

Goldilocks and the Three Electricity Prices: Are Irish Prices “Just Right”?^{*}

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Abstract: In this paper we analyse the 2008 electricity price in the Irish All-Island Market. We test whether this price is ‘efficient’ by comparing it to the electricity price in Great Britain. This analysis suggests that around €16 per MWh of the difference in wholesale prices between Ireland and Britain is due to differences in generating technology. The new wholesale electricity market for the island of Ireland appears to be working well – it is producing a wholesale price that approximates the long run marginal cost that would apply in a large liquid competitive market. In the British market the wholesale price appears to be below the long run marginal cost of producing electricity. Retail margins in Great Britain are high, especially for households. Only some of this margin compensates vertically integrated utilities for the low wholesale price. In the Republic of Ireland the retail margin was probably also higher than it should have been.

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1. Introduction

In the story of Goldilocks and the Three Bears, Goldilocks tries three bowls of porridge – one is too cold, another is too hot and one is just right. This paper looks at electricity prices in Ireland and Great Britain and questions whether they are too high, too low or “just right”.

This paper uses data on the electricity prices from three related but separate jurisdictions (the Republic of Ireland, Northern Ireland and Great Britain) to examine the efficiency of their electricity markets in terms of the prices charged to consumers. It uses a model of the electricity market to derive the short run and long run marginal cost of electricity in the different markets. Using this as a benchmark, it considers the actual wholesale and retail prices in the separate markets. This analysis throws light on the extent to which liberalisation has delivered an efficient electricity market.

The electricity markets on the island of Ireland and in Great Britain are affected by the legacy effects of different histories of investment in electricity generation, as well as differences in the nature of their labour markets, which affect operating costs. Since the end of 2007 Northern Ireland and the Republic of Ireland¹ have shared a wholesale electricity market, here referred to as the All Island Market (AIM).² The two regulators on the island (the Northern Ireland Authority for Utility Regulation, NIAUR, and the Commission for Energy regulation, CER) cooperate to regulate the wholesale market; retail markets are, however, regulated separately. Additionally, Northern Ireland is subject to the same taxes as Great Britain. Great Britain and Northern Ireland also 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

¹ While the official name of the country is Ireland, for clarity of exposition we here refer to Ireland the country as the Republic of Ireland.

² It is also commonly referred to as the Single Electricity Market (SEM).

Northern Ireland, while both regions of the United Kingdom, have separate regulators: the Office of Gas and Electricity Markets (OFGEM) and the Northern Ireland Authority for Utility Regulation, 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 aspects of the cost base 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 economies³.

Great Britain also faces an uncertain future with respect to electricity prices. Most existing nuclear plants are due to close by 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 bilateral contracts market 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.

Using a model of the electricity market, we consider whether prices for electricity consumers in Ireland represent the outcome of an efficient and competitive market or whether there are avoidable costs, keeping prices unnecessarily high, which should be reduced by government policy action. Applying a similar model we evaluate whether prices in Great Britain are sustainable in the long term. While there is a danger that problems in the Irish electricity market or in the British market could result in prices

³ For example, the National Competitiveness Council, 2009.

being too high, damaging the competitiveness of the business sector, 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.⁴

In Section 2, we look at the behaviour of electricity prices in Ireland relative to those in Great Britain over the last 30 years. In Section 3 we briefly describe our model of the electricity markets in Ireland and Great Britain, which takes account of input costs and the generation technologies in the two markets. In Section 4 we apply this model to data for Ireland and Great Britain for 2008 to determine what would be the short-run and the long-run marginal wholesale cost of electricity generation in the two markets under conditions of perfect competition. We then compare these results with the observed wholesale and retail price of electricity in the two markets and consider some of the reasons for the difference in costs between the two markets – labour costs and government policy. In Section 5 we discuss the implications of these results for electricity prices in the future. Section 6 concludes the paper.

2. History

Over the last 30 years electricity prices have generally been higher in the Republic of Ireland than in Great Britain. The gap was particularly big in the 1980s. This reflected the need 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

⁴ Prices could also be “too low” because of environmental policy failure resulting in excessive consumption of energy with damaging consequences for the environment.

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 plant, which was 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 on the basis of short run marginal costs. As discussed later, this appears to have pushed the price below long run marginal cost.⁵

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*.⁶ 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

⁵ Because of the nature of the GB market with integrated utilities and bilateral contracts, the wholesale price is not revealed. We use a model of the GB market to estimate this wholesale price.

