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THE ECONOMICS OF ELECTRICITY STORAGE

by

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Thesis submitted for the degree of
DOCTOR OF PHILOSOPHY
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Abstract

THIS thesis investigates the issues surrounding electricity storage systems from various perspectives. It assesses the impact on the power system operation and the resulting benefits for developers versus system operators. It then examines the impact of storage on electricity prices in a gross pool market. The wider economic benefits are then considered through examination of gross value added.

The effects of the electricity storage operation on the plant mix, level of CO_2 emissions from the power system and net demand variations are investigated according to various storage and wind power output scenarios. The economic viability of various types of electricity storage systems are also examined. Results show that the deployment of electricity storage increases the participation of base-load power plants but at the cost of increased CO_2 emissions from the power system. However, net demand variations were found to be reduced which can be beneficial to system operators. However, in the absence of any support mechanism, none of the storage technologies considered are found to be economically viable.

The effects of the electricity storage system on the wholesale electricity price and the total cost of the power system are then investigated using a unit commitment tool, and the results are verified with real world data using econometric techniques. It is found that the deployment of electricity storage reduces the total cost of the power system, but the wholesale electricity price is found to increase due to the effect of storage on the operation of the marginal power plant. This is verified by the regression results.

Given the important role of electricity as an input in both the service and industrial sectors, it may be feared that energy conservation policies may adversely impact these sectors and consequently worsen the national economic situation. Findings show that the sector specific gross value added, electricity consumption, electricity price and technical efficiency are co-integrated for both the service and industrial sectors. However, impulse response functions show that positive consumption shocks have persistent negative effects on the gross value added of both sectors, while positive price shocks have insignificant effects.

In summary, this thesis presents an economic evaluation of electricity storage and finds that although it provides some benefits to the power system (such as reduced cost, and reduced variability) the added costs are considerable. These costs include increased wholesale price and increased CO_2 emissions. While storage may have net benefits from a power system operator perspective, these are unlikely to be realised by a private developer.

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Any Ph.D provides its trials and disappointments along the way. To have come this far would not have been possible without the help and support of a great number of people I wish to acknowledge.

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Publications Arising from Thesis

Journal Papers:

1. B. Nyamdash & E. Denny, "The viability of balancing wind generation with large scale energy storage", *Energy Policy*, Volume 38, Issue 11, November 2010, Pages 7200-7208. doi:10.1016/j.enpol.2010.07.050
2. B. Nyamdash & E. Denny, "The impact of electricity storage on wholesale electricity prices", *Energy Policy (in review)*.
3. B. Nyamdash & E. Denny, "The economic impact of electricity conservation policies: A case study of Ireland", *Energy Policy (in review)*.

Conference Papers:

4. B. Nyamdash & E. Denny, "Analyzing the impact of electricity storage on the wholesale electricity price: A case of Ireland", *in* 9th *Young Energy Engineers & Economists Seminar*, Dublin, Ireland, November 2010. Also presented *in* 11th *IAEE European Conference*, Vilnius, Lithuania, August 2010 and *in* 5th *International Renewable Energy Storage Conference*, Berlin, Germany, November 2010.
5. B. Nyamdash & E. Denny, "Economic of Electricity Storage", *in Economics of Ocean and Marine Renewable Energy Conference*, Cork, Ireland, April 2010.

6. B. Nyamdash & E. Denny, "Causal relationship between Sectoral electricity consumptions and GDP: Case of Ireland", *in 2009 Irish Society of New Economists Conference*, Limerick, Ireland, October, 2009. Also presented *in* 8^{th} *Young Energy Engineers & Economists Seminar*, Cambridge, UK, April 2010.
7. E. Denny, D. Burke, R. Fitzmaurice, A. Keane, B. Nyamdash, P. Richardson, E. Silke, N. Troy, A. Tuohy, S. Twohig, E. Vittal, & M. O'Malley, "Developments in Energy Technology and Policy Research", *in U21 International Conference on Energy Technologies and Policy*, Birmingham, UK, September 2008.
8. B. Nyamdash, E. Denny, M. O'Malley, C. Feely & A. G. Bryans "The viability of balancing wind generation with large scale energy storage", *in IEEE Power Engineering Society General Meeting*, Pittsburgh, Pennsylvania, USA, July 2008.

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CHAPTER 1

Introduction

DUE to the recent global financial crisis, the three pillars of the energy policy; security of supply, sustainable development and the promotion of competitiveness, have taken a backstage in the policy agenda. During the last few years, energy demand growth has temporarily slowed down and investments in the energy sector have fallen (IEA, 2009b). When energy demand growth resumes as economies recover from recession, the energy sector is likely to be under the threat of capacity shortfall and may see a surge in prices. In the medium term, it is uncertain whether the energy demand will be met by an adequate supply of energy, and in the longer term, the chances of meeting the climate targets become slimmer (IEA, 2010b).

Despite the current economic crisis, tackling climate change is still a major challenge. Currently, there are 1.2 billion people in the world with no access to electricity (IEA, 2010b). By providing these people with accessible and clean energy, the Millennium Development Goal (MDG) of reducing extreme poverty and achieving sustainable developments would be possible (United Nations, 2011). Therefore, significant efforts need to be made in order to build and upgrade the physical infrastructure required to deliver energy to the end-users. In developed countries, this issue is less severe. However, significant efforts need to be made to expand the existing capacities, to find secure non-fossil fuel energy sources and to adapt existing networks to renewable energy sources.

In order to reduce the effects of greenhouse gas (GHG) emissions in the future, the EU has committed to increase the share of renewable energy in the consumption of primary energy by 20% and also committed to increase energy efficiency by 20% by the year 2020 (European Commission, 2006, 2007b). Likewise, the USA has deployed a policy to increase the share of renewable energy in its energy mix (DOE, 2008). Global leaders have been united under the goal to reduce greenhouse gas emissions by 50% from their current level and to limit the average temperature increase to 2°C above the pre-industrial period by 2050 (United Nations, 1998; G8 Summit, 2011).

Since the industrial revolution, the level of carbon dioxide in the atmosphere (which is the main driver of climate policies) has increased by one third from 280ppm in 1750 to 380ppm in 2005, as a direct result of the consumption of fossil fuels (IPCC, 2007). In terms of the sectors responsible for the current level of GHG emissions, the power and heat generation sector was found to be responsible for 42% of the emissions in the atmosphere, the transport sector was responsible for 22%, the industrial sector was responsible for 20%, and other sectors were responsible for the remaining amount (IEA, 2011).

The power and heat generation sector is the greatest polluting sector compared to other sectors. This has resulted in a shift away from traditional fossil fuels towards cleaner technologies in terms of emissions, such as nuclear and renewable energy.

The secure and safe disposal of nuclear waste is uncertain under its current technological level and public acceptance remains a major barrier. Permanent nuclear waste storage projects have been considered in the USA, Australia, Mongolia and Finland (DOE, 1998; ANSTO, 2011; Lawrence, 2011). Due to the strong public opposition, these proposals were abandoned as early as at the discussion stages, apart from the Finnish radioactive waste storage project (Holland, 2010). The recent accident in Fukushima weakened the future of nuclear energy generation, even though this is a zero-emission technology and is considered to be relatively safe. Hence, countries that utilise nuclear energy have reconsidered the development of projects and the extension of their existing plants. For example in Germany, the German Chancellor Angela Merkel announced in May 2011, the government's decision to shut down all of its nuclear power stations by the year 2020 (Merkel, 2011).

Thus, increasing the share of renewable energy sources (RES) in the fuel mix of the power and heat generation sectors becomes one of the safest and the most viable options in reducing GHG emissions from this sector globally; hence governments all over the world have implemented various support mechanisms for renewable energy.

These emission reducing policy goals and targets also need to be in line with the next pillar of energy policy: sustainable and affordable energy supply. This requires extensive efforts to be made in the areas of waste management, low-carbon technologies and the efficient use of energy, which should not to interfere with other policy goals such as poverty reduction and sustainable food supply.

More diverse, interconnected systems and smart market arrangements should facilitate a secure and sustainable energy sector to be fostered in both developing and developed countries (European Commission, 2010). Providing a sustainable and secure sector ensures that competition in the energy sector and the competitiveness of the economy would not be undermined while, at the same time, making sure that the energy is delivered to the end-users at affordable prices.

1.1 Renewable energy in the power sector

The existence of renewable energy has an important role to play in terms of security of energy supply. As it is likely to be indigenous, the use of renewable energy contributes to the diversity of the energy mix, reduces the dependency of the energy system on imported fuel and reduces the risk of exposure to foreign market failures and fuel price fluctuations.

Renewable energy technologies are used to harness the energy contained in nature and these do not use any of the polluting fuels that contribute to the stock of GHG emissions in the atmosphere. For instance, wind farms use the wind to generate electricity, hydro power stations use the mass of the water to move the turbines, while biomass power stations use the energy contained in woodchips or animal waste etc., to generate electricity. Such technologies are expected to play a central role in achieving the global target of a reduction of GHG emissions (IEA, 2011).

In the last decade, wind power generation grew rapidly on a global scale and it was the fastest growing renewable technology in Europe (EWEA, 2005). The global total installed wind capacity increased from just 6.1GW in 1996 to over 120.8GW in 2008 (EWEA, 2011) and it is likely to become the most promising alternative source of electricity generation in terms of both technical and economic viability (European Commission, 2007c).

This growth was mainly due to support mechanisms such as the Renewable Energy Feed-In Tariff (REFIT). For instance, Ireland guarantees the floor price for on-shore and off-shore wind farms (DCMNR, 2006). The UK also introduced a support mechanism for small to medium scale low-carbon electricity generation technologies (DECC, 2008). Such support mechanisms were complemented with guaranteed priorities when they participated in the electricity market.

As the electricity generated from RES, particularly wind and solar, is weather dependent, it is likely to be subject to forecast errors. It is also intermittent in nature and not likely to follow the timing of electricity demand. In order to accommodate such intermittent and unpredictable energy, power systems are required to be more flexible, *i.e.* conventional plants are required to curtail their outputs or to dispatch more of the flexible yet expensive peaking units, in order to balance the demand and supply at all time (Denny and O'Malley, 2007). As a consequence of the accumulated stress in the power system, the safety and security of electricity supply can be greatly affected, even when the total cost of the power system is reduced as more power and heat are generated from renewable energy sources.

Due to the remote locations of many renewable energy projects, significant investments are often required in the transmission and distribution system in terms of upgrades and extensions (AIGS, 2008; Piwko *et al.*, 2005).

1.2 Power generation

In the past two decades, the vertical separation of potentially competitive segments of the power system and the privatization of state owned monopolies have been promoted in order to reduce market power and to improve the performance of the power system (Joskow, 2008). However, individual countries and regions have chosen different approaches in implementing such reforms and restructurings to different effect.

The power system usually consists of power stations, the electricity market or the system operator, supply companies or retailers and consumers (Figure 1.1).

Power stations participate in electricity market operations by offering to generate a particular amount of electricity (Q_t) at a certain price (P_t) at a certain time. The prices offered usually reflect the fuel cost of generating electricity from a particular power plant.

Then, the electricity market allocates the electricity supply (S_t) from the power plants in such a way that it meets the given demand (D_t) at the lowest cost. These electricity markets do not exist physically, but are operated under predefined trade and settlement codes.

Once the market is settled for a given time period, the supply companies buy electricity from the market at the market price (MC_t) which usually reflects the short run marginal cost of the power system, *i.e.* the price of the most expensive unit that is dispatched to generate electricity at that time.

Finally, the electricity is delivered to consumers at a final end-user price (Price) which includes the costs and margins of the supply companies. This is usually an average regulated tariff which is fixed over a long period of time.

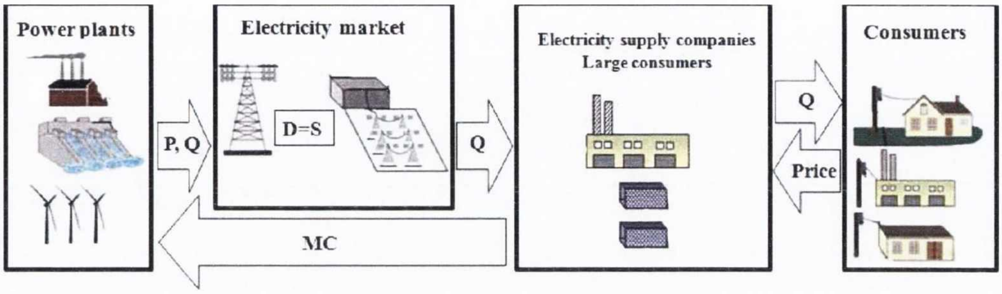


Figure 1.1: Power system operation.

Thus, the end-user electricity price is not usually based on the short-run marginal cost of the power system, but rather it is based on the long-run marginal cost of the power system. Hence, consumers usually face relatively flat rates for their electricity consumption compared to the supply companies that buy electricity from the electricity market.

Like the security of energy supply in a broader sense, the security of electricity supply has significant social and economic implications. Any interruption in electricity supply would not only cause economic losses for local businesses, but would also put many lives at stake. According to CER and NIAUR (2009) the value of lost load (consumers' willingness to pay in order to have an uninterrupted electricity supply) for Ireland was found to be €10.27/KWh. This implies that if there is going to be an electricity shortage, consumers are willing to pay €10,270 for every MWh of electricity to avoid such interruptions.

In every power system, power stations are run under strict technical and regulatory constraints. The power system should be able to meet any changes in demand at all times and it is required to carry reserve capacities in the case of incidents such as a rapid increase in demand or a failure in the power system (Doherty and O'Malley, 2005). The reserve capacity is a spare generating capacity in the power system that is available to generate electricity at short notice ranging from a few milliseconds to a few minutes. It is divided into several categories depending on how fast it can respond to a system signal. A primary reserve is a reserve that can respond within seconds, while secondary reserve is a reserve that can respond within minutes and tertiary reserve is reserve capacity that can be online within a longer time period. Therefore, in order to provide these reserve capacities and to maintain the security of electricity supply, many power plants will be required to operate at less than maximum output, so capacity would be available if needed. Reserve capacity has to be provided by the power plants for every hour of the day in addition to the demand (Reserve).

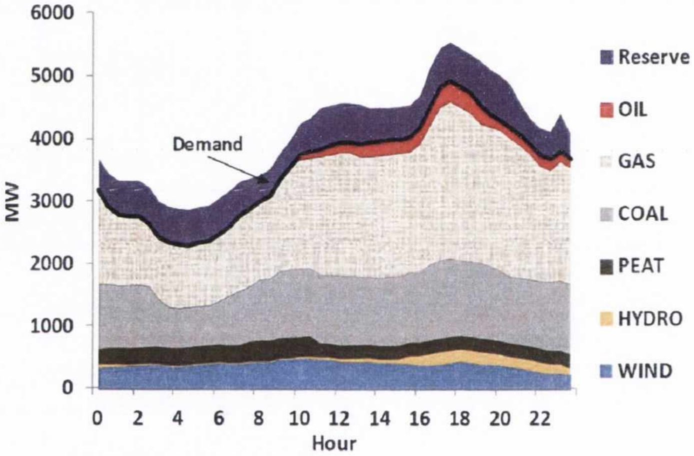


Figure 1.2: Typical thermal plant dispatch order (Ireland).

In Figure 1.2, the graphical illustration of the power system operation for one day shows the dispatch order of power plants. It shows that the electricity demand is met by the power plants at all hours in addition to providing enough reserve capacity. Based on their fuel types, generators are divided into two categories: renewable and conventional power plants. Most electricity systems give priority to electricity that has been generated from renewable sources. Thus, wind and hydro units are dispatched with priority and injected into the power system when available.

Conventional power plants are divided into three different categories based on their fuel type and operations: Base-load, mid-merit and peaking plants.

Base-load plants are usually the least expensive and most inflexible power plants that supply most of the electricity demand. These plants do not usually shut down or alter their output levels throughout the day. In Ireland these are coal, peat and gas fired stations. Mid-merit plants are relatively flexible compared to the base-load plants. These plants are usually used to follow the fluctuations in demand throughout the day and are switched on when demand increases beyond the capacity of the baseload power plants. Mid-merit power plants are usually switched on in the morning and switched off at night. Peaking units are the units that are switched on when demand peaks. These are the most flexible units yet the most expensive units to run on the power system.

1.3 Electricity storage system

Electricity has to be generated as demand occurs. Therefore, it is usually considered to be a non-storable commodity. However, various ways of storing electricity exist and are used regularly on small scale. According to the International Electricity Storage Association, the first pumped hydro electric storage was installed in Italy and Switzerland in 1890 (Electricity Storage Association, 2009).

Electricity storage uses the electricity generated by conventional or renewable energy power plants and stores this electricity in the form of water stored in an elevated lake, or compressed air in the underground cavern or inertia stored in the steel rotor. Electricity storage has been used for different purposes on a variety of scales, depending on its physical ability to store and generate electricity. In most cases, it is used to store electricity at low demand hours and generate electricity at peak hours. This essentially increases the net electricity demand at off-peak hours (and allows conventional power plants to be utilized at full capacity) while decreasing the net demand at peak hours (preventing the dispatch of expensive peaking units)

(Figure 1.3). It can also provide reserve for the power system.

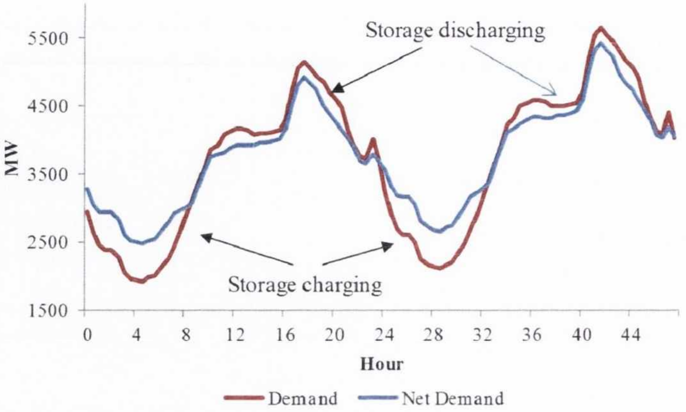


Figure 1.3: Effect of storage operation on the net demand.

Electricity storage is able to respond to system signals within minute or second intervals and provides a power system with a vital security of supply. Another benefit of storage is that it can be used to smooth the power outputs of the intermittent sources, such as renewable energy. For example, high wind output at night time can be stored and released at a later time during the day. Also, this can reduce the electricity price at peak hours.

Furthermore, the deployment of the storage system may also be used to defer investment in the transmission system or future power plants. This is an important issue in a power system with weak networks and increasing generation from renewable energy.

The capacity of a storage system depends on the energy capacity and the power capacity. Power capacity is the MW rate at which electricity can be generated. Energy capacity is determined by the number of hours that the storage system can generate electricity at its maximum power rate, *e.g.* how many MWh of electricity it can store. Another vital dimension of the electricity storage system is its round trip efficiency. It measures the ratio between its KWh input and its KWh output. For instance, if 100KWh of electricity is used to charge the storage, which has a

Table 1.1: Storage technologies (Susan and Hassenzahl, 2003; EPRI, 2004)

Type	Application	Round trip	Capital cost (USD)		Disadvantages	Replacement period (years)
			Power (per KW)	Energy (per KWh)		
Pumped Hydro storage	Demand shifting Primary reserve	75%	1000	10	Site specific	None
Compressed Air Electricity Storage	Load shifting Regulation Primary reserve	73-79%	425-550	3-120	Site specific	None
Batteries Electricity Storage	Grid Stability Power quality	65-85%	125-175	150-600	Limited life cycle, Low energy density	5-15
Flywheel Storage	Grid Stability Power quality	90-95%	300-330	1000--125000	Low energy density	16-none
Hydrogen FC	Demand shifting	59%	1500	15	Non-existence	6
Supercapacitors	Grid stability Power quality	95%	300	30000	Low energy density	none

round trip efficiency of 75%, only 75KWh of electricity can be generated at a later time.

A summary review of storage technologies is given in Table 1. It presents the applications that are the most suitable for each technology type, round trip efficiencies, the capital cost in terms of both the power and energy capacities and the disadvantages of each technology type. Some technologies are required to be replaced frequently and the table also shows the frequency of replacement periods of each technology type.

Applications of the electricity storage system:

Demand shifting: a portion of demand is shifted from periods of high to periods of low demand *i.e.* electricity generated at low demand hours is used to supply the electricity demand at high demand hours. As a result, power plants are more efficiently dispatched throughout the cycle.

Primary reserve: is provided by storage units which can increase their output immediately in response to a major generator or transmission outage and can reach full output at short notice.

Regulation: is an automatic generation control that can respond rapidly to the requests of the system-operator for up and down movements; it is used to track the minute-to-minute fluctuations in demand and to correct for unintended fluctuations in the output of the generators.

Grid stability: This refers to the ability of a transmission grid to regain a state of operating stability after being subjected to a disturbance, so that the entire system essentially remains intact.

Power quality: This refers to the protection against voltage sags as well as outages for a few minutes and also, if the outages are not mitigated, provide power for an orderly shutdown in order to protect electronic appliances.

1.3.1 Pumped hydro storage system

This is the large scale storage type that has been widely used around the world. A pumped hydro electricity storage (PHS) system stores electricity in water stored in an elevated lake (Figure 1.4). This usually consists of two lakes that are located at different altitudes. When there is excess electricity in the power system, this system is used to pump water from the lower lake to the upper lake and the water in the upper lake is then released through the turbine to generate electricity.

The total amount of pumped hydro capacity in the world is over 90GW and the total number of pumped hydro plants worldwide are over 300 (Gonzalez *et al.*, 2004). It is expected that an additional 7,000MW of new PHS would be installed in the near future around the world and most of these are expected to be installed in Europe (Deane *et al.*, 2010). The installed power capacity of the PHS ranges from a few hundred MWs to a few GWs while energy capacity ranges from a few hours to a few days.

1.3.2 Compressed air electricity storage (CAES)

This type of storage system uses electricity to compress air, either into an underground cavern (*i.e.* aquifer, cavern or abandoned mine) or into an above-the-ground system of tanks or pipes (Figure 1.5). The compressed air is later mixed with nat-

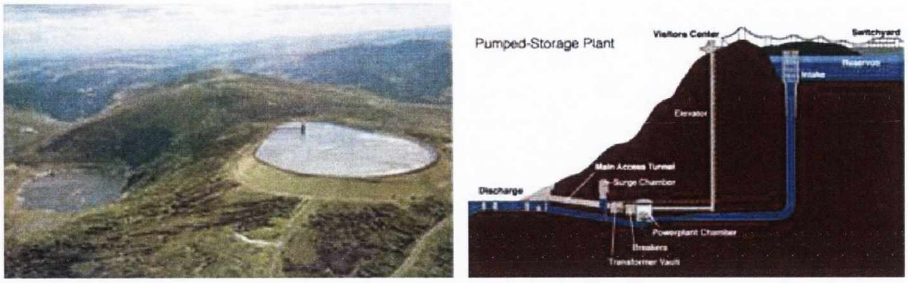


Figure 1.4: Pumped hydro storage (Electricity Supply Board, 2010; Electricity Storage Association, 2009).

ural gas and this is used to generate electricity. The capital cost of this form of electricity storage is the cheapest of the storage technologies as it mostly uses a natural structure. It is a proven and feasible technology - however, there are only three such storage systems in existence and only two of them are operational at present (with a power capacity of 290MW in Hundorf, Germany and 110MW in McIntosh, Alabama). As natural gas is used when generating electricity, the fuel costs also need to be accounted for.

