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Irish and British historical electricity prices and implications for the future

Paul Deane,[a] John FitzGerald,[b,c] Laura Malaguzzi Valeri,[b,c*] Aidan Tuohy[d] and Darragh Walsh[b,c]

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Abstract: This paper compares retail and wholesale electricity prices in SEM, the market of the island of Ireland, and BETTA in Great Britain. Wholesale costs are much lower in BETTA. We show that this is mostly because the wholesale price in BETTA is set too low to cover generation costs, although it is compensated by large retail margins. The substantial need for new investment in generation in Great Britain suggests that returns to generators will have to increase. Developing a market mechanism to compensate generators fairly while simultaneously reducing retail revenue will help in achieving this goal.

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**Corresponding author*: laura.malaguzzivaleri@esri.ie

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[a] Energy Policy and Modelling Group, Environmental Research Institute, University College Cork
[b] Economic and Social Research Institute
[c] Department of Economics, Trinity College Dublin
[d] Electric Power Research Institute, Knoxville, TN

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1. Introduction

This paper investigates the prices of electricity in Ireland and Great Britain, two very different markets. We compare both wholesale and retail prices during the 2008-2011 period, suggest structural, technological and regulatory characteristics that determine the price differences and consider their implications for future electricity price trends.

The electricity markets on the island of Ireland and in Great Britain have followed different histories of investment in electricity generation and exhibit differences in the nature of their labour markets, which affect operating costs. Since the end of 2007 Northern Ireland and the Republic of Ireland have shared a wholesale electricity market, here referred to as the Single Electricity Market (SEM). The two regulators on the island (the Northern Ireland Utility Regulator and the Commission for Energy regulation, CER) cooperate to regulate the wholesale market through the SEM committee, which has an independent chair. To maintain regulatory certainty, the SEM arrangements were created via a treaty. Retail markets are, however, regulated separately.

Great Britain and Northern Ireland share similar (and interrelated) schemes to encourage renewable electricity generation: the Renewable Obligation Certificates (ROCs) and the Northern Ireland ROCs respectively. In the Republic of Ireland support for renewables is provided by a different mechanism – a feed-in tariff (REFIT). Great Britain and Northern Ireland, while both jurisdictions within the United Kingdom, have separate regulators: the Office of Gas and Electricity Markets (Ofgem) and the Utility Regulator, respectively.

Even before the current crisis, the Irish economy was under serious pressure due to its high cost basis. With the dramatic downturn over the 2008-10 period, this serious failing has been painfully highlighted (Bergin *et al.*, 2009). As a result, all costs facing businesses in Ireland are under scrutiny, including energy prices. While it is acknowledged that there is little that Ireland can do about the price of imported oil and gas, there is widespread questioning as to whether the price of electricity facing consumers, both business and residential, is too high. A range of different bodies have looked at Irish energy prices in a comparative context. In particular much attention has focussed on Irish electricity prices and how and why they differ from those in Great Britain and other relevant economies (see for example the National Competitiveness Council, 2009).

Great Britain also faces an uncertain future with respect to electricity prices. Most existing nuclear plants are due to close around the end of the decade and much coal-fired capacity will also have to close in 2016 as a result of the EU Large Combustion Plant Directive. It is not clear how this obsolete plant portfolio will be replaced and there are concerns that the prospective returns from investment under the current market rules may not result in adequate investment (Helm, 2009). Giulietti *et al.* (2010) show that the move to a market based on bilateral contracts in GB, combined with other changes in market structure, saw a squeezing of wholesale margins, with profitability being enhanced at the retail end. The problems facing the British electricity market need to be taken into account in any comparison of current prices in the Irish and British electricity markets.

While there is a danger that problems in the Irish electricity market or in the British market could result in prices being too high, damaging the competitiveness of the sectors that trade on international markets, it is also possible that prices could be too low. This could be the case if the markets do not provide an adequate return on capital to new investors – if the price falls below the long run marginal cost. Prices could also be "too low" if the negative environmental effects of consuming energy are not taken into due account (for example if greenhouse gas emissions are priced too low).

The paper is organised as follows. In Section 2, we look at the behaviour of retail electricity prices in Ireland relative to those in Great Britain over the past 30 years. We then compare historical wholesale prices in the two markets in Section 3. Since the British market is based on bilateral contracts that are not public information, we discuss several estimates of its wholesale price. To determine the cost of generation in BETTA, we build a model of the British market that defines the price that would arise with the current plant portfolio if generators did not bid strategically and were dispatched efficiently. Using the same model and imposing identical fuel input prices in BETTA and SEM, we determine how much of the difference between wholesale prices is due to differences in generation technology. In Section 4 we examine domestic retail prices in detail and discuss some of the drivers of retail margins. Section 5 discusses the likely trend in future prices given our findings and Section 6 concludes.

