also with reference to energy crops, biodiversity must be maintained so as not to have lasting impacts on global natural habitats and food resources.

Experience in Germany (Hartmann and Kaltschmitt, 1999) has found that overall the cofiring of biomass provided benefits both in terms of emissions mitigation and also economic benefits in comparison with other renewable energy sources, meaning that in the future biomass could make a substantial contribution to a more environmentally efficient energy supply system. In Holland, Verbong and Geels (2007)

found that while the cofiring of biomass in existing coal stations had positive benefits in terms of emissions and other environmental factors, it was still met by widespread opposition from local groups in relation to the types of biomass being used and as a result many cofiring plants encountered problems in permit procedures. This has already been an issue in Ireland, with many residents groups wanting clarification of what types of biomass will be used and the general public being opposed to incineration for waste disposal (Gormley, 2008; South East Waste Management Region, 2010).

While most cofiring to date internationally is in conjunction with coal, as can be seen in Baxter (2005) and Molcan *et al.* (2009), this paper will focus on the cofiring of biomass with peat in Ireland for several reasons; firstly because it is a higher emitter of CO₂ than coal, secondly because peat is a more expensive fuel than coal and therefore creates an added incentive to reduce its consumption, thirdly more types of biomass can be cofired with peat than with coal as a result of the stations being better suited to dealing with variable moisture levels and thus higher quantities of biomass, and finally due to the fact that peat is an indigenous fuel to Ireland unlike coal and therefore offers job creation benefits and cofiring prolongs the supply of this resource for future generations.

Peat has been a significant source of energy for electricity generation in Ireland since the 1950's, and was possibly the most important indigenous energy resource prior to natural gas coming on stream in 1979 (Bord na Móna, 2001). The bulk of domestic gas has now been consumed, and the majority of natural gas is currently imported. At its peak, peat provided just under 40% of all electricity generated in the State, though this figure has been falling steadily over the last 50 years. Peat is one of the most polluting fuels in use for electricity generation, emitting 1.167 kg of CO₂ per kWh of electricity generated, as can be seen in Figure 3.1. While not a significant source of energy in most countries, peat is also used for electricity generation in Sweden and Finland (Ericsson *et al.*, 2004; Schilstra, 2001). Peatlands in Ireland were estimated to be 0.95 million hectares (Mha) or 13.8% of the national land area by Connolly *et al.* (2007). While peat is indigenous in all three countries,

Finland and Sweden are part of the Nord Pool common electricity area alongside Denmark and Norway, rendering them far less dependent on peat for energy security than Ireland. In fact, of the 363.3TWh of electricity produced in the Nord Pool area in 2003, 24% came from nuclear energy, 46.3% from hydro stations and 1.7% came from wind (Laurikka and Koljonen, 2006). Peat's contribution however is negligible - representing only 1.2% of installed capacity in the Nord Pool area in 2005 (Oranen, 2006). In contrast, peat is subsidised in Ireland to ensure it operates 24 hours per day at maximum stable output when available, in an attempt to alleviate import dependency as well as to preserve jobs in the industry (Styles and Jones, 2007). Peat represents 5% of installed capacity in Ireland (SEAI, 2009b), and accounted for 6% of its electricity generated in 2010 (CER, 2011a).

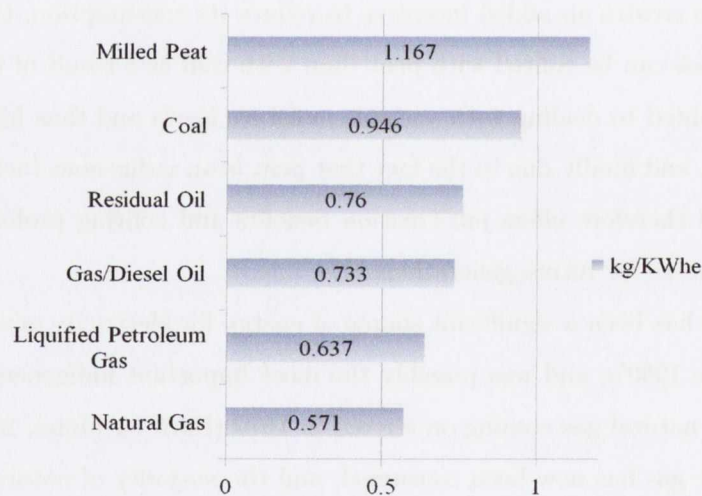


Figure 3.1: CO₂ emissions of fuels for electricity generation

Source: SEAI (2011)

The remainder of the paper is structured as follows; Section 3.1 outlines the methods and data used in the study and Section 3.2 introduces the case study. Sections 3.3 and 3.4 will look at the costs and benefits associated with cofiring in Irish peat stations respectively; Sections 3.5 and 3.6 will compare these and discuss the outcomes of this study and Section 3.7 will conclude.

3.1 Methods and Data

This paper endeavours to value the changes associated with cofiring, considering both the additional costs to the generating stations and the benefits incurred through the emissions savings arising from generating electricity from biomass, a carbon-neutral fuel, relative to the status quo.

Costs considered are the biomass fuel costs, capital costs, and increased operations & maintenance (O&M) costs associated with handling the biomass at the power stations. The transport of biomass fuels to the stations and all farm level costs are assumed to be included in the cost of biomass fuels delivered to the stations. Benefits to be included are the fuel savings in terms of peat and carbon abatement. Qualitative benefits which are not included but are discussed in Section 3.5 are the changes in employment arising from cofiring and the effects on other plant emissions which are highly dependent on the fuel mix used at each point in time. All costs and benefits are relative to how peat stations are currently utilised. Equation 3.1 represents the cost benefit equation used, calculating the net present value (NPV) of additional costs and benefits relative to the current peat station operation.

$$\begin{aligned} \text{Net present value} = & \text{Annual } CO_2 \text{ saving} + \text{Annual peat fuel cost saving} \\ & - \text{Capital cost} - \text{Annual biomass cost} - \text{Other variable costs} \quad (3.1) \end{aligned}$$

A major challenge of this paper was the collection of data. Publicly available data has been used wherever possible, however much of the information required is commercially sensitive and as a result comes from direct communication and from biomass cofiring trials undertaken at Edenderry Power Ltd. Wood resource estimates are taken from COFORD (2009); Meat and Bone Meal production levels come from the Meat Industry Ireland (2010), import cost levels relate to communications with Edenderry Power Ltd, and energy crop levels are adapted from Conway (2009). CO₂ emissions are calculated from total annual peat consumption at the three stations and the average emissions as per SEAI (2011). Values for capital costs for equipment and handling at the stations are from direct communication with various machinery

suppliers, and are all confirmed to be within the range estimated by Edenderry Ltd.

Four scenarios will be compared - cofiring of 15%, 30% (the target), and 45%; and no cofiring but a reduction in output in each of the 3 peat stations equivalent to 30%. The reduced output scenario values the savings in terms of fuel cost and emissions from the peat stations and includes the costs associated with meeting this lost electricity generation through natural gas. It is assumed that the supply of additional output will be met through the consumption of natural gas due to the fact that coal stations tend to represent base load generation, wind is “must run” meaning it receives priority dispatch, and oil units tend to be much more expensive to run than gas units. This fourth scenario is included in order to gain insight into alternative options for the stations relative to the status quo of 100% peat.

Each of the scenarios portrayed uses a 15 year time frame, and is shown considering a range of discount values - 4%, 6% and 8%. The mid range of 6% is considered to be the appropriate discount factor, based on the Weighted Average Cost of Capital proposed for the Single Electricity Market for 2011 (CER, 2010a). The values of 4% and 8% are given to demonstrate the sensitivity of the results to the discount factor in question. Costs of fuels and emissions are assumed constant throughout the 15 year period for ease of comparison and due to the fact that no specific start date is assumed for any cofiring level. Sensitivity analysis is included in Section 3.6.

3.2 Case Study - Ireland

The 2007 Irish Government White Paper has set targets for 30% cofiring with biomass in each of three peat stations with a view to reducing Ireland’s CO₂ emissions and meeting various EU and international goals (DCENR, 2007). It is assumed that if this target is met, then the emissions from the three peat stations will be 30% less than their current average - resulting in a saving of about 836,000 tonnes of carbon dioxide per annum.

Ireland has very little in terms of indigenous conventional energy resources; it has some resources in the form of considerable peatlands; estimated to be 0.95 million

hectares (Mha) or 13.8% of the national land area; and some natural gas, although this is expected to further decline over the next few years (Connolly *et al.*, 2007). Ireland's energy mix for electricity is unique for a number of reasons; firstly as a result of being an island economy the level of interconnection between it and neighbouring countries is low - at present there is only one interconnector between the GB and Northern Ireland which operates at 400MW, with another 500MW capacity expected to be online by 2012 (Malaguzzi Valeri, 2009). Ireland's indigenous resources are insufficient to meet Irish energy demand, and in 2007 Ireland imported 88.3% of its energy needs - one of the highest levels of energy imports in the EU, after only Luxembourg (97.5%), Malta (100%) and Cyprus (95.9%) (Eurostat, 2011). As a result, Ireland is very susceptible to shocks to energy prices and needs to encourage as diverse a fuel mix as possible in order to protect its security of supply. In terms of understanding the trend in fuel mix usage over time, Table 3.1 shows the changes in the mix of fuels for electricity generation in Ireland between 2005 and 2010.

Table 3.1: Shares % Electricity Generation Fuel Mix

	2005	2010
Coal	24	16
Peat	8	6
Oil	12	2
Gas	46	64
Renewables	9	12
Other	1	0

Source: CER (2011a)

Looking at the share of fossil fuels, it is clear that the use of coal and peat is much lower than it was previously, due in large part to an increase in the share of natural gas. While this is clearly a positive outcome in terms of emissions reductions it poses problems in relation to maintaining the country's security of supply with over half of all electricity generated coming from natural gas. This heavy reliance on imported gas presents another incentive for the promotion of indigenous biomass.

The main biomass fuels available in Ireland which are suitable for cofiring with peat are willow, miscanthus, wood resources and MBM. Other indigenous biomass

resources are available for electricity generation, such as spent mushroom compost, chicken litter and straw; however these are not suitable for co-combustion in peat stations due to technical reasons (SEAI, 2004). Figure 3.2 demonstrates the breakdown of current indigenous biomass resources appropriate for cofiring to generate electricity which are available on an annual basis, in terms of their GJ potential.

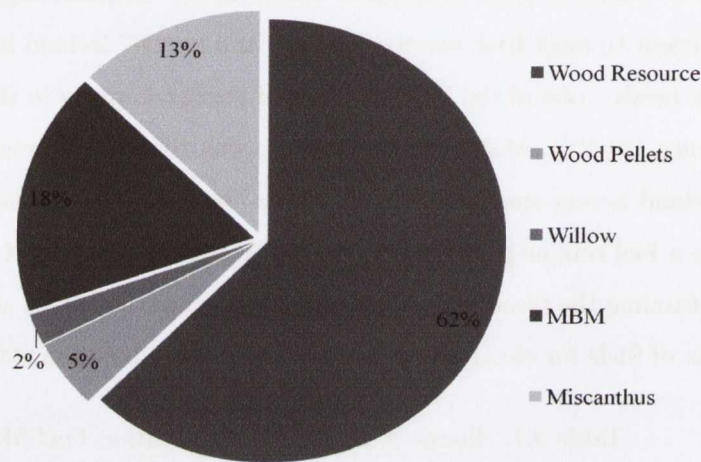


Figure 3.2: Current Indigenous Biomass Resources

3.2.1 Energy Crops - Willow & Miscanthus

Energy crops have gained much interest in recent years, with studies suggesting the most appropriate for Ireland to be Miscanthus and Willow (Styles and Jones, 2007). These crops take approximately 1-4 years to reach harvest potential, and the same plot of land can be harvested on repeatedly for about 20-25 years, since both willow and miscanthus are perennial crops. According to the European Commission (2010), the growing of energy crops is particularly advantageous for farmers, as some reports believe it can be done on land where little else can be commercially grown, and is an alternative source of income for farmers affected by changes to the Common Agricultural Policy (CAP). As these crops are indigenous, they have the potential

to maintain the level of indigenous energy used for electricity generation that is currently provided through the consumption of peat. Levels of 360ha for Willow and 2000ha for Miscanthus are scaled up to 500 and 2500 respectively in this study in an attempt to account for additional planting under the Bioenergy Scheme.

3.2.2 Wood

SEAI classifies wood fuel resources available to Ireland as saw dust, cutter chips, demolition wood, recycled wood, logging residues, and processed wood pellets (SEAI, 2004). According to Kofman and Kent (2006), Ireland is in the fortunate position of having a significant source of indigenous wood, some of which may be available for electricity generation, due to Ireland's afforestation programmes of the past twenty years. Conversely, Walker *et al.* (2009) point out that while Irish supply of pulpwood and wood industry residues is expected to increase by 30% in the period to 2016, the demand for these products could potentially increase by more than 70% over the same period, thus far outstripping supply and presumably increasing the cost of these resources quite significantly. COFORD (2009) estimates the annual wood resource available to be 302,000m³, which would result in 2.1 million GJ of energy that could theoretically be delivered through the use of wood resources. We are assuming that all available wood will be available for cofiring; as a market for these wood resources already exists elsewhere this could be considered the best case scenario in terms of wood resource.

3.2.3 Meat and Bone Meal

Meat and bone meal (MBM) is a product of the rendering industry, which involves the processing of animal by-products into more useful materials. Due to changing regulations in the agricultural sector for the use of MBM in recent years, its application as a fuel for electricity generation has gained enormous interest internationally (European Parliament, 2009). This is of particular importance for Ireland, where 150,000 tonnes of MBM waste are produced each year, costing in the region of €22 per tonne per year in terms of storage and excluding disposal (Cummins *et al.*, 2006).

It is assumed that 150,000 tonnes of MBM will be available for cofiring in Ireland per annum.

3.2.4 Potential Imports

A number of different types of imports have been trialled in peat stations to date, such as coco shells & horticultural biomass. Due to the technology in place in the peat station boilers, it is expected that it would be possible to import a range of materials without any technical issues. Biomass resources can be shipped from anywhere, and provided that the price including shipping is below the cost of indigenous biomass it is likely to be the preferred choice by peat stations. From existing trials, it is expected that sufficient levels of biomass can be sourced at a cost of €6-8/GJ. For the purposes of this study, imported biomass resources are assumed to be unlimited.

3.3 Costs

Adapting existing power stations in order to cofire with alternative fuels requires changes to the fuel handling and processing at the station, and increased capital investment through additional storage facilities; ultimately affecting the variable cost of the units through changes to fuel and O&M costs.

3.3.1 Variable Costs Associated with Increased Biomass

3.3.1.1 Biomass Fuel Costs

There are various operational issues associated with each biomass fuel, along with their underlying prices and availability, all of which have an impact on their suitability for use in cofiring with peat. Table 3.2 presents the GJ potential of each of the viable biomass resources and the corresponding contribution to each cofiring level.

It can be seen from the table that there is insufficient biomass to meet any cofiring scenario. Due to this lack of indigenous resources, it is assumed in this paper that any increase in demand of biomass will be met through the use of imports. All cofiring scenarios therefore require imports - the level of which depends entirely

Table 3.2: Biomass Resources

Fuel (GJ/tonne)	Calorific Value	GJ Potential	Prop. 15% cofiring	Prop. 30% cofiring	Prop. 45% cofiring
Wood Resource	6.50	1,784,543	0.51	0.25	0.17
Wood Pellets	17.00	170,000	0.05	0.02	0.02
Willow	12.13	77,000	0.02	0.01	0.01
MBM	15.00	600,000	0.17	0.09	0.06
Miscanthus	13.72	427,500	0.12	0.06	0.04
Total		3,059,043	0.87	0.43	0.29

on the proportion to be cofired. It is assumed in this analysis that all available resources of each biomass type will be consumed for electricity generation, with the balance met through imports, at an assumed cost of €6-8/GJ, based on current Bord na Móna estimates. Given resource estimates outlined in Section 3.1, even if all indigenous resources were consumed, it would only be possible to achieve just under half of the cofiring target using exclusively indigenous resources. This seems reasonable as the potential to increase current biomass resources is somewhat limited for the following reasons; as MBM is a residue of the beef industry which is forecast to decline on an EU level by 5% by 2015, we assume that an average level of current Irish stocks to be a best case scenario (Meat Industry Ireland, 2010). Wood resources cannot be increased quickly enough to meet target deadlines as they require 20 years from planting to harvesting. Energy crops adoption has been low to date and given the uncertainty of the market for energy crops going forward levels are not expected to increase beyond their current levels. Cofiring will not drive the demand for energy crops going forward, as imports are sufficiently cheaper. Imports are consequently assumed to be sufficient to meet all additional demand in this analysis. A number of biomass fuel cost scenarios were developed using data from existing contracts from Bord na Móna in place with biomass suppliers, and offers which they received from prospective suppliers in the case of some fuels. The fuel cost scenarios are presented in Table 3.3. The Total Resource Cost shown uses the mid range cost estimates in €/GJ shown in the table. These costs are assumed to cover farm level costs and transport to the peat stations.

Table 3.3: Cost Scenarios Current Indigenous Resources

Fuel	Low Cost	Mid Cost	High Cost	Total Resource Cost
Wood Resources	5	6.25	7.5	11,153,391
Wood Pellets	5.9	6.2	6.5	1,054,000
Willow	8	10	12	770,000
MBM	5	5.5	6	3,300,000
Miscanthus	8	10	12	4,275,000
Total				22,583,638

3.3.1.2 O&M Costs

The use of alternative fuel sources affects the fuel cost of the peat generating units - which to this point had a relatively constant peat price. Each of these biomass fuels must be sampled for consistency, which in turn increases necessary staffing levels. It also increases the level of additional variable materials consumed by the units, in the forms of sand, fuel oil (for starts) and electricity consumed on site. In this study, we assume that these costs will lead to approximately a doubling in the O&M costs of the existing peat stations. This is in accordance with experience from the initial cofiring trials at Edenderry Power station, based on personal interviews. This allows the stations to cover the additional sampling, handling, maintenance or variable materials associated with cofiring. Due to higher ash content associated with biomass fuels compared to peat, biomass fuels are prone to increasing combustion and ignition problems; and the effect of ash can result in additional fouling and slagging issues (Sami et al. 2001). Doherty *et al.* (2005) calculate O&M costs for stations of similar size to the three in existence at a level of €55,200/MW installed annually. Assuming a doubling of this figure would result in a total additional O&M cost to the peat stations of €20.3 million annually.

