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Optimal interconnection and renewable targets for North-West Europe[**]

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Abstract

We present a mixed-integer, linear programming model for determining optimal interconnection for a given level of renewable generation using a cost minimisation approach. Optimal interconnection and capacity investment decisions are determined under various targets for renewable penetration. The model is applied to a test system for eight regions in Northern Europe. It is found that considerations on the supply side dominate demand side considerations when determining optimal interconnection investment: interconnection is found to decrease generation capacity investment and total costs only when there is a target for renewable generation. Higher wind integration costs see a concentration of wind in high-wind regions with interconnection to other regions.

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1 Introduction

1.1 Context

Cross-border electricity transmission, which in a European context is referred to as interconnection[5], is often presented as a panacea for various challenges that surface in electricity systems. Traditionally, electricity systems evolved in a relatively isolated manner, frequently with one dominant player for generation, supply and transmission. As liberalisation of electricity markets has become a policy aim in many jurisdictions, interconnection has been frequently proposed as the primary, if not only, means of increasing market integration across borders and mitigating market power (Gilbert *et al.*, 2004; Brunekreeft *et al.;* 2004, Neuhoff *et al.*, 2005). Interconnection between regions with a diverse demand profile could also serve to bring about a reduction in the range of the total demand curve. This can reduce generation costs by facilitating a proportional increase in cheaper inflexible generation plant, such as coal and nuclear, and reducing dependence on flexible high-cost peaking plant. Indeed, this is a primary rationale behind large scale power systems – that by meeting demand at an aggregate level, larger and cheaper generation plant can be built which can meet large portions of demand at lower cost. The reliability of the system could also be improved. Finally, as concerns over climate change and energy supply security lead to investment in renewable electricity, interconnection is proposed as a means of facilitating such investment by enabling a country or region with a significant level of intermittent renewable generation to export their surplus electricity and import when supply is low (De Jonghe *et al.*; 2011, EWIS, 2010; EWITS, 2011; Ostergaard, 2003). Thus the potential for interconnection to smooth both the supply and demand of electricity, particularly as intermittent renewable generation is increased, is seen as one of the major reasons for interconnection investment.

An increase in renewable energy is a stated aim of the European Commission with targets in place which aim to source twenty per cent of electricity from renewable sources by 2020 (EC, 2009). Under Directive 2009/28/EC, this is to be achieved by imposing specific national targets for each individual country within the EU. Aune *et al.* (2011) find that a policy of differentiated national targets is not a cost-effective way to reach a certain renewable share, even if there is a market for renewable certificates. However they do not consider the effect of increased interconnection on meeting renewable targets. The question of differentiated targets for individual regions as opposed

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[5] Interconnection can also refer to generators connecting to the grid (for example in electricity systems in the USA). For the purposes of this paper interconnection is taken to mean cross-border transmission.

to a global target is of relevance to other jurisdictions such as the USA, where many states have individual targets for renewable generation (Wiser and Bolinger, 2011).

1.2 Literature

Much of the literature on interconnection considers the effect of building a specific interconnector between two countries or between two regions within a country. Examples include Kanagawa and Nakata (2006), who use the META-Net economic modelling system to conclude that the utilisation of interconnection between Japan and Korea is largely determined by the generation plant mix and emissions or by nuclear energy policy. Schroder *et al.* (2010) use the WILMAR model to examine the implications of interconnecting Sweden, Germany and Denmark while incorporating an offshore wind farm in the North Sea and the Baltic Sea. Maluguzzi Valeri (2009) examines interconnection between Great Britain and Ireland and concludes that the socially optimal level of interconnection is higher than the level of interconnection likely to be delivered by market forces. This is due to the fact that interconnection tends to harmonise prices in the two connected markets, and so interconnection erodes its own value as an investment opportunity.

Interconnection also features in some generation resource planning models. De Jonghe *et al.* (2011) use a linear programming model to determine the optimal electricity plant mix with a high level of wind generation. They include existing interconnection in the model but do not examine the effects of adding more interconnection. Neuhoff (2008) includes wind variation and transmission constraints in an expanded investment-planning model, and calculates the additional cost savings from expansions in transmission capacity. Most studies in this area, however, consider interconnection levels as an exogenous variable and do not consider the effects of constructing new interconnection.

Unsihuay-Vila *et al.* (2011) use a multi-objective model to identify optimal generation and interconnection investments while attempting to find the best compromise between three objectives: minimise cost, minimise greenhouse gases and maximise diversification of the electricity generation mix. They find that no one objective produces a solution which satisfies the other two objectives and so use a weighted average of all three objectives to obtain the optimal solution. Their model is one of the few to include transmission as an endogenous variable, however specific results relating to interconnector investments are not reported, with the authors concentrating more on fuel mix and carbon emissions. The shortcomings of this paper include the fact that demand is included as three load-blocks of low, medium and peak demand over the planning horizon, and as such does not fully capture the variable nature of demand or renewable generation and any correlations between demand and renewable generation, which may constitute a major component of interconnector value.

Some of the more general work in this area studies the economic impacts of interconnection in terms of regulator and generator behaviour, and implications for markets. Brunekreeft *et al.* (2004) concludes that deep connection charging as well as Locational Marginal Pricing (LMP) may be required to signal efficient investment locations, and that merchant interconnection, while raising new regulatory issues, may still be a suitable means of increasing interconnection. Neuhoff and Newbery (2005) find that integrated electricity markets lead to the highest social welfare, but consumer prices may increase in the short run. Brunekreeft (2004) addresses the regulatory issues pertaining to the regulation of merchant interconnection and concludes that competition law is sufficient to justify refraining from sector-specific arrangements. The optimal ownership and operation of interconnectors is also a well-developed strand in the literature. Brunekreeft and Newbery (2006) find that a regulatory decision to prohibit capacity withholding decreases welfare if the capacity withholding is due to uncertainty and demand growth, and increases welfare if the withholding is due to pre-emptive investment. Kristiansen and Rosellow (2006) propose a mechanism to incentivise investment in merchant transmission using long-term financial transmission rights (FTRs). Buijs *et al.* (2007) claim that underinvestment in transmission in Europe is due to regulatory failures and that merchant interconnectors provide an acceptable alternative to regulated investments in transmission by TSOs.

1.3 Model

There has been little investigation of methods for determining optimal locations for specific interconnectors, other than in specific case studies examining the construction of a particular interconnector such as those mentioned above (Kanagawa and Nakata, (2006); Schroder *et al.,* (2010); Malaguzzi Valeri (2009)). Furthermore, the interaction between interconnection expansion and renewable generation has not been modelled extensively in the literature. Here we present a model which includes interconnector locations as an endogenous variable, thus solving for optimal interconnection for a given renewable target in an objective manner. Thus the impact of renewable targets on optimal interconnection expansion can be examined.

