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Welfare and competition effects of electricity interconnection between Ireland and Great Britain

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Abstract: This study analyzes the effects of additional interconnection on welfare and competition in the Irish electricity market. I simulate the wholesale electricity markets of Great Britain and the island of Ireland for 2005. I find that in order for the two markets to be integrated in 2005, additional interconnection would have to be large. The amount of interconnection decreases for high costs of carbon, since this causes the markets to become more similar. Irish consumers obtain most of the welfare gains of interconnection. As the amount of interconnection increases, there are also positive effects on competition in Ireland, the less competitive of the two markets. Finally, it is unlikely that private investors will pay for the construction of the interconnector since they are unable to extract all its welfare benefits.

Keywords: interconnection; electricity; Ireland
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1. Introduction

In recent years the European Union (EU) has suggested that electricity markets should be more interconnected in order to create regional markets, rather than ones limited by State borders. The main advantages of larger markets are the enhancement of security of supply and a reduction in reserves needed to maintain any given level of system performance. Security of supply improves since problems on one grid may be alleviated by importing energy. Reserves can be lower since the outage of one plant will have a relatively smaller impact on a larger system.

In line with European Union recommendations the most recent White Paper on energy published by the Department of Communications, Marine and Natural Resources (DCMNR) in Ireland has declared that an additional interconnector with Great Britain will be implemented.[1] The new interconnector is planned to be in place around 2012, will connect Wales with the Republic of Ireland and is expected to provide about 500 Megawatts (MW) of capacity.

As with other forms of trade, trade in electricity across borders is driven by price differentials between countries. The difference in price may arise for a series of reasons, for example because of differences in the technology of electricity generation, in demand patterns, in factor costs, in levels of competition and in forms of regulation.

The goal of this paper is to assess the impact of additional electricity interconnection both on Ireland and on Great Britain. Specifically, I am interested in 1. the welfare effects of interconnection, i.e. who will gain and who will lose from additional interconnection; 2. the size of the interconnector necessary to make Great Britain and Ireland a single market; 3. the impact of additional interconnection on the level of competition in the electricity generation sector in Ireland. The results of question 1 will suggest who should fund the project.

Most of the research on interconnection and welfare assumes that the driving force behind welfare changes is the change in the strategic incentives of electricity

[1] DCMNR (2007). Note that the DCMNR has recently been renamed Department of Communications, Energy and Natural Resources (DCENR).

generators. Independent of this issue of market power, the effect of interconnection is also affected by how the flows along the interconnector are allocated. When transmission and energy markets are separated, physical transmission rights are auctioned and traded in advance of energy markets. In integrated (or coupled) markets a single system operator simultaneously determines generation amounts and transmission flows.

Neuhoff and Newbery (2005) measure the welfare effects of going from separate to integrated markets. They find that normally integrated markets lead to the highest social welfare. However prices might increase in the short run if the number of competitors in generation is initially very small and rises slowly, or if regulators of separate jurisdictions do not coordinate and reduce their level of supervision post integration. Hobbs et al. (2005) measure the welfare effects of interconnection between two equally sized markets, Belgium and the Netherlands. Specifically they estimate the increase in social surplus if markets go from being separate to being integrated. The authors focus on improvements that arise because flows in opposite directions are allowed to net each other out and because an explicit spot market is set up in Belgium, initially the high-price jurisdiction. The former simply allows a more intensive use of the interconnector, since constraints are loosened. The latter reduces the cost of selling electricity into Belgium since it allows agents to cover imbalances at a (more) predictable cost and therefore encourages entry of foreign companies in the Belgian market. They find that allowing for an efficient use of interconnectors is welfare enhancing. The size and distribution of the gains depend crucially on companies' pricing behavior. If the Belgian incumbent behaves consistently as a Cournot competitor, Dutch consumers end up facing higher electricity prices. On the other hand if the Belgian incumbent is consistently a price taker gains in social surplus are smaller, but more evenly distributed between the Netherlands and Belgium.

Ehrenmann and Neuhoff (2008), summarising the literature, find that in a two-node scenario moving to integrated markets is always going to reduce market power and increase welfare. In a three node scenario the theoretical results are ambiguous, but when they apply their findings to the case of interconnection between Germany, Belgium, France and the Netherlands, they conclude that wholesale prices are reduced.

Borenstein et al. (2000) analyze both how large the interconnector needs to be in order to define a single market and what the impact of interconnection is on competition. The authors determine that in a two-country world, where each country is identical and endowed with a monopolistic generator, a very small amount of interconnection is needed in order for the two monopolists to engage in (Cournot) competition in the larger market. Additionally, they find that the competitive effect is larger the smaller the number of initial competitors (in the absence of collusive behavior). Finally, they observe that even if the interconnector size is small, in equilibrium it will not be congested, suggesting that merchant interconnectors might not be remunerated for their investment. They apply this model to the deregulated market in California for 1998, analyzing the peak demand for December. Under a few assumptions they find that the interconnector between the southern and northern areas of California would have to be 3,835MW for the market to be competitive. This amounts to about 20 percent of the installed capacity in the smaller area.[2]

Finally Moselle et al. (2006) analyze the electricity market in the Netherlands and measure how large an interconnector with Belgium/Germany would have to be to induce a competitive electricity market. They conclude that interconnection between the Netherlands and Belgium/Germany would have to be at least 6,500MW, or 30 percent of total Dutch installed capacity in 2005. They reach this conclusion by evaluating if profitable price increases could be sustained by a monopolist in the Netherlands. For interconnection with Belgium/Germany of 6,500 MW prices would have to be 45 percent larger in order to increase profits. This increase is deemed high enough that regulators would detect it and is therefore not sustainable. Smaller sizes of interconnection would allow a monopolist to profitably increase prices with a low probability of detection, indicating segmented markets.

