How much wind energy will be curtailed on the 2020 Irish power system?

E. V. Mc Garrigle[a,*], J. P. Deane[b], P. G. Leahy[a,b]

[a] *School of Engineering, University College Cork, College Road, Cork City, Ireland.*
[b] *Environmental Research Institute, University College Cork, Lee Road, Cork City, Ireland.*

Abstract

This paper describes a model of the 2020 Irish electricity system which was developed and solved in a mixed integer programming, unit commitment and economic dispatch tool called PLEXOS®. The model includes all generators on the island of Ireland, a simplified representation of the neighbouring British system including proposed wind capacity and interconnectors between the two systems. The level of wind curtailment is determined under varying levels of three influencing factors. The first factor is the amount of offshore wind, the second is the allowed limit of system non-synchronous penetration (SNSP) and the third is inclusion or exclusion of transmission constraints. A binding constraint, resulting from the 2020 EU renewable energy targets, is that 37% of generation comes from wind. When the SNSP limit was increased from 60% to 75% there was a reduction in wind curtailment from 14% to 7%, with a further reduction when the proportion of wind capacity installed offshore was increased. Wind curtailment in the range of SNSP limit of 70-100% is influenced primarily by the inclusion of transmission constraints. Large changes in the dispatch of conventional generators were also evident due to the imposition of SNSP limits and transmission constraints.

Keywords: Wind Energy, Offshore wind, Power systems, Unit commitment, Electricity markets.

1. Introduction

Ireland has an abundant natural resource in wind energy, with some of the highest average wind speeds in Europe [1]. There is currently 1955MW of installed wind capacity and a total conventional generation capacity of 9356MW on the island of Ireland [2]. In the Republic of Ireland (ROI) the government has set a target of 40% for renewable electricity generation (RES-E) by 2020 [3]. In Northern Ireland (NI) the Executive has also set a target of 40% RES-E by 2020 [4]. As wind is the most mature of the renewable technologies it is expected to be the biggest contributor to fulfilling the RES-E targets. This will be achieved through the planned installation of up to 5300MW of wind generation capacity on the island of Ireland (AI)[1] [2]. This means that wind turbines will be expected to produce 37% of AI electrical energy needs in 2020 assuming that existing hydroelectric plant and other forms of renewable electricity generation will only make up 3% of total generation.

1.1. Installed wind capacity

Estimates of the wind capacity required to be installed in ROI and NI to meet the 2020 RES-E targets vary according to reports. These variations are in the order of hundreds of MW and represent hundreds of millions of Euro in additional installation costs [5].

The most current estimate of the required wind capacity is of up to 5300MW for AI, with between 3500MW and 4000MW in ROI while NI will have 1278MW (978MW onshore and 300MW offshore). These figures make up the main contribution to the 40% RES-E target in both jurisdictions [2]. For ROI it has been reported that 36.5% of total generation will come from 4649MW of wind capacity [3]. A comparison cannot be drawn with the UK NREDP as it does not separate NI capacity from the rest of the United Kingdom. With a total AI installed wind capacity of 6000MW in 2020, almost entirely onshore, wind has been predicted to produce 34% of total generation [6]. However these figures are based on predictions of system demand growth which have since been revised downwards due to the ongoing recession and wind curtailment has not been taken into account.

1.2. Offshore Wind

There are currently five developments equating to approximately 2400MW of offshore wind capacity under consideration in ROI waters. These developments all have either grid connection offers or foreshore licenses approved (Table 1). Strong interest is also being shown in the potential development of 600MW of offshore wind capacity off the coastline of county Down. This is part of the Crown estate licensing rounds in NI [7].

The National Renewable Energy Action Plan (NREAP) for ROI suggests that 555MW of offshore wind is needed to ensure ROI meets its RES-E targets for 2020 [3]. This recommendation comes from concern that onshore wind developments may not be sufficient to meet the RES-S targets as many onshore wind developments are encountering difficulties in the planning process. This would result in at least one and possibly two of the five ROI offshore wind developments being constructed.

*Corresponding author, Tel.: +353 21 490 3767
Email address: `e.mcgarrigle@umail.ucc.ie` (E. V. Mc Garrigle)

[1] All-island of Ireland (AI), consisting of Northern Ireland (United Kingdom) and the Republic of Ireland.

Table 1: Existing and proposed offshore wind farms.

Name	Capacity (MW)
Dublin Array (ROI)	364
Oriel (ROI)	320
Doolick (ROI)	100
Codling wind park (ROI)	1100
Arklow Bank Phase 1 (ROI)	25.2
Arklow Bank Phase 2 (ROI)	493
Crown Estate round (NI)	600

Sources: [7] [10] [11] [12] [13] [14].

While it is unlikely that all of the possible 3000MW of offshore wind capacity under consideration in ROI and NI will be constructed, it will only take less than 10% of what has been proposed to exceed the estimate proposed in the All-Island Grid Study (AIGS) Portfolio 5 [8]. The suggestion from the transmission system operator (TSO)[2] of ROI is that the system will only be able to cater for 600-700MW of offshore wind due to issues such as reserve provision and system stability.

Currently all proposed offshore wind farms in AI waters are located on sand banks or rock shelves in less than 30 metres of water depth, in what would generally be considered shallow waters. There is an argument for installing wind turbines in deeper water to avail of the greater capacity factors generally present at locations further offshore. The greater geographical spread would also contribute to reducing wind curtailment. However there is an increase in cost as wind turbines are placed further offshore [9] and this is likely to rise further if floating wind turbines are required in deeper waters.

1.3. Wind Curtailment and Constraint

Wind curtailment is an intentional reduction in overall wind power output ordered by a TSO due to the risk of instability on the electricity grid from non-synchronous generation as well as other reasons such as managing grid stability and reserve requirements. As installed wind turbine capacity on the power system increases, this will result in an increased frequency and magnitude of wind curtailment events becoming necessary [15, 16, 17] . Wind curtailment could have a considerable effect on estimates of required installed capacity in order for ROI and NI to meet their 2020 RES-E targets. Wind curtailment will also result from the increased variability of generation from renewable sources and the re-dispatch of conventional plant for reserve and ramping requirements during periods of high instantaneous wind penetration, resulting in a temporary decrease in wind generation [18].

To date, most studies have shown that wind curtailment will have minimal effects at installed wind capacities of less than 7000MW on the AI system [19, 20, 21, 22]. Tuohy et al. [21] demonstrated that significant wind curtailment would only begin to occur when installed wind capacity exceeded 7000MW on the AI system, however the authors acknowledged that taking account of inertia issues or voltage stability on the system might change this estimate. Also, it must be noted that these figures were based on pre-recession projections of system demand growth which are now unlikely to be met. Doherty et al. [23] discussed that wind curtailment may be used in a future AI system with a scenario of high wind power and HVDC interconnection to Great Britain[3] (GB), in order to avoid risks to system stability. An assumed high interconnection capacity of 2000MW with GB resulted in negligible changes in wind curtailment compared with a baseline scenario of 1000MW interconnection. However, overall curtailment was in the order of 0.12% to 0.15% [20].