⁶ To convert the UK prices to euro we use the average yearly exchange rate published by Eurostat post 1999. Pre 1999 IEA uses the irrevocable 1999 exchange rate between the Irish Punt and the euro for the Irish series. We take the £/Punt rate pre 1999 and express it in euro at the irrevocable Irish Punt/euro rate to provide a comparable UK price series in euro.

1980s was eroded by increased demand so that the repayments on past investment were spread over an ever increasing volume of sales.

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

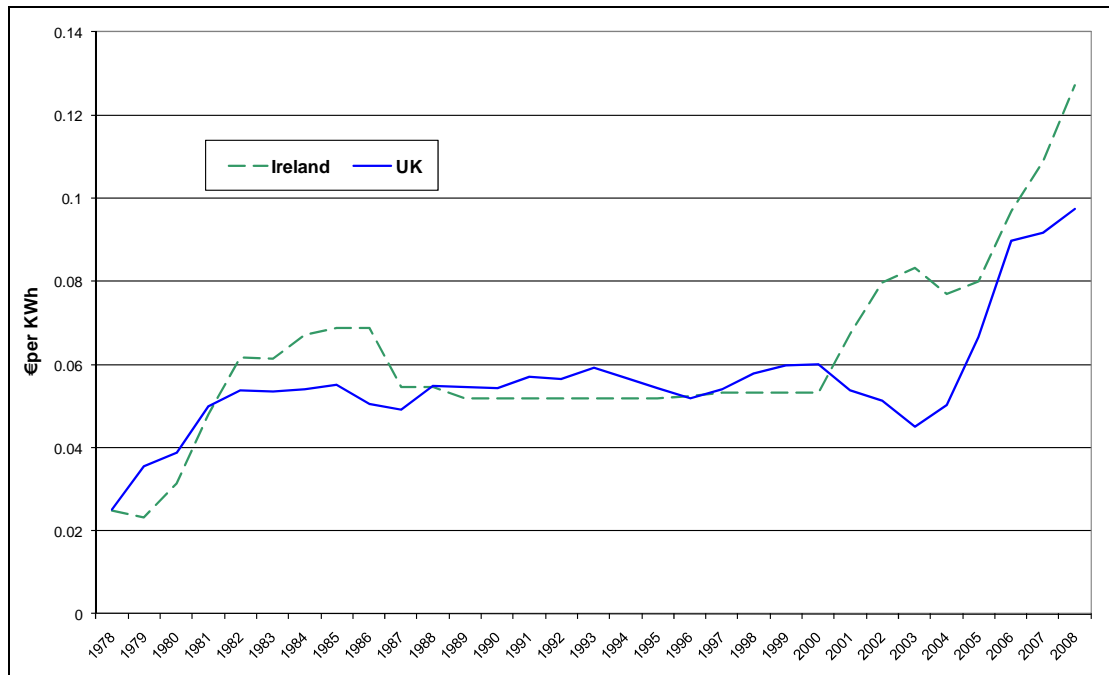
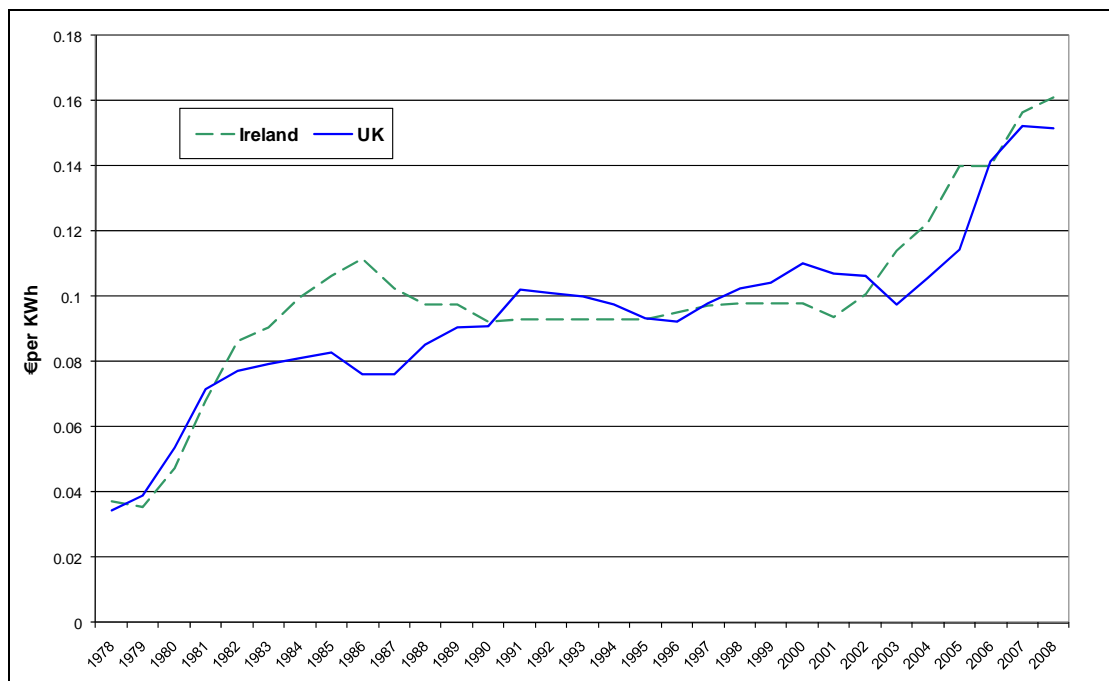