The next generation of CAES is the Adiabatic CAES which generates electricity without the use natural gas when it is heating the air, but uses the heat that has been retained from the compression to generate electricity (Bieber, 2010).

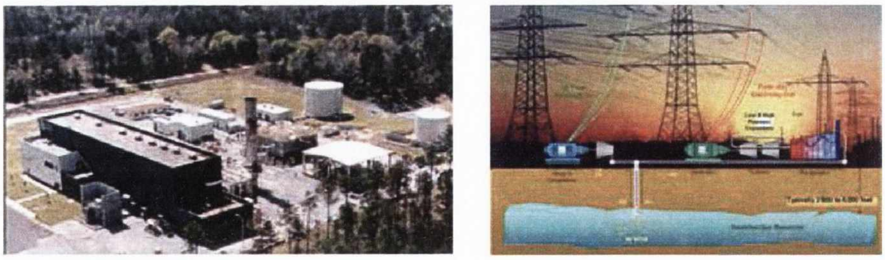


Figure 1.5: Compressed air electricity storage (IWEA, 2011).

1.3.3 Battery electricity storage

Battery electricity storage systems are electrochemical devices that convert electrical energy into chemical energy when it is being charged, and chemical energy into electrical energy when it is being discharged (Figure 1.6). It is a technology that has been utilized for many different purposes in our daily lives. However, large-scale deployments have been criticized from both economic and environmental perspectives. Batteries usually have high round trip efficiencies. However, their lifetime is relatively low and they require frequent renewals. In addition, its life cycle depends on how deeply it has been discharged.

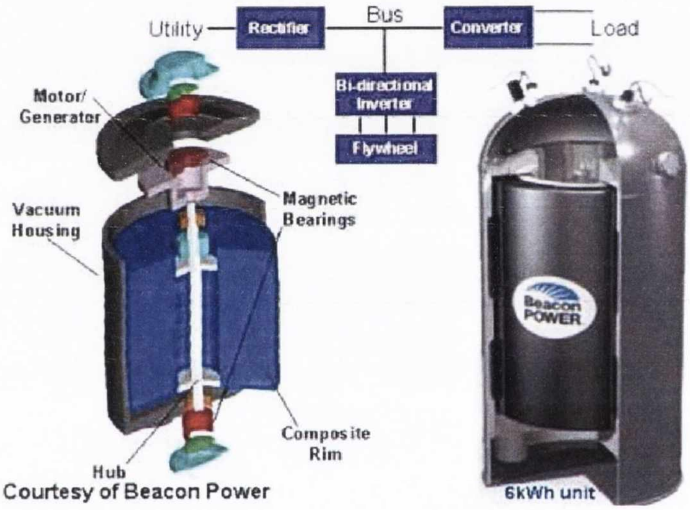
The advantage of the battery system is that it can be used for a variety of applications such as energy, power and voltage. Another advantage of such a system is that it can be built on a relatively small scale; hence it can be moved to different locations and used to provide vital supports for the power system. The largest battery system in operation is located in Fairbanks, Alaska, USA which can discharge 26MW for 15 minutes (or 40MW for 7 minutes). It is mainly used for spinning reserve (ABB, 2011).

Figure 1.6: Battery electricity storage (ABB, 2011).

1.3.4 High speed flywheel

This consists of a heavy rim attached to the shaft in a vacuum environment which is rotated when it is connected to the electricity. The inertia that has been created is used to generate electricity at a later time (Figure 1.7). This is usually connected to a generator, which is integrated with the grid, in order to provide stability. It is an example of a short-term storage system which is used for intra-second or intra-minute periods. The efficiency of such a system is relatively high and its life cycle is relatively long.

The environmental impact of the flywheel system is minimal compared to the other types. However, its capital cost is relatively high. It is also scalable, and several flywheel farms that can provide many MW of power for a duration of several minutes have been installed or are currently in the construction stages (Electricity Advisory Committee, 2011).



Courtesy of Beacon Power

Figure 1.7: High speed flywheel energy storage (Beacon Power, 2011).

1.3.5 Hydrogen electricity storage system

This is one of the most promising technologies of storing electricity (Carton and Olabi, 2010). Hydrogen storage uses the excess electricity to separate hydrogen from water and then stores it in a tank (Figure 1.8). Once hydrogen is separated and stored, it is then used to generate electricity using fuel cells. One of the key technical challenges to accomplish is the development of a safe, reliable, and low cost storage system for the hydrogen. Its application in the transport sector is being considered as one of its viable applications. In 2010, a test hydrogen electricity storage system was built in Nuuk, Greenland which is the first of its kind in Greenland (Icelandic New Energy, 2011).

Figure 1.8: Hydrogen energy storage (Icelandic New Energy, 2011).

1.3.6 Supercapacitor electricity storage

A supercapacitor is the electrochemical capacitor that stores energy in the electrostatic field (Susan and Hassenzahl, 2003). This is similar to the build-up of electrical charge when walking on a carpet. Touching an object releases the energy through the finger. They have greater energy densities than regular electrochemical capacitors and have a greater power capacity than the regular batteries and fuel cells. While small electrochemical capacitors are a rather mature technology, the units with higher energy densities are still under development (EPRI, 2004).

1.4 Integration of electricity storage in the power system

The benefits of the electricity storage system, when it is integrated with the power system, are not limited to the ability of the electricity storage system to provide vital supports for the power system, but also extend to the promotion of renewable energy, the reduction in greenhouse gas emissions, a reduction in the total cost of the power system and a potential reduction of the electricity price. In addition, it decouples electricity generation from electricity demand and makes electricity a storable commodity and enables it to exercise the benefits of a storable commodity.

Hence, electricity generated by power plants with low fuel costs or renewable sources at off-peak hours can be stored and used in order to displace electricity generated by the expensive peaking units at peak hours. It is also expected that it will generate a significant gain in welfare for consumers if the reduction in electricity cost at peak hours is greater than the increase in cost at off-peak hours (Crampes and Moreaux, 2010; Sioshansi, 2010).

Due to the strict power system operational and security rules, some of the electricity generated from renewable sources needs to be curtailed *e.g.* when wind power output is greater than the capacity of the transmission system. The integration of electricity storage with RES, is expected to increase the penetration of electricity generation from RES and to reduce curtailments (Sioshansi *et al.*, 2009).

Depending on the type and characteristics of the electricity storage system, it offers various benefits for the power system. When it is integrated with an intermittent source of electricity generation such as renewable energy, it reduces the variable operation of conventional power plants. If the storage system is used to reduce the variability in electricity generation, it reduces the pressure on the power system and consequently reduces the cycling of flexible conventional power plants (Troy *et al.*, 2010).

As the charging and discharging of the electricity storage system can be stopped at short notice it also provides reserves (extra capacity carried by the power system in order to prevent power system failures) for the power system. Moreover, short term fast response storage systems, such as the flywheel, are able to improve the stability of the grid. Therefore, the utilization of electricity storage from the power system perspective has significant potential economic benefits

1.5 Objective of the thesis

Most of the energy storage technologies are in their infancy stage in terms of their technological development. The technical feasibility of various electricity storage systems has been studied extensively in Brown and Lopes (2008); Zeng *et al.* (2006); Abbey and Joós (2007). However, the economic feasibility of electricity storage has been given little attention so far, except for a few case-specific studies. Example of those studies are Tuohy and O'Malley (2011), Greenblatt *et al.* (2007) and Kaldellis *et al.* (2009).

Therefore, the objective of this thesis is to investigate the effects of the electricity storage system on the power system and the electricity market from various perspectives *i.e.* developers, the power system as well as the perspective of consumers (Figure 1.9).

In a decentralised electricity market, the revenue source for the electricity storage would likely be the arbitrage value between buying electricity at off-peak hours and selling at peak hours. If the investment that would be incurred up-front could be recovered from future storage operation, this would have a significant influence on the investor's decisions relating to the deployment of electricity storage. However, this cannot be studied in isolation from the power system. Therefore, this thesis attempts to investigate the economic viability of large scale electricity storage in a system with increasing wind power generation.

The consumers would benefit from the deployment of the electricity storage system if it reduces the electricity cost for them. In light of the Millennium Development Goals, in the future, energy should be delivered to consumers at an affordable price and the deployment of electricity storage should be in line with these goals. Therefore, if electricity storage would result in a reduction in the electricity price, it would be considered as a benefit to the consumer or to society. Thus, this study investigates the impact of electricity storage on electricity prices.

Finally, due to the fact that the deployment of electricity storage would have

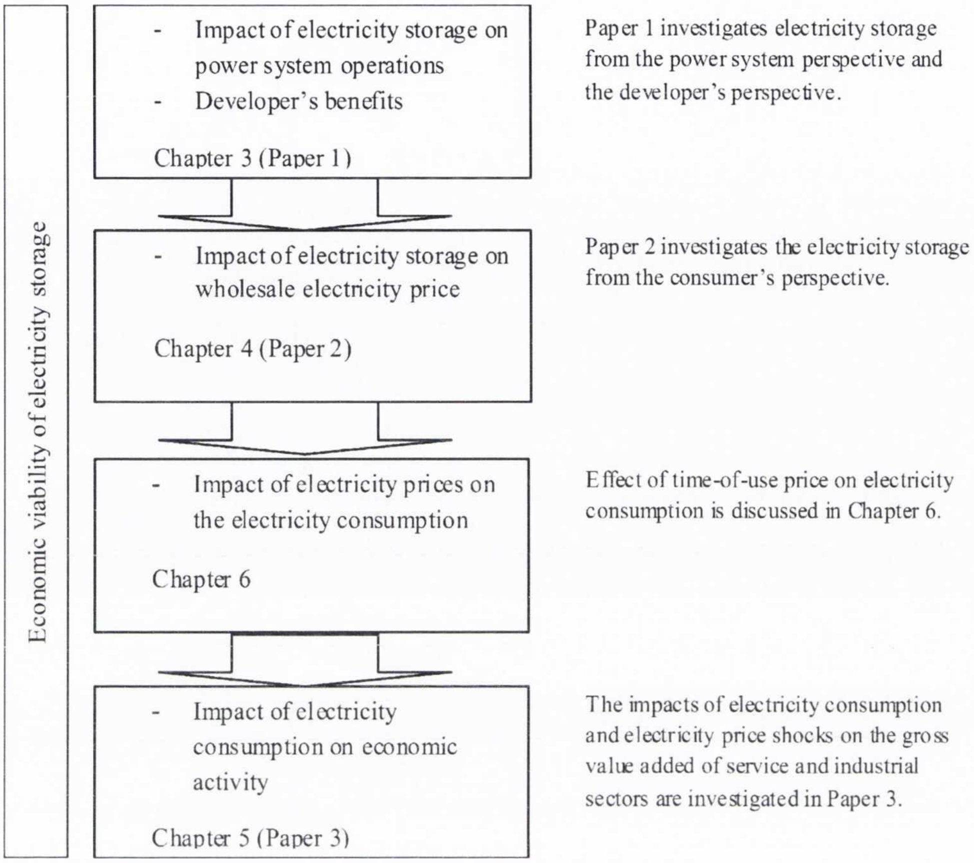


Figure 1.9: Structure of the thesis.

significant impacts on the operation of the power system and on the outcomes of the electricity market, the objective of this thesis extends to the effects of the electricity storage system on the whole economy. If electricity storage impacts the electricity prices, it is likely that there would be a "knock-on" effect on the economic activity . This would be significant if economic activity and electricity market operations are co-integrated.

This thesis excluded the study of the effect of the change in electricity price on electricity consumption, because while this research was in progress, the Commission for Energy Regulation of Ireland conducted an extensive Smart Metering Trial in 2010 which included 5650 residential and business consumers. In this trial, customers were provided with smart meters and were charged time-of-use rates for their electricity usage and the high resolution consumption data was then collected. The findings of the trial indicated that as a result of the deployment of the smart meter, residential consumers were found to have reduced their overall electricity consumption by 2.5% and their peak consumption by 8.5%, while business consumers believed that they had reduced their electricity usage (CER, 2010). This is discussed in further in Chapter 6 and the results of the Smart meter trial (CER, 2010) are used to infer the impact of electricity storage system on the electricity consumption.

1.6 Structure of the thesis

This thesis consists of 6 chapters which address and discuss the issues surrounding electricity storage deployed to promote the penetration of renewable energy in the power system.

Chapter 2 provides a detailed description of the case study system. As this thesis is based on a particular power system, the assumed plant mix, operational rules and scenarios are given in this chapter. Appendix A was also provided to give further details of the power plant characteristics.

Chapter 3 explores the viability of large-scale electricity storage system when it is integrated with wind generation in a simplified power system set-up. This has been examined from both the power system and developer's perspectives. The effects of the deployment of electricity storage on the power plant mix were explored for various levels of installed wind and storage capacities. Based on its effects on the power plant mix, the effect that the electricity storage system has on the level of CO_2 emissions from the power system and the variations of the net load (demand) are examined. Furthermore, the profitability of various storage systems are investigated.

Chapter 4 continues to examine the effect of electricity storage on the power system in detail, using the WILMAR unit commitment tool that reflects the power plant portfolio of the Irish power system and also explores the effect of storage operation on the system marginal price (wholesale electricity price). Also, real world data is analyzed in order to verify the effects of storage operation on electricity price, using econometric techniques.

Chapter 5 explores the effects of electricity storage on the sector-specific amount of gross value added. The effects of unobserved shocks in the electricity price and electricity consumptions on the amount of gross value added and *vice versa* are also examined in this chapter.

Chapter 6 presents a discussion covering the main results of Chapters 2-4, also possible extensions to the current work and the conclusions of this thesis.

CHAPTER 2

Case study system

IRELAND is a small island country with a population of approximately 4.4 million in 2010 (CSO, 2011). Over the past decade, it experienced a period of dramatic economic growth, the so called "Celtic Tiger". During this period, the industrial sector grew about 8.2%, construction sector growth was approximately 4.7% while the service sector grew by approximately 5.2% (ESRI). Unfortunately, a slow down in the housing boom drove the Irish economy into a contraction at the same time as the financial crisis spread across the EU (Whelan, 2011). Since the last quarter of 2007, the GDP growth of Ireland fell constantly until the end of 2009 (Figure 2.1). Total energy consumption growth, which is closely linked to GDP, fell as GDP fell (CSO, 2011).

In terms of its energy supply, Figure 2.2 shows that Ireland greatly depends on imported fuels such as coal, oil and gas. Indigenous fuel supply (peat and renewable energy) accounts for only 10% of the primary energy consumption while oil accounts for the largest share, 52% (FitzGerald, 2011).

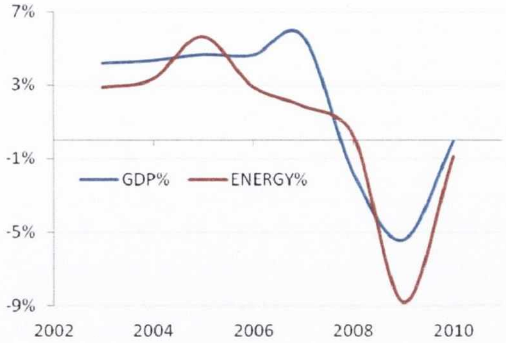


Figure 2.1: Growth rates of GDP and Final energy consumption in Ireland.

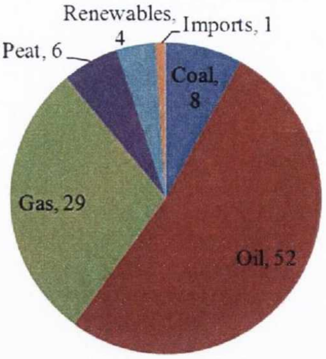


Figure 2.2: Source of primary energy, % (FitzGerald, 2011).

2.1 Electricity sector

In 2009 the total installed capacity in both the Republic of Ireland and Northern Ireland was 11,388MW which includes 9,535MW of thermal plants, 1,331MW of wind, 292MW of pumped hydro storage, 216MW of hydro and 14MW of biomass power plants. Moreover, 14% of total electricity generation came from coal, 56.9% came from gas and, 14.1% came from renewable sources and the remaining amount came from peat and oil power plants, and imports in 2009 (Figure 2.3). The winter peak demand in 2009 was 6,502MW while the minimum demand was 1,864MW.

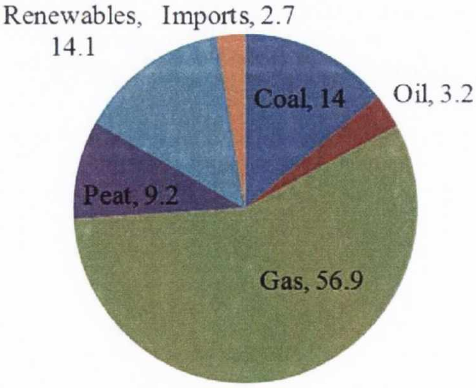


Figure 2.3: Share of electricity generated by Fuel used, % (SEAI, 2009).

2.2 Renewable energy

As a result of the various support schemes (AER[1] and REFIT) for renewable energy in Ireland, a significant amount of investment has been made in relation to wind generation (DCMNR, 2006). The total amount of installed wind capacity increased from 62MW in 1990 to over 1.7GW in 2009 and this figure is expected to increase up to 7.8GW in the coming decade (IWEA, 2009). Therefore, wind power output is expected to play a major role in Ireland meeting its target to receive 40% of the total amount of electricity generation from renewable sources by 2020 (DCENR, 2009).

In terms of the hydro power plants, there are 4 hydro power stations located along the River Liffey and the potential for more hydro power plants along this river has been exhausted. The total amount of the installed capacity of these 4 power plants is 216MW and they supply approximately 2.5% of the total electricity demand ((SEMO, 2011), calculated from the raw data).

2.3 Pumped hydro storage system

In Ireland, there is an existing pumped hydro storage system that has been operational since 1974 (Figure 1.4 in Chapter 1). It consists of four 73MW units and it can generate 292MW at its full capacity for approximately 4 to 5 hours. Due to its existence, coal power plants are able to run at their full capacity, even when demand falls to a very low level. When pumped hydro storage uses the excess electricity during the night to pump water to the reservoir at the top of Turlough Hill, the net demand increases at night. When actual demand rapidly increases, *e.g.* in the morning, stored electricity is released and is used to balance the demand and supply. Also, it is used to reduce the net demand at peak hours in order to avoid the dispatch of expensive peaking units which usually run on oil. The Turlough Hill

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[1] Alternative Energy Requirement. AER programme was launched by the Department of Communications, Marine and Natural Resources in 1996 and was the first step towards a market support for wind energy as part of the Department's programme to promote the generation of electricity from renewable resources.

unit is also crucial in terms of providing primary reserve *i.e.* reserve which responds to system failures such as unexpected generator outages.

2.4 Interconnection

Currently, Ireland has one interconnector, the Moyle interconnector, between Northern Ireland and Scotland. The import capacity of the Moyle interconnector stands at 400MW while the export capacity is only 80MW. Another interconnector, the East-West interconnector with a total installed capacity of 500MW, which will link Ireland and Wales, is currently under construction.

In light of the increased importance of renewable energy penetrations and the deployment of intermittent electricity generation, the importance of interconnection is enhanced (Diffney *et al.*, 2009).

This isolated system makes Ireland a suitable candidate for the investigation of the effects of deploying renewable energy and storage systems as impacts are not cushioned by the response of neighbouring systems.

2.5 Single electricity market

The Single Electricity Market (SEM) consists of two electricity systems, which are the Republic of Ireland and Northern Ireland systems (Figure 2.4), and both these systems are operated by the Single Electricity Market Operator. Prior to November 2007, both systems were operated by separate transmission system operators. Eirgrid was in charge of the electricity system in the Republic of Ireland which had approximately 2.5 million electricity consumers and SONI was in charge of Northern Ireland's electricity system which had approximately 1.8 million electricity consumers. In November 2007, SEM, which is licensed and regulated by the Commission for Energy Regulation (CER) in Ireland and the Northern Ireland Authority for Utility Regulation (NIAUR), was established. It was the first gross mandatory pool electricity market which operates with dual currencies and in multiple jurisdictions.

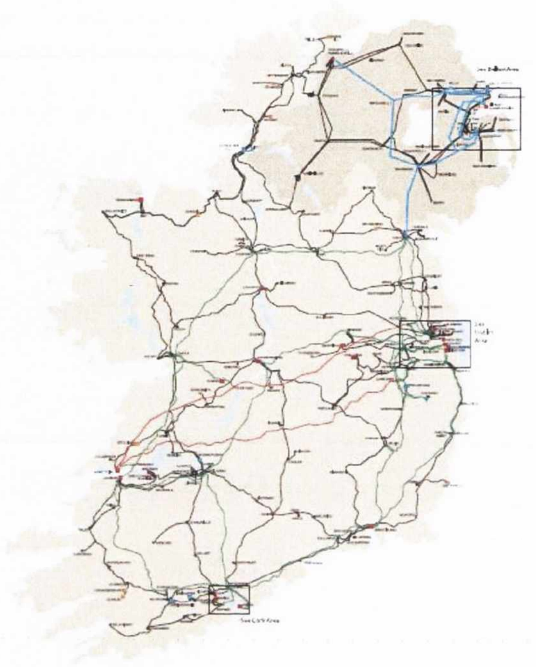

Figure 2.4: All Island electricity system.

In the SEM, when generators are participating in the electricity spot market, they are required to bid a "price-quantity" pair, which reflects their fuel costs of producing a given amount of electricity, and their technical availabilities for each trading day. The single electricity market operator then determines the lowest cost dispatch schedule to meet the forecasted demand at all hours for the following day. This schedule takes account of the wind forecast, while also ensuring that there is enough primary reserve capacity available in the system. Indicative dispatch orders change in order to accommodate changes in wind and demand forecasts throughout the actual day. After the trading day has ended, ex-post electricity prices are calculated based on the actual demand and wind power outputs (CER, 2008).

The All Island Grid Study is the first comprehensive assessment of the ability of the power system and transmission network to absorb large amounts of electricity generated from renewable sources on the island of Ireland. Moreover, the economic feasibility of the single electricity market was assessed with regards to the various scenarios of renewable energy. In this study, the optimal dispatch order of the power plants was simulated for a range of scenarios using a unit commitment tool, which would minimise the total cost of the power system, based on the technical constraints of the power plants in addition to the assumed demand, wind and fuel prices (AIGS, 2008). The unit commitment tool employed for this study was the WILMAR tool which was initially developed in Norway and later adapted to the All Island power system.

This tool has been adapted and employed in the analysis for Chapter 4.

2.5.1 Power plants mix assumed for the WILMAR tool

The WILMAR unit commitment tool is described in detail in Tuohy *et al.* (2009b); Troy *et al.* (2010); Meibom *et al.* (2007). It simulates a schedule of which power plants should be switched on and off and how much electricity each power plant should generate in order to meet the demand at particular time period. This is optimised to ensure that the total cost of the power system is minimised. When the optimal schedule is being produced by the unit commitment tool, the security of system is also accounted for *i.e.* the primary reserve targets are met.