3.3.2 Capital Costs Associated with Increased Biomass

At the peat stations, in order to maintain boiler moisture contents and heat levels, all fuels of different calorific value and moisture content must be stored and fed into the boiler separately. The additional fuel stored on site increases insurance related costs of the stations, alongside additional handling. As a result, stations will require

extra storage facilities in the form of covered storage for wood and logs, silos for wood chips, and refrigerated silos for MBM, as demonstrated in Figure 3.3. It is presumed that each of the three peat stations will require capital investment for all biomass fuel options, as their biomass mix is assumed to be similar to the mix shown in Figure 3.2. This is predominantly due to fuel mix constraints within the station boilers, rather than an expected lack of specialisation at the stations- meaning each station is assumed to burn a mixture of all fuels rather than specialise and focus on one or two.

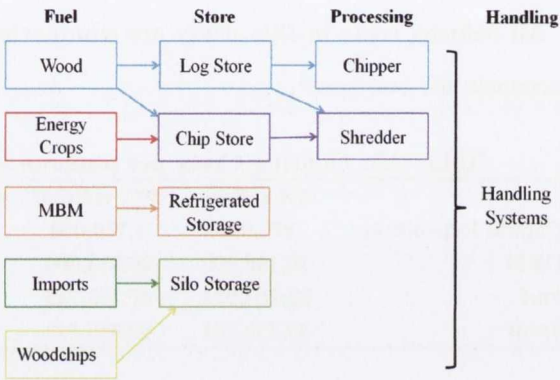


Figure 3.3: Cofiring Capital Processes Required

Each of the viable biomass fuels for cofiring requires different capital investment, as shown in Figure 3.3, and due to the fact that indigenous biomass resources are insufficient in order to meet the target of 30%, it is assumed that the capital expenditure associated with each fuel type will be necessary and purchased. The cost associated with each of these requirements is detailed further below in Table 3.4.

This total represents the estimated additional capital cost faced by each of the three peat stations due to cofiring at a 30% level. As a result, the total capital cost can be assumed to be approximately €26.25 million (i.e. €8.75 million*3). These costs are directly related to the proportion of cofiring taking place; as the machinery will all either be custom made for the stations specific needs or have

Table 3.4: Capital costs on a per station basis

Products	Cost € at 30% cofiring	Units	Total € at 30% cofiring
Shredder	1,250,000	1	1,250,000
Wood Chippers	250,000	3	750,000
Covered Storage	1,750,000	1	1,750,000
Open Storage	2,250,000	1	2,250,000
Silos	375,000	4	1,500,000
Handling Equipment	1,250,000	1	1,250,000
Total			8,750,000

numerous machines used depending on the level or materials handled, we can assume that these costs can be halved for the 15% scenario and multiplied by 1.5 for the 45% scenario. All cofiring costs in this study are summarised in Table 3.5, using a mid-cost fuel scenario for one year¹.

Table 3.5: Cofiring Costs per annum in €

	15% cofiring	30% cofiring	45% cofiring
Capital Expenditure	875,000	1,750,000	2,625,000
O&M	10,156,800	20,313,600	30,470,400
Fuel	22,703,924	47,322,749	71,941,574
Total	33,735,724	69,386,349	105,036,974

3.4 Benefits

All costs discussed in the above section relate exclusively to the costs incurred by the peat stations through the implementation of cofiring. The benefits discussed here can be considered as societal benefits, however emissions reductions are also targets which the peat stations are required to meet in accordance with both national and international targets. Carbon emissions savings made by peat stations can also be sold via the EU ETS, thereby internalising the societal benefit (European Commission, 2009b). In order to determine the total benefits to the peat stations from cofiring, the cost of carbon must be accounted for. All biomass is considered to be carbon neutral by the EU, and therefore there are no CO₂ costs associated with these fuels, unlike peat (European Commission, 2005). Peat stations are estimated

¹Mid-cost values from Table 3.2

to emit 1.167 tons CO₂/MWh (SEAI, 2011). Table 3.6 presents the annual cofiring benefits using an assumed carbon cost of €15/ton and a mid-cost fuel scenario. In relation to the reduced output scenario, the CO₂ savings are taken to be the difference between peat and gas emissions per MWh, and the fuel cost savings relate to the difference between the cost of peat and the average cost of gas, using figures from O'Mahoney and Denny (2011a).

Table 3.6: Cofiring Benefits per annum in €

	15% cofiring	30% cofiring	45% cofiring
Peat fuel cost savings	14,771,295	29,542,590	44,313,885
CO ₂ savings	6,211,981	12,423,962	18,635,943
Total	20,983,276	41,966,552	62,949,828

Other benefits related to cofiring do exist, but are more difficult to quantify, such as the potential positive effects of cofiring on SO₂ and NO_x emissions. SO₂ emissions are controlled in power stations through the use of limestone (Ma *et al.*, 2000). Orjala *et al.* (2001) found that interactions between wood and peat fuels and their ashes could result in the binding of roughly one third of the SO₂ from peat. If these are reduced via the fuel mix, this would have the potential to reduce some of the existing O&M costs currently faced in the peat stations. The effects of cofiring on all emissions are highly dependent on the fuel mix in question and the boiler chemistry. While Table 3.2 presents an assumed fuel mix, this the overall fuel mix on an annual basis - at any given moment the specific mix will vary, and as a result we cannot say with any certainty what effect this will have on the chemical makeup in the boiler, and as a result changes in emissions other than CO₂ are not included in this paper.

There is also a benefit in preserving peatlands, allowing this resource to last longer, although electricity generation is not the only consumer of peat in Ireland and therefore it is impossible to determine what would happen to these resources should the amount of peat consumed in electricity generation vary. Qualitative benefits related with cofiring include maintaining the fuel diversification and fuel hedging benefits currently in place from peat; however these are not additional benefits as a result of cofiring and are therefore omitted from this cost benefit analysis.

3.5 Net Present Values

Figure 3.4 represents the net present value (NPV) of the four scenarios considered - 15%, 30% and 45% cofiring compared to a reduction in output equivalent to 30% (reduced output scenario). This is shown using the base case scenario of a €15/ton of carbon and a mid range fuel cost. Since all NPV's are negative regardless of the discount rate used, cofiring is always a more costly option than the status quo of 100% peat. The discount rate used can have an effect of up to €102.3 million over the entire time period, as can be seen in the 45% cofiring scenario below. The reduced output scenario is more cost effective than the status quo regardless of the discount rate considered. In this scenario, the output of the peat stations is assumed to be reduced by 30%, and the balance made up by gas stations. This results in a net saving in fuel costs and reduces CO₂ emissions from electricity generation. Assuming €15/ton of carbon and mid range fuel costs, this scenario represents savings of €115-148 million relative to the status quo, depending on the discount factor employed.

A number of sensitivities were subsequently carried out; examining the effects of changes in the cost of carbon and fuel prices alongside the various discount rates. The carbon levels considered were €8/ton, which was the lowest spot market price seen in 2009 (SEM-O, 2010), and €39/ton, which represents the Department of Finance (2009) guidelines for CO₂ emissions from 2015 onwards. Fuel cost ranges used are displayed in Table 3.2. Figures 3.5 and 3.6 present these results graphically; Figure 3.5 illustrating the range of NPVs seen at a discount rate of 6% with a mid carbon cost (15%) with varying fuel costs and Table 3.6 the range of NPVs when mid fuel costs are used and a discount rate of 6% when carbon costs are contrasted. It can be seen that cofiring is always a more costly option than the status quo, ranging from an additional cost of €43.3 million at 15% cofiring with a high carbon cost (seen in Figure 3.6), to €559.4 million at 45% cofiring with a high fuel cost (seen in Figure 3.5).

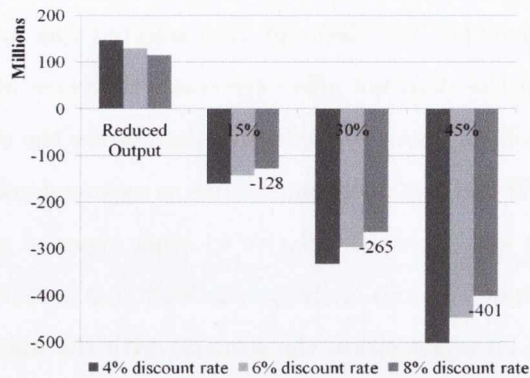


Figure 3.4: NPV with varying discount rates

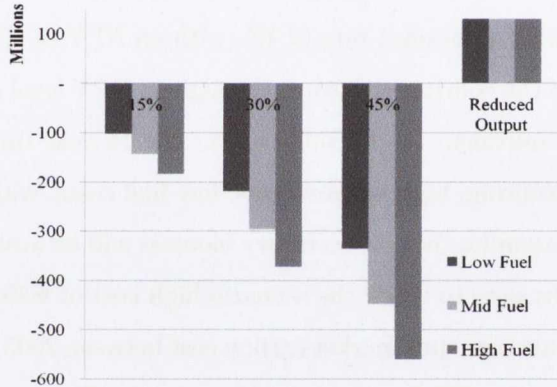


Figure 3.5: NPV with varying Fuel Cost

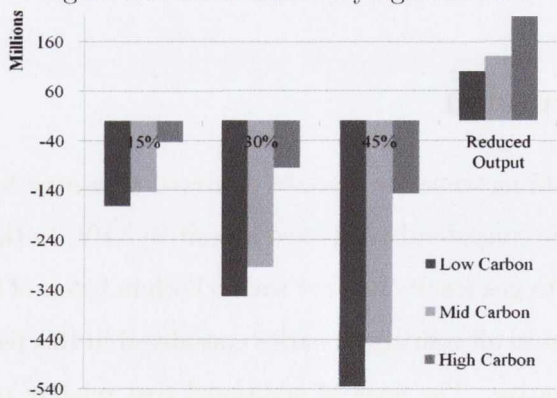


Figure 3.6: NPV with varying Carbon Cost

It is clear that regardless of the percentage cofired in the peat stations, reducing output is always the least costly option from a societal perspective. Sensitivity analysis identifies that the discount rate selected has an effect of up to €152.3 million, however this does not affect the competitiveness of alternative options, and never renders cofiring more cost effective than either the status quo or the reduced output option. If fuel costs continue to rise as expected going forward, cofiring may prove relatively less expensive relative to other types of generation. Nevertheless, the reduced output scenario is always the least cost scenario.

Considering all sensitivities, the scenario with the highest NPV (€266 million) assumes reduced output, high carbon costs, and has a discount rate of 4%. The scenario with the lowest NPV is the low carbon (€8/ton) high fuel costs scenario, at 45% cofiring with a discount rate of 4%, with an NPV of €730 million less than the status quo. Of the cofiring scenarios, the highest NPV level estimated relative to the status quo is equivalent to -€1 million over the 15 year time period assessed. This assumes 15% cofiring, high carbon costs, low fuel costs, with a discount rate of 8%. This scenario assumes that all necessary biomass will be available for cofiring, which, if carbon prices were to reach the scenario high cost of €39/ton seems unlikely at a low cost. The average spot market carbon cost between 2005 and 2010 was €14.4/ton - far lower than the €39/ton used in this analysis. These results are summarised in Figure 3.6.

3.6 Discussion

None of the cofiring scenarios assessed delivered a positive NPV whereas the reduced output scenario consistently delivered a positive NPV. In this final scenario, switching from peat to gas results in a net saving both in terms of fuel and emissions costs. It is found that in all cofiring scenarios considered in this paper, the estimated total NPVs are negative. The level of additional cost relative to the status quo ranges from €1-730 million, depending on the level of cofiring. This outcome holds constant under a range of sensitivities. In contrast, the reduced output scenario consistently has a higher NPV than the status quo - ranging from €88-266 million depending

on the sensitivities in question.

All cost and benefit estimates are considered to be relatively conservative estimates. A benchmark price of €66.52/MWh was set out for the 2009 period in the PSO as a floor price that peat generators receive for the electricity that they generate (CER, 2009). The benchmark price received by peat stations is essentially a price floor, meaning that if the cost of fuel in other generating stations increases significantly it will not prove to be binding and a higher profit level would be possible in the peat stations than the level assumed in the reduced output scenario, as this is indexed to the price of other fuels used for electricity generation. The gas price used is 3.2823 €/GJ, adapted from O'Mahoney and Denny (2011a). This is the average gas price over the course of a year of daily spot prices, and as a result large variations are to be expected. Capacity payments² allow units that do not feature in the merit order to recoup their fixed capital costs when they are not producing electricity, but providing reserve which ensures the availability of that facility should it be required to meet demand in future. This payment would increase in the reduced output scenario. As a result, it is assumed that the estimates demonstrated will result in an underestimation of the potential costs associated with cofiring.

It is important to note that a number of assumptions have been made in order to simplify the analysis. It is assumed that all technically feasible biomass resources will be available for cofiring, when in reality other demand for these resources does exist and this in turn could drive up the price of resources going forward. Costs are assumed to remain constant over the 15 year period of analysis, for ease of comparison between scenarios and as a result of not assuming a fixed start date for cofiring. These costs are unlikely to remain constant over such a timeframe. If, for example biomass becomes more prominent within the heating industry, demand for these resources will increase significantly, as could economies of scale in their production. This could result in increased costs for both biomass and natural gas, and as a result it is unclear if this would make cofiring more cost effective relative to the reduced

²Capacity payments to peat stations will increase as their output decreases, as they will be providing additional reserve to the electricity system, however this has not been quantified in this paper.

output scenario.

The entirety of each resource is also assumed to be available at the same price. In reality, it is unclear whether these resources become more costly as the quantity consumed increases or the opposite. It could be that economies of scale reduce costs for suppliers, but if wood and energy crops are to be grown on less productive land or on more distant plots of land this could in fact lead to increased costs per GJ delivered.

We are assuming that the capital expenditure faced by all peat stations will be identical, and that a mid cost fuel price estimate is the appropriate forecast. If the costs were to increase beyond this level, cofiring would prove more expensive relative to the status quo. As none of the cofiring scenarios are capable of being met through indigenous resources, we assume that they will be met through imports at the mid cost level of €7/GJ. If the cost of importing biomass were above our assumed levels cofiring would again prove more costly than the levels shown in the paper. Meeting the balance of the target through energy crops is clearly a much more expensive option relative to importing biomass from abroad (at a mid cost level of €10/GJ) while at the same time only delivering the same amount of energy. It is important to note however that while this is a less expensive option; importing biomass results in higher emissions due to the fact that the biomass fuels must be transported great distance, which consumes energy in itself. A carbon cost of €15/ton is used as a base case throughout this study. While CO₂ is classified as carbon neutral, there still are emissions associated with it; particularly if it is being transported over vast distances. These are not included in this study.

The justification of cofiring is considered to be in order to meet various emissions reduction and bioenergy policy targets. Emissions reduction in this paper is shown to be most effectively achieved through the reduction in output of peat stations as opposed to cofiring. In order to meet bioenergy targets and make use of scarce biomass resources, the authors propose that their use would be more efficient in the renewable energy in the heating and cooling (RES-H) sector. In order to meet targets set out in Directive 2009/28/EC, Ireland has set a national target of 12%

RES-H by 2020 (European Commission, 2009a,b). In 2009, Ireland had achieved a level of 4.2% RES-H, leaving a significant gap between existing levels and the target (SEAI, 2010a). The majority of Ireland's current RES-H levels derive from industrial biomass use, predominantly from the wood and food sectors; in 2008 this accounted for 70% of all thermal renewable energy in Ireland (SEAI, 2010b). This would be displaced if biomass for cofiring were to increase significantly, creating further difficulties in meeting this EU heating target.

3.7 Conclusion

This paper considers the long term effects of cofiring with biomass in Irish peat stations. The results demonstrate that Ireland has only half the necessary resource to meet the 30% target and as a result imports will be required in large quantities to meet the national cofiring target. It is found that in all cofiring scenarios, the estimated total NPVs are negative. This outcome holds constant under a range of sensitivities. None of the cofiring scenarios assessed delivered a positive NPV whereas the no-cofire scenario consistently delivered a positive NPV. Thus, it is found that while it may be technically possible to meet the target by combining national resources with imported biomass this is never the least cost option, and as a result the Governmental target may need to be reconsidered. The authors conclude that cofiring is currently not a feasible option, and if the goal of which is to reduce emissions this is best achieved through a reduction in the output of Irish peat stations.

Modelling the Impact of Wind Generation on Electricity Market Prices using Empirics and Simulation

RENEWABLE generation sources are becoming increasingly important considerations in power system planning and operations. Climate change concerns, alongside dwindling fossil fuel resources has resulted in increasing global interest in renewable generation, which allows for lower carbon emissions from electricity generation and contributes to policy targets such as the Kyoto Protocol (1992), US cap and trade programs such as the CAA (2008) and the Regional Greenhouse Gas Initiative, and the EU Emissions Trading Scheme (European Commission, 2009b). A key challenge internationally is the design of future electricity systems which will bring about emissions savings and fuel security at least cost.

Due to the recent crisis in Japan, many nuclear programs have been put on hold, with other nations undergoing re-examination of their nuclear facilities post Fukushima (Schneider *et al.*, 2011). Germany, Switzerland, and Italy have all announced plans to phase out or cancel all of their existing and future reactors over safety concerns (EIA, 2011), and France has called for a reduction in the country's nuclear energy mix from 75% presently, to 50% by 2025 (REN21, 2012). This will

have implications for renewable energy resources, as they are consequently considered a viable alternative to conventional generation with zero or lower emissions. Of the renewable technologies currently available for electricity generation, wind is one of the most developed and as a result is gaining significant market share internationally. This has resulted in greater focus on the impact of wind on the electricity system, as until quite recently no system had faced the challenges associated with high penetrations of wind - namely the need for greater flexibility and reserve due to the increase in volatility (NERC, 2008; NREL, 2011).

The benefits associated with wind generation include a reduction in fossil fuel consumption for electricity generation, environmental benefits, diversity of supply, reduced reliance on international fuel price fluctuations, and the meeting of national and international policy targets. Holttinen *et al.* (2011) observe that as wind replaces fossil fuels for electricity generation, total operational costs and emissions are reduced. It is noted by Clifford and Clancy (2011) that wind generation acts as a hedge against high fuel costs by depressing the wholesale cost of electricity.

Much of the literature surrounding the increased penetration of renewables focuses on the additional costs associated with renewable generation, and, in the case of wind, increased levels of variability and unpredictability (Troy *et al.*, 2010) rather than on the associated benefits. Smith *et al.* (2007) found that integrating high levels of wind can affect both transmission and generation through utility system planning and operations. They found that this is driven primarily through increased load-following and unit commitment costs. Dale *et al.* (2004) establish that, as the level of wind generation increases in an electricity market, extra balancing costs are incurred in the form of additional reserve and frequency response. They also indicate that as wind farms tend to be located in rural and often remote areas, wind generation tends to have a significant effect on transmission costs. The extra reserve costs are also observed in Denny and O'Malley (2007), as wind is shown to increase uncertainty in the system as it is reasonably unpredictable and non-dispatchable. Holttinen *et al.* (2011) found that adding wind to an electricity system results in added integration costs, which relate to the extra investment and operational costs associated with

the non-wind generating units. Wind generation has also been shown to result in the increased cycling of existing units (Troy *et al.*, 2010). This relates to start-ups, ramping and operation at part load which is caused by adding more variability to a power system (Denny and O'Malley, 2009; Troy *et al.*, 2010). Milligan *et al.* (2011) also found that systems with significant levels of variable and uncertain primary energy sources require different operation than electricity systems based exclusively on conventional resources. However, they point out that integration costs to power systems are imposed by all forms of generators - such as gas scheduling restrictions and hydro generators with dissolved gas limitations - yet these costs are not allocated to the generators in question. Denny and O'Malley (2006) demonstrate that while wind can reduce the emissions of an electricity market, it is dependent on the method of system operation.