It has been shown that wind output will sometimes have to be constrained on the All-Island system as a result of network congestion. One study estimated 6.8% reduction in wind output due to network constraints with 7000MW of installed wind capacity on the system, however in the same study for a minimum inertial constraint showed wind curtailment to be almost negligible [19]. While wind constraint taking place on the system due to network congestion is a separate issue to wind curtailment that would occur due to the imposition of a fixed, system-wide percentage limit on generation from non-synchronous machines, it is however not possible to determine how much the two separate issues will cause wind curtailment simultaneously without detailed modelling of a transmission grid. For this reason these issues are not considered separately in this paper.

1.3.1. System non-synchronous penetration (SNSP)

Curtailment of wind power is dependent on a number of factors such as the instantaneous system demand and the system's capacity to safely produce a certain percentage of its generation from non-synchronous sources such as wind turbines based on double-fed induction generators or high voltage direct current interconnections [18, 24]. The penetration of non-synchronous generation is described by Eqn. 1, and an SNSP limit may be imposed by the TSO to prevent exceedance of a certain percentage of total generation by non-synchronous sources at any one time. This constraint on non-synchronous generation is called the system non-synchronous penetration (SNSP) limit [18].

$$SNSP = \frac{wind\ generation + HVDC\ imports}{system\ demand + HVDC\ exports} \quad (1)$$

Estimates for the required installed wind capacity for AI have been mainly based on the wind capacity factor for an area and also include allowances for a minimum number of large conventional generators to be on-line at all times. Excluding SNSP limits leads to an under-estimation of the required installed wind capacity for AI to meet its 2020 targets. This is a result of over-estimating the annual energy yield per MW of installed wind capacity due an under-estimate of wind curtailment.

It has been estimated that the SNSP limit will be between 60 and 75% in 2020, with recommendations that a SNSP of 75% could be technically achieved [18]. The issues resulting in the

[2]The TSOs are Eirgrid for ROI and the System Operator for Northern Ireland (SONI)

[3]Great Britain (GB) refers to the mainland island of Britain

75% ceiling for SNSP are associated with frequency response to disturbances and transient stability on the power system. It has been suggested that the possible curtailment of wind power or HVDC interconnector imports may be most economic solution to stability issues at certain times [23] .

It has been shown that with 5000MW of installed wind capacity on the island, negligible wind curtailment would take place if a SNSP limit of 66.6% were imposed [25]. When the installed wind capacity is increased to 9500MW wind curtailment was estimated at 14.4% of the available energy. This does not however include the non-synchronous properties of interconnection imports and assumes a much higher system demand as it contains pre-recession demand projections.

Simulations run by the TSOs have shown that AI would not meet its 2020 RES-E targets with 6000MW of installed wind capacity under a 60% SNSP limit. It was found that the 2020 RES-E targets could be achieved using 6000MW of installed wind capacity with a 80% SNSP constraint, however due to grid stability reasons, the TSOs did not consider an 80 % limit to be feasible by 2020 [18]. In the same report a 7550MW wind scenario is determined to meet the targets with a 60% SNSP limit. Taking these results into account, considerable uncertainty remains over whether or not AI can achieve its 2020 RES-S targets with 5300MW of installed wind capacity when SNSP limits are taken into account. This poses the question of how much wind capacity will actually be required.

1.3.2. Transmission Constraint Groups (TCGs)

Another contributor to wind curtailment is the requirement that certain generators or certain numbers of a generator group to be online at certain times, embodied in the TSOs' Transmission Constraint Groups [26]. There are also constraints on generation from certain groups of generators and maximum export capacities from certain areas. Accounting for these constraints in the model allows for a more realistic power system simulation.

1.4. Interconnection

From Eqn. 1 it is evident that increasing exports to a maximum during times of high wind power penetration on the AI system will be essential in order to reduce the amount of wind curtailment necessary with a fixed SNSP limit. This raises an issue over the use of the interconnectors[4]. A major influence on Ireland's ability to export electrical energy to the British market will be Britain's targets for installed wind capacity of 27GW in a system with 113GW installed generation capacity by 2018 [28].

In addition to this the times of peak wind power on the All-island system and time difference, leading or lagging, relative to wind power peaks in Britain will also be important [29]. Previous work assumed that most of Britain's installed wind would be built onshore in Scotland but with recent developments in offshore wind, the largest proportion of the installed wind capacity will be in the North Sea with lesser amounts in the Irish Sea.

2. Aims

The aims of this study are: (1) to estimate the level of wind curtailment on the 2020 AI system under three different mixes of offshore/onshore wind capacities while accounting for the effects of inclusion of five different system non-synchronous penetration limits and transmission system constraints; (2) to determine the required total wind capacities under each scenario in order to achieve the 2020 renewable generation targets; (3) to analyse changes in dispatch of the conventional generation portfolio due to the inclusion of SNSP and TCGs; (4) to identify the most feasible onshore/offshore wind energy portfolio to meet the 2020 RES-E target under realistic assumptions of power system operation.

3. The Model

The model simulates the 2020 AI electricity system and a simplified version of the GB electricity system. It includes offshore wind scenarios, SNSP constraints, predicted generation capacity on the All-island system, an aggregate form of GB generation, and incorporates wind generation time series data.

PLEXOS® for Power Systems (Energy Exemplar Pty., Adelaide, Australia), a mixed integer unit commitment/economic dispatch modelling tool, is used to build and simulate the models. PLEXOS® determines the most economic means of production of electricity on the system within the constraints applied to the model. From this it will simulate supply, demand and prices on the electricity system. Version 6.203 (R02) of PLEXOS® was used on a Dell OptiPlex 380 Desktop with an Intel® CoreTH2 Duo Processor. The Xpress-MP solver was used using Mixed integer programming at a relative gap 0.05%. Single runs of all scenarios took approximately 20 hours to solve. PLEXOS® has been used in other studies examining the impacts of energy storage, high wind penetration and wave power on electricity systems and markets [5, 30].

The model consists of a short-term schedule that optimises each of the 366 days in 2020 on the 30 minute intra-day trading period. It has a six-hour look-ahead period where forced outages and wind variabilty are known. The scheduling method replicates the Single Electricity Market (SEM) dispatch scheduling, helping to give accurate results for the dispatch of generators on the AI power system [31]. Maintenance outage rates were also applied to all generators.