Details of the power plant mix are used in the WILMAR unit commitment tool are given in Appendix A. The same power plant characteristics as were assumed in the All Island Grid Study (AIGS), such as the maximum efficiency, synchronisation time from cold/warm/hot states, the no-load fuel consumption and the contribution towards primary reserve, were employed except for the installed capacities. The installed capacities of the existing power plants were adapted in this thesis in order to reflect the 2009 All Island power system (SEMO, 2011).

Wind and hydro units are assumed to be aggregated units respectively which reflect the total amount of wind and hydro outputs as assumed in the AIGS. The aggregated total amount of the wind power output according to the 2009 All Island power system was used in the simulations.

CHAPTER 3

Paper1: The Viability of Balancing Wind Generation with Large Scale Energy Storage

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THIS paper studies the impact of combining wind generation and dedicated large scale energy storage on the conventional thermal plant mix and the CO_2 emissions of a power system. Different strategies are proposed here in order to explore the best operational strategy for the wind and storage system in terms of its effect on the net load. Furthermore, the economic viability of combining wind and large scale storage is studied. The empirical application, using data for the Irish power system, shows that combined wind and storage reduces the participation of mid-merit plants and increases the participation of base-load plants. Moreover, storage negates some of the CO_2 emissions reduction of the wind generation. It was also found that the wind and storage output can significantly reduce the variability of the net load under certain operational strategies and the optimal strategy depends on the installed wind capacity. However, in the absence of any supporting mechanism none of the storage devices were economically viable when they were combined with the wind generation on the Irish power system.

3.1 Introduction

Wind power penetrations have increased rapidly in the last decade with wind generation as the fastest growing renewable energy technology in the EU (EWEA, 2005). This growth is expected to continue as a result of EU policies for the promotion of renewable energy sources in order to reduce greenhouse gas emissions (European Commission, 1997). Wind generation provides a variable form of electricity generation, with the capacity factor of a mid merit plant. Wind generation delivers the power to the grid when it is available, in a variable and relatively unpredictable way, while traditional thermal mid-merit plants operate during the times when the system demand and price are high. Simply put, an uncontrollable variable source of power cannot satisfy the demand for electricity at all times and will need to be supplemented by a firm source of power. There has been no shortage of solutions proposed in this area. Reserve power, provided by flexible, dispatchable thermal and hydro plant offers one such solution to the intermittency problem (Doherty and O'Malley, 2005). Large interconnection with a large grid (Arnold, 2001; Denny and O'Malley, 2007) along with accurate forecasting techniques would facilitate the scheduling and dispatching of wind power (Beyer *et al.*, 1994; North American Electric Reliability Corporation, 2009). Storage facilities have the potential to provide reserve and, in the case of remote wind farms offer an alternative to grid reinforcement. Furthermore, coupling wind and storage in order to produce a dispatchable power output could be of significant benefit to those trading in a market system.

The EU policy for the promotion of renewable energy resources has sparked much interest in energy storage systems (European Commission, 2007a). The concept of switching from conventional thermal power generation to renewable generation, which is powered by variable energy sources, has proven to be challenging. Energy storage systems are a proven technology and are in economically successful operation in many systems today providing critical system support for the electricity systems. Greenblatt *et al.* (2007) compared the use of Compressed Air Electricity

Storage (CAES) versus gas plant (Open Cycle Gas Turbine and Combined Cycle Gas Turbine (CCGT)) to produce base-load wind power. The cost competitiveness of the competing schemes was largely reliant on the gas price: at low gas prices the CCGT system had the lowest dispatch cost. As the gas price increases, a large wind with CAES system was favored (Greenblatt *et al.*, 2007).

The benefits of storage where transmission constraints frequently limit the power delivered by a wind farm to the grid were explored by Castronuovo and Lopes (2004). Korpaas *et al.* (2003b) investigated a system where storage is used to smooth wind power output to follow a production plan. Doherty *et al.* (2006) found that increasing wind generation displaces the base-load plants and dispatches the higher merit order plants and results in higher operational costs. Therefore, energy storage technology could be used to mitigate this problem as it has the potential to control the wind power output.

In a deregulated electricity market, storage units can be either considered as merchant units, which maximize their profits, subject to technical constraints (Sioshansi, 2010), or as system assets utilized by the system operator to assist in maintaining system security and in reducing operational costs. For a merchant unit, revenues will be received from the sale of energy to the market. Compensation may also be received for the provision of some ancillary services, depending on the market arrangements. When the storage unit is utilized by the system operator as a system asset, many of the benefits of the storage are external and cannot be compensated for (e.g. a reduction in the ramping required from conventional units).

This work will look at storage from the position of a merchant plant and will address the following distinct questions. Firstly, the impact of wind and storage on the plant mix and carbon emissions (*i.e.* how the mix of thermal plants and the carbon emissions will change with the addition of dedicated storage for wind). Secondly, the impact of wind and storage on the net load. Finally, whether investment in a storage plant would be justified by its annual per MWh electricity profit if the storage is operated as a merchant type. This is studied for different types of storage technologies (CAES, Pumped Hydro Energy Storage (PHS), Lead Acid Battery (LAB) and Vanadium Redox Battery (VRB)). The other system benefits of storage units, which may or may not receive financial compensations are discussed in Section 3.6.

The structure of the paper is as follows: Section 3.2 gives some general information about storage technologies, Section 3.3 sets out the methodology. Section 3.4 shows the results of the study based on the case study of the Irish electricity system followed by the sensitivity analysis in Section 3.5. A discussion of the results is given in Section 3.6 and Section 3.7 concludes.

3.2 Storage Technologies

Energy storage is not a new concept in the electricity sector. Numerous types of energy storages are currently available and others are in the development phase. Large scale PHS is in wide scale operation worldwide and there are currently two large scale CAES units in operation. Battery energy storages (LAB, NaS (*Na*-Sodium *S*-sulphur), Metal air, Li-ion, VRB etc.), flywheels, superconducting magnetic energy storages and capacitors are often used in smaller application (Kondoh *et al.*, 2000).

In general existing storage technologies are divided into three major functional categories: power quality (to assure the continuity of quality power supply), bridging power (to assure the continuity of supply when switching from one source of energy generation to another) and energy management (to decouple the timing of generation and consumption of electricity from seconds to hours) (Electricity Storage Association, 2009). Storage is now also attracting more attention in a bid to increase renewable power penetrations.

In this research, energy storage is assumed to be the supplementary unit of the wind generation and is primarily used to balance the total wind output, whereas existing technologies are designed mainly for the system security and power quality reasons. It is assumed in this paper that:

(i) Scheduled storage output is defined by the forecasted wind and previously stored energy.

(ii) Operation of the storage depends on the strategies outlined in Section 3.3.

(iii) Energy loss is incurred when the storage is being charged.

(iv) Technologies differ only in their assumed level of efficiency, capital costs and the life time.

(v) Price arbitrage is the only source of revenue to recover the short run and long run costs.

3.3 Methodology

It should be noted that studying the economic viability of storage units is likely to produce a context specific rather than a general answer due to the diverse nature of electricity systems across the world. For the purposes of this study the Irish system is chosen as a test system, because it is a small system with poor interconnection and increasing wind generation. Thus issues concerning high levels of variable electricity generation may be seen more clearly than in larger interconnected systems.

In this research, the 2006 Irish system marginal price, the 2006 Irish demand profile and the 2006 Irish wind generation are used (Eirgrid Transmission System Operator, 2008).

In this study we assume no network constraints. According to AIGS (2008) Workstream 2A, the Irish electricity system does not require any network upgrades until approximately $1500MW$ of installed wind capacity and for $2550MW$ of installed wind capacity (which is the maximum wind capacity considered here), network-wide development of approximately €100 million is required. We assume the upgrade for the wind energy will also alleviate any constraints from the storage unit.

Since the aggregation of wind power output over a large area significantly increases the wind power output forecast accuracy (Ernst *et al.*, 2007) and the daily load fluctuation is perfectly predicted, we assume perfect forecasts of the load and the wind power outputs. In the presence of high penetrations of wind generation, system operators may be required to carry additional reserve capacity to deal with the uncertain variability of the wind power output (Doherty and O'Malley, 2005). Increased storage may reduce this reserve requirement by reducing the uncertain variability of the wind power output. Thus, assuming perfect wind power forecasts may somewhat underestimate the system benefits of the storage unit. However, whether a merchant storage unit will be compensated for this benefit will depend on the underlying market arrangements. The likely financial benefit that could accrue to a merchant storage unit from a reduction in the reserve requirement on the Irish system is discussed further in Section 6.1.

3.3.1 The impact of wind and storage on the thermal plant mix

A diverse portfolio of generating units helps to ensure the secure supply of electricity. Firstly, it is prudent not to be overly reliant on one fuel source. Secondly, to follow the fluctuating demand curve, a mix of cheap base-load plant and cycling mid-merit and peaking units are required.

In order to explore the effect of storage on the power system, a model was developed that sought to determine how the plant mix (percentage share of the base-load, mid-merit and peaking plants output in the total load over one year) adapted itself to the varying levels of wind power capacity and storage power rating. The purpose is to define the effect of wind and storage on the plant mix of base-load, mid-merit and peaking plants based on the following assumptions related to the storage and thermal plant operations.

It is assumed that the 'wind and storage output is scheduled once for the next 24 hours at the beginning of the period using a perfect wind forecast. Moreover, the storage operational strategy is assumed to be such that it is charged by the wind energy for 12 hours continuously (storage output is negative: $P_{st,t} < 0$) and discharged in the next 12 hours ($P_{st,t} > 0$) in order to level the wind output (Figure 3.1). In the case where the wind output exceeds the scheduled output, the extra wind energy is used to charge the storage regardless of time of day (circled area in Figure 3.1).

Based on 2006 Irish System Marginal Price, hours between 21:00 and 9:00, and 9:00 and 21:00 were selected for the charge and discharge periods respectively, as these periods on average guarantee the prices at the time of charge are lower than the prices at the time of discharge. Therefore, storage operation is purely price driven and charged during the night when prices are low and discharged during the day when prices are high. The amount of charge/discharge of storage will depend on the wind power availability during the night/day.

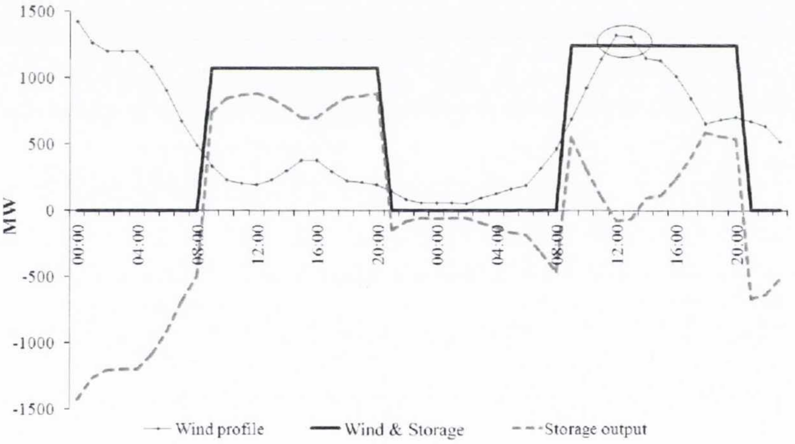

Figure 3.1: Controlled wind output (Wind & Storage) for sample two days.

The upper limit of base-load plant allowable on a typical system was defined as the MW figure above which demand rises 85% of the time. This ensures that the base-load plant maintains a high capacity factor. Moreover, peaking plant requirement was defined as the MW figure above which demand rises 15% of the time. Mid-merit plant is assumed to supply the balance of MW required to cover the demand given the above definitions of base-load and peaking plants. The plant mix is then found from the 'net load' duration curve (Figure 3.2) which is drawn from the net load profile ($\hat{P}_{load,t}$, i.e demand met by the conventional thermal plants):

$$\hat{P}_{load,t} = P_{load,t} - P_{wind,t} - P_{st,t} \tag{3.1}$$

where $P_{load,t}$, $P_{wind,t}$ and $P_{st,t}$ are the demand, wind profiles and storage output respectively.

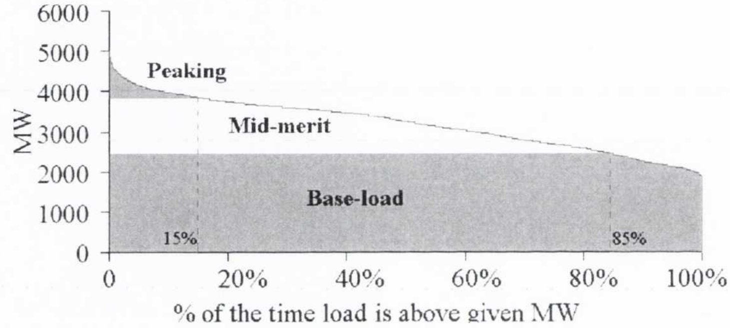

Figure 3.2: Net load duration curve and assumed thermal plant mix.

Based on these assumptions made on the MW figures of allowable base-load, mid-merit and peaking plants, and the percentage of the total load supplied by the base-load (P_{base}), mid-merit $(P_{midmerit})$ and peaking plants (P_{peak}) are then calculated for the varying levels of wind capacity and storage power rating:

$$P_{base} = \sum_{t=1}^{T} (P_{base,t}) \tag{3.2}$$

$$P_{peak} = \sum_{t=1}^{T} (P_{peak,t}) \tag{3.3}$$

$$P_{midmerit} = \sum_{t=1}^{T} (\hat{P}_{load,t} - P_{base,t} - P_{peak,t}) \tag{3.4}$$

where:

$$P_{base,t} = \begin{cases} P_{85\%} & \text{if } \hat{P}_{load,t} \geq P_{85\%} \\ \hat{P}_{load,t} & \text{if } \hat{P}_{load,t} < P_{85\%} \end{cases} \tag{3.5}$$

$$P_{peak,t} = \begin{cases} \hat{P}_{load,t} - P_{15\%} & \text{if } \hat{P}_{load,t} \geq P_{15\%} \\ 0 & \text{if } \hat{P}_{load,t} < P_{15\%} \end{cases} \tag{3.6}$$

where T is the number of hours in one year, $P_{85\%}$ is the MW amount that the net load is above for 85% of the time, $P_{15\%}$ is the MW amount that the net load is above for 15% of the time.

3.3.2 The impact of wind and storage on the CO_2 emissions

Based on the results of the previous section (P_{base}, $P_{midmerit}$ and P_{peak}) the impact of wind and storage on the CO_2 emissions of the power system is investigated.

It is assumed that the portfolio of the conventional plants is such that base-load, mid-merit and peaking plants are represented by the coal (pulverized fuel-PF) and peat, CCGT and OCGT plants respectively which can be considered as a reflection of the conventional thermal plants of the Irish Electricity System (Denny and O'Malley, 2006; Royal Academy of Engineering, 2004). The peat plant is assumed to operate under the 'must-run' scenario[1]. The CO_2 emissions from typical power plants are given in Table 3.1.

Table 3.1: CO_2 emissions from typical power plants(Denny and O'Malley, 2006)

Plant type	Tonnes/MWh
Peat	1.15
Coal PF	0.92
CCGT	0.36
OCGT	0.41

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[1] The operation of the peat plant is similar to coal-fired units. Despite being more expensive, inefficient and a high emitter of CO_2, the Irish Government made a policy decision to adopt a must run approach for all peat-fired generators for security of supply reasons, thus making them base-loaded. The peat is then subsidized by a Public Service Obligation on all electricity bills. Combined installed capacity of the existing three peat fired plants is $360MW$.

3.3.3 The impact of wind and storage on the net load

The analysis described in Section 3.3.1 assumes that the storage charges during 12 hours at night and releases stored energy during 12 day hours. Henceforth referred to as *Mid-merit* strategy. In this section two additional operational strategies for the storage unit are proposed to compare the impact of the 'wind and storage' on the net load to the impact of a 'no-storage' scenario. The *Base-load* strategy produces a flat 24 hours generation profile and the *Peak* strategy generates during 6 hours of the highest demand. Under *base-load*, *mid-merit* and *peak* strategy wind and storage can replace the base load, mid-merit and peaking plants respectively as they are supplying electricity to the market at the hours when those plants are likely to supply.

Moreover, the storage technology employed in this model is assumed to be non-specific. The size of the storage is defined by the following approach based on the utilization of discharge rate for every wind scenario and every strategy in order to use practical storage sizes and avoid the case where there is excess or shortage of storage capacity. First, the unconditional discharge rate is defined by running the simulation without any upper limit on the storage power rating, so it could store and release as much energy as needed. Then the storage power ratings are set equal to the 95^{th} percentile of the unconditional discharge rate (Figure 3.3: storage power rating for mid-merit strategy is shown as an example). Once the storage power ratings are found, storage energy sizes are also defined according to the method in Section 3.3.1.

It is assumed that the requirement of the minimum number of units online is defined by the number of units online during the minimum demand within a year. Therefore, the output of storage is curtailed if the net load falls below the requirement.

The impact of wind and storage output on the net load is found by introducing the storage into the system with wind generation under the proposed operational

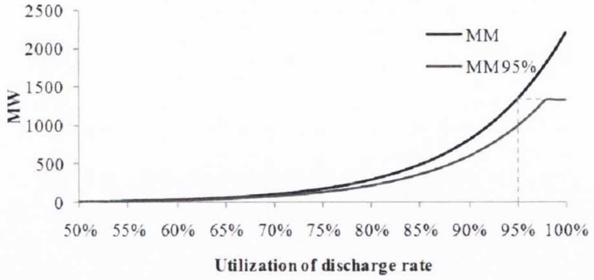

Figure 3.3: Unconditional (MM) and Conditional (MM 95%) discharge rate.

strategies and examining the variation of the net load. In reality these scenarios will be difficult to reproduce due to the errors associated with wind power forecasts and the network constraints etc. However the results provide interesting insights into the optimal operational strategy of the combined wind and storage.

3.3.4 Profitability of the Storage

In a competitive electricity market, investors will not invest in a project unless investment costs are justified (Crampes and Moreaux, 2010). On the other hand, electricity storage could be of great interest for power system operators if it contributes to the least cost operation and improves the security of supply. However, if storage is to be operated as a merchant type, the system benefits will not be of interest for the storage owner if there is no compensation for the benefits that it creates[2]. Therefore, the energy related revenue is considered to be the only source of revenue and it should cover the long run costs, *i.e.* capital, replacement and fixed O&M costs (fixed costs) and input energy cost (variable cost), or at least it should be able to cover its short run cost (input energy cost) in order to give an incentive to the investors.

For a given storage technology, its operation is scheduled as described in Section 3.3.3 (according to *base-load*, *mid-merit* and *peak* strategies) and the operation of storage is such that it buys/sells the energy at the market price in order to

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[2] This is discussed further in the Section 6.1.

charge/discharge. It is assumed that storage has no effect on the electricity price. Therefore, it is possible to consider the storage revenue and costs separately and the profit (π) of the storage as the total revenue (revenue from selling energy to the market) net of the fixed and variable costs associated with its operation:

$$\pi = TR - TC \tag{3.7}$$

$$TR = \sum_{P_{st,t}>0} SMP_t * P_{st,t} \tag{3.8}$$

$$TC = C_{cap} + C_{rep} + C_{O\&M} - \sum_{P_{st,t}<0} SMP_t * P_{st,t} \tag{3.9}$$

where TR is the total revenue, TC is the total cost, SMP_t is the system marginal price, C_{cap} is annual capital cost, C_{rep} is annual replacement cost (some technologies require frequent replacements of parts, e.g batteries), $C_{O\&M}$ is annual fixed operation and maintenance cost per MW installed, and $P_{st,t}$ is storage output. Power rating and energy capacities of the storage are defined in the previous section and used to calculate the capital, replacement and fixed O&M costs of the storage.

The wind generation is assumed to operate as it operates in the competitive market and the earns what it would earn without storage, because storage buys the energy at the market price. Therefore any revenues and cost associated with the wind generation are not considered here.

3.4 Results

3.4.1 The impact of wind and storage on the thermal plant mix

In the model, maximum demand is $5014MW$ and minimum is $1803MW$. The round trip efficiency of the storage is considered to be 75% in this study which is equal to the round trip efficiency of the currently available PHS. However the results would also be relevant for other storage technologies with 75% efficiency.

Table 3.2: Share of the net load supplied by each plant type (%)and the total generation of each plant type (TWh)

Wind	Plants	Storage Power Rating (MW)					
		0	200	400	600	1200	1800
Low wind 1300MW	Base-load	72% *17.83*	76% *18.88*	77% *19.26*	77% *19.45*	77% *19.47*	77% *19.47*
	Mid-merit	27% *6.62*	23% *5.77*	22% *5.49*	21% *5.36*	21 *5.38*	21% *5.38*
	Peaking	1% *0.35*	1% *0.33*	1% *0.32*	1% *0.32*	1% *0.32*	1% *0.32*
Medium wind 1950MW	Base-load	69% *16.08*	73% *17.13*	75% *17.70*	76% *17.91*	75% *17.86*	75% *17.71*
	Mid-merit	29% *6.80*	25% *5.97*	23% *5.53*	23% *5.43*	23% *5.55*	23% *5.62*
	Peaking	2% *0.37*	1% *0.34*	1% *0.33*	1% *0.33*	1% *0.32*	1% *0.33*
High wind 2550MW	Base-load	64% *13.78*	68% *14.80*	70% *15.36*	71% *15.62*	69% *15.50*	68% *15.2*
	Mid-merit	35% *7.53*	31% *6.72*	29% *6.31*	28% *6.17*	29% *6.50*	31% *6.89*
	Peaking	2% *0.39*	2% *0.37*	2% *0.37*	2% *0.36*	2% *0.36*	2% *0.34*

The effect of increasing wind capacity and increasing storage power rating on the plant mix is calculated by equations (5.1)-(5.10) and shown in Table 3.2. It is evident from the table that the output of base-load plant is displaced (from 72% to 64%) as wind capacity increases and the requirements for load following mid-merit and peaking plants are increased from 27% to 35% and 1% to 2% respectively when there is no storage on the system. The use of relatively small storage (200MW - 600MW) with wind generation reduces the participation of the mid-merit plants and increases the participation of the base-load plants. Moreover, with low wind (1300MW) on the system, increasing storage power rating substantially has no impact on the plant mix, because wind and storage system output depends on the available wind output. However, the use of relatively large storage (1200MW-1800MW) with high wind has the opposite effect to small storage due to the load shifting from day to night (peak load appears during the night and off-peak load appears during the day).

Therefore, storage could be used to offset the additional costs that wind generation places on the system by increasing the generation of base-load plants and decreasing the generation of mid-merit plants when the storage power rating is not sufficiently large to shift the system peak load.

3.4.2 The impact of wind and storage on the CO_2 emissions

Assuming that the base case scenario is the 'no-storage' case, the impact of storage on the CO_2 emissions of the power system is calculated for the different wind and storage scenarios.