Costs savings have been examined based on benefits such as a environmental benefits and the meeting of national and international policy targets, however very little has been done from the price reduction perspective. Various studies to date have shown that increased wind power in the generation mix would lead to reductions in the Spot Market Price (Moesgaard and Morthorst, 2007; Sensfuß *et al.*, 2008; Pöyry, 2010), however these have largely involved simulated wind production and prices as opposed to historical data, as up until quite recently wind levels were insufficient to measure with actual data. Results from Moesgaard and Morthorst (2007) illustrate that wind power benefits the consumer through economic as well as environmental benefits, yet that the price reducing effect could be higher than the studies estimate, while Sensfuß *et al.* (2008) indicate that the cost for renewable support paid by consumers is not as high as is generally expected when the merit order effect is taken into account. The All Island Grid Study (DCENR, 2008) found that "at higher proportions of renewable capacity installed, less conventional capacity is required to run and thus the operational cost decreases". In reality, markets will differ from results seen by models assumed in such studies as they are based on the assumption that a well functioning market will optimise costs, and so total cost savings will be different for these compared to market savings which we identify.

Simulations are a very necessary method of testing how systems with increasing levels of variable generation will behave at high integration levels. Whether these simulations are accurate portrayals of real world behavior is not always clear, however, and up until recently the lack of available data meant that econometric analyses were not possible. This paper aims to consider the historic cost savings arising from wind generation in a case study system using an inverse supply function time series regression analysis, and then comparing these results to simulated values for the same system using PLEXOS, a power market simulation software. This will allow us to consider whether the outcomes of both methodologies are in line with each other, and consider the effects of wind on the short run marginal cost of electricity i.e. not only are we interested in seeing the impact of wind on prices and system costs/emissions but we want to compare the results from approaching this question in two ways.

Traditionally, most studies have used a sophisticated unit commitment model (such as PLEXOS) to simulate the impact of wind on the system while accounting for all the engineering constraints on the system. These models require significant knowledge of the underlying system and model tool and often take many hours to converge. We hypothesise that a historical econometric model should produce the same results while being much more efficient in terms of data requirements and computation time. Thus, in this paper we assess the impact of wind on system prices using both an econometric model and a unit commitment model and compare the results in an attempt to determine if the results are comparable.

This study will not attempt to estimate the costs incurred as a result of wind integration, valuing only the savings to the wholesale generation market, which are often overlooked within the literature. Once the average hourly effect has been calculated, we can estimate the cost of electricity using both methodologies over the course of the year had no wind been available. It is important to note that the prices discussed in this paper refer to the prices generators receive and suppliers pay rather than the prices to end consumers. In addition, we quantify the value of emissions savings in the market as a result of wind generation.

The remainder of this paper is structured as follows; Section 4.1 outlines the merit order effect of wind on supply and demand, and Section 4.2 introduces the Irish electricity market as the case system. Section 4.3 details the two methodologies considered and data used, and the results, discussion and conclusion are presented in Sections 4.4, 4.5 and 4.6 respectively.

4.1 Merit Order Effect

We assume that electricity is a homogenous good, to which suppliers are indifferent between generators, as there is no product differentiation¹. The market is capacity constrained; with each generator limited in their supply by the maximum output they are capable of producing. As a result, we can describe the generation of electricity as a Cournot oligopoly model, whereby generators are able to choose their level of supply but not the price which they receive for the electricity that they generate. The price of electricity, P is therefore determined by market demand Q times a variable component b , which corresponds to the marginal cost of electricity, plus a constant, or fixed cost component, a . Thus, the price can be defined as:

$$P = a - bQ \quad (4.1)$$

Generators still have market power, as each firm's output decision affects the price of electricity, and their rival's output level.

As a firm begins to generate a portion of its electricity portfolio output through wind generation, it can now supply electricity at a lower average marginal cost (MC) (since wind has a $MC = 0$) than previously. The firm will benefit from this change in costs in two ways; firstly due to the fact that the quantities of electricity produced from competing firms are strategic substitutes, meaning that as wind output increases, rival generators will produce less as demand is held constant, and secondly

¹This is not necessarily the case in markets with certain renewables schemes such as ROC in the UK, which is designed to incentivise renewable generation into the electricity generation market by placing an obligation on all UK suppliers of electricity to source an increasing proportion of their electricity from renewable sources (OFGEM, 2011). However, for the purposes of the theoretical model, this homogenous assumption is justified.

because the Cournot-Nash outcome of a firm depends on the costs of its rival.

Industry output will remain constant as the shift is taking place between firms only, and demand is in no way affected by this change in supply². Theoretically both firms could continue to increase the proportion of wind in their portfolio up to 100%, which would result in the same proportion of electricity being produced, but at a $MC = 0$. This however is not feasible in practice as it does not consider the fixed cost element of a generator's portfolio.

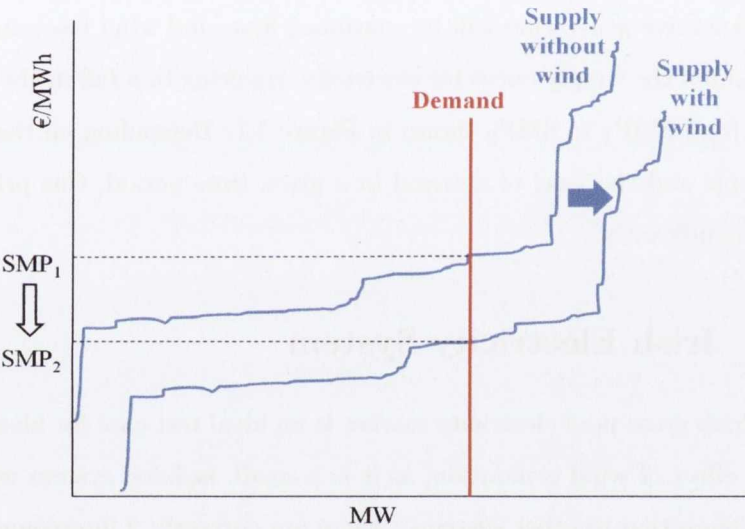


Figure 4.1: Sample Merit Order Effect

Wind generation affects the intersection of the merit order (supply curve) with the demand curve; Figure 4.1 demonstrates that it essentially shifts the supply curve for generation to the right as more generating capacity comes online.

Wind generation will always be consumed prior to other forms of generation due to its zero marginal cost, and the fact that it has priority dispatch, meaning that all electricity produced by wind in Europe must be given priority access to the grid by the transmission system operator (European Commission, 2001). This is because

²Additionally, consumer prices are typically fixed in the short run, and therefore they are not affected by changes in the marginal cost of generating electricity and thus they do not change their demand as prices shift.

once the supply curve is defined and it is compared to demand, the System Marginal Price is set to the bid price of the most expensive plant required to meet demand (CER, 2007; Devitt *et al.*, 2009; Clifford and Clancy, 2011). This is known as the Merit Order Effect (MOE), which arises from the fact that, all else equal, adding wind power to the system should replace higher marginal cost plant on the system, and this in turn is likely to lower wholesale electricity prices (Indecon, 2008; Felder, 2011).

As wind generated electricity comes online, it reduces the amount of conventional generation required to meet demand. Electricity is a homogenous good therefore less expensive generation will be consumed first, and wind has a marginal cost = 0. This shifts the supply curve for electricity, resulting in a fall in the system marginal price from SMP_1 to SMP_2 shown in Figure 4.1. Depending on the amount of wind available and the level of demand in a given time period, this price reduction can vary significantly.

4.2 Irish Electricity System

The Irish gross pool electricity market is an ideal test case for identifying the merit order effect of wind generation, as it is a small, isolated system with little existing interconnection to other systems - there are currently 2 interconnectors each rated at 500 MW - and high levels of fuel import dependency and wind power generation.

Figure 4.2 demonstrates the import dependencies of EU members in 2010, which overall had an import dependency of 51.3% at this time. Ireland imported 86.2% of its energy needs - one of the highest levels of energy imports in the EU, after only Luxembourg (96.9%), Malta (99.9%) and Cyprus (96.3%) (World Bank, 2013). Denmark is the only net exporter within the EU. As a result of its high import dependency, Ireland is particularly susceptible to shocks in energy prices, and needs to encourage as diverse a fuel mix as possible in order to protect its security of supply.

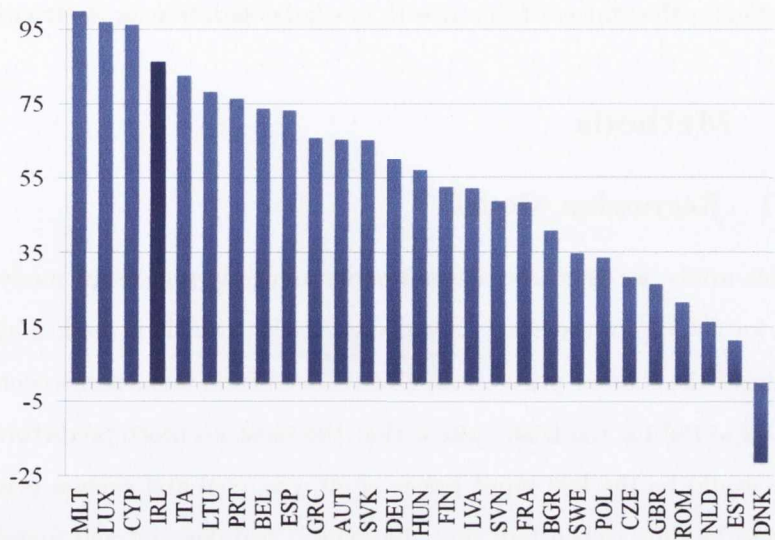


Figure 4.2: EU Import Dependency

Ireland also has extremely ambitious renewable energy targets, resulting in a high penetration of wind generation. The substitution of conventional energy sources with renewable energy sources such as wind energy offers considerable potential for reducing a nation’s carbon emissions and meeting national and international policy targets (DCENR, 2007; European Commission, 2009a). Since the 2009 European Directive, all EU countries are required to increase their renewable proportion so that 20% renewable energy is achieved on average across member states by 2020 (European Commission, 2009a). With regard to Ireland this target is set at 16% renewables of total final consumption – which incorporates the use of renewables in electricity, transport and heat sectors. Within the electricity sector specifically, Ireland has a target of 40% from renewable sources to be achieved by 2020, of which wind promises to be a major contributor (Department of the Taoiseach, Ireland, 2008).

Installed wind capacity has grown from a level of 182MW in 2002 for the island of Ireland, to 1998MW at the end of 2011 (Eirgrid, 2011), dramatically changing the fuel mix for Irish electricity. In 2011, 15.7% of gross electrical consumption was derived from wind energy, which is equivalent to 4,380GWh, or 377 ktoe. This is an increase of 48% from 2009 levels of 2,955GWh (SEAI, 2011, 2012). This paper

investigates the impact of this growth in wind generation on electricity market prices.

4.3 Methods

4.3.1 Regression Model

In this study we generate a times series multiple regression model. Irish hourly data for 2009 from the Single Electricity Market (SEM) is used to identify the main drivers of the shadow price³ through a reduced form times series econometric model. It is expected for the Irish system that the most accurate predictors of the shadow price would be the fuel input prices of oil, gas, coal and carbon price from the day prior to bidding (when bids must be made), and demand and marginal capacity of the day in question. The Shadow Price in a given period is set at the marginal cost of the most expensive unit required to meet demand in the same period. This is consistent with the guidelines for bidding set out in the Irish electricity market (CER, 2007; SEM-O, 2010), and is described in the following equation:

$$\begin{aligned} ShadowPrice_t = & \alpha + \beta_1 NetDemandk_t + \beta_2 NetDemandk_t^2 \\ & + \beta_3 Wind_t + \beta_4 Wind_t^2 + \beta_5 MarCap + \beta_6 Gas_{t-24} \\ & + \beta_7 Oil_{t-24} + \beta_8 Coal_{t-24} + X_t + \epsilon_t \end{aligned} \quad (4.2)$$

Net demand refers to total system demand less demand that is met through peat output and imports⁴ at time t , which is measured on an hourly basis. *Gas*, *Coal*, *Oil* and *Carbon* relate to the daily spot prices of these fuels on the global exchange, as the Irish Regulator requires units to bid their fuel costs in this manner. These are set and bid into the market on the day ahead in practice, and therefore are lagged by 24 periods.

This model is an extension of that presented in Chapter 2, with wind and its

³It should be noted that this price is not a shadow price in the economic sense, in that it is not the value of the Lagrange multiplier at the optimal solution. However, the Irish market documentation refers to the shadow price (essentially SMP in Figure 4.1) so for consistency we will continue to use this terminology here.

⁴As peat and imports do not bid into the Irish electricity pool.

square term included separately instead of netted off as in O'Mahoney and Denny (2011a) (Chapter 2). We expect wind to have a negative sign, as our hypothesis is that wind will reduce the price of electricity at any given time. We include a square term in order allow the relationship between the price and wind to be non-linear.

As demand increases towards total possible supply available, one would expect prices to increase dramatically due to a scarcity premium. In order to see if this is taking place, we include a marginal capacity ("MarCap") variable in the model, which can be described as $MW_{Offline} / Demand$ - the number of megawatts which are unavailable for generation as reported by each individual generating unit. This is essentially the difference between the maximum rated number of megawatts a unit is able to supply and their actual availability in a given hour. This is included in the model in order to identify whether a scarcity premium is found to be significant, with a fall in availability resulting in an increase in the price of electricity.

Controls are included for each hour of the day, day of the week, month and public holidays, as all of these have an effect on the demand for electricity, the availability of wind for generation, and the scheduled maintenance of conventional plant, which additionally has an effect on the fuel mix. Murray (2009) highlights that while the price is very closely linked to the demand level in power markets; it tends to be stratified as it reflects the different types of plant which are brought into service on a merit order basis.

4.3.2 Simulation Model

The second method of evaluating the impact of wind generation on electricity prices is conducted using a simulation model of the Irish electricity system for the same period. This simulation model of the Irish electricity system was used including 2009 hourly data. This model runs on the PLEXOS electricity modelling software platform (Energy Exemplar, 2013) and is similarly configured to the model used by the Irish regulatory authorities for this period. The model handles both the short term unit commitment, which determines the commitment schedule of units (Kiviluoma *et al.*, 2012), and the economic dispatch, which relates to the dispatch

levels of those units (Baldick, 1995), of the Irish system. It also replicates the pricing formulation used in the Irish wholesale electricity market, including both shadow prices and uplift⁵ (CER, 2010b). The following equation describes the cost function which Plexos minimises:

$$\min \left(\sum_{i=1}^N \text{Start costs}_i + \sum_{i=1}^N \text{No load costs}_i + \sum_{i=1}^N \text{Marginal Costs}_i \text{Output}_i \right) \quad (4.3)$$

$$\text{s.t. } \sum_{i=1}^N \text{Generation} = \sum_{i=1}^N \text{Demand}$$

Generators are assumed to have linear bids for energy and reserve and the constraints included are load balance, and minimum generation level and maximum capacity (Denny and O'Malley, 2007). Other costs and constraints can include reserve capacity requirement, O&M costs and carbon costs, and constraints such as minimum generation, up and down times. Scheduled and forced outages of the generation fleet were taken into account, allowing for a more realistic schedule and price.

Unit commitment and economic dispatch is carried out using a rounded relaxation optimisation process using the Xpress suite (Fair Isaac Corporation, 2013). Using piece-wise linear heat rates and generator characteristics units are represented individually in the Irish market. A lumped generator model of the Great Britain market is included, as well as 500 MW of high voltage direct current interconnection to the Irish system. Wind generation was represented by aggregate output time series presented above in Table 4.1. Wind and hydro generation were modelled as price taker units. As a result, the simulation model provides much more detail about the operation of the Irish electricity system which cannot be captured using time series econometrics however, the input data for net demand, wind, fuel and carbon prices are identical for each model.

This additional information is beneficial in trying to determine the impact of wind on the scheduling of individual units, for example, as we could consider the operation of a particular plant or type of plant if wind were not available in 2009. One disadvantage of using a simulation model is the data requirements which are

⁵Uplift is a payment that allows generators to recover start-up and maintenance costs.

onerous - technical characteristics and capabilities of each specific generator on the system are required. Additionally, there is the time associated with running a simulation model is typically much greater than an econometric model. In this case, PLEXOS took approximately 16 mins to run one model specification compared to less than a minute for the econometric model. This is not prohibitively longer, however as greater timeframes, more scenarios are analysed, or more robust optimisation constraints are included, this can result in much longer delays.

4.3.3 Data

The following table provides summary statistics for each of the variables included within this study on an hourly basis. Data for the Shadow price⁶, load and number of units available is taken from the SEM-O website, which provides data on a half hourly period since the inception of the Single Electricity Market in 2007 (SEM, 2013). Wind data is published on the Eirgrid website for the Republic of Ireland, and data for Northern Ireland was provided by SONI (Eirgrid, 2013b; SONI, 2010). Fuel and carbon prices were taken from daily global exchanges, and converted into euro using historical exchange rates. This information is included in both the econometric and unit commitment model for consistency. Observations with electricity prices exceeding €150 have been omitted from both models, as prices of this level can be attributed to technical failure rather than normal operation; observations missing values for load have also be omitted⁷.

4.4 Results & Discussion

4.4.1 Regression Model Results

Table 4.2 presents the results of the main drivers of shadow price using the regression model presented in Equation 4.2. Multicollinearity was tested for, and rejected, by

⁶This represents the marginal cost of electricity.

⁷If one of the technical constraints is violated the system marginal price defaults to an arbitrarily large number. However, this price is not actually paid/received by participants in the market but is reported as a signal of system constraint. Thus, these outliers are omitted in this analysis as they do not represent 'real' prices.

Table 4.1: Summary Statistics

Variable	Obs	Mean	Std. Dev.	Min	Max
Shadow price	8682	36.04	12.44	14.49	146.57
Net demand	8682	3381	820	1470	5862
Wind	8682	426	318	1	1323
Marcap	8682	4.31	3.20	0.9	24.7
Gas	8682	34.63	13.27	15.51	77.1
Oil	8682	44.46	6.87	28.16	54.32
Coal	8682	51.17	5.46	44.12	65.04
Carbon	8682	13.53	1.54	8.2	15.9

analysing the correlations of the estimated coefficients as opposed to the independent variables. Serial correlation was not detected.

