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Gaming in the Irish Single Electricity Market and Potential Effects on Wholesale Prices[1]

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Abstract: The Irish Single Electricity Market is establishing how to comply with the European Union Target Model. One option is to move away from the regulated environment used in the current design and allow generating firms to bid freely in the market. This study shows that in 2011, allowing firms to freely compete in quantities (Cournot) would have increased prices by 52%, using Irish-specific estimates for the price elasticity of demand. When redesigning the market, regulators should consider how best to control market power.

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1 Introduction

Ireland and Northern Ireland are redesigning their wholesale electricity market to comply with the EU Target Model (SEM, 2014a). Changes in the market design will affect both wholesale and retail prices. The current market is a mandatory pool market and limits generators' strategic behaviour through the Bidding Code of Practice. The regulatory authorities (the Commission for Energy Regulation in the Republic of Ireland and the Utility Regulator in Northern Ireland) are considering how to reform the market and which market power measures to enact.

Delivering electricity efficiently while mitigating market power and encouraging entry is as important today as when the Single Electricity Market (SEM) was set up in 2007. In this paper we explore what would happen to wholesale prices if generators were free to bid strategically. We find that the wholesale electricity price may increase substantially in the absence of strong policies to mitigate market power.

In the next section we describe the state of the SEM in 2011. Section 3 briefly explains how bidding strategically can increase prices in the wholesale market. Section 4 introduces the simulation setup using the portfolio mix and level of demand in the SEM in 2011, with strategic bidding. Section 5 presents and discusses the change in wholesale prices that could occur and Section 6 concludes.

2 The Single Electricity Market

The SEM currently operates as a mandatory pool system where generators bid their short-run marginal costs (fuel, carbon, operational and maintenance costs), in line with the Bidding Code of Practice. Plants are stacked according to their bid, from lowest to highest and the cheapest plants needed to meet demand in each half hour are dispatched. All plants called to generate receive the bid price of the marginal plant, or the most expensive plant dispatched in each period. All generating plants also receive a payment, called uplift, designed to remunerate the marginal plant for any start-up and fixed generation costs. Generators are also compensated for their availability with capacity payments. The sum of all these payments is designed to closely approximate the long run marginal cost of generation. All generators with a capacity over 10MW must bid into the pool.

In terms of market structure, the SEM market can be characterised as an oligopoly with a competitive fringe. In 2011 two firms had a capacity share over 10%, as shown in Table 1, although 3 firms had market shares above 10% (market share numbers include both wind that bids into the market and smaller wind farms that do not). The largest firm is ESB, encompassing both ESB-PG –the incumbent in the Republic of Ireland– and ESB International (ESB-I), followed by AES, which owns the majority of the thermal plants in Northern Ireland. In 2012 the regulators decided to let ESB bid as an integrated firm since the Bidding Code of Practice limited market power.[1]

Table 1: Market share by capacity and generation in the Single Electricity Market, 2011.

Firm	Capacity (MW)	Capacity Share (%)	Gen. share (%)
ESB	3763	34.4	43.7
AES	1830	16.9	11.0
Viridian	1046	9.6	12.4
Endesa	1016	9.3	0.2
Fringe-Thermal	1108	10.1	15.2
Fringe-Renewables	2167	19.8	12.4
Net Imports	-	-	5.1
Total	10,930	100	100

ESB is sum of ESB-PG and ESB-I. Capacity and market shares include ownership of wind.
Dublin Bay is included in ESB-I's portfolio, as ESB-I owns 70% of its shares.
Data from SEMO, allislandproject.org, EirGrid, SONI, windpower.net,

In 2011 renewables (mostly wind) accounted for about 27% of total capacity. Table 1 shows a smaller share since some of the wind is included in large firms' holdings. Wind can only generate electricity when wind is blowing and has a priority dispatch according

[1]See http://www.allislandproject.org/GetAttachment.aspx?id=fd2b05ff-b0ee-443d-87db-01b1ac4fe27a.

to EU regulation.[2] Its marginal cost of production is close to zero, suggesting that when the wind blows it is always profitable to generate. In practice wind can be considered a price taker, although it can influence the bidding strategy of firms that own both wind and dispatchable generation. As the market price increases, all generators, including wind, obtain higher revenues.

The current design of the SEM limits strategic behaviour by generators. The market will have to be reformed to comply with the European Target Model by 2016 SEM (2014a). The Target Model is designed to support the efficient exchange of electricity across borders. It does not impose a specific market design, although it was developed based on markets where bilateral contracts are an important component. Examples include the Nordpool and the British markets.