Table 3.2 shows that increasing wind capacity decreases the generation of base-load plants and increases the generation of mid-merit and peaking plants at a lower rate than base-load plants. This implies that the CO_2 emissions savings increase with increasing wind capacity.

Figure 3.4 shows the effects of incorporating storage with wind under different scenarios. Under the low wind scenario, increasing the storage power rating reduces the CO_2 savings by up to 5%. When the medium wind scenario is considered, CO_2 savings are further eroded. Under the high wind scenario, increasing the storage power rating above approximately $900MW$ reduces the declining trend in CO_2 emissions reductions. This is due to the storage decreasing the total generation of the base-load plants and increasing the total generation of mid-merit plants (Table 3.2).

3.4.3 The impact of wind and storage on the net load

Large amounts of variable and intermittent power supply increase the challenge of matching generation and demand at all times, hence there will be a possibility of curtailing the wind output due to high wind at off-peak hours. Therefore, wind power producers may use the storage unit with their wind farms in order to hedge

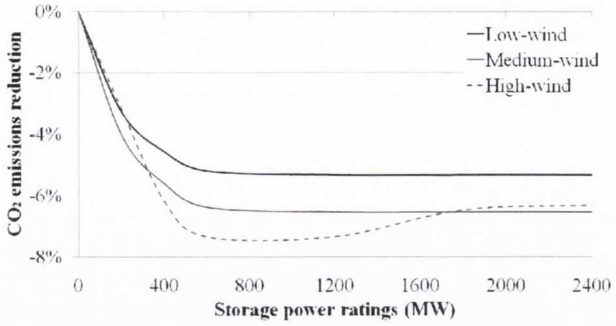

Figure 3.4: Impact of storage on the CO_2 emissions reductions.

against the risk of being curtailed.

In this section a scenario with a small amount of wind capacity (Low/2-650MW which is less than the current level of installed wind capacity in the Republic of Ireland (Eirgrid Transmission System Operator, 2007)) was included to explore the impact of low wind on the system. The storage power ratings, which are based on the 95th percentile of the unconditional discharge rate, are shown in Table 3.3.

Table 3.3: Storage Power Ratings (MW)

Strategy	Wind scenarios			
	Low/2	Low	Medium	High
Base-load	98	208	342	522
Mid-merit	280	560	830	1211
Peak	630	1231	1595	1603

Figures 3.5-3.7 show the effect of combining wind and storage on the net load (demand net of wind and storage output) for the high wind scenario.

Figure 3.5 shows that the *base-load* strategy does not reduce the variability of the net load and merely shifts the load curve downward. In fact the wind and storage provides energy to the grid during the night[3] and thereby displace the base load units. Therefore, the wind and storage output is curtailed during some nights due to the requirement of minimum number of units online. Table 3.4 illustrates the number of hours of curtailments occurred on the wind and storage output and

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[3] Due to the strategy used in this scenario, which has flat output rate for 24 hours, storage discharges during the night if wind output is less than the scheduled output.

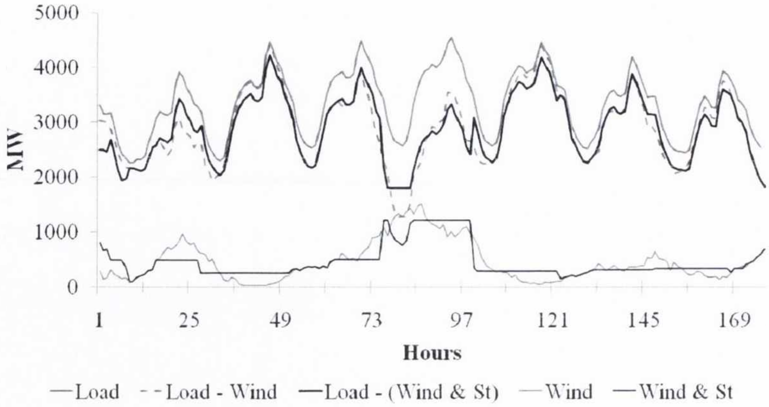

Figure 3.5: Impact of controlled wind output (Wind & ST) on the net load: Baseload strategy.

curtailed energy as a fraction of the total energy supplied over the year.

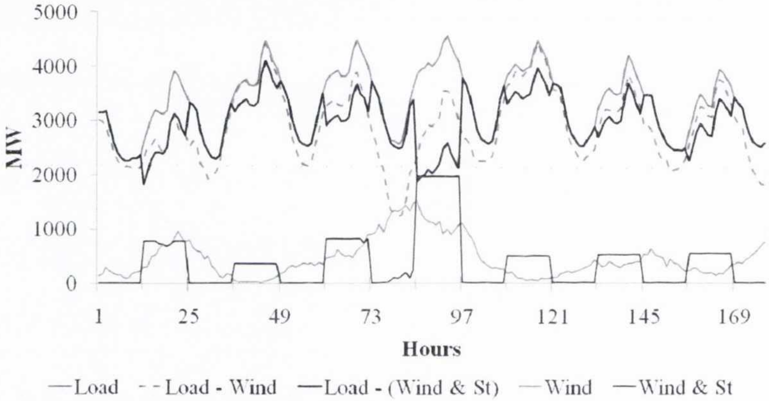

Figure 3.6: Impact of controlled wind output (Wind & ST) on the net load: Mid-merit strategy.

Mid-merit strategy (Figure 3.6) increases the net load during the night and decreases it during the day by the wind and storage output. Thus, during the night all demand is met by the conventional thermal units and all the wind is used to charge the storage. During the day stored energy is discharged in addition to the wind output to meet the schedule. As it is only supplying the energy during the day there is significantly less curtailments on the output of the wind and storage system due to the requirement of minimum number of units online (Table 3.4).

The effect of the *peak* strategy (Figure 3.7) is more dramatic than the effect of

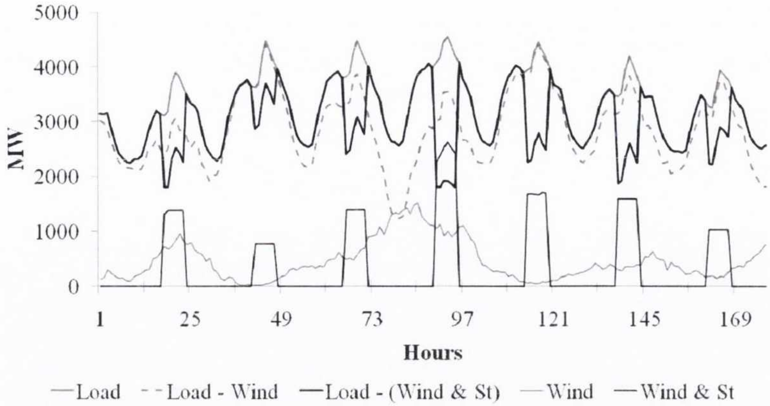

Figure 3.7: Impact of controlled wind output (Wind & ST) on the net load: Peak strategy.

the *mid-merit* strategy as it discharges large amounts of energy in a shorter period of time, thus results in more curtailments (Table 3.4) and high variation of the net load. However, with low wind on the system it performs better than the *base-load* strategy as it serves as the peak shaving system and the variation of the net load decreases. But as wind increases to medium and high scenarios its advantage diminishes as the curtailed energy and the variation of the net load increase dramatically (Table 3.4 and Figure 3.8).

Table 3.4: Hours of Curtailments on the Wind and Storage Output *(Curtailed MWh energy as percentage of the total load over a year)*

Strategy	Wind scenarios			
	Low/2	Low	Medium	High
Base-load	83	499	1057	1727
	0.03%	*0.43%*	*1.60%*	*3.77%*
Mid-merit	0	27	419	1360
	0.00%	*0.01%*	*0.65%*	*4.44%*
Peak	3	453	1097	1362
	0.00%	*1.75%*	*10.42%*	*17.82%*

Figure 3.8 shows the effect of combining wind and storage on the variation (i.e SDev: standard deviation) of the net load and compares different operational strategies of the storage for increasing wind capacity on the system to the 'no-storage' scenario.

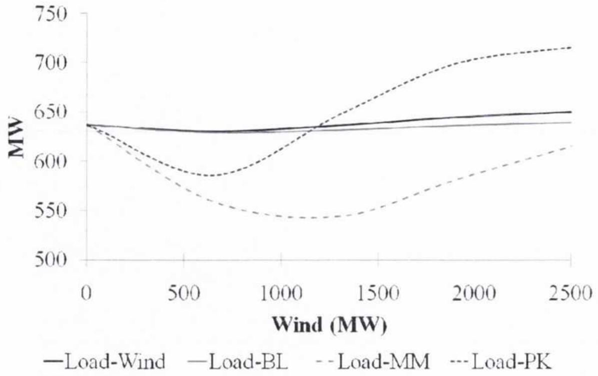

Figure 3.8: Impact of wind and storage output on the standard deviation of the net load.

Figure 3.8 shows that *mid-merit* (Load-MM)and *base-load* (Load-BL) strategies are more beneficial for the whole system and the former is more attractive than latter for all wind scenarios as it decreases the variability of the net load the most. While *peak* (Load-PK) strategy is preferred to *base-load* strategy only with small wind on the system as it shaves the peak load rather than shifting load curve.

3.4.4 Profitability of the Storage

In this section the profitability of CAES, PHS, LAB and VRB are discussed as these are (excluding VRB) the most suitable bulk energy storage systems (Susan and Hassenzahl, 2003). It is assumed that these technologies differ by their round trip efficiency, capital cost and the life time. VRB is not commercially available for the large scale, however, here it is assumed that it is possible to build as large as needed.

Based on the methodology of previous section, storage operations were scheduled and the revenues and costs for a given technology were calculated using equations 5.9-3.9 and currently available technology specific data (Table 3.5 (Susan and Hassenzahl, 2003)) and system marginal price (Eirgrid Transmission System Operator, 2008). The exchange rate of 1.42$/€was used to convert the currency to euro.

Table 3.5: Characteristics of Energy Storage (1000€)(Susan and Hassenzahl, 2003)

CHARACTERISTICS	CAES	PHS	LAB	VRB
Capital cost €/MW*	299	704	88	123
Capital cost €/MWh**	2	7	106	423
Fixed O&M cost €/MW	36	36	116	35
Replacement cost €/MWh	0	0	106	423
Round trip Efficiency	73%	75%	75%	70%
Replacement frequency (years)	-	-	6	10
Repayment period (years)	20	20	18	20

* Capital cost €/MW is the cost of turbine in the case of CAES and PHS, and power conversion system for LAB and VRB

** Capital cost €/MWh is the cost of cavern(reservoir) in the case of CAES (PHS) and battery for LAB and VRB

Due to similar round trip efficiencies of the storages (Table 3.5), the required power rating and energy capacity are similar to what is found in Table 3.3. Thus, the storage output, revenue and energy costs are also similar and the comparison of the profitability of the storage is mainly driven by their capital costs and the requirement of replacement. Figure 3.9-3.10 show that the revenue from selling energy to the market is not enough to cover the input energy cost (net revenues are negative) and creates a loss regardless of the strategy. Technologies which require frequent replacements (LAB and VRB) have higher losses than those which do not require any replacement (CAES and PHS) and CAES has the least loss per MWh energy discharged.

It shows that the *mid-merit* strategy creates the least monetary loss compared to the other two strategies (Figure 3.10). While *base-load* strategy creates slightly less monetary loss than *peak* strategy.

This result shows that, the concept of using storage with wind generation in order to gain extra margin by participating in the market is not economically feasible at the current level of technology and market condition.

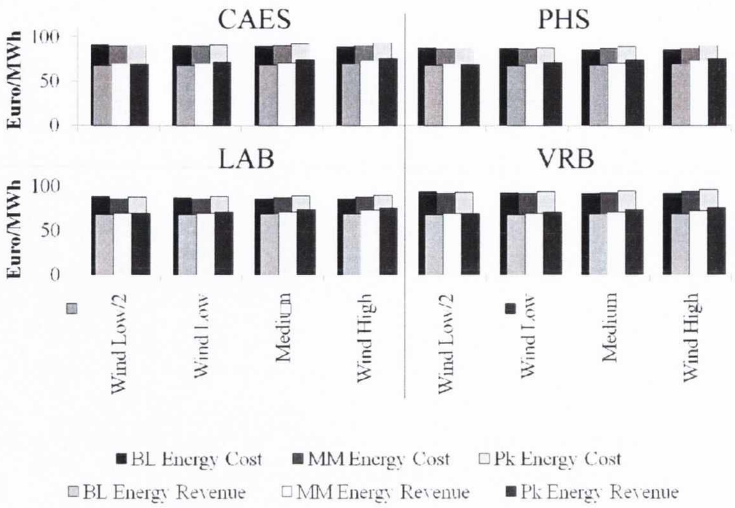

Figure 3.9: Annual Storage Cost and Revenue per *MWh* energy supplied by the storage (€/*MWh*).

3.5 Sensitivity analysis

A further scenario is examined where the storage power ratings were set equal to the 85^{th} percentile of the unconditional discharge rate. The impact on net load and profitability of this smaller storage is considered.

It was found that utilizing the 85^{th} percentile resulted in the storage power ratings, as shown in Table 3.3, being decreased by 40-59%. Moreover, the standard deviations of the net load (Figure 3.8) were increased for the base-load strategy by 0.13-0.27% and decreased for the peak strategy by 0.76-9.1% while there were mixed effects for the mid-merit strategy between ±3%. The mid-merit strategy remained the optimal strategy in terms of reducing the standard deviation of the net load.

The annual storage monetary losses per *MWh* energy supplied, as shown in Figure 3.10, were also decreased by 20-32% (with less than ±3% change in the energy related cost and revenue in Figure 3.9). The mid-merit strategy was still the best strategy, however profits were still negative. Thus even if the size of the storage is decreased significantly, storage is still not profitable due to the high capital cost and low round trip efficiency.

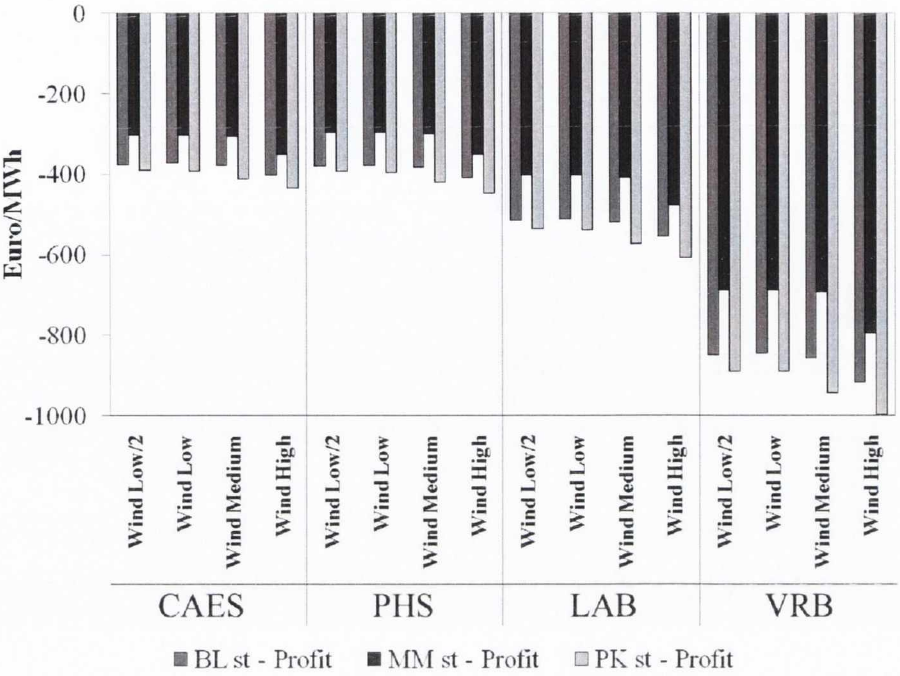

Figure 3.10: Annual Storage Profit per *MWh* energy supplied by the storage ($€/MWh$).

3.6 Discussions

In order to be economically viable, the storage unit should at least recover its variable cost from the revenue of selling energy to the market (positive net revenue). Here, this condition is not being satisfied (Figure 3.9). The price differential between night and day in our data, showed a weekday average high to low price ratio of 1.19. This resulted in the storage efficiency requirement to be at least 92% in order to break even in terms of the energy related costs and revenue. Thus price differential needs to increase substantially to improve the economics of storage. For instance, weekday average high to low price ratios in Britain, USA PJM and Netherlands markets are 3, 3.7 and 5.1 respectively while it is approximately 1.3 in Scandinavia (Li and Flynn, 2006). In fact, the operation of storage unit could reduce the peak price and increase the off-peak price, the net revenue shown in Figure 3.10 may be overestimated. Furthermore, the capital costs (long run costs) need to be subsidized, as the net revenue is not covering the capital cost, replacement cost and fixed O&M cost.

As wind power penetration grows, demand for reserve capacity increases due to the uncertain variability of wind and an increased probability that a significant wind variation may coincide with a large generation failure (Dany, 2001; Doherty and O'Malley, 2005). It is estimated that as wind power capacity increases from $0MW$ to $2550MW$, demand for reserve on the Irish system will increase from approximately $450MW$ to $850MW$ (Doherty and O'Malley, 2005). At current reserve prices, the projected increase in reserve costs associated with $2250MW$ of wind is €7.7 million per annum (Eirgrid Transmission System Operator, 2010). The addition of storage on the system may reduce the need to carry this additional reserve (Baxter, 2003; Benitez *et al.*, 2008). If the merchant storage unit completely eliminated the need for this additional reserve capacity, and was compensated accordingly (by the full €7.7 million per annum), it would still make a loss with the reserve benefits representing just 15% of the net loss at $2250MW$ of wind (from Figure 3.10).

In addition, an increase in wind penetration may increase the number of start-ups and ramping duties (commonly termed cycling) of the conventional units on the system (Holttinen and Pedersen, 2003). In some electricity systems, an increase in electricity storage may reduce this externality associated with increased wind. However, it was found that for the Irish system, additional storage with wind generation actually increases the cycling of the base-load plants. This is because the presence of storage displaces the primary reserve contributions required from the conventional units (Troy *et al.*, 2010). In other words, base-load units, which were previously kept on to provide reserve, are switched off instead as the storage unit becomes the primary reserve provider.

If the storage unit is considered to be a system asset, the effect of the storage on the cycling and reserve requirements of the conventional units can be considered in the economic analysis. In some systems, capacity payments are utilized to reward generating units for the system benefits they can provide. However, the methodologies commonly used to calculate capacity benefits are somewhat unsuitable for evaluating storage as it is energy limited *i.e.* storage cannot guarantee the supply of electricity for longer than its energy ratings (Walawalkar *et al.*, 2007) and therefore cannot be a perfect substitute for thermal units that provide ancillary services. To date, there has been no definite methodology for the calculation of storage capacity value.

The analysis shown in Section 3.4.4, omitted the economic value of the impact of storage on CO_2 emissions. However, it was shown that storage on the Irish electricity system actually increases the CO_2 emissions due to the increased participation of the base-load plants (Table 2 and Figure 4). Thus, if the cost of the additional CO_2 emissions were included in the economic analysis, the economic losses incurred by the storage unit would increase.

A further benefit of storage might be a reduction in the requirement for network upgrade associated with increased wind penetration. As stated previously this is estimated at €100 million for $2550MW$ of wind on the Irish system. If the storage owner was a utility with wind generation assets and was likely to incur some of the network upgrade costs associated with the wind generation then they would benefit from a reduction in these costs. However, if the storage developer and wind generation owner are separate entities, as assumed in this paper, it is unclear how this benefit would be compensated. It is proposed to examine portfolio ownership structures in more detail in future work.

The comprehensive 'All Island Grid Study' has shown that wind power up to 42% of wind power penetration can be accommodated without any need of storage in the Irish system (AIGS, 2008). Similar research was conducted by the U.S Department of Energy and has shown that wind power up to 20% of the penetration level can be achieved without any need of additional energy storage capacity (DOE, 2008).

In this paper, a merchant type storage unit was found to be unprofitable under the storage operational strategy of 'buy-low and sell-high' when wind and load forecasts are assumed to be perfect and the network has no congestion. In the presence of stochastic wind, load and congested network, storage units operated by the power system operators or located at the load centres (Ahler and Block, 2010; Sioshansi, 2010) may have higher values due to their system benefits or consumer savings. The authors intend to address this in future work.

3.7 Conclusion

In this research the Irish power system is studied for different 'wind and storage' scenarios and energy storage is treated as a dedicated storage for the wind and charged by the wind output only. When storage power rating and energy capacity are not large enough to shift the system peak load, combining wind and storage increases the operation of the base-load plants and decreases the mid-merit plants. This results in the increased level of CO_2 emissions from the power system. But, storage operation based on the *mid-merit* strategy (12 hours of charge/12 hours discharge) reduces the variability of the net load to the greatest extent. Moreover, the choice of operational strategy depends on the level of wind on the case study system. However, when economic viability is considered, without any supporting mechanism such as capacity payment and subsidy, the merchant type operation of storage is not economically attractive due to its high capital cost and low round trip efficiency. Finally, the CAES was found to be the most preferable technology compared to other three in terms of the capital cost.

3.8 Acknowledgement

The authors thank C. Feely and A. Garth Bryans for their valuable contributions to this work.

CHAPTER 4

Paper 2: The impact of electricity storage on wholesale electricity prices

THIS paper analyzes the impact of electricity storage on the production cost of a power system and the marginal cost of electricity (wholesale electricity price) using a unit commitment model. Also real world data has been analyzed to verify the effect of storage operation on the electricity price using econometric techniques. The unit commitment model found that the deployment of a storage system reduces the fuel cost of the power system but increases the average electricity price through its effect on the power system operation. However, the reduction in the production cost was found to be less than the increase in the consumer's cost of electricity resulting in a net increase in costs due to storage. Different storage and CO_2 price scenarios were investigated to study the sensitivity of these results. The regression analysis supports the unit commitment results and finds that the presence of storage increases average wholesale electricity prices for the case study system.

4.1 Introduction

The European Union has committed to reducing greenhouse gas emissions by increasing the share of renewable energy in the energy mix and increasing energy efficiency by 2020 (European Commission, 2006, 2007b). In meeting these commitments, wind energy has attracted more attention than other renewable energy sources (RES) (*i.e.* tidal, wave, geothermal etc.) as it is currently considered to be the most economical renewable generation type.

As the role of RES increases in the power system, changes to the power system operation are required such as greater reserve capacity from conventional power plants to deal with unanticipated reductions in renewable energy generation (Dany, 2001; Holttinen and Pedersen, 2003; Doherty *et al.*, 2005). In order to accommodate the variability and uncertainty of wind generation, thermal generators are often required to operate on a sub-optimal regime which can impose additional cycling on these units (Denny and O'Malley, 2007). Moreover, it requires increased network enforcement due to the wide and remote geographic dispersion of wind farms.