3.1. Model description

The simplified mixed integer linear programming formulation for dispatchable units is:

[4]Interconnection between Ireland and Britain in 2020 is expected to consist of: the existing Moyle interconnector with a maximum capacity of 500MW in both directions (currently limited to importing 450MW in the winter and 410MW in the summer) [2, 27] and the East-West interconnector (EWIC) with a maximum capacity of 500MW in each direction, which was first energised in 2012.

$$min\left\{\sum_{t=1}^{48}\left\{\sum_{i=1}^{N} d_i\, C_i(P_i)\right\} + C_{uplift}\right\},\ d_i \in \{0,1\}$$

subject to the constraints:

$$\sum_{i=1}^{N} P_i = P_d$$

$$P_i^{min} \leq P_i \leq P_i^{max}$$

where d_i is a binary quantity indicating whether a unit has been scheduled (1) or not (0), C_i is the unit generation cost of unit i, P_i is the unit power generation, P_d the system demand, N the number of dispatchable generation units, P_i^{max} and P_i^{min} the unit power output limits, i the index of generation units, and C_{uplift} is the uplift cost which is determined from start-up, no-load and other fixed costs. Additional constraints on unit ramp-up and ramp-down rates, minimum on and off times are not shown here.

3.2. Scenario Descriptions

The AI system's three assumed offshore wind scenarios represent low, medium, and high offshore wind penetration levels with installed capacities of 25.2MW, 850MW and 1300MW respectively with the remainder of the installed wind capacity onshore to meet the 2020 renewable targets. Within each of the three offshore wind scenarios there will be five thresholds applied for SNSP limits on the AI system. These are limits of 60%, 65%, 70%, 75% and 100% of total generation from non-synchronous machines on the system at any time (eqn. 1). The SNSP limit of a 100% is only included as a comparison case. In addition to the 15 offshore wind and SNSP sub-scenarios described above there will be five more sub-scenarios consisting of the medium offshore wind scenario on all the SNSP limits where the TCGs will be excluded from the model in order to allow for the contribution to wind curtailment from SNSP limits to be quantified separately. The conventional generation capacity and all non-wind renewable generation capacity remains unchanged for all scenarios.

The low offshore scenario is essentially a "baseline scenario" consisting only of the 25.2MW of installed offshore wind capacity that currently exists. This is from a single windfarm at Arklow Bank. For this scenario it is assumed that no more offshore wind will be developed in AI prior to 2020 and the 2020 RES-E targets will be met almost entirely by onshore wind developments.

The medium offshore scenario consists of 850MW installed offshore wind capacity. This is an amalgamation of the NREDP recommendations and half of the offshore wind portion of the Crown Estate's NI round, consisting of 550MW and 300MW respectively. Dublin Array and Oriel offshore wind farms are reduced proportionally in capacity, by 278MW and 245MW respectively, to make up the ROI contribution. The NI contribution will consist of a single proposed offshore wind farm off the Co. Down coast in NI.

The high scenario consists of 1300MW installed offshore wind capacity. This is a amalgamation of the upper limit recommended by Eirgrid for installed offshore wind in the ROI and the full offshore wind portion of the Crown Estate Northern Ireland licencing round, or 684MW and 600MW respectively. The Dublin Array and Oriel offshore wind farms make up the ROI contribution and two 300MW proposed offshore wind farms off the Co. Down coast fulfil the NI contribution.

3.3. All-island generation

The generation portfolio reflects the predicted development of the AI generation mix by 2020 which is based on [2], with some minor changes due to the exclusion of a small proportion of non-wind renewable generation. The conventional generation portfolio has been developed from the Single Electricity Market Operator (SEMO) forecast model of 2011-2012, created by Redpoint Energy Ltd [32]. Generator synchronisation time, "must-run" units and modified start-up costs with additional off-take fuel[5] based on recent market data have been added as additional constraints to the models.

3.4. Non-wind renewable sources of electricity

The four existing conventional large hydroelectric power stations in ROI with a total capacity of 218MW are expected to produce on average 1.5% of AI 2020 system demand [33]. Under [2] generation from waste is considered to be 50% renewable and with 77MW installed by 2020 this will produce 0.6% of total generation in AI. The 118 MW peat-fired power station at Edenderry in ROI will be 30% co-fired with biomass, equating to about 0.6% of 2020 AI total generation. Tidal sources are predicted to contribute 0.2% of total generation for AI. Tidal generation was simulated by a periodic oscillation of period 12 hours and 25 minutes, modified to represent the non-linear correlation between fluid velocity and power extraction, and to achieve an overall 20% capacity factor associated with tidal energy [2].

This results in a total mean annual electrical energy contribution from non-wind renewable sources of 2.9%. This then leaves 37% of generation to come from wind energy in order for AI to meet the 2020 targets.

The other renewable sources that are highlighted in [2] but excluded from the model, are as follows: biomass CHP in ROI (2.4%); biomass in NI (1.5%); bio-fuel in NI and ROI (1.0%); marine (wave) in ROI (0.3%). These generator types were excluded due to the present lack of development or planning permission activity in these categories.

3.5. Wind generation

For a realistic simulation of wind generation, it is important to capture the spatial and temporal variability of the resource. Therefore, wind generation was aggregated on a regional basis (Fig. 1), based on hourly resolution time series for multiple wind regions across the island developed by Eirgrid for use in

[5] The quantity of fuel required for the generator to go from cold to synchronous to the grid, allowing for addition of the carbon tax to start-up costs

[32]. These data were based on the year 2008 as it was determined to be a mean wind speed year. New timeseries to represent additional offshore regions which were added to the model so that it consisted of 14 onshore wind regions and six offshore wind regions.

3.5.1. *Onshore wind*

The AI onshore wind capacity consisted as of October 2011 of 1991MW of installed wind farms and 1875MW of planned wind farms [2]. Knowledge of wind farm locations allowed for the installed capacity of each wind region profile to be calculated at present and for the future planned installations. However this only comes to a total installed capacity of 3866MW, which is not sufficient for meeting the 2020 renewable generation targets.

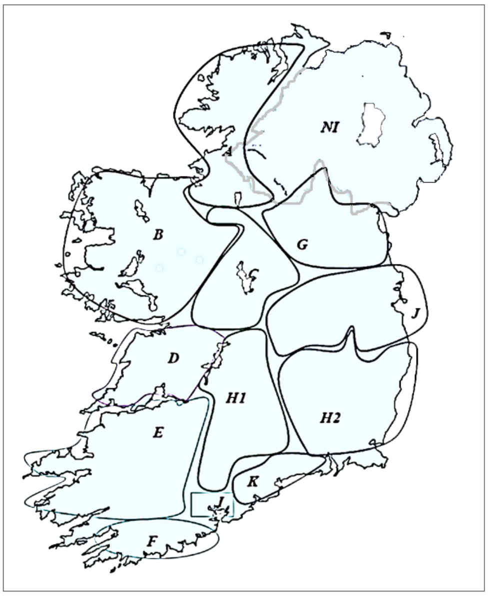
The installed capacity of each wind region was therefore linearly scaled up in order to meet the target amount, with the exception of Region E (Kerry/West Cork). Region E has a total existing and planned installed wind capacity of 1036MW which is reaching its export limit due to transmission constraints (assuming eight 110kV lines at an average rating of 120MW). The final total wind capacity was determined by an iterative process in order to obtain the required capacity to achieve 37% of total generation for AI from wind.