[2] Own calculation based on the fact that peak demand in the south was approximately twice the peak in the north and using information on California installed capacity from: California Energy Commission, Siting and Environmental Protection Division, Power Plant Database, available at www.energy.ca.gov/database/powerplants and

This paper differs from the previous research by concentrating on the case of perfect competition in generation and by measuring the benefits of interconnection due to differences in demand, factor costs and generation technology. The issue of market power and strategic behaviour is the addressed separately in Section 4. As expected, I find that Ireland enjoys larger net benefits than Great Britain. This is not surprising since it starts off with higher wholesale electricity prices. The results indicate that the interconnector owner is unable to extract all the welfare gains accruing from the interconnector, assuming efficient allocation of interconnection volume. This is especially true for larger amounts of interconnection and suggests that pure merchant investments in interconnection are unlikely. Finally, as the price of carbon dioxide increases to the point where it penalizes coal generation, relatively more abundant in Great Britain, the two markets become more similar. This decreases the amount of interconnection needed to establish an integrated market.

Section 2 introduces the electricity systems of Great Britain and Ireland. Section 3 describes the simulation model used in this paper and its results for different levels of interconnection and different prices of CO_2 emission permits. Section 4 focuses on the effects of interconnection on competition in the Irish wholesale market. Section 5 provides concluding remarks.

2. The case of interconnection between Ireland and Great Britain

A new All-Island Market for wholesale electricity, including both the Republic of Ireland and Northern Ireland, started on 1 November 2007. Each generator submits its bid to a common pool where a single price is determined for every half-hour period. The bids are designed to account only for the short run marginal costs of generators. Long run capital costs are covered by capacity payments, which are assigned to generators depending on their availability and on the tightness of the system in each period. When the margin between generation and demand of electricity is narrow, generators will receive larger payments to make their plants available. More detailed information on the new market is reported in the Appendix. All plants in Ireland and Great Britain, as in the rest of Europe, are subject to the EU Emissions Trading Scheme (ETS) whereby generators are responsible for the cost of carbon emissions released during electricity production.

In Great Britain the wholesale electricity market is operated within BETTA, the British Electricity Trading and Transmission Arrangements, which includes England, Wales and Scotland. It was created in 2005 when Scotland joined NETA (New Electricity Trading Arrangements). NETA in turn replaced the pool arrangement that existed prior to 2001. Both NETA and BETTA are based on voluntary bilateral arrangements between generators, suppliers, traders and customers. In practice BETTA does not set a unique price, since the actual price generators are paid or customers have to pay is different if there is underproduction (for generators) or overconsumption (for consumers).[3] In this paper, however, I abstract from the specific arrangements of the British market and model it as being the same as Ireland, that is as a pool system where generators bid short run marginal costs. I also consider Great Britain to be only linked to Ireland. In reality, in addition to Ireland, it is also connected to France and a new interconnector with the Netherlands is under construction.

Table 1 summarizes some of the characteristics of the two electricity systems in 2005. In 2005, the maximum demand on the Irish system of 6,432 MW was reached in mid December. In Great Britain, the maximum demand, equal to 58,285 MW, occurred at the end of January. These values are typical of Northern European countries, where demand tends to be highest in the winter, when days are short and there is high demand for heating. The fact that the peaks do not occur at the same time suggests that, all other things being equal, a single Great Britain-Ireland market might induce savings, since it would need a smaller amount of installed capacity than the sum of the two independent systems. However, since periods of high demand are highly correlated in the two systems, in practice the savings would be small.[4] The demand comparison also highlights the fact that the electricity system in Great Britain is about ten times as large as in Ireland.

[3] Newbery (2006) gives a thorough account of NETA, BETTA and their performance.
[4] For 2005 the correlation coefficient between the electricity demand curves in Ireland and Great Britain equalled 0.89, which is quite high.

Table 1. Electricity systems in Great Britain and Ireland, 2005

	Great Britain	**Ireland**
Installed capacity (MW)[5]	72,588	8,453
Coal-fired installed capacity (%)	40%	14%
Gas-fired installed capacity (%)	35%	51%
Wind generation, installed capacity (%)	2%	8%
Maximum hourly demand (MW)	58,285	6,432
Installed capacity share of 3 largest generators[6]	39%	93%
Isolated market Time-Weighted Average Price[7]	€29	€50

Coal-fired generation accounted for a significantly larger share of generation capacity in Great Britain than in Ireland. Ireland in addition had about 5 percent of peat generation, designed to run continuously at baseload. Gas-fired generation was a relatively larger component of the Irish system, making it the fuel most likely to set the price. Great Britain also had about 20 percent of nuclear generation capacity, designed to run continuously. This suggests that coal plants are likely to define the price of electricity more often in Great Britain than in Ireland, and the opposite is true for gas-fired generation. In addition, Ireland has about four times as much wind generation relative to its size than Great Britain. This is important because wind in Ireland has priority dispatch, and therefore will be used by the system operator any time it is available, displacing generation based on natural gas.