Therefore, the use of electricity storage systems, which store electric energy in terms of water in elevated reservoirs or compressed air in underground caverns etc., are attracting more attention in a bid to increase renewable energy penetrations (McDowall, 2006; Weis and Ilinc, 2008). Such systems are able to provide fast startups and rampings, thus allowing the power system to offset the impact of renewable energy generation (Brown and Lopes, 2008; Zeng *et al.*, 2006; Abbey and Joós, 2007; Li and Joós, 2007; Carton and Olabi, 2010). The integration of storage in weak networks with an intermittent energy source improves power quality and reduces the cost of electricity significantly (Kaldellis *et al.*, 2009). Korpaas *et al.* (2003a); Benitez *et al.* (2008) found that the deployment of storage reduces the need for generating capacity. Also, it may decrease the wind curtailment and shift off-peak wind power output to the peak hours. However, large scale storage units are site specific and capital intensive (Susan and Hassenzahl, 2003; EPRI, Palo Alto, 2003; EPRI, 2004).

It has been shown that optimally sized electricity storage could result in more economic operation of both wind farms and the storage itself by taking advantage of arbitrage, ancillary services, and transmission and balancing costs (Korpaas *et al.*, 2003b; Castronuovo and Lopes, 2004; Leou, 2008; Greenblatt *et al.*, 2007; Lund *et al.*, 2009; Kaldellis *et al.*, 2009; Zafirakis and Kaldellis, 2009; Sioshansi, 2011; Tuohy and O‘Malley, 2011). In addition, the distributed storage system has the potential to reduce the electricity cost of the household (Ahlert and Block, 2010). The hydrogen storage concept has been studied from an investment perspective and it was found that the use of hydrogen storage for electricity generation is uneconomical (Taljan *et al.*, 2008). Nyamdash and Denny (2010) found that electricity storage is not viable if it is considered only from the perspective of the developer for 2006 Irish power system since the peak and off-peak price differentials are insufficient to cover round-trip efficiency losses. Storage benefits depend on the location of the storage, whether it is close to the transmission line or the utility and also the type of the system (Nieuwenhout *et al.*, 2005). Sioshansi (2010) shows that storage utilization depends on whether it is operated by the individual power plant, consumer or operated as a standalone unit. Troy *et al.* (2010) looked at the large scale storage benefits from the power system perspective.

From the perspective of the power system, storage benefits would be significant when failure occurs in the power system. However, most of the storage benefits, such as reduction of the variability of renewable generation, deferring of transmission and distribution investments, and capacity investments are case-specific. Benefits relating to the supply of ancillary services are also market specific.

One way of looking at the storage system from the perspective of society, which has received relatively little attention, is to estimate the effect of storage on the electricity price. In a purely theoretical framework, the operation of storage is able to decouple the load from the generation, and reduce the electricity cost for consumer's (Crampes and Moreaux, 2010; Sioshansi *et al.*, 2009; Weissensteiner *et al.*, 2011). However, this is challenging to explicitly examine, as the electricity price often consists of various elements and the methodology is not uniform through different markets. But, implicitly if storage can affect the average wholesale price of electricity generated, it is likely to have a similar effect on the end-use electricity price. Since electricity storage uses the electricity produced by power plants, the operation of the storage unit affects the economic dispatch of thermal power plants; hence the wholesale electricity price. Thus, the effect of storage on the power system operation and the electricity price is unlikely to be specific to the storage technology adopted but it will depend on the case system.

This paper looks at large scale electricity storage, which is used to minimize the total cost of the power system, from a societal perspective. This is done by estimating the value of storage in terms of its effect on the wholesale electricity price for the case study system for various storage scenarios as well as estimating its effect on the total production cost of the power system. The WILMAR[1] (Wind Power Integration in Liberalized Electricity Markets) tool is used to model the unit commitment decisions. The impact of storage operation on the shadow price of electricity of the Irish Single Electricity Market is investigated econometrically.

The rest of the paper is organized as follows. Section 4.2 reviews the case system, scenarios, the unit commitment model and the econometric model. Section 4.3 shows the results, Section 4.4 presents the discussions and Section 4.5 concludes.

4.2 Methodology

4.2.1 Case study system and scenarios examined

The case study system is based on the 2009 Irish power system and the plant portfolio is adapted in the WILMAR tool to match the 2009 system. The thermal capacity

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[1] The WILMAR planning tool is a unit commitment model that is being widely used in power system analysis (National Laboratory for Sustainable Energy, 2010; AIGS, 2008; European Wind Integration Study, 2010; Tuohy *et al.*, 2009b).

consisted of coal, gas, oil and peat fired power plants. In total, 49 conventional power plants are modeled and they are summarized in Table 4.1. The renewable capacity consists of an aggregated hydro unit and an aggregated wind farm in such a way that there is only one combined hydro and one combined wind unit. Renewable electricity generation has a priority dispatch in the Irish system meaning that generations from RES are given precedence when dispatch decisions are made (CER, 2008). The largest conventional unit modeled has a maximum power capacity of 480MW (SEMO, 2011). A simplified Great Britain power system with aggregated power plants is also assumed when modeling interconnector flows. Extended description of the case study system was given in Chapter 2

Table 4.1: Installed capacity (MW) and fuel price (€/GJ) by fuel type in Ireland

Type	Number of units	Total capacity (MW)	Fuel Price		
			RoI[1]	*NI*[2]	*GB*[3]
Peat (baseload)	3	343	3.71		
Coal (baseload)	5	1324	1.75	2.11	1.75
Base-load gas	16	4123	7.06	7.06	4.16
Mid-merit gas	4	508	7.26	7.27	6.9
Oil (peaking)	21	1962	9.64	8.33	9.64
Hydro		216	0	0	0
Wind		1054	0	0	0

[1]Republic of Ireland. [2]Northern Ireland. [3]Great Britain

The base-case scenario for the analysis is ‘no-storage. This scenario assumes 0MW of installed storage capacity. Storage scenarios with 200MW, 400MW, 600MW and 800MW of installed capacities with an energy capacity of 5 hours are compared against the base-case scenario, in all cases replacing the existing pumped hydro system. The plant mix is not assumed to be affected by the addition of the storage unit to the power system (*i.e.* new storage units do not displace any thermal unit) as the storage unit is energy limited and is not the perfect substitute for conventional power plants (Walawalkar *et al.*, 2007; Tuohy and O‘Malley, 2011).

The assumed fuel prices are shown in Table 4.1. Fuel prices are assumed to remain constant throughout the year. A carbon price of €30/ton was assumed.

4.2.2 Unit commitment model

The WILMAR Planning Tool, which is a dynamic partial equilibrium model of the electricity sector, finds the economic dispatch of generating units over the optimization period based on the demand and wind forecasts. It takes into account power plant constraints, such as minimum downtime (the minimum time a unit must remain offline following shutdown), synchronization times (time taken to come online), minimum operating time (the minimum time a unit must spend online once synchronized), heat rate (efficiency of the generator) and ramp rates. The model has an hourly resolution, with planning being done for the next 36 hours on a rolling basis. The deterministic version of this tool, which assumes the perfect wind forecast, was used in this paper. Definition of the objective function and further details are given by Tuohy *et al.* (2009a); Troy *et al.* (2010); Meibom *et al.* (2007). The electricity price is determined by the marginal cost of an extra one MWh of electricity produced by the power system.

Storage is assumed to provide reserves (primary and secondary) to the power system. In the model, the storage unit is represented by a reservoir, with the inefficiencies associated with pumping and generating accounted for when filling the reservoir. The round-trip efficiency assumed (KWh produced divided by KWh stored) is 75%. When pumping, electricity used to pump is added to the system demand, and the amount being pumped is subtracted from primary and replacement reserve targets, as pumping can be stopped to reduce demand on the system. When generating, it is treated as any conventional unit. Both pumping and generating are subject to ramping and minimum and maximum capacity constraints, as any other unit. However, a pumped storage unit usually has a very high ramping rate, which when examined on an hourly resolution means that storage can go from full pumping capacity to full generating capacity in less than 1 hour. All units are assumed to serve one reservoir in order to avoid a situation where generation and pumping occurs at the same time for different units[2]. To ensure there is energy in the storage system at the end of the day, the minimum storage content level is accounted for.

Here we assume that the storage system is pumped hydro, however the same approach could be used to assess other types of storage units, such as battery, by simply using different round-trip efficiencies. No scheduled and forced outages are considered for generating units.

The Generic Algebraic Modeling System (GAMS) was used to solve the unit commitment problem using the mixed integer feature of the Cplex solver. For all the simulations in this study, the model is run with a duality gap of 0.01%.

While the WILMAR tool is not a perfect model of the actual market design (gross pool) of Ireland's electricity system, it is an appropriate proxy for the dispatch decisions within the marketplace.

4.2.3 Econometric estimations

End-use electricity prices do not tend to respond to power system shocks in the short run because end-use prices are usually based on the long run marginal cost of electricity production. However, wholesale prices would respond to any structural changes in the power system, which would in time feed into end-user prices (Friedman, 2009). Thus, examining the effect of storage on the wholesale electricity price would show the value of storage from the societal perspective.

In an attempt to explore the impact of storage on the wholesale electricity price econometrically, the actual storage output level for the year 2009 was investigated. Since storage output levels are scheduled based on the demand level, electricity generations from the RES and the power system operation, it was not possible to include it in the regression as an explanatory variable as it would result in perfect multicollinearity. Therefore, a proxy for storage operation that is not correlated with demand and wind level is required. The pumped hydro storage units in the Irish

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[2] This constraint is used as the most common setup for the pumped hydro electricity storage with a reversible turbine/generator.

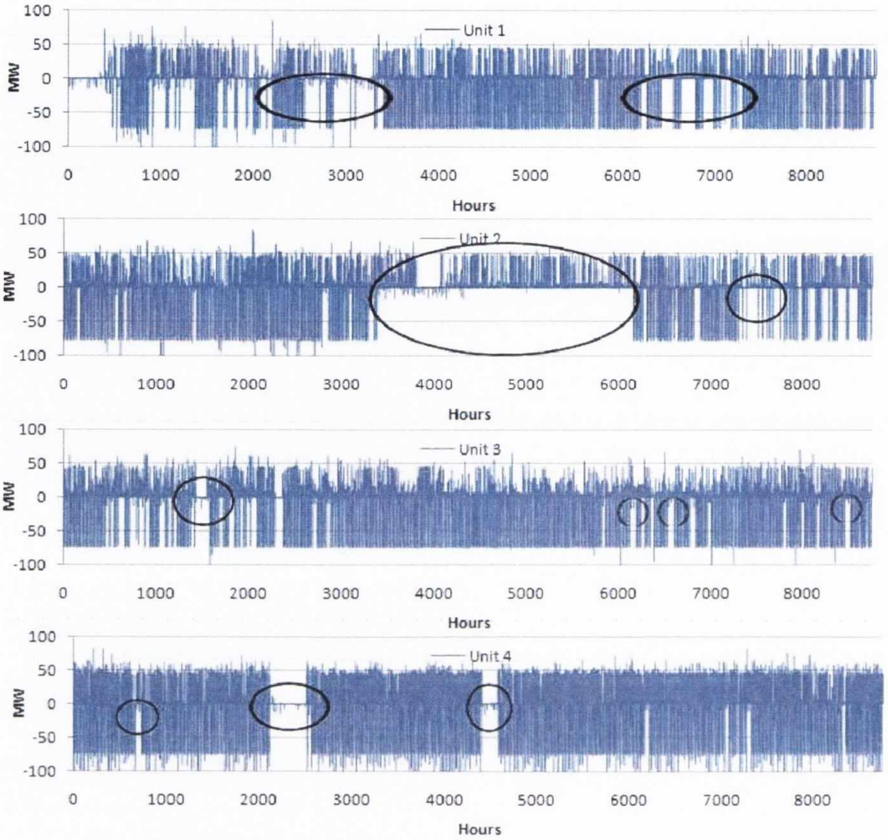

Figure 4.1: Hourly generation profiles of Turlough Hill pumped hydro storage units.

system were subject to number of scheduled outages in 2009 (EirGrid, 2009b,a,c,d). Figure 4.1 shows the actual storage generation profile for each unit of storage system. It shows that the storage units were subject to a number of scheduled[3] and unscheduled outages (examples are marked by circles). The dispatch order of the conventional plants will be different when storage is available and the wholesale electricity price will thus change depending on storage availability when everything else is held constant *i.e.* demand level, wind speed, fuel and carbon prices.

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[3] Power plants are periodically taken off the power system for several days to several weeks for the maintenance.

The following regression model is estimated to examine the effect of storage interruption on the shadow price of electricity:

$$SMP_t = \alpha + \beta_1 D_t^{pump} + \beta_2 D_t^{generation} + \gamma_1 X_t + \gamma_2 X_t^2 + \gamma_3 P_{t-24}^e + \omega_t + e_t \quad (4.1)$$

where D_t^{pump} is a dummy for a interruption in storage pumping, $D_t^{generation}$ is a dummy for a interruption in storage generation, $X_t = (Demand_t,\ Wind_t)$ are demand and wind profiles, $P_t^e = (P_t^{oil}, P_t^{gas}, P_t^{coal}, P_t^{carbon})$ is oil, gas, coal and carbon prices, ω_t is the unobserved heterogeneity, and e_t is the error term.

4.3 Results

4.3.1 WILMAR results: Storage operation

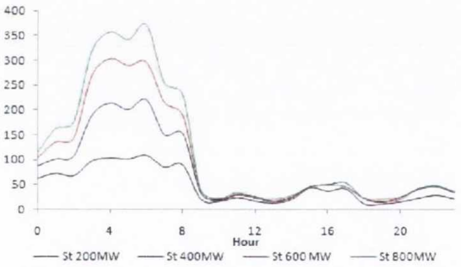


Figure 4.2: Hourly average charge profile of storage units.

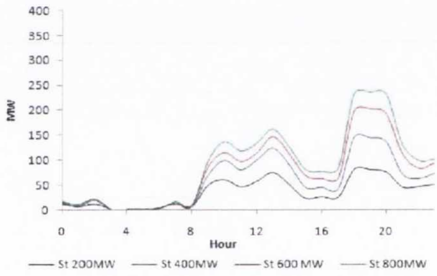


Figure 4.3: Hourly average generation profile of storage units.

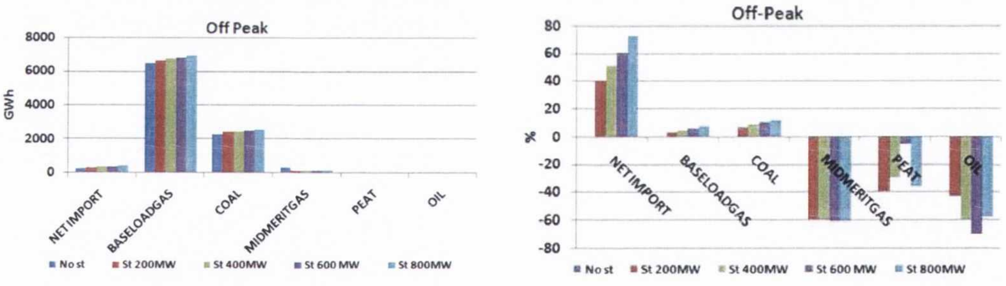
Figure 4.2 shows the hourly storage pumping profiles for different levels of storage capacity. It is shown that the storage was used to pump the water using surplus electricity of the power system throughout the night and day. The utilization rate was found to be considerably higher during the night than during the day. It was also found to increase as the available storage capacity increases while the utilization rate during the day does not change. This demonstrates that the storage is charged mostly by the off-peak generations of conventional power plants.

In terms of the storage generation profiles (Figure 4.3), it was found that storage would only generate during the day and the total amount of generation was found to increase as the storage capacity increased.

4.3.2 Simulation results: Effect of storage on power system operation

If the dispatch decisions relating to the conventional power plants change depending on the availability of the storage capacity, the wholesale price set by those plants would be different depending on the availability of the storage unit. Therefore, the generation output from those plants during the night and during the day need to be looked at separately.

Theoretically, the deployment of storage should increase the generations of conventional power plants at night and decrease during the day. Although, when technical constraints of the power system are taken into account, the effect of storage may not be as expected.



(a) Total annual generation outputs

(b) Change in total annual generation with respect to the base-case scenario.

Figure 4.4: Annual generations of conventional power plants and Irish import and export at off-peak hours.

Figures 4.4 demonstrates the effect of storage capacity on the outputs of conventional power plants and the power flow through the interconnector during the night[4]. It shows that as storage capacity increased, total annual generation of baseload gas

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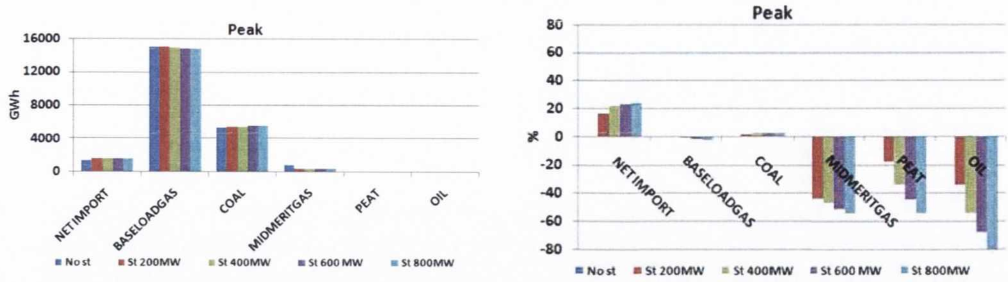
[4] Night time is defined as the hours between 11.00PM and 7.00AM inclusive.



(a) Total annual generation outputs

(b) Change in total annual generations with respect to the base-case scenario.

Figure 4.5: Annual generations of conventional power plants and Irish import and export at peak hours.

and coal plants increased by 2.8%-7.4% and 6.4%-11% respectively. The total net import level found to increase by 40%-72% compared to the base-case scenario. These increases in output are used to charge the storage units. During the night, the utilization of midmerit gas plants were found to be decreased by 60% with the addition of storage over the base-case. This is due to discrete constraints in the unit commitment model. Since the storage unit reduces the demand at the peak hours, these units will not be needed later in the day, so are not switched on at night. In the absence of storage, the start-up time for these units requires them to be kept online over night. Similarly, a significant proportion of the generation of oil plants were found to be displaced. Total generations of peat plants were found to be reduced by approximately 40% initially as a result of storage deployment and increased as an additional storage capacity (200MW and 400MW) became available.

Figure 4.5 demonstrates the utilization of conventional units and the interconnector during the day[5]. It shows that the total annual generation of baseload gas and coal plants were affected marginally while the total annual generation of midmerit gas plants fell by 43% when storage became available. This is due to the reduced net load at peak hours with increasing penetrations of storage. Moreover, when storage capacity increases up to 400MW, 600MW and 800MW, the generation of midmerit

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[5] Day time is defined as the hours between 8.00AM and 10.00PM inclusive.

gas plants were found to be reduced by a further 4% respectively. A similar effect persisted for the peat and oil fueled plants and their total annual generations were found to have fallen by 17%-54% and 37%-79% respectively. Also, the cumulated annual net import level found to have increased by 16%-24% due to the storage.

Therefore, the effect of storage capacity on power system operation was found to be as expected with few exceptions. It was found to increase the generations of baseload gas, coal, peat plants and import levels during the night. Due to the fact that the storage system is able to provide reserves (primary, secondary and replacement), the need for midmerit gas, oil and peat plants online is reduced. Hence, the generation of midmerit gas, oil and peat plants was reduced during the night with the introduction of storage. This is in line with Troy *et al.* (2010). Also, during the day, generation of coal plant was found to be increased because it was no longer required to hold spare capacity for the replacement reserve which was instead facilitated by storage units. With storage providing reserves and energy, the power system is able to maintain the security of supply.

4.3.3 Simulation results: The effect of storage on the simulated shadow price of electricity and the production cost

Since the economic dispatch decisions relating to the conventional power plants are affected due to the presence of storage, the corresponding fuel cost of the power system and the electricity price that has been set in the marketplace are likely to be affected. Therefore, it is necessary to study the effect of storage on the total dispatch cost of the power system and the electricity price in order to explore the net cost or the benefit to the system. This approach would show the value of storage from the societal perspective.

4.3.3.1 Production cost

The results given in the previous subsection demonstrated that the generation output of the conventional plants are affected as storage capacity increases. Figure 4.6 shows the effects that the changes in the output of conventional power plants have on the total costs of the power system. As midmerit gas plants were found to be displaced (Figure 4.4) when storage was included initially, the load weighted average cost (LWAC) of electricity was found to decrease from approximately €34/MWh to €33/MWh at night. However, as storage capacity increases above 200MW, the production cost increases slightly as generations of conventional power plants increase due to the additional night-time demand from charging the storage units.

But, during the day, *i.e.* when storage is generating, the LWAC was found to reduce from €38/MWh to €35/MWh as storage capacity increased from 0MW to 800MW.

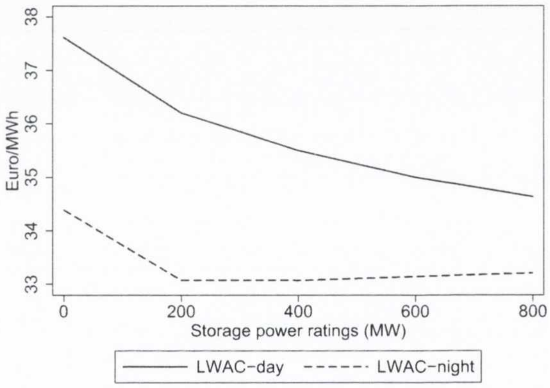

Figure 4.6: Load Weighed Average Cost per MWh.

When night and day electricity generations are combined, the total cost of the power system was found to reduce as the slight increase in the cost at off-peak hour is not higher than the reduction in the cost during peak hours. This is in line with the existing literature.

4.3.3.2 System marginal price

Given the way in which the WILMAR tool sets the price, the reduction of the electricity cost due to the storage deployment would not necessarily reduce the electricity price. This is because the WILMAR tool allocates the generation schedules for the power plants based on the economic dispatch, and sets the price of electricity equal to the marginal cost of the intraday balance equation (Tuohy *et al.*, 2009a). The marginal cost can be approximated according to how the generation of midmerit gas plants are affected as it is most likely that these plants would be the marginal power plants, *i.e.* would be dispatched to meet the change in electricity demand.

Therefore, the effect of storage on the wholesale price can be proxied by how storage affects the midmerit gas plants (marginal plants). Table 4.2 shows the number of hours midmerit gas plants were online throughout the year simulated, and fixed and variable fuel consumptions. Unit 1 has the lowest fixed cost while the Units 2 and 3 are next expensive units. If midmerit gas plants are categorized by their ability to ramp and start up (from hot, warm and cold states) according to Tuohy and O‘Malley (2011), Unit 1 is considered to be flexible while Units 2 and 3 are considered to be relatively inflexible. Since, storage is able to provide more economic reserves and capacity, Unit 3, which has the highest fixed cost, was found to be displaced completely by the storage units. Also, it can be seen that the generation of Unit 1 was displaced as the storage capacity increased. The number of online hours of Unit 2 were found to be increased slightly as Units 1 and 3 were displaced. Therefore the electricity prices are set by Unit 2 more often as storage capacity increases as it would, most likely, be the marginal plant. As shown by variable fuel consumption, once online, Unit 2 is the most expensive of the three units.

