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Abstract:

Electricity market liberalisation has become common practice internationally. The justification for this process has been to enhance competition in a market traditionally characterised by statutory monopolies in an attempt to reduce costs to end-users. This paper endeavours to see whether a pool market achieves this goal of increasing competition and reducing electricity prices. Here the electricity market is set up as a sealed bid second price auction. Theory predicts that such markets should result with firms bidding their marginal cost, thereby resulting in an efficient outcome and lower costs to consumers. The Irish electricity system with a gross pool market experiences among the highest electricity prices in Europe. Thus, we analyse the Irish pool system econometrically in order to test if the high electricity prices seen there are due to participants bidding outside of market rules or out of line with theory. Results indicate that the Irish pool system appears to be working efficiently and that generators are bidding their true marginal costs. Thus, the pool element of the market structure does not explain the high electricity prices experienced in Ireland.

Keywords: Electricity Markets; Auction Theory; Multiple Regression Analysis

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Introduction

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

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

In the EU, the Internal Market in Electricity Directive came into force in August 2003. This put forward several measures designed to open up the electricity market to benefit end-users; among these were the right for all consumers to choose their electricity supplier. The overall objective of liberalising the EU electricity market was to enable it to be fully competitive and remove any existing difference between Member States (European Commission 2003).

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

Table 1 below presents the installed capacity as of 2008, and electricity prices to end-users in the EU 15 countries as of 2009 (Eurostat ; SEAI 2009b). It shows Ireland, whose electricity market is the focus of this paper, to have the second smallest capacity of countries shown while having some of the highest end-user prices. Italy, on the other hand, has one of the highest installed capacities and still has relatively high end-user prices, which implies market structure may be an important determinant of the costs faced by consumers for the electricity they consume. If this is in fact the case, then high end-user prices could be reduced through a change in electricity market structure. In this paper we will investigate whether electricity costs are driven by market structure in the Irish context.

Table 1: End-User Prices in EU 15 countries, 2009

Country	Industrial Prices € /100 kWh	Domestic Prices € /100 kWh	GW Installed
Austria	n/a	19.09	20.75
Belgium	11.11	19.16	16.70
Denmark	8.59	26.98	12.50
Finland	6.89	12.96	16.64
France	7.02	12.73	117.62
Germany	11.32	22.82	133.94
Greece	9.48	11.54	14.24
Ireland	12.06	20.30	7.20
Italy	14.35	20.93	97.88
Luxembourg	11.57	18.82	1.64
Netherlands	11.30	19.00	24.83
Portugal	8.94	15.08	15.70
Spain	11.54	15.77	90.19
Sweden	6.67	16.02	33.94
UK	11.17	14.66	85.58

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

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

The method of increasing competition within electricity markets which this paper will focus on is the use of mandatory gross pool electricity markets. Where implemented, participation in such a pool is mandatory, thus ensuring no physical trade of electricity outside of the pool. Each generator bids a price at which it is willing to supply electricity. These bids are then ranked to form a merit order, with electricity demand being met by dispatching units (switching plants on), beginning with the lowest cost unit, until demand is satisfied. Firms are expected to bid based on the prices at which they will cover the variable costs of operating their power plants. These power plants are then ranked based on a merit order, thus making generation costs and network constraints the determining factors for dispatch. The market clearing price is then established by a one-sided auction at the intersection of the supply curve and the forecasted demand for each period (Weron 2006).

In the early 1990's a gross pool system was in operation in England and Wales; however it was later replaced by New Electricity Trading Arrangements (Bunn 2004; Green and Newbery 1992; Weron 2006). Gross pools are currently in operation in Spain, Ireland, and Alberta (Weron 2006). Figure 1 illustrates an example of a gross pool structure.