All independent variables are found to be statistically significant at the 99% level with the exception of the price of coal; as coal serves as a baseload fuel it tends not to set the price of electricity and therefore will not directly affect the shadow price of electricity. Gas and oil do however set the price at varying points along the demand curve, and are therefore highly significant in driving the cost of electricity. The coefficient on gas (0.5607) is approximately 5 times greater than that of oil (0.1016); this is most likely explained by the fact that just under 60% of Ireland's installed conventional capacity uses natural gas (SEAI 2009)⁸. The marginal capacity ("MarCap") variable identifies that there is a statistically significant scarcity premium with regards to the availability of generation; a 1MW increase in the ratio of unavailable plant divided by total demand (the load) results in a price reduction of €0.26/MWh.

The net demand has a positive effect on the price, as an increase in net demand causes a movement up the merit curve to more expensive generating units, causing the price to increase. This relationship is non-linear as both net demand and its square are found to be statistically significant at the 99% level. Irish demand can be seen to be highly cyclical and predictable, as are the prices over time. This is illustrated in Figure 4.3, which presents Demand and Price in the first eight days of

⁸Figure 1.8 illustrates Ireland's fuel mix capacity in 2011

Table 4.2: Model Results	
VARIABLES	Shadow Price
NetDemandk	-15.3778*** (1.256)
NetDemandk ²	2.7562*** (0.204)
Wind	-0.0099*** (0.001)
Wind ²	0.0000*** (0.000)
MarCap	-0.2575*** (0.042)
GasLag	0.5607*** (0.018)
OilLag	0.1016*** (0.039)
CoalLag	-0.0452 (0.064)
CarbonLag	0.2679*** (0.100)
Constant	36.2638*** (5.196)
Observations	8,664
R-squared	0.8133

Standard errors in parentheses
*** p<0.01, ** p<0.05, * p<0.1

June 2011.

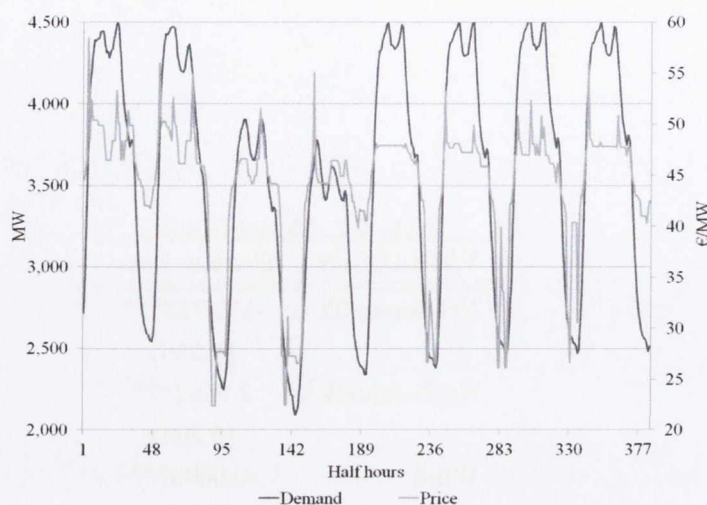


Figure 4.3: Load & Pool Price end of June 2011

The coefficient on wind is -0.0099 , meaning that an increase of 1 MW of wind on the Irish system led, on average over the course of 2009, to a fall in the shadow price of $\text{€}0.0099/\text{MWh}$. The squared output of wind, while significant, is equal to $\text{€}/\text{MWh}$ 0.0000 and therefore we can assume that while statistically significant, the impact squared wind output is not economically significant.

In isolation, this may not seem to be a significant amount, particularly given that the mean Shadow Price is $\text{€}36.044$, therefore we will re-estimate our model on an hourly level in order to find the value of the coefficient on wind at each hour in order to get further insight into the total value to the system. As wind reduces the demand for generation with higher marginal costs, its value will depend on the demand at the time and the cost of the units it displaces. As a result, using the hourly coefficient should give a reasonable indication of the true shadow price saving on an hourly level; Figure 4.4 below presents the hourly coefficients on wind.

The results show what the value of wind was to the Irish system in 2009, controlling for day of the week and month in question. As expected, the greatest price reduction in the market coincides with both peak demand and prices, as wind generation at 7pm represents the greatest saving along the merit curve. The value of wind

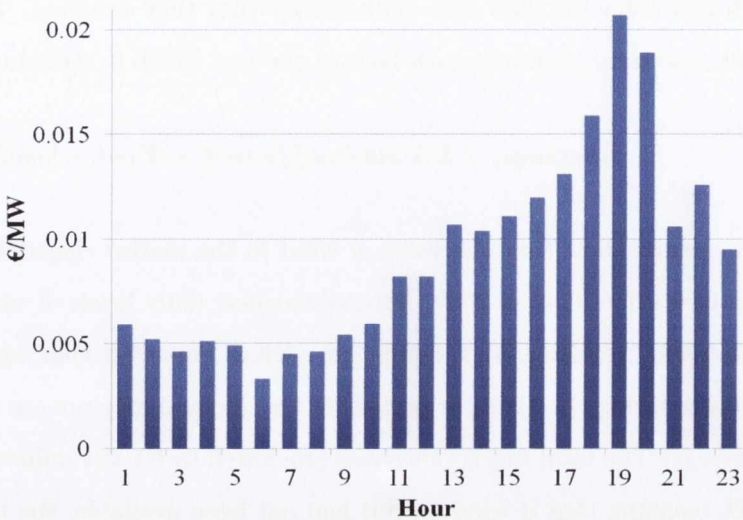


Figure 4.4: Hourly Wind Savings per MW

is directly related to the units which it displaces, which is why the value of -0.0189 seen at 7pm is more than double the coefficient seen at 7am (-0.0046). While the average reduction is €0.009 the value of a reduction in electricity price at peak hours is much more beneficial to consumers than a reduction during the night so looking just at the impact of wind during peak hours may be a better representation of the price reducing benefit of wind. Thus, when analysing the overall benefit of wind generation on price reduction (in the next section) we use these hourly coefficients rather than the overall average of 0.009.

4.4.2 Overall Price Reduction Benefit - Econometric Regression Model

In order to quantify overall price reduction benefit, the hourly wind coefficients from the econometric specification are multiplied by the historical wind outputs and system demand at each hour of 2009, as shown in equation 4.4 below. The Shadow price of electricity is set by at the marginal cost of the most expensive generator required to meet demand in a given period. As a result, each MW generated receives the same shadow price; a reduction in this price due to wind reduces the price paid

to each generator for each unit of electricity that they produce. This allows us to calculate the total saving at each hour of the day which is attributable to wind.

$$\Sigma Savings_t = \Sigma Wind Coefficient_t * Wind_t * Load_t \quad (4.4)$$

The results show that the value of wind to the market dispatch has resulted in savings of €141 million in 2009. Ireland's highest daily levels of wind coincide with peak demand, resulting in a significant saving; countries that experience highest wind levels during the night, or periods of low demand may not see the same level of cost savings. The total market dispatch amounted to €1,284 million over the course of 2009, meaning that if wind output had not been available, the total costs would have been approximately 12% higher than actual values seen.

4.4.3 Average Emissions Savings - Econometric Regression Model

Using the SEAI (2009) average emissions for the Irish electricity market, we can estimate the carbon savings arising from the displaced fossil fuel generation. This value of 0.582kg/MWh CO₂ is multiplied by the wind output at each hour and the daily carbon price for the same time period lagged by 24 hours, as shown in equation 4.3. This aggregates to a saving of €29.3 million over the course of 2009. This saving is assumed to be accounted for in our regression model, as the cost of carbon is incorporated into our regression analysis. EPA (2009) values of SO₂ and NO_x for electricity generation are used to assess the savings of emissions arising from wind generation. These are estimated at €0.5 million and €7.9 million respectively.

If we do not consider the value of carbon to be accurately represented by the price of carbon, we can instead simply consider the level of savings in kg CO₂, which equates to 2.2 million. Both estimates of emissions can be considered conservative, as the average emissions value of 0.582kg/MWh CO₂ is already accounting for wind on the system, and therefore in reality this figure would have been higher if no wind had been available.

We include the emissions results from both model types as a control to identify whether the model results are in fact consistent in areas other than price.

4.4.4 Simulation Results

PLEXOS was run using a model of the Irish electricity system for 2009, which uses actual plant availability, demand levels and generator bids for 2009 in order for it to mimic the true operation of the system, as well as the CER PLEXOS validation file as the data source for the generators (CER, 2010b). We also include historical time series values of wind output and load in order to obtain values that are as close to true system operation as possible. These are the identical wind and load data series used in the regression model. This model was then rerun a second time, with no wind available in any period, in order to simulate how existing generating plant would be operated if there were no wind on the system. Table 4.3 presents the simulation summary statistics for the shadow price and CO₂ emissions under both scenarios.

Table 4.3: Simulated Summary Statistics

Variable	Obs	Mean	Std. Dev.	Min	Max
Price without wind	8737	35.55	6.57	0	69.02
Price with wind	8737	32.7	8.06	0	65.44
Emissions without wind	8736	1329221	448005	520047.2	4564587
Emissions with wind	8736	1118617	417938.5	273116.5	5852808

4.4.5 Simulated Prices

These simulated results are relatively in line with the true historical values of the Shadow price, with a slightly lower average price than found historically, and a much lower standard deviation than the true values. As the simulated values with and without wind are consistent with one another, we compare the differences as a result of wind to our econometric model using the percentage change in prices due to wind to identify whether the patterns can be considered similar using the different methodologies. Figure 4.5 presents the hourly saving in €/MW as a result of wind on the Irish system as estimated by the simulation models.

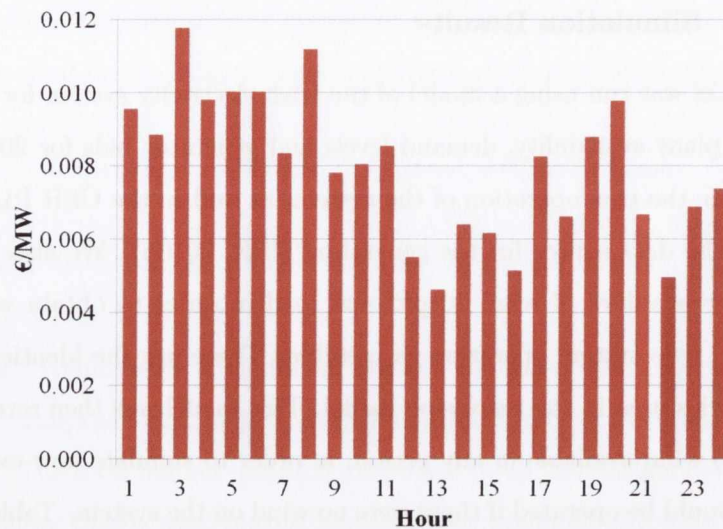


Figure 4.5: Simulated savings from Wind

Overall, the simulation results find that, had no wind been available in 2009, the cost of electricity would have been 9% higher on average. Comparing both simulations (with and without wind) for each hour of the year, we find that the value of wind to the market dispatch resulted in estimated savings of €93 million in 2009. The shape of the savings on an hourly basis is not in line with the econometric model results, and instead finds that wind is more valuable during the early hours of the day. This is counter to intuition, as demand at these hours is typically lower than later on in the day, and thus supplied by less expensive generating units. As a result, the price suppression effect of wind should be less during these hours.

4.4.6 Simulated Emissions

As calculated in PLEXOS, the availability of wind on the Irish system resulted in emissions savings of 1.8 million kg of CO₂, or 16% less emissions than if no wind output had been available over this year. We quantify this saving in terms of using

the following equation:

$$\Sigma EmissionSavings_t = \Sigma (Emissions_{NoWind} - Emission_{Wind})_t * Carbon_t \quad (4.5)$$

This equates to an estimated CO₂ saving deriving from wind equal to €24.4 million, using the same daily carbon prices described in Table 4.1. Using our econometric model, the estimated savings were €29.3 million. These are in line with our expectations, particularly given the fact that the simulation results also indicate a lower price effect from wind than our econometric model.

4.5 Discussion

Both types of model find that wind results in a cost saving and an emission saving to the Irish electricity market in 2009. They find that the level of these savings is non-trivial, and results in a market dispatch saving of between 8-11%, and emissions savings of between €24.4-29.3 million. These are largely in line with one another, and demonstrate that regardless of the type of model used, similar results can be found. While the econometric results show greater savings than the simulations results, this may be in part due to the fact that the simulation outputs do not represent the true increased standard errors brought about by the variability of wind generation.

Overall our results indicate that electricity market analysts can use a simple econometric model such as the one presented in this paper and still obtain similar results to that of a full unit commitment model. Depending on the type of analysis required, this will result in time savings as the econometric model requires less time to run in addition to less detailed, unit specific information in order to achieve similar results.

Figures 4.4 and 4.5 present the estimated distribution of the shadow price reduction per MW of wind on an hourly basis. The results from our econometric model find that wind has the greatest price suppression effect during hours of peak

demand, which would imply that wind is most valuable at times of higher prices (as a result of more expensive units being called into the merit order). The simulation results find that impact of wind is greatest during the early hours of the day, when demand is generally lower. This may explain why on average the econometric model shows a greater saving as a result of wind when compared to the simulation model (an average saving of €4.07/MWh vs €2.85/MWh). Figure 4.6 compares the true hourly prices to those simulated by PLEXOS, and demonstrates that the simulated prices tend to overstate the true value of wind during the early hours of the day, and understate them during hours of peak demand.

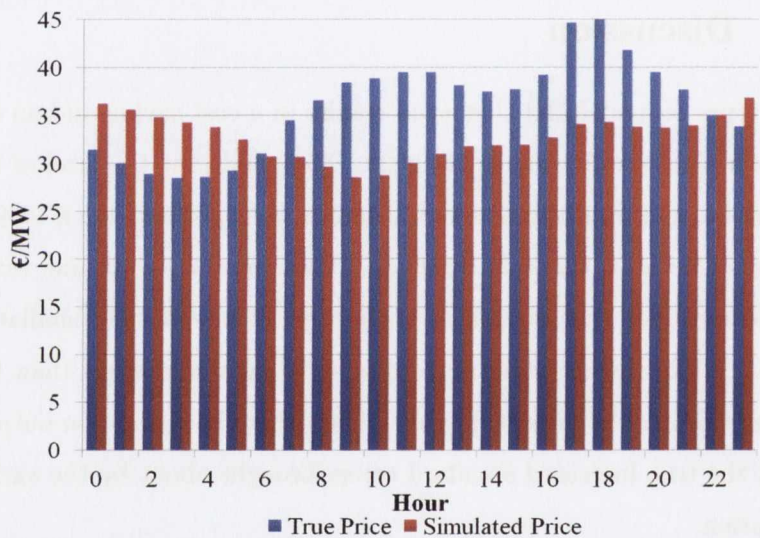


Figure 4.6: Estimated savings from Wind

This may explain the difference between the value of wind over the course of the day from the two types of models. It implies that the econometric analysis may prove a better model in terms of the impact of wind on prices, as PLEXOS smooths much of the variability in prices and emissions derived from wind generated electricity.

As demonstrated in the analysis, this result is heavily dependent on both the level of wind output and total demand at each point in time, and therefore predicting future cost savings will be highly dependent on the assumptions surrounding these

parameters. It should also be noted that results are exclusive to the test system, and further study would be needed if attempting to calculate the benefits to other systems. Figures 4.7, 4.8, and 4.9, from AEMO (2011) highlight this fact.

While Ireland, the focus of this study, has wind which is correlated with demand for electricity, this is the opposite of the case on the ERCOT system in Texas. Here, wind output is lowest at times of peak demand and therefore the price suppression potential of wind will be much lower. The New South Wales system shows a different correction pattern, with peak wind output on average arising after peak load, yet still following a reactively similar pattern.

4.6 Conclusions

In this paper we assess the impact of wind on system prices using both an econometric model and a unit commitment model and compare the results in an attempt to determine if the results are comparable. We hypothesise that a historical econometric model should produce the same results while being much more efficient in terms of data requirements and computation time than a simulation model. Results indicate that both models result in costs savings as a result of wind generation on the Irish system. They indicate that the level of these savings is non-trivial, and results in a market dispatch saving of between €93-141 million or 8-11%, and emissions savings of between €24.4-29.3 million. Thus, it appears that electricity market analysts can use a simple econometric model such as the one presented in this paper and still obtain similar results to that of a full unit commitment model. Depending on the type of analysis required, this will result in time savings as the econometric model requires less time to run in addition to less detailed, unit specific information in order to achieve similar results.



Figure 4.7: Ireland



Figure 4.8: ERCOT (Texas)



Figure 4.9: New South Wales (Australia)

The Drivers of Power System Emissions: An Econometric Analysis

IN recent years, international policies focussing on emissions reduction in electricity markets have had two main goals – internalising the cost of carbon and promoting the use of renewable generation (Kyoto Protocol, 1992). The promotion of carbon pricing has been primarily through mechanisms such as the US Clean Air Act (2008), EU Emissions Trading Scheme (European Commission, 2009b), Australia’s Clean Energy Act (2011), and Germany’s Renewable Energy Sources Act (2000), while increasing renewable generation has been encouraged through mechanisms such as the US Energy Independence and Security Act of 2007 and the EU Renewables Directive (2009/28/EC) (European Commission, 2009a). This EU Directive has driven national policies such as the Renewables Obligation Certificate Scheme in the UK (2011) and French and Irish National Renewable Energy Action Plans (2009). To meet these policy goals, emissions reductions and renewable supplies are needed in the electricity, heat and transport sectors. But given the power sector’s centrally controlled nature, reducing emissions is relatively more straightforward in that sector, and so it has been the focus of these policies.

Wind is one of the most developed forms of renewable energy, and as such its

market share has grown considerably in recent years. On a global scale, wind power capacity has grown by 50% from 159 GW in 2009 to 238 GW in 2011 (REN21, 2012). Table 5.1 presents the level of new renewable installations within Europe between 2000–2011.

Table 5.1: European Renewable Installations in GW

Renewable	GW
Wind	84
Solar PV	47
Large Hydro	4
Biomass	3
Waste	2
CSP	1
Small Hydro	0.3
Geothermal	0.2
Ocean	0.01
Source: EWEA (2012)	

Demand side management (DSM), through programs such as energy efficiency (e.g. through the installation of more efficient electrical appliances and improved building regulations) and smart metering also allows for emissions reduction management¹. Dietz *et al.* (2009) estimate that 10 years after DSM implementation, the US could save 123 million metric tons of carbon per annum, which is 20% of national household direct emissions. However, others have warned that demand response, as it shifts loads from periods with low marginal emissions to ones with high emissions could actually increase emissions (Holland and Mansur, 2007).