Irish generation is dominated by the Electricity Supply Board (ESB), the incumbent. Alone, it accounted for a share of about 80 percent of the market in 2004. The Irish State owns 95 percent of ESB, with the remaining 5 percent owned by employees of the company. [8] Electricity generation in Great Britain is much less concentrated, with the top three generators jointly serving about 40 percent of the market.

[5] Excludes interconnectors.
[6] End of 2004 information, from EU (2005). In this case, the statistic for Great Britain applies to all of the United Kingdom, including Northern Ireland, whereas the number for Ireland is exclusively for the Republic of Ireland.
[7] Estimated short run marginal price weighted by the share of demand in each period, given 2005 fuel prices and a zero cost of carbon.
[8] For more details on the Irish electricity market, see FitzGerald et al. (2005).

3. Simulation model and results

In what follows the level of competition and the form of regulation are taken as being the same across the two countries, whereas factor costs, demand patterns and generation technologies are allowed to differ. Within this framework I calculate welfare changes for different levels of interconnection. I also study how sensitive the results are to changes in generation induced by different prices of CO_2 emission permits.

The average yearly wholesale price of electricity on the two islands is determined by optimal dispatch models for 2005. An exogenous demand curve determines the amount of electricity that is needed in each half hour of the year, with Great Britain and Ireland following separate patterns based on their actual 2005 demand. On the supply side, the model assumes identical wholesale markets on either side of the Irish Sea. They are modeled as mandatory pool systems, with generators bidding the short run marginal cost of electricity production. Essentially, the short run marginal cost accounts for fuel costs and costs of carbon emissions if the price of CO_2 permits is positive. Plants are stacked according to their bid, from the cheapest to the most expensive, and the cheapest plants that are needed to match demand in each half hour are dispatched. The bid price of the marginal dispatched plant determines the system marginal price, and all the plants that are dispatched are remunerated at this price. The model takes into account key features of the electricity systems in Ireland and Great Britain. For Ireland it details all the plants generating electricity in 2005, their size, the type of fuel they use, their yearly availability (accounting for typical maintenance schedules) and how efficient they are at converting fuel into electricity.[9] The dispatch model for Great Britain is similar to the one for Ireland, albeit less detailed. Generating plants that use the same type of fuel (e.g. coal or natural gas) are aggregated into a few large plants. The model assumes that generators bid their marginal cost of fuel, without any attempt to game the system.

[9] The model abstracts from some more detailed engineering constraints, such as the time needed (and the costs incurred) to turn a power plant on or off and to increase or decrease output. It also does not account specifically for the provision of ancillary services, such as reserves. For more details on the simulation model, see McCarthy (2005).

I assume that there are no transmission constraints within Ireland or Britain, which yields a single wholesale price of electricity within each jurisdiction. The price of electricity in Great Britain determines the price at the Great Britain node of the interconnector. The average yearly price is calculated as the time weighted average price. I assume integrated markets, where the transmission flow is determined simultaneously with electricity generation. In any period where the prices at the two nodes of the interconnector are different, demand will increase for the low-cost country and decrease for the high-cost country until one of the following conditions is met: the prices are the same at the two nodes; the interconnector is congested; the low-cost country has exhausted its excess capacity. This eliminates all issues related to transmission ownership and non-competitive behavior that can be associated with the ownership of a scarce resource. As Joskow and Tirole (2005) and Turvey (2006) argue, the incentives associated with ownership of scarce resources may lead to inefficient allocation of interconnection flows and substantially vary the use of the interconnector and its associated benefits.

Currently Ireland and Great Britain are joined by a 500MW high voltage direct current (HVDC) interconnector between Scotland and Northern Ireland that operates at 400MW. The government's White Paper (DCMNR, 2007) has pledged additional interconnection and suggested that a 500MW interconnector between Wales and the Republic of Ireland (a distance of approximately 135 kms) might be implemented by 2011. In these simulations I therefore start by analyzing a 500MW additional interconnector and gradually increase its size. An interconnector can be thought of as a piece of transmission infrastructure, but it can also be a substitute for generation for a country that mostly imports electricity. On the other hand for an exporting country interconnector flows are additional demand that must be served by domestic generators. Therefore the interconnector flows affect the price in both countries by changing the amount of electricity that must be generated domestically.

The results presented in Tables 2 to 5 are based on 2005 fuel prices. This year is selected in part because it was the year chosen for the snapshot of the generating plant portfolio. In addition a quick analysis of the prices shows that the ratio of the prices of coal and natural gas in 2005 was close to its ten-year average.[10] This ratio is important because it determines the relative cost of coal and gas fueled plants, which between them set the system marginal price for the majority of periods in both the Irish and the British systems.

In what follows I evaluate the welfare effects of interconnection. In order to determine changes in social (international) surplus I distinguish between the groups affected by interconnection and specifically British and Irish consumers, British and Irish generators and the interconnector owner.[11] The welfare changes taken into account in this section include those driven by price changes, by changes in generation patterns and changes in interconnector use. For consumers, welfare changes are calculated as the price difference induced by added interconnection multiplied by the level of annual demand, under the assumption that electricity generation is inelastic to price (at least in the short run).[12] For producers the change in surplus measures the change in total industry short run profits when added interconnection is introduced. Short run profit is calculated as total yearly revenue minus total yearly fuel (and carbon) cost. Welfare changes for interconnector owners are calculated as the changes in total yearly revenues with respect to the baseline scenario, where the interconnector is 400MW. Yearly revenues are calculated as the sum of half-hourly revenues, which are in turn measured by the price difference at the two nodes times the actual flow for each half-hour period. It should be noted that the welfare measures adopted here do not include welfare increases due to the need for lower reserves in the system, or those due to increased security of supply. Finally, note that in this section I do not address changes in competition due to increased interconnection.