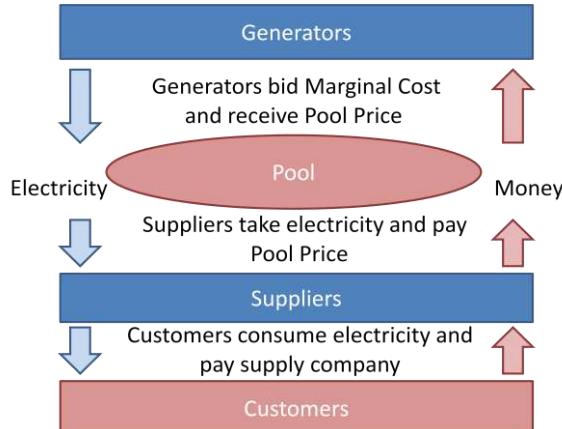


Figure 1: Example of a Gross Pool Market Structure

This paper estimates the magnitudes of the main determinants of electricity prices using historical data. While much work has been done in the areas of electricity demand forecasting and price prediction (Bunn 2000; Conejo et al. ; Nogales et al. 2002), little work has been done focusing solely on the effect of the drivers. The majority of studies use simulated as opposed to historical data (Bierbrauer et al. 2004; Knittel and Roberts 2005). Historical studies allow us to see the true impact of each independent variable over the period in question and may give a more accurate representation than purely simulation-based studies.

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

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

The remainder of this paper is structured as follows; Section 2 outlines the theoretical framework of bidding within a sealed bid second price auction within which we expect generators to operate, and Section 3 introduces the Irish electricity market as the case system. Section 4 details the model and data used and the results, discussion and conclusion are presented in Sections 5, and 6 respectively.

Electricity Pool Market as an Auction

According to David and Fushuan (2000), “Almost all operating electricity markets worldwide employ the sealed bid auction with uniform market price”. While typically one thinks of buyers auctions, where several bidders attempt to buy a good, electricity markets reflect sellers auctions, where firms bid to supply a good or service.

Barriers to entry in the form of capital costs should not affect the short term operation of the market as these costs to the generating firms are often recovered through separate cost recovery or revenues streams. In the long term it is recognised that they do have an impact, but this is not the focus of this research. In the short run, each unit is constrained by the quantity of electricity which it is capable of producing. Participation in the market is determined solely by the price at which they bid into the market. Electricity is an entirely homogenous good; however in most systems, no single unit is large enough to meet demand individually and thereby capture the entire market.

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

While tacit collusion through inflated bids would allow for a collectively more profitable result, each unit is increasing the risk that they will not be dispatched by pricing themselves out of the market. A unit bidding below marginal cost will increase the likelihood that they will be dispatched, but also increase the probability that the market clearing price will be set below their true marginal cost. Thus, it is expected that bids made by generators will reflect their true marginal cost.

When a generator bids something other than its marginal cost, in an attempt to exploit imperfections in the market and increase its profits, this behaviour is called strategic bidding (David and Fushuan 2000). This leads to distorted prices and higher electricity costs for end-users. The electricity market structure under a mandatory gross pool system can be examined as a sealed bid second price auction, where no firm knows exactly what any other firm has bid, and a firm’s bid does not affect the price they receive for their electricity, only whether they are dispatched. Electricity is provided by a few major suppliers, with each individual generating unit competing against the others (even those owned by the same company) in order to be “dispatched” and enter into the market, as shown in Figure 2.

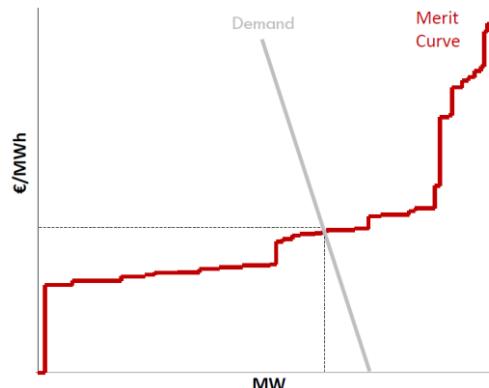


Figure 2: Merit Order

We propose to model this as a Vickrey auction. Vickrey (1961) demonstrated that a particular pricing rule makes it a dominant strategy for bidders to report their values truthfully, even when they know that

their reported values will be used to allocate goods efficiently². If a Vickrey auction is the correct framework for modelling the interaction between generators and electricity pools, then one would expect to find generators are in fact bidding truthfully and efficiently by reporting their true short run marginal costs. The purpose of this paper is to test whether this is the case in the Irish electricity market.