Figure 4.7 shows how storage impacts the load weighed average price (LWAP) as a result of its effect on the dispatch of the marginal plants (midmerit gas plants). When no storage was considered, LWAP was found to have been approximately

Table 4.2: Online number of hours, fixed fuel consumption and variable fuel consumption of midmerit gas plants.

Storage power ratings	Unit 1	Unit 2	Unit 3
0MW	2422	8376	5390
200MW	2037	8412	0
400MW	1710	8412	0
600MW	1402	8412	0
800MW	1235	8412	0
Fixed fuel consumption (GJ/h)	88.335	249.8	351.77
Variable fuel consumption (GJ/MWh)	6.003	6.516	6.074

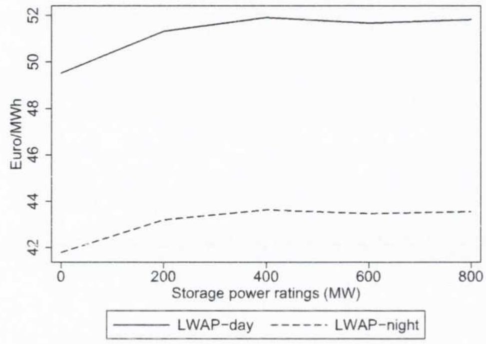

Figure 4.7: Load Weighed Average Price per MWh.

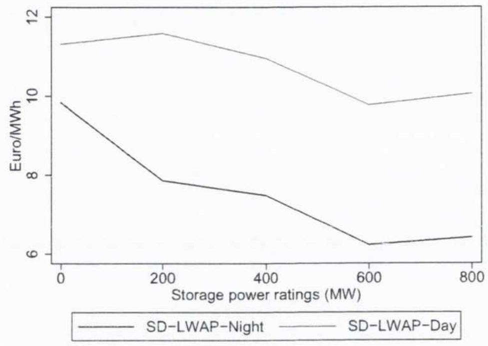

Figure 4.8: Standard deviation of hourly electricity price.

€41.7/MWh at night and €49.5/MWh during the day. As expected, the LWAP was found to increase at night as storage units are added.

As is shown in Table 4.7, because the number of online hours of the flexible midmerit unit was reduced (Unit 1 and 3) due to the deployment of storage and resulted in the inflexible midmerit gas plant (Unit 2) being the marginal plant more often, higher prices are seen more often. Therefore, as storage capacity increases, electricity price was found to be increasing during the day as opposed to decreasing, according to the expectation.

4.3.3.3 The volatility of the system marginal price

According to how the WILMAR tool sets the electricity price, price volatility depends on whether fuel shifting or marginal plant changes occur more frequently as storage units are deployed. Since the participation of the flexible midmerit gas plant (Unit 1) was found to be reduced significantly, the electricity price is most likely to be set by the more inflexible and more expensive midmerit gas plant (Unit 2). Therefore, the deployment of storage units was found to stabilize the hourly electricity price even though electricity prices are set at higher level. This is shown through the reduction in the standard deviation of the electricity price from €10 to €6 at night and from €11 to €10 during the day (Figure 4.8).

4.3.3.4 Comparison of the savings in the consumer cost and the reduction in the production cost

In the case study system, the total generation of baseload units was found to be increased while the total generations of peaking and midmerit plants were reduced due to the deployment of electricity storage units. The total production cost was found to decrease, while equilibrium electricity price (LWAP) was found to increase due to storage. Therefore, total consumer and production costs are compared. The total consumer cost can be approximated by how much electricity supply companies pay in order to buy electricity from the marketplace since the end-use price is unknown.

$$ConsumerCost = \sum_{t=1}^{T} WholesalePrice_t * Demand_t \tag{4.2}$$

where $WholesalePrice_t$ is the system marginal price at hour t and T is the total number of hours in a simulation.

Figure 4.9 shows the changes in production costs and consumers costs approximated by (5.2) due to storage deployment with respect to the base-case scenario. In terms of the production cost, a reduction of €4 million was achieved per annum when 200MW storage became available and this reduction was found to increase by €0.5 million as the installed storage capacity was increased by 200MW up to 800MW. The total reduction in the production cost was reached approximately €6

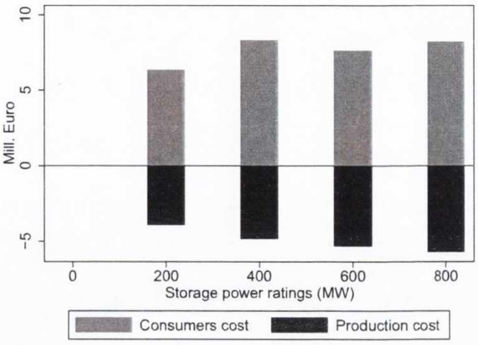

Figure 4.9: Storage values from the societal and power system perspectives.

million per annum at 800MW. The consumer cost, on the other hand, was found to increase by approximately by €6 million per annum due to the deployment of storage initially. When storage capacity of 400MW was considered, the consumers cost was found to have been increased by a further €2 million while further additions of 200MW did not affect this significantly.

4.3.3.5 Sensitivity analysis

In previous results it is assumed that the storage units can provide the power system with reserve capacity.

Figure 4.10 compares storage effects on the LWAC and LWAP when the storage unit provide reserve with when it does not provide the reserve.

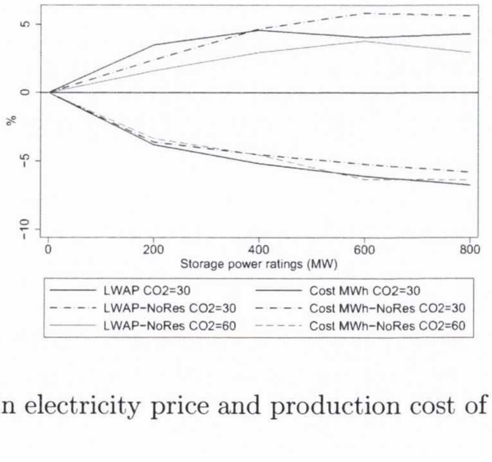

Figure 4.10: Change in electricity price and production cost of 1MWh of electricity.

When storage was assumed not to provide the reserve, initially its effect on the LWAP was found to be slightly smaller than the effect of the storage that provides reserve. As its installed capacity increases to 600MW and 800MW, the increase in LWAP was found to be higher than the case with conventional storage. This shows that when the effect of the reserve provided by the storage was excluded, the electricity price is still affected by the deployment of storage. From a fuel cost perspective, reductions in the cost of 1MWh of electricity were similar for all storage scenarios.

Also a CO_2 price of €60/tonne was considered as a sensitivity for the above analysis. The effect of storage on the LWAP for the higher CO_2 price scenario was found to be significantly less pronounced than was the case with the lower CO_2 price scenario. Moreover, the effect of deploying storage units on the LWAC is also shown to be slightly less pronounced when a higher carbon price was considered.

4.3.4 Econometric estimation

4.3.4.1 Data

Half-hourly ex-post wholesale prices, generation of pumped hydro units, conventional power plants, wind farms and power flows through the inteconnectors in the Irish Single Electricity Market (SEM) during 2009 (SEMO, 2011) are used in this paper to identify the effects of pumped hydro storage operations on the actual wholesale electricity price in Ireland.

The existing pumped hydro unit in the SEM consist of 4 units with 73MW of installed capacity each and approximately 4 hours of energy capacity. In the SEM, unit commitment is scheduled every half hour, hence storage operation could change from pump mode to generation mode within an hour. The ex-post hourly electricity price is based on the market scheduling software run that is carried out four days after the delivery date and as such is able to utilize full sets of actual wind and load data with no forecast values (SEMO, 2011).

Since the SEM-O database contains only the system load which is the demand net of the wind output, the half-hourly demand profile is constructed from the generation, import and storage charging profiles:

$$d_t = \sum_{i}^{m} q_t^i - q_t^{st-pump} + q_t^{im} \tag{4.3}$$

where m is the total number of power plants, d_t is the demand, q_t^i is the metered generation of power plant i at hour t, $q_t^{st-pump}$ is storage pumping and q_t^{im} is the import from GB.

The daily spot prices[6] per barrel of oil, and tonne of gas, coal and carbon for 2009 were obtained from various global exchanges which were then converted into euro based on the daily exchange rates for the year.

Table 4.3: Summary statistics

Variable	Obs	Mean	Std. Dev.	Min	Max
$WholesalePrice_t$ (€/MWh)	12456	37.136	16.204	14.44	350.43
$Demand_t$ (MW)	12456	4186.668	971.2286	2082.409	6502.824
$Wind_t$ (MWh)	12456	159.7251	122.1177	.224	529.085
P_{coal} (€/bbl)	12456	36.89039	5.120261	31.2549	51.40111
P_{gas} (€/t)	12372	36.79153	11.45994	25.27127	69.61626
P_{oil} (€/t)	12372	44.50905	6.700267	31.79472	54.31594
P_{carbon} (€/t)	12372	13.33226	1.529554	8.2	15.8

The summary statistics of the data employed is shown in Table 4.3. Half hourly $WholesalePrice_t$ ranged from €14.44-€350.43 while the estimated demand was found to range from 2082MW-6502MW[7].

In the SEM, pumped hydro units are utilized daily by the market to balance the electricity demand and electricity supply. Therefore, based on Figure 4.1, the storage unit is assumed to be interrupted if the total amount of electricity used to pump water or the electricity generated by the storage unit is less than 10MWh during one day. Dummy variables for storage interruptions D_t^{pump} and $D_t^{generate}$ are

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[6] Oil price is according to the UK Brent Crude Index (\$/bbl). Gas price is according to UK National Balancing Point price (£/t). Coal price is according to the Coal Newcastle Index (\$/t). Carbon price is according to ECX exchange price (€/t).

[7] The difference between the demand profile assumed in this section and Section 4.2 is attributed to the difference between half-hourly and hourly profiles.

estimated so that it takes the value of 1 if the storage unit is interrupted over the hours when pumping is most likely to occur (off-peak hours) and generation is most likely to occur (peak hours) respectively, or 0 if the storage unit is uninterrupted. The total number of interruptions are summarized by each storage unit in Table 4.4.

Table 4.4: Number of estimated interruptions[1] for Turlough Hill storage units in 2009.

	Unit 1	Unit 2	Unit 3	Unit 4
D_t^{pump}	1195	1872	631	343
$D_t^{generation}$	720	432	180	450

[1] Based on the half-hourly storage output profiles.

In this study, multiple time series regressions, specified by (4.1), are estimated to investigate the effect of interruptions in storage operations on the wholesale price. Electricity demand and the availability of wind for generation exhibits seasonality therefore, controls are included for each hour of the day, day of the week and months to control for the unobserved heterogeneity.

4.3.4.2 Actual effect of storage on the wholesale price

Table 4.5 presents the results of regressions that investigate the effects of interruptions in storage operations while controlling for the main drivers of SMP such as demand, wind and the fuel spot prices of the previous day. While the power plants are required to bid continuously for 24 hours a day and 7 days a week, exchanges are closed over the weekend. Thus, weekend observations are excluded from the regressions. The log of the wholesale price has been used as a dependent variable instead of the actual wholesale price. When autocorrelation and partial autocorrelation functions of the log of the wholesale price are examined, the *AR(2)* model was found to fit the data well, hence two lags of autoregressive and no moving average parts are included.

Regressions 1-4 in Table 4.5 explore the impact of interruptions in each storage unit on the log of the wholesale electricity price of electricity. The demand was found to have a positive effect on the wholesale electricity price as if demand increases a

Table 4.5: Effect of storage interruptions on the SMP

	(1)	(2)	(3)	(4)
VARIABLES	Unit 1	Unit 2	Unit 3	Unit 4
$D_t^{generation}$	-0.0201***	-0.00172	-0.0250***	-0.0170***
	(0.00483)	(0.00805)	(0.00889)	(0.00508)
$D_t^{pumping}$	0.00846***	-0.0326***	0.00767**	0.00332
	(0.00273)	(0.00328)	(0.00340)	(0.00438)
$Demand_t$	0.000125***	0.000102***	0.000128***	0.000132***
	(1.84e-05)	(1.88e-05)	(1.85e-05)	(1.83e-05)
$Wind_t$	-6.65e-05**	-8.69e-05***	-6.19e-05**	-6.40e-05**
	(3.08e-05)	(3.10e-05)	(3.09e-05)	(3.09e-05)
P_{coal}	-0.00281***	-0.00216**	-0.00231**	-0.00282**
	(0.00106)	(0.00104)	(0.00105)	(0.00111)
P_{gas}	0.00637***	0.00646***	0.00637***	0.00649***
	(0.000706)	(0.000704)	(0.000706)	(0.000735)
P_{oil}	0.00319***	0.00361***	0.00314***	0.00301***
	(0.000627)	(0.000638)	(0.000625)	(0.000633)
P_{carbon}	0.000392	0.000926	-0.000721	-0.00109
	(0.00148)	(0.00152)	(0.00151)	(0.00157)
Constant	0.726***	0.744***	0.703***	0.722***
	(0.0727)	(0.0722)	(0.0722)	(0.0745)
Obs	12372	12372	12372	12372
R^2	0.886	0.886	0.886	0.886
Auxiliary regression[1]				
e_{t-1}	0.1096	0.1051	0.1118	0.1034
	(1.454)	(1.395)	(1.483)	(1.374)

Robust standard errors in parentheses. *** $p<0.01$, ** $p<0.05$, * $p<0.1$

$Demand_t^2$ and $Wind_t^2$ are included. [1] Auxiliary regressions with robust standard error.

unit with higher fuel cost has to be dispatched in order to meet the demand, causing an increase in price. The effect of an increase in wind output was found to have a significant negative and nonlinear effect on the wholesale electricity price, as it would be displacing the outputs of several thermal units. The gas and oil prices found to have significant positive effects on the wholesale electricity price; this is most likely due to the fact that 64.3% of Ireland's installed capacity uses natural gas and oil (IAE, 2011). But the coal price was found to have a negative and significant effect. Carbon price was found to have an insignificant positive effect on the wholesale price of electricity. Coefficients of these control variables were found to be stable across different regressions and in line with O'Mahony and Denny (2011). Considerably high R^2 with significant explanatory variables implies that the model fits the data and is a good predictor of the wholesale electricity price.

The effects of interruptions in storage generation were found to have significant negative effects on the wholesale electricity price (except Unit 2). This is unexpected based on the theory but in line with results from the unit commitment simulations in previous sections. This is due to the fact that storage units contribute to the flexibility of the power system by providing ancillary services. When its ability to provide ancillary services are reduced, another thermal plant is likely to be dispatched in order to maintain the security of the system. Thermal units usually have minimum output levels, and the dispatch of the new thermal unit is likely to reduce the generation of the marginal unit; hence the price set by the marginal plant is affected.

When there is an interruption in the pumping of Unit 4, it is found to have an insignificant effect on the wholesale electricity price, while an interruption in Unit 2 was found have a negative and significant effect on the wholesale price of electricity. Interruptions in Unit 1 and Unit 3 were found to have significant positive effects.

The robustness of the results presented in Regressions 1-4 of Table 4.5 are checked in Table 4.6. Regression 5 includes dummy variables that take the value of 1 if there is at least one storage unit interrupted, and it is estimated for the storage pumping and generation. Interruption in storage pumping was found to have a significant negative effect while the interruption in storage generation mode was found to have a negative significant effect.

Since the existing Turlough Hill pumped hydro units are identical, the dispatch of a single unit may not have a major impact on the power system, as long as the total output level of the storage system is not impacted. When one of the four units is interrupted, the remaining storage capacity would be able to cope with the system requirements. When more than one unit is interrupted, the capacity remaining may not be able to provide the same service as the full storage capacity would provide. Therefore, the number of interrupted units at the same time has been included in

Table 4.6: Robustness test

	(5) Interruptions	(6) Number of interrupted units
$St_t^{generation}$	-0.0182***	-0.0170***
	(0.00353)	(0.00323)
St_t^{pump}	-0.0170***	-0..0141***
	(0.00311)	(0.00258)
Obs	12372	12372
R^2	0.886	0.886
Auxiliary regression		
e_{t-1}	0.1163	0.1181
	(1.54)	(1.57)

Robust standard errors in parentheses
*** p<0.01, ** p<0.05, * p<0.1

the regression instead of the dummy variable for the interruption in a single unit (Regression 6). It was found that 2 units at most were interrupted at the same time for both storage pumping and generation. The number of interrupted units for storage pump mode has been found to have a significant negative effect on the wholesale electricity price. For generation, the number of interrupted units has been also found to have a significant negative effect on the wholesale electricity price. This supports the effect of storage generation on the log of wholesale electricity price which was found in Table 4.5.

Based on the auxiliary regression with robust standard errors, serial correlation was not found to be present in Regressions 1-6. Since resulting test statistics are asymptotically appropriate, whether or not the errors have a constant variance, the regression results are considered to be accurate.

4.4 Discussion

In the Irish system, the actual price paid by electricity suppliers consists of two elements. The marginal price (as represented by the wholesale price in previous sections) and also an 'uplift' payment. This uplift payment compensates generator for start up costs. Table 4.2 shows the total number of online hours of the midmerit plants and, as storage capacity increases, the number of online hours of midmerit plants were found to have been reduced significantly. Thus, if associated startup/shutdown costs are reduced, the uplift payment should be reduced and the net price should be reduced as a result. Therefore, the increase in the marginal price of electricity (Figure 4.10) due to storage operation may be offset by the reduction in uplift payments and fuel cost savings. However, this is beyond the scope of this paper. Also, as was shown in Figure 4.8, the supply company's risk of buying electricity from the marketplace at high prices at peak hours is reduced; hence supply companies may reduce retail prices to consumers.

When a high carbon cost scenario was considered, the effect of storage on the electricity price became less pronounced. In the scenario with even higher carbon prices, less efficient power plants would become uneconomic based on their carbon costs and would be displaced by renewable generation or more efficient plants with low operational costs. In such cases, the deployment of storage units would benefit the system by utilizing efficient units more and displacing the remaining inefficient high-cost plants at peak hours. This would achieve considerable fuel savings as well as potential price reductions.

In terms of the effect of utilizing storage units to store excess electricity, econometric estimations presented in Table 4.5 do not fully support simulation results presented in Figure 4.7 fully. This could be attributed to the fact that the power plant characteristics may not be exactly the same in the WILMAR tool and in the SEM. Another drawback of the simulation result is that it does not reflect the market exactly when it is setting the electricity price. However, it provides a good proxy for the benefits of storage. In future work, differentiated incremental heat rate slopes, which should be increasing with the level of outputs, should be considered in order to reflect better price and quantity pairs used in the SEM.

4.5 Conclusion

This paper investigated the impact of deploying storage units on the electricity price through its effect on the power system operations. It was found that the utilization of the storage system increases the generation of baseload plants and the net import level at off-peak hours, and displaces the generation of oil and midmerit gas plants at peak hours. Hence, a considerable reduction in production costs was achieved.

However, the simulated electricity price was found to increase as a result of deploying storage units because of its effect on the marginal plants. It was found that the savings in the fuel cost achieved was not able to justify the increased cost of electricity to consumers. In the real world, storage generation was found to result in a higher wholesale electricity price. This partially supports the simulation results.

If all indirect storage effects (such as the effect on the uplift payment and reduction in price volatility) are considered, the increased consumer costs may be justified. Finally, at a high carbon price scenario, the effect of storage on the electricity price was found to be less pronounced.

CHAPTER 5

Paper 3: The economic impact of electricity conservation policies: A case study of Ireland

AS electricity is an key input in almost every production process, it is essential to quantify the impact of economic policies aimed at electricity conservation on output. This research investigates the effect of unanticipated shocks in electricity consumption, technical efficiency, and electricity price on the value added in the service and industrial sectors, under a demand side model. Ireland is utilized as a case study as it is pursuing ambitious electricity conservation targets while in the midst of a severe economic recession. Given the important role of electricity as an input in both the services and industrial sectors, it was feared that these energy conservation targets may adversely impact on these sectors and as a result worsen the national economic situation. Findings show that value added, electricity consumption, electricity price and technical efficiency are co-integrated for both the service and industrial sectors. However, impulse response functions show that positive technical efficiency and consumption shocks have persistent negative effects on the value added of both sectors. Therefore, a direct electricity conservation policy, that puts a constraint on electricity consumption, should not have an adverse effect on sector specific value added.

5.1 Introduction

In recent decades, policy makers have been implementing ambitious policies to tackle climate change. At a global level, the Kyoto protocol sets binding emissions targets for participating countries amounting to an average of 5% against 1990 levels over the five-year period 2008-2012 (United Nations, 1998). The European Union (EU) has commitments to reduce greenhouse gas emissions to 20% below the 1990 level by 2020 (European Commission, 2007b), to increase the share of renewable energy in the energy mix to 20% by 2020 (European Commission, 2007c) and to increase energy efficiency by 20% by 2020 (European Commission, 2006). In other words, energy conservation has become a cornerstone for tackling global climate change.

Energy demand has steadily increased with the growth in world population and the increase in global output and as such, the design of targets to conserve energy, without affecting output have proved challenging (Kaufmann, 1992). Energy is an essential part of the production process and hence economic activity (Stern, 1997; Chian-Lee and Chang, 2007; Sorrell, 2009; Marinescu *et al.*, 2007). Therefore, it raises the question of whether energy conservation policies could be implemented successfully at an individual country level without distorting output and international competitiveness.

This paper examines a case study of the impact of electricity conservation in Ireland. In the last two decades, Ireland experienced rapid economic growth and transformed from an agricultural to a service oriented economy. However, since 2007 Ireland has seen a dramatic reversal of fortunes fueled by the international banking crisis, a property crash and inflated public sector expenditure (Whelan, 2009). At the end of 2010, Ireland's sovereign bond spreads were the highest in Europe and resulted in a high profile rescue package from the European Union and the International Monetary Fund (Department of Finance, 2010b). Despite its economic challenges, Ireland remains committed to meeting its energy related obligations, in particular in the electricity sector (as it is relatively easier to achieve savings here rather than in the transport and heat sectors) (Department of Finance, 2010a,c). This paper investigates the relationship between electricity consumption, electricity price, technical efficiency and value added of service and industrial sectors in Ireland in order to ascertain if pursuing electricity conservation policies is likely to impact positively, negatively or neutrally on Ireland's current economic situation.

In 2008, the electricity sector was responsible for the 32% of total CO_2 emissions in Ireland (IEA, 2010a). Based on EU targets, Ireland has set an ambitious target of achieving 40% of electricity generation from renewable energy sources by 2020 (European Commission, 2006, 2007b,c; DCENR, 2009). In addition to the promotion of renewable energy, the Irish Government are also pursuing measures to boost energy-efficient behaviour (Diffney *et al.*, 2009) and a nationwide roll-out of smart meters with time of use electricity consumption and price information (CER, 2009). It has been shown that targets aimed at energy efficiency, which is an indirect energy conservation policy, can result in a rebound effect (Grepperud and Rasmussen, 2004; Barker *et al.*, 2009; Broadstock *et al.*, 2007) which increases energy demand at later date. On the other hand, direct conservation policy, such as placing a constraint on energy consumption, may reduce the growth of energy demand and as a result reduce growth in the economy, in particular if the economy is energy intensive.