Figure 2. Household electricity prices, ex-tax, €/kWh



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 also meant that, in spite of differences in generating technology, the cost of the energy needed to generate electricity in Ireland also fell in real terms.

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 less since the mid-1990s. We return to this issue later in this paper.

3. The Model

For this study, we used the WILMAR model for unit commitment and economic dispatch (Tuohy *et al.*, 2009b and Meiborn *et al.*, 2011), originally developed to study wind variability in the Nordic countries and subsequently adopted for the All Island Grid Study (DCENR and DETINI, 2008). WILMAR is designed to model hourly unit commitment and economic dispatch for power systems with significant wind penetration. In every hour generation has to match demand, determined by an exogenous demand curve that is assumed to be price-inelastic. The model initially assumes that there are no transmission constraints. It allocates demand across the range of generating stations that are available so as to minimise the overall cost of the system for each day. Costs include fuel costs (based on each individual plant's efficiency), carbon taxes and start-up costs. The cost-minimising solution is subject to constraints on units determined by engineering factors, such as start-up time, minimum up and down times, ramping rates, and minimum and maximum generation, as well as interconnection constraints and losses, and penalties for not being able to meet load targets. The model has foresight of the outages of units, and does not consider reserve targets in this study.⁷

The results are designed to model the AIM, which dispatches the system based on the least cost system operation. The AIM is a mandatory pool where all generators have to bid costs (including carbon). The cheapest plant will generally be dispatched first,

⁷ The model uses Mixed Integer Programming, with the state of each unit (online or offline) represented by decision variables. This ensures that each unit is modelled accurately.

subject to engineering constraints. The system will also ensure that there is a minimum number of conventional units online to guarantee system stability. Plants are added until there is sufficient generation to meet existing demand. The most expensive plant that is dispatched sets the shadow price for that hour. The shadow price is effectively the cost of generating of the most expensive plant used in each hour of each day. The model thus estimates the shadow price for each hour of each day and this price is paid to all plants that are generating in the relevant period. This is the short run marginal cost (SRMC) of producing electricity for the system. If the shadow price is not sufficient to cover all the plants' short-run costs (due for example to additional costs incurred when plants are warming up) there is an additional uplift payment. When the cost of capacity payments is added to each unit of electricity the resulting price reflects the long run marginal cost (LRMC) of production.⁸

A similar model is set up for Great Britain. We model the wholesale market in Great Britain on the same basis as the Irish market, i.e. as a mandatory wholesale market where generators bid their short run marginal cost of production. Great Britain faces its own (separate) demand curve, which is also assumed to be inelastic to price changes. Whereas each plant on the Irish system is modelled separately, for the British system plants of the same type and similar efficiency are aggregated. Both the Irish and British systems are jointly optimised, to produce the optimal dispatch of the interconnection between the two islands, resulting in the lowest cost for the two systems taken together.