Table 2 displays the changes in welfare due to added interconnection for likely amounts of additional interconnection, namely 500MW, 1000MW and 1500MW. It also shows the changes in welfare with an interconnector large enough for the two markets to be integrated. When the cost of carbon is zero, the additional

[10] The ratio of the price of coal and natural gas (per ton of oil equivalent) is basically identical to the 1996 – 2006 average for Ireland, and is equal to the average minus 1.2 standard deviations for Great Britain.
[11] Changes in consumer surplus are calculated under the assumption that changes in wholesale price are passed on to final consumers.
[12] Total annual electricity demand on the island of Ireland for 2005 was about 36 TWh (Tera Watt hour), whereas in Britain it was about 320 TWh.

interconnection amount needs to be quite large, at more than 3000MW. I define the markets to be integrated if the average yearly price in the two markets is similar.[13]

The need for a large interconnector is driven by several factors. First of all the initial price difference is fairly large. Electricity prices are estimated to be about 40 percent lower in Great Britain than in Ireland. This is due both to the fuel price differences between the countries, and to technological differences. In 2005, the price of gas in Great Britain was about 20 percent lower than in Ireland (IEA 2006). As shown in Table 1, Great Britain also has a higher share of coal plants than Ireland and has a few nuclear plants, which are absent in the Irish system. Moreover in 2005 the capacity to demand ratio was quite low in Ireland, contributing to high prices. Additionally, in this model I assume that there are no transmission losses. Explicitly modeling transmission losses would somewhat decrease the amount of interconnection needed to achieve the same price of electricity at the two interconnector nodes, since the markets would be integrated when the price differential at the two nodes equalled the amount of transmission losses per MW. Finally, in Table 2 the assumption is that there is no cost for carbon emissions. This tends to favor coal plants, perhaps unrealistically keeping their cost of production low.

Table 2. Annual welfare changes in million euro, 2005 prices

	Welfare effects of additional interconnection 0 carbon costs			
	500MW	1000MW	1500MW	3400MW
Irish Consumers	166	277	387	680
Irish Producers	-143	-222	-281	-390
GB Consumers	-55	-115	-182	-348
GB Producers	59	124	195	367
Interconnector	54	82	73	-62
Net Benefit	81	145	193	246
Net Benefit/MW	0.16	0.15	0.13	0.07
Net Benefit/MW, last 500MW	0.16	0.13	0.09	0.04
Capital cost/MW$^{\pm}$	0.06-0.07			

$^{\pm}$ yearly capital cost, including fixed O&M

Consumers in Ireland gain with more interconnection since they face lower wholesale prices. When the cost of carbon is zero, an additional interconnector of 500MW

[13] To be more precise, I define the two prices to be similar when their difference is less than 1.5% of the Irish price.

causes prices in Ireland to decrease by about 9 percent. When interconnection is increased by 3400MW, the decrease in price is about 38 percent.

The largest effects are on the Irish market, as expected. In all cases Irish consumers are the category that gains the most in absolute terms. The net effect for Great Britain is smaller than for Ireland, but of the same order of magnitude. Consumers in Great Britain end up with substantially lower welfare at high interconnection sizes, whereas producers gain somewhat. It should be noted that per capita changes in Great Britain are much smaller than in Ireland given that its population is about ten times larger. The net welfare effects for Ireland are generally larger than for Great Britain. Interconnector owners' revenue depends on the flow and the price difference at the two nodes. Once the two systems are part of the same market interconnector owners obtain almost no revenue since the price at the two nodes is virtually the same. The negative welfare for interconnector owners at 3400MW of added interconnection reflects the fact that at that point they receive less revenue than in the baseline case, with 400MW, since the price difference between the two nodes decreases. As expected, the marginal benefit of additional interconnection decreases as the amount of interconnection increases. The decrease is even larger when focusing on the last 500MW addition, as shown in the one to last row of Table 2. This is of interest if we assume that interconnectors are built in 500MW blocks, as is likely in an electricity system as small as Ireland.

These welfare calculations are useful to compare different scenarios and they can be used to compare the welfare effects of interconnection to the capital costs of building it. The yearly estimated capital cost of an interconnector (per MW) is reported in the last row of Table 2. DKM (2003) estimated that a 500MW interconnector would cost about €185 million, although this amount is probably a lower bound. In 2007 Imera Power, a private company that is preparing a bid to build the East-West interconnector, suggested costs of about €150 million for a 350 MW interconnector (which would correspond to about €215 million for 500 MW), although these costs are not audited and could therefore rise (Construction Engineer, 2007). Taking the Imera estimate and adding the estimate for yearly fixed operations and maintenance costs listed in the DKM study (about €33 thousand per MW at 2005 prices), I can calculate a yearly capital cost for the interconnector. I use two alternative interest rates, both coming from the Commission for Energy Regulation (2005). The first assumes that the interconnector will be state owned and equals to 3.73 percent. The second assumes that the interconnector will be a private investment. In this case the appropriate cost of capital is 6.58 percent. All this would suggest that the yearly capital cost for an interconnector is between €0.06 million €0.07 million per MW.[14] On this basis an interconnector up to 3400MW would have benefits larger than (or equal to) costs. If we consider that interconnectors are likely to come in 500MW instalments the move to 3400MW would decrease total welfare. In fact only about 2000MW of additional interconnection would be built in this case. This calculation is based on the assumption that economies of scale in interconnection construction are negligible.