2. History

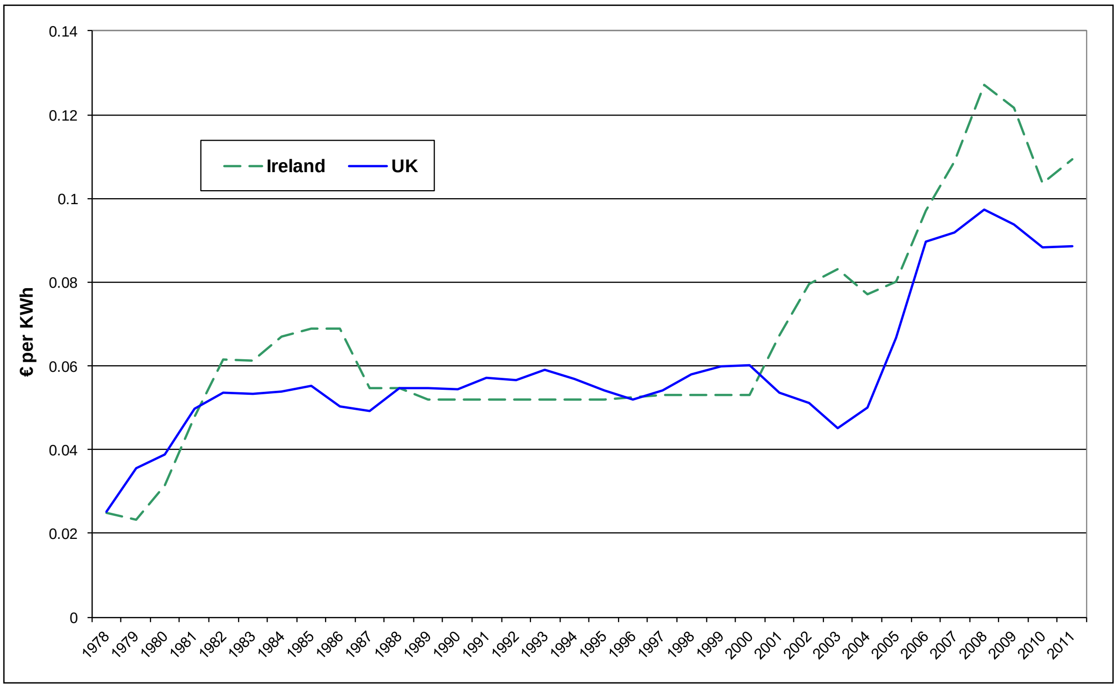
Over the last 30 years retail electricity prices have generally been higher in the Republic of Ireland than in Great Britain. The gap was particularly big in the 1980s, especially for the household sector. This reflected the need in Ireland to fund major investment in the main coal-fuelled generating station: Moneypoint. However, by the end of the 1990s that station had largely been paid for and investment in Ireland was at a low level. Over that period prices were generally based on the average cost of electricity generation, significantly below long run marginal cost by the end of the 1990s. Until the late 1990s the state-owned utility, the Electricity Supply Board (ESB), had total responsibility for the sector in Ireland. Over the period 1980-2000, when investment was undertaken this resulted in high prices and when there was a lull in investment the assets were "sweated" seeing prices fall below long run marginal cost. This approach to pricing was common in regulated utilities (Helm 2004). However, it is a suboptimal approach from a wider economic efficiency point of view, sending the wrong signals to the market and possibly leading to inefficient investment choices elsewhere in the economy.

By contrast, in Great Britain following on privatisation of the industry and the break-up of the monopoly Central Electricity Generating Board (CEGB) in the early 1990s, there was substantial excess capacity. The transmission and distribution infrastructure was already fully developed and the growth in the UK economy in the subsequent period did not result in a major increase in demand. The advent of new more efficient technology using natural gas (combined with low gas prices) saw a "dash for gas" in the 1990s, which further increased capacity. When this resulted in a major drop in utilisation of existing coal-fired plants, which were already fully depreciated, this spare capacity was moth-balled rather than decommissioned. There has consequently been no need for major new investment in generating capacity over the past decade. However, as outlined above, the prospects for the coming decade are rather different.

The result of this excess capacity has been that, over time, electricity prices in the British market did not reflect the long run marginal cost of producing electricity. Given costs sunk in excess generating capacity, generators competed for market share on the basis of short run marginal costs. As discussed later, this appears to have pushed the price below long run marginal cost.

