GL Garrad Hassan

ELECTRICITY DEMAND AND GENERATION FOR IRELAND IN 2030

Client	WWF NI
Contact	M Campbell
Document No	110739-UKGL-R-01
Issue	E
Status	Final
Classification	Client's Discretion
Date	31 August 2012

Author: D Argyropoulos, P Gardner

Checked by: DA Williams

Approved by: P Gardner

Garrad Hassan & Partners Ltd
2064 Maryhill Road, Glasgow G20 0AB, Scotland Tel: +44 (0)141 945 4774 Fax: +44 (0)141 945 5076
Garrad Hassan & Partners Ltd is registered in England (1878456) and has its registered office at St Vincent's Works, Silverthorne Lane, Bristol BS2 0QD, UK.

IMPORTANT NOTICE AND DISCLAIMER

1. This report ("Report") is prepared and issued by Garrad Hassan & Partners Ltd ("GH" or "Garrad Hassan") for the sole use of the client named on its title page (the "Client") on whose instructions it has been prepared, and who has entered into a written agreement directly with Garrad Hassan. Garrad Hassan's liability to the Client is set out in that agreement. Garrad Hassan shall have no liability to third parties (being persons other than the Client) in connection with this Report or for any use whatsoever by third parties of this Report unless the subject of a written agreement between Garrad Hassan and such third party. The Report may only be reproduced and circulated in accordance with the Document Classification and associated conditions stipulated or referred to in this Report and/or in Garrad Hassan's written agreement with the Client. No part of this Report may be disclosed in any public offering memorandum, prospectus or stock exchange listing, circular or announcement without the express written consent of Garrad Hassan. A Document Classification permitting the Client to redistribute this Report shall not thereby imply that Garrad Hassan has any liability to any recipient other than the Client.

2. This report has been produced from information relating to dates and periods referred to in this report. The report does not imply that any information is not subject to change.

KEY TO DOCUMENT CLASSIFICATION

Strictly Confidential	:	For disclosure only to named individuals within the Client's organisation.
Private and Confidential	:	For disclosure only to individuals directly concerned with the subject matter of the Report within the Client's organisation.
Commercial in Confidence	:	Not to be disclosed outside the Client's organisation
GH only	:	Not to be disclosed to non GH staff
Client's Discretion	:	Distribution for information only at the discretion of the Client (subject to the above Important Notice and Disclaimer).
Published	:	Available for information only to the general public (subject to the above Important Notice and Disclaimer and Disclaimer).

REVISION HISTORY

Issue	Issue date	Summary
A	2 Nov 2011	Draft for client comment
B	19 Dec 2011	Draft for client comment
C	6 Jan 2012	Demand forecasts updated for latest SEAI data.
D	9 July 2012	Updated after client comments, biomass capacity increased. Comparison with other systems updated to 2011 data. New sections added on additional interconnections, some reorganisation of sections.
E	31 August 2012	Updated after further comments

CONTENTS

LIST OF TABLES

LIST OF FIGURES

1 INTRODUCTION

This report has been prepared by GL Garrad Hassan (GLGH) in response to a request from WWF Northern Ireland (WWF). WWF wishes to understand renewable generation options, in particular the following issue:

How could Northern Ireland (NI) and the Republic of Ireland (ROI) meet electricity demand in 2030 and achieve the maximum possible decarbonisation of the power sector by that same date, without endangering security of supply, relying on new nuclear capacity or the use of unsustainable biomass?

The analysis and results are presented where possible on the basis of the entire island, i.e. the combined electricity systems of ROI and NI.

This report does not attempt to investigate whether renewables are the 'best' way to achieve decarbonisation, as compared to solutions including proportions of thermal generation with Carbon Capture and Storage, nuclear, or 'unsustainable' biomass: it seeks to establish the extent to which this is possible.

This report is structured as follows:

- Section 3: Forecasts of electricity demand to 2030
- Section 4: Renewable electricity generation resources
- Section 5: Security of supply
- Section 6: Analysis of renewable generation and electricity demand to 2030
- Section 7: Conclusions

Previous work addressed similar issues for the UK [29] [30].

2 BACKGROUND

Policy and targets

The requirement for 'maximum possible decarbonisation of the power sector' is interpreted in this study as achieving the carbon intensity recently recommended by the Committee on Climate Change for the UK in 2050, i.e. 50 g/kWh.[1] These figures are on an 'average year' basis, i.e. calculated over a year without extreme events.

In 2009, both ROI and the UK signed up to the triple 2020 targets under EU climate & energy policy (20% energy from renewable energy sources, 20% reduction of primary energy use, 20% reduction of greenhouse gas emissions by 2020[2],[3]). The policy instruments for reducing emissions and supporting renewable electricity generation differ between the countries.

Electricity industry structure

The island of Ireland is effectively one electricity system, though with several owners.

- EirGrid operates the transmission system in ROI. It also owns SONI (System Operator Northern Ireland), which operates the transmission system in NI.
- NIE owns the transmission and distribution systems in NI, and operates the distribution system. NIE is owned by ESB.
- ESB Networks owns the transmission and distribution system in ROI and operates the distribution system..
- EirGrid also operates SEMO (Single Electricity Market Operator), which runs the single electricity market covering both ROI and NI.

'Transmission' refers to the higher-voltage networks (typically 110 kV and above), principally used for bulk transfer of electricity over long distances, from major generators to the main centres of electricity demand. Traditionally, the vast majority of electricity generators are connected to the transmission system. 'Distribution' refers to the lower-voltage networks, principally used for transferring electricity from the transmission system to individual consumers. Large amounts of 'embedded generation' or 'distributed generation', principally wind, are now connecting to distribution systems, so that in some cases power may actually flow 'upwards' from the distribution system into the transmission system. Large renewable generation projects, for example offshore wind, may connect to the transmission system directly.

---

[1] There is no equivalent 'target' for 2050 at EU level. However the recent EU Energy Roadmap (http://ec.europa.eu/energy/energy2020/roadmap/index_en.htm, Dec 2011) shows carbon intensity figures for electricity generation in 2050 which are of the same order, depending on scenario.

[2] http://ec.europa.eu/clima/policies/package/index_en.htm.

[3] The agreed target for ROI is 16% of energy from renewable energy sources, and 15% for the UK (Directive 2009/28/EC, http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:140:0016:0062:EN:PDF).

3 TASK 1: ELECTRICITY DEMAND TO 2030

3.1 Electricity Demand Scenario Definitions

Two electricity demand scenarios for the years to 2030 are defined:

- A 'central' scenario based on scenarios produced by official bodies.
- An 'ambitious' scenario, i.e. with greater demand reduction than assumed in the 'central' scenario. The purpose of including this scenario is to show to what extent aggressive demand reduction will reduce the need for electricity generating capacity of all types.

The central and ambitious scenarios are described in detail in the following sections.

3.2 Central Scenario

GLGH has reviewed the following studies and documents published by government agencies, TSO and at EU level in order to derive estimates of electricity demand in 2030 for the island of Ireland:

- National Renewable Energy Action Plan Ireland [1]
- National Renewable Energy Action Plan UK [2]
- Maximising Ireland's Energy Efficiency. The National Energy Efficiency Action Plan 2009 – 2020 [3]
- Delivering a Sustainable Energy Future for Ireland. The Energy Policy Framework 2007 – 2020 [4]
- All Island Generation Capacity Statement 2011-2020[4] [5]
- Sustainable Energy Authority of Ireland (SEAI), Energy Forecasts for Ireland to 2020 [6]
- SEAI: Demand Side Management in Ireland. Evaluating the Energy Efficiency Opportunities [7]
- SEAI: Energy in Transport [8]
- EirGrid Generation Adequacy Report 2009-2015 and 2010-2016[5] [9] [10]
- Department of Enterprise, Trade and Investment (DETI): Energy. Strategic Energy Framework for Northern Ireland [11]
- EU Energy Trends [12]
- Department of Energy and Climate Change (DECC): Energy Trends. December 2010 [13].
- SEAI revised energy forecasts to 2020 for ROI, Dec 2011 [28].

[4] An updated Statement for 2012-21 has now been published.

[5] An All-Island Generation Capacity Statement has now been published.

A range of different scenarios is presented in the reviewed documents. However, it has to be noted that no forecast of electricity demand exists for the entire island of Ireland, and there are no forecasts for either ROI or NI for 2030[6].

In order to develop 2030 scenarios, GLGH has extrapolated 2020 forecasts to 2030 by using the assumed growth rates in the scenarios up to 2020. Table 3.1 gives an overview of the set of forecasts that have been derived.