In the electricity sector, much of the focus to date has been on supply side measures such as as promoting renewable generation (in particular wind for the purposes of this paper) and more efficient conventional generation sources. However, DSM also offers significant benefits with potentially lower adoption costs. Benefits of both wind and DSM include a reduction in fossil fuel consumption, emissions reduction benefits, security of supply benefits and assisting in meeting international

¹One of the benefits of DSM is demand smoothing, whereby demand from peak hours is reduced and shifted to periods of lower demand, however we focus on an absolute reduction in demand in this study.

and national policy targets. In particular, wind increases levels of variability and unpredictability on an electricity system (Troy *et al.*, 2010), yet acts like a hedge against high fuel costs by reducing the wholesale cost of electricity (O'Mahoney and Denny, 2011b). DSM does not require the construction of additional generating units, and enables existing plant to be run more efficiently (Yik and Lee, 2005). One issue with DSM is the need for changing consumer behaviour. As it is unclear how much a consumer will react to different price changes, the impact of various DSM policies focussed on demand response to prices is ambiguous a priori, whereas wind energy is consumed whenever available. As systems struggle to balance supply and demand with increasing levels of variable generation such as wind, demand side solutions may become increasingly beneficial, particularly in terms of providing standing reserve (Strbac, 2008).

There is a forecast error associated with wind, and as a result additional reserve is required as wind penetration levels increase. This can increase emissions by having more generation (and perhaps dirtier generation) started up and on-line to provide reserves. Adding wind to a system has the advantage of being centrally controlled, removing the need to affect consumer behaviour, however wind cannot be deployed on demand, therefore is not guaranteed to reduce emissions at the most inefficient, peak hours.

The aim of this research is to model the drivers of emissions historically for a real system, in an attempt to identify the factors most effective in reducing power systems emissions. We hypothesise that supply and demand side measures should have the same impact on emissions reduction. For example, a 10 MW injection of wind output is equivalent to a 10 MW reduction in demand in terms of emissions reduction, as both in effect reduce the amount of electricity to be generated by fossil fuels by 10 MW and so should reduce the associated emissions by the same amount.

This paper estimates the historical effects of wind and demand on the Republic of Ireland's electricity market CO₂ emissions. This will enable us to compare the effects of wind versus a reduction in demand (as a proxy for DSM) in terms of reducing electricity market emissions. This study is different from the majority of

existing literature in this area in that it uses actual system level data rather than a market simulation approach and considers the effects of both wind and demand side management on CO₂ emissions. We also compare the forecast errors associated with both load and demand on a half hourly basis in an attempt to identify whether one form of error results in higher levels of CO₂ emissions than the other.

Section 5.1 discusses the characteristics of electricity market emissions and outlines the two methods of interest for reducing said emissions, and Section 5.2 describes the reduced form econometric model employed. Section 5.3 outlines the case study electricity system analysed in this work and Section 5.4 describes the data. Results, discussion and conclusions are presented in Sections 5.5, 5.6 and 5.7 respectively.

5.1 Electricity Market Emissions

Emissions from electricity markets are produced through the burning of fossil fuels. In order to reduce these emissions, systems must reduce the share of generation from fossil fuel sources. This can be achieved either through supply or demand side approaches.

5.1.1 Supply Side Approaches

In power systems, emissions result from the technical characteristics of each generating plant on the system, based on individual heat rate and the calorific values and carbon content for each type of fuel used. The heat rate measures the thermal efficiency of a generator, and is calculated by dividing the energy content of the fuel burned to produce electricity by the amount of electrical energy generated from it. These heat rate curves are then used to determine the efficiency at which a generator burns fuel at any given time. Renewable energy does not cause emissions from the burning of fossil fuels, and therefore displacing generation from fossil fuel units can reduce overall power system emissions. Traditionally, renewable energy sources had low market shares, thus much of the earlier literature on power system emissions in the presence of renewables is simulation based. This paper represents one of the first

studies to compare the effects of renewable generation and demand econometrically on emissions output, while also considering the effect of forecast errors.

Denny and O'Malley (2006) use a unit commitment simulation model to demonstrate how wind generated electricity can reduce CO₂ emissions from conventional units on a power system. It simulates a number of different operating strategies and shows the impact of these on emissions. The Electric Reliability Council of Texas (2009) report also uses a simulation based approach, modelling the operation of generating units on the ERCOT system in a manner consistent with market operation on an hourly basis, using historical data as an input. They consider the impact on wholesale and end user prices of emissions reduction. They analyse the impact of proposed US emissions reduction legislation, assuming that the goals are met directly through emissions reduction in the case study region. A number of scenarios are considered, each with CO₂ costs ranging from \$0-100/ton CO₂, also finding a negative relationship between wind and emissions.

As wind penetrations have increased in recent years there has been a growing number of econometric analyses in this literature. Some of these studies, however, find a significantly different relationship between wind and emissions than the earlier simulation based studies. Bentek Energy LLC (2011) finds that the emissions savings derived from wind power are either so small as to be insignificant or too expensive to be practical. They use hourly data from 2007 to 2009 for the Electric Reliability Council of Texas (ERCOT), Bonneville Power Administration (BPA), California Independent System Operator (CAISO) and Midwest Independent Transmission System Operator (MISO) power systems and emissions data from the Environmental Protection Agency (EPA). They find that wind coincides with times of low demand for electricity, and as such emissions reductions are relatively small. However, they use temperature as a proxy for electricity demand, which calls into question the validity of the results. While temperature can be a good indicator of seasonal trends in demand, it is inappropriate on an hourly basis, particularly in temperate climates, as a number of other more significant factors drive electricity demand, such as consumers' cycles of activity.

Forbes *et al.* (2011) use half hourly data from the Irish electricity system from March 2008 to August 2010 to consider the emissions from the Irish power system. They use time-series regression analysis to determine the effects of wind and wind forecast errors, in particular on the output of CO₂ emissions, and find that wind has a small impact on the level of emissions from the Irish system. However, they include wind forecasts, positive and negative wind forecast errors which results in endogeneity issues. They also include fuel prices with load as independent drivers of emissions, yet prices only affect emissions through their effect on the load, causing collinearity issues. The spot price of electricity is also included as an independent variable, yet this price is not determined until 4 days ex post, implying reverse causality. This calls into question the robustness of results.

Cullen (2008) also uses a reduced form time series model, with 15 minute resolution data from 2005-2007 from the ERCOT system. His results find generator level substitution of wind for fossil fuel generation of approximately 20% from coal plants, with the remainder from gas fired units. He includes both temperature and load in his model - it is not clear whether there is a collinearity issue with these variables though, as temperature appears to have a much greater effect on emissions than load which appears somewhat counter intuitive.

Kaffine *et al.* (2012) estimate the emissions savings from wind using hourly resolution data from 2007-2009 from ERCOT, MISO and CAISO systems. They find that the share of coal on a system strongly influences the emissions savings associated with wind.

Marcantonini and Ellerman (2013) examines the effects of solar and wind generated electricity in emissions reduction on the German electricity market. They use data from 2006-2010 and find that the carbon abatement cost for wind is €43/tCO₂ whereas the cost for solar is €537/tCO₂. This clearly demonstrates that not all methods of emissions reduction are equal, and each should be investigated individually. These values are not representative of global figures, but reflect Germany's relatively poor resources and capacity factors.

Gowrisankaran *et al.* (2011) considers the value of variable generation on an elec-

tricity system by considering the effect of solar generation on the Tuscon Electric Power System in Arizona. They use hourly data for 2008 to estimate the relationship between load and its day ahead forecast, and solar and its day ahead forecast, using a Seemingly Unrelated Regression (SUR) specification. The authors find an equilibrium cost of 20% solar PV RPS would result in \$136.1/MWh – of which unforecastable intermittency accounts for only \$2.7/MWh. This is much less than many industry observers would have predicted.

Novan (2011) examines the variation in emission savings over time associated with wind using hourly data from 2007–2009 from the ERCOT system. He uses both a simple dispatch and reduced econometric model in his specification in order to identify the average reduction in aggregate emissions caused by wind. However, the econometric model does not include forecast errors or demand as drivers of emissions. The author finds that as renewable generators producing at different times will reduce emissions by differing amounts, policies should be changed to reflect the quantity of pollution avoided rather than renewable output.

5.1.2 Demand Side Approaches

In terms of demand-side methods of reducing electricity market emissions, more active demand-side involvement would have additional advantages in making electricity markets more efficient and competitive (Strbac, 2008; Kirschen, 2003). While efficiency mechanisms such as loft insulation and double glazing tend to act as a shock to the market, as consumers switch from standard to more energy efficient goods such as light bulbs and washing machines, smart metering allows for consumers to engage more effectively with the electricity market.

Gaterell and McEvoy (2005) find that demand side management will help maintain energy security and reduce energy consumption levels. They note that the domestic sector could make a significant contribution to reducing energy consumption. Kneifel (2010) estimate energy savings in the commercial sector, and find that conventional technologies could be used to decrease energy use in commercial buildings by 20-30% on average and by up to 40% in certain circumstances.

Thollander *et al.* (2005) study the effects of increased electricity prices in Sweden, and quantify the energy efficiency potential on the iron and steel foundry through an energy audit. They consider potential cost reductions through the use of reduced energy use, load management measures, and changing load carriers. The results from the audit indicate that possible energy efficiency measures could exceed 33%.

At present, the majority of consumers pay a flat rate for the electricity that they consume, thus temporal variations in their demand is a function not of price but of their behavioural patterns. DSM, however, would create an incentive for consumers to modify their behaviour in the face of variable electricity prices (Kirschen, 2003). This may take the form of time of use pricing, or longer term price agreements with the system. Higher wholesale electricity prices usually coincide with times of high CO₂ emissions as they represent times when the system is under pressure and all generators are operational. Thus, the price signal through smart metering should reduce demand, and therefore emissions at peak hours. DSM allows the electricity market to utilise existing generation more effectively by shifting some demand from peak times to times of lower demand (Yik and Lee, 2005); as a result less units may be required to meet demand, allowing long term capital investment to be postponed.

However, Kirschen (2003) found that the capital costs associated with installing the necessary equipment to allow consumers to actively manage demand in response to price signals can, on occasion, be prohibitively expensive. Additional issues include a lack of existing incentives to invest in this capital cost. Strbac (2008) indicates that many of the benefits relating to DSM are currently system-wide; therefore the individual level incentives need to be addressed.

5.2 Methodology

The aim of this research is first to identify the most significant drivers of CO₂ emissions, and then consider whether the magnitudes of the effects of wind and demand – which we hypothesis should be equivalent – are comparable. The overall approach undertaken is time series regression analysis.

We do not include an intercept in our specification, as we believe that in this

instance Regression Through the Origin (RTO) is appropriate². This is due to the fact that if demand and wind output were both equal to zero then there would be no emissions associated with the power system. In all versions of our reduced form Models, X_t represents a vector of control variables included for hours, months and years.

Model 1:

$$CO_{2t} = \beta_1 Netload_t + \beta_2 Wind_t + \beta_3 (Loaderr_t - Winderr_t) + \beta_4 (Loaderr_t - Winderr_t)^2 + X_t + \epsilon_t \quad (5.1)$$

Net load is defined in our dataset as *Net load* = *Load* - *Hydro* - *Interconnector flows*, where load represents electricity demand, hydro represents the demand met through hydro generation, and Interconnector flows account for electricity imports from the UK. We expect that net load should have a positive effect on emissions, as this represents the proportion of total electricity demand met through fossil fuel operated units in the case study system. $Wind_t$ is the actual output of all wind farms in the case study system at time t .

We expect wind to have a negative effect on emissions, as it is an emission-free substitute to thermal generation and is thus meeting demand that would otherwise be supplied by fossil fuels from the system. In Model 1 we aggregate load and wind forecast errors into one variable, $(Loaderr_t - Winderr_t)$, to determine the effect of total forecast error on emissions; we expect that any error in forecasting will increase CO₂ emissions on the system, as if perfect information were available the system would be run optimally. We include a squared error term in addition in order to allow the relationship between errors and emissions to be non-linear.

The second goal of this research is to consider whether load forecast errors and wind forecast errors have similar effects on CO₂ emissions. Thus, we are interested in comparing the magnitudes of these variables in an attempt to identify whether one increases emissions more than its counterpart. This will allow for system oper-

²RTO is discussed in greater detail in Eisenhauer (2003)

ators to identify which is more important in terms of improved forecasting options. It is expected that demand forecasts should be more accurate than wind as they are based more predominantly on consumer behavior and patterns whereas wind forecasts are weather dependent.

Models 2 and 3 contain disaggregated values for wind and load forecast errors. We expect both sets of errors to have a positive significant effect on emissions, as any error in predicting either demand or wind output will result in the power system being operated in a suboptimal fashion. We use the absolute values of both sets of errors, as regardless of whether the variables are over or under forecast, they will result in the system being operated differently.

Model 2:

$$CO_{2t} = \beta_1 Netload_t + \beta_2 Wind_t + \beta_3 Loaderr_t + \beta_4 Loaderr_t^2 + \beta_5 Winderr_t + \beta_6 Winderr_t^2 + X_t + \epsilon_t \quad (5.2)$$

Model 3:

$$CO_{2t} = \beta_1 Netload_t + \beta_2 Wind_t + \beta_3 Loaderr_t + \beta_4 Loaderr_t^2 + \beta_5 Winderr_t + \beta_6 Winderr_t^2 + \beta_7 (Loaderr * Winderr)_t + X_t + \epsilon_t \quad (5.3)$$

Model 3 includes an interaction term between the two sets of forecast errors, as we expect that the impact of having both types of error should increase emissions by more than either in isolation. Finally, Model 4 includes the interaction terms and its square without the other error terms, in order to identify whether Model 3 results in collinearity issues resulting from the interaction term $Loaderr * Winderr$ in addition to them included separately.

Model 4:

$$CO_{2t} = \beta_1 Netload_t + \beta_2 Wind_t + \beta_3 (Loaderr * Winderr)_t + \beta_4 (Loaderr * Winderr)_t^2 + X_t + \epsilon_t \quad (5.4)$$

5.3 Case Study - Ireland

The Irish electricity market has a number of characteristics which makes it an ideal case study for electricity market research. It is a small island system, with an installed capacity of 9 GW of conventional capacity of which approximately 2 GW is excess capacity and planning reserve, and limited interconnection to the GB system through two interconnectors. These are each rated at 500 MW.

The All-Island system has a high proportion of installed wind capacity - equivalent to roughly 18% of total installed capacity. This has been used to generate up to 50% of the island's electricity demand in some half hour intervals; wind is curtailed if it exceeds 50% of total system load at any given time. Ireland is also unusual in that its baseload plant³ contains peat fuelled plants, which an indigenous source of fuel. Nuclear is currently prohibited under Irish law. Figure 5.1 is indicative of the Irish fuel type used for electricity generation on a half hourly basis.

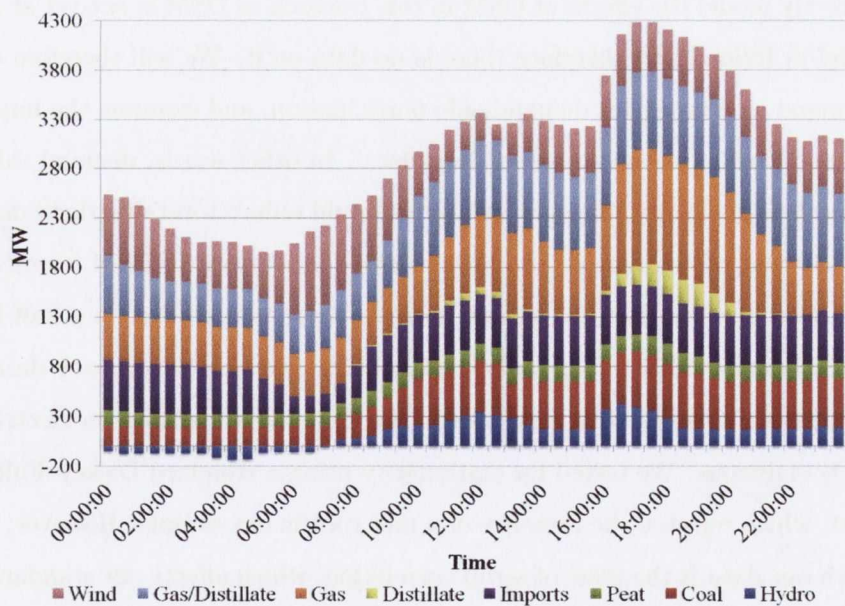


Figure 5.1: Irish Dispatch example

³Baseload plants are used to meet a system's minimum continuous energy demand

In this study, we focus on the Republic of Ireland segment of the All Island Market, which represents 72% of the total market, and 79% of installed wind capacity. We do so due to a lack of available data for Northern Ireland over a similar time period, however as both systems are operated as a whole we anticipate that the results of our study would also be applicable in Northern Ireland. We effectively isolate the ROI system by considering only the Republic's loads and plants, and by deducting net imports from NI from the net load served by thermal and wind.

5.4 Data

The dataset for the study is for the Republic of Ireland, and comes from publicly available data from Eirgrid (2013a) and SEMO (SEM, 2013). SEMO is a joint venture between Eirgrid plc - the Transmission System Operator (TSO) in the Republic of Ireland - and SONI Limited, the TSO in Northern Ireland. It is not possible to directly model the effects of DSM in this research as DSM is not yet at a significant level in Ireland and therefore there is no data on it. We will therefore consider net demand as a proxy for demand side participation, and examine the impact of a net demand reduction on emissions in general. In other words, demand side participation through energy efficiency measures should reduce total electricity demand, thus, a reduction of net demand can be considered as a proxy for DSM (energy efficiency). All data is actual historic output from the system, recorded on a half hourly basis from January 2010 to September 2012. Such micro-high-frequency data enables us to test the effect of wind and load in the Republic of Ireland on electricity market CO₂ emissions. We tested for stationarity using a standard Dickey-Fuller unit root test, which rejected the presence of a unit root in our sample. However, one concern with our data is the issue of serial correlation, which affects our standard errors. As a result we use a Prais-Winsten Generalised Least Squares estimation to correct for our serially correlated residuals. Table 5.2 presents summary statistics for each of the variables included in our various model specifications on a half hourly basis.

CO₂ emissions are calculated in real time by Eirgrid using the true generator

Table 5.2: Summary Statistics

Variable	Obs	Mean	Std. Dev.	Min	Max
CO ₂	32655	1405	360	533	2897
Netload	31973	2766	583	1481	4693
Loadfcst	32723	2980	639	1584	5144
Wind	32655	458	355	1	1474
Windfcst	32723	473	367	0	1523
Loaderr	32655	556	400	0	1301
Winderr	32655	89	85	0	1127

MW output, the individual heat rate curves for each power station and the calorific values for each type of fuel used. They do not use continuous emissions monitors, unlike the US. The heat rate curves are used to determine the efficiency at which a generator burns fuel at any given time. The fuel calorific values are then used to calculate the rate of carbon emissions for the fuel being burned by the generator. CO₂ emissions presented in Table 5.2 are defined as tonnes of emissions per MW in each half hour time period.