A further requirement was imposed that 37% of generation must come from wind for both jurisdictions NI and ROI independently. This results in the onshore wind capacities being adjusted to take account of the varying amounts of offshore wind installed in each jurisdiction under each of the three offshore wind scenarios. The relationship between the installed wind capacity and the balancing of generation in the two jurisdictions is almost linear in nature, this resulted in a simple manipulation of the data to reflect the annual proportion of the total system demand requirement by NI and ROI from AI. The percentage of installed onshore wind in each wind region is shown in Table 2.

Table 2: The regional breakdown of wind capacities across onshore wind regions for the three wind scenarios.

	Offshore scenario		
Wind region	**Low** (%)	**Medium** (%)	**High** (%)
A	12.3	12.7	13.4
B	8.7	9.0	9.5
C	0.7	0.7	0.8
D	8.0	8.3	8.7
E	16.5	17.1	18.0
F	2.7	2.8	3.0
G	3.5	3.6	3.8
H1	9.9	10.3	10.9
H2	8.9	9.2	9.7
J	2.0	2.1	2.2
K	0.5	0.5	0.6
NI	26.2	23.6	19.4

Figure 1: Eirgrid wind regions, reproduced from [32]



3.5.2. *Offshore Wind*

With only a single, small operational offshore windfarm on the AI system, there is a lack of representative data for offshore wind generation. Therefore, time series for the offshore wind regions presented in this model were modified from those of neighbouring onshore wind regions. The onshore regions' wind time series data were converted into a power duration curve and scaled to achieve a representative 40% capacity factor for offshore, (Fig. 2), using Eqn. 2 before being converted back to time series. Due to Ireland's predominantly westerly wind, offshore data was time lagged or led by one hour with respect to the neighbouring onshore region to reflect this (cf. [29]). This resulted in the offshore wind regions' data on the east coast of AI being time-lagged by one hour relative to their respective onshore wind regions, and the single offshore wind region off the west coast of AI being time-led by one hour.

$$CF_{OF,n} = CF_{ON,n}\left(\left(\frac{a}{1-N}\right)n + a + 1\right) \tag{2}$$

In Eqn. 2 CF_{OF} and CF_{ON} are the capacity factors offshore and onshore respectively, a is a scaling factor, chosen to achieve a 40% capacity factor, n is the interval number and N is the number of interval points.

3.5.3. *Spatial correlation of wind regions*

The Pearson product-moment correlation coefficient, R, was used to determine the spatial correlation of the regional wind time series with respect to each other. Correlation coefficients between pairs of onshore wind regions were in the range 0.51-0.90. The correlation coefficients between the manipulated offshore wind regions (G_{OF}, J_{OF}, NI_{OF} and their respective neighbouring onshore wind regions (G, J, NI) were in the range 0.94-0.97. The lowest correlation (R = 0.51) occurred between

Figure 2: Wind power duration curves for one onshore region and the corresponding adjusted offshore region.

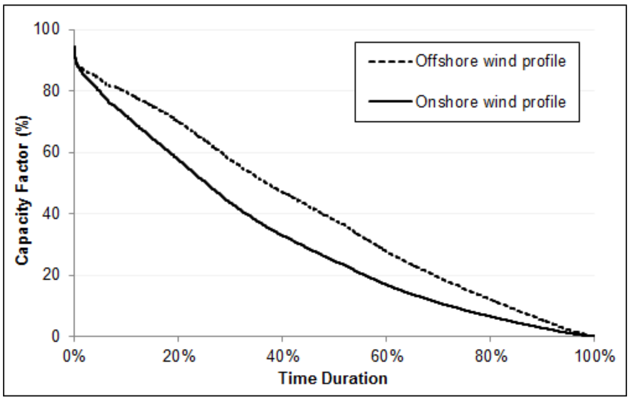
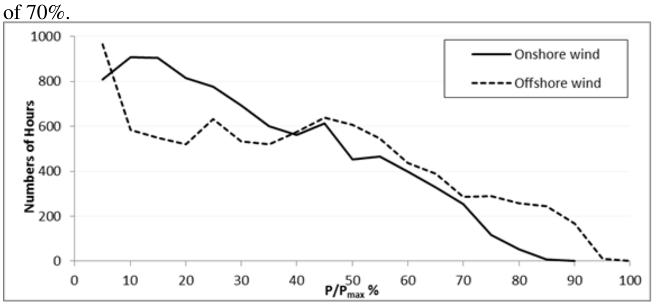


Figure 3: Wind generation duration curves for aggregated onshore and offshore power, net of curtailment, for the high offshore wind scenario with a SNSP limit of 70%.



two onshore regions, A and E, both of which have considerable installed capacity and are separated by a large north-south distance. From this it is clear that the adjustments made to create the offshore wind data can be viewed as conservative in terms of the likely effects on wind curtailment.

There is a clear indication from aggregated onshore and offshore duration curves (Fig. 3) that offshore wind suffers less curtailment during periods of high wind generation than onshore wind. This is a result of the greater overall spatial dispersion of wind capacity when more wind capacity is located offshore.

3.6. Great Britain generation

Due to the approximately 950MW of interconnection capacity between AI and GB expected to be in place by 2020, it is necessary to simulate a simplified GB system in order to replicate the power flows on the two interconnectors. This was achieved by creating a GB generation system large enough to export to AI and, in doing so, creating a price differential across the interconnectors. The GB replica generator is increased in capacity from that of [32] in order to meet the import requirements of the AI system. To simulate the fluctuations that will result from the large amount of proposed GB wind capacity, a single, large wind generator is added. The GB wind generator takes account of the planned installation of GB wind capacity in 2020 by being sized in proportion to the conventional generation plant [28]. The GB wind generator is based on data taken from the wind region J and is time lagged by 2 hours, consistent with the findings of [29]. This gives a truer reflection of the interconnector usage when there is excess wind power available for export.

3.7. Transmission Constraints

The AI model consists of two separate nodes representing the NI and ROI systems, which results in the NI and ROI systems being effectively unconstrained. To take account of constraints between and within the two electricity systems, limitations were imposed on generators due to transmission constraints and system stability requirements which are embodied in the TCGs implemented by the TSOs [26].

The assumption was taken to retain all the TCGs unchanged in the 2020 system with one exception. The decision not to modify the majority of the TCGs was due to the difficulty in predicting which TCGs will be relaxed, assuming that the current plans to strengthen the transmission grid will take place [34]. The TCG that was considered likely to change was the restriction of flow between NI and ROI as it is planned to have the North-South interconnetor in place by 2020. Currently flow is restricted to 450MW in the NI-ROI direction and 400MW ROI-NI due to system security issues, however the full rating of transmission lines joining the NI and ROI grids in 2020 could equate to at least 3768MW [35]. The model accommodates this by allowing flows of 2000MW both ways between the NI and ROI grids.

All TCGs in the model are represented by soft constraints which incur a penalty price if violated. The penalty prices were set in order to only allow violation of the constraints for a maximum of a 100 hours of the year. As a check, TCGs were also modelled as hard constraints in order to determine if any infeasible solutions would occur. All resulting changes were negligible and therefore ignored. The model also includes modified Transmission Loss Adjustment Factors (TLAF) to account for transmission losses within the system [36]. This is not ideal as they do not reflect the 2020 grid entirely accurately, but does allow a representation of likely grid losses within the model.