For reference, electricity demand for the island of Ireland in 2010 was 36,316 GWh [5].

Electricity demand has been defined in this report as "gross final electricity consumption", based on the methodology outlined in the Renewable Energy Directive [14]. According to this definition, gross final consumption of energy includes the losses involved in transporting energy from the point of production to the final consumer. Not all of the reviewed studies have followed this methodology, e.g. [5] has not included losses during transmission and distribution of electricity. In order to make data as consistent as possible, GLGH has included an estimate of electricity losses[7].

Depending on the level of ambition, the scenarios include the effect of changes in government policies related to renewable energies and energy efficiency that have been implemented, or anticipated policy changes.

[6] EirGrid/SONI are working on projections beyond 2020 for ROI and NI, but results were not available at the time of writing.

[7] EirGrid/SONI consider electricity transmission and distribution losses to be 8.3%, and this figure has been used here [5].

Source	Area	Demand 2015 [GWh/y]	Demand 2020 [GWh/y]	Demand 2025 [GWh/y]	Demand 2030 [GWh/y]	Comment
SEAI ("White Paper Plus" scenario) for 2020	RoI	34,020	34,508	35,733	37,001	Extrapolated to 2030 by assuming growth rate for 2012-2020 (0.7% per annum) continues after 2020.
SEAI Energy Forecasts to 2020 (Dec 2011) [28]: NEEAP/NREAP scenario, 2020	RoI	32,227	33,105	34,007	34,933	Extrapolated to 2030 by assuming growth rate for 2015-2020 (0.5% per annum) continues after 2020.
NREAP ROI - Reference scenario, 2020	RoI	32,145	34,157	36,411	38,815	Extrapolated to 2030 by assuming growth rate for 2015-2020 continues after 2020.
NREAP ROI– Additional Efficiency Scenario, 2020	RoI	30,657	32,715	34,776	36,967	Extrapolated to 2030 by assuming growth rate for 2015-2020 continues after 2020.
NREAP UK – Additional Energy Efficiency Scenario, 2020	NI	10,826	10,928	11,037	11,147	Scaled from UK figures by population (1.8m vs. 62m.). Extrapolated to 2030 assuming growth for 2015-2020 continues after 2020. Used instead of UK NREAP Reference Scenario because latest views in UK DECC favour greater energy efficiency, as lowest-cost option.
SONI/EirGrid: 2020 Forecast-Median Demand	All-Island	42,740	46,077	49,151	52,430	Extrapolated to 2030 by assuming growth rate for 2019-2020 (1.3% per annum) continues after 2020.
SONI/EirGrid: 2020 Forecast - Low Demand	All-Island	41,482	43,734	45,965	48,309	Extrapolated to 2030 by assuming growth rate for 2019-2020 (1.3% per annum) continues after 2020.

Table 3.1: Comparison of electricity demand forecasts

The table shows that there are significant but not enormous differences between the forecasts for 2030, of the order of 10%.

In this report, the SEAI Energy Forecast and the NREAP UK Additional Energy Efficiency figures are used. This is principally because the SEAI Energy Forecast is the most recent (December 2011) at the time the analysis was conducted, and can be assumed to have the most accurate assessment of the effects of the economic downturn. No other figures for NI are available, and the figures scaled from the UK NREAP figures appear realistic.

For reference, this forecast is presented for the Republic of Ireland and Northern Ireland in the following table. Figures for 2010 are included for comparison, scaled up to include an estimate of losses as described above.

Electricity demand [GWh/y]	**2010**	**2015**	**2020**	**2025**	**2030**
Republic of Ireland	29,511	32,227	33,105	34,007	34,933
Northern Ireland	9,820	10,826	10,928	11,037	11,147
All-Island	39,331	43,053	44,033	45,044	46,081

Table 3.2: Gross final electricity consumption forecasts, Central demand scenario

It has to be noted that these figures are indicative only: any forecast 20 years into the future will be subject to significant uncertainty. The greatest influence on electricity demand forecasts, once corrections are made for weather, is economic growth[8]. See e.g. [28].

Note also that, as elsewhere in this study, uncertainty is substantially greater than the accuracy implied by the resolution of the figures in the table (to five significant figures in this case). This resolution is maintained in order to avoid accumulation of rounding errors.

Electric Vehicles

Demand from the expected increasing use of electric vehicles by 2020 is considered in the forecast. Both Ireland and the UK have set the target of sourcing 10% of final energy use in the transport sector from renewable energies by 2020. This is expected to be implemented by increasing the use of biofuels, and deployment of electric vehicles. ROI has set a target of 10% of its vehicle fleet to be powered by electricity by 2020. Additional electricity demand from transport in ROI is forecast to be 560 GWh in 2020 [28], i.e. 2% of projected demand.

It is difficult to forecast deployment of electric vehicles and concurrent electricity demand beyond 2020 since this will depend on technical and cost evolution, and future policies. In this study it is

[8] Some of the annual statements on which this analysis is based have since been updated, as noted above, but do not give any indication that revision of the demand forecasts for 2030 is justified.

assumed that, in the circumstances that would lie behind the Central demand scenario, very widespread penetration of electric vehicles in 2030 is unlikely. This is because substantial efforts to encourage electric vehicle use are likely to be accompanied by substantial efforts to reduce demand, i.e. the Ambitious demand scenario. Therefore no additional allowance for further growth in electricity demand for EVs is included for 2030 in the Central demand scenario.

Electric Heating

Electrification of heat supply is an option to de-carbonise[9] energy supply, therefore it is possible that electricity demand in this area, particularly for residential heating, will grow in the future.

SEAI has modelled impacts of an increased electrification of residential heat in ROI [6]. It was assumed that 10% of thermal energy in the residential sector is provided by electricity. The modelling carried out by SEAI assesses the impact of increasing electrification of residential heating to 20%, i.e. doubling the share provided by electricity. This could include a substantial contribution from heat pumps. The calculated additional electricity demand is 2,338 GWh/y.

This figure is relatively small compared to total forecast demand in 2030. Also it is hard to see circumstances in which electric heating demand would grow in this way, against the background of the Central demand scenario. Therefore, no allowance for additional electric heating is included in the Central demand estimate for 2030.

Diurnal demand curves

Figure 3.1 shows the days of maximum and minimum electricity demand for the combined system for 2010.

The minimum load was 2,007 MW (on 4 July) and maximum load was 6,851 MW (on 21 December). As is common for northern European systems, there are significant differences in shape between the days of maximum and minimum demand, especially the evening peak on winter weekdays.

[9] Achievable by combinations of low-carbon electricity generation, including renewables, and higher-efficiency heating, especially heat pumps.

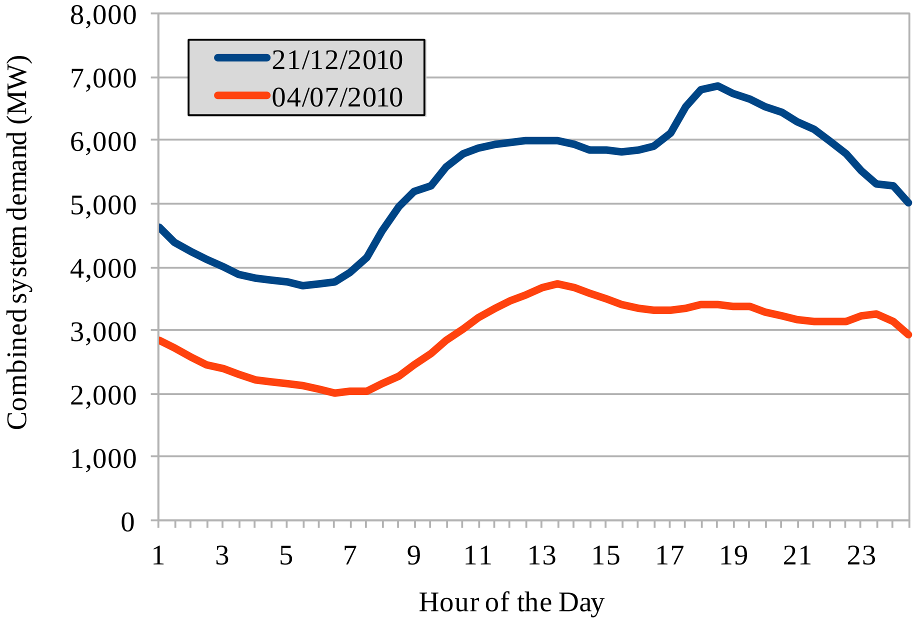

Figure 3.1: Diurnal demand curves, combined system (ROI + NI) 2010 (source: SEMO)

Several factors may affect the diurnal demand curve in future:

- Smart metering: Irish and UK governments plan to introduce smart metering. If this were combined with an appropriate pricing structure, it should cause a flattening of the daily demand curve by encouraging customers to switch consumption away from peak times, thereby reducing the total generating capacity required.