The model determines the optimal amount of investment in new generation capacity as well as optimal investment in interconnection. As such, the model captures the interdependent nature of generation capacity and interconnection rather than attempting to solely identify optimal interconnection investment for a given generation portfolio. This is accomplished by means of an iterative approach in which a linear program and then a mixed integer program are run for each year under investigation, with the linear program determining the optimal generation capacity and the mixed integer program determining optimal interconnection investment.

The model captures the increased capacity to balance supply and demand afforded by interconnection by including demand and renewable generation at an hourly resolution. The model can be used to examine the interchangeable nature of investment in generation capacity or interconnection. By including constraints in the model which require certain proportions of electricity generation to come from renewable sources, the complementary nature, if any, of interconnection and intermittent renewable generation can also be investigated. This is done by applying the model to a test system of eight Northern European countries from the year 2011 to the year 2030. Differentiated renewable targets for each country and a global renewable target are imposed, and the various effects on interconnection are identified.

The paper is structured as follows. Section 2 presents the model. Section 3 outlines the test system to which the model was applied. Section 4 presents the results and discussion. Section 5 concludes.

2 Model

The model seeks to meet the electricity demand for all regions modelled while minimising total costs. As such a social planner is assumed, whereby total costs across all regions is minimised rather than each country minimising its own individual costs. This is in contrast to the current approach in which each country or region within a country has a separate Transmission System Operator (TSO), or in some cases more than one TSO, and one regulator which take responsibility for electricity provision and/or market operation.

Ideally the model would optimise both the location and the capacity of new interconnection investment. However, this would render the problem too computationally intensive. For this reason it is necessary to select a default interconnector size and to assume that any interconnection built is of this fixed capacity.

The model meets electricity demand by dispatching available generation capacity while minimising total costs arising from both interconnection investment and generation investment over the course of one planning horizon. An iterative approach is taken (see Figure 1). In the first step of the iterative process a Capacity Optimisation Module (COM) is run. The COM is a linear program as all variables are continuous and enter the objective function in a linear manner. The inputs include the existing interconnection portfolio between the regions and the existing generation portfolio for each region. The demand in each region is given as a parameter at an hourly resolution. The COM has the option of building new generation capacity in any given region while determining the optimal dispatch of the generation assets and the optimal utilisation of the existing interconnectors. The model determines the optimal dispatch of the total generation capacity portfolio, given by the existing generation assets as well as any new generation assets solved for by the model.

In the second step of the iterative process an Interconnection Optimisation Module (IOM) is run. The IOM is a mixed integer program as the decision variable which determines whether to build interconnection between two regions is an integer quantity. The inputs of the IOM include the generation portfolio arrived at in the first step along with the existing interconnection portfolio. The model does not, model retirements of generation or interconnection assets. The IOM determines the optimal dispatch of the generation plant and the optimal operation of the existing interconnection, as does the COM. The IOM also has an option to build interconnection between any two regions, in which case it determines the optimal operation of the total interconnection portfolio, given by the existing interconnection capacity and the new interconnection capacity arrived at by the model.

If interconnection is built in the IOM, the portfolio of existing interconnection which was given as an input to the COM is updated to include this new interconnection. The COM is then rerun using the original portfolio of existing generation assets and the new interconnection portfolio. The generation capacity portfolio arrived at is then given as a parameter to the IOM which is rerun using the original existing interconnection portfolio. If the new interconnection investments arrived at differ from those arrived at in the first step, the new interconnection portfolio arrived at is reintroduced to the COM and the process is repeated. When the IOM arrives at the same interconnection investments as in the previous iteration, the model terminates for that planning horizon and carries the generation and interconnection portfolios arrived at on to the next planning horizon (see Figure 1).

The objective functions and constraints for each Module are outlined below.

2.1 Cost function

Total costs are broken down below into several components.

The first component considered is the fixed cost associated with building generation capacity, given by the following expression:

$$\sum_{g,s} capacity_{g,s} * capacity\_costs_g \ldots (1)$$

where *capacity* stands for capacity in MW of generation technology *g* in supply region *s.* Each region is treated as a supply region, *s*, when considering generation capacity in each region, and as a demand region, *d*, when considering the demand in each region. Furthermore, supply region and demand region can refer to the same region, thus allowing regions to supply themselves. The generation technologies considered are coal, nuclear, wind and gas.

The second component of total costs is the cost of interconnection between two regions and is given below as expression (2):

$$\sum_{s,d} ic_{s,d} * distance_{s,d} * ic\_cost \ldots (2)$$

where *ic* is the binary quantity denoting interconnection between two regions. The distance between each region is set to the distance between their main load centres, typically the capital city. The distance between each region and itself is set to zero which ensures there is no cost to interconnecting within a particular region; thus transmission within regions is not modelled. The cost per unit distance of interconnection is given by *ic_cost.*

While the purpose of the model is to determine optimal investment in interconnection and generation capacity, these investments are influenced by variable cost of the economic dispatch of generation units. Thus the cost function must also include these variable costs, given by equation (3) below.

$$\sum_{g,s,d,t} generation\_cost_g * dispatch_{g,s,d,t} \cdots (3)$$

The fourth component of total costs is the value of lost load (VOLL) term. This term is included as a penalty for failing to meet all the demand while avoiding a binding constraint requiring all demand to be met. Losses per unit distance are accounted for. The fact that there is a distance of zero between each region and itself means that transmission losses within regions are not accounted for. The term is given below as expression (4):

$$\left(\sum_{g,s,d,t} demand_{d,t} - \left(dispatch_{g,s,d,t} + dispatch\_wind_{g,s,d,t}\right) * \left(1 - loss\_factor * distance_{s,d}\right)\right) * VOLL \ldots (4)$$

The cost of wind integration is likely to be underestimated by the model since full unit commitment including start-up and no load costs are not included, and reserve is not modelled explicitly. In an attempt to account for this, a wind integration cost per MWh was included, as per Eq (5):

$$\sum_{s,d,t} dispatch\_wind_{s,d,t} * wind\_integration\_cost \ldots (5)$$

Figure (1) outlines the objectives functions of the Capacity Optimisation Module and Interconnection Optimisation Module and specifies which terms appear as endogenous variables and which appear as fixed parameters for each Module. The iterative model process for each time horizon is also represented. The constraints which appear are detailed in the next section.