A large body of research has looked at the relationship between energy consumption and economic activity to study the impact of climate policies, *i.e.* energy conservation policy, for various countries. However, inconclusive results were produced due to the varying energy intensities of heterogenous production sectors in the different countries (Mishra *et al.*, 2009; Soytas and Sari, 2007).

While previous studies have examined the relationship between aggregate energy consumption and aggregate output, in order to contribute to the research, this paper studies the impacts of different electricity conservation policies on the economic performance of the Irish economy at a disaggregate level, *i.e.* industrial and service sectors[1]. Following the methodology in Stern (2004) and Hall *et al.* (2001), we employ a demand side time series model and examine the effects of unanticipated shocks in technical efficiency, electricity consumption and electricity price on the value added of both sectors and *vice versa*.

The structure of the paper is as follows: Section 5.2 reviews the existing literature, Section 5.3 describes the econometric methodology employed, Section 5.4 shows the empirical results, Section 5.5 gives a brief discussion and Section 6.3 concludes.

5.2 Literature review

The main body of research in this area has employed time series econometrics models to investigate the direction of Granger causality between energy consumption and economic activity (Table 5.1). In general, forecasts of energy consumption were improved when output was taken into account (multi-country cases). In other words, energy consumption was Granger caused by economic output, hence energy conservation policy would not affect economic output. But, this result does not hold at a country or at a disaggregate levels. For instance, in the Turkish economy, industrial value added Granger caused the industrial electricity consumption in the long run (Karanfil, 2008) while there was no-causality found at the aggregate level (Jobert and Karanfil, 2007). This is an appealing result because intuitively, some fraction of the current revenue is invested in the energy intensive capital in the industrial sector which is then utilized in the next period. But, for the US economy, it was found that uni-directional causalities run from output to energy consumption in the industrial sector, and from energy consumption to the value added in the service sector (Zachariadis, 2007; Thoma, 2004) while bi-directional causality was found at

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[1] In 2008, 32% of the total electricity consumption was consumed by the industrial consumers while 33% was consumed by commercial consumers (IEA, 2009a)

Table 5.1: Overview of the selected studies.

Country		Model	Short run	Long run
Multi-country Studies:				
Asian 10	(Chen *et al.*, 2007)	Bi-variate	Y→EC	Y→EC
Developed	(Chian-Lee and Chang, 2007)	Bi-variate	Y↔EC	-
Developing			Y→EC	-
G-7	(Narayan *et al.*, 2008)	Bi-variate	Y↔EC	-
Pacific Islands	(Mishra *et al.*, 2009)	Demand	Y↮EC	Y↔EC
Caribbean	(Francis *et al.*, 2007)	Bi-variate	Y↔EC	-
Single country studies:				
USA	(Chiou-Wei *et al.*, 2008)	Bi-variate	Y↮EC	-
	(Lee, 2006)	Bi-variate	Y↔EC	-
Korea	(Oh and Lee, 2004)	Supply	Y←EC	Y↔EC
	(Chiou-Wei *et al.*, 2008)	Bi-variate	Y↮EC	-
China	(Shiu and Lam, 2004)	Bi-variate	Y↔EC	Y←EC
	(Yuan *et al.*, 2007)	Bi-variate	Y←EC	Y←EC
Australia	(Narayan *et al.*, 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	(Mashih 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	-
Studies at a disaggregate level				
USA:SVA	(Zachariadis, 2007)	Bi-variate	Y←EC	Y↮EC
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 it is specified) by *Y*, and energy/electricity consumptions by *EC*. IP-Industrial Production. SVA-Service sector Value Added. IVA-Industrial sector Value Added.

the aggregate level (Lee, 2006).

Mishra *et al.* (2009); Soytas and Sari (2007) emphasized the importance of studying this relationship at a disaggregate level rather than at an aggregate level (aggregate measures suffer from an aggregation bias) and Hall *et al.* (2001) found that energy input is more important than capital and labour inputs. Stern (2004) argued that omitting such variables would result in spurious regression results.

5.3 Econometric methodology

In order to investigate the relationship between value added and electricity consumption for the industrial and service sectors, we employed the following standard time series econometric methodology, which was based on the stationarity and the co-integrating relationships across the variables considered.

Let y_t be a vector of m variables that satisfies the following process:

$$\phi(L)y_t = \delta + \epsilon_t \tag{5.1}$$

where $\phi(L)y_t = I_m - \sum_{i-1}^{p} \phi_i L^i$, δ is constant and ϵ_t is white noise. Also, I_m is identity matrix, L^i is lag operator and p is the maximum lag length. In the case when the above Vector Autoregressive Regression (VAR) is stationary *i.e.* $det|\phi(L)| = 0$, we do not need further transformation. In the case when the above VAR is non-stationary, *i.e.* $det|\phi(L)| = 0$ is singular, y_t would be the vector of *I(1)*[2] variables and $\triangle y_t$[3] would be the vector of *I(0)* variables. Also, according to the representation theorem (Engle and Granger, 1987) the combination of *I(1)* variable can be *I(0)*, *i.e.* co-integrated and the (5.1) can be written in the following form:

$$\triangle y_t = \delta - \phi(1)y_{t-1} + \sum_{i-1}^{p-1} \psi_i \triangle y_{t-i} + \epsilon_t \tag{5.2}$$

If the rank of $\phi(1)$ is zero, which is the equivalent of $\phi(1)$=0, the model can be written in the form of *VAR*. If the rank of $\phi(1) = r < m$, with r being the number of co-integrating relationships among m variables in the y_t vector, there exists a B$[m \times r]$ matrix of rank r such that $\phi(1) = BA^T$, and the (5.2) follows the Vector Error Correction Model (VECM) representation.

$$\triangle y_t = \delta - BA^T[1, t, y_{t-1}] + \sum_{i-1}^{p-1} \psi_i \triangle y_{t-i} + \epsilon_t \tag{5.3}$$

where $A^T[1, t, y_{t-1}]$ is the *I(0)* error correction terms (ECT). The ECT may include a constant and/or deterministic trend. The deterministic trend is intended

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[2] *I(d)* variable is a variable that becomes stationary after the difference is taken d times. *I(1)* variable would become stationary when the first difference is taken. *I(0)* variable is a stationary variable.

[3] $\triangle$ is the difference operator which takes the first difference of the variable.

to capture the behavior of trend stationary variables *i.e.* variables that are stationary after detrending rather than first differencing (Johansen and Juselius, 1995).

Granger causality, which shows whether the particular variable improves the forecast of the dependent variable when included in the model, is tested according to the standard Granger or Engle-Granger approach (Engle and Granger, 1987) for the perceived VAR or VECM, respectively. When VAR was adopted, the joint significance of lagged independent variables in the model are tested. In the case of VECM, the Granger causality is distinguished into long and short run causalities and tested by the significance of error correction terms and the joint significance of lagged independent variables, respectively. Since, all variables in (5.1) and (5.2) are *I(0)*, simple t- and F-tests would be employed to investigate the direction of the Granger causality.

Based on the estimates of the VAR or VECM, (5.1) could be written in the moving average form. Then, the impulse response function can be calculated by the following (Enders, 2004):

$$\frac{\partial y_{i,t+s}}{\partial \epsilon_{j,t}} \tag{5.4}$$

where $i, j = \overline{1, m}$.

It describes the response of $y_{i,t+s}$ ($s=0,1,2...$) of y_t to a one-time impulse/shock in $y_{j,t}$ with all other variables dated t or an earlier held constant.

5.4 Results

5.4.1 Data and Hypothesis

Electricity consumption[4] for the industrial and the service sectors and non-residential electricity prices for the period of 1978-2007 for Ireland were obtained from the IEA (2009a). Service and industrial sectors' value addedfor the same time period were

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[4] Electricity consumption of the construction sector has been included in the industrial sector electricity consumption.

obtained from the World Bank (2009).

Figure 5.1, 5.2 show that, in the Irish economy, electricity consumption is linearly related to the value added while it is nonlinearly related to the electricity price[5].

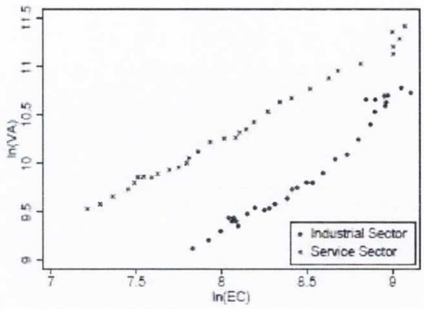

Figure 5.1: Electricity consumption and Value added

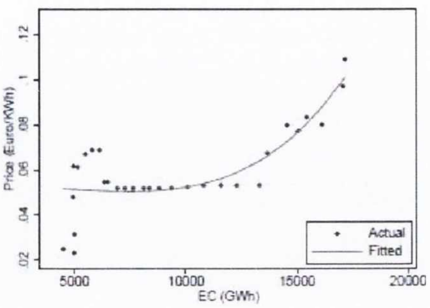

Figure 5.2: Electricity price and consumption

5.4.2 Identification

Electricity is an essential component of the production process which has few substitutes. Energy conservation policies can be delivered by setting constraints on electricity consumption, improving the technical efficiency or by affecting the electricity price. Technical efficiency is proxied by the sector specific value added per GWh electricity consumed by the sector:

$$TE_t^i = \frac{VA_t^i}{EC_t^i} \tag{5.5}$$

where TE_t^i is the technical efficiency, VA_t^i is the value added and EC_t^i is the electricity consumption (*i=service, industrial*)

The reduced form time series model is almost theory free and gives an opportunity to analyse the effect of an unanticipated shock in the independent variable on the dependent variable and *vice versa* without being required to set up an explicit

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[5] Electricity is produced according to the economic dispatch of power plants with different fuel costs. In Ireland, the electricity price is then associated with the fuel cost of the marginal plant which is dispatched to balance demand and supply.

mechanism that explains the underlying process. The model deals with the endogeneity issue by using the past values of the dependent variable as an instrumental variable[6].

Stationarity and co-integration tests found that the variables considered in this research were found to be difference stationary[7] and value added, electricity consumption, electricity price and technical efficiency for industrial and service sectors were found to be co-integrated[8]. Therefore, we posit the following VECMs to test the directions of Granger causalities for service and industrial sectors, and the impacts of unanticipated shocks in the value added, electricity price, electricity consumption and technical efficiency on each other:

$$\triangle EC_t^i = \alpha + \kappa^{ec} e_{t-1}^i + [lagged\ \triangle VA^i;\ \triangle \hat{EC}^i;\ \triangle P^i,\ \triangle TE^i] + u_t^i \tag{5.6}$$

$$\triangle VA_t^i = \alpha + \kappa^{va} e_{t-1}^i + [lagged\ \triangle VA^i;\ \triangle \hat{EC}^i;\ \triangle P^i,\ \triangle TE^i] + u_t^i \tag{5.7}$$

$$\triangle P_t^i = \alpha + \kappa^{p} e_{t-1}^i + [lagged\ \triangle VA^i;\ \triangle \hat{EC}^i;\ \triangle P^i,\ \triangle TE^i] + u_t^i \tag{5.8}$$

$$\triangle TE_t^i = \alpha + \kappa^{a} e_{t-1}^i + [lagged\ \triangle VA^i;\ \triangle \hat{EC}^i;\ \triangle P^i,\ \triangle TE^i] + u_t^i \tag{5.9}$$

where α is the constant and e_{t-1}^i is the error correction term, κ^i is the coefficient to be estimated, TE^i is the technical efficiency, VA^i is the value added, $\hat{EC}^i$ is the square of the electricity consumption, P^i is the electricity price and u_t^i is the error term (*i=service, industrial*). Since, the variables considered here were found to be difference stationary, the co-integrating relation would not include the deterministic trend and the explicit definitions of ECTs would be as follows:

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[6] Inclusion of l more variables in the model would increase the size of the model as p lags of the included l variables have to be added and l new regressions have to be estimated.

[7] See Table 5.4 in the Appendix for the unit root test.

[8] See Table 5.5 in the Appendix for the co-integration tests.

$$VA_t^i = a_0 + \pi_0^i EC_t^i + \pi_1^i P_t^i + \pi_2^i TE_t^i + e_t^i \tag{5.10}$$

where a_0, $\pi_{0,1,2}$ are coefficients to be estimated and e_t^i is the error term *i.e.* ECTs.

5.4.3 Co-integrating relations

The co-integrating relationship of the value added, electricity price and electricity consumption showed that the electricity consumption was negatively related to the electricity price while it was positively related to the value added for both sectors (Table 5.2). This is the long run relationship of these variables and at least one of the ECTs should be significant in the VECM.

Table 5.2: Co-integrating relations

Variables	$e_{t-1}^{industrial}$	$e_{t-1}^{service}$
P	1	1
EC	1.100 (0.425)***	3.804 (0.972)***
VA	-1.377 (0.310)***	-3.52 (1.38)***
TE	0.660 (.692)	5.090 (1.69)

Standard errors are in parentheses.
*** $p<0.01$, ** $p<0.05$, * $p<0.1$

5.4.4 Granger causality

Table 5.3 shows the short and long run Granger causality tests for models specified by (5.6) - (5.10). It was found that no Granger causalities exist in the relationship between electricity consumption and value added. Nevertheless, the error correction term was significant in the underlying process of the electricity price in both sectors which represents the long run Granger causality. Thus, any deviation from the long run trend was corrected in the short run for electricity price. This is in line with rules of the electricity market, *i.e.* electricity price strongly relates to the current generation of electricity.

It was found that technical efficiency Granger causes electricity consumption and electricity price while the value added causes only the electricity price in the service sector. There was no dynamic Granger causality found in the industrial sector.

Table 5.3: Coefficients of VECMs

	Industrial				Service			
	$\triangle EC_t$	$\triangle VA_t$	$\triangle P$	$\triangle TE$	$\triangle EC_t$	$\triangle VA_t$	$\triangle P$	$\triangle TE$
Long run:								
e_{t-1}	0.05	0.001	-0.448***	-0.028	-0.036	-0.021	-0.293***	0.009
Short run:								
$\triangle EC_{t-1}$	-	-0.159	0.195	0.037	-	-0.144	-1.025**	0.487**
$\triangle VA_{t-1}$	0.003	-	-0.092	0.016	0.544	-	-1.471**	-0.325
$\triangle P_{t-1}$	-0.338***	-0.057	-	0.158**	-0.93	-0.071***	-	-0.093
$\triangle TE_{t-1}$	0.439	-0.579	-0.617	-	-0.331	-0.331	2.83***	-

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

- No autocorrelation found for the lag length of 2.

- Akaike Information Criterion (AIC), Schwarz Bayesian Information Criterion (SBIC) and Hannan-Quinn Information Criterion (HQIC) were used to select the lag length.

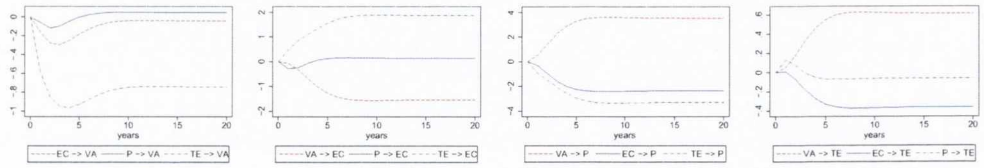
5.4.5 Impulse response functions

In this section, we further investigated the impulse response functions (IRF) of the value added, electricity consumption, technical efficiency and electricity price. IRFs show the response of the dependent variable to an unexpected shock in one of the independent variables while holding everything else constant. Since, electricity is one of the main components of the production process, it is expected that decisions by firms regarding electricity consumption are made to maximise profits, *i.e.* electricity consuming equipment is allocated optimally. If electricity consumption is not an important factor of the production process or the daily activity of the service sector, it would be neutral in the value added; neither changes in the growth of consumption nor an unanticipated increase in consumption would have an impact on the value added and *vice versa.*

Since the models we posit have stationary right-hand side variables, impulse response functions would yield consistent estimates (Enders, 2004) and reactions of the value added of industrial (Figure 5.3) and service (Figure 5.4) sectors would be sensible estimates.

Impulse responses of value added to unanticipated shocks in electricity consumption and technical efficiency showed that they were important factors for both sectors as they have persistent effects on the value added. A shock in the electricity price had a small transitory effect on both sectors (Figure 5.3(a), 5.4(a)). Hence, decisions regarding electricity consumption were made in order to increase the profit of the firm.

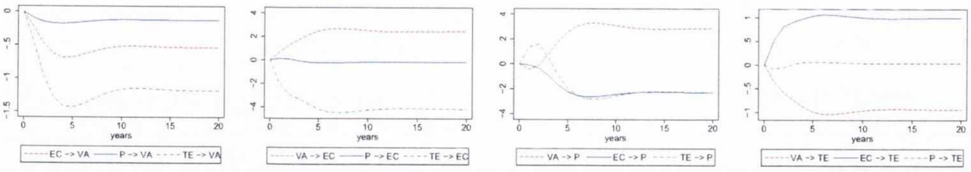
Figures 5.3(b), 5.4(b) showed the response of electricity consumption to various shocks. Electricity consumption was found to be more affected by a shock in the value added for both sectors, but in different ways. For the industrial sector, electricity consumption decreases when value added increases unexpectedly. A shock in value added has the opposite effect in the service sector. But, the effect of technical shocks had a positive permanent effect on industrial electricity consumption and a negative permanent effect on the service sector electricity consumption. This could be due to the rebound effect in the industrial sector. The effect of electricity price was small and transitory. It is in line with the price inelastic demand of electricity.



(a) Response: *VA* (b) Response: *EC* (c) Response: *P* (d) Response: *TE*

Figure 5.3: Impulse response functions of the industrial sector

On the other hand, the response of the electricity price was in line with the supply schedule of the electricity market (Figure 5.3(c), 5.4(c)). It decreases in the



(a) Response: *VA* (b) Response: *EC* (c) Response: *P* (d) Response: *TE*

Figure 5.4: Impulse response functions of the service sector

long run due to the electricity demand shock because an increase in demand would increase the participation of cheap, base-load power plants. But, an unanticipated increase in value added of both sectors would result in increased electricity prices in the long run. A shock in technical efficiency (increase) had a short run small positive and a long run negative effect on the electricity price.

Finally, Figure 5.3(d), 5.4(d) shows that the technical efficiency responded positively to the value added in the industrial sector while the value added in the service sector had an opposite effect. It responded positively to the shock in electricity consumption in the service sector while it had an opposite reaction in the industrial sector. The impact of price was transitory and small for both sectors.

5.5 Discussion

In this paper, a reduced form time series model was adapted to empirically test the relationship between electricity consumption and value added for industrial and service sectors of the Irish economy. A Granger causality test did not find any causality between value added and the electricity consumption in both sectors. It found some causalities with the electricity price and technical efficiency. This indicates that electricity consumption (value added) is exogenous to the underlying process of value added (electricity consumption) for both sectors. However, this only shows the capability of one variable in forecasting the other and the Granger causality test cannot be used to describe the true causation *i.e.* the underlying mechanism that links those variables.

Nevertheless, the impulse response functions showed the impact of an exogenous shock in the independent variable on the dependent variable. It should be noted that it also does not explain the underlying mechanism that links electricity consumption and value added, but it gives an indication of what might happen if there was such an exogenous shock (Stock and Watson, 2001).

Energy or electricity conservation policies could be considered as a negative shock (that is a direct constraint on the electricity consumption rather than electricity saving through technological advancements) to electricity consumption and would have the opposite effect to what was shown by the IRFs previously. Thus, such a policy targeted at a specific sector would not have an adverse effect on its value added. The effect was smaller for the service sector compared to the industrial sector. Nevertheless, such a policy, through efficiency was explained by the exogenous shock in the technical efficiency as the positive shock would be an increase in the efficiency which would explicitly reduce the consumption of electricity. But, it was found that the shock in the technical efficiency increases the electricity consumption.

From the perspective of the electricity system as a whole, the residential sector is a vital sector to be studied. But, from an economic perspective, the residential electricity consumption is more related to the household characteristics such as the number of people and the number of rooms in the house than any other aggregate measures such as household expenditure or the disposable income[9], and not related to the economic activity of the country.

5.6 Conclusion

In this paper, the relationship between the value added and electricity consumption was investigated for industrial and service sectors of the Irish economy controlling for

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[9] It was found that there is no co-integration and the Granger causality between aggregate household expenditure and the electricity consumption. Results are available from the author upon request.

electricity price and technical efficiency. Based on the unit root and co-integration tests, VECMs were employed. The Granger causality was tested and the results showed the non-existence of Granger causality between the value added and the electricity consumption for both sectors. Furthermore, IRFs showed that the electricity conservation policy would not have an adverse impact on the value added of both sectors unless it is implemented through improvements in technical efficiency.

5.7 Appendix

5.7.1 Unit root test

The Dickey-Fuller (*DF*) test is applied to test whether a time series variable has a unit root and the Kwiatkowski, Phillips, Schmidt and Shin (*KPSS*) test is used to verify the results of the DF test (Soytas and Sari, 2007). The null hypothesis of the DF is H_o: *variable is non-stationary* while *KPSS* tests the null hypothesis of H_o: *variable is stationary*.

Table 5.4: Unit root tests

	ADF			KPSS		
	τ_c	τ_{ct}	$\triangle^a$	K_c	K_{ct}	$\triangle^a$
Industrial sector						
EC_t	-1.027	-2.010	-4.054***	0.746***	0.848	0.118
VA_t	0.011	-1.176	-3.586**	0.723	0.136	0.103
TE_t	-1.027	-2.904	-5.379***	0.758***	0.065	0.077
Service sector						
EC_t	0.391	-1.414	-4.26***	0.741***	0.187	0.132
VA_t	2.025	-0.318	-3.217**	0.738	0.158	0.377
TE_t	0.031	-1.464	-4.324***	0.731	0.164	0.113
P_t	-1.279	-1.625	-3.205**	0.512**	0.099	0.136

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

[a] first difference, with constant and no trend.

Table 5.4 shows that at level, none of the variables were stationary as DF tests failed to reject the H_o of the non-stationarity series with (τ_{ct}) and without (τ_c) trend. KPSS tests rejected the H_o of the stationarity of *EC* of both sectors and industrial sector *TE* when there is no trend and accepts when there is a trend. But, the first difference of these variables were found to be stationary without trend under KPSS. As the first difference of time series are stationary (integrated order of 1 - *I(1)*), the co-integration test can be applied in order to select the appropriate model.

5.7.2 Co-integration test

Johansen co-integration tests (λ_{max} and λ_{trace}) are employed (Johansen and Juselius, 1990; Johansen, 1991) to test the existence of co-integrating relations among the variables since the first difference of variables considered here were found to be stationary.

Table 5.5: Co-integration tests: Johansen Trance and Eigenvalue tests

		λ_{trace}			λ_{max}		
Ho	*Ha*	Statistics		Critical Value	Statistics		Critical Value
		industrial *VA-EC-* *-P-TE*	*service* *VA-EC-* *-P-TE*	Value	*industrial* *VA-EC-* *-P-TE*	*service* *VA-EC-* *-P-TE*	Value
r=0	$r \geq 1$	64.69	54.67	47.21	37.86	34.82	27.07
r=1	$r \geq 2$	26.82*	19.85*	29.68	15.45*	12.58*	20.97
r=2	$r \geq 3$	11.37	7.27	15.41	10.16	6.63	14.07
r=3	$r \geq 4$	1.21	0.63	3.76	1.21	0.63	3.76

- 5% critical values are reported in the table
* number of co-integrating relations.