Interconnection is modelled as a limit in transmission between the two regions, with an efficiency loss of 3% to ensure that one region has to be significantly cheaper than the other for import or export to occur. We abstract from the actual arrangements on the British market, which is governed by BETTA (British Electricity Trading and Transmission Arrangements) and is based on voluntary bilateral arrangements between generators, suppliers, traders and customers.⁹ If the British market is efficient, the wholesale price of electricity on the GB market should reflect the long-run marginal cost of production, which is estimated independently by the model.

⁸ The long run marginal cost is the cost of remunerating the system including the cost of energy used in generation, operating cost and the remuneration of the capital employed in the system.

⁹ For more on BETTA and its performance, see Newbery (2006).

4. Comparing Prices

There are a range of possible reasons why electricity prices might be different in the All-Island Market (AIM) from those in the British market and we use the WILMAR model of the electricity generating systems in both markets as a means of identifying the SRMC and the LRMC in the two jurisdictions. WILMAR models both markets as mandatory pools with capacity payments. Thus, to the extent that there is a difference in the wholesale price estimated by the model for the two markets, this is due to either differences in energy input prices or differences in the generation technologies used on the two islands.

The AIM market was designed to minimise the opportunity for any individual firm to use market power to leverage higher wholesale prices. 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, as expected, firms have priced at short-run marginal cost and that the wholesale price that has resulted reflects the underlying perfectly competitive market price. A previous study (Lyons *et al.*, 2007) showed that the AIM incentivises investment in new generation without rewarding new generators excessively.

We then use the capacity payments methodology applied in the AIM to measure comparable capital costs in the two markets to derive the long run marginal cost of the two electricity systems, conditional on the short run marginal cost estimated by the electricity model. Different approaches to remunerating capital could see departures from the optimal approach of pricing at long run marginal cost. This is no longer the case in Ireland as the market design ensures that consumers of electricity are faced with the long run marginal cost of the electricity that they consume. In the case of the British market, as discussed later, there are doubts as to whether the current price actually covers the long run marginal cost for that system so that prices may have to rise over the coming decade (Helm, 2009).

Later in this Section we also consider the factors determining the distribution margin – the difference between the wholesale price and the retail price of electricity. This margin, covering the costs of transmission, distribution and supply, is derived as the difference between long run marginal cost and the actual price faced by consumers in the industrial and the household electricity markets on the two islands.

We use data for 2008, the first full year of operation of the AIM. As discussed above, there are good theoretical reasons for believing that the new AIM, by providing a suitably transparent market structure, results in the wholesale price of electricity approximating the long-run marginal cost of production – what one would expect from a perfectly competitive market. The evidence for the first year of operation suggests that the AIM has largely delivered on expectations.

It may be difficult to make definite conclusions based on one year of data since firms could recover in the following year excess costs from the year before. However, the prices calculated by the model are on the basis of no hedging of fuel prices.

Table 1 shows the results obtained from applying the model to the Irish and British electricity markets for 2008. The results derived using the model are compared with observed wholesale prices for the markets, shown in the last line of Table 1.

Table 1. Estimated Wholesale Price, 2008

		Ireland	Great Britain
	Source	(€/MWh)	(€/MWh)
SRMC	Model Estimate	66.0	49.6
Capacity Payments	Model Estimate	15.4	15.4
LRMC	Model Estimate	81.4	65.0
LRMC incl uplift and bal. cost	Derived	93.7	n.a.
Market “wholesale” price	Market outturn	103.0	68.9

We have used energy input price data from the International Energy Agency (IEA) publication on the price of fuel used in electricity generation for Ireland and Great Britain (IEA, 2009). For Great Britain we report the price provided for the UK as a whole. We assume that the price for the Republic of Ireland applies to the whole island. The IEA does not provide information on the price of gas used in electricity generation in Ireland after 2003 (for confidentiality reasons) so we have used the UK price since then to estimate the price in both markets (€351.1/TOE for 2008).¹⁰ We

¹⁰ Because of the higher transmission costs for transporting gas to Ireland the price in Ireland is slightly higher than in GB. This would mean that the estimated cost differential between the two markets should be slightly higher than estimated here.

use an average yearly carbon price of €22.4 per tonne of CO₂.¹¹ On this basis, using actual hourly demand for the year separately for each jurisdiction, we estimate that the average price of electricity in Ireland, weighted by the share of demand in each hour, should have been €66.0 per megawatt hour (MWh) – equivalent to Short Run Marginal Cost (SRMC).¹² This price reflects the price of the energy used in generating the electricity and any carbon cost. For Great Britain the model estimates a SRMC of €49.6 per MWh. Because fuel prices were fairly similar across the two jurisdictions, the difference in generating technologies used in the two markets accounts for most of the difference in SRMC between the two markets of €16.4 a MWh. CER (2009) estimate that the forward spark spread for 2009/10 for the AIM relative to BETTA was around €10.7 a MWh higher and that this was largely accounted for by differences in generation technology and differences in system size. This estimate is consistent with our estimate for 2008.