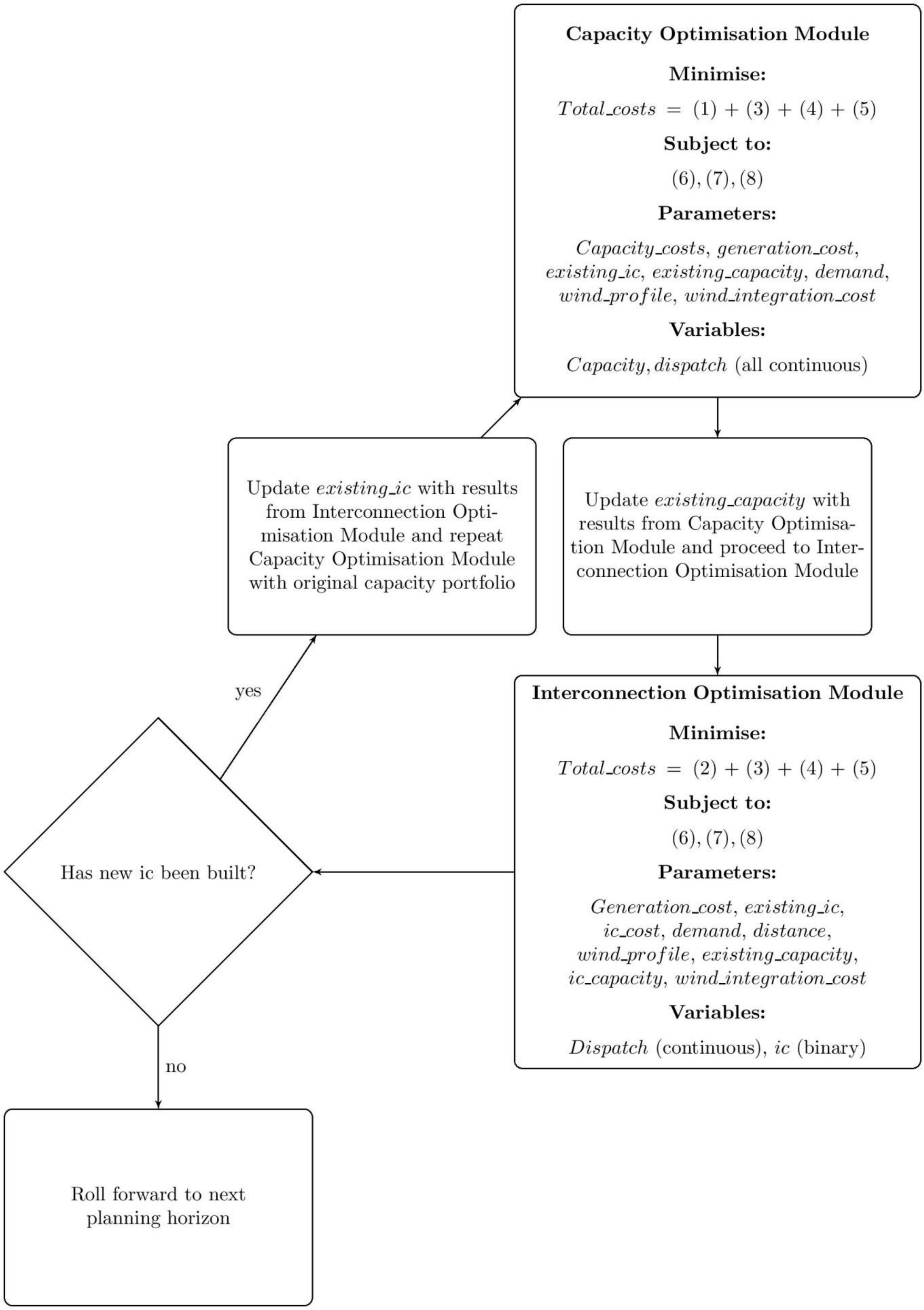

Figure 1: Flowchart outlining iterative nature of the model between the Interconnection Investment Module and the Capacity Investment Module

2.2 Constraints

The first constraint in the model specifies the maximum generation of each type of generation given by the capacity of each type of generation. The minimum generation for each generation type is assumed to be zero, i.e. unit commitment of individual units is not modelled:

$$\sum_{d} dispatch_{g,s,d,t} \leq capacity_{g,s} \;\; \forall\, t \ldots (6)$$

A wind capacity constraint is included separately as wind generation is determined by a time series given by *wind_profile,* the wind available in each region at time *t*:

$$\sum_{d} dispatch\_wind_{s,d,t} \leq wind\_profile_{s,t} * \; wind\_capacity_{s} \;\; \forall\, t \ldots (7)$$

Expression (8) below is the constraint representing interconnector capacity:

$$\sum_{g} dispatch_{g,s,d,t} + \; dispatch\_wind_{s,d,t} \leq ic_{s,d} * ic\_capacity + existing\_ic\_capacity_{s,d} \; \forall t \ldots (8)$$

where *existing_ic_capacity* is the interconnection capacity which existed prior to this time horizon. Thus *existing_ic_capacity* is given by the sum of interconnection capacity which existed prior to the first run of the model, along with any interconnection capacity which was built during previous time horizons and previous iterations during the current time horizon. Equation (8) ensures that the sum of electricity transmitted from region *s* to region *d* from every generation type, both conventional and wind, is less than the existing interconnection capacity between those two regions.

These constraints apply in both the Capacity Optimisation Module and the Interconnection Module, as seen in the flowchart in Figure 1.

2.3 Limitations of the model

The formulation of the model as outlined above has some inherent limitations. These include the assumption that transmission within regions is costless and boundless, the fact that interconnection capacities greater than the pre-specified *ic_capacity* can only be realised in an incremental manner from one time horizon to the next and the assumption that plants are not retired as they age.

Much of the resulting interconnection links modelled are AC which in a meshed grid will have flows determined by Kirchhoff's laws. This is in contrast to DC which can be controlled individually. Thus the transmission within regions must be modelled and possibly reinforced to obtain more realistic engineering and design quantities. Therefore the model is likely to underestimate the total costs associated with the construction of these new AC links.

The model assumes one European market, with least cost generation and capacity expansion determined at European level. Such a market is desirable but unlikely to emerge in the near future. Thus the value added is to identify trends and study interactions of various decisions when taken from a socially optimal point of view, while recognising that all of these decisions may not or in all likelihood will not be taken. In the USA, FERC order 1000 (FERC, 2011) attempts to ensure a fair allocation of costs and benefits from interconnection, and so the social planner assumption may be more realistic in this context.