- Electric Vehicles: it is likely that most charging of the batteries will occur overnight. This could help to smooth out the night trough.

- Further electrification of heat supply. Electrification of heat supply is likely to be managed so that much of the additional demand occurs outside peak times. The table below presents an estimate of the effect on low and peak demand in ROI in 2020, taken from [6].

	New electric heat demand to 2020			
Electrified heat scenario	**Summer Low [MW]**	**Winter Average [MW]**	**Winter Peak [MW]**	**Year Total [GWh]**
10% (base)	-	-	-	-
20%	8	444	1,112	2,338

Table 3.3: Effect of increased use of electric heating above base case of 10%, ROI [6]

3.3 Ambitious Scenario

The Central demand scenario already assumes demand reduction measures in line with current policies and as required to meet ROI and UK targets for 2020. In particular, the assumptions for NI are based on the UK NREAP 'Additional Energy Efficiency' figures rather than the 'Reference' scenario, because it is understood that recent thinking within UK DECC acknowledges that demand reduction is cheaper than low-carbon generation[10]. Arriving at an Ambitious demand scenario for 2030 is therefore difficult.

A further complicating factor is that aggressive policies to reduce demand are likely to be accompanied by policies to increase the transfer of heat and transport demand to electricity, beyond the levels assumed in the 2020 data used to produce the Central demand scenario. Therefore reduction in electricity demand will be counterbalanced, and it is feasible that very aggressive policies to reduce total emissions would result in a net increase in electricity demand.

Because of these uncertainties, it is considered unproductive to attempt to derive the Ambitious scenario from the 'bottom up', i.e. by estimation of each of the components of electricity demand in 2030. Instead, previous work by GLGH for the UK is used [30]. In this work, an Ambitious demand scenario was produced, based on work on the demand reduction which may be achievable assuming very substantial lifestyle changes by the majority of the population [50]. The net result is that annual electricity demand is reduced to 80% of the Central scenario.

This factor is therefore assumed to apply also to Ireland. The two scenarios are shown in Table 3.4.

[10] DETI has devolved responsibility for energy matters in NI, and also places high value on demand reduction [11].

	Central [GWh]	Ambitious [GWh]
Republic of Ireland	34,900	28,000
Northern Ireland	11,100	8,900
All-Island	46,100	36,900

Table 3.4: Gross final electricity consumption, 2030 Central and Ambitious demand forecasts[11]

It must be emphasised that the Ambitious scenario is no more than an indication of what may be achieved given very substantial political and personal will[12]. Other demand scenarios for 2030 are entirely credible. The aim of the Central and Ambitious demand forecasts is merely to bracket the range of likely outcomes.

Diurnal demand curves

As noted above, developments in electrification of heat and transport may well have a significant effect on electricity demand, and this will have a further effect on the annual load duration curve and the diurnal demand curves. Table 3.3 shows that an increase in heating load from 10% to 20% is expected to have no significant effect on the minimum load in summer, but could increase the winter peak by around 1100 MW for ROI (equivalent to around 1500 MW for the combined system). It is likely that EV charging demands can be moved almost entirely out of peak periods, with a large part moving to overnight. However electric heating loads are likely to be greater, and are harder to defer. The ability to defer these loads into the night trough will depend greatly on improvements in building insulation and thermal mass. The extent to which building insulation and electrification of heating may occur by 2030 is highly uncertain.

[11] Figures are rounded to avoid implied accuracy which is not justified by the uncertainties in the methodology and assumptions

[12] Achievable through a combination of many possible options such as reform of transport policy, spatial planning policy, greatly improved building regulations, mandatory efficiency requirements for domestic appliances, mandatory use of LED lighting, moving to year-round summer time or to CET, mandatory lower maximum temperatures in public and commercial buildings, and personal behavioural changes such as fewer single-person households, reduced meat consumption, reduced non-essential travel, and living closer to work.

3.4 Conclusions

Although development after 2020 is uncertain in terms of the economic environment, technology options and energy policy, GLGH believes the scenarios used in this report bracket the range of likely outcomes, and provide a robust basis for the analysis later in this report.

The transport and especially the electric heating loads could become very significant by 2030. It is very likely that much of these loads can be deferred within-day, particularly as buildings become better insulated. Economics are likely to drive much of these loads into the night-time trough, and the magnitudes are such that a substantial flattening of the diurnal demand profile is possible, i.e. a substantial reduction in within-day variation.

Deferral of these loads may be achieved by time-of-day pricing, or by responses to short-term wholesale electricity price signals, either by the electricity consumer, or by the electricity supplier through some commercial arrangement with its customers.

4 TASK 2: RENEWABLES RESOURCE SIZE AND GENERATION CAPACITY

4.1 Renewable resources selected

The following renewable electricity generation technologies have been included in this study.

- Onshore wind
- Offshore wind
- Wave
- Tidal
- Sustainable biomass
- Geothermal
- Hydro
- Landfill gas

Although solar photovoltaic (PV) has a potential role in helping to reduce reliance on fossil fuels, it has not been included in this analysis, because the available resource and costs are currently uncertain: the resource could be large if costs come down very significantly. Also, solar PV does not contribute anything during what are assumed to be the critical periods for system security, i.e. peaks in late afternoon in winter (see Task 3 below).

4.2 Published information on resource size

4.2.1 Sources

Published studies and reports have been screened to identify the resource potential of renewable energies in ROI and NI. Sources from the public domain were used for this purpose. These include:

- Sustainable Energy Authority of Ireland (SEAI) (2004): *Renewable Energy Resources in Ireland for 2010 and 2020 – a methodology* [15]
- SEAI (2011): *Industrial Development Potential of Offshore Wind in Ireland*. [16]
- SEAI (2004): *Offshore Wind Energy and Industrial Development in the Republic of Ireland*. [17]
- SEAI (2009): *SEA Scoping Report. Scoping for the Strategic Environmental Assessment on Plans to Develop Offshore Renewable Energy* [18]
- SEAI/Irish Maritime Development Office (IMDO) (2011): *Assessment of the Irish Ports & Shipping Requirements for the Marine Renewable Energy Industry* [19]
- SEAI (2010): *Ocean Energy Roadmap* [20]
- Department of Communications, Energy and Natural Resources (DCENR)/Department of Enterprise, Trade and Investment (DETI) (2008): *All Island Grid Study. Workstream 1. Renewable Energy Resource Assessment.* [21]
- Marine Institute/SEAI (2005): *Accessible Wave Energy Resource Atlas Ireland* [22].

- Marine Institute/SEAI (2005): *Ocean Energy in Ireland* [23].
- SEAI (2004): *Tidal & Current Energy Resources in Ireland* [24].
- Department of Energy Ireland (1985): *Small Scale Hydro-Electric Potential of Ireland* [25].
- Action Renewables (2008): *Report on the Potential for Deep Geothermal Energy in Northern Ireland* [26].
- Department of Enterprise, Trade and Investment (NI) (2011): *Draft Onshore Renewable Electricity Action Plan 2011-2020* [53].
- Department of Enterprise, Trade and Investment (NI) (2012): *Offshore Renewable Energy StrategicAction Plan 2012-2020* [54].

Data on the renewable energy resource potential in Ireland from a range of sources was reviewed and compiled to provide an overview of existing information. GLGH has not undertaken any generic calculation to derive new data. Resource potential is often categorised as follows (or similar: there are no recognized standard definitions), in decreasing order of resource size:

- Theoretical potential: usually assumes all the land or sea areas within national boundaries can be utilized. Therefore hypothetical interest only.
- Technical potential: area reduced by factors usually including urban areas, national parks, military training areas etc.
- Practical potential: reduced further by excluding areas unsuitable for the technology, such as steep slopes for onshore wind, or extreme water depth.
- Accessible potential: often based on assumptions about public acceptance, such as (for wind) proximity to habitation. May exclude areas which are likely to be uneconomic, because of distance from centres of demand.
- Viable potential: economic factors included, such as distance to the transmission system, or (for offshore wind) distance to shore, to allow some assessment of Cost of Energy and economic viability.

In this analysis, estimates of the practical and accessible resource potentials are the most useful.