Capacity payments, paid to ensure security of supply, are estimated to be €15.4 MWh in the two markets.¹³ Capacity payments for the AIM and BETTA were calculated using the ESRI's IDEM model (Diffney *et al.*, 2009).¹⁴ The calculated value for the AIM corresponds closely to the value reported in MMU (2009). The capacity payments are calculated based on the full costs of an efficient new peaking plant fuelled by oil distillate (SEM, 2007). The capacity “pot” is divided among the plants that are available. The total size of the capacity pot is calibrated so that when the margin between demand and available capacity is small, payments will be larger to encourage further investment. Payments will be inadequate to remunerate new investment if capacity is greater than required.

As mentioned above, Irish plants are compensated directly for start up and no load costs (since this is not part of either energy costs or capacity payments) if they cause

¹¹ This is the unweighted average of carbon prices for 2008, based on EU allowances with the shortest settlement date.

¹² Because there is a single wholesale electricity market on the island of Ireland the SRMC is identical for both Northern Ireland and for the Republic of Ireland.

¹³ For GB we aggregate some of the plants into larger plants. Thus we somewhat overestimate the probability that demand will not be met by supply. This in turn feeds into the calculation of capacity payments which means that the capacity payments presented here are an upper bound.

¹⁴ IDEM also provided SRMCs that were similar to the WILMAR results reported here. WILMAR was preferred as it incorporates more detailed engineering constraints such as ramping rates.

any plant to make losses during a generating period. This additional payment is measured by the uplift term, which MMU (2009, p.38) reports as 11 per cent of the SRMC (expressed as an unweighted average) or about €8.9/MWh. In addition, if transmission constraints cause plants not to be dispatched when they should be according to the merit order, the plants are compensated for their loss. These balancing costs accounted for about €3/MWh in Ireland (MMU, 2009). Unfortunately it proved impossible to obtain an estimate of these costs for the GB market. Because of its larger size, with many more plants, it is likely that these costs in GB would be less than the cost in Ireland.

The final row of Table 1 shows the wholesale price observed on the market. In the case of the Irish market it is derived from the price reported in MMU (2009). It is calculated as the sum of the SRMC, uplift, balancing costs and capacity payments. The historic wholesale price for Ireland, while of a similar magnitude, is somewhat higher than that estimated using WILMAR.

The GB market operates through bilateral contracts, and is therefore much less transparent. The spot market price in GB represents only about one percent of the market, and is therefore unlikely to be representative of the wholesale price. In 2008 it was equal to €87.6.¹⁵ Spot market exchanges are typically made when a company has to balance their position at the last moment. As such, we expect the spot market price to be higher than the average exchange price. Another estimate of the wholesale market price for GB is given by the average price from OFGEM (2009) for 18-month hedged prices. We calculate the weighted average for 2008, where the weights are the share of consumption in each quarter, to find an average price of €8.9. The ‘true’ price is probably somewhere in the middle, although it is more likely to be closer to the latter price, for the reasons given above. We therefore adopt the price reported by OFGEM (2009) as the most representative price in the following analysis. It is striking that this price is very close to the Long Run Marginal Cost (LRMC) estimated using the model, even before adjusting for the cost of “uplift”. This suggests 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

¹⁵ Data from www.elexon.com

assets” so that the price has fallen below LRMC. This would suggest that in the future the British price will have to rise relative to that of Ireland if there is to be adequate investment in new generation over the coming decade. 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).

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, as has happened in Ireland. 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. Thus the effect of this strategy is to protect incumbents from new entry.