The model does not impose minimum operation constraints, start-up costs or ramping costs and constraints on the conventional generation sources. This means that many of the operational benefits of interconnection, such as the increased operational flexibility available to system operators, are not captured by the model. Market effects such as a reduction in market power are also not examined. The omission of such benefits may lead the model to underestimate the value of interconnection.

The model does not provide an analysis of some of the reliability issues which arise as a result of contingencies on the system. The penalty determined by the value of lost load ensures reliability regarding meeting all demand. However other reliability issues such as failures of thermal plant or transmission lines, and very high or low wind events, have not been examined. The model assumes generators and transmission are reliable, and models wind output deterministically. Modelling wind stochastically would considerably increase computational time (Meibom *et al.,* 2011).

The cost of wind integration may vary (most likely will reduce) as more interconnection is added. Some of this reduction in wind integration costs can be captured by the model, ie, by decreasing the amount of conventional generation which is required to compensate for the intermittency of renewable generation. However, it is not possible to fully quantify this reduction without performing a full integration study. Furthermore interconnection may reduce wind integration costs for a given level of wind, but this model increases both renewable generation and interconnection. Therefore the net effect on wind integration costs may remain static.

3 Test system

3.1 Case study parameters

The model was applied to a case study for eight regions in northern Europe: Ireland, Great Britain, France, Germany, Belgium, Netherlands and East and West Denmark. These regions were chosen as data was available and their geographical location justified concentrating on wind generation to fulfil renewable targets. Hourly demand data for these eight northern European regions from 2010 was obtained from ENTSO-E and was scaled up to 2030 according to annual growth estimates contained in the European Commission's report 'EU energy trends to 2030 update 2009' (EC, 2009). Wind data for the regions in question was obtained at hourly resolution from the relevant TSOs, with the exceptions of the Netherlands (Gibescu *et al.,* 2009) and Great Britain (Elexon - http://www.bmreports.com/).

The time horizon was set to one year. The start year was set to 2011 and the end year to 2030. Thus the model was run for twenty one-yearly time steps. While this means the model exhibits myopic expectations, the process of the power system evolution can be seen as a consequence of individual investment decisions. Similar approaches are taken in Swider and Weber (2007), who use a time horizon of one year. The results of this paper should be interpreted as providing particular insight to the trends which can be seen under various interconnection and transmission scenarios, rather than providing absolute certainty as to which investments are optimal.

The 2011 plant mix was set at 2009 levels for each country for the parameter *existing_capacity* (Eurostat, 2010) and is given in Table 1: 2009 generation capacity mix. The 2009 plant mix was selected as it was the most recent date for which generation capacity data for all eight countries under study was available.

Country	Coal	Gas	Nuclear	Wind
Ireland	1.4	4.3	0	1.3
Great Britain	34.0	29.1	10.9	4.4
Germany	56.0	23.3	20.4	25.7
France	24.9	2.5	63.1	4.5
Belgium	3.4	4.6	5.9	0.6
Netherlands	9.5	12.5	0.5	2.2
East Denmark	2.6	1.2	0	0.8
West Denmark	3.8	1.7	0	2.5

Table 1: 2009 generation capacity mix (GW) (Source: Eurostat)

Capacity costs for plant and interconnection were taken from the EIA (2010) and fuel and carbon price projections to 2030 were taken from the IEA New Policies scenario (IEA, 2011), as per Table 2 and Table 3. According to EU Directive 2003/87/EC, carbon permits must be purchased in order to emit carbon on a large scale, such as in electricity generation, and so the cost of carbon is included. All costs remain in 2011€ throughout the paper; thus the real cost of generation capacity is assumed to remain constant over time and the increasing cost of fuel and carbon are given in real terms.

Parameter	Nuclear	Coal	Gas	Wind
Construction time (year)	5	2	2	1
Asset lifetime (year)	40	30	20	20
Overnight cost (2011€/MW)	2,847,500	1,664,500	721,600	1,465500
Fuel costs	2011€/mmBtu	2011€/tonne	2011€/mmBtu	
2011	0.35	72.79	5.54	
2015	0.35	73.08	7.80	
2020	0.35	76.08	8.68	
2025	0.35	77.87	9.20	
2030	0.35	79.0	9.65	

Table 2: Capacity investment costs and parameters

Carbon price	2011	2020	2030
2011€/tonne	16.46	28.43	34.41

Table 3: Carbon price (Source: IEA)

Estimates of the value of lost load (VOLL) vary depending on country as well as electricity consumer type (Kariuki and Allan, 1996; Leahy and Tol, 2011; de Nooij *et al.,* 2007). For the purposes of this study VOLL was set to €10,000 per MWh, the value which was used in the Single Electricity Market in Ireland for 2007/2008 (CER, NIAUR, 2010).

The current level of interconnection was obtained from ENTSO-E's Winter 2011 net transfer capacity (NTC) figures (ENTSO-E, 2011) and is given in Table 4. A discrepancy exists between the flow on some lines, depending on the direction, due to regulatory issues or asymmetric technical limits on the line. Where a discrepancy existed, the capacity was set to the higher of the two values.

	IE	**GB**	**FR**	**BE**	**NL**	**DE**	**DK_W**	**DK_E**
IE		*1*						
GB	*1*		*2*		*1*			
FR		*2*		*3.4*		*3.2*		
BE			*3.4*		*2.4*			
NL		*1*		*2.4*		*3.85*		
DE			*3.2*		*3.85*		*1.5*	
DK_W						*1.5*		0.6
DK_E							*0.6*	

Table 4: Existing interconnection (GW)

The parameter *ic_capacity* was set to 1GW in each direction. This capacity was chosen as a suitable size as most current and planned European interconnectors are of no more than 1,000MW. The cost of interconnection per thousand km was obtained from Bahrman (2006), and is given in Table 5. The cost of submarine DC transmission lines was taken to be twice that of DC transmission lines, as per Bahrman.

Investment	**Overnight cost (2011€)**	**Construction time (years)**	**Lifetime**
AC station	430M	2	30
DC station	540M	2	30
AC transmission line	992,300/km	2	60
DC transmission line	793,858/km	2	60

Table 5: Transmission costs and characteristics

The interconnector in each case is set to be AC, DC or submarine DC for each pair of regions according to Table 6. Five hundred kilometres was chosen as the cut-off point at which DC rather than AC interconnection is preferable (Meah and Ula, 2007). Some of the links between regions would most likely be brought about by connecting through other regions rather than connecting directly, but the cost of this would be less than that of submarine DC and so the cost of such links is still realistic, if not over-estimated.