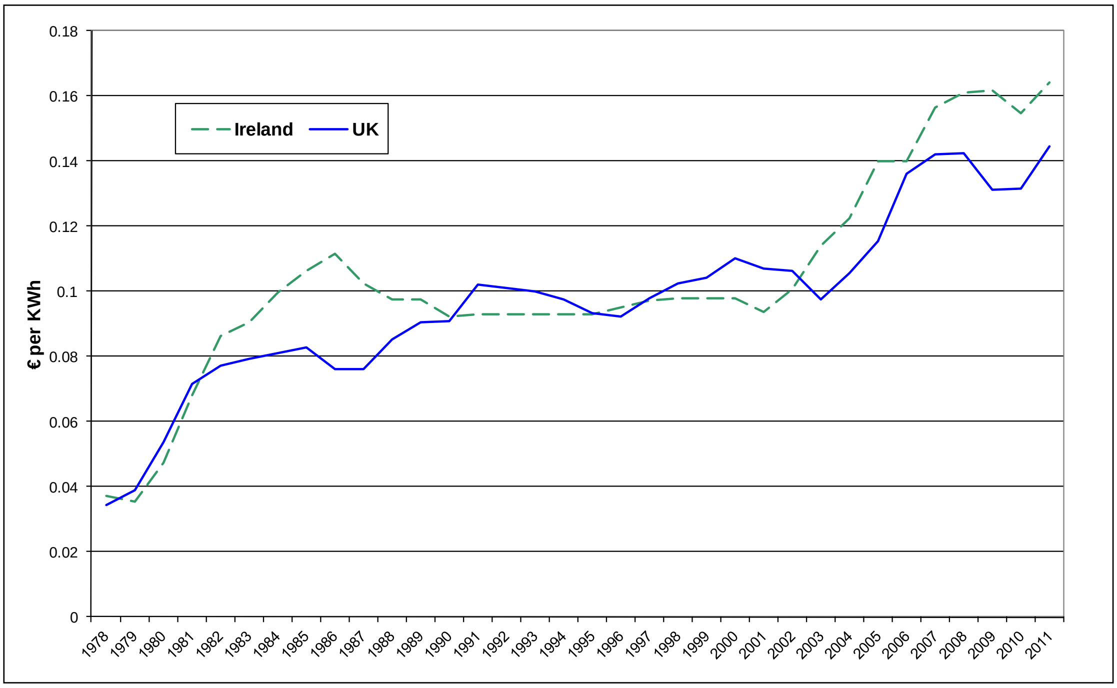
This approach to pricing saw a certain "cyclicality" in the movement of Irish prices relative to those in Great Britain (GB from now on). Figures 1 and 2 show a comparison of the electricity prices (excluding both excise tax and VAT) faced by industry and households in Ireland and GB in nominal Euro. These data are taken from the IEA publication Energy Prices and Taxes, the only source that provides prices back to the 1970s on a consistent basis. To convert the UK prices to euro we use average yearly exchange rates published by Eurostat.

Figure 1. Industry electricity prices, ex-tax, €/kWh, nominal



Source: IEA Energy Prices and Taxes, various years

Figure 2. Household electricity prices, ex-tax, €/kWh, nominal



Source: IEA Energy Prices and Taxes, various years.

Figures 1 and 2 show that in the 1980s the price of electricity in Ireland was much higher than in GB for the reasons set out above. However, from 1990 to the early years of the current decade there was little investment in the Irish system and prices tended to reflect average cost rather than long-run marginal cost, as was the case in GB. The excess capacity built in the 1980s was eroded by increased demand so that the repayments on past investment were spread over an ever increasing volume of sales.

The comparison between the prices in Ireland and GB was also affected by the movement in energy prices. The fall in oil prices and the low gas price in Ireland in the 1990s drove the cost of the energy needed to generate electricity in Ireland down.

The result of the fall in average capital costs and the change in relative prices of fuels meant that in the late 1990s, for a short period, prices in Ireland actually fell below those in GB. However, the rapid rise in gas prices (relative to coal) since 2000, combined with the necessary shift to pricing at long run marginal cost, has seen a substantial wedge open up between Irish and British prices for industrial users. The difference in prices for households has been somewhat milder since the mid-1990s. We return to this issue later in this paper.

3. Wholesale prices

This section compares historical wholesale electricity prices for SEM and BETTA. The SEM is a mandatory pool market with capacity payments. Wholesale prices for SEM are the sum of the System Marginal Price (SMP), which reflects the marginal cost of generating electricity in the short run, and capacity payments, designed to compensate for the capital costs of building new generation. Capacity payments are allocated on a half-hourly basis, and are larger when the gap between available generation capacity and consumption of electricity is smaller. The SMP and capacity payments for SEM are published by the system operator SEMO (www.sem-o.com) for every half hour. The transparency of the market design facilitates the regulators' monitoring ability. The actual operation of the market since its inception in November 2007 indicates that firms have priced at short-run marginal cost and that the wholesale price that has resulted reflects the underlying perfectly competitive market price (Market Monitoring Unit, 2009). A previous study (Lyons *et al.*, 2007) showed that the SEM incentivises investment in new generation without rewarding new generators excessively.

It is more difficult to obtain data for the British system. BETTA is an energy only market and is designed to encourage bilateral trading, on which there is no public information. Most of the transactions take place within vertically integrated firms. The system operator is in charge of the balancing market, which itself does not provide a unique price signal: there are a buy and a sell price and generators can be on either side of the buy/sell relation.[1] The balancing price itself is traded on different markets that generate different prices. In this study we use data from the APX exchange, which is available for the length of our study period.

Here we calculate two sets of wholesale prices: the spot market and a price based on18 month hedged prices for the years 2008 – 2011. The spot price is the average of the sell and buy price in the balancing market. The balancing market represents only one percent of total electricity demand, although Bunn and Zachmann (2010) suggest that balancing prices are in line with over the counter prices, accounting for a further 9 per cent of total volume.

The 18-month hedge price is built in line with the methodology presented in Ofgem (2009b), assuming that generators enter into forward contracts with suppliers and they sell their power starting 18 months ahead of the generating period and sell a residual 10 per cent at the spot price. The price generators obtain for electricity at time t therefore depends in part on the forward price established 18 months prior to t. Data come from the ICE exchange (www.theice.com). Note that BETTA does not remunerate generators separately for capacity costs, so they must be able to recover their long run costs through energy prices in order to remain profitable. When examining wholesale prices across the systems we therefore compare the sum of SMP and capacity payments in SEM to energy market prices in BETTA. Table 1 reports the prices for all years, transformed into euro for ease of comparison.