3.8. System demand

We assumed an increase of 17% in system demand over the time frame of 2010-2020. This was applied by means of a linear scaling to the AI system demand time series for the year 2010 from [32]. The system demand of both jurisdictions, NI and ROI, are modelled as percentages (25.8% and 74.2% respectively) of the AI system demand time series data in order to allow for each jurisdiction to be treated separately to ensure compliances with the RES-E targets and a more accurate model representation. The increase in total electricity requirement was taken from a median growth projection scenario [2]. This takes account for the latest reduced projections in demand growth due to the recession in the NI and ROI economies.

3.9. Costs Information

Fuel prices are based on predictions for of 2020 from [37]. This also correlates with the 2020 base case in [38]. This has a direct influence on the annual mean system marginal price (SMP), however more crucially it also has a direct influence on the dispatch of the different types of generation plant technologies. This is particularly acute in the relationship of the price of coal and gas. A carbon tax of €25/tonne CO_2 was applied to fossil fuel burning plant [33]. Generator start costs, including fuel take-off were included, allowing for the total carbon tax to be applied and the uplift cost to be calculated.

4. Results

The level of wind curtailment is evaluated for all 20 sub-scenarios, these consisting of three offshore wind scenarios all with TCGs imposed, and an extra case of a medium offshore wind scenario without TCGs. The four scenarios of offshore wind and TCGs then have five SNSP limits imposed on them (60%, 65%, 70%, 75% and 100%). There is a binding constraint in all scenarios that the 2020 RES-E target must be met, meaning wind generation will equal 37% of total generation, within a tolerance of 0.1%. The installed onshore wind portfolio is scaled to achieve this in each case. This enables a clear results comparison between the different sub-scenarios and ensures the elimination of bias. The installed wind capacities are shown in Table 3, and the wind curtailment resulting from the installed wind capacities chosen is shown in (Fig. 4).

Table 3: The AI onshore wind capacities of the offshore wind scenarios, including and excluding TCGs under the different SNSP limits.

	Offshore scenario			
	Incl. TCGs			**Excl. TCGs**
SNSP	**Low** (MW)	**Med** (MW)	**High** (MW)	**Med** (MW)
All-island				
60%	6865	5760	5199	5388
65%	6512	5747	4878	5040
70%	6324	5248	4643	4833
75%	6262	5193	4602	4710
100%	6273	5212	4614	4545
Republic of Ireland				
60%	5069	4351	4155	4085
65%	4815	4382	3945	3871
70%	4673	3974	3748	3728
75%	4630	3927	3714	3638
100%	4609	3907	3686	3502
Northern Ireland				
60%	1796	1408	1044	1303
65%	1697	1365	933	1169
70%	1651	1274	895	1105
75%	1632	1266	888	1072
100%	1664	1305	929	1043

Table 4: The assumed AI, ROI and NI offshore wind scenarios installed capacities

	Offshore scenario			
	Incl. TCGs			**Excl. TCGs**
Region	**Low** (MW)	**Med** (MW)	**High** (MW)	**Med** (MW)
AI	25.2	848.2	1309.2	848.2
ROI	25.2	548.2	709.2	548.2
NI	0	300	600	300

Table 5: The percentage of wind curtailment on the AI system for the offshore wind scenarios, including and excluding TCGs, under various SNSP limits.

	Offshore scenario			
	Incl. TCGs			**Excl. TCGs**
SNSP	**Low** (%)	**Med** (%)	**High** (%)	**Med** (%)
60%	15.3	14.5	14.1	12.5
65%	10.9	10.2	9.9	8.0
70%	8.3	7.7	7.3	5.2
75%	7.3	6.8	6.5	3.3
100%	7.2	6.9	6.6	0.9

Total non-renewable generation duration curves are shown in Figs. 5 & 6 to illustrate the variations in the sub-scenarios of the use of generator plant type (Base plant, Mid-merit, Peaker plant). Base plant comprises all coal generation, the remaining oil plant, all peat generation, all conventional hydro generation, waste to energy generation, the gas fuelled steam turbine and CHPs. Mid-merit generation consists of all existing CCGT and a new CCGT to be constructed at Great Island. Peaker plant is a collection of all gas and distillate fuel OCGTs, both existing and planned, as well as the one pumped-hydro energy storage plant.

Figure 4: Wind curtailment for offshore wind scenarios, including and excluding TCGs: (a) versus SNSP limits of 60-100%; (b) versus SNSP limits of 60-75% ("b" is a detail of "a"). Installed wind capacity satisfies 37% of system generation for all scenarios.

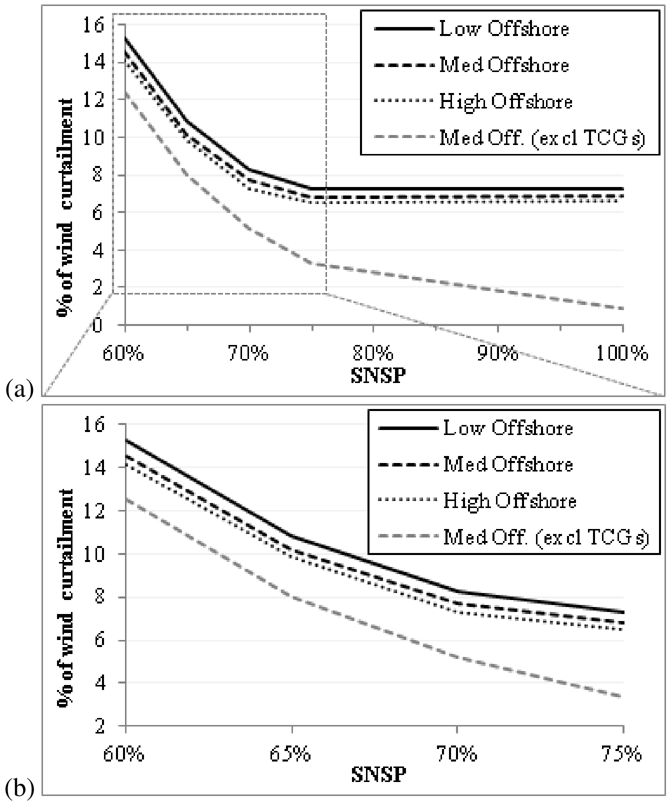


Figure 5: Load duration curves showing use of different conventional plant type for the medium offshore wind scenario including TCGs. (a) at SNSP of 60%, (b) at SNSP of 70% & (c) at SNSP of 100%