The Republic of Ireland system load represents the electricity production required to meet national electricity consumption, including system losses, but net of generators' requirements. Generators consume some energy as they convert fuel into electricity and this is accounted for in electricity demand values. We then correct this to Net load presented in Table 5.2 to account for interconnector flows and hydro output on a half hourly basis over the period of investigation. We net their contribution from gross load, because that net load is what thermal and wind must be dispatched to meet.

Additionally, the hydro units are scheduled to run as peaking units at times of high demand, and are therefore not independent of system demand. This means that including hydro output separately as an independent variable will result in endogeneity issues and lead to bias. As described earlier, net load is defined as $Netload = Load - Hydro - Interconnector\ flows$.

Load forecast data is available on the SEMO website SEM (2013). Load is highly predictable as it is a function of time, weather patterns and social events, as can

be seen in Figure 5.2. In Ireland, demand forecast errors could be considered more random than other regions as they are less temperature driven than areas with vast quantities of air heating or cooling, particularly as Ireland experiences relatively small changes in temperature on both an hourly and seasonal basis. Load forecast errors are defined as $Loaderrors = |load - forecast|$. In real time operation, Eirgrid receive forecasts 4 times a day, 5 days ahead and a short term forecast which updates every 15 minutes for the coming 12 hours. This data however is not publicly available and thus we use the published data available online, which gives forecasted load at 24 hours before real time. This overstates the likely impact of load errors, as in reality better forecasts are used by the system operator. Thus, our results may overstate the significance of load forecast errors.

The wind power forecast data published on the Eirgrid website is updated once daily for the following 48 half hourly periods (Eirgrid, 2013a). A snapshot of data can be seen in Figure 5.3. Average wind error equates to 19% of average wind over the entire period studied. Wind forecast errors are defined as $Winderrors = |wind - forecast|$.

In some cases there may be a difference between actual and forecasted wind which has nothing to do with the forecast error. This may occur if there is wind curtailment due to power system reliability issues. In the case study system, operating practise is to curtail wind if wind exceeds 50% load. For completeness, wind and its forecast errors are corrected for wind curtailment if $wind > load/2$, it is set to $wind = load/2$; errors are then relative to this curtailed value.

Variations in available plant mix arise naturally over the course of a year. Both thermal generation and wind will be unavailable due to scheduled maintenance, and wind through natural weather variations. As more wind turbines came online over the period under investigation, we also control for changes in installed wind output alongside variations in plant mix through the use of control dummies. Between January 2010 and October 2012, 6 windfarms with a combined 111 MW Maximum Export Capacity (MEC) were connected to the TSO network (Eirgrid, 2012), and 34 windfarms were connected on the Distribution System Operator (DSO) network

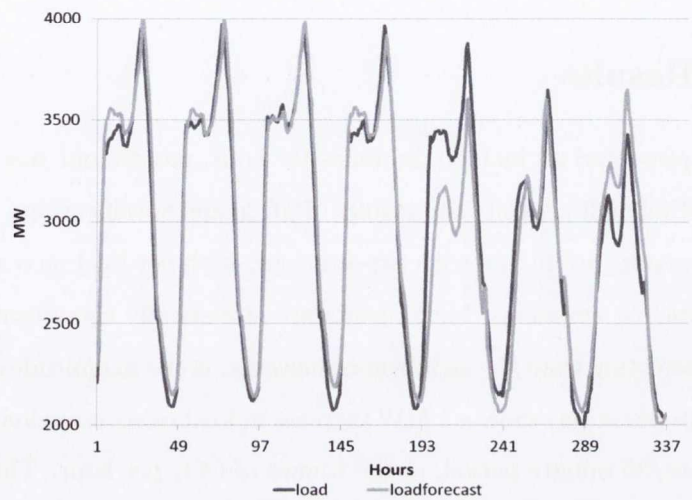


Figure 5.2: Load & Load forecast for week beginning 22nd Oct 2012

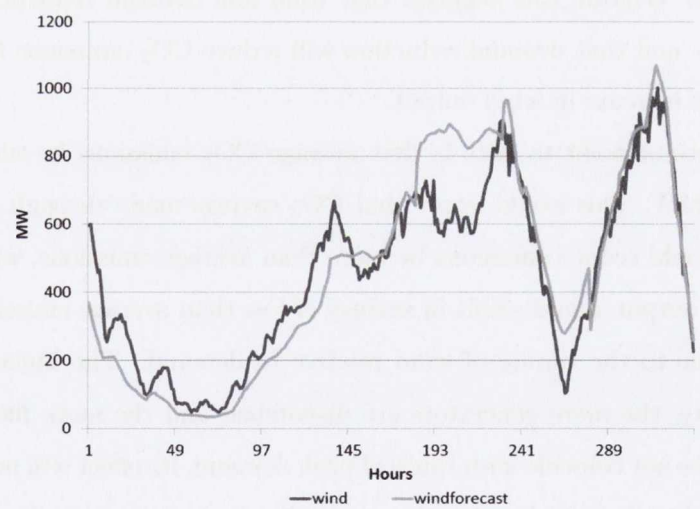


Figure 5.3: Wind & Wind forecast for week beginning 22nd Oct 2012

with a combined MEC of 316 MW, starting with Mace Upper Windfarm of 2.55 MW on the 2nd January 2010 (ESB Networks, 2012). This is captured in the model through our array of time dummy variables.

5.5 Results

Models presented all include dummies for hour, month and year, and have no constant⁴. Table 5.3 presents the results of all model specifications.

Our results are in line with expectations, with net load increasing emissions and wind reducing emissions, both results are statistically significant at the 99% level. More interesting than the significance however, is the magnitude of these effects. All model specifications show a 1 MW increase in load raises emissions by approximately 0.3 tonnes/30 minute period, or 0.6 tonnes of CO₂ per hour. This is approximately 50% greater than the emissions reductions associated with wind, which is seen to reduce emissions by 0.4 tonnes of CO₂ per hour. These effects are not sensitive to the model specification, and hold regardless of the type of system error terms included. Overall, this suggests that wind and demand reduction are not equally effective, and that demand reduction will reduce CO₂ emissions by 50% more than a similar increase in wind output.

A second point to note is that average CO₂ emissions in our dataset are 0.48 tonnes/MW. This would imply that CO₂ savings made through a reduction in demand would reduce emissions by more than average emissions, whereas an increase in wind output would result in savings of less than average emissions. This is likely to be due to the timing of wind relative to demand. The higher the demand for electricity, the more generators are dispatched and the more fuel is consumed. If wind does not coincide with times of peak demand, its effect will not be as significant as it might otherwise be. Another possibility is that the units displaced by wind are not the most highly emitting units on the system, as baseload units of coal and peat will be higher emitters of CO₂ yet are not flexible enough to be ramped in relation

⁴When these constraints are removed, the coefficients on our variables of interest do not change (nor does the AIC) however the model fit worsens.

Table 5.3: Model Results

VARIABLES	Model 1	Model 2	Model 3	Model4
netload	0.31253*** (0.003)	0.31201*** (0.003)	0.31200*** (0.003)	0.31067*** (0.003)
wind	-0.20179*** (0.006)	-0.20573*** (0.006)	-0.20620*** (0.006)	-0.20533*** (0.006)
loaderr		-0.03046*** (0.006)	-0.01983*** (0.007)	
loaderr2		-0.00002*** (0.000)	-0.00002*** (0.000)	
winderr		0.00727 (0.012)	0.03246** (0.013)	
winderr2		-0.00012*** (0.000)	-0.00013*** (0.000)	
error	-0.02756*** (0.005)			
error2	-0.00003*** (0.000)			
inter			-0.00011*** (0.000)	-0.00017*** (0.000)
inter2				-0.00000 (0.000)
Observations	32,041	32,041	32,041	32,041
R-squared	0.63353	0.63608	0.63625	0.63418

Standard errors in parentheses

*** p<0.01, ** p<0.05, * p<0.1

to wind.

In Model 1, the impact of forecasting error is about 10% of the effect of wind on emissions; a 10 MW increase in forecasting error reduces emissions by approximately the same level as a 1 MW increase in wind output. In order to consider this effect more carefully, we separate the two forecast error components in Models 2 & 3. In Models 2 and 3, the forecast error for both load and its square are statistically significant at the 99% level, but wind error is not significant in the linear form in Model 2. Counter to expectations, the effects of forecasting error are negative in all model specifications. When we disaggregate the effect of load and wind forecast errors, the impacts of both net load and wind are consistent with previous specifications.

Both wind and load errors have a statistically significant effect on the level of emissions in a given time period, and their coefficients are relatively similar. In Models 2 & 3, load errors appear to reduce emissions, at an increasing rate, and the coefficients are quite similar. Both types of error have a counter-intuitive sign, meaning that they reduce rather than increase emissions. As stated previously, the forecast data used in this study is not as high frequency as that used by the system operator. From the summary statistics, load error has a mean of 556 MW while load error has a mean of 89 MW, thus if improved load forecast data were available the magnitude of load errors may decrease, or potentially have the correct sign.

From our interaction term in Model 3, we see that having both load and wind forecast errors combined further reduces emissions - this appears counter-intuitive as having two different types of error, if independent, would result in a less efficient operation of the electricity system as a whole. This interaction term is important to include as there are only 23 observations in our entire dataset where $error = 0$ for one of the two terms.

Model 4 considers the interaction term between load and wind forecasting error and its square exclusively in terms of the effect of errors on emissions output. This is found to be statistically significant, but not largely different from its effect in Model 3, and therefore cannot be assumed to capture the entire effect of errors on the system level emissions.

We also ran a simple regression of wind errors on load errors in order to identify whether there may be an endogeneity issue, and find that while statistically significant at the 99% level the magnitude of the effect is extremely small; a 10 MW increase in wind error increases load errors by 0.6 MW. Thus, wind error does not appear to be a primary economic driver of load error.

5.6 Discussion

Our analysis indicates that wind is less effective than demand reduction in terms of reducing CO₂ emissions⁵. A 1 MW reduction in demand results in a reduction of 0.3 tonnes of CO₂ per 30 minute period for demand compared to a ~0.2 tonnes of CO₂ reduction from wind for a 1 MW increase in wind output (~33% less reduction as a result of wind if we assume model is absolutely accurate). This implies that wind and demand reduction are not perfect substitutes in terms of emissions reduction. The difference between the two values is most likely attributable to the timing of wind. Wind is non-dispatchable and as a result does not always coincide with peak emissions or demand.

This 0.2 tonne/30 min period coefficient is approximately half the average half hourly CO₂ emissions value. While this may seem surprising, it is most likely due to the fact that the marginal units which will be removed from the merit order, by more wind, are not the most highly emitting units such as coal and peat. This appears reasonable, as these units are less flexible and thus less likely to be ramped frequently as a result of changes in demand, and they are both also baseload plant, which means that they are not likely to be the marginal unit in terms of cost. Gas accounted for 55.5% of Ireland's primary fuel mix for electricity generation in Ireland (SEAI, 2012), and thus is the fuel type most often displaced.

This result implies that a policy focussing on either reducing demand or increasing the output of a variable renewable generation source such as wind will be effective in terms of emissions reduction for the Irish system, however the impact of

⁵As estimated by the system operator.

wind is less than that of demand side measures. As a result, policies can be selected based on the specific characteristics of an individual system, such as existing fuel mix, transmission constraints, and cost.

CER smart metering trials in the Republic of Ireland estimate that a fully smart meter with In Home Display will cost €219 per meter installed. This cost is inclusive of the meter purchase, installation and a replacement battery (CER, 2011a). Using household figures from the Irish Central Statistics' Office (CSO, 2006), this would aggregate to a national cost of approximately €322 million⁶, to enable all Irish households to participate in smart metering, net of O&M costs.

Based on SEAI estimates regarding the cost per installed MW of wind power capacity, this capital cost would equate to approximately 200 MW of installed wind power capacity in the Republic of Ireland (SEAI, 2010a). With a load factor of 29% (Eirgrid, 2013a), this would equate to approximately 508,100 MWh of wind per annum. To get a similar MWh saving from DSM would require an annual reduction in demand of ~2% based on our load data from 2010–2012. This is slightly lower than historical load reductions from smart metering trials undertaken in the Republic of Ireland, which found overall electricity usage reduced by 2.5% using time of use pricing in conjunction with In Home Displays (CER, 2011b). Thus, if we assume financially the same level of MWh can be achieved through either policy, a reduction in demand is more effective in terms of CO₂ emissions reduction for the same capital investment.

Our second aim in this research was to identify whether load errors and wind errors could be considered as substitutes. If this were the case, concerns over the implications of wind errors may be successfully dealt with by improving load forecasts, because load is more predictable than wind output. However, while both load forecast and wind forecast are significant drivers of CO₂ emissions, errors do not appear to be substitutes. More surprising, however, is the sign of both load and wind forecast errors. We anticipated that any error would result in suboptimal operation of the electricity system, which in turn would result in increased errors. However,

⁶If the regulator allows real time pricing to be used

when we aggregate and separate out these forecast errors they have a negative effect, meaning that forecast errors appear to be reducing CO₂ emissions. Results of Model 2 and 3 wind and load errors are presented in Figure 5.4.

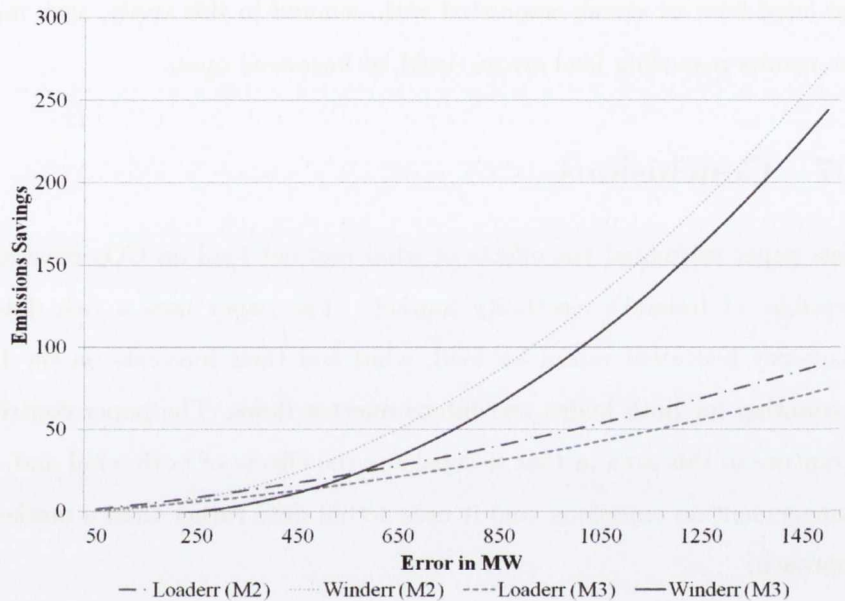


Figure 5.4: Impact of Errors on CO₂ in Models 2 & 3

One possible explanation for this is that if the system under-forecasts demand or over-forecasts wind, less units are dispatched and then any additional requirements are taken from operating reserves. This may potentially be the cause of the positive effect, particularly if reserves are more carbon intensive, or plants are being operated in their less efficient ranges. However, it is important to note that simply over- or under-forecasting will not result in less emissions, this is due to the fact that the errors are within reserve levels and thus should not be used as an emissions reduction policy or approach. Wind and load errors in our dataset have a cross correlation of 0.09, but the effect of load forecast errors may change dramatically with the uptake in smart meters, as consumers become more elastic in their demand for electricity

at various points over the course of an average day. DSM could potentially be used to increase demand at some stages, which in turn could be used to correct for over-generation in certain situations.

Thus while net demand is used as a proxy for demand reduction in this study, it is hoped that future work could include actual DSM data in the analysis. Given the large forecast errors associated with demand in this study, with improved data the results regarding load errors could be improved upon.

5.7 Conclusions

This paper estimated the effects of wind and net load on CO₂ emissions from the Republic of Ireland's electricity market. The paper uses a rich dataset of high frequency historical values for load, wind and their forecasts on the Irish system, accounting for both hydro and interconnector flows. The paper contributes to the literature in this area in that it considers the effects of both wind and demand-side management on emissions, and it uses actual data rather than a market simulation approach.

Overall, the findings of this paper suggest that wind and load are not equally effective in terms of reducing emissions. Results find a 1 MW reduction in demand leads to approximately 0.3 tonnes of CO₂ per 30 minute period reduction for demand, compared to approximately 0.2 tonnes of CO₂ reduction from wind for a 1 MW increase in wind output. This suggests that policies promoting energy efficiency, such as DSM, are more effective in achieving climate change goals. Our analysis of the Irish system finds that the capital costs associated with installing smart meters in all households could result in MWh and emissions savings roughly equivalent to what would be yielded by an equal investment in wind. In addition, DSM can be considered a complementary policy to variable generation sources, as it allows demand to be matched to variable renewable energy availability.

Results also show that load and wind forecast errors do not have comparable effects on power system emissions. While the findings here suggest that forecast errors have a negative effect on emissions, future work will investigate the forecast

error more closely using multiple forecasts.

Discussion and Conclusions

WITH new methods of achieving energy policies becoming increasingly popular, understanding the effects of specific technologies and policy outcomes is critical in order to successfully meet energy policy objectives. The three energy policy objectives of sustainable costs, emissions reduction and security of supply are not always complimentary, and therefore the impacts on all objectives should be considered before implementing a new policy or mandate.

6.1 Discussion and Conclusions

Theory predicts that markets set up as a Vickrey auction should result with firms bidding their true marginal cost, thereby resulting in an efficient outcome and lower costs to consumers. The Irish electricity system with a gross pool market experiences among the highest electricity prices in Europe. Thus, in Chapter 2 we considered the interaction between generators and the pool in the Irish electricity market, and analysed the Irish pool system econometrically in order to test if the high electricity prices seen there are due to participants bidding outside of market rules or out of

line with theory. Chapter 2 results indicate that the Irish pool system appears to be working efficiently. Generators appear to be bidding the spot price of their inputs correctly in the model and the behaviour of the units was found to remain constant over the course of the day and varying levels of demand.

This is not the case in all gross pool systems historically. In 2000 in California where there exists a similar gross pool market, wholesale electricity prices were seen to increase by over 800% between April and December (Weare, 2003). An investigation by the US Federal Energy Regulatory Commission (FERC) found that these prices were affected by economic withholding and inflated price bidding. However, they also noted that attempts to manipulate the market would have been unsuccessful if not for underlying market dysfunction (FERC, 2003). The Electricity Pool of England and Wales was introduced in 1990, however was subsequently replaced, due to criticisms such as market manipulation and governance. Newbery (1998) notes that the introduction of this pool market structure created an effective duopoly in the market, in which National Power and Powergen set the wholesale price over 90% of the time resulting in unnaturally high prices.