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

Gross Pool Electricity Market as a Vickrey Auction

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

$$\text{The payoff for firm } i \text{ will be } \begin{cases} \max_{j \neq i} b_j - c_i & \text{if } b_i < \max_{j \neq i} b_j \\ 0 & \text{otherwise} \end{cases}$$

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

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

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

If $c_i > \max_{j \neq i} b_j > b_i$ then only the strategy of bidding below marginal cost would win the auction. The payoff for underbidding would be negative as the firm would receive less than their marginal cost for the electricity they supply. If they had made a truthful bid ($b_i = c_i$) no loss would be made as the firm would simply not be dispatched and its payoff would be 0. Consequently the strategy of bidding below one's true marginal cost is dominated by truthful bidding.

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

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

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

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

² This sealed bid, second price auction is considered more appropriate than a uniform-price auction to represent the gross pool electricity market as each generator is capable of bidding multiple units. Under a uniform price auction, this does not lead to bidders bidding their true valuation.

Case Study System: The Irish Electricity Market

The Irish electricity market, similar to many others internationally, consisted of a statutory monopoly (ESB in the Republic and Viridian in Northern Ireland) until the market was fully opened to competition in February 2005. These two previously independent systems (of the Republic of Ireland and Northern Ireland) are now combined to create a Single Electricity Market (SEM) for the island of Ireland.

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

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

The third payment is called the shadow price and simply refers to the marginal cost of producing electricity in any period³. In other words, it is the bid (marginal cost) of the last unit to be dispatched in meeting the demand in any hour.

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

The Irish electricity market is a small, isolated system with a maximum demand of 6488 MW in 2009 and a total installed capacity of 8061MW for the same period. On 1st November 2007 the Single Electricity Market (SEM) went live, commencing the trading of wholesale electricity in Ireland and Northern Ireland on an All-Island basis. The SEM consists of a gross mandatory pool market, into which all electricity generated on or imported onto the island of Ireland must be sold, and from which all wholesale electricity for consumption on or export from the island of Ireland must be purchased (SEM-O 2010). Table 2 below represents Ireland's installed capacity by fuel type.

Table 2 Capacity by Fuel Type

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

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

Ireland is connected to the Great Britain (GB) system via the Moyle interconnector from Northern Ireland to Scotland, with a maximum import capacity of 400 MW, and export of 80 MW. This means Ireland is essentially self sufficient in its electricity generation. Figure 3 below demonstrates the mean proportion of total demand met through conventional supply (which refers to fossil fuel generation), wind, peat and imports over the course of the day.

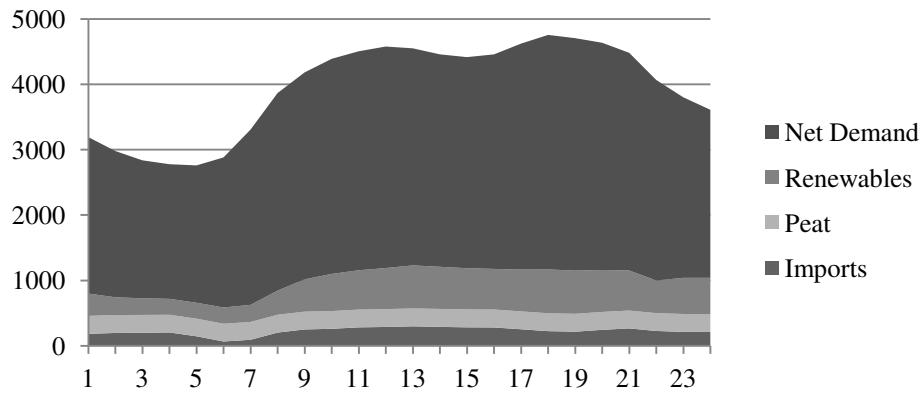


Figure 3: Average Supply Breakdown in Ireland

According to the Market Operator (SEM-O 2010), conventional generators must bid price and quantity pairs relating to the electricity they can provide for the following day. The price which generators bid is expected to reflect the marginal cost of generating the quantity of electricity specified, and as such is expected to include fuel and carbon prices. While each generator will most likely have hedged fuel costs, the market rules state that the bids should reflect the opportunity cost of the fuel, meaning the spot price at the time of the bid (CER 2007).