It has to be noted that the reviewed studies are not always consistent in scope and methodology. GLGH has not made a detailed assessment and comparison of the different approaches. Instead, a ‘reality check’ has been applied, based on GLGH experience.

4.2.2 Onshore Wind

SEAI published the Practical and Accessible resource potentials of onshore wind in 2004 for ROI as shown in Table 4.1 [15].[13]

Technology	Resource	2010 (3 MW turbines)	2020 (7 MW turbines)
Onshore wind	Practical resource – Annual wind energy production	947,969 GWh/y	1,902,023 GWh/y
	Practical resource – Installed wind turbine capacity	360 GW	724 GW
	Accessible resource – Annual wind energy production	26,207 GWh/y	36,701 GWh/y
	Accessible resource – Installed wind turbine capacity	10 GW	14 GW

Table 4.1: Onshore wind resource (for ROI only), from [15]

The wind turbine capacity figures (i.e. in GW) shown in Table 4.1 are indicative only, based on a capacity factor of 30%, which GLGH considers is realistic for Ireland. Capacity factor can be expected to improve in future, as wind turbine designers become better at minimising the forces on the wind turbine structure, thereby making larger rotors more economic. However, sites developed in future are likely to be less windy, as the best sites are developed first.

Later work for the entire island [21] indicated that sites are likely to be available for at least 7 GW onshore. Current capacity is around 1.7 GW.

SEAI's recent Roadmap for wind energy in ROI [51] indicates that 11-16 GW of onshore wind could be deployed by 2050, and around 10 GW could be achieved by 2030.

The recent Onshore Renewable Electricity Action Plan for NI [53] states that the Practical onshore wind resource is 1.5 GW.[14]

[13] The estimates assumed a typical wind turbine of 3 MW capacity for 2010 and 7 MW for 2020. Typical onshore turbine size now is less than 3 MW, and GLGH does not believe average onshore turbine size will grow significantly by 2020.

[14] Note that the very large difference between the Practical resource identified for NI in [53] and for ROI in [15] illustrates our point about the widely differing definitions for terms such as Theoretical, Practical and Accessible.

4.2.3 Offshore Wind

The resource potential of offshore wind in Ireland has been assessed in several studies [16][17][19]. The most recent are compared in Table 4.2. The calculation of total installed capacity in the table is indicative, assuming a net capacity factor of 43%[15].

For SEAI/IMDO [19], for the Republic of Ireland, the practicable resource ranges from 48.7 to 55.5 TWh/year. This is based on water depths less than 20m, and minimum distances offshore between 2km and 10km. This assumes 3 MW turbines at 500m spacing throughout the resource area

Under equivalent assumptions, the resource for Northern Ireland ranges from 0.10 TWh/year to 6.53 TWh/year.

For the entire ROI exclusive economic zone (EEZ)[16] and at water depths up to 50m, GLGH [16] assessed the wind resource, accounting for selected spatial restrictions and major shipping routes, to be very much larger, at 283 TWh/year.

The major difference between the two sets of results is the very much larger area available at water depths between 20 m and 50 m, mainly to the west of Ireland.

SEAI's recent Roadmap for wind energy in ROI [51] indicates that around 30 GW of offshore wind could be deployed by 2050 (possibly more), and up to 4.5 GW by 2030.

Technology	Resource	SEAI/IMDO [19] (for ROI + NI)	SEAI/GLGH [16] (for ROI only)	SEAI Roadmap [51] (for ROI only)
Offshore wind	Practical resource – Annual wind energy production	48,800 – 62,000 GWh/y	283,000 GWh/y	-
	Practical resource – Installed wind turbine capacity	13 – 16.5 GW	75 GW	30 GW

Table 4.2: Offshore wind resource, summary of published data

[15] GLGH considers this to be approximately in the centre of the likely future range of capacity factor for offshore wind. Economic optimisation of offshore turbines and wind farms continues to evolve, and future offshore wind farms may have different capacity factors. This would mean that proportionately more or less offshore wind capacity would be needed to provide the same energy production.

[16] Up to 200 nautical miles from the coast.

4.2.4 Wave

A report prepared by ESBI for the Marine Institute and Sustainable Energy Ireland in 2005 [22] provided ranges for the practicable wave resource in Irish waters (including NI), for both energy yield and capacity. In 2009 SEAI [18] estimated a potential installed capacity for wave energy of over 1,400 MW for 2020. This is summarised in Table 4.3.

Note that different assumptions were made in the studies, including the technology. Due to the quickly evolving technology, these figures are likely to change in future.

Technology	Resource	SEAI/MI [22]	SEAI [18]
Wave	Practical resource – Annual wave energy production	1,200 – 24,000 GWh/y	-
	Practical resource – Installed wave device capacity	0.18 – 2.77 GW	> 1.4 GW

Table 4.3: Wave resource, published data

4.2.5 Tidal

Analysis of the tidal energy resource indicates a practical resource of 2,633 GWh/year in Irish waters (including NI) up to 12 nautical miles from shore and in a water depth between 10m and 40m [23][24]. If a capacity factor of 40%[17] is assumed this would translate into a potential capacity of around 750 MW.

As with wave energy, evolving technology will have an impact on future resource assessments for tidal energy.

4.2.6 Sustainable biomass

Biomass is assumed here to include biogas, sewage gas, anaerobic digestion (AD) and solid biomass possibly with co-firing in generators using fossil fuels (including peat)[18]. The input fuel can be wastes

[17] There are several tidal device concepts, with different capacity factors. Also, for many devices, real-life capacity factors have not yet been determined. The 40% figure is chosen by GLGH on advice from internal experts, and is believed to be realistic.

[18] WWF does not support continued use of peat.

(see next paragraph), energy crops grown in Ireland, and energy crops imported for the purpose. Landfill gas is treated separately below.

Well over 100 MW of potential waste-to-energy capacity is identified in [21], from various waste streams. WWF regards energy derived from organic based materials including what are currently referred to as farming or forestry 'wastes', including manures and forestry brash (off cuts), as sustainable or renewable, but not energy from municipal solid waste (MSW). As there is no information on the proportion of these waste streams which meet sustainability criteria, this waste-to-energy capacity is not included in this analysis.

One area that offers an opportunity for greater energy production across the island is anaerobic digestion (AD) of farm and animal wastes. In NI, the manure generated annually by housed livestock has the potential to produce 73MW electricity [57]. For ROI, a recent Government report proposed 380 MW of AD plant could be supplied by agriculture [58].[19]

According to [21], energy crops are likely to come from the forestry industry, and new short-rotation coppice plantations. They are likely to be used for co-firing in fossil- or peat-fired power stations. Around 100 MW of electricity generating capacity is attributed to the co-firing component, with an assumed capacity factor appropriate to base-load plant (85%), i.e. around 750 GWh/y. However there is substantial uncertainty around this figure, because:

- The principles of 'sustainability' for energy crops are not generally agreed: WWF includes social and environmental issues in its criteria for sustainability.
- Feedstocks produced in Ireland may be competing against imported biomass burnt in large power stations with port facilities, and against demand for biomass for heat production.

The conclusion is that there could be a substantial contribution to electricity generation from various forms of biomass which meet WWF's criteria for sustainability. This is likely to come principally from AD and co-firing of forestry biomass. There is substantial uncertainty about the size of this electricity generating capacity in 2030, but from the above, GLGH believes that an estimate of around 400 MW is conservative[20].

Further investigation of the economics and sustainability of these biomass options would be useful.

4.2.7 Geothermal

No analysis was found which quantified the geothermal energy resource for electricity generation. However, a geothermal resource map has been produced by SEAI for Ireland which indicates that

[19] This may not be the maximum amount of energy that could be generated from AD, but is the level the report settled on. If sited appropriately, AD plants could also provide a significant heat contribution, though this was not addressed in the report.

[20] I.e. 73 MW AD from livestock in NI, 380 MW AD from agriculture in ROI, and some contribution from co-firing with sustainable energy crops leads to the conclusion that 400 MW is a conservative estimate.

significant[21] geothermal sources exist with the potential for commercial development [27]. Also, a study has shown that geothermal applications may be possible in Northern Ireland [26], though the study suggests it may be better used directly for heating, rather than for electricity generation with CHP.

4.2.8 Hydro power

Existing hydro generation capacity is around 240 MW (230 MW in ROI, 10 MW in NI). The capacity is dominated by 220 MW of ‘large’ stations in ROI, operated by ESB.