Table 2. Retail Prices and Margins, 2008

	Source	Republic of Ireland (€/MWh)	Northern Ireland (€/MWh)	Great Britain (€/MWh)
Market “wholesale” price	Market outturn	103.0	95.54	68.9
Industry	Price – IEA pre-tax	127.2		97.3
	Implied distribution margin	24.2		28.4
Households	Price – IEA	161.0	140.4	152.1
	Other Costs (PSO and ROC/CERT)	0	6.73	9.6
	Implied distribution margin	58.0	38.2	73.6

In Table 2 we compare the wholesale market prices in the two markets with the retail prices reported by the IEA. This price is the average price per MWh, including standing charges and excluding all taxes. We also include information for Northern Ireland.¹⁶ We define the retail margin as the difference between the retail price and the wholesale price. The gap between these two prices is made up of payments for transmission and distribution (use of the wires) as well as for supply of electricity (billing etc.). The margin also includes the profit of the firms operating in the sector. Finally, public policy also has an impact on the margin, in particular through implementing a range of incentive measures to encourage activities that are considered desirable from a public policy point of view – such as renewable generation

The GB market has experienced many years of competition between what are now vertically integrated utilities. In addition the transmission system is owned by National Grid, a regulated private monopoly. This structure might be expected to have driven down costs in the industry in GB. However, as discussed above, the nature of the market could see the incumbent integrated utilities extracting excess profits, in part due to their ability to restrict entry.

By contrast, in 2008 the Irish market was dominated by the state-owned Electricity Supply Board (ESB). The ESB is responsible for building and managing the transmission and distribution network and also, until recently, was effectively the sole supplier of electricity to the household market. In the absence of appropriate regulation, with a state-owned dominant player there is the danger that the cost of delivering electricity could be excessive, either due to very high profits or, alternatively, to very high labour costs, where employees capture the monopoly rent. The task of the regulator, the CER, is to ensure that this does not occur. If they have been successful then any monopoly rents captured by labour will result in lower

¹⁶ While Northern Ireland in 2008 was part of the AIM wholesale market, the “wholesale price” shown here is derived as a weighted average of the price for the years 2007/8 and 2008/9. Hence it differs slightly from the wholesale price for the Republic of Ireland. However, we use a consistent set of weights for all the other prices in Northern Ireland so that the information on retail margins is internally consistent.

profitability (and dividends) for the owner – the state, rather than higher prices. However, if through information asymmetry the regulator does not manage to fully control costs, this could result in a higher cost for consumers than would occur if the market were “competitive”.¹⁷

In Table 2 we consider this implied retail margin for 2008. For industrial users in the Republic of Ireland, the margin is actually very similar to that in Britain. On a priori grounds one would expect it to be a bit higher in Ireland because of the lower density of the electricity network. However, as discussed earlier, some of the higher margin observed in the GB market may reflect the fact that the wholesale price is less than LRMC and integrated firms recoup some of this “loss” through higher retail margins.

The difference in the retail margins between the different household markets is significantly greater than in the case of the industrial market. The margin in the British market is exceptionally high, even when allowance is made for government mandated environmental costs, which include the cost of the Renewable Obligations scheme and the Carbon Emissions Reducing Target.¹⁸ The margin in the Republic of Ireland is significantly lower than in Great Britain, with the margin in Northern Ireland being lower still. As in the case of the industrial market, some of this enhanced margin in the British market may be due to firms recouping their “losses” on the wholesale market. Nonetheless, the margin still looks high and it raises issues about the extent of competition between the integrated utilities on the British household market.

This issue is examined in Giulietti *et al.* (2010). They find a substantial impact in the GB market arising from the strong retail positions 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

¹⁷ The Northern Ireland market is similar to the Republic of Ireland market with a single dominant firm, Northern Ireland Electricity/Viridian which is regulated by the NIAUR.