One reason why this market structure may be more effective in the Irish context than it has been seen to work elsewhere is due to the small size of the Irish system. Ireland does not have large generators such as nuclear plants, and as a result no single plant sets the market price in general. This makes each unit more likely to set/not set the price increasing competition amongst firms. Another reason is the prescriptive nature of the Irish market; instead of allowing generators to bid their marginal costs arbitrarily they are expected to bid their fuel prices at spot market values rather than their true hedged prices. If interconnection capacity increased, electricity prices overall might be lower, but the conventional units would still operate in the same manner; there would simply be less demand to be met by conventional generation. Any changes to the existing market structure due to changes in regulation or policy could potentially impact on the effectiveness of this market.

Chapter 3 assessed the feasibility of achieving Ireland's 30% cofiring target by calculating the available indigenous biomass resource capable of being cofired; the cost of meeting the target; the benefits in terms of carbon abatement; and finally the present value in economic terms of meeting the target. Chapter 3 results demonstrate that Ireland has only half the necessary resource to meet the 30% target and as a result imports will be required in large quantities to meet the national cofiring target. It is found that in all cofiring scenarios, the estimated total NPVs are negative. This outcome holds constant under a range of sensitivities. None of the cofiring scenarios assessed delivered a positive NPV whereas the no-cofire scenario consistently delivered a positive NPV. Thus, it is concluded that while it may be technically possible to meet the target by combining national resources with imported biomass this is never the least cost option, and as a result the Governmental target may need to be reconsidered. The authors conclude that cofiring is currently not a feasible option, and if the goal is to reduce emissions this is best achieved through a reduction in output of Irish peat stations.

As the national target focusses specifically on cofiring in peat stations, biomass resources which were not capable of being cofired were not included in this study. This includes straw, spent mushroom compost and chicken litter in the Irish context, all of which have the potential to be used for small scale generation. For example, there are presently 3 poultry litter power stations in the UK with a combined output of 65 MW (Fibrowatt Ltd., 2013). While this is small as a proportion of total electricity generation, they have the potential to consume over 672,000 tonnes of poultry litter annually, which is a waste residue with environmental benefits (Fibrowatt Ltd., 2013).

Employment effects are also not considered in this study, and it is assumed that job creation in the biomass sector would be met with a proportional decline in employment in the peat industry. Peat stations are located in areas of low employment, and as a result if biomass jobs were not located in these areas there would be significant regional impacts. The UK Bioenergy Strategy finds that up to 11% of all UK energy could be supplied by biomass by 2020 (DEFRA, 2012). If this were the case,

McDermott (2012) estimates that this could result in the creation of 30,000 jobs in the electricity sector, and 18,000 jobs in the heat sector through the promotion of biomass resources.

Chapter 4 considered the impact of wind on the spot price of electricity using simulation and empiric based models. Both models find that wind reduces the spot price of electricity. Results indicate that both models result in costs savings as a result of wind generation on the Irish system. They indicate that the level of these savings is non-trivial, and results in a market dispatch saving of between €93-141 million or 8-11%, and emissions savings of between €24.4-29.3 million. Thus, it appears that electricity market analysts can use a simple econometric model such as the one presented in this paper and still obtain similar results to that of a full unit commitment model.

The period analysed (2009) was a low fuel cost year, and is therefore not representative of existing fuel costs. This however means that the results presented in this chapter can be considered conservative estimates, which do not overstate the value of wind to the Irish system.

Subsidies received by wind in Ireland through the Public Service Obligation levy¹ are valued at €48 million for 2009. This value is 34-52% of the estimated cost savings arising from wind output, depending of the type of model used. The lower profits as a result of the merit order effect will impact on the revenues of conventional fossil fuel generators, and may in turn have implications for future investment levels. These effects are not considered in this thesis, however.

Chapter 5 estimated the effects of wind and net load on CO₂ emissions from the Republic of Ireland's electricity market. The chapter contributes to the literature in this area in that it considers the effects of both wind and demand-side management on emissions, and it uses historical data rather than simulations.

¹The PSO is a levy charged to all electricity customers in Ireland which is designed to recoup the additional costs incurred by purchasing electricity from specified sources, including sustainable, renewable and indigenous sources (CER, 2006).

Overall, the findings of Chapter 5 suggest that wind and load are not equally effective in terms of reducing emissions. Results find a 1 MW reduction in demand leads to approximately 0.3 tonnes of CO₂ per 30 minute period reduction for demand, compared to approximately 0.2 tonnes of CO₂ reduction from wind for a 1 MW increase in wind output. This suggests that policies promoting energy efficiency, such as DSM, are more effective in achieving climate change goals. Our analysis of the Irish system finds that the capital costs associated with installing smart meters in all households could result in MWh and emissions savings roughly equivalent to what would be yielded by an equal investment in wind. In addition, DSM can be considered a complementary policy to variable generation sources, as it allows demand to be matched to variable renewable energy availability.

However, one issue is the fact that the CO₂ emissions data used is calculated in real time by the system operator rather than measured output on a unit level basis such as the Continuous Emissions Monitoring System (CEMS) used in the US. These Irish emissions are calculated using the individual heat rate curves for each power station and the calorific values for each type of fuel used. The heat rate curves are used to determine the efficiency at which a generator burns fuel at any given time. They do not capture emissions from startups, shut downs or steep ramps in these calculations, however Brinkman (2011) found that these only have a relatively small impact on emission levels.

One of the findings of this paper suggests that forecast errors have a negative effect on emissions. This is counter to expectations, and we anticipated that any error would result in suboptimal operation of the electricity system, which in turn would result in increased errors. One possible explanation for this is that if the system under-forecasts demand or over-forecasts wind, less units are dispatched and then any additional requirements are taken from operating reserves. This may potentially be the cause of the positive effect, particularly if reserves are more carbon intensive, or plants are being operated. Another explanation for this could be that our forecast data is not of sufficiently high frequency. The available forecast data is updated every 6 hours, however the system operator uses forecasts which are up-

dated more regularly.

6.2 Conclusions

In conclusion, this thesis examined four distinctive pieces of work. Overall the findings suggest that the choice of policy is important in terms of meeting energy goals, for example Chapter 3 demonstrates that cofiring is not the best use of biomass resources in meeting EU biomass goals. Chapter 5 illustrates that different policies do not always result in the same policy outcomes, and as a result the aim of a policy should be clearly identified before it is implemented.

Based on the results found in each of the papers, I think it is important to note that any energy policy decision should be made with consideration to the system in question. All electricity markets have their own specific sets of constraints in terms of interconnection levels, indigenous resources and plant mix, which will affect the impact of renewables and a system's ability to utilise renewables effectively. The Irish system makes for a good case study as it has low levels of interconnection and indigenous resources, yet high levels of renewables potential and the system flexibility to use this potential effectively. Thus while the conclusions made are Ireland specific, they are a good starting point to inform energy policy elsewhere.

6.3 Extensions of Work Presented and Future Work

An extension of the model presented in Chapter 2 is used in a conference paper entitled "Econometric Analysis of Flexibility Rewards in Electricity Markets"². In this paper, we presented a metric which can be used to measure system flexibility (as determined by ramp capability) on an hourly basis, given the system dispatch for the year along with generation unit characteristics. The value of the metric was

²M. Lynch, E. Lannoye, & A. O'Mahoney, "Econometric Analysis of Flexibility Rewards in Electricity Markets", in *9th International Conference of the European Energy Market (EEM'12)*, Florence, Italy, May 2012.

calculated for each hour in 2009 for the Irish electricity system. The metric was then included in an econometric analysis of the shadow price for the Irish system for 2009 in order to determine whether a pricing structure based on marginal cost leads to higher prices when there is increased flexibility on the system, thereby providing an incentive to invest in flexible generation. It was found that flexibility was not statistically significant in determining the shadow price.

It would appear that incentives to invest in flexible generation must therefore be provided explicitly by market operators. This can be achieved through a capacity payment mechanism, an uplift payment mechanism or ancillary services payments, should the system operator or regulator wish to preserve the marginal cost pricing structure. We leave for further work the possible designs of such mechanisms to incentivise investment in flexible generation.

Chapter 2 exclusively considered the Shadow price element of the Irish electricity market, and as a result did not consider whether the Uplift element is also being bid appropriately by individual generators. Based on the results of this work we anticipate that the uplift payments mechanism is more likely to be the driver of Ireland's relatively high electricity prices. Future work will consider whether generators are in fact bidding their true start up costs in the uplift mechanism or if this will show elements of strategic behaviour.

At present, current Irish market rules allow generators to include the cost of cycling in their start up costs. This has been the case since 2009, and as a result uplift costs before and after this rule change allow for a natural experiment. Another market rule requires that uplift costs are recovered within a period of 18-48 hours, depending on how long the unit is online for. Future work could consider different time horizons, such as whether units recover their start up costs in general over the course of a week or month, and investigate whether this could result in lower costs to the market as a whole, and in turn lead to cost savings for consumers overall.

An extension of the model presented in Chapter 2 is used in a conference paper

entitled “Econometric Analysis of Flexibility Rewards in Electricity Markets”. In this paper, we presented a metric which can be used to measure system flexibility (as determined by ramp capability) on an hourly basis, given the system dispatch for the year along with generation unit characteristics. The value of the metric was calculated for each hour in 2009 for the Irish electricity system. The metric was then included in an econometric analysis of the shadow price for the Irish system for 2009 in order to determine whether a pricing structure based on marginal cost leads to higher prices when there is increased flexibility on the system, thereby providing an incentive to invest in flexible generation. It was found that flexibility was not statistically significant in determining the shadow price.

It would appear that incentives to invest in flexible generation must therefore be provided explicitly by market operators. This can be achieved through a capacity payment mechanism, an uplift payment mechanism or ancillary services payments, should the system operator or regulator wish to preserve the marginal cost pricing structure. We leave for further work the possible designs of such mechanisms to incentivise investment in flexible generation.

Chapter 5 estimated the effects of wind and net load on CO₂ emissions from the Republic of Ireland’s electricity market. While the findings suggest that forecast errors have a negative effect on emissions, this is counter intuitive. Thus, future work will investigate the forecast errors in greater detail through the use of higher frequency forecasts if available, or through the use multiple forecasts.

The effects of installing new generating capacity on job creation is not considered in this thesis. Future work will examine the volumes of energy that can be consumed or exported (in appropriate phases) from wind generation. It then specifies the necessary infrastructure to deliver this target, and the enterprise categories and number of jobs created as a result of existing wind capacity in the Republic of Ireland. It will also assess the potential for future for job creation at higher levels of on and offshore wind capacity, accounting for the types of jobs that would be

created (skilled and unskilled) and the value of the royalties, tax and non payment of social welfare the government can earn as a result.

References

- Adams, J., OMalley, M., 2010. Flexibility requirements and potential metrics for variable generation: implications for system planning studies. *NERC* Princeton, NJ.
- AEMO, 2011. Wind integration in electricity grids: International practice and experience. *Work Package 1*.
- Akarca, A., Long II, T., 1979. Energy and employment: a time-series analysis of the causal relationship. *Resources and Energy* 2 (23), 151 – 162.
- Al-Ghandoor, A., Al-Hinti, I., Jaber, J., Sawalha, S., 2008. Electricity consumption and associated ghg emissions of the jordanian industrial sector: Empirical analysis and future projection. *Energy Policy* 36 (1), 258 – 267.
- Alpanda, S., Peralta-Alva, A., 2010. Oil crisis, energy-saving technological change and the stock market crash of 197374. *Review of Economic Dynamics* 13 (4), 824 – 842.
- Asafu-Adjaye, J., 2000. The relationship between energy consumption, energy prices and economic growth: time series evidence from asian developing countries. *Energy economics* 22 (6), 615–625.

- Australian Government, 2001. Clean energy act. *Act No. 131 of 2011*.
- Ausubel, L., Cramton, P., 2004. Vickrey auctions with reserve pricing. *Economic Theory* 23, 493–505 (2004), 10.1007/s00199-003-0398-8.
- Bain, R. L., Overend, R. P., Craig, K. R., 1998. Biomass-fired power generation. *Fuel Processing Technology* 54 (1-3), 1–16.
- Baldick, R., February 1995. The generalized unit commitment problem. *Power Systems, IEEE Transactions on* 10 (1), 465–475.
- Baxter, L., 2005. Biomass-coal co-combustion: opportunity for affordable renewable energy. *Fuel* 84 (10), 1295–1302.
- Bentek Energy LLC, July 2011. The wind power paradox. *Technical report*.
- Bierbrauer, M., Trueck, S., Weron, R., Feb. 2005. Modeling electricity prices with regime switching models. *Econometrics* 0502005, EconWPA.
- Bord na Móna, 2001. Peat for energy.
- BP, June 2012. Bp statistical review of world energy.
URL bp.com/statisticalreview
- Brinkman, G., October 2011. Emission impact of fossil fuel unit cycling. *UWIG User Group Meeting*.
- Bunn, D., feb. 2000. Forecasting loads and prices in competitive power markets. *Proceedings of the IEEE* 88 (2), 163–169.
- Bunn, D., 2004. Modelling prices in competitive electricity markets. Wiley finance series. Wiley.
- CAA, 2008. Clean air act as of 2008. *U.S. Government Printing Office*.
- CEC, March 2010. Economic Recovery: Second batch of 4-billion-euro package goes to 43 pipeline and electricity projects. Europa.eu, ip/10/231 Edition.

- CER, 2006. Public service obligation levy 2007 - a decision by the commission for energy regulation.
- CER, 2007. Helicopter guide to the single electricity market trading and settlement code.
- CER, 2009. Public service obligation levy 2009/2010. *Decision Paper*.
- CER, 2010a. Fixed cost of a best new entrant peaking plant & capacity requirement for the calendar year 2011.
- CER, 2010b. Redpoint validated forecast model and plexos validation report 2010.
- CER, 2011a. Cost-benefit analysis (cba) for a national gas smart metering rollout in ireland. *Information Paper CER11180c*.
- CER, May 2011b. Electricity smart metering customer behaviour trials (cbt) findings report. *Information paper CER11080a*.
- Chen, S.-T., Kuo, H., Chen, C.-C., 2007. The relationship between gdp and electricity consumption in 10 asian countries. *Energy Policy* 35 (4), 2611–2621.
- Chiou-Wei, S. Z., Chen, C.-F., Zhu, Z., 2008. Economic growth and energy consumption revisited – evidence from linear and nonlinear granger causality. *Energy Economics* 30 (6), 3063–3076.
- Chow, E., February 2013. Shifting global energy landscape. *Electricity Research Centre presentation*.
- Clifford, E., Clancy, M., 2011. Impact of wind generation on wholesale electricity costs in 2011. *SEAI*.
- COFORD, 2009. Roundwood production from private sector forests 2009-2028: a geospatial forecast. COFORD.
- Conejo, A. J., Contreras, J., Espnola, R., Plazas, M. A., 2005. Forecasting electricity prices for a day-ahead pool-based electric energy market. *International Journal of Forecasting* 21 (3), 435 – 462.

- Connolly, J., Holden, N. M., Ward, S. M., 2007. Mapping peatlands in ireland using a rule-based methodology and digital data. *Soil Science Society of America Journal* 71 (2), 492–499.
- Conway, J., 2009. Non - food crops in ireland. *Department of Agriculture, F. a. F.*
- CSO, 2006. Number of private households and persons in private households in each province , county and city. *Households by County, Year, Statistic and Type of Ownership.*
- Cullen, J., 2008. What's powering wind? measuring the environmental benefits of wind generated electricity. *In: American Agricultural Economics Association Annual Meeting.*
- Cummins, E. J., McDonnell, K. P., Ward, S. M., 2006. Dispersion modelling and measurement of emissions from the co-combustion of meat and bone meal with peat in a fluidised bed. *Bioresource technology* 97 (7), 903–913.
- Dale, L., Milborrow, D., Slark, R., Strbac, G., 2004. Total cost estimates for large-scale wind scenarios in uk. *Energy Policy* 32 (17), 1949–1956.
- David, A., Wen, F., 2000. Strategic bidding in competitive electricity markets: a literature survey. *In: Power Engineering Society Summer Meeting, 2000. IEEE.* Vol. 4. pp. 2168 –2173 vol. 4.
- DCENR, 2006. Green paper on energy policy: Towards a sustainable energy future for ireland.
- DCENR, 2007. Government white paper: Delivering a sustainable energy future for ireland.
- DCENR, 2008. All island renewable grid study - workstream 2b. *Wind Variability Management Studies.*
- De, S., Assadi, M., 2009. Impact of cofiring biomass with coal in power plants—a techno-economic assessment. *Biomass and Bioenergy* 33 (2), 283–293.

- DEFRA, April 2012. Uk bioenergy strategy.
- Denny, E., O'Malley, M., February 2006. Wind generation, power system operation, and emissions reduction. *Power Systems, IEEE Transactions on* 21 (1), 341 – 347.
- Denny, E., O'Malley, M., 2007. Quantifying the total net benefits of grid integrated wind. *Power Systems, IEEE Transactions on* 22 (2), 605–615.
- Denny, E., O'Malley, M., 2009. The impact of carbon prices on generation-cycling costs. *Energy Policy* 37 (4), 1204 – 1212.
- Department of Agriculture, F. a. F., -. Bioenergy scheme.
- Department of Finance, June 2009. Revised arrangements regarding department of finances guidelines for the appraisal and management of capital expenditure proposals in the public sector (2005) and proposed working rules for cost benefit analysis (1999). *S431/65/07*.
- Department of the Taoiseach, Ireland, 2008. Building irelands smart economy - a framework for sustainable economic renewal. *Retrieved October 18, 2009*.
- DETI, 2005. Irish electricity market principal challenges discussion paper.
- Devitt, C., Diffney, S., FitzGerald, J., Malaguzzi Valeri, L., Tuohy, A., Feb. 2011. Goldilocks and the three electricity prices: Are irish prices 'just right'? Papers WP372, Economic and Social Research Institute (ESRI).
- Devitt, C., Diffney, S., Gerald, J. F., Lyons, S., Valeri, L. M., 2009. The likely economic impact of increasing investment in wind on the island of ireland. Tech. rep., ESRI working paper.
- Dietz, T., Gardner, G. T., Gilligan, J., Stern, P. C., Vandenberg, M. P., 2009. Household actions can provide a behavioral wedge to rapidly reduce u.s. carbon emissions. *Proceedings of the National Academy of Sciences*.