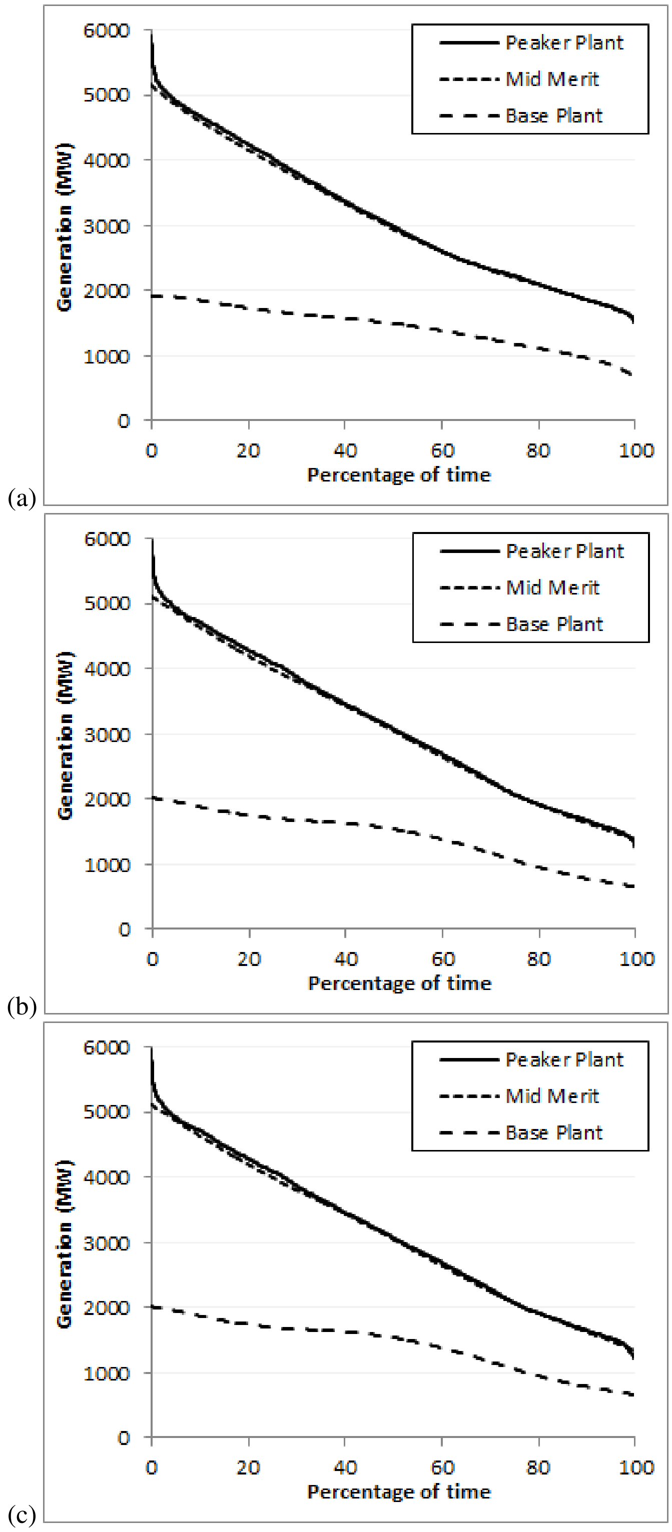
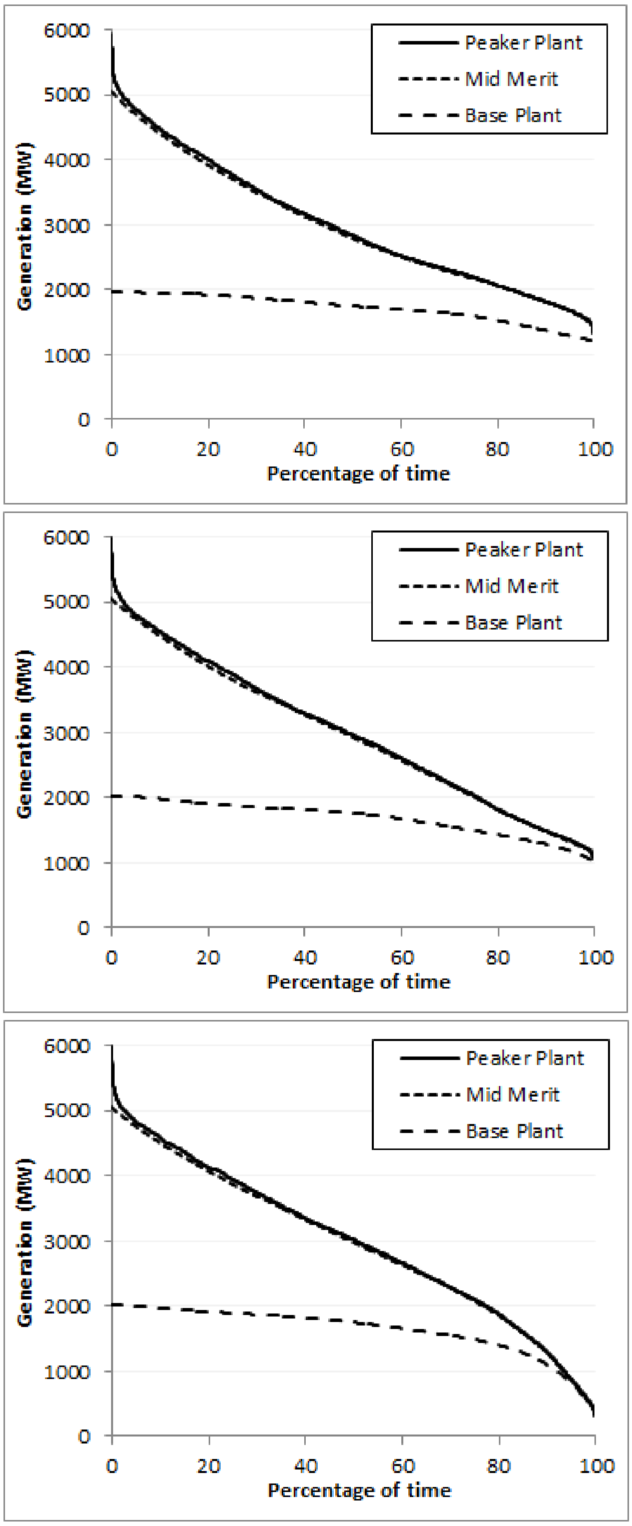


Figure 6: Load duration curves showing use of different conventional plant type for the medium offshore wind scenario excluding TCGs: (a) with an SNSP limit of 60%; (b) SNSP limit of 70%; & (c) SNSP limit of 100%.



(a)

(b)

(c)

5. Discussion

The primary result from this work is an estimate of the required installed wind capacities for both NI and ROI to meet their 2020 RES-E targets. It is evident that this varies greatly due to the large differences in wind curtailment that will occur based on the assumptions made. The required capacity estimates range from 5911MW to 6890MW which results in extra cost of €459 million between what is considered to be the lowest technically feasible wind curtailment scenario (high offshore wind at SNSP limit of 75%, including TCGs) to that of the highest (low offshore wind at SNSP limit of 60%, including TCGS)[6]. In the context of the electricity system this is a considerable extra expense similar in magnitude to the cost of two of the proposed North-South interconnector between NI and ROI [40]. This illustrates the importance of increasing the SNSP limit as high as technically and economically feasible.