[1] For more on the British market, see for example Steggals *et al.* (2011).

Table 1. Wholesale System Prices in SEM and BETTA, in €/MWh

	SEM			BETTA (GB)	
Year	SMP	Capacity Payments	Total	Spot	18 month hedge
2008	84.2	15.7	99.9	84.9	62.9
2009	46.5	18.6	65.1	44.1	64.9
2010	56.9	15.7	72.6	49.4	53.4
2011	64.9	16.2	81.1	54.5	54.4

Note: all prices are average yearly prices, in nominal euro.
Source: authors' elaboration of SEM data from www.sem-o.com and APX data from ICE (www.theice.com).

SEM prices are closely tied to spot fuel and carbon dioxide permit prices, as generators are expected to bid on the basis of the spot prices of fuel and carbon inputs. The strong drop in oil and natural gas prices that occurred in February 2009 translated into lower spot prices in both jurisdictions. Not surprisingly it took a bit longer to emerge in the hedged prices series. In general, however, BETTA prices appear lower than SEM prices. There are several potential drivers of this result. In section 3.2 we examine if British wholesale prices might actually be too low, in the sense that they are not sufficient to cover long run marginal costs. This could explain in part why the electricity sector in Great Britain is currently dominated by vertically integrated firms, whereas vertical ties had been eliminated at the onset of deregulation in the early 90s (Wolfram 1999). On the other hand, the existence of vertically integrated companies might have depressed wholesale prices. British prices could also be lower because of a different portfolio of plants. We examine this option by simulating the SEM and BETTA markets with equal fuel input prices in Section 3.3. Before addressing the findings of our simulation, section 3.1 explains how the model for BETTA is built.

3.1 The Model

We have built the electricity market models using PLEXOS.[2] The PLEXOS modelling tool is used by the CER and the Utility Regulator to validate the Single Electricity Market and has a history of use in Ireland (Commission for Energy Regulation and Utility Regulator 2011). PLEXOS optimises hydro, thermal, renewable, and reserves simultaneously. Modelling is carried out using mixed integer linear programming that minimises costs of generation, including fuel, carbon and start-up costs, while meeting generating plants' technical constraints. PLEXOS reports the shadow price and the uplift for each period. The shadow price can be interpreted as the marginal price of electricity generation, that is the cost incurred to match an incremental change in demand. Any additional start-up costs are remunerated through the uplift factor.

2 PLEXOS for Power systems. Online at www.energyexemplar.com

The British model used here is based on the version built in Deane et al. (2013) and uses the Xpress[3] Mixed Integer Programming solver. The plant types and their capacities are taken from the Digest of UK Energy Statistics (DUKES).

To calibrate the model to historical values between 2008 and 2011, we have made the following adjustments. We have imposed average renewable generation levels equal to their historic amounts, as reported in the DUKES, Table 6.1. Nuclear generation in Britain has experienced a number of closings and maintenance issues in the past few years. We use the historical annual load factors reported in DUKES, Table 5.10. Finally, a number of coal plants have opted out of the Large Combustion Plant Directive (LCPD) and are therefore constrained to generate up to a maximum of 20,000 hours between 2008 and 2015. We limit their yearly availability to the number of hours they actually generated during these four years.[4] Interconnector flows and pumped storage are notoriously difficult to model. We avoid modelling them by taking demand net of historic levels of interconnector flows and pumped storage use. The half-hourly values for the interconnectors and pumped storage operations are reported by National Grid.[5] Note that transmission constraints are not included in the model, which means that the model reports a single price for the whole market in any given period.

Fuel input prices are taken from the quarterly survey of British major power producers published in DUKES. Table 2 states the annual average of the fuel prices, expressed in nominal euro per MWh and euro per tonnes of CO_2 permits for the Emissions Trading System.

Table 2. Prices of input fuels in British market, €/MWh

	Coal	**Natural Gas**	**Oil**	**CO_2 (€/tonne)**
2008	7.38	13.06	18.85	18.82
2009	6.98	12.49	19.77	13.16
2010	7.72	12.53	29.90	14.31
2011	9.93	16.61	38.32	12.99

Note: exchange rate is average yearly exchange rate.
Fuel prices from DUKES. CO_2 prices are EUA prices published by Bluenext.

To create a measure of long run marginal costs, in addition to the SMP we need to estimate the British equivalent of the capacity payments. We do so by building a yearly capacity pot for Great Britain. The calculation is based on the cost of capital for a best new entrant published by the Irish regulators each year.[6] Capacity payments are calculated assuming that all thermal plants are available to generate about 90 per cent of all times. This reflects best practice levels, not historic plant availability. Nuclear plants are assumed to be available

3 FICO Xpress Optimiser. Available online at http://www.fico.com
4 This information is available from the Environment Agency at: http://www.environment-agency.gov.uk/business/sectors/32621.aspx.
5 http://www.nationalgrid.com/uk/Electricity/Data/
6 See http://www.allislandproject.org/en/cp_decision_documents.aspx

about 70 per cent of the time. The forced outage probability is set at around 5 per cent across plants.