The additional hydropower resource is considered to be limited. The National Renewable Action Plan for ROI forecasts no growth for electricity generation from hydro-power between 2005 and 2020. The All-Island Grid Study [21] found a potential capacity of 99 MW for small hydropower, much of it in very small project sizes. This potential could result in a yearly energy yield of ca. 350 GWh/year, assuming a capacity factor of 40%.

The existing pumped-storage station at Turlough Hill (290 MW) is assumed to continue in operation, but does not contribute to net electricity production. Additional pumped storage plant is anticipated.

4.2.9 Landfill gas

Although not treated as a renewable source, the potential of landfill gas in 2020 has been assessed as 58 MW [15] or 47 MW [21]. If a capacity factor of 75% is assumed[22], the use of the higher of these figures will yield around 430 GWh/year. It is likely that by 2030 waste reduction measures and the exhaustion of existing landfills will have resulted in a substantially reduced landfill gas potential, and the SEAI Roadmap for bioenergy [52] shows landfill gas production in ROI dropping to zero by 2030.

4.3 Conclusions

GLGH conclusions for the renewable resource sizes to be used in subsequent analyses are shown in Table 4.4. These figures are in effect GLGH’s estimates of the resource that could be exploited if there was sufficient political will, without substantial restrictions due to cost. These numbers are indicative only. GLGH has reviewed a wide range of sources but has not ensured consistency of the scope and methodologies of the various approaches. The table should be read in connection with the comments provided in the previous sections.

The picture is dominated (>90%) by onshore and offshore wind.

[21] I.e. appears to be sufficiently large to justify further investigation.

[22] Landfill gas plant economics are dominated by capital cost. Also, gas production is not strictly controllable, and above-ground gas storage capacity adds cost. Therefore the project economics are best if operated as baseload, hence the relatively high capacity factor assumed here.

The ‘dispatchable’ proportion of this renewable generation capacity is very small, principally the biomass plant. A very small proportion of the existing hydro generation capacity is fed by reservoirs and is therefore dispatchable[23] without energy loss.

Technology	**Electricity production [GWh/y]**	**Capacity [GW]**	**Comments**
Onshore wind	44,000	16.8	Based on ‘accessible’ resource for ROI from [15], scaled up for the entire island by relative land area. Net capacity factor 0.30 assumed.
Offshore wind	62,000	16.5	Upper estimate from [19], for water depths <20m. The resource in water depths up to 50 m is very much greater. Net capacity factor 0.43 assumed.
Wave	3,000	1.4	Capacity from [18]. Net capacity factor of 0.25 assumed (could vary significantly as technology develops).
Tidal stream	2,600	0.75	Net capacity factor 0.4 assumed (could vary significantly as technology develops)
Sustainable biomass	3,200	0.4	Assumed to be provided by AD, and co-firing in fossil and peat thermal power stations, with 0.9 net capacity factor. SEAI predicts 1,735 GWh/yr for ROI by 2020 [28], though this includes ‘non-sustainable’ biomass such as EFW.
Geothermal	0	0	Potentially a significant resource, but currently too uncertain to include in this study for 2030.
Hydro	1,000	0.3	Assumes that existing capacity (~240 MW) is augmented by around half of the identified potential new capacity. Net capacity factor 0.4 assumed (based on 2010 data [28]).
Landfill gas	0	0	Assume that no new landfills are created, and all existing landfills are exhausted by 2030.
Totals	**116,000**	**36**	(Totals rounded to avoid implied accuracy which is not justified by the uncertainties)

Table 4.4: Renewable resource sizes assumed

[23] Note that ‘dispatchable’ in this context means that the plant output can be scheduled in advance and is not dependent on variable input energy such as wind and water. This is not to be confused with the term ‘dispatchable’ as applied to wind generation in some jurisdictions to denote the ability of the system operator to require the wind generation to reduce output below that available from the wind at any specific time.

Note that the Central demand assumption is for around 46,000 GWh/y (Table 3.2). The total renewable resource assumed here is therefore more than twice the annual electricity consumption of the island of Ireland under the Central demand assumption.

If instead the maximum estimates of ‘practical’ resource listed earlier in this section are summated, the total annual renewable electricity production is over 2,000 TWh/y, i.e. over 40 times the forecast electricity consumption for the island with the Central demand assumption, and almost 60 times with the Ambitious demand assumption. Virtually all of this is wind. This figure is included to show the enormous size of the renewable energy resource. To get anywhere near this level of electricity production would require a density of large onshore wind turbines that would dominate a large part of the land mass.

5 TASK 3: SECURITY OF SUPPLY

5.1 Issues affecting security of supply

This section considers the issue of security of electricity supply on the island of Ireland.

The term 'security of supply' covers a range of technical issues, with a range of emphasis and interpretation [31] [32]. The relevant technical issues are discussed in this section.

The term also in principle includes issues of fuel supply security, including international energy trading and political risks. These are not relevant for the renewable resources considered here. This section considers only the technical issues. No widely-accepted term exists for these technical issues, so 'security of supply' is used here for convenience.

Security of supply is a complex issue to address in detail, requiring detailed probabilistic assessment. The best way of doing this in a system with a high proportion of variable renewables is not yet fully established, as the established techniques assume conventional 'dispatchable' generation, and electricity demand which is almost entirely uncontrolled.

5.1.1 Voltage control and reactive power

Conventional electricity generators such as large fossil or nuclear stations use synchronous generators. These have the ability to produce or consume reactive power, adjustable virtually instantaneously over a wide range. Reactive power flows affect the voltages at each point on the network, and so this capability of synchronous generators allows the network operators to control voltages to stay within the network design limits. Reactive power and voltage can also be controlled by other means, but synchronous generators are very significant contributors, especially on transmission systems, as they provide very good control at almost no additional marginal cost.

Some renewable generating technologies such as biomass, landfill gas and some hydro generators also use synchronous generators. Their contribution can be particularly important as they are often connected to distribution networks, where there are few other sources of controllable reactive power.

However wind turbines, PV installations and some tidal and wave technologies do not use synchronous generators. In particular, earlier wind turbine technology (still representing a very significant fraction of installed capacity) used fixed-speed induction generators. These had only very crude ability to control reactive power.

There is therefore a concern that, as the proportion of renewable generators increases, especially wind generation, fewer synchronous generators will be in operation at any time, and the ability to successfully control network voltages will be lost.

Modern wind turbine technology is entirely variable-speed, with several competing generator options. The vast majority of modern wind turbines have power-electronic converters, which in principle offer control of reactive power comparable with that available from synchronous generators[24]. Some wind turbine designs can provide this capability even when the wind turbine is not generating, and in principle all could. There is no impact on energy production.

Very little use is currently made of this capability, which is in part to do with current contractual arrangements between network operators and wind farm operators.

In addition, network operators now also have the ability to install power-electronic equipment on their network which can provide very fast and accurate control of reactive power. This is expensive, but has an advantage in that it may be located at the optimum points on the network, rather than where the conventional generators or the wind farms are located.

Therefore in principle there is no technical reason (though there may be cost implications) why reduced conventional generating capacity and increased renewable generating capacity should threaten the ability of network operators to control voltage satisfactorily. This is a substantial area of investigation [59].

5.1.2 Frequency control, response and inertia

Similarly to the issue of voltage control, conventional generators provide control of the system frequency (nominally 50 Hz in Europe). Electricity demand and supply must be balanced at all times: when demand exceeds supply, all the synchronously-rotating masses connected to the system slow down slightly, and so the frequency drops. The opposite happens when supply exceeds demand. The synchronously-rotating masses are currently dominated by the inertias of the large conventional generators, though loads such as pumps and motors also contribute.

At present the large conventional generators control the frequency to its nominal value: when a drop in frequency is sensed, some generators automatically increase their energy input (typically steam), thereby increasing electricity supply to match demand and restore the frequency to its nominal value.

With fewer conventional generators in operation, there is less control capability, and more significantly the total rotating inertia reduces. This makes the system more sensitive: a small mismatch in supply and demand results in a greater frequency deviation. This is particularly critical in the case of a sudden loss of supply, for example a sudden failure of a large generator, or loss of import through an interconnector. In such circumstances the frequency can drop very rapidly.

This is a serious concern of system operators faced with increasing renewable generation, and Eirgrid and SONI are at the forefront of analysis of this issue [33][34][35][36][59].

Older wind turbine technology contributes nothing to frequency control (though fixed-speed turbines do contribute considerable inertia). Modern variable-speed pitch-regulated wind turbines can and do contribute to frequency control, through Grid Code[25] requirements, but contribute nothing to inertia.