	DE	IE	GB	FR	BE	NL	DK_E	DK_W
DE		SM	SM	DC	DC	DC	SM	AC
IE	SM		SM	SM	SM	SM	SM	SM
GB	SM	SM		SM	SM	SM	SM	SM
FR	DC	SM	SM		AC	AC	SM	SM
BE	DC	SM	SM	AC		AC	SM	SM
NL	DC	SM	SM	AC	AC		SM	SM
DK_E	SM	SM	SM	SM	SM	SM		SM
DK_W	AC	SM	SM	SM	SM	SM	SM	

Table 6: AC, DC or submarine DC link

Transmission losses are taken to be 3% per 1,000km for DC lines and 6% per 1,000km for AC and are based on Bahrman (2006). These figures are lower than those quoted in Bahrman, but this is to take account of the fact that the lines will not always operate at full load.

The annual cost of capital was calculated based on the construction and lifetimes given above for three different discount rates of 4%, 6% and 8%. The model was run for each of these different discount rates. Running the model one time horizon at a time was necessary due to computational constraints. The myopic expectations of the model, whereby each time horizon is solved in isolation, may lead to a situation where a given investment is optimal for the year in question but does not prove optimal in the long run; the model may also fail to invest in capacity which is not optimal for the year in question but proves optimal in the long run.

The cost of wind integration (not including the cost of interconnection) is seen to vary between €1 and €4 per MWh (IEA, 2009). The model was run under each of these values for wind integration costs (WIC).

3.2 Case study scenarios

The model was run for three scenarios. Scenario I is a base case with no targets imposed for renewable generation. Scenario II is as Scenario I with extra constraints (equation (9)) which require that 20% of the electricity consumed in each individual country be generated from renewable sources:

$$\sum_{g,t,s} 0.25 * dispatch_{g,s,d,t} < \sum_{s,t} dispatch\_wind_{s,d,t} \quad \forall\, d \;\ldots (9)$$

Scenario III is as Scenario I with an extra constraint (equation (10)) which requires that 20% of total electricity consumed be generated from renewable sources without including targets for individual countries:

$$\sum_{g,t,s,d} 0.25 * dispatch_{g,s,d,t} < \sum_{s,t,d} dispatch\_wind_{s,d,t} \quad \ldots (10)$$

Scenarios II and III therefore implicitly assume that there is a market for renewable obligations as the renewable electricity required in order to meet an individual country's target need not have been generated there. Such full scale trading of renewable obligations as assumed by the model is currently not permitted under EU regulations, but it is advisable according to Aune *et al.* (2011). This model therefore expands on the approach of Aune *et al.* by assuming a market for renewable obligations and by investigating the effects of interconnection investment in the presence of such markets.

In an attempt to isolate the benefits of interconnection each scenario was run under the full model and under the Capacity Optimisation Module only. Thus the evolution of the total costs could be seen both with and without the opportunity to invest in interconnection.

4 Results and discussion

In interpreting the results it should be remembered that investments were determined based on myopic expectations and thus as highlighted above some may not prove optimal in the long run. Furthermore other investments which were not arrived at by the model may nonetheless have proven optimal. However the qualitative results, in particular the trends between scenarios, should prove robust and thus are of interest to policy makers and market participants.

Interconnection takes place in all scenarios and under all discount rates and wind integration costs. The interconnection and wind investments undertaken for each scenario are shown in tables in the Appendix A.1 – A.3.

Any change in total costs under Scenario I is negligible; the cost of what little interconnection built is offset by the small reduction in fuel and carbon costs. Allowing interconnection in Scenario I brings about no change to the generation capacity portfolio. It therefore appears that current interconnection capacities are optimal for the current generation mix.

The percentage reduction in total costs attributable to interconnection over the twenty years is given in Table 7, for Scenarios II and III only. The percentage change in total costs is calculated by the difference in total costs under the full model, and under the COM only.

	Discount rate: 4%		**Discount rate: 6%**		**Discount rate: 8%**	
	WIC = €1	**WIC = €4**	**WIC = €1**	**WIC = €4**	**WIC = €1**	**WIC = €4**
Scenario II	2.8	3.5	1.9	3.8	4.0	4.2
Scenario III	3.5	3.5	3.5	3.5	4.1	4.1

Table 7: Percentage reduction in total costs attributable to interconnection

Interconnection reduces total costs for Scenarios II and III, with the magnitude of the reduction dependant on the discount rate and the wind integration cost. The reduction in costs is primarily brought about by a decrease in total investment in generation capacity, both conventional and renewable, under these scenarios. While some regions see an increase in generation capacity investment under a scenario that allows interconnection investments, total generation capacity decreases under interconnection.

Wind generation is not built under Scenario I, thus at current market conditions it appears that wind investment will not occur under a least-cost expansion without EU mandated targets. Scenarios II and III see wind investment in most regions, but Scenario III sees a concentration of wind investment in regions with higher capacity factors, such as Great Britain and Ireland (Table A.2 8 and A.3 8). There is also a concentration in interconnection from these high-wind regions to other regions, while the interconnection portfolio observed under Scenario II is more evenly distributed across all regions studied. This is because a total target for all countries allows countries with the highest capacity factors for wind to meet more than 20% of their total electricity demands from renewable sources, thus allowing other countries to meet less than 20% of their demand from renewables, and to build interconnection to export during times of high wind. Mandating individual targets for each country rather than introducing targets for the all of Europe mean that it is cheaper to build renewable generation in countries with lower capacity factors and to connect heavily to other regions in order to smooth the intermittent supply from renewable if the target must be met at national level. Furthermore, allowing new investment in interconnection sees the total amount of wind investment decrease under both Scenario II and Scenario III when compared to the wind investment observed under the COM only, under which no interconnection investment can occur. Considering both these observations together, it appears that the imposition of renewable targets increases the amount of wind capacity built while interconnection decreases the wind capacity investment. The percentage decrease in investment in generation capacity is given in Table 8 and Table 9.