Table 3. Revenue changes for interconnector owner in million euro, 2005 prices

	Welfare effects of additional interconnection 0 carbon costs			
	500MW	1000MW	1500MW	3400MW
Interconnector	54	82	73	-62
Revenue/MW	0.11	0.08	0.05	-0.02
Revenue/MW, last 500MW	0.11	0.06	-0.02	-0.22
Capital cost/MW[±]	0.06-0.07			

[±] yearly capital cost, including fixed O&M

Table 3 shows what happens to interconnector revenue as size increases. The results allow us to explore who would be likely to invest in additional interconnection. The comparison between the second row of Table 3 and the capital costs reported in the last row shows that a private interconnector owner might build up to 1000MW of interconnection, but would not provide any further investment. In fact, if interconnectors were to be built in blocks of 500MW, only 500MW of additional interconnection would be backed by private investment. This is much lower than what would be socially optimal.

At this point I analyze what happens if the cost of carbon emissions is accounted for. The price of carbon allowances in the European Trading Scheme has varied between about €20/ton of CO_2 in 2005 to €30/ton in April 2006 before falling sharply to much lower levels.[15] As stronger policies to fight global warming are put in place, the cost

[14] As mentioned, this includes yearly fixed operations and management costs, but not variable ones.
[15] Carbon prices come from www.eex.de

of carbon is expected to increase. Analyzing how sensitive the results are to different levels of the cost of carbon is also similar to studying their sensitivity to changes in relative fuel prices. The need to pay for carbon emissions makes coal plants less profitable relative to plants fuelled by natural gas. The following simulations consider three different levels of the cost of carbon dioxide: €20/ton, €30/ton and €50/ton. Once the cost of CO_2 reaches €50/ton, coal plants become much less profitable.

Figure 1. Irish price premium at different costs of carbon permits and interconnector size

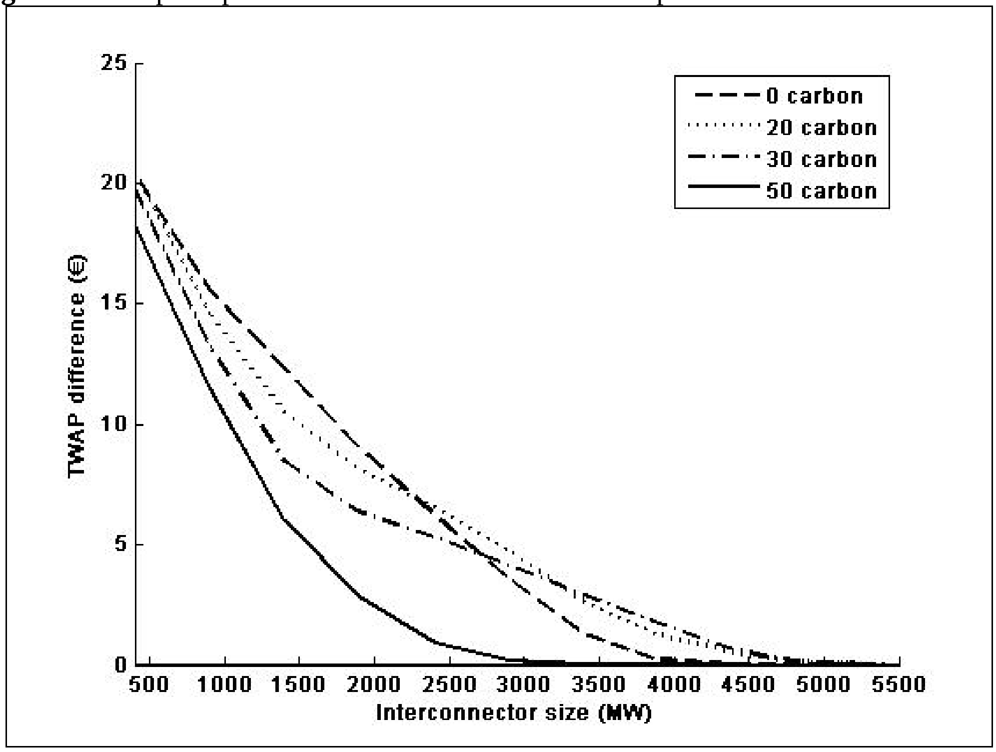


Figure 1 shows how the price difference between the two countries varies with interconnection size at different prices of CO_2 emission permits. As the level of interconnection increases, the price difference between the two systems decreases, as expected. The biggest effect on prices, i.e. the area where the slope of the curves is steepest, occurs up to 1400MW of interconnection.[16] While the decrease is almost linear when there is no carbon cost, the curves level off when the cost of carbon is included. For the two markets to become integrated (as defined in footnote 13), total interconnector size must be between 2400MW, when carbon costs are equal to €50/ton, to 4400MW at €20-€30/ton of carbon. Once the cost of carbon reaches €50/ton coal plants in Britain set the system price less often, substituted by gas plants. This makes the British system more similar to the Irish one and the price difference

[16] This includes the current 400MW of the Moyle interconnector.

between the two narrows quickly as the interconnector size increases, which causes the minimum level of total interconnection needed for a single market to fall sharply to 2400MW.[17]

Tables 4, 5 and 6 report the welfare effects of added interconnection in the presence of carbon costs. As in Table 2, the amount of added interconnection considered is 500MW, 1000MW, 1500MW and the minimum interconnection needed to make Ireland and Great Britain a single wholesale electricity market at each level of CO_2 price. The bottom rows report the net revenue per MW for an interconnector owner.