[24] I.e. the range of reactive power generation and consumption capacity, the speed of response, and the accuracy of response can all be as good as or better than that obtained from conventional electromechanical synchronous generators fitted with Automatic Voltage Regulators.

It is technically feasible for modern wind turbines to provide the same response to sudden disturbances as conventional generation, and possibly a better response. Some wind turbine manufacturers may offer a controller function which provides ‘pseudo inertia’.

GLGH believes that, with adequate definition of technical requirements in Grid Codes, and adequate allocation of responsibilities in connection agreements and other contractual arrangements, satisfactory control of frequency[26] and response to disturbances[27] is possible in systems with high penetration of wind and other variable renewables. Substantial work may be required to achieve this, but the issue is not a show-stopper.[28]

5.1.3 Variability and ramp rates

Variability of output from wind generation and other variable renewables should not be confused with predictability, which is discussed further below. To clarify this, consider tidal generation: its output is highly variable (four generation periods per day), but highly predictable.

The variability of wind generation is best considered in terms of timescale and geographic scale. The output of a single wind turbine is highly variable on timescales of tens of seconds and longer: the turbulent variations in the wind on shorter timescales are effectively averaged over the entire rotor disc, and the net result is very little variability on timescales of seconds. Similarly, the variability of the output from a wind farm is subject to substantial averaging over the area of the wind farm, and the net result is that variability is only significant on timescales of minutes and longer. There is an even greater effect when considering the variability in the output of multiple wind farms spread across an area the size of a European state: there is very little variability on timescales of tens of minutes, and analyses of wind farm output data indicate that the most extreme variations are of the order of 20% of total wind generation capacity in half an hour[29].

---

[25] ‘Grid Code’ is a general term for technical requirements imposed on all users of an electricity system. They are generally published by the System Operator. See e.g. Eirgrid Grid Code [55], SONI Grid Code [60].

[26] Modern wind turbines can control their output to respond to changes in frequency, i.e. increasing the output when the frequency drops, and decreasing output when it rises. This provides the same function as conventional thermal generation.

[27] Similarly, modern wind turbine technology could provide a rapid increase in output power for very short periods in response to sudden disturbances, providing an ‘inertia response’ similar to that provided by conventional thermal generators.

[28] System operators may know of substantial technical difficulties and costs in achieving this on their systems, but in GLGH’s opinion, there is no insurmountable theoretical barrier.

[29] See e.g. analysis of National Grid data for wind farms in GB, reported in [30].

This is not to say that variability in wind production is not an issue: with large total wind generation capacity, the variability in output adds to the variability in demand, to create a larger problem for the system operator to manage. This is particularly significant in electricity systems such as Ireland, with relatively little interconnection to other systems. Increased interconnection to other systems can be a substantial benefit in managing wind variability, and also general variability of electricity demand.

However, there are several mitigating factors:

- periods where rapid changes in wind production are likely (for example, storm fronts) can be anticipated by forecasting;
- ‘ramp rate’ limits can be imposed by the system operator during risky periods, to set the turbine or wind farm controllers to limit the maximum rate at which wind production can increase;
- If there is a risk of a rapid reduction in wind production, the wind generation output can be reduced smoothly in advance.

The economic losses caused by reducing wind production or limiting positive ramp rates (irrespective of who actually pays for them) could be significant, for any one event, but in any one year the number of events is expected to be low.

Note also that electricity systems at present are designed to cope with the instantaneous loss of the largest generator or interconnector, which typically can be 1000 MW or greater (500 MW for the island of Ireland).

Given adequate forecasting ability, and allocation of responsibilities and contractual arrangements for implementing these functions, GLGH believes that variability need not be a risk to security of supply, though at high wind penetrations the costs of dealing with variability may be significant. It may be economic to change the mix of the other generation, to increase the proportion of plant which is able to start up relatively quickly and adjust its output quickly.

Wave generation faces the same issues, but generally changes happen more slowly over longer timescales.

5.1.4 Predictability and forecasting

Forecasting wind production, whether for individual wind farms or all generation in a country, is now an established technology, with several providers of commercial products [37]. Forecasting is now accurate enough on forecast timescales of a few hours to allow system operators to run their systems with adequate security. At the least, system operators can detect periods where the forecast wind production is very uncertain, or when high variability is expected, and if necessary reduce wind production.

GLGH expects forecasting to continue to improve, driven by the commercial advantages to electricity traders as well as the benefits to system operators.

Again, the same issues are relevant for wave generation, though output will change more gradually.

5.1.5 Resource availability

All forms of generation are to some extent vulnerable to fuel availability. However wind, wave, tidal stream and PV are unique in having no way to store the 'fuel'. For other generators, the amount of fuel storage is a relatively straightforward comparison of the risks against the cost of storage: a larger hydro reservoir, gas tank or coal stockyard.

The issues of variability and predictability of wind production have been discussed above. However, the critical issue for countries considering high wind penetrations is coping with long periods of low production due to anticyclonic conditions. In northern Europe, this is exacerbated by correlation with low temperatures in winter, leading to high electricity demand for heating, and possibly also to reduced output from run-of-river hydro due to frozen groundwater.

5.1.6 Summary

In the context of this study, it is concluded that the most significant risk to security of supply for northern European countries with high penetration of renewables is an extended period of anticyclonic weather in winter, similar to the winters of 2009/10 and 2001/11 with low temperatures and little output from wind, wave and hydro generation, lasting for several weeks.

It is assumed in this study that, if this issue is resolved through the solutions discussed below, other issues of security of supply (mainly to do with short-term variability) are also resolved.

5.2 The current situation in Ireland

In comparison with other countries, the island of Ireland has very limited interconnection with other systems, and high wind generation capacity. Experience shows that, while all electricity systems have different characteristics, issues such as those discussed in Section 5.1 appear in many systems as the proportion of wind (or other variable renewables) increases. This section therefore compares Ireland with another relatively isolated system with high wind penetration: Iberia.

Iberia (Spain and Portugal) is synchronously connected to the rest of the continental European system via France, and a connection to Morocco, but the connections are relatively small compared to the size of the system. Therefore the large component of wind generation, and also solar, has to be managed largely within the area [38]. During critical periods, the Spanish TSO curtails the output of wind generation, and in 2010 0.6% of wind production was lost in this way.

It is necessary to define the concepts of 'penetration'.

- ***Energy penetration*** is the ratio, over a long period such as a year, of the electrical energy (GWh) produced by a particular generating source (in this case wind), to the total electrical energy consumed (GWh).

- ***Capacity penetration*** is defined here as the ratio of the total wind generating capacity installed (GW), to the average electricity demand (GW). This gives a better indication of the short-term issues that could arise during periods of high wind production.

- ***Instantaneous penetration*** is defined here as the ratio of wind production (GW) to electricity demand at any instant.

Other definitions of penetration exist[30]. For the purposes of comparison here, the definitions above are satisfactory.

For instantaneous penetration, information is often not readily available, and for any system the peak values may vary significantly from year to year, depending on the coincidence of high winds across the country with low electricity demand. Spain has recorded 59%, for a period of several hours in November 2011 [39]. Instantaneous 'non-synchronous' penetration (i.e. wind plus DC interconnections with the GB system) on the Irish (all-island) system is currently regulated to no more than 50% [33] (largely for frequency control and inertia reasons as discussed above), and the highest recorded energy penetration level over a day is 40.8% [33]. EirGrid are investigating the technical issues which could allow this instantaneous non-synchronous penetration limit to be increased to 75%.

Energy and capacity penetration parameters are calculated for Ireland and Iberia in Table 5.1.

Note that Spain also has around 4 GW of solar capacity, which is also variable, though with different characteristics to wind. This is not included in the table.

	Annual consumption (TWh)	**Wind production (TWh)**	**Energy Penetration**	**Mean demand (MW)**	**Wind capacity (MW)**	**Capacity penetration**
Spain	255	41.7	16.3%	29,130	20,733	71.2%
Portugal	50.5	9.0	17.8%	5,765	4,084	70.8%
Iberia	306	50.7	**16.6%**	34,895	24,817	**71.1%**
NI	9.0	1.0	11.1%	1,029	405	39.4%
RoI	26.0	4.1	15.9%	2,973	1,557	52.4%
Ireland	35.0	5.2	**14.7%**	4,002	1,962	**49.0%**

Table 5.1: Comparison of electricity systems by wind penetration levels, 2011 data

The table shows that Iberia currently operates satisfactorily with penetration levels higher than Ireland. However Iberia has advantages of greater geographical diversity, and also significant controllable hydro generation.