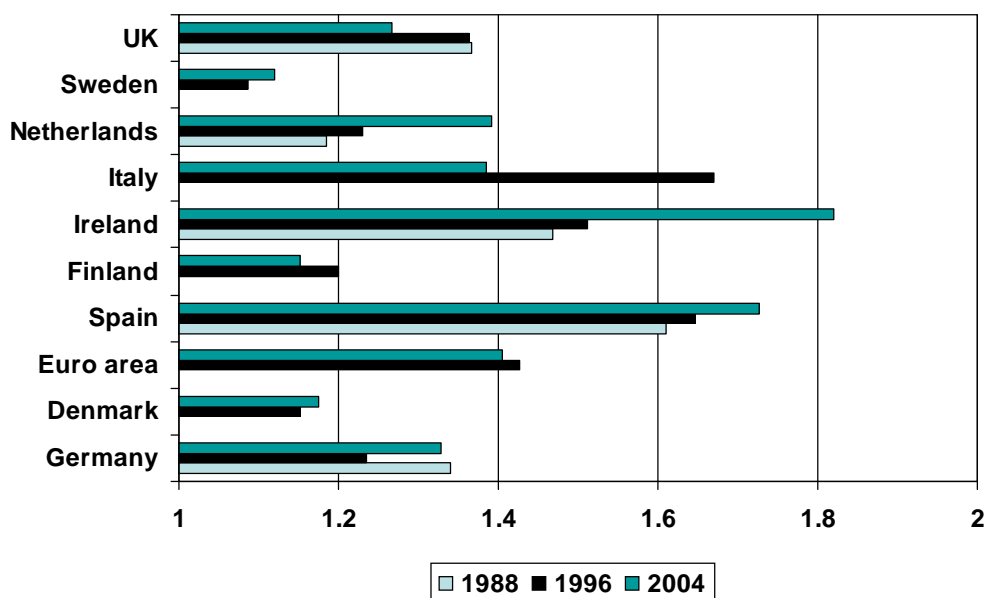
¹⁸ The estimate of these costs presented in Table 2 is calculated from Ofgem and NIAUR (2009), page 27. Ofgem reports that environmental costs account for about 6 per cent of the residential electricity bill.

their electricity costs by choosing the cheapest supplier, leading to higher average retail margins for suppliers in Great Britain.

There was a lower margin in Northern Ireland relative to the Republic of Ireland, even before adjusting for payments under the Public Service Obligation (PSO).¹⁹ To some extent this margin is affected by a legacy long-term contract. Nonetheless, Northern Ireland consumers face similar wholesale prices to consumers in the Republic of Ireland and as the price in both cases is controlled by the relevant regulator they are comparable. This lower margin would suggest that the NIAUR has been reasonably successful in regulating the market to ensure that costs are kept to a minimum.

While the CER in the Republic of Ireland should only allow “reasonable” labour costs and profits in the charges for use of the network and for supply, it may be difficult for them to arrive at an estimate of what is “reasonable”. Thus, in 2008, there may have been some pass through of high labour costs into consumer prices, affecting the retail margin. In the price review being currently being undertaken by the CER they are seeking significant further reductions in cost.

Figure 3: Labour costs in electricity gas and water relative to manufacturing



¹⁹ Data for Northern Ireland come from NIAUR (2009) and the Northern Ireland Authority for Utility Regulation directly.

There are reasons for believing that the costs, especially labour costs, of the ESB in the Republic of Ireland were relatively high (Deloitte, 2007). While new entry has provided competition in the generation market, the ESB's business in building and maintaining the transmission and distribution systems has only been subjected to limited competitive pressures by contracting out the provision of some of the necessary services. This shows up in the fact that labour costs in the electricity, gas and water sector in Ireland are much higher relative to manufacturing than is the case for other comparable EU countries.²⁰ In 2004 labour costs in the sector in Ireland were more than 80 per cent higher than in manufacturing whereas in the UK they were only 27 per cent higher (see Figure 3). This premium for working in the utilities sector (largely electricity) has actually increased in Ireland since 1988 (FitzGerald and McCoy, 1993) and it is the highest amongst the countries shown. For countries that have had competitive electricity markets since at least the early 1990s (e.g. the UK, Sweden, Finland and the Netherlands) the premium is much smaller and, in the case of Britain, it has fallen over the same period. This would suggest that the employees in the monopoly element of the electricity sector in Ireland continued to enjoy rents up to at least 2004, rents which had been competed away elsewhere.

However, when contrasted with the margin in Britain, the evidence would suggest that the CER has maintained significant control over the pass through of costs into the retail market. This means that, to the extent that labour costs are excessive in the sector, the result has been reduced profitability (and a reduced dividend for the owner, the government) rather than higher retail prices.

5. Future Prices

In the case of Great Britain, the wholesale price in 2008 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

²⁰ Data are not available for electricity on its own. However, employment in electricity makes up the bulk of employment in the sector.

remunerated through the wholesale electricity price rising to reflect the true long run marginal cost of producing electricity.

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 may be further squeezed by the regulator over the next few years. However, for industrial consumers the retail margin appears reasonably competitive relative to Britain.