The size of the capacity pot is somewhat sensitive to availability and forced outage assumptions. If plant availability were set lower, capacity payments would be higher. The goal of capacity payments is to encourage availability of existing plants and entry of new plants when the margin between demand and available capacity is tight. The theoretical availability used to calculate total capacity payments should therefore be based on the expectation that plants will be run following best practice, which is the approach we use here.

3.2 BETTA and long run marginal costs

Table 3 reports the SMP, disaggregated into shadow price and uplift, and the capacity payments derived from the simulation of the British system. The average price reported here is weighted by demand.

The system prices we report are lower bounds of the historical generation costs. The PLEXOS model determines the least cost solution to meet demand while respecting generator technical-economic constraints. The actual BETTA market, based on bilateral contracts, can deviate significantly from an optimal dispatch framework and therefore generate more with plants that are relatively more costly. We find, for example, that coal generation for 2009-2011 has been much higher than our model would predict given the fuel prices that occurred.[7] This is not necessarily irrational, as bilateral contracts are set up ahead of time, when future fuel prices are uncertain.

Table 3. British estimated wholesale costs, €/MWh

Year	Model Results					Historical Data
	Shadow Price	Uplift	Total SMP	Capacity Payments	Total LRMC	Hedged price
2008	61.5	10.3	71.8	15.1	86.9	62.9
2009	46.2	10.4	56.6	16.4	73.0	64.9
2010	50.6	13.1	63.7	16.0	79.7	53.4
2011	55.6	11.1	66.7	15.4	82.1	54.4

Note: model numbers are all averages weighted by period demand. For historical data, see notes for Table 1.

It is striking that the price we calculate for the SMP, which as mentioned earlier is a lower bound of the historical generation costs, exceeds the hedged wholesale price obtained on the balancing market for all years except 2009.

Adding the estimate of capacity payments per MWh, the Long Run Marginal Cost (LRMC) is always higher than the hedged price. If we were to use the spot price reported in Table 2 the

7 Results on generation by fuel type are not reported but are available from the authors.

general conclusion would not change. Except for 2008, spot prices are significantly lower than the cost of generation we estimate here.

Our findings suggest that the British wholesale market might be underpricing electricity. With substantial excess generating capacity over the last decade, the market has seen firms "sweating their assets" so that the price has fallen below LRMC. Unless the wholesale price increases to at least LRMC in the near future, the GB market could have difficulties securing replacement investment for the generating capacity to be retired over the coming decade (Helm, 2009 and CER, 2009). We discuss this aspect in more detail in Section 5.

While the wholesale price in the GB market appears to be below LRMC, because the industry is dominated by vertically integrated utilities, profitability may be best assessed across the range of activities undertaken by these firms. It seems likely that the integrated energy utilities, while not receiving adequate remuneration from the wholesale market, derive exceptional profits from their retail operations, which could incentivise new investment (Giulietti *et al.*¸2010).

This strategy has significant attractions for integrated firms. By keeping the wholesale price low they discourage entry by new generators. It is much more difficult for firms to build a retail customer base than to build a generator and hence building a new integrated firm from scratch is exceptionally difficult, other than by takeover. The effect of this strategy is to protect incumbents from new entry. We explore retail prices further in Section 4.

3.3 The impact of technology differences

To examine technology differences, we impose the same prices shown in Table 2 on both SEM and BETTA. Each plant in SEM is modelled based on the public parameters reported yearly by the CER (see www.allislandproject.org). To be consistent with the modelling of BETTA, we simulate demand net of interconnector flows and do not model interconnector use. We use historical wind generation series.

We find that in 2008, with the same input fuel prices, British wholesale prices are lower than the ones in the SEM by €7.9/MWh, or about 10 per cent. As the British market becomes tighter, due to constraints on coal plants and outages of nuclear plants, the plant portfolio becomes more expensive in Great Britain than in Ireland. In 2010 Ireland has a technology advantage (in cost terms). The result is also driven by the relative cost of coal with respect to natural gas. Prior to 2009, natural gas prices were relatively high, giving a relative advantage to Great Britain. As prices of natural gas decreased with respect to coal prices, the cost of generating electricity decreased in Ireland with respect to Great Britain. In 2011 the SEM experienced large outages in the interconnector with Scotland, which probably led to the narrowing of the price difference with BETTA. Table 4 summarises the results.

Table 4. BETTA and SEM SMP prices, with equal fuel input costs, €/MWh

	BETTA	SEM	Difference
2008	71.8	79.7	7.9
2009	56.6	58.1	1.5
2010	63.7	57.7	-6.0
2011	66.7	66.6	-0.1

Source: PLEXOS model results

The importance of technology differences is lower than for previous estimates (Devitt et al. 2011) because here we take into account the limitations on the availability of coal and nuclear plants in Great Britain.

4. Domestic retail prices

In this section we compare retail prices for Ireland and Great Britain for the household sector and disaggregate them in their main components. The residential sector is the sector for which information in different jurisdictions is available on a comparable basis.