[30] The most comprehensive definitions were produced by the IEA Working Group Task 25 [31]. Often capacity penetration is defined as the ratio of the total wind capacity to the *peak* electricity demand, or to the total installed generating capacity (possibly with an allowance for interconnection capacity). However precise values for these variables are hard to find, particularly for systems spanning several countries.

5.3 Electricity demand and supply in 2030 during critical periods

5.3.1 Demand

As discussed above, the critical situation for security of supply is believed to be the extended cold period.

In Section 3, electricity demand in 2030 is estimated. Figure 3.1 shows the diurnal demand curve for the island of Ireland under current conditions, with a peak of 6850 MW. Estimating the peak demand in 2030 is subject to significant uncertainties, principally:

- changes in underlying demand as discussed in the Central and Ambitious scenarios in Section 3, in particular the uptake of electric heating;
- the ability to defer loads away from the peak period.

In order to arrive at an estimate of peak demand, the following assumptions have been made:

- The underlying demand (i.e. without allowance for further electrification of heat and transport) in winter in 2030 follows the same daily shape as at present.
- The peak of the underlying demand scales in proportion to the change in annual electricity demand between 2010 and 2030 (i.e. a factor 1.17 for the Central demand scenario and 0.93 for the Ambitious demand scenario).
- New electric vehicle charging loads do not affect the peak demand, even during extended cold periods, as charging is deferred into the night trough.
- New electric heating loads increase the peak demand by 1,100 MW. This figure is taken from SEAI's forecasts to 2020 published in 2010 [6] and shown in Table 3.3, but is no more than an indicative figure. GLGH believes that there will be strong financial incentives to defer demand from peak periods in 2030, and improved building insulation and thermal mass should allow deferral of heat demands by several hours. There will also be some other loads which can be deferred at peak periods, which are not included in the simple scaling assumption here.

The net effect is an estimate for peak demand during critical periods of 9100 MW (Central demand scenario) and 7500 MW (Ambitious demand scenario).

5.3.2 Renewables production during critical periods

In order to estimate production from renewables during critical periods, it is necessary to estimate the installed capacity in 2030. GLGH has therefore selected a representative mix as shown in Table 5.2, on the following fundamental assumption:

> ***The total renewable generating capacity is equivalent to maximum demand plus the capacity of interconnections.***

This is based on the following logic:

- Technical issues do not fundamentally set a limit on renewable generation capacity, as discussed above.[31]

- The renewable resources do not fundamentally set a limit on renewable generation capacity. From Table 4.4, it is seen that there is very substantially more renewables capacity available to Ireland in 2030 than is needed to meet annual electricity demand.

- For the purposes of this study, it is assumed that the political will exists, and public support will not constrain the development of renewable generation capacity.

- Therefore, the renewable generation capacity is set by financial viability. For variable renewable generation technologies (which form the great majority of the resource available to Ireland), financial viability is critically dependent on finding purchasers for the electricity when it is generated.

Setting the total renewable capacity approximately equal to the maximum demand plus capacity for export through interconnectors[32] means that for much of the year (i.e. when demand is lower than peak demand), renewable generation will not be able to operate at full output as there will be insufficient demand.

The argument set out here contains some major simplifying assumptions, and the reality in 2030 could easily be 50% or 150% of the results in Table 5.2. However, it is necessary to make some judgement, and any more detailed analysis would have to make equally uncertain assumptions about the costs of all competing generation technologies in 2030. Note also that further analysis below shows that the conclusions for security of supply are relatively robust to the uncertainties inherent in this decision.

The split between onshore and offshore wind in the table is relatively arbitrary, and it should be noted that this is not a critical issue: the characteristics of onshore wind, offshore wind, wave and to some extent tidal stream generation are very similar in the context of this study. An alternative allocation of capacities between these four technologies would not affect the conclusions significantly.

---

[31] Though of course economic considerations driven by technical issues may well do, in any given set of circumstances. Also, system operators at present are likely to set limits, due to technical limitations of the renewable generation currently installed, other technical limitations of the existing electricity system, and uncertainty.

[32] Interconnector capacity here is assumed to be 1000 MW. Current interconnector capacity to the Great Britain (GB) electricity system is around 500 MW, and the new East-West interconnector currently in progress is also 500 MW. No further interconnector capacity is assumed in this calculation.

Technology	Capacity [MW] – Central demand scenario	Capacity [MW] – Ambitious demand scenario	Comments
Peak demand	9,100	7,500	Defined in text
Interconnector capacity	1,000	1,000	Current existing and proposed interconnector capacity
Assumed limit on renewable generation capacity	**10,100**	**8,500**	As explained in text.
Onshore wind	4,000	4,000	Achievable with known projects. Well below level anticipated in [51] for ROI alone.
Offshore wind	3,700	2,700	Achievable with known projects. Similar to level anticipated in [51] for ROI alone.
Wave	1,000	400	Less than capacity defined in Table 4.4, but large enough to make a small number of viable projects.
Tidal stream	700	700	Close to full capacity defined in Table 4.4 is assumed to be constructed
Sustainable biomass	400	400	Full capacity defined in Table 4.4 is assumed to be constructed
Geothermal	0	0	Potentially a significant resource, but currently too uncertain to include in this study for 2030.
Hydro	300	300	Full capacity defined in Table 4.4 is assumed to be constructed
Landfill gas	0	0	Assume that no new landfills are created, and all existing landfills are exhausted by 2030.
Total renewable capacity	**10,100**	**8,500**	

Table 5.2: Renewable generation mix assumed in 2030

From the capacities defined in Table 5.2, the output of renewable generation in cold calm conditions is estimated in Table 5.3. Wind production in these worst case scenarios is assumed to be 5% of rated capacity: this has also been assumed by the UK Department of Energy and Climate Change (DECC) in the 'stress test' included in the 2050 Pathways Calculator methodology, and in reports which are based on this [40].

Technology	Production [MW] – Central demand scenario	Production [MW] – Ambitious demand scenario	Comments
Onshore wind	200	200	Assume 5% of rated capacity
Offshore wind	200	150	Assume ~5% of rated capacity
Wave	50	20	Assume 5% as for wind. It is assumed that the calm period lasts for long enough and extends far enough into the Atlantic.
Tidal stream	200	200	Assume some geographical dispersion, sufficient to give net output at critical periods slightly below the annual mean value (280 MW)
Sustainable biomass	400	400	Fully dispatchable, managed in order to ensure full production during critical periods.
Hydro	150	150	Assume run-of-river hydro is limited due to frozen rivers. Reservoir hydro is unaffected and is operated to achieve peak output during critical periods
Total renewable production	**1,200**	**1,120**	

Table 5.3: Renewable production during critical periods

5.3.3 Shortfall

Clearly during the critical cold calm period, the renewable generation capacity defined in Table 5.3 is much less than demand. The shortfall is estimated in Table 5.4.

	Central demand scenario	**Ambitious demand scenario**	**Comments**
Peak demand [MW]	9,100	7,500	
Plant margin [MW]	910	750	10% additional plant margin required to guard against failure of major generators or transmission, failure of demand control measures, or unforecasted demand increases (assumed not concurrent)
Total generation required [MW]	10,010	8,250	
Renewables production [MW]	1,200	1,120	From Table 5.3
Contribution from imports via interconnectors	910	750	See text
Additional capacity needed	**7,900**	**6,380**	By subtraction

Table 5.4: Calculation of additional capacity needed to ensure security of supply

Note that in this calculation, interconnectors are not assumed to be providing substantial imports during critical periods, because conditions in GB cannot be relied on to be substantially different from conditions in Ireland, due to the physical extent of anticyclonic conditions. Therefore reliance on interconnectors during critical demand periods would not be robust. However, import *can* be assumed to be feasible during emergencies such as loss of a major generator, as it is not credible that a concurrent event would also occur in GB. The size of the potential shortfall during an emergency is implied by the plant margin, so the contribution from interconnectors in the table is limited to the plant margin.

5.4 Available solutions

There are currently three realistic means to provide a secure electricity supply in these circumstances:

- large energy storage capacity, able to meet a large part of electricity demand for periods of weeks;
- conventional thermal generating capacity;
- interconnection to other electricity systems.

These are discussed in more detail below.

Deferrable demand does not provide a solution, as most demands can only be deferred within-day, and certainly there are no significant electricity demands which can be deferred for several weeks.

Electric vehicle charging demand could in principle be deferred within-week, if users can be persuaded to purchase sufficient battery capacity to allow charging at weekends. Understanding the likely contribution of EV charging to deferrable demand on timescales of a week or more may become important in the situation analysed here, but GLGH considers it would be unwise to rely on this on current understanding.