Assuming the medium offshore wind scenario is the closest reflection of the future generation portfolio identified in [2], the required wind capacity differs between the latter and this study. For ROI there is an assumed wind capacity requirement for 2020 of 3500-4000MW, which is short of the highest assumed feasible SNSP limit requiring 4475MW. When considering NI there is an assumed wind capacity requirement for 2020 of 1278MW, which is short of the 1566 MW required under the highest assumed feasible SNSP limit. The required wind capacity figures identified in [2] do account for other renewable sources not included in our model which do bring the results closer together, however with the present lack of activity around the non-wind renewable sources it has to be assumed that wind energy will have to replace the shortfall in other renewable electricity generation in order to meet the 2020 RES-E targets.

5.1. Wind curtailment

Assuming again that the medium offshore wind scenario represents the most likely outcome of the wind scenarios in 2020. There is a dramatic reduction in wind curtailment, from an average of 14.5% to 6.8%, with an increase in the SNSP limit from to 60% up to 75%. This reduction in wind curtailment allows for an average reduction in installed wind capacity of 567MW.

The inclusion of the TCGs, which in their present form prevented a further reduction in wind curtailment beyond the 75% SNSP limit, is a notable result. This is a result of a minimum number of generators being forced to remain on-line generating at their minimum stable capacities. This result differs from those of other studies in the area [19, 20, 21, 22]. The inclusion of TCGs in the model resulted in a minimum wind curtailment occurring of at least 6.5% irrespective of the SNSP limit imposed.

Comparing wind curtailment for the medium offshore wind scenario with and without TCGs the SNSP limit imposed contributes to the majority of wind curtailment between the SNSP limits of 60-70%. However the TCGs contribute to the majority of wind curtailment between the SNSP limits of 70-100%. This was an unexpected result and indicates that both the TCGs as well as the SNSP limit are of equal importance in affecting wind curtailment.

There is a further clear reduction of 1-1.5 percentage points in wind curtailment if the proportion of offshore wind is increased. This is largely a result of the wider geographical spread of installed wind capacity, and the assumed 40% offshore wind capacity factor, which is higher than that of the onshore regions.

5.2. Conventional generator dispatch

It must be noted that running the model with inclusion of TCGs is not reflective of the true operation of the market, as it is optimised on a purely economic means assuming an unconstrained grid. The main changes to the dispatch of the conventional generators result from the inclusion or exclusion of the TCGs in the model scenarios. These changes occur at the times of the lowest point of allowable conventional generation and a change in the portions of generation from mid-merit and base load plant with respect to each other.

There is notable difference in the minimum amount of conventional generation occurring in the extreme SNSP limit of 100% with and without TCGs in Figs. 5(c) & 6(c). It is a large assumption to make to allow all conventional generation to be off-line at certain times but it is useful as a comparison case. The other large difference in conventional generator dispatch is the relative proportion of generation from mid-merit and base load plant in (Fig. 5 & 6). This is a result of the TCGs controlling the use of the CCGTs for system stability issues in the 80%-100% time range.

5.3. Problems in over-estimation of wind curtailment

The times of peak wind power on the AI system relative to the time difference, leading or lagging, of wind power peaks in GB will also be important. The assumption for GB wind data that it is at a constant time lag of two hours to that of a AI wind region may result in an over-estimate of wind curtailment. This is due to the usage of the interconnections being restricted in times of peak wind generation in Ireland when in fact peak wind generation in GB may have occurred slightly earlier.

It would be reasonable to assume that there will be relaxations of the TCGs in the future. This could be justified by the transmission grid reinforcement plans in place, use of the East-West interconnector, and more control and monitoring by the TSOs of the transmission and distribution grids. The exclusion from the model of some of the non-wind renewable sources in [2], leads to a higher percentage of total generation coming from wind energy and therefore higher amounts of wind curtailment occurring in order to fulfil the 2020 RES-E targets.

5.4. Problems in underestimation of wind curtailment

Incorporation of the AI transmission grid into the model may also have added to curtailment as the grid is weak in western

[6]The assumed cost of an installed MW of wind is 1.23 million €/MW for onshore wind (2006 prices) and 1.81 million €/MW for offshore wind (2015 prices) from [39].

parts of ROI, where the largest proportion of wind will be installed. In this model, it assumes perfect foresight on wind generation but in reality this is not the case. As a result there will be an increase in the reserve requirements of the system in-order to maintain the required loss of load probability (LOLP). The creation of the day ahead dispatch schedule by the System Operator uses forecast wind generation to estimated the required conventional generation plant to be informed of there dispatch in advance. Due to the increased requirement for system reserve the AI system may require more generators operating at their minimum stable level at times of high wind power penetrations resulting in additional wind curtailment. With the increasing complexity of the transmission system, new TCGs will become necessary in the future.

6. Conclusion

Taking account of issues causing wind curtailment on the 2020 Irish electricity system dramatically increases the amount of installed wind capacity required to meet the renewable targets. There is also large variation (5911MW to 6890MW) in the amount of installed wind capacity required which depends on the assumed system non-synchronous penetration (SNSP) limits that maybe imposed and the proportion of wind that is installed offshore in the future.

Wind curtailment is shown to drop from an average of 14% to 7%, as the SNSP limit is raised from to 60% to 75%. The contribution of offshore wind also is shown to help in the reduction of wind curtailment, removing at least one percentage point of curtailment in going from the low to high offshore scenarios. The wider spatial spread of wind turbines and higher overall capacity factors due to increased offshore wind installation are the main contributors to reducing the wind curtailment occurring on the system as a whole.

A more detailed study on the technically and economically achievable limits of non-synchronous generation on the Irish electricity system is crucial to minimise the associated costs of wind curtailment by means of increasing the SNSP and maximising wind integration.

7. Acknowledgements

Edward Mc Garrigle is supported by The Irish Research Council. Paul Leahy is supported by the Stokes Lectureship programme of Science Foundation Ireland and by Enerco Energy. The support of Energy Exemplar through the academic license for PLEXOS®is gratefully acknowledged. The Commission for Energy Regulation is acknowledged for providing data, the Redpoint Validated Forecast Model and the PLEXOS® Validation Report 2010. Finally, the staff of the TSOs are acknowledged for their helpful discussions, in particular John O'Sullivan of Eirgrid.

[1] "European on-shore wind resources at 50 metres," 1989. Risoe National Laboratory, http://www.windatlas.dk/Europe/landmap.html.

[2] Eirgrid and SONI, "All-Island Generation Capacity Statement 2012-2021," tech. rep., Eirgrid and System Operator of Northern Ireland, (SONI), 2011.

[3] "National Renewable Energy Action Plan," tech. rep., Department of Communications, Energy and Natural Resources, 2010.

[4] "Northern Ireland Strategic Energy Framework," tech. rep., UK, Department of Enterprise, Trade and Investment, 2010.