Table 5. Retail costs and margins for domestic consumers, €/MWh, nominal prices

	2008		2009		2010		2011	
	GB	IRL	GB	IRL	GB	IRL	GB	IRL
Retail Price	146.2	167.5	137.0	171.2	135.1	160.9	143.7	167.0
Wholesale Price	62.9	99.9	64.9	65.1	53.4	72.6	54.4	81.1
Balancing costs	1.5	3.3	1.4	2.8	1.3	3.1	1.4	5.4
PSO/Environmental costs	9.2	0.9	11.5	5.3	13.5	8.9	16.1	6.5
Transmission	4.6	6.6	4.3	6.9	5.7	7.7	6.1	8.1
Distribution	23.1	42.6	21.6	41.5	22.7	51.3	25.3	50.9
Retail Margin	44.8	14.1	33.2	49.7	38.5	17.2	40.5	14.9

Note: Estimates in italic. Domestic price from Eurostat. Simple average of 6-month reported data; Price for band DB (between 2500MWh and 5000MWh consumption yearly).
Breakup of costs: authors' calculations based on OFGEM and CER data.
When fixed costs are present, averages taken for a consumer using 3.3 MWh/year.

Eurostat reports electricity prices by bands of consumption. We take the 2500-5000KWh per year band as representative of the domestic sector. Average domestic consumption was 4150KWh for all domestic households in GB in 2009 (and 3800KWh/year for households on standard meters, which accounted for more than 80 per cent of total households).[8]

Suppliers have to pay the following costs to provide electricity to final consumers: the wholesale electricity price, balancing costs, transmission and distribution charges,

[8] See Table 2 in: http://www.decc.gov.uk/assets/decc/11/stats/publications/energy-trends/articles/4782-subnat-electricity-cons-stats-article.pdf and Table 1, page 108 of http://www.decc.gov.uk/assets/decc/11/stats/publications/energy-trends/3917-trends-dec-2011.pdf

environmental charges, in addition to the costs they sustain to meter and bill electricity usage.

We have already discussed wholesale prices extensively. In this section, we take the hedged price presented in Section 3 as the representative price for Britain. Balancing costs are costs incurred to maintain the reliability of the system. In some instances, for example in the presence of congestion on the transmission lines, the system operator has to deviate from the optimal dispatch schedule and constrain some plants on or off. Balancing payments cover the costs of these constraints. In order to reach final consumers, electricity has to travel through large transmission and smaller distribution lines.

Environmental costs include the Public Service Obligation in Ireland (although we should note that the PSO supports non renewables as well, such as peat plants). In Great Britain they consist of Renewable Obligation Certificates (ROCs) and the Carbon Emissions Reduction Target (CERT). In Ireland balancing charges per MWh are determined every year by the CER. For Great Britain, they are published on an hourly basis by National Grid. Table 5 presents the average balancing cost per unit of final demand. Transmission, distribution and environmental costs for Great Britain are calculated on the basis of their shares of the overall bill published by Ofgem (2008, 2009a). Costs for 2010 and 2011 are based on the information reported by the Committee on Climate Change (2011a and 2011b). For Ireland, they are calculated based on the official tariffs imposed by the CER[9] for standard electricity users, assuming a yearly consumption of 3.3MWh, weighted by monthly generation when the tariffs do not coincide with calendar years. Moreover, distribution costs are averaged by the share of urban versus rural households reported in the 2011 Census (64 per cent urban and 32 per cent rural). This is necessary since electricity prices are two-part tariffs and charge a different fixed amount if the consumer lives in a rural or urban area.

There are a few aspects of Table 5 that are striking. First of all, retail margins in Great Britain are substantially larger than in Ireland. In light of the findings in our previous section, this is not surprising. Vertically integrated electricity companies are recouping on the retail market part of the costs they incur generating electricity. The net impact on final consumers is unclear. Whereas in principle one might expect large retail margins to encourage new entry into the retail market, in practice retailers must find generators willing to sell to them. If this is difficult because most electricity companies are vertically integrated, entry in the retail sector might be limited and average consumer prices might be higher than they need be. For a description of how vertical integration can limit competition, see for example Rey and Tirole (2007).

We should note that the net effect of vertical integration on final consumer prices is uncertain. It is likely to decrease wholesale prices, as we saw in this analysis (see also Bushnell *et al*., 2008 who study US markets). The effect of vertical integration in the British markets is examined in Giulietti *et al.* (2010). They find a substantial impact in the GB market

[9] Documents on transmission and distribution tariffs can be found respectively at http://www.allislandproject.org/en/transmission_decision_documents.aspx and http://www.cer.ie/en/electricity-distribution-network-decision-documents.aspx.

arising from the strong retail position of integrated firms and they cite evidence of large positive changes in supplier profitability over time as vertical integration developed. Giulietti *et al.* (2005) show that the incumbent electricity provider has maintained significant market power in the residential sector. Wilson and Waddams (2010) also find that after liberalisation consumers have not minimised their electricity costs by choosing the cheapest supplier, leading to higher average retail margins for suppliers in Great Britain.

The second issue that arises from Table 5 is the large cost of distribution for Irish consumers. Some of this is due to the sparser population in Ireland versus Great Britain. Ireland has 82 meters of distribution per customer on average (CER 2010). For Great Britain as a whole, elaboration of data in Ofgem (2012) shows that the average was 27 meters per customer. There are 14 distribution networks operating in Great Britain and the average length of the network per customer varies substantially, from 16 meters in London to 63 in Northern Scotland.