Table 4. Annual welfare changes in million euro, 2005 prices; €20/ton carbon

	Welfare effects of additional interconnection € 20/ton carbon			
	500MW	1000MW	1500MW	4000MW
Irish Consumers	210	353	437	698
Irish Producers	-181	-288	-338	-415
GB Consumers	-19	-39	-59	-174
GB Producers	20	41	61	181
Interconnector (IC)	42	58	62	-52
Net Benefit	72	124	164	238
Net Benefit/MW	0.14	0.12	0.11	0.06
Net Benefit/MW last 500MW	0.14	0.10	0.08	0.001
ICRevenue/MW	0.08	0.06	0.04	-0.01
ICRevenue/MW last 500MW	0.08	0.03	0.01	-0.04

Table 5. Annual welfare changes in million euro, 2005 prices; €30/ton carbon

	Welfare effects of additional interconnection € 30/ton carbon			
	500MW	1000MW	1500MW	4000MW
Irish Consumers	232	398	470	656
Irish Producers	-199	-326	-372	-409
GB Consumers	-37	-73	-107	-273
GB Producers	39	76	112	285
Interconnector (IC)	34	37	42	-44
Net Benefit	68	113	145	214
Net Benefit/MW	0.14	0.11	0.10	0.05
Net Benefit/MW last 500MW	0.14	0.09	0.06	0.01
ICRevenue/MW	0.07	0.04	0.03	-0.01
ICRevenue/MW last 500MW	0.07	0.01	0.01	-0.07

[17] Since the curves flatten as the prices in the two jurisdictions converge, the amount of interconnection needed to create a single market is somewhat sensitive to the exact definition of integrated markets. If the markets were defined as integrated for a 5% price difference (as opposed to 1.5%), the amount of interconnection needed to achieve integration would be 400MW to 500MW lower.

As the cost of carbon increases, the two systems become more ‘similar’ since coal generation is disincentivized. The effect can be seen comparing Table 4 and 5 to Table 2: any given level of interconnection becomes less useful. In fact total yearly welfare changes of an additional 500MW interconnector go from €81 million in the absence of carbon costs, to €72 million when the carbon cost is €20/ton, €68 million when it is €30/ton and finally €63 million in Table 6, where the carbon cost is €50/ton.

Table 6 Annual welfare changes in million euro, 2005 prices; €50/ton carbon

	Welfare effects of additional interconnection € 50/ton carbon			
	500MW	1000MW	1500MW	2000MW
Irish Consumers	236	422	527	587
Irish Producers	-200	-339	-406	-438
GB Consumers	-90	-173	-253	-328
GB Producers	94	181	267	348
Interconnector (IC)	23	9	-15	-40
Net Benefit	63	99	119	128
Net Benefit/MW	0.13	0.10	0.08	0.06
Net Benefit/MW last 500MW	0.13	0.07	0.04	0.02
ICRevenue/MW	0.05	0.01	-0.01	-0.03
ICRevenue/MW last 500MW	0.05	-0.03	-0.05	-0.05

As before, there are decreasing returns to interconnection. The addition of the first 500MW has the largest effect on social surplus. It decreases costs for Irish consumers by about 8 percent. Once the interconnector size reaches 2000MW Irish consumers spend 20 percent less per MWh of electricity. Revenues for the interconnector owner decrease when the two systems become more similar. In fact, for an added 500MW of interconnection, interconnector revenue increases by €54 million with no cost of carbon, €34 million when carbon prices are €20/ton, down to €23 million at €50/ton. This is mostly due to the prices in the two jurisdictions being closer prior to interconnection.

When the cost of carbon is €20-€30/ton, social welfare would be improved with interconnection up to (at least) 1500MW. This conclusion is reached by comparing the net benefit per MW of interconnection in Tables 4 and 5 with the capital cost of interconnection presented in Table 2. Increasing interconnection by 4000MW, the amount needed to create a single Ireland-Great Britain market, is unlikely to be welfare maximizing. A private interconnector owner would have the incentive to build only 500MW of additional interconnection, due to the rapid decrease in interconnector revenue per MW as interconnection size increases. When the price of carbon is €50/ton it is likely that a merchant investor would not build any additional interconnection at all. The socially optimal amount on the other hand is between 1000MW and 1500MW, not quite reaching the level that would allow for a single market.

As mentioned earlier, the measure of social welfare is not comprehensive. First of all issue of security of supply is excluded from the analysis. Furthermore a larger system will need a smaller percentage of reserves (amount of electricity generation above the maximum expected level of electricity consumption) than two small systems to maintain the same standard of service. This implies a reduced need for new investment in generation infrastructure and therefore allows the system to operate at lower cost. Both of these points would suggest that the amounts reported above underestimate the true welfare effects of interconnection. On the other hand, this model is static and does not account for possible changes in the generation structure in the two countries. If new generation makes the countries more similar over time, welfare effects of interconnection will decrease, with the opposite being true if the differences increase. In addition, since interconnection between Great Britain and Ireland is expected to increase over time, revenues for existing interconnectors will decrease. This paper has also assumed efficient use of interconnectors. If interconnectors were used inefficiently, their size would have to be larger to achieve the same results. Finally, the model does not consider competition issues. In as much as interconnection increases competition in the more concentrated market (in this case Ireland) the model is underestimating both welfare gains for Irish consumer and welfare losses for Irish generators and is potentially underestimating the losses to British consumers.[18] I analyze the issue of competition in more detail in the following section.