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 commensurate societal benefits, for example in the form of lower pollution, but in other cases the societal benefits may be strictly limited.

The EU Emissions Trading Regime (ETS) is likely to see a rising price for carbon within the EU. With competitive markets this price of carbon has already been incorporated into the price facing consumers. 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.

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).²¹ The cost in 2008 of this scheme for consumers is included in Table 2. In addition to the current situation, where payments are made to relatively low cost onshore wind generators, the commitment to developing 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,

²¹ McIlveen (2010) estimates that the implied carbon price under the scheme is £130 per tonne of carbon dioxide.

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.

In the Irish case, because of high energy prices in 2008 and overpayment in previous years, the Public Service Obligation (PSO), designed to support public objectives, including deployment of renewables, was zero. However, for 2011 it will amount to around €6 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. The justification for this expenditure is partly to support employment and partly for security of supply. However, it is an expensive way of meeting both these targets.²² A removal of this obligation would clearly be beneficial (Tuohy *et al.*, 2009a)

A second element of public policy in the Republic of Ireland, which could end up proving expensive, is part of the REFIT scheme to support renewables.²³ 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. Wind lowers the average shadow price when it is blowing (since it displaces fossil-fuel operated plants). At the same time it increases uplift and PSO costs. 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. This means that the extensive deployment of onshore wind (with interconnection to the GB market) will provide an important hedge against the risk of high energy prices.

²² Because of the high gas price in 2008 and the relatively low carbon price it was economic to run the peat stations. However, with lower gas prices peat stations will again raise electricity prices while continuing to add unnecessarily to Ireland's greenhouse gas emissions.

²³ This is a feed-in tariff. In 2008 because of high energy prices the cost of this scheme was very low.

The fact that Ireland may see a very large deployment of wind by 2020 and that this may reduce the cost of electricity for consumers under certain plausible scenarios is due to the nature of Ireland's onshore wind resource.

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 dominated by onshore wind because of its likely higher capital cost.

Finally, in 2009 the government used a significant part of the windfall gain accruing to generators from the free allocation of ETS permits to subsidise electricity consumption for industrial users. This was not a sensible use of these windfall gains. It would have been wiser if they had been paid to the government (the owner of the ESB) as a dividend, facing industrial consumers with the true economic cost of electricity.

6. Conclusions

Electricity prices for consumers must reflect the long run marginal cost - they should face the true economic cost of electricity (including environmental costs). Underpricing is bad environmentally and economically.

The new All Island Market in Ireland began successfully. It has ensured that the wholesale price is set at short run marginal cost – the minimum sustainable level. In addition, the capacity payments regime seems to be reasonably well calibrated so that the price paid to consumers reflects the true long run marginal cost of producing electricity in Ireland. Investors need to minimise uncertainty and regulators should be loath to make major changes in this regime, which could raise doubts about the viability of investment. This suggests that the wholesale price for electricity in Ireland was “just right” in 2008.

By contrast the wholesale price of electricity in Great Britain was below the long run marginal cost of generating electricity. This is unsustainable in the long run. In 2008 the wholesale price of electricity in Ireland was over €30 a MWh higher than in Great

Britain. Around €6 a MWh of this price difference is attributable to differences in generating technology. However, the bulk of the rest is due to prices being “too low” in the British market.

There is evidence that the retail margin for consumers, especially households, was too high in both markets, resulting in prices for consumers being “too high”. This confirms the findings of *Giulietti et al.*, 2010. In the case of the British market this was made possible by the growth of vertically integrated utilities. Some of this excess margin compensated these companies for the very low wholesale price.

In the case of the Republic of Ireland, the high cost base of the ESB probably resulted in some increase in the retail margin above what would have arisen in a competitive market. However, this “excess” was limited in size and the regulator may erode this in coming years. However, while the consumer may be insulated from high costs, the result would be lower profitability and dividends in the state run utility than would occur under a competitive regime – a cost to society.

Finally, public policy is adding to electricity prices in both jurisdictions. In some cases this increase in cost is justified by the commensurate societal benefits which will result from the charges. However, in the Republic of Ireland the policy of subsidising peat generation is unwise, as was the use of windfall profits to subsidise electricity prices for industrial consumers in 2009. In the case of the United Kingdom, the policy of supporting major investment in renewables offshore, if implemented, is likely to prove hugely expensive over the coming decade and there are unlikely to be commensurate societal gains from this policy.

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