Table 6 compares the distribution costs for a household consuming 3.3.MWh per year for the years 2010 to 2011 in Northern Scotland and Ireland. Even if we were to adjust for Ireland's longer distribution network, Irish prices would still be higher.

Table 6. Comparison of household distribution costs, €/MWh

	2010	**2011**
Scottish and Southern Hydro	34.8	35.0
Republic of Ireland	51.3	50.9

Source: authors' elaboration from http://www.ssepd.co.uk/Library/ChargingStatements/2013-2014/
Calculated based on yearly consumption of 3.3MWh. For the Republic of Ireland see also notes for Table 3.

There are several reasons why this difference may be sustained over short periods of time. It may be that one system is undertaking greater investments than the other. However it is also possible that some of the difference is due to labour costs. Diffney et al. (2009) argue that labour costs in Irish utilities (and specifically in electricity) have always been high relative to the UK.

Finally, the environmental costs appear to be substantially higher in BETTA than in Ireland even though the penetration of renewables in electricity generation is about half that of Ireland, as shown in Table 7. Probably in part in reaction to these high costs, the Department of Energy and Climate Change (2012) is suggesting changing ROCs for feed-in-tariffs.

Table 7. Share of renewables in final electricity demand, %

	2008	2009	2010	2011
Great Britain	6.2	7.6	7.6	9.8
Ireland	13.4	16.3	14.7	21.8

Source: authors' elaboration of data from Dukes and Restats (GB) and Energy Balances (Ireland).

5. Future Prices

In the case of Great Britain, the wholesale price in the 2008 to 2011 period was probably too low, being insufficient to remunerate the long-run marginal cost of generating electricity. This conclusion is similar to that of other studies (Helm, 2009 and CER, 2009). If the British market is to continue to enjoy a secure electricity supply over the coming decade very substantial new investment in generation will be required. For this to happen investors will have to be reassured that their investment will be adequately remunerated through the wholesale electricity price rising to reflect the true long run marginal cost of producing electricity.

The Department of Energy and Climate Change (2012) suggests a capacity mechanism to encourage new investment in generation. This would obviously increase final prices, so it is reasonable to ask if current retail prices are in fact too low. If we substitute our estimate of generator long run costs from Table 3 in the calculation of retail margins, we obtain the results shown in Table 8.

Table 8. Retail margin in Great Britain, with estimated LRMC, €/MWh

	2008	2009	2010	2011
Retail Price	146.2	137.0	135.1	143.7
LRMC	86.9	72.4	78.0	82.0
Other costs	38.5	38.9	43.2	48.8
Retail Margin	20.8	25.7	13.9	12.9

Source: Model results and DUKES. See notes to Table 3 and Table 5. Estimated values in italics

For 2008 and 2009 there was enough revenue in the system to encourage new generation. The margin decreased in 2010 and 2011. Note that the lower retail margin of €13/MWh to €14/MWh does not deviate substantially from the 2010-2011 average in Ireland, which was about €16/MWh. Whereas some increase in generator returns might be needed to encourage new investment, it appears that it would be even more effective to develop market mechanisms that allocate increased revenue to generators while decreasing it for retailers. This would provide an incentive for firms to enter the generation market independent of the retail market.

How to implement such a mechanism is not an easy question and is beyond the scope of this paper. One option that would help increasing generator profits might be to move away from bilateral contracts. Mansur and White (2012) argue that from a theoretical point of view a system based on bilateral contracts can be as efficient as a centralised market. However, they find that when the Midwest of the US moved away from bilateral markets to join a centralised auction market in the east of the country, trade (and dispatch efficiency) greatly increased.

In the Irish market prices already reflect LRMC so that, *ceteris paribus*, there is likely to be some narrowing in the difference between the retail prices in the two markets over the coming decade. The retail margin for household consumers in Ireland may be further squeezed by the regulator over the next few years.

There are a number of areas where current public policy may cause higher electricity prices in Ireland and Great Britain in the future. In some cases these higher prices will come with some societal benefits, for example in the form of lower pollution, but in other cases the societal benefits may be strictly limited.

With competitive markets the price of carbon is already incorporated into the price facing consumers. The EU Emissions Trading Scheme (ETS) is likely to see a rising price for carbon within the EU. This provides the appropriate signal for consumers, encouraging a reduction in emissions at a minimum cost to society. Until now these permits have been largely granted at a zero cost to incumbent generators. This has resulted in windfall gains for companies owning electricity generation, strengthening the position of incumbents relative to new entrants (FitzGerald, 2004). However, from 2013 an increasing share of the ETS permits will be auctioned. This should not directly affect electricity consumers, as they are already paying the full market price of the permits in their electricity bills, but it will decrease the profitability of the incumbents. It may affect taxpayers, to the extent that some of the generating companies are state owned and the windfall gains may therefore at least in part be paid back to the public sector.