The marginal unit during each trading period sets the price which all units receive for that period, meaning every other unit that is dispatched receives above the price it bids in at. Generators do not simply receive their bid price as this would act as an incentive to submit bids based not on their marginal cost but their expected value of the breakeven price of electricity (Kirschen and Strbac 2005)

Due to the set up of the Irish electricity market, it is a prime case study in which to test the effectiveness of a gross pool system based on a Vickrey-style auction. It has little interconnection with other markets, and supply of electricity from all conventional units is required by the Regulator to bid in quantities and prices thus resulting in a Vickrey supply auction set up.

Data and Model

Demand

Theoretically we expect demand for a good to depend on the price of the good. However, on an hourly basis, demand for electricity is affected exclusively by cycles of activity, as the price final consumers pay for their electricity is fixed⁴ and is therefore entirely independent of the shadow price (Kirschen and Strbac 2005). As demand is independent of the price of electricity in the short run, it can be considered to have zero price elasticity (David and Fushuan 2000).

⁴ With the exception of a small number of firms who pay the pool price, however these represent a small fraction of total demand in any hour and can be ignored for the purposes of this study.

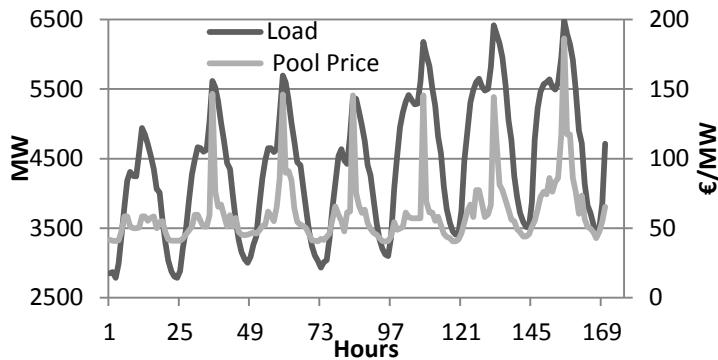


Figure 4: Electricity Demand and Price for 1 week Jan '09

While the shadow price does not impact on demand, other factors have an influence on the demand in any hour such as sunshine hours, rainfall, whether it is day or night and daily, monthly and seasonal factors. Social events such as sporting events will also affect demand (Owaidh et al. 2000)⁵. From Figure 4 above one can see demand for electricity is highly cyclical with a peak in the evening and minimum during the night.

$$\text{Demand} = f(\text{time, weather, social events}) \quad (1)$$

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

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

Supply

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

⁵ Other factors affect the load including losses incurred on the network, the need for reserve, and the amount of electricity required by the generators themselves. These elements are not considered in this study.

Committee 2009). Imports are not required to bid according to market rules, and as a result both of these should have a negative impact on the price of electricity in a given period.

Peat and renewables do not participate in the market financially as they are supported separately through a Public Service Obligation (PSO) levy, however they do participate physically in the sense that all electricity is supplied via the pool⁶. This means they have a regulatory mandatory purchase agreement which results in all electricity generated by these units being consumed regardless of their marginal costs. Thus they are not considered as part of the merit order in the operation of the market.