[5] A.M. Foley, B. Ó Gallachóir, D. Milborrow, E.J. McKeogh and P.G. Leahy, "Technical, Policy and Market Challenges to High Wind Power Integration in Ireland," *Renewable & Sustainable Energy Reviews*, in press.

[6] P. Meibom, "All Island Grid Study Workstream 2(b): Wind Variability Management Studies," tech. rep., The Department of Communications, Energy and Natural Resources and UK, The Department of Enterprise, Trade and Investment, 2007.

[7] "Northern Ireland, Offshore wind and tidal stream leasing rounds," 2012. Crown Estate, http://www.thecrownestate.co.uk/energy/offshore-wind-energy/our-portfolio/.

[8] ESB International, "All Island Grid Study Workstream 1: Renewable Energy Resource Assessment," tech. rep., The Department of Communications, Energy and Natural Resources and The Department of Enterprise, Trade and Investment, UK, 2008.

[9] M. J. Kaiser and B. Snyder, "Offshore wind capital cost estimation in the US Outer Continental Shelf-A reference class approach," *Marine Policy*, vol. 36, pp. 1112–1122, 2012.

[10] "Dublin Array," 2012. Saorgus Energy Ltd, *http : //www.saorgus.com/projects/dublin_array.html*.

[11] Natural Power, "Offshore Wind Farm at Codling Bank, Non-Technical Summary," tech. rep., Codling Wind Park, 2002.

[12] Aqua-Fact International Services Ltd., "Oriel Offshore Windfarm, Non-Technical Summary," tech. rep., Oriel Windfarm Ltd, 2007.

[13] Aqua-Fact International Services Ltd., "Sceirde Offshore Windfarm, Non-Technical Summary," tech. rep., Fuinneamh Sceirde Teoranta, 2008.

[14] "Arklow Bank Wind Park Phase 2," 2012. http://www.poweredgenerators.com/wind/offshore/arklow-bank.php.

[15] D. P. Nedic, "All-Island Grid Study Workstream 3," tech. rep., The Department of Communications, Energy and Natural Resources and UK, The Department of Enterprise, Trade and Investment, 2007.

[16] P. Bousseau, F. Fesquet, G. Belhomme, S. Nguefeu, and T. C. Thai, "Solutions for the grid integration of wind farms - A survey," *Wind Energy*, vol. 9, no. 1-2, pp. 13–25, 2006.

[17] B. C. Ummels, M. Gibescu, E. Pelgrum, W. L. Kling, and A. J. Brand, "Impacts of wind power on thermal generation unit commitment and dispatch," *IEEE Transactions On Energy Conversion*, vol. 22, pp. 44–51, Mar. 2007.

[18] Eirgrid and SONI, "All Island TSO Facilitation of Renewables Studies," tech. rep., Eirgrid and System Operator of Northern Ireland, (SONI), 2011.

[19] D. Burke and M. O'Malley, "Factors Influencing Wind Energy Curtailment," *Sustainable Energy, IEEE Transactions on*, vol. 2, no. 2, pp. 185 –193, 2011.

[20] E. Denny, A. Tuohy, P. Meibom, A. Keane, D. Flynn, A. Mullane, and M. O'Malley, "The impact of increased interconnection on electricity systems with large penetrations of wind generation: A case study of Ireland and Great Britain," *Energy Policy*, vol. 38, no. 11, pp. 6946 – 6954, 2010.

[21] A. Tuohy and M. O'Malley, "Impact of pumped storage on power systems with increasing wind penetration," in *Power Energy Society General Meeting, 2009. PES '09. IEEE*, pp. 1 –8, July 2009.

[22] A. Tuohy and M. O'Malley, "Pumped storage in systems with very high wind penetration," *Energy Policy*, vol. 39, no. 4, pp. 1965 – 1974, 2011.

[23] R. Doherty, A. Mullane, G. Nolan, D. Burke, A. Bryson, and M. O'Malley, "An Assessment of the Impact of Wind Generation on System Frequency Control," *Power Systems, IEEE Transactions on*, vol. 25, pp. 452 –460, Feb. 2010.

[24] P. Eriksen, T. Ackermann, H. Abildgaard, P. Smith, W. Winter, and J. Rodriguez Garcia, "System operation with high wind penetration," *Power and Energy Magazine, IEEE*, vol. 3, no. 6, pp. 65 – 74, 2005.

[25] R. Doherty, "All Island Grid Study Workstream 2A: High Level Assessment Of Suitable Generation Portfolios For The All-Island System In 2020," tech. rep., The Department of Communications, Energy and Natural Resources and UK, The Department of Enterprise, Trade and Investment, 2008.

[26] Eirgrid and SONI, "Transmission Constraint Groups," tech. rep., Eirgrid and System Operator of Northern Ireland, (SONI), 2011.

[27] "Moyle Interconnector," 2012. Mutual Energy, *http : //www.mutual –*

energy.com/The_Moyle_Interconnector/Index.php.

[28] National Grid, "National Electricity Transmission System Seven Year Statement," tech. rep., National Grid, 2011.

[29] A. M. Foley, P. Leahy, and E. J. McKeogh, "Wind Energy Integration and the Ireland-Wales Interconnector," in *Proceedings IEEE-PES/IAS Conference on Sustainable Alternative Energy*, (Valencia, Spain), September 2009.

[30] J. P. Deane, G. Dalton and B. Ó Gallachóir, "Modelling the economic impacts of 500MW of wave power in Ireland *Energy Policy*, vol. 45, pp. 614-627, 2012.

[31] Poyry Energy Consulting, "Trading & Settlement Code, Helicopter Guide," tech. rep., Commission for Energy Regualtion (ROI) and Utility Regulator, Electrcity, Gas, Water (NI), 2007.

[32] Redpoint Energy Ltd, "Single Electricity Market Operator (SEMO) forecast model of 2011-2012," tech. rep., Commission for Energy Regulation (CER), 2011.

[33] M. Clancy, J. Scheer, and B. Ó. Gallachóir, "Energy Forecasts for Ireland to 2020," tech. rep., The Energy Modelling Group, SEAI, 2010.

[34] Eirgrid, "Grid25," tech. rep., 2010. http://www.eirgrid.com/media/Grid

[35] Eirgrid, "Transmission Forecast Statement 2011-2017," tech. rep., 2010.

[36] All-Island Project, "Transmission Loss Adjustment Factors from 1st January 2010," 2009. Commission for Energy Regulation (CER) & the Northern Ireland Authority for Utility Regulation (NIAUR).

[37] Eirgrid, "Interconnection Economic Feasibility Report," tech. rep., Eirgrid, 2009.

[38] Redpoint Energy Ltd, "The impact of wind on pricing within the Single Electricity Market," tech. rep., 2011.

[39] European Wind Energy Association (EWEA), "The Economics of Wind Energy," tech. rep., 2009.

[40] B. Normark, O.-H. Hoelsaeter, and R. Belmans, "Meath-Tyrone International Expert Commission," tech. rep., Department of Communications, Energy and Natural Resources., 2011.