	Discount rate: 4%		Discount rate: 6%		Discount rate: 8%	
	WIC = €1	WIC = €4	WIC = €1	WIC = €4	WIC = €1	WIC = €4
Scenario II	1.3	1.4	1.9	2	2.6	2.6
Scenario III	1.6	1.6	1.5	1.5	2.3	2.3

Table 8: Percentage decrease in conventional generation investment attributable to interconnection

	Discount rate: 4%		Discount rate: 6%		Discount rate: 8%	
	WIC = €1	WIC = €4	WIC = €1	WIC = €4	WIC = €1	WIC = €4
Scenario II	6.3	8.3	1.8	7.7	6.8	7.4
Scenario III	8.3	8.3	8.0	8.0	7.9	7.9

Table 9: Percentage decrease in new wind generation investment attributable to interconnection

It can be seen from Tables 8 and 9 that the percentage reduction in wind capacity is greater than that of thermal capacity. This suggests that benefits on the demand side arising from further interconnection, such as smoothing of demand over a greater area as discussed in the introduction, are limited – such demand side benefits may already be sufficiently exploited by the existing interconnection portfolio. Indeed, the reduction in capacity investment under Scenario I, which saw no investment in wind capacity, was negligible. Thus the reduction in conventional capacity which is seen under Scenarios II and III, while slight, can be interpreted as a reduction in back-up generation required as wind generation increases. The potential for interconnection to bring about a decrease in generation capacity, both renewable and conventional, are a result of varying the supply side by increasing renewable generation.

The percentage changes in total costs over the three Scenarios is presented in Table 10.

	Discount rate: 4%		Discount rate: 6%		Discount rate: 8%	
	WIC = €1	**WIC = €4**	**WIC = €1**	**WIC = €4**	**WIC = €1**	**WIC = €4**
S. I – S. II	-0.2 (-72M€)	-0.2 (-69M€)	-0.2 (-81M€)	-0.2 (-72M€)	-0.2 (-72M€)	-0.2 (-71M€)
S. I – S. III	-0.1 (-63M€)	-0.2 (-63M€)	-0.2 (-65M€)	0.0 (-65M€)	0.0 (-65M€)	0.0 (-65M€)
S. II – S. III	0.0 (10M€)	0.0 (6M€)	0.0 (16M€)	0.0 (6M€)	0.0 (7M€)	0.0 (6M€)

Table 10: Percentage decrease in total costs between Scenario I, Scenario II and Scenario III

The change in total costs between Scenario II and Scenario III is given as a percentage of the total costs of wind in Table 11. These costs include the cost of wind integration over the twenty years modelled, as well as the cost of new wind capacity investments over the years modelled.

	Discount rate: 4%		Discount rate: 6%		Discount rate: 8%	
	WIC = €1	**WIC = €4**	**WIC = €1**	**WIC = €4**	**WIC = €1**	**WIC = €4**
S.II – S.III	4.4	4.3	4.7	4.7	5.0	5.0

Table 11: Percentage decrease in wind-related costs between Scenario II and Scenario III

The difference in reduction in total costs between Scenario II and Scenario III is low as a percentage of total costs, thus the design of renewable targets does not significantly change the results. However the finding that a scenario with a global target reduces the cost of meeting renewable targets compared with scenarios with differentiated national targets holds with the findings of Aune *et al.* (2011). The fact that this reduction is slight (<5%) suggests that increased interconnection can mitigate the ill-effects of differentiated renewable targets.

The results of the model provide evidence that interconnection is a worthwhile investment under a scenario which includes renewable generation. However it must be noted that the fact that the model minimises total costs across all countries, rather than minimising costs on a region-by-region basis, may be a strong driver of this interconnection investment. At present, interconnection investment is primarily funded by TSOs within a particular country, with some funding available at EU level. Unless the cost of interconnection is borne at EU level then each individual interconnector must prove beneficial to the consumers within a particular region or profitable to a merchant interconnector investor in order for the investment to occur, and this may limit investment in interconnection. It is likely that the cost of interconnection investment being borne at EU level will not happen until there is a fully integrated EU market for electricity, or at the very least until a greater amount of these investment decisions are determined at EU rather than national level.

The model can identify which of the potential drivers of interconnection discussed in the introduction (integration of renewable generation, smoothing of demand profiles and thus reduction of investment in generation capacity) are found to have an effect in determining interconnection investment. Mitigation of market power is also a potential driver of interconnection investment; however the model does not consider markets and so cannot shed light on this issue. There is little evidence in the results to indicate that demand smoothing is sufficiently beneficial to prompt further investment in interconnection over and above that which exists already. While there is some decrease in conventional generation capacity investment when interconnection is allowed (Table 8) this effect is not present under Scenario I, which includes no new renewable generation. The decrease in wind capacity when interconnection is included (Scenarios II and III) is much more pronounced. Thus it appears that of the potential drivers of interconnection which can be examined by the model, it is primarily factors on the supply side, rather than the demand side, which drive the observed investment.

The reduction in costs that is seen as a result of allowing interconnection investment is greater under Scenarios II and III than Scenario I. This suggests that wind investment and interconnector investment are complimentary. Even under Scenario II, where wind generation is not particularly concentrated in high-wind regions, there is sufficient variation in the wind time series to allow some export and import of wind generation, which reduces dependence on conventional generation.

Under Scenario II the higher wind integration cost sees much greater concentration of wind in those regions which have a higher wind resource, such as Ireland and Great Britain (Appendix 2). The higher wind integration cost also sees a higher investment in interconnection capacity. This is because individual targets for each region at a low integration cost mean wind generation in each region is optimal, with interconnection adding value by balancing supply and demand. However a higher cost of wind integration means the relative advantage of a high wind capacity factor is increased. Thus wind is better concentrated in the windier regions, and extra interconnection is then required to export the surplus generation.

The results of Scenario III do not see the same variation under the different wind integration costs. This is because under Scenario III the wind is built in the optimal location regardless of the cost of wind integration. Thus the wind is located in the windier regions as a matter of course, with some regions seeing no investment in wind (France, Germany).

The wind generation seen under Scenarios II and III when investment in interconnection is not allowed (i.e. when the COM only is run) is the same regardless of wind integration cost. This is because the model does not have the option of relocating the wind according to the least-costly area and transporting the electricity as required and so the wind is built in the least cost area given the existing interconnection portfolio. This least cost solution will hold for any wind integration cost. Thus the ability of interconnection to mitigate some of the costs incurred from wind integration has again been borne out.

The potential for other technologies to reduce the total costs of scenarios which include renewable generation has not been considered here. Such technologies include storage and demand responsive load, which could be found to balance intermittent renewable generation more efficiently than interconnection. We leave the inclusion of these considerations for further work.

5. Conclusion

This paper presented an optimisation model which can be used to determine optimal interconnection investment between regions for a given set of inputs and renewable penetration targets. These inputs include hourly demand, the existing generation portfolio, the existing interconnection portfolio, fuel and generation capital costs and interconnection investment costs. The model can include constraints which require a certain amount of electricity to be generated from renewable sources. The model determines optimal generation and interconnection capacity in an iterative process on an annual basis.