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

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

$$\text{Total Supply}_t = \text{Conventional Supply}_t + \text{Renewables}_t + \text{Peat}_t + \text{Imports}_t \quad (2)$$

$$\text{Total Supply}_t \equiv \text{Total Demand}_t \quad (3)$$

$$\text{Net Demand}_t = \text{Total Demand}_t - \text{Renewables}_t - \text{Peat}_t - \text{Imports}_t \quad (4)$$

$$\text{Net Demand}_t \equiv \text{Conventional Supply}_t \quad (5)$$

The model

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

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

$$\begin{aligned} \text{ShadowPrice}_t = & \alpha + \beta_1 \text{NetDemand}_t + \beta_2 \text{NetDemand}_t^2 + \beta_3 \text{MarCap}_t + \beta_4 \text{Gas}_{t-24} + \beta_5 \text{Oil}_{t-24} \\ & + \beta_6 \text{Coal}_{t-24} + \beta_7 \text{Carbon}_{t-24} + \varepsilon_t \end{aligned} \quad (6)$$

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

As demand increases towards total possible supply available, one would expect prices to increase dramatically due to a scarcity premium. In order to see if this is taking place, we include a

⁶ The PSO levy was introduced in January 2003, and relates to the purchase of the output of peat generated electricity, in the interests of security/diversity of supply, and the output of renewable energy generating stations (DETI 2005). The PSO levy promotes the national policy objectives of ensuring a secure energy supply, the use of indigenous fuels and the use of renewable energy sources in electricity generation. This means if the market clearing price is below the price guaranteed under the PSO, then these generators will be topped up to this levy amount.

marginal capacity (“MarCap”) variable in the model, which can be described as $MW_{Offline} / Demand$ – i.e. the number of megawatts which are unavailable for generation as reported by each individual generating unit. This is essentially the difference between the maximum rated number of megawatts a unit is able to supply and their actual availability in a given hour. This is included in the model in order to identify whether a scarcity premium is found to be significant, with a fall in availability resulting in an increase in the price of electricity.

The following table provides summary statistics for all observations of variables included within this study.

Table 3: Summary Statistics

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

In this study we generate a times series multiple regression model. Controls are included for each hour of the day, day of the week, month and public holidays as all of these have an effect on the demand for electricity, the availability of wind for generation, and the scheduled maintenance of conventional plant which has an effect on the fuel mix. Figure 4 shows the highly cyclical nature of electricity prices. Murray (2009) highlights that while the price is very closely linked to the demand level in power markets; it tends to be stratified as it reflects the different types of plant which are brought into service on a merit order basis.

Results

Table 4 presents the results of the main drivers of shadow price using the fuel prices lagged by 24 hours with robust standard errors in order to see if the fuel spot price set out by the Market Rules can be used to effectively estimate electricity prices. Observations with electricity prices exceeding €150 have been omitted from the model, as prices this high are not due to normal market operation and can instead be attributed to technical issues such as unit failure. Serial correlation is not found to be an issue in either the overall model or in any of the peak hours observed.

The main drivers of the electricity price are found to be net demand, the marginal capacity and the gas price of the previous day. The net demand has a positive effect on the price, as an increase in net demand causes a movement up the merit curve to more expensive generating units, causing the price to increase. This relationship is not linear as both net demand and its square are found to be statistically significant at the 99% level. The marginal capacity (“MarCap”) variable is significant and negative. This seems reasonable, as more plant becomes available the cost of generation falls, again due to the merit order effect. Natural gas is found to be a significant driver of the price in our model; this is most likely due to the fact that just under 60% of Ireland’s installed conventional capacity uses natural gas (SEAI 2009a). This is the only significant fuel type. The other fuels will only be significant at various stages along the supply curve, with only one fuel setting the price at any given point in time. These results can be considered to be in line with both expectations and theory. The high R^2 and would seem to imply that

our model is a good predictor of shadow prices, and that firms appear to be behaving appropriately in general, as spot prices are relatively good indicators of the price of electricity.

Table 4: Shadow price model

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

Standard errors in parentheses

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

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

Looking at Figure 5 below, it can be seen that while load increases at a much steeper rate to meet the morning peak, the price increases at a greater rate during peak hours. In order to identify the effect each of the variables in the model has over the course of the day the model is rerun separately for each hour of the day. If firms were to act strategically in peak hours when the demand is highest, we would expect this to be seen in the marginal capacity variable which relates to a potential scarcity premium.