[18]Higher levels of interconnection will reduce generators’ revenues also by increasing the margin between available generation and consumption of electricity, thereby diminishing generators’ capacity payments.

4. Competition effects

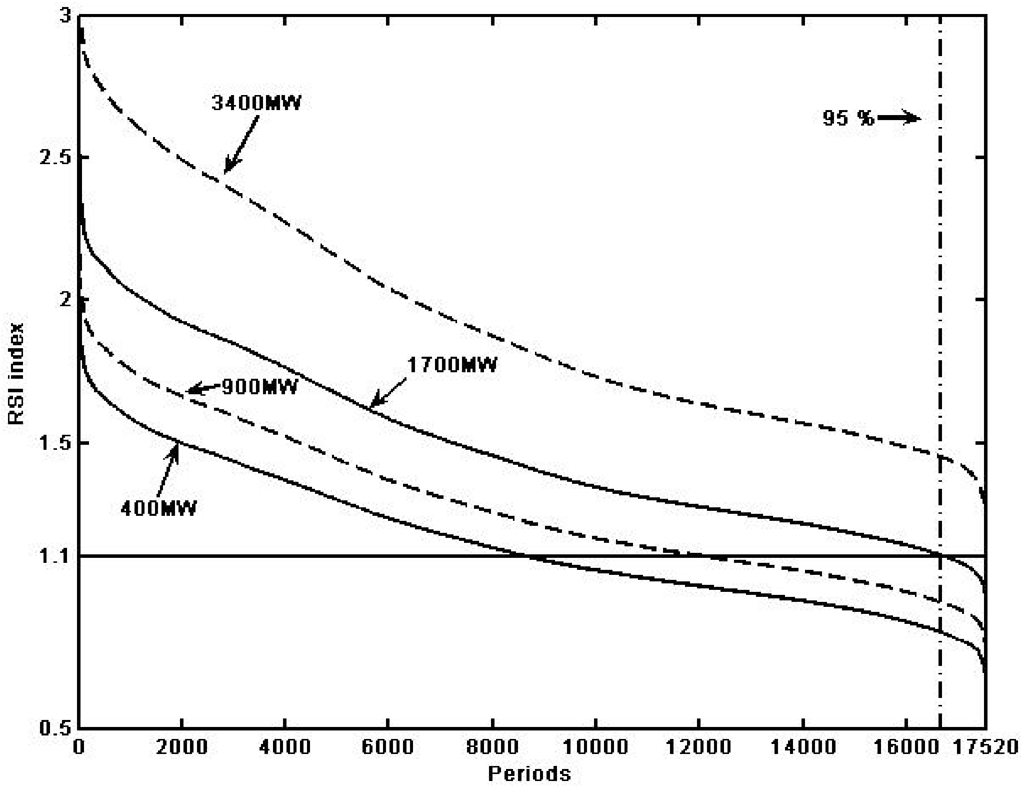
The All-Island Market in principle does not admit anti-competitive behavior. All generators are expected to follow the bidding principles and bid their short-run marginal cost. There are concerns that market power might emerge anyway. Companies could increase their profits by limiting availability of plants, a behavior that emerged in the PJM market on the East Coast of the United States, for example (see Creti and Fabra, 2007). Plant availability in the Republic of Ireland has been below 80 percent for the past few years, compared to best practice availability rates of about 90 percent. The simulation model presented in this paper assumes that companies do not game the system, so it cannot be used to study changes in market power. I therefore analyze the issue indirectly.

Since Ireland is the less competitive of the two systems, added interconnection will cause its level of competition to change the most. Figure 2 shows the level of competition in Ireland, measured by the Residual Supply Index (RSI) introduced by Sheffrin (2002). It also depicts how competition varies with different amounts of interconnection. The RSI is defined as:

$$RSI_t = \frac{SystemCapacity_t - LargestCapacity_t}{Demand_t}$$

where *LargestCapacity* measures the installed capacity of the largest player in the market and *t* indexes the period. Essentially the RSI measures the importance of the largest player in the market. When the RSI is large it means that the largest player is not very influential, and the opposite is true if the RSI is small. Sheffrin (2002) suggested that for an electricity system to be considered competitive the RSI index should be above 1.1 at least 95 percent of the time. This corresponds to about 16,600 half-hourly periods.

Figure 2. Irish RSI index with different amounts of interconnection (2005 data)



As shown in Figure 2, the Irish market is far from this level in 2005, with the RSI above 1.1 for only about 50 percent of the time. An additional 500MW of interconnector does not improve the situation significantly, whereas once 3000MW is added the market is definitely classified as competitive. In fact the minimum level of additional interconnection needed to establish a competitive market according to this measure is around 1300MW. Including the existing 400MW of interconnection this corresponds to 1700MW, or about 18 percent of total Irish installed capacity.

5. Conclusions

This paper has studied the effects of additional interconnection between Ireland and Great Britain using a static optimal dispatch model. It is based on historic 2005 fuel prices and generation plant mix and assumes perfect competition in wholesale generation markets. The analysis also determines how sensitive the results are to changes in the cost of carbon. The main goals of the paper are to define: 1. the welfare effects of interconnection, i.e. who will gain and who will lose from additional interconnection; 2. the size of the interconnector necessary to make Great Britain and

Ireland a single market; 3. the impact of additional interconnection on the level of competition in the electricity generation sector in Ireland.