The model was run as a case study for eight Northern European countries under three scenarios, one in which there was no target for renewable generation, one with a target for each individual country and one with a total target for all countries modelled. It was found that interconnection investment reduces total costs only in scenarios which include renewable generation. Current interconnection capacities are therefore sufficient for the current generation mix and new interconnections are only warranted by EU mandates for renewable generation. Renewable generation is found to be concentrated in areas of high wind under a scenario with global targets, and under higher wind integration costs. The benefits of smoothing demand profiles and increasing capacity factors of thermal plant by increasing interconnection investment beyond its current levels do not appear to be significant.

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Appendix

A.1 Results from Scenario I

	Ireland	GB	France	Denmark_E	Denmark_W	Netherlands	Germany	Belgium
Ireland		0	0	0	0	0	0	0
GB	0		1	0	0	0	0	0
France	0	1		0	0	2	0	1
Denmark_E	0	0	0		0	0	0	0
Denmark_W	0	0	0	0		0	0	0
Netherlands	0	0	2	0	0		0	1
Germany	0	0	0	0	0	0		0
Belgium	0	0	1	0	0	1	0	

Table A.1 1: Interconnection investment with discount 4%, WIC = 1€/MWh, 4€/MWh (GW)

	Ireland	GB	France	Denmark_E	Denmark_W	Netherlands	Germany	Belgium
Ireland		0	1	0	0	0	0	0
GB	0		1	0	0	0	0	0
France	1	1		0	0	4	1	1
Denmark_E	0	0	0		0	0	0	0
Denmark_W	0	0	0	0		0	0	0
Netherlands	0	0	4	0	0		0	1
Germany	0	0	1	0	0	0		0
Belgium	0	0	1	0	0	1	0	

Table A.1 2: Interconnection investment with discount rate = 6%, WIC = 1€/MWh, 4€/MWh (GW)

	Ireland	GB	France	Denmark_E	Denmark_W	Netherlands	Germany	Belgium
Ireland		0	1	0	0	0	0	0
GB	0		2	0	0	0	0	1
France	1	2		0	0	4	1	2
Denmark_E	0	0	0		0	0	0	0
Denmark_W	0	0	0	0		0	0	0
Netherlands	0	0	4	0	0		0	1
Germany	0	0	1	0	0	0		0
Belgium	0	1	2	0	0	1	0	

Table A.1 3: Interconnection investment with discount rate = 8%, WIC = 1€/MWh, 4€/MWh (GW)

A.2 Results from Scenario II

	Ireland	GB	France	Denmark_E	Denmark_W	Netherlands	Germany	Belgium
Ireland		6	7	1	3	4	6	5
GB	6		3	0	1	0	2	3
France	7	3		2	1	1	1	3
Denmark_E	1	0	2		1	1	5	2
Denmark_W	3	1	1	1		1	5	2
Netherlands	4	0	1	1	1		3	2
Germany	6	2	1	5	5	3		7
Belgium	5	3	3	2	2	2	7	

Table A.2 1: Interconnection investment with discount rate = 4%, WIC = 1€/MWh (GW)

	Ireland	GB	France	Denmark_E	Denmark_W	Netherlands	Germany	Belgium
Ireland		7	16	3	2	6	11	7
GB	7		1	0	1	0	3	1
France	16	1		1	1	1	1	3
Denmark_E	3	0	1		0	0	1	1
Denmark_W	2	1	1	0		0	4	1
Netherlands	6	0	1	0	0		4	3
Germany	11	3	1	1	4	4		8
Belgium	7	1	3	1	1	3	8	

Table A.2 2: Interconnection investment with discount rate = 4%, WIC = 4€/MWh (GW)

	Ireland	GB	France	Denmark_E	Denmark_W	Netherlands	Germany	Belgium
Ireland		1	2	1	1	1	2	1
GB	1		1	0	1	0	2	1
France	2	1		1	1	1	1	2
Denmark_E	1	0	1		0	0	1	0
Denmark_W	1	1	1	0		0	1	0
Netherlands	1	0	1	0	0		2	1
Germany	2	2	1	1	1	2		2
Belgium	1	1	2	0	0	1	2	

Table A.2 3: Interconnection investment with discount rate = 6%, WIC = 1€/MWh (GW)

	Ireland	GB	France	Denmark_E	Denmark_W	Netherlands	Germany	Belgium
Ireland		8	13	3	3	6	12	5
GB	8		1	1	0	0	2	2
France	13	1		1	1	1	1	2
Denmark_E	3	1	1		1	0	2	2
Denmark_W	3	0	1	1		0	3	1
Netherlands	6	0	1	0	0		3	1
Germany	12	2	1	2	3	3		8
Belgium	5	2	2	2	1	1	8	

Table A.2 4: Interconnection investment with discount rate = 6%, WIC = 4€/MWh (GW)

	Ireland	GB	France	Denmark_E	Denmark_W	Netherlands	Germany	Belgium
Ireland		8	11	2	4	4	10	5
GB	8		1	0	1	0	1	2
France	11	1		1	1	1	1	2
Denmark_E	2	0	1		0	1	1	0
Denmark_W	4	1	1	0		0	4	0
Netherlands	4	0	1	1	0		4	1
Germany	10	1	1	1	4	4		7
Belgium	5	2	2	0	0	1	7	

Table A.2 5: Interconnection investment with discount rate = 8%, WIC = 1€/MWh (GW)

	Ireland	GB	France	Denmark_E	Denmark_W	Netherlands	Germany	Belgium
Ireland		8	11	2	2	7	8	5
GB	8		1	0	0	1	2	1
France	11	1		1	1	1	1	2
Denmark_E	2	0	1		2	1	5	1
Denmark_W	2	0	1	2		1	4	1
Netherlands	7	1	1	1	1		3	1
Germany	8	2	1	5	4	3		5
Belgium	5	1	2	1	1	1	5	

Table A.2 6: Interconnection investment with discount rate = 8%, WIC = 4€/MWh (GW)

	Discount rate = 4%		Discount rate = 6%		Discount rate = 8%	
	WIC = €1	WIC = €4	WIC = €1	WIC = €4	WIC = €1	WIC = €4
Ireland	2.99	2.99	2.98	2.98	2.98	2.98
GB	33.58	33.54	33	32.99	32.42	32.42
France	21.16	21.17	21.1	21.1	21.33	21.33
Denmark_E	3.8	3.8	3.81	3.81	3.84	3.84
Denmark_W	3.25	3.25	3.21	3.21	3.16	3.15
Netherlands	13.71	13.76	15.04	15.05	16.36	16.37
Germany	9.82	9.81	9.95	9.95	9.95	9.95
Belgium	21.53	21.53	20.85	20.86	20.03	20.02
Total	109.84	109.85	109.94	109.95	110.07	110.06