The challenges facing the new Integrated Single Electricity Market (I-SEM) are similar to those tackled, successfully, by the SEM: mitigating market power, delivering electricity efficiently and encouraging entry. Additionally, the SEM has experienced a large increase in wind generation, making it more challenging for the system operator to balance the market. The new market design has not been decided yet (SEM, 2014a,b), but it is likely to allow generators to offer electricity at prices above marginal cost.

A centrally controlled dispatch can comply with the Target Model and Gorecki (2013) recommends retaining this key feature of the SEM.

We determine by how much the wholesale price of electricity could increase if generation companies were free to act strategically.

3 Cournot Competition

This section first discusses why the Cournot approximation is appropriate in this framework, then shows how the wholesale price is affected by the presence of an oligopoly

[2] EU directive 2009/28/EC.

competing à la Cournot with a competitive fringe. Finally, it compares the oligopoly price to the one arising in perfect competition.

The assumption of Cournot competition, where firms bid the quantities of electricity they will generate in each period, is an approximation. When there are capacity constraints and demand is rationed efficiently, the Cournot outcome mimics a two step game where firms choose capacity in stage one and compete in prices (à la Bertrand) in stage two (Tirole, 1988). Some of the strong assumptions needed to obtain the Cournot equilibrium in the two-part game are verified in the case of electricity markets: electricity is a non-differentiated good, capacities are observable by all, capacity costs are relatively large and bids are set simultaneously. This explains why the Cournot competition framework has often been used to analyse outcomes in electricity markets, both in Europe and the US (see Wolfram, 1999; Bushnell, 2007; Borenstein et al., 1999).

In this section we present a simple example to clarify the relation between the price determined in a competitive market and the one in Cournot competition. Assume that there are 2 symmetric firms, each with total cost function C^j, and increasing marginal costs c^j, i.e. $c_j'(q_j) > 0, \forall j$. To simplify assume: $C^j = q_j^2/2$, with marginal cost $c^j = q_j$. We also include fixed capital costs F_j in firms' profit functions. The firms face a (inverse) linear demand curve $P = a - b \cdot Q$ for every period, where $P(0) > 0$.

There are a number of generating plants that are price takers. They include independent power producers with single thermal plants, generators with Combined Heat and Power (CHP) plants and all the plants that bid in quantities and not prices, such as wind generators.[3]. To simplify the analysis, we limit the competitive fringe to 0 marginal cost producers in the following example. Such producers will offer generation on the market any time the price is non-negative. The sum of all the price-taking output at time t is represented by Q_t^F, often called the competitive fringe.

[3]In this example we assume that all wind generation is part of the fringe. In Appendix B we show that if wind is owned by a firm that bids strategically, it decreases firms' optimal quantity. This is also consistent with the findings in Ben-Moshe and Rubin (2014), who take a slightly different approach

Each strategic firm j chooses the generation quantity in each period to maximise its expected profits Π_j.

$$\max_{q_j} \Pi_j = (a - b \cdot Q) \cdot q_j - q_j^2/2 - F_j \qquad \text{where } Q = \sum_j (q_j) + Q^F \tag{1}$$

The first order condition for each firm j yields the following equilibrium quantity:[4]

$$q_j = \frac{a - b \cdot Q^F}{(1 + 3b)} \tag{2}$$

With corresponding Cournot equilibrium price:

$$P^C = \frac{(1 + b)(a - b \cdot Q^F)}{1 + 3b} \tag{3}$$

The larger the competitive fringe, the lower the equilibrium price will be.

We can compare the price in Cournot with the price that would occur in perfect competition, where $P = MC$. In equilibrium $MC_i = MC_j = \bar{MC}$ and $P(q_i + q_j + Q^F) = \bar{MC}$:

$$P^* = \frac{a - b \cdot Q^F}{1 + 2b} \tag{4}$$

P^C is always larger than P^*.

Forward contracts may also influence the competitive performance of electricity markets. We address this point later in the paper.

4 Gaming in the SEM

We simulate the market with Energy Exemplar's PLEXOS[5] Integrated Energy Model which allows generation companies (collections of generators) to act strategically by withdrawing capacity in order to increase their profits (Nash-Cournot competition). We

[4] It is easy to verify that the second order condition for a maximum is also met.

[5] Available online at www.energyexemplar.com

use the Xpress Mixed Integer Programming solver.[6]

To implement Nash-Cournot competition, PLEXOS divides demand into multi-period 'blocks', calculates the linear demand function in each block and solves the game (the strategic interaction between firms) independently for each block. Once a game has been played for each block, this information is passed to the full hourly resolution calculation and provides prices and generation level. Adjustments are then made to the algorithm that calculates the outcomes in perfect competition. The price we report for the Cournot model is the average of the Nash-Cournot equilibrium price which is reported for each period in 2011, where each hour's price is weighted by that hour's electricity generation.