In general Ireland gains and Great Britain loses with interconnection. In particular, Irish consumers are always the group that gains the most (and even more so in per capita terms). Irish producers are the group that loses the most. The sum of Irish and British social welfare increases with interconnection, although at a decreasing rate.

In addition to measuring welfare changes for the whole economy, I have analyzed changes in returns to interconnector owners. The static model suggests that for small amounts of interconnection interconnector owners profit from the project, except when the cost of carbon reaches €50/ton. Under this scenario merchant interconnectors would not invest in any amount of additional interconnection. Taking into account dynamic effects the picture is likely to change. In particular the interconnector receives less revenue per MW as the size of interconnection increases. It also receives less as the linked systems become more similar since this causes the flows along the interconnector to decrease. This suggests that pure merchant investments are unlikely to take place in this area. If merchant investment is put in place it will be limited to an amount that falls short of the socially optimal one. Since most of the welfare benefits would accrue to Ireland, the entity most likely to finance additional interconnection is the Irish government.

Results show that in order to create a single market between Ireland and Great Britain, there would have to be between 2000MW and 4000MW of additional interconnection. This represents between 24 and 47 percent of total Irish installed capacity and about 3 to 6 percent of British installed capacity. As the cost of carbon rises, making coal plants less profitable, the difference between average electricity prices in the two systems diminishes and so does the minimum interconnection size necessary to achieve integrated markets. This suggests that technological differences are the main drivers of gains from trade and are definitely more important than differences in market size.

The results show that it is unlikely that the level of interconnection needed to create a single market will be welfare enhancing. One should note however that there are a few aspects likely to affect social surplus that are not taken into account in this paper. In particular, consumers might also benefit because the Irish electricity market would become more competitive, because of enhanced security of supply, and because the amount of reserves needed to maintain a secure system would be lower. On the other hand I have assumed throughout that interconnection will be allocated efficiently. If this were not the case, interconnection would have to be larger (and therefore costlier) in order to obtain the same benefits.

Finally, I analyzed the size of interconnection that would lead to a competitive Irish generation market. Using the Residual Supply Index introduced by Sheffrin (2002) I find that interconnection would have to be at least 1700MW, or about 18 percent of existing Irish generation. Moselle et al. (2005) find that interconnection should be about 30 percent of existing installed capacity in order for the Dutch generation market to be competitive. The analysis in Borenstein et al. (2000) suggests that interconnection needs to amount to about 20 percent of installed capacity in northern California for that region to be competitive.

The current analysis is based on a static model. However changes in the amount and type of installed generation will also affect the results. In particular, the large increase in wind installations currently taking place in Ireland might allow coal plants to set the price more often, given that wind is likely to substitute for baseload gas generation since it has priority dispatch. This would make the fuel of the system-price-setting plant more similar to the one in the British system and possibly reduce the amount of generation needed for integration of the markets. The same would be true if there were a greater investment in coal plants in Ireland. It is also possible that large wind investments in Ireland would take advantage of the interconnector to export more electricity from Ireland at times of high wind. These issues warrant further study.

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Appendix

The All-Island wholesale market: rules of the game[19]

The Irish All-Island Market (AIM) started in November 2007. It includes both the Republic of Ireland and Northern Ireland and was designed with the goal of increasing investment in new generating plants and availability of existing generators.

The AIM is characterized by a single pool market for wholesale electricity, where all generators submit their bids, and a system of capacity payments. Participation in the pool is mandatory for any generator with an export capacity larger than 10 MW. Each plant that generates electricity during a given period is paid the same price, which is determined by the bid of the most expensive plant necessary to meet electricity consumption in that period.

Bids

For each trading day generators offer their bids up to a day ahead of trade. Each bid consists of a maximum of 10 price-quantity pairs that are subject to price floors and caps set by the regulator.[20] In addition generators submit the cost of no load (representing operation costs invariant to actual generation) and ramp up costs (the cost of increasing generation volumes). The bid pairs, no load and ramp up costs are the same for all periods of the relevant day. Generators can also attach technical conditions to their bid, including a minimum level of generation and a minimum number of periods of generation or downtime. Bidding principles require that generators bid their short run marginal cost.

Capacity payments

Every year the Commission for Energy Regulation (CER) determines the size of the pot for capacity payments. It is calculated as the price needed to cover fixed costs of a 'best new entrant' peaking plant multiplied by the volume needed to maintain a predetermined reliability standard (defined as a maximum amount of hours of lost load during the year). The pot is then distributed among generators depending on their availability. Plants that are available at times when the margin between electricity demanded and electricity supplied is tight will be allocated a relatively larger share of the pot.

Interconnector

Registered users can bid up to 10 price-quantity pairs for the interconnector for every time period during the day, up to a day ahead of trade. The sum of all these bids (up to the capacity of the interconnector) is bid by the interconnector owner in the pool. The interconnector is paid capacity payments based on the actual flow along the interconnector at every period.

[19] For further details, see Commission for Energy Regulation (2008) and documents cited therein.

[20] These limits are currently quite loose. The price floor is set at € -100/MWh, whereas the price cap is set at €1,000/MWh. Neither of these limits has been reached up to April 2008 (Single Electricity Market Committee, 2008).