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

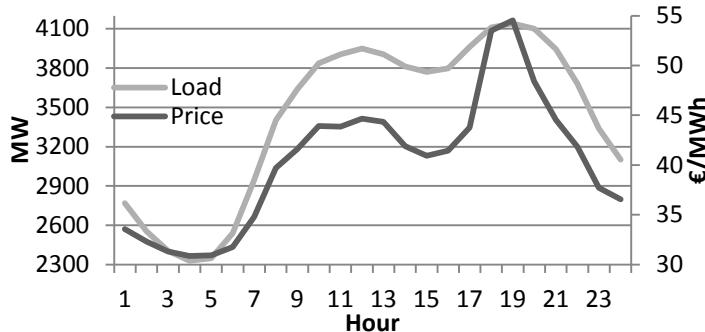


Figure 5: Mean Load & Price over 24 hours

Table 5 below demonstrates the results during the peak hours of 5-8pm. The effect of Net Demand is only significant in one peak hour, where it has a positive effect on the shadow price of 3.7033 €/MW. The square of Net Demand is significant during all peak hours, with its effect varying according to the hour in question. While this may be in part due to inappropriate bidding, it is primarily caused by a shift in the merit order to more expensive generating units, thereby increasing the entire system cost as output increases (as shown in the above merit order in Figure 2).

Table 5: Shadow Price Peak Hours

VARIABLES	17	18	19	20
Net Demand	-1.1592 (3.317)	-5.0978 (3.422)	-0.3807 (2.239)	3.7033*** (0.915)
Net Demand ²	1.3311** (0.641)	2.3802*** (0.757)	1.4884*** (0.555)	0.4534* (0.234)
MarCap	0.2493 (0.241)	-0.4990 (0.407)	-0.3194 (0.314)	-0.1354 (0.188)
GasLag	0.9985*** (0.134)	1.0061*** (0.208)	0.7247*** (0.112)	0.4819*** (0.044)
OilLag	-0.3765* (0.222)	-0.0872 (0.229)	-0.0268 (0.226)	0.1081 (0.131)
CoalLag	-1.1885 (0.784)	0.1842 (0.535)	-0.8016* (0.472)	-0.3287 (0.285)
CarbonLag	3.1424*** (0.784)	-0.8215 (0.911)	0.1391 (0.692)	0.4612 (0.299)
Constant	46.3568	15.0354	37.1634	9.7468
Observations	(52.615)	(40.891)	(30.245)	(15.985)
R-squared	358	359	360	361

Robust standard errors in parentheses

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

Marginal Capacity is not found to be a significant driver of the price in any of the peak hours observed, and as a result one cannot conclude that generators are restricting the use of less expensive generating units or behaving inappropriately in any other way based on this sample data. As the same variables are significant in peak hours as during the rest of the day it can be understood that generators are not behaving differently during these hours or bidding differently in these times. Marginal capacity is statistically significant in the overall regression model, this is not the case during peak hours, which is when one would typically expect it to have the greatest effect; however, average hourly demand in 2009

peaked at 4139.65MW at 7pm, while maximum capacity in 2009 was 6130MW. This would imply that there is no great risk in general of the system not being able to meet demand.

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

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

Conclusions

Overall it would appear that the interaction between generator and the pool in the Irish electricity market is efficient and the shadow price represents the true marginal cost of generation, with generators bidding the spot price of their inputs correctly in the model and the behaviour of the units remaining constant over the course of the day and varying levels of demand. The results of our OLS regression model are in line with both the theoretical framework outlined in Section 2 and Irish regulatory policy on the issue. One reason why this market structure may be more effective in the Irish context than it has been seen to work elsewhere is due to the small size of the Irish system. Ireland does not have large generators such as nuclear plants, and as a result no single plant sets the market price in general. This makes each unit more likely to set/not set the price increasing competition amongst firms. Another reason is the prescriptive nature of the Irish market; instead of allowing generators to bid their marginal costs arbitrarily they are expected to bid their fuel prices at spot market values rather than their true hedged prices. If interconnection capacity increased, electricity prices overall might be lower, but the conventional units would still operate in the same manner; there would simply be less demand to be met by conventional generation. Any changes to the existing market structure due to changes in regulation or policy could potentially affect the effectiveness of this market.

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

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