We start from the 2011 PLEXOS model used in (Deane et al., 2014) with historical fuel and carbon prices and representative start-up and no load costs. Demand is the historical demand for 2011 net of interconnector flows, as we do not model interconnection. Firms act strategically (i.e. decide what generation level will maximise their profits) given their generation portfolio. Note that ownership of wind by large firms changes their incentives, and therefore influences final results. Wind, hydro and biomass generators not owned by one of the major firms are assumed to be price takers. Peat plants are taken as a separate category as they have priority dispatch.

Wind capacity ownership in the SEM was determined using information from the Irish Wind Energy Association (IWEA) website. Where Power Purchase Agreements were in place between individual turbine owners and these generation companies we omitted that capacity from the company's strategic portfolio. Wind not associated with large companies is deemed non-strategic.

We assume that demand for electricity is elastic to price. If the price of electricity increases, demand will decrease. The Price Elasticity of Demand (PED) for electricity in Ireland by sector is taken from (Di Cosmo and Hyland, 2013). It is combined with the consumption share of electricity by sector from the SEAI National Energy balances[7]

[6] FICO Xpress Optimiser, available at http://www.fico.com

[7] http://www.seai.ie/Publications/Statistics-Publications/Energy-Balance/Previous-

to form a weighted estimate of the total PED for electricity in Ireland. We assume that numbers for Northern Ireland would be similar. This calculation is outlined in table 2 and gives a PED for electricity of e=-0.16 which is consistent with international estimates (see Table 1 in Fan and Hyndman, 2011).

Table 2: Price Elasticity of Demand by Sector, Ireland.

Sector	Consumption share	PED	Wholesale price as a share of retail price	PED*Share	Wholesale PED
Industrial	38%	-0.275	76%	-0.105	-0.080
Residential	33%	-0.07	55%	-0.023	-0.013
Commercial	26%	-0.09	55%	-0.024	-0.013
Agriculture	2%	-0.38	55%	-0.009	-0.005
Weighted PED				-0.16	-0.11

Consumption share from SEAI National Energy Balances for 2011 (see footnote 7).
Elasticities by sector from Di Cosmo and Hyland (2013).

Using EuroStat data we calculated the wholesale share of final electricity prices. (For example, wholesale electricity price is 55% of final residential electricity price but is a much higher share of final electricity cost for industrial users, at 76%). This calculation suggests that the wholesale PED is e=-0.11.

5 Results and discussion

Table 3 presents the results of our analysis. The Perfect Competition row refers to a situation where no strategic behavior is allowed and models the SEM in its current form. The perfectly competitive price in our model picks up only the short run costs of generating electricity, ignoring the costs of turning plants on and off and paying for the capital costs. To compare this price with a price that emerges in an energy-only market, we add the uplift component of €7/MWh and the historical capacity payments,

Energy-Balances/

equivalent to €16.2/MWh for 2011.[8]

With a price elasticity of demand of e=-0.11, there is a 52.3% increase in price. We assume that if firms are allowed to bid strategically, they will not receive any payments in addition to the energy payments they receive in the market. This finding is in qualitative agreement with our theoretical results in Section 2.

In addition to controlling how generators are allowed to bid, SEM regulators currently use 'directed contracts'. The largest generating firms are forced to sell a certain amount of their output at a price determined by the regulators. In 2011, the only firm subject to directed contracts was ESB (SEM Committee, 2010, 2011). We study how this could affect prices in the Nash-Cournot game in three scenarios: ESB has to sell 10%, 50% or 100% of its total generation forward. Note that in each of these scenarios, all other strategic generators bid strategically with 100% of their capacity.

Table 3 shows that the directed contracts on ESB's generation will not limit market power significantly when generators are allowed to act strategically in I-SEM, unless ESB is forced to sell all or most of its generation forward. Of the three directed contract scenarios, the one where ESB is forced to sell just 10% of its generation forward is closest to the historical requirement on ESB. When defining the level of directed contracts, the regulators also determine which directed contracts apply to base-load, mid-merit or peak loads. In this analysis we do not disaggregate forward contracts by level of demand.

The analysis we presented is based on a static environment. In practice firms also consider dynamic incentives when bidding. For example, firms might recognise that if prices greatly increase, there is a risk of regulatory intervention or new firms may find it profitable to enter the market.

The results reported in this table also assume that imports along the interconnector will not increase with prices. For 2011 this is a reasonable assumption as interconnection to the SEM was limited to the Moyle interconnector. Moreover, it was on complete

[8] Capacity payments are paid out to generators on a per MW basis. Here we present the average effect per MWh to facilitate comparisons with the energy only price.