The results of co-integration tests for the relationship between electricity consumption and value added, controlling for electricity price, for both sectors are summarized in Table 5.5. The underlying VAR model includes an intercept but no trend. It is shown that test statistics of λ_{max} and λ_{trace} tests are lower than their critical values for one co-integrating relationship for both sectors, *i.e.* there is one co-integrating (long run) relationship among electricity consumption, value added and electricity price. Hence it is appropriate to conduct further analysis under the VECM framework for both sectors.

CHAPTER 6

Discussion and Conclusions

THIS thesis investigated the effect of the electricity storage system on the power system and the electricity market from various perspectives, *i.e.* the developer, power system and consumer. Moreover, the effects of the electricity storage system on the sector specific economic activity, through its effect on the electricity market, were also investigated. Distinct methodologies were employed for the purpose of each chapter.

Section 6.1 below presents a discussion on the impact of the change of electricity price on electricity consumption, the environmental impact of electricity storage systems, long- *versus* short-term storage operation and the effect of ownership type on the storage operations. Section 6.2 present some ideas for future works that could be done as a continuation of the thesis and the main conclusions of the thesis are illustrated in Section 6.3.

6.1 Discussion

This thesis has examined the economics of the electricity storage system in a specific market. Therefore, the results presented here are case specific and may not be translated to other markets directly without proper alterations to the underlying assumptions such as ownership type of the storage, power plant mix and price levels.

It was found in Chapter 3 that if storage is operated as a merchant type, which maximises its own profit, the price arbitrage between off-peak and peak hours is not significant enough to overcome the large capital costs in the Irish context. However, it was discussed that if such a system was to be incorporated into the power system in such a way that it was operated as a power system asset, the benefit of storage could be significant especially if the power system was subject to significant congestion problems, or there was a mismatch between availability of renewable energy and demand level.

Moreover, it was found in Chapter 4 that when a storage system is operated as a power system asset, due to its effect on the dispatch order of the thermal power plants, total dispatch cost can be reduced. However, it was found that for the Irish power system, the effect of the storage system on the wholesale electricity price was positive and significant. This implies that the costs of supply companies would be increased due to the deployment of the electricity storage system even though the total cost of the power system would be reduced. It is a fact that some of the electricity supply companies own some of the power plants; hence, the increase in wholesale electricity price is hedged for those supply companies. However, this is a company specific scenario and is not considered in an economic analysis of electricity storage. Thus, the addition of storage is likely to increase retail electricity prices.

6.1.1 Impact of electricity price change on consumption: CER Smart metering project

The smart metering project was conducted by CER in conjunction with ESB Networks and ESRI (CER, 2010). The project was established in late 2007 with the objective of setting up and running smart metering trials. As part of the project, electricity smart metering technology and consumer behaviour trials were conducted.

In the technology trial, various communication technologies (power-line carrier communication, GPRS and wireless mesh) were tested with the smart metering system and their performances and associated risks were assessed. This trial was concluded in October 2010.

In the consumer behaviour trial (CER, 2010), the representative sample of 5000 residential consumers and 650 businesses throughout Ireland were included. The trial started in September 2008 and installations were finished by June 2009. The benchmark period was then conducted for 6 months and, during this period, participants were charged regular rates for their electricity usage and the usage profiles were recorded. From 1st January 2010 to the end of 2010, the consumer behaviour trial was conducted whereby participants were charged time-of-use tariffs, subject to various billing schemes (monthly and bi-monthly), provided with a device that displayed real time information regarding their electricity consumptions, given financial rewards for reducing their electricity usage, and given detailed online information regarding electricity consumption and costs (targeted small and medium enterprises).

The main findings of the consumer behavioral trial were as follows:

(i) Residential consumers were found to have reduced their overall and peak hours electricity usages by 2.5% and 8.8% respectively and load shifting was observed. This implies that the residential consumers are responsive to the price changes.

(ii) Electricity usage of Small, medium enterprise (SME) customers were found to be less responsive compared to the residential customers although SME customers believed that they had reduced their electricity usage. Statistical analysis found that the overall and peak hours electricity usages were reduced by 0.3% and 2.2% respectively for SME customers. However, they were insignificant.

In the trial, the peak electricity price was set at rates shown in Table 6.1 for the time-of-use tariff (ToU) groups (A, B, C and D) while the control group price was 14.1c per KWh (excluding VAT).

Table 6.1: Consumer behavior trial results

	Groups			
	A	B	C	D
Peak price[a] (c/KWh)	20	26	32	38
Peak usage (%)	-7.2*	-9.8*	-9.0*	-10.9*
Overall usage	-2.7*	-3.4*	-1.9*	-2.4*

[a] Peak price is charge between 17.00-23.00 from Monday to Friday excluding bank holiday.
* statistically significant at the 90% confidence level.

Since peak hour electricity consumption is directly linked to people's regular daily routines such as making dinner, it is the most difficult form of electricity consumption to have an effect on. However, results show that ToU tariff groups have reduced their peak hour electricity consumption significantly and also their overall electricity consumption at a lesser degree. Also, the reduction of peak hour electricity consumption that corresponds to a 1% increase in the peak hour electricity price is found by dividing the change in the electricity consumption given in Table 6.1 by the change in the electricity price relative to the control group price . It shows that the peak hour electricity consumption reduces by approximately 0.06-0.17% when the peak hour electricity price increases by 1%.

Therefore, electricity consumption is not as inelastic as is usually assumed in theory. It shows that even though it is inconvenient to change electricity consumption patterns, electricity consumers are now aware of the consequences and are willing to make an effort to reduce their carbon footprint of their daily life.

Chapter 4 results showed that the deployment of electricity storage system increases the wholesale electricity price by approximately 4-5% compared to a no storage scenario. If this increase in wholesale price was passed on to the final consumer, and given the results of the smart metering trial, it can be inferred that the deployment of storage could reduce the residential peak hour electricity consumption and as well as the overall electricity consumption by approximately 0.24-0.68% and overall usage by approximately 0.04-0.24%.

Results in Chapter 5 showed that the sector specific gross value added was responsive to electricity consumption shocks while they were not responsive to the electricity price shocks. It was found that the gross value added is reduced permanently if electricity consumption increases while the electricity price does not affect it.

Combining the results from Chapter 4 and smart metering trial imply that storage system could reduce the electricity consumption. From the results in Chapter 5, this would imply that gross value added could increase. Thus, one of the benefits of electricity storage could be an increase in gross value added.

6.1.2 Environmental impacts and disposal

Due to the fact that some electricity storage systems are site specific and some contain toxic materials, the environmental impacts and the disposal of toxic materials also need to be considered when the viability of electricity storage systems is examined.

For the pumped hydro unit, the impact of building reservoirs on the surrounding ecosystem needs to be assessed as it requires the top of the hill to be converted into a large water tank and the bottom of the hill to be flooded or converted into a second water tank to hold the water.

When converting a regular hydro power plant to a reversible pumped hydro unit, it also requires that an additional significant amount of area surrounding a river to be flooded in order to create the second water tank. It may also require some other rivers to be diverted in order to provide enough water supplies for the hydro units, and the environmental impacts of such plans also need to be considered.

The environmental impact of compressed air electricity storage may be minimal as only exhausted mines, salt domes or aquifers are likely to be used for it, and it can even be built on the sea bed. As it would use a small amount of natural gas when generating electricity, the level of GHG emissions would need to be considered. However, this would be negligible compared to conventional power plants.

According to EPRI (2003), battery energy storages on one hand would have a minimal impact on the environment compared to PHS and CAES as they are usually built on a small scale and are often portable. However, replacement is required more frequently; hence the disposal of used batteries would be a major issue. Depending on the technology, the battery would contain toxic materials such as lead, bromine or cadmium, and these are required to be handled with extreme care. Lead acid battery storage produces small quantities of toxic gases and therefore it is required to be appropriately ventilated.

6.1.3 Long vs Short term storage technologies

This thesis only investigated the scenario of deploying a relatively short-term electricity storage system that operates intra-hour and intra-day.

Seasonal variation with regard to renewable energy does not usually follow seasonal variation with regard to electricity demand. For example, during summer when electricity demand peaks in warm regions, the wind power output reaches its minimum. However, in Ireland they are more aligned. Therefore, like natural gas storage systems, electricity storage systems can also be used to operate within longer time periods in order to reduce the seasonal variations in electricity demand and renewable energy outputs. A large scale pumped hydro unit or compressed air electricity storage could be the most suitable storage types for this purpose because their energy capacity can be built on considerably larger scales, *i.e.* for several days or months, compared to other types of storage technologies. These types of storage systems could incorporate the dual access types (short and long term), *i.e.* it could store electricity during the season when the renewable power output is relatively high while also providing short term support (intra-hour and intra-day) for the power system (Yu and Strunz, 2004). This stored electricity could be used during the season with relatively low renewable power outputs and high electricity demand.

However, the viability of using long term storage as for short term storage should be judged on the merit of its ability to provide energy security, costs and benefits, and impacts on the environment (Leonhard and Grobe, 2004).

If hydrogen electricity storage is at a stage where it can be commercially utilised, the electricity storage can be used in dual markets. Through electrolysis, hydrogen and oxygen can be produced when there is excess electricity generation from renewable sources or the power system, and the hydrogen that is produced can be used in the transport sector if the hydrogen car concept is commercialized while it is also used to generate electricity.

6.1.4 Ownership of electricity storage

In a competitive electricity market, electricity storage systems can be owned by different participants (individual power plants or customers) in the electricity market and operated in order to benefit specific participants. Sioshansi (2010) addressed this issue by examining the different types of ownership structures for the electricity storage system in terms of its utilisation rates and compared them to the socially optimal storage operation. It was found that if storage is utilized as a merchant type, which is a standalone unit, it is likely to be under used compared to the socially optimal usage. When storage is operated as generator's asset, which is a unit incorporated with a power plant, it is likely to be under used as well. But when it is considered to be an asset of the consumer, which maximises the arbitrage value and the consumer surplus change, it is likely to be overused compared to the social optimal usage level.

On the other hand, in a regulated electricity market, electricity storage systems are likely to be a power system asset which is utilised in order to minimise the total cost of the power system. As a result, there would be significant operational differences between various ownership structures, so the best practice should also be judged on the merit of the maximisation of social welfare.

In this thesis, Chapter 3 investigated the merchant type electricity storage and Chapter 4 utilised the storage system as a power system asset. Merchant type storage was assumed to only use night-time electricity generation when charging, while the power system asset type was found to use mostly night-time electricity generations to charge.

6.2 Future work

In this thesis, the effect of electricity storage on the wholesale electricity price was found based on the marginal cost of the power system. In the SEM, the wholesale electricity price consists of the system marginal price, uplift and capacity payments. Therefore, future works could incorporate these elements when defining the effect of electricity storage on the overall wholesale electricity price.

With regards to the WILMAR tool, most of the power plants were assumed to have one incremental heat rate which reflects the amount of fuel used to generate a certain amount of electricity. To improve the results, for each power plant, different heat rates should be considered for various levels of power generation. In this way, generator bids would be reflected more realistically in the simulations. Also, the stochastic version of the WILMAR tool should be used to incorporate the wind and demand forecast errors in the results. It was found by Tuohy and O‘Malley (2011) that as uncertainty increases, the value of storage also increases.

As this thesis only investigated the power system asset and the merchant type storage systems, storage that benefits only the consumers or the generator should be investigated in the future.

6.3 Conclusion

This thesis investigated the economics of electricity storage from various perspectives and assessed the possible benefits to the power system and the change in the consumers cost of electricity due the deployment of electricity storage. The effect of electricity storage operation through the electricity market on the sector specific gross value added was also investigated. The results of the each chapter are incorporated with the CER smart meter trial results and systematically shown in the Figure 6.1.

The main conclusions drawn from this thesis are as follows:

(i) The utilisation of the electricity storage system would increase the participation of base-load power plants and reduce the participation of mid-merit and peaking power plants. Hence, a considerable reduction in the total cost of the power system is achievable.

(ii) Due to its effect on the base-load power plants, the CO_2 emissions for the power system would be increased.

(iii) The variation in the net-demand reduces due to the deployment of electricity storage.

(iv) The choice of storage operations depends on the wind power profiles.

(v) Without any supporting mechanism, the arbitrage value between buying electricity during off-peak hours and selling it at peak hours does not generate enough of an economic incentive for the electricity storage system.

(vi) The wholesale electricity price may increase due to the effect of storage on the economic dispatch order of the power plants. The benefit of a reduction in the total power system dispatch cost would be outweighed by the increase

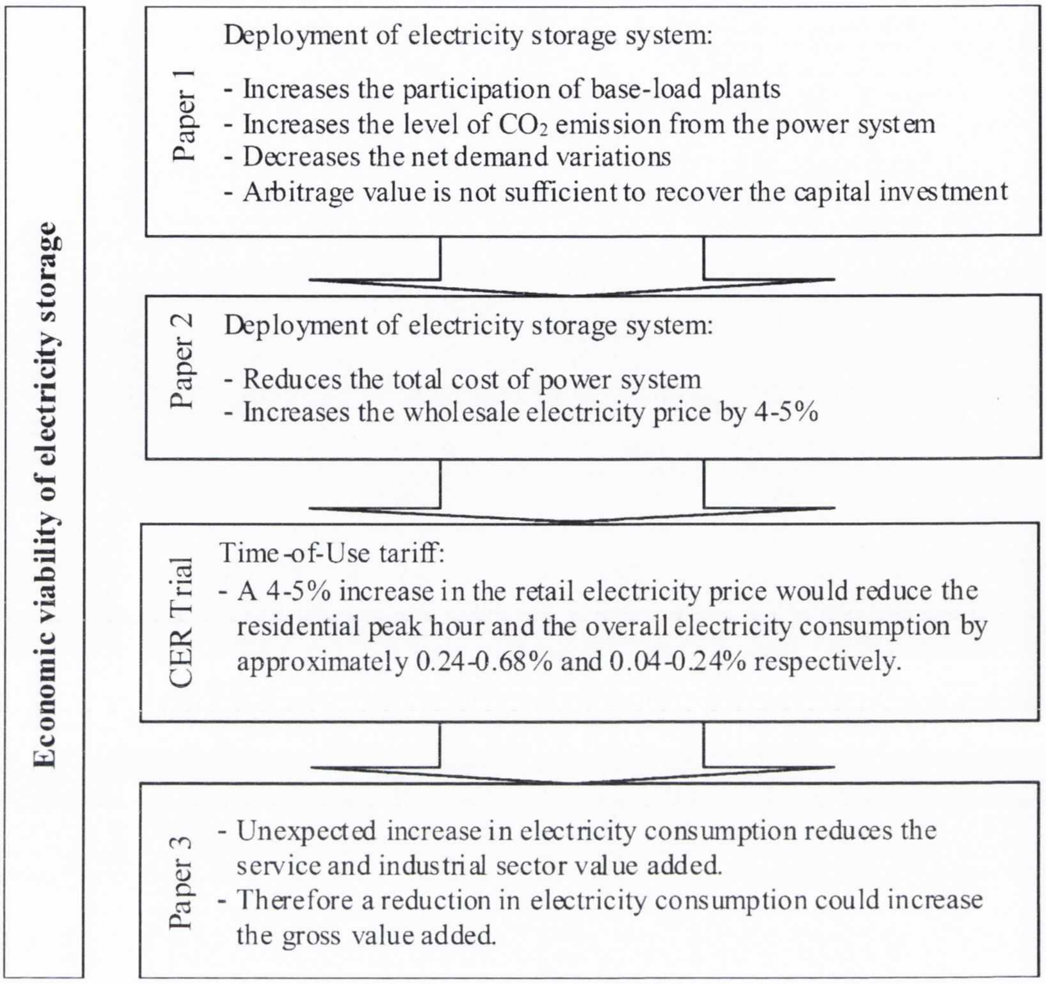

Figure 6.1: Economic viability of electricity storage system.

in electricity cost. The deployment of the electricity storage system combined with the high carbon tax may benefit the electricity storage system scenario.

(vii) Gross economic activity is more responsive to the change in electricity consumption than the change in electricity price. However, electricity consumption is responsive to the change in electricity price. Therefore, any policy that would affect electricity consumption directly or indirectly would be likely to have an impact on gross economic activity.

In conclusion, the development of electricity storage system is uneconomical in the current climate and the costs outweigh the benefits in terms of power system impacts.

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APPENDIX A

Power plants mix assumed for the WILMAR tool

Table A.1: Power plants characteristics

	Unit ID	Unit	Area	Max Power (MW)	Min Power (MW)	Max Eff	Fuel	Noload heat rate	Sync time cold	Sync time warm	Sync time cold	POR	SOR	TOR
1	AD1	Aghada Unit 1	ROI	258	35	0.4	BLGAS	187.53	3	7	18	22	22	22
2	AD2	Aghada Unit 2	ROI	431	35	0.59	BLGAS	187.53	3	7	18	22	22	22
3	DBP	Dublin Bay Power	ROI	415	207	0.57	BLGAS	479.34	2	4	5	13	37	42
4	HNC	Huntstown	ROI	343	220	0.54	BLGAS	423	2	6	12	17	18	25
5	HNC2	Huntstown 2	ROI	412	220	0.54	BLGAS	423	2	6	12	17	18	25
6	PBC	Poolbeg CC	ROI	480	280	0.51	BLGAS	704.52	4	5	6	60	112	150
7	SK3	Sealrock 3 (CHP)	ROI	65	35	0.47	BLGAS	100	0	0	0	3.7	3.7	9
8	SK4	Sealrock 4 (CHP)	ROI	65	35	0.47	BLGAS	100	0	0	0	3.7	3.7	9
9	TE	Tynagh	ROI	450	224	0.56	BLGAS	564	2	4	8	19	19	31
10	WG	White Gate Gas	ROI	450	225	0.54	BLGAS	495.8	1	2	8	40	40	40
11	MP1	Moneypoint Unit 1	ROI	282.5	136	0.37	COAL	148.34	5	10	15	19	44	44
12	MP2	Moneypoint Unit 2	ROI	282.5	136	0.37	COAL	148.34	5	10	15	19	44	44
13	MP3	Moneypoint Unit 3	ROI	282.5	136	0.37	COAL	148.34	5	10	15	19	44	44
14	AT1	Aghada CT Unit 1	ROI	88	15	0.32	GASOIL	279.86	0	0	2	20	20	20
15	AT2	Aghada CT Unit 2	ROI	88	15	0.32	GASOIL	279.86	0	0	2	20	20	20
16	NW5	Northwall Unit 5	ROI	109	5	0.28	GASOIL	309.39	0	0	0	20	20	20
17	RH1	Rhode Unit 1	ROI	52	5	0.34	GASOIL	85.01	0	0	0	0	0	0
18	RH2	Rhode Unit 2	ROI	52	5	0.34	GASOIL	85.01	0	0	0	0	0	0
19	GI1	Great Island Unit 1	ROI	54	25	0.3	Lightoil	49.57	2	3	12	3	6	9
20	GI2	Great Island Unit 2	ROI	54	25	0.3	Lightoil	49.57	2	3	12	3	6	9
21	GI3	Great Island Unit 3	ROI	108	30	0.34	Lightoil	102.04	2	3	11	15	20	20
22	PB1	Poolbeg Unit 1	ROI	109.5	56	0.36	Lightoil	80.18	2	8	10	14	28	28
23	PB2	Poolbeg Unit 2	ROI	109.5	56	0.35	Lightoil	80.18	2	8	10	14	28	28
24	TB1	Tarbert Unit 1	ROI	54	25	0.29	Lightoil	46.05	2	3	12	3	6	9
25	TB2	Tarbert Unit 2	ROI	54	25	0.29	Lightoil	46.05	2	3	12	3	6	9
26	TB3	Tarbert Unit 3	ROI	240.7	35	0.38	Lightoil	256.89	3	7	18	15	19	25
27	TB4	Tarbert Unit 4	ROI	240.7	35	0.38	Lightoil	256.89	3	7	18	15	19	25
28	AT4	Aghada CT Unit 4	ROI	90	15	0.32	MMGAS	279.86	0	0	2	20	20	20
29	MRT	Marina CC	ROI	85	40	0.39	MMGAS	249.8	0	0	5	29	33	35
30	NW4	Northwall Unit 4	ROI	163	99	0.43	MMGAS	351.77	0	0	5	15	40	53
31	ED1	Edenderry	ROI	117.6	41	0.38	PEAT	497.6	1	4	12	5.9	5.9	9.4
32	LR4	Lough Rea	ROI	90	40	0.36	PEAT	89.55	6	12	18	5	5	5
33	WO4	West Offaly Power	ROI	135.65	52.5	0.37	PEAT	124.59	6	12	18	7	7	14
34	B31	Ballylumford* 31	NI	160	80	0.46	BLGAS	446.22	1	2	8	37.1	37.1	37.1
35	B32	Ballylumford* 32	NI	160	80	0.46	BLGAS	446.22	1	2	8	35	35	35
36	B4	Ballylumford Unit 4	NI	170	80	0.31	BLGAS	161.34	3	5	12	35	35	35
37	B5	Ballylumford Unit 5	NI	170	80	0.31	BLGAS	161.34	3	5	12	35	35	35
38	B6	Ballylumford Unit 6	NI	170	80	0.31	BLGAS	161.34	3	5	12	14.5	14.5	14.5
39	CPS CCGT	Coolkeeragh CCGT	NI	404	260	0.54	BLGAS	495.8	1	2	8	25	25	25
40	K1	Kilroot Unit 1	NI	238.19	64.127	0.37	COAL	293.14	4	6	12	25	25	25
41	K2	Kilroot Unit 2	NI	238.19	64.127	0.37	COAL	293.14	4	6	12	7.25	7.25	7.25
42	B10	Ballylumford Unit 10	NI	170	80	0.47	MMGAS	88.34	0	0	1	37.1	37.1	37.1
43	BGT1	Ballylumford GT1	NI	58	8	0.23	GASOIL	162	0	0	0	14.5	14.5	14.5
44	BGT2	Ballylumford GT2	NI	58	8	0.23	GASOIL	162	0	0	0	15.5	15.5	15.5
45	CGT8	Coolkeeragh GT8	NI	53	8	0.24	GASOIL	176.94	1	0	0	40	40	40
46	KGT1	Kilroot GT1	NI	29	5	0.25	GASOIL	102.5	0	0	0	7.25	7.25	7.25
47	KGT2	Kilroot GT2	NI	29	5	0.25	GASOIL	102.5	0	0	0	7.25	7.25	7.25
48	KGT3	Kilroot GT3	NI	40	5	0.25	GASOIL	102.5	0	0	0	7.25	7.25	7.25
49	KGT4	Kilroot GT4	NI	40	5	0.25	GASOIL	102.5	0	0	0	7.25	7.25	7.25
50	Hydro	RunOfRiver	ROI	216	0	1	WATER		0	0	0	4	12	0
51	WIND	Wind in ROI and NI	ROI/NI	0.0002		1	WIND	0						

* CCGT