Table A.2 7: Wind investment under Scenario II with no interconnection (GW)

	Discount rate = 4%		Discount rate = 6%		Discount rate = 8%	
	WIC = €1	WIC = €4	WIC = €1	WIC = €4	WIC = €1	WIC = €4
Ireland	14.26	21.63	6.74	20.62	18.88	19.49
GB	30.87	29.45	32.16	28.94	28.66	28.12
France	8.01	7.09	17.78	8.15	8.7	7.77
Denmark_E	6.28	3.28	4.41	3.29	3.26	5.9
Denmark_W	3.4	2.57	2.96	2.52	2.59	2.58
Netherlands	13.71	13.68	15.04	15.03	16.36	16.37
Germany	5.3	4.7	8.88	5.43	6.56	6.16
Belgium	21.11	18.32	19.99	17.51	17.54	15.54
Total	102.94	100.72	107.96	101.49	102.55	101.93

Table A.2 8: Wind investment under Scenario II when interconnection is allowed (GW)

A.3 Results from Scenario III

	Ireland	GB	France	Denmark_E	Denmark_W	Netherlands	Germany	Belgium
Ireland		18	13	3	2	18	3	8
GB	18		6	4	4	3	4	9
France	13	6		2	1	1	0	3
Denmark_E	3	4	2		2	1	4	2
Denmark_W	2	4	1	2		1	2	2
Netherlands	18	3	1	1	1		0	6
Germany	3	4	0	4	2	0		2
Belgium	8	9	3	2	2	6	2	

Table A.3 1: Interconnection investment with discount rate = 4%, WIC = 1€/MWh (GW)

	Ireland	GB	France	Denmark_E	Denmark_W	Netherlands	Germany	Belgium
Ireland		17	14	2	2	18	3	10
GB	17		5	5	4	3	3	8
France	14	5		2	1	1	0	4
Denmark_E	2	5	2		2	1	4	2
Denmark_W	2	4	1	2		1	2	2
Netherlands	18	3	1	1	1		0	5
Germany	3	3	0	4	2	0		1
Belgium	10	8	4	2	2	5	1	

Table A.3 2: Interconnection investment with discount rate = 4%, WIC = 4€/MWh (GW)

	Ireland	GB	France	Denmark_E	Denmark_W	Netherlands	Germany	Belgium
Ireland		14	15	3	3	15	3	9
GB	14		5	3	3	3	2	8
France	15	5		2	1	1	1	3
Denmark_E	3	3	2		1	1	3	2
Denmark_W	3	3	1	1		1	1	2
Netherlands	15	3	1	1	1		0	3
Germany	3	2	1	3	1	0		1
Belgium	9	8	3	2	2	3	1	

Table A.3 3: Interconnection investment with discount rate = 6%, WIC = 1€/MWh (GW)

	Ireland	GB	France	Denmark_E	Denmark_W	Netherlands	Germany	Belgium
Ireland		17	14	3	2	17	2	10
GB	17		5	3	3	3	3	7
France	14	5		2	2	1	1	3
Denmark_E	3	3	2		1	1	3	2
Denmark_W	2	3	2	1		1	1	2
Netherlands	17	3	1	1	1		0	3
Germany	2	3	1	3	1	0		2
Belgium	10	7	3	2	2	3	2	

Table A.3 4: Interconnection investment with discount rate = 6%, WIC = 4€/MWh (GW)

	Ireland	GB	France	Denmark_E	Denmark_W	Netherlands	Germany	Belgium
Ireland		17	13	2	3	18	2	11
GB	17		5	3	2	3	3	6
France	13	5		2	1	2	1	2
Denmark_E	2	3	2		1	1	3	2
Denmark_W	3	2	1	1		1	1	1
Netherlands	18	3	2	1	1		0	2
Germany	2	3	1	3	1	0		1
Belgium	11	6	2	2	1	2	1	

Table A.3 5: Interconnection investment with discount rate = 8%, WIC = 1€/MWh (GW)

	Ireland	GB	France	Denmark_E	Denmark_W	Netherlands	Germany	Belgium
Ireland		16	14	3	2	17	2	10
GB	16		6	3	3	2	3	7
France	14	6		1	1	2	1	2
Denmark_E	3	3	1		1	1	3	2
Denmark_W	2	3	1	1		1	1	1
Netherlands	17	2	2	1	1		0	2
Germany	2	3	1	3	1	0		1
Belgium	10	7	2	2	1	2	1	

Table A.3 6: Interconnection investment with discount rate = 8%, WIC = 4€/MWh (GW)

	Discount rate = 4%		Discount rate = 6%		Discount rate = 8%	
	WIC = €1	**WIC = €4**	**WIC = €1**	**WIC = €4**	**WIC = €1**	**WIC = €4**
Ireland	6.06	6.06	6.14	6.14	6.15	6.15
GB	43.97	43.97	43.11	43.11	43.67	43.67
France	19.01	19.02	16.17	16.16	15.53	15.54
Denmark_E	5.66	5.66	5.59	5.6	5.48	5.48
Denmark_W	2.94	2.94	2.94	2.93	2.85	2.85
Netherlands	3.08	3.09	7.73	7.74	8.89	8.89
Germany	0	0	0	0	0	0
Belgium	23.72	23.7	22.71	22.71	21.82	21.82
	104.44	104.44	104.39	104.39	104.39	104.4

Table A.3 7: Wind investmend under Scenario III with no interconnection (GW)

	Discount rate = 4%		Discount rate = 6%		Discount rate = 8%	
	WIC = €1	**WIC = €4**	**WIC = €1**	**WIC = €4**	**WIC = €1**	**WIC = €4**
Ireland	24.26	24.27	24.37	24.36	24.49	24.49
GB	42.88	42.85	40.22	40.22	40.32	40.32
France	0	0	0	0	0	0
Denmark_E	4.84	4.83	4.67	4.67	4.72	4.72
Denmark_W	2.16	2.16	2.09	2.08	1.92	1.92
Netherlands	2.01	2.04	6.16	6.17	7.36	7.36
Germany	0	0	0	0	0	0
Belgium	19.66	19.66	18.58	18.57	17.33	17.33
	95.81	95.81	96.09	96.07	96.14	96.14

Table A.3 8: Wind investment under Scenario III when interconnection is allowed (GW)