A second important area of public policy is the range of measures that have been taken to encourage renewable generation. In Great Britain the approach taken through the imposition of a Renewables Obligation (ROCs) is significantly more costly than it need be (Helm, 2010). McIlveen (2010) estimates that the implied carbon price under the scheme is £130 per tonne of carbon dioxide. In addition to the current situation, where payments are made to relatively low cost onshore wind generators, the commitment to develop large volumes of offshore wind and wave power in the future is likely to prove very expensive. If this policy is implemented over the coming decade through the current ROCs mechanism, it will result in a major increase in the cost of electricity for customers in GB (McIlveen, 2010). From an environmental point of view, it will be very bad value for money as the same reduction in carbon dioxide emissions can be achieved at a much lower cost to consumers. It remains to be seen how these costs will adjust if subsidies move to a fee-in-tariff approach, as the cost will depend on the level of support offered for each renewable technology.

In the Irish case, the Public Service Obligation (PSO), designed to support public objectives, including deployment of renewables, was low in 2008 and 2009. However, for 2011 it is around €6.5 per MWh. While some of this PSO goes to fund the support mechanism for renewables, a substantial part goes to support peat-fired generation. This fuel produces very large amounts of carbon dioxide per unit of electricity generated so it is particularly damaging from an environmental point of view (Tuohy *et al.*, 2009). The justification for this expenditure is officially for security of supply although in the past it was also used to support employment. However, it is an expensive way of meeting both these targets. This obligation will be removed by 2020, which will clearly be beneficial: it will lower carbon dioxide emissions and costs of the Irish electricity system.

An element of public policy in the Republic of Ireland, which could end up proving expensive, is one aspect of the REFIT scheme enacted to support renewables. This scheme provides a guaranteed price which is different for different types of renewables. In the case of onshore wind this arrangement may well be broadly appropriate. It serves to reduce uncertainty for investors which, in turn, should reduce the cost of capital reducing the price they need to receive to make investment economic. There are some concerns that support may prove overgenerous in the long term and the regime may, as a result, need some tweaking (Devitt and Malaguzzi Valeri, 2011). Wind lowers the average shadow price when it is blowing (since it displaces fossil-fuel operated plants). At the same time it increases PSO and ramping costs of thermal plants (Di Cosmo and Malaguzzi Valeri, 2012). The net effect is a priori unclear, but will tend to be more beneficial the higher fossil fuel prices are. Diffney *et al.* (2009) conclude that the level and mechanisms of support appear broadly correct and likely to deliver benefits for consumers if energy prices are in the mid to high range as suggested by the IEA, but will provide lower benefits at low fossil fuel prices.

Because Ireland is likely to see all the onshore wind that the system can absorb without major cost to consumers there is unlikely to be any room or need for very high cost offshore wind. Thus the high REFIT price for offshore wind could see Irish electricity consumers paying a very high price by 2020, with no commensurate savings in greenhouse gases, because offshore wind would only replace cheap onshore wind. Denny (2009) has shown that tidal power, which is supported by the REFIT scheme, is also likely to be much more expensive than onshore wind because of its likely higher capital cost per unit generated.

Higher levels of wind are likely to affect the returns on investment of thermal plants, which might be a concern in any market where high investment is needed for system reliability. This is especially true in Great Britain.

6. Conclusions

This paper examines the wholesale and retail prices in Ireland and Great Britain. The British market is not price transparent, so the results presented here have to be interpreted as approximations of true prices and costs. That said, our findings strongly suggest that wholesale prices in Great Britain are much lower than in Ireland. Moreover, using a model that commits and dispatches generating plants optimally, we show that the wholesale price in Great Britain is not sufficient to cover long run generation costs.

Not surprisingly, domestic retail margins are extremely high in Britain. Vertically integrated companies use the returns on the retail market in part to finance generation costs.

In 2008 Great Britain had a technological advantage with respect to Ireland, resulting in lower generation costs all else being equal. Over time the price of natural gas decreased with respect to the price of coal. Moreover, the Large Combustion Plant Directive and extensive maintenance of aging nuclear plants created a tighter market in Great Britain. The joint effect of price and plant availability changes caused the technological advantage to shift in favour of Ireland by 2010.

An upward pressure on prices is likely in the future. Both jurisdictions aim to increase the share of renewables in electricity generation and this will likely increase costs. The cost of supporting renewables per MWh of electricity consumed is however much higher in Great Britain, even though renewables account for a smaller share of overall consumption. There is therefore scope to decrease the effect of environmental measures on final electricity prices while achieving the same environmental impact. The move in the UK towards feed-in tariffs might help. Both jurisdictions are also likely to need further investment in transmission and distribution. Great Britain, in addition, faces substantial investments in new generation to maintain a reliable system.

For Great Britain our analysis suggests that total electricity costs are sufficient (or close to being sufficient) to remunerate all aspects of providing electricity, but currently all the profits are extracted at the retail stage. There might be an opportunity in Great Britain to mitigate the upward pressure on electricity prices associated with increased investment in new generation. The market could be restructured to allow generators to be fairly remunerated for their costs (while simultaneously decreasing retail margins). This would increase the incentive to invest in new generation with minimal changes to final consumer prices.

In Ireland, the relative cost of distribution is higher than in Britain. Some of this is due to the lower density of population in Ireland. Some, however, may be due to higher labour costs in Ireland relative to Great Britain.

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