- Doherty, R., Outhred, H., O'Malley, M., 2005. Generation portfolio analysis for a carbon constrained and uncertain future. *In: Future Power Systems, 2005 International Conference on*. IEEE, pp. 6–pp.
- Domac, J., Richards, K., Risovic, S., 2005. Socio-economic drivers in implementing bioenergy projects. *Biomass and Bioenergy* 28 (2), 97–106.
- EIA, 2009. International statistics.
- EIA, September 2011. International energy outlook.
- Eirgrid, December 2011. All-island generation capacity statement 2012-2021.
- Eirgrid, November 2012. Tso connected wind farms.
- Eirgrid, 2013a. All-island wind and fuel mix summary report. *Eirgrid & Soni Operations*.
- Eirgrid, 2013b. System demand and wind generation data for the irish single electricity market.
- Eisenhauer, J., Autumn 2003. Regression through the origin. *Teaching Statistics* 25 (3), 76–80.
- Electric Reliability Council of Texas, 2009. Analysis of potential impacts of co2 emissions limits on electric power costs in the ERCOT region.
- Energy Exemplar, 2013. PLEXOS for Power Systems - Electricity Market Simulation.
- Energy Independence and Security Act of 2007, December 2007. Public law 110140.
- Ericsson, K., Huttunen, S., Nilsson, L. J., Svenningsson, P., 2004. Bioenergy policy and market development in Finland and Sweden. *Energy Policy* 32 (15), 1707–1721.
- ESB Networks, December 2012. DSO energised-connected wind farms Dec 2012.
- European Commission, 2001. Directive (2001/77/EC). *Official Journal of the European Union*.

- European Commission, 2003. Directive (2003/54/ec). *Official Journal of the European Union*.
- European Commission, 2005. Biomass action plan. *Energy* Brussels.
- European Commission, 2009a. Directive (2009/28/ec). *Official Journal of the European Union*.
- European Commission, 2009b. Eu action against climate change: The eu emissions trading scheme.
- European Commission, 2010. The common agricultural policy explained. *Agriculture and Rural Development*.
- European Parliament, 2009. Regulation (ec) no 1069/2009. *Official Journal of the European Union*.
- Eurostat, 2010. Statistics database.
- Eurostat, 2011. Statistics database, 2010.
- EWEA, February 2012. Wind in power. *2011 European Statistics*.
- Fabra, N., von der Fehr, N., Harbord, D., 2002a. Designing electricity auctions: uniform, discriminatory and vickrey. *preprint*.
- Fabra, N., von der Fehr, N.-H., Harbord, D., 2002b. Modeling electricity auctions. *The Electricity Journal* 15 (7), 72 – 81.
- Fair Isaac Corporation, 2013. Xpress-mp academic version.
URL <http://www.fico.com>
- Fantazzini, D., Hk, M., Angelantoni, A., 2011. Global oil risks in the early 21st century. *Energy Policy* 39 (12), 7865 – 7873, *ice:title¿Clean Cooking Fuels and Technologies in Developing Economies¿/ce:title¿*.
- Felder, F. A., 2011. Examining electricity price suppression due to renewable resources and other grid investments. *The Electricity Journal* 24 (4), 34–46.

- FERC, 2003. Price manipulation in western markets - findings at a glance. *Staff Report PA02-2-000*.
- Fibrowatt Ltd., 2013. Poultry-litter power station fibrowatt thetford, uk. *Task 29: IEA Bioenergy Network on Socio-economics*.
- Forbes, K., Stampini, M., Zampelli, E., 2011. Wind energy, the price of carbon, and carbon emissions: Evidence from ireland. *In: 2011 International Energy Workshop*. Stanford University.
- Francis, B., Moseley, L., Iyare, S., 2007. Energy consumption and projected growth in selected caribbean countries. *Energy Economics* 29 (6), 1224–1232.
- Gaterell, M., McEvoy, M., 2005. The impact of climate change uncertainties on the performance of energy efficiency measures applied to dwellings. *Energy and Buildings* 37 (9), 982 – 995.
- Gaye, A., 2007. Access to energy and human development. *Human Development Report 2007/2008*.
- Ghosh, S., 2002. Electricity consumption and economic growth in india. *Energy Policy* 30 (2), 125–129.
- Gormley, J., December 2008. Gormley responds to epa decision on poolbeg incinerator.
- Gowrisankaran, G., Reynolds, S., Samano, M., May 2011. Intermittency and the value of renewable energy. Working Paper 17086, National Bureau of Economic Research.
- Green, R. J., Newbery, D. M., 1992. Competition in the british electricity spot market. *Journal of Political Economy* 100 (5), pp. 929–953.
- Grimsrud, G. P., Lefton, S. A., 1995. Economics of cycling 101: what do you need to know about cycling costs and why? Tech. rep., APTECH Engineering Technical Paper TP098.

- Harris, C., 2006. Electricity markets : pricing, structures and economics. The Wiley Finance Series. Wiley.
- Hartmann, D., Kaltschmitt, M., 1999. Electricity generation from solid biomass via co-combustion with coal: energy and emission balances from a german case study. *Biomass and Bioenergy* 16 (6), 397–406.
- Holland, S. P., Mansur, E. T., October 2007. Is real-time pricing green? the environmental impacts of electricity demand variance. Working Paper 13508, National Bureau of Economic Research.
- Holttinen, H., Meibom, P., Orths, A., Lange, B., O'Malley, M., Tande, J. O., Estanqueiro, A., Gomez, E., Sder, L., Strbac, G., Smith, J. C., van Hulle, F., 2011. Impacts of large amounts of wind power on design and operation of power systems, results of iea collaboration. *Wind Energy* 14 (2), 179–192.
- IEA, 1993. Shared goals.
- IEA, 2006. Chinas power sector: Where to next?
- IEA, 2011. Oil market report. *Annual Statistical Supplement*.
- IEA, 2012a. Energy balances of oecd countries.
- IEA, November 2012b. World energy outlook.
- Indecon, 2008. Economic appraisal of the potential for offshore wind energy generation in ireland.
- IPCC, September 2007. Climate Change 2007 - The Physical Science Basis: Working Group I Contribution to the Fourth Assessment Report of the IPCC. Cambridge University Press, Cambridge, UK and New York, NY, USA.
- Jobert, T., Karanfil, F., 2007. Sectoral energy consumption by source and economic growth in turkey. *Energy Policy* 35 (11), 5447–5456.
- Kaffine, D., McBee, B., Lieskovsky, J., 2012. Emissions savings from wind power generation: Evidence from texas, california and the upper midwest.

- Karakatsani, N., Bunn, D., 2010. Fundamental and behavioural drivers of electricity price volatility. *Studies in Nonlinear Dynamics & Econometrics* 14 (4).
- Karanfil, F., 2008. Energy consumption and economic growth revisited: Does the size of unrecorded economy matter? *Energy Policy* 36 (8), 3019–3025.
- Kirschen, D., may 2003. Demand-side view of electricity markets. *Power Systems, IEEE Transactions on* 18 (2), 520 – 527.
- Kirschen, D. Strbac, G., 2005. Fundamentals of power system economics. Wiley.
- Kiviluoma, J., Meibom, P., Tuohy, A., Troy, N., Milligan, M., Lange, B., Gibescu, M., O'Malley, M., October 2012. Short-term energy balancing with increasing levels of wind energy. *Sustainable Energy, IEEE Transactions on* 3 (4), 769–776.
- Kneifel, J., 2010. Life-cycle carbon and cost analysis of energy efficiency measures in new commercial buildings. *Energy and Buildings* 42 (3), 333 – 340.
- Knittel, C., Roberts, M., 2005. An empirical examination of restructured electricity prices. *Energy Economics* 27 (5), 791–817.
- Kofman, P., Kent, T., 2006. Harvesting and processing forest biomass for energy production in Ireland. *The Forest Energy*.
- Kyoto Protocol, 1992. United nations framework convention on climate change.
- Laurikka, H., Koljonen, T., 2006. Emissions trading and investment decisions in the power sector - a case study in Finland. *Energy Policy* 34 (9), 1063–1074.
- Lee, C.-C., 2006. The causality relationship between energy consumption and GDP in G-11 countries revisited. *Energy Policy* 34 (9), 1086–1093.
- Lee, C.-C., Chang, C.-P., 2007. Energy consumption and GDP revisited: A panel analysis of developed and developing countries. *Energy Economics* 29 (6), 1206–1223.
- Lefton, S., Besuner, P., Grimsrud, G., 1997. Understand what it really costs to cycle fossil-fired units. *Power* 141 (2), 41–42.

- Lutz, C., Lehr, U., Wiebe, K. S., 2012. Economic effects of peak oil. *Energy Policy* 48 (0), 829 – 834, [Special Section: Frontiers of Sustainability](#).
- Ma, X., Kaneko, T., Tashimo, T., Yoshida, T., Kato, K., 2000. Use of limestone for so₂ removal from flue gas in the semidry fgd process with a powder-particle spouted bed. *Chemical Engineering Science* 55 (20), 4643–4652.
- Malaguzzi Valeri, L., 2009. Welfare and competition effects of electricity interconnection between ireland and great britain. *Energy Policy* 37 (11), 4679–4688.
- Marcantonini, C., Ellerman, A. D., 2013. The cost of abating co₂ emissions by renewable energy incentives in germany. *Climate Policy Research Unit, European University Institute, Italy*.
- Masih, A. M., Masih, R., 1998. A multivariate cointegrated modelling approach in testing temporal causality between energy consumption, real income and prices with an application to two asian ldc's. *Applied Economics* 30 (10), 1287–1298.
- McDermott, F., April 2012. Uk jobs in the bioenergy sectors by 2020. *NNFCC 11-025*.
- Meat Industry Ireland, 2010. 2020 strategy - beef sector.
- Milligan, M., Ela, E., Hodge, B.-M., Kirby, B., Lew, D., Clark, C., DeCesaro, J., Lynn, K., 2011. Cost-causation and integration cost analysis for variable generation. *Contract* 303, 275–3000.
- Ministere de l'Ecologie, de l'Energie, du Developpement durable et de la Mer, 2009. National action plan for the promotion of renewable energies.
- Mishra, V., Smyth, R., Sharma, S., 2009. The energy-gdp nexus: Evidence from a panel of pacific island countries. *Resource and Energy Economics* 31 (3), 210–220.
- Modi, V., McDade, S., Lallement, D., Saghir, J., 2005. Energy services for the millennium development goals: Achieving the millennium development goals. *UN Millenium Project*.

- Moesgaard, R., Morthorst, P. E., 2007. The effect of wind power on spot market prices. *Danish Wind Industry Association-Risoe/DTU EWEC*.
- Molcan, P., Lu, G., Bris, T. L., Yan, Y., Taupin, B., Caillat, S., 2009. Characterisation of biomass and coal co-firing on a 3mwth combustion test facility using flame imaging and gas/ash sampling techniques. *Fuel* 88 (12), 2328–2334.
- Murray, B., 2009. Power markets and economics : energy costs, trading, emissions. Wiley.
- Narayan, P. K., Narayan, S., Prasad, A., 2008. A structural var analysis of electricity consumption and real gdp: Evidence from the g7 countries. *Energy Policy* 36 (7), 2765–2769.
- Narayan, P. K., Smyth, R., 2005. Electricity consumption, employment and real income in australia evidence from multivariate granger causality tests. *Energy Policy* 33 (9), 1109–1116.
- NERC, 2008. Accommodating high levels of variable generation.
- NERC, 2009. Integration of variable generation task force, accomodating high levels of variable generation. *Princeton, NJ*.
- Neuhoff, K., Newbery, D., 2005. Evolution of electricity markets: Does sequencing matter? *Utilities Policy* 13 (2), 163 – 173, [Electricity Transmission](#)/[Electricity Transmission](#).
- Newbery, D. M., November 1998. The regulator's review of the english electricity pool. *Utilities Policy* 7 (3), 129–141.
- Nogales, F. J., Contreras, J., Conejo, A. J., Espinola, R., march 2002. Forecasting next-day electricity prices by time series models. *Power Engineering Review, IEEE* 22 (3), 58.
- Novan, K., 2011. Valuing the wind: Renewable energy policies and air pollution avoided. *University of California, San Diego. Job Market Paper*.

- NREL, 2011. Eastern wind integration and transmission study.
- Nyamdash, B., Denny, E., 2011. The economic impact of electricity conservation policies: A case study of Ireland.
- OFGEM, 2011. Renewables obligation.
- Oh, W., Lee, K., 2004. Causal relationship between energy consumption and GDP revisited: the case of Korea 1970–1999. *Energy Economics* 26 (1), 51–59.
- O'Mahoney, A., Denny, E., 2011a. Electricity prices and generator behaviour in gross pool electricity markets.
- O'Mahoney, A., Denny, E., October 2011b. The merit order effect of wind generation. *IAEE/USAEE Annual Conference*.
- Oranen, A., July 2006. The impact of emissions trading on the price of electricity in Nord Pool: Market power and price determination in the Nordic electricity market. *Masters thesis*.
- Orjala, M., Heiskanen, V., Ingalsuo, R., Hämäläinen, J., 2001. Effect of wood fuel on SO₂ emissions in co-firing with peat and coal in fluidised bed boiler. In: *5th International Biomass Conference of the Americas, Orlando, Florida, September*. pp. 17–21.
- Owayedh, M., Al-Bassam, A., Khan, Z., 2000. Identification of temperature and social events effects on weekly demand behavior. In: *Power Engineering Society Summer Meeting, 2000. IEEE*. Vol. 4. pp. 2397–2402 vol. 4.
- Pirani, S., June 2007. Ukraine's gas sector. *The Oxford Institute for Energy Studies*.
- Pöyry, 2010. Wind energy and electricity prices - exploring the merit order effect.
- Quadrelli, R., Peterson, S., 2007. The energy - climate challenge: Recent trends in CO₂ emissions from fuel combustion. *Energy Policy* 35 (11), 5938–5952.

- Raupach, M. R., Marland, G., Ciais, P., Le Qur, C., Canadell, J. G., Klepper, G., Field, C. B., 2007. Global and regional drivers of accelerating co2 emissions. *Proceedings of the National Academy of Sciences* 104 (24), 10288–10293.
- REN21, 2012. Renewables 2012 global status report. *REN21*.
- Renewable Energy Sources Act (EEG), March 2000. Bgbl i 2000, 305.
- Sami, M., Annamalai, K., Wooldridge, M., 2001. Co-firing of coal and biomass fuel blends. *Progress in energy and combustion science* 27 (2), 171–214.
- Schilstra, A. J., 2001. How sustainable is the use of peat for commercial energy production? *Ecological economics* 39 (2), 285–293.
- Schneider, M., Froggatt, A., Thomas, S., 2011. The world nuclear industry status report 2010-2011: Nuclear power in a post-fukushima world. *Worldwatch Institute*.
- SEAI, 2004. Co-firing with biomass report.
- SEAI, 2009a. Energy in ireland 1990-2008.
- SEAI, 2009b. Understanding electricity & gas prices in ireland.
- SEAI, 2010a. Energy in ireland, 1990-2009.
- SEAI, 2010b. Renewable energy in ireland - 2010 update.
- SEAI, 2011. Emission factors.
- SEAI, November 2012. Energy in ireland. *Key Statistics 2012*.
- SEM, 2011. Validated sem generator data parameters. *SEM-11-052*.
- SEM, 2013. Market schedules of the irish single electricity market.
- SEM Committee, 2009. Information paper on short to medium term interconnector issues in the sem.
- SEM-O, 2010. Sem trading and settlement code.

- Sensfuß, F., Ragwitz, M., Genoese, M., 2008. The merit-order effect: A detailed analysis of the price effect of renewable electricity generation on spot market prices in germany. *Energy policy* 36 (8), 3086–3094.
- Shiu, A., Lam, P.-L., 2004. Electricity consumption and economic growth in china. *Energy Policy* 32 (1), 47–54.
- Smith, J. C., Milligan, M. R., DeMeo, E. A., Parsons, B., 2007. Utility wind integration and operating impact state of the art. *Power Systems, IEEE Transactions on* 22 (3), 900–908.
- SONI, 2010. Personal communication.
- South East Waste Management Region, 2010. Submission on draft statement of waste policy.
- Soytas, U., Sari, R., 2009. Energy consumption, economic growth, and carbon emissions: challenges faced by an eu candidate member. *Ecological economics* 68 (6), 1667–1675.
- Strbac, G., December 2008. Demand side management: Benefits and challenges. *Energy Policy* 36 (12), 4419–4426.
- Styles, D., Jones, M. B., 2007. Current and future financial competitiveness of electricity and heat from energy crops: A case study from ireland. *Energy Policy* 35 (8), 4355–4367.
- Thollander, P., Karlsson, M., Sderstrm, M., Creutz, D., 2005. Reducing industrial energy costs through energy-efficiency measures in a liberalized european electricity market: case study of a swedish iron foundry. *Applied Energy* 81 (2), 115 – 126.
- Thoma, M., 2004. Electrical energy usage over the business cycle. *Energy Economics* 26 (3), 463–485.

- Troy, N., Denny, E., O'Malley, M., May 2010. Base-load cycling on a system with significant wind penetration. *Power Systems, IEEE Transactions on* 25 (2), 1088–1097.
- Verbong, G., Geels, F., 2007. The ongoing energy transition: Lessons from a socio-technical, multi-level analysis of the dutch electricity system (1960–2004). *Energy Policy* 35 (2), 1025–1037.
- Verbruggen, A., Marchohi, M. A., 2010. Views on peak oil and its relation to climate change policy. *Energy Policy* 38 (10), 5572 – 5581, *The socio-economic transition towards a hydrogen economy - findings from European research, with regular papers*.
- Vickrey, W., 1961. Counterspeculation, Auctions and Competitive Sealed Tenders. *Journal of Finance*, 8–37.
- Walker, N., Bazilian, M., Buckley, P., 2009. Possibilities of reducing co2 emissions from energy-intensive industries by the increased use of forest-derived fuels in ireland. *Biomass and Bioenergy* 33 (9), 1229 – 1238.
- Weare, C., 2003. The california electricity crisis: Causes and policy options.
- Weron, R., 2006. Modeling and forecasting electricity loads and prices : a statistical approach. Wiley finance series. Wiley.
- Wolfram, C., Shelef, O., Gertler, P., January 2012. How will energy demand develop in the developing world? *Energy Institute at Haas Working Paper Series*.
- World Bank, 2007. Air pollution. *World Development Indicators*.
- World Bank, January 2013. World development indicators 2013.
- Yik, F., Lee, W., 2005. Rebate as an economic instrument for promoting building energy efficiency in hong kong. *Building and Environment* 40 (9), 1207 – 1216.

- Yuan, J., Zhao, C., Yu, S., Hu, Z., 2007. Electricity consumption and economic growth in china: Cointegration and co-feature analysis. *Energy Economics* 29 (6), 1179–1191.
- Zachariadis, T., 2007. Exploring the relationship between energy use and economic growth with bivariate models: New evidence from g-7 countries. *Energy Economics* 29 (6), 1233–1253.
- Zhang, X., Cheng, X., 2009. Energy consumption, carbon emissions, and economic growth in china. *Ecological Economics* 68 (10), 2706–2712.