Table 3: Summary of results comparing perfect competition to Cournot competition with price elasticity of demand e=-0.11

Scenario	Price (€/MWh)	% change
Perfect Competition	76.01	
(includes uplift and capacity payments)		
All Companies 100% Strategic	115.74	52.3
ESB 10% of generation forward	115.39	51.8
ESB 50% of generation forward	108.04	42.1
ESB 100% of generation forward	70.12	-7.7

outage from the 24th of August to the end of the year.

History has shown that electricity prices can exceed perfect competition levels significantly. In Great Britain (GB), electricity generation was privatised in 1990 and moved to a market-based system. Wolak and Patrick (2001) show that the generators withheld capacity in certain half-hour periods, driving up the pool price. Wolfram (1999) shows the higher prices didn't quite reach Cournot predictions, while remaining significantly higher than in perfect competition. In a dynamic setting firms may restrain prices to discourage entry of new competitors or to limit potential increases in regulation.

A recent study Deane et al. (2014) found that in the current GB market, with vertically integrated firms and bilateral contracts, firms appear to underprice wholesale electricity and recover their profits in the retail segment. This behaviour limits entry into the wholesale market.

6 Conclusion

Controlled bids in the SEM were set up to avoid abuses of market power in a market that displayed an oligopolistic structure. The simulations presented in this paper show that moving away from a model with controlled bids to one with strategic behavior will increase wholesale electricity prices.

The implementation of the Target Model in the SEM should prioritise the need to control market power and strategic behaviour. The challenge will be to use the flexibility inherent in the Target Model's guidelines to best serve final consumers.

7 Appendix A-Sensitivity Analysis

Below we present a table displaying the results of our PLEXOS simulation with elasticity of -0.16 and with elasticity of -0.3. These results are consistent with what we would expect: the lower the elasticity the more power the generation companies have to set market price so we get dramatically higher prices as $e \to 0$. Furthermore, as we increase the value of the elasticity we recover the perfect competition result where prices are set at marginal cost.

Table 4: Summary of results comparing perfect competition to Cournot competition with price elasticity of demand e=-0.16 and e=-0.3 . Note that in both scenarios, all companies act strategically with all of their generation capacity (excluding wind, hydro, peat and CHP generation plants).

Scenario	Price (€/MWh)	% change
Perfect Competition (includes uplift and capacity payment)	76.01	
All Companies 100% Strategic, e=-0.16	97.06	27.7
All Companies 100% Strategic, e=-0.3	79.61	4.7

8 Appendix B - Wind ownership and competition

This section shows why ownership of wind affects the incentives of firms that own thermal plants.

In Equation 1 we presented the profit maximization function of a firm operating as a Cournot competitor in an environment that has a fringe of price-taking firms, including wind generators. What happens when some of the wind is owned by firms that bid strategically? We assume that the marginal cost of wind generation is 0 and that both generators own wind.

Suppose each firm generates a quantity of electricity denoted by $q_j + \frac{q^w}{2}$. The profit maximizing function for strategic firm 1 becomes the following:

$$\max_{q_1} \Pi_1 = [a - b \cdot (q_1 + q_2 + q^w + Q_0^F)] \cdot (q_1 + \frac{q^w}{2}) - q_1^2/2 - F_1 \tag{5}$$

and similarly for the symmetric firm 2. Note that the firm cannot choose the amount of q^w since wind generation is not dispatchable. Also, in every period where wind is available, it will be optimal for the firm to bid it in. This however does not exclude that wind ownership will affect the optimal quantity of a generator. Because any existing wind will benefit from higher prices, there is an added incentive to decrease quantity offered in the market.

Now the competitive fringe generation is $Q_0^F = Q^F - q^w$, i.e. some of the wind generation is owned by the strategic firms.

The first order condition (FOC) for maximisation is

$$q_1 = q_2 := \hat{q} = \frac{a - b(\frac{3}{2}q^w + Q_0^F)}{1 + 3b} \tag{6}$$

As wind generation increases, strategic firms decrease the optimal amount of thermal generation.

However, recall the Cournot Price function:

$$P^C(q^w) = a - b \cdot (q_1 + q_2 + q^w + Q^F)) := a - b \cdot (2\hat{q}(q^w) + q^w + Q_0^F).$$

How does P^C vary with quantity of wind owned by a strategic firm? Using comparative statics, we can define the effect on the equilibrium price of a change in q^w.

$$\frac{dP^C}{dq^w} = -2b \cdot \frac{d\hat{q}}{dq^w} - b = \frac{-b}{1 + 3b} < 0 \quad \forall b > 0. \tag{7}$$

We compare this to the change in the equilibrium Cournot price when strategic firms do not own wind generation. Differentiating equation 3 yields the following:

$$\frac{\partial P^C}{\partial q^w} = \frac{-b(1+b)}{1+3b} \tag{8}$$

If we compare equation 7 to equation 8, we see that the when wind is owned by strategic firms the equilibrium price decreases less in the presence of more wind.

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