5.4.1 Energy storage

In preparing for a worst case scenario, the critical anticyclonic conditions must be assumed to last for several weeks. In the UK, the DECC 'stress test' referred to earlier [40] assumes a five-day period, but GLGH believes that, based on recent winters, this is likely to be an underestimate.

The only energy storage technologies which are currently technically proven and have sufficient capacity at acceptable capital cost are pumped hydro storage, and compressed-air storage in underground caverns. The island of Ireland has few opportunities for new large-scale facilities of these types, though there are proposals for pumped storage using seawater, and also for compressed-air storage near Larne [56].

Note that conventional pumped storage, as in operation at Turlough Hill in County Wicklow, does not provide a solution, as the storage capacity is equivalent to only a few hours of operation at full output.

It is entirely feasible that other bulk energy storage technologies will become available at acceptable cost by 2030, but GLGH believes it is not sensible to base energy policy on an assumption that these will emerge. Note in particular that currently pumped storage plants are economic on the basis of frequent use, for example by charging during the night and generating at peak periods during the day. To provide a solution to the long cold calm period, storage installations would have to be economic on the basis of being used only a few times a year.

5.4.2 Conventional generating capacity

Conventional thermal generating plant would provide a solution. This could be gas or coal, for the following reasons:

- There is no history of nuclear power in Ireland, so that building the skills and supply chain for design, operation, decommissioning and waste storage would be expensive. The majority of the costs would be expended abroad.
- Further coal-fired generation may require Carbon Capture and Storage (CCS), and coal produces approximately twice the volumes of carbon for storage compared to gas. However, as some of the conventional generation capacity would only be required to run infrequently, it may be justified to use existing coal-fired generation capacity instead of building new generation.
- Gas with CCS is currently anticipated to be the cheapest clean fossil generation.
- Gas generation options allow a mix of plant types to provide flexibility: from highly efficient baseload plants with heat recovery (closed-cycle gas turbines, CCGT) and CCS, to less efficient plants with lower capital cost capable of rapid starting and rapid variation in output (open-cycle gas turbines, OCGT). The latter category may be intended to run for only a few hundred hours a year, in which case it may not be justified to fit it with CCS capability.

5.4.3 Interconnection to other systems

Interconnection to other systems can provide substantial benefits to systems with high renewables penetration [41][42][43][44][45]. The benefits flow from the geographical variation in renewables production, renewables type (for example, solar PV or concentrating solar thermal), and from diversity in electricity demand. For Ireland, the options are limited to GB, France and possibly northern Spain. Interconnection to GB has the disadvantage that wind conditions are likely to be very similar to the island of Ireland, especially anticyclonic conditions. Interconnection to continental Europe potentially offers greater benefits, though at greater cost.

In this study, interconnector[33] capacity of 1000 MW is assumed as the base case, equivalent to the existing Moyle interconnector, and the East-West interconnector due for completion in 2012.

5.4.4 Summary

From the discussion above, three options for ensuring a secure electricity supply with high renewables penetration are chosen for further analysis in the next section:

- Case A: conventional thermal generation;
- Case B: thermal generation with increased interconnection capacity to GB.
- Case C: thermal generation with increased interconnection capacity to continental Europe.

[33] These interconnectors use High Voltage DC technology (HVDC), which is non-synchronous. Depending on how it is controlled, this has implications for frequency control of the Irish system. HVDC is also the most likely technology for future interconnectors.

6 TASK 4: ANALYSIS

6.1 Case A: conventional thermal generation

From the discussion above, it is assumed here that in order to have an electricity system that is reliable in this worst case scenario of cold calm conditions due to a stable anticyclone, 7,900 MW of gas-fired generation capacity is required under the Central demand scenario in 2030, and 6,400 MW under the Ambitious scenario.

This can be provided by around eight large stations, or a mix with some smaller stations, possibly sited for best use of waste heat for district heating.

Current gas-fired generation is 5,700 MW (including 1,300 MW of OCGT). Total thermal generation capacity is 7,700 MW, excluding older oil-fired stations which are anticipated to close [5]. Therefore the total thermal generating capacity required in 2030 is similar to today's level.

Even assuming complete replacement of the current conventional generating fleet in Ireland, which is unlikely to be necessary by 2030, the required build rate to 2030 is eminently achievable.

Although the scope of this study excluded consideration of possible transmission reinforcements required within Ireland, it seems clear that new thermal generation can be sited on existing power station sites or close to demand centres. Therefore the major requirement for transmission reinforcement will be to accommodate the wind, wave and tidal resources, which are generally located further from demand centres.

Table 6.1 shows the renewable and thermal generation capacities determined in previous sections. From this the electricity production of the renewable and thermal generation is calculated, and the emissions.

There are two important caveats.

Curtailment of renewables production

The output of the renewables generation is calculated from the installed capacities and assumed capacity factors. No allowance has been made for curtailment of renewables production. Curtailment could well occur, for two reasons;

- As noted in Section 3, some of the technical issues that will become important at high wind penetrations can be resolved by infrequent curtailment of the wind generation. Operation of power systems with very high renewables penetration, as is assumed here, has not yet been achieved, and although it is likely that the technical issues can be resolved satisfactorily, the amount of renewables curtailment that would be necessary or economic is not known.

- The total renewables capacity assumed here is equivalent to maximum demand plus interconnector capacity. Therefore at all times of the year except the times of very highest demand, the renewable generators would not be able to run at full production, if the renewable resource permitted, because there will be insufficient purchasers for the output.[34]

Use of deferrable demands should reduce the need for curtailment of renewable production, but there will still be some impact. It is not possible to quantify this effect in this study. Therefore the estimates for renewables output in the table must be treated as indicative only. The output of the gas generation is determined by the calculated renewables output and therefore must also be considered as indicative only.

Net import/export

The analysis assumes no significant net import or export over the year, which is a reasonable simplifying assumption in the context of the limited interconnection capacity assumed in this case.

Note also that, if there were substantial exports of renewables production from Ireland, the importing country would very likely be purchasing the renewables benefits along with the energy, so the emissions reduction benefits could not logically also be claimed for Ireland, though the economic benefits will accrue to Ireland.

The gas generation mix assumed is shown in Appendix 2. This is an indicative mix, and other mixes will also meet the requirements.

The table and Appendix 2 show that the gas generation runs at very low capacity factors. This will be a challenge for financing these projects, and is likely to require payments for capacity[35] in some form, in addition to the energy market.

The table shows that a relatively small part of the gas capacity is required to be fitted with CCS in order to meet the decarbonisation target of 50 g/kWh.

[34] In northern Europe, wind and wave have a definite correlation with electricity demand on a seasonal basis, but on shorter timescales (days and hours), demand and renewables production are not well correlated.

[35] The Single Electricity Market already provides capacity payments. In these circumstances, the total of capacity payments can be expected to increase.

Scenario	Central demand scenario	Ambitious demand scenario	Comments
Total renewables capacity	10,100 MW	8,500 MW	From Table 5.2
Total gas generation capacity	7,900 MW	6,400 MW	From Section 5
Annual electricity demand	46.1 TWh	36.9 TWh	From Section 3
Total renewables production	33.4 TWh	28.3 TWh	See Appendix 1.
Renewables production as fraction of demand	72%	77%	
Required output from gas generation	12.7 TWh	8.6 TWh	
Average capacity factor for gas generation	18%	15%	
Emissions from gas plant, assuming no CCS	4.8 mt $CO2_e$	3.2 mt $CO2_e$	Assume 376 kt/TWh: see Appendix 2
Overall emission intensity (gas plus renewables) assuming no CCS	104 g/kWh	86 g/kWh	
Emissions from gas plant, assuming all fitted with CCS	0.5 m t $CO2_e$	0.3 m t $CO2_e$	Assume 38 kt/TWh: see Appendix 2
Overall emission intensity (gas plus renewables) assuming all with CCS	10 g/kWh	9 g/kWh	
Gas generation required to have CCS in order to achieve emission intensity of 50 g/kWh	1.7 GW out of 7.9 GW	1.2 GW out of 6.4 GW	See Appendix 2

Table 6.1: Summary of renewable & gas generation capacity and emissions by scenario, Case A

6.2 Case B: increased interconnection capacity to GB

6.2.1 Additional 1000 MW connection to GB

A further 1000 MW increase in interconnection capacity to the GB system is assumed. Following the logic of Section 5.3, and in particular Table 5.2, it can then be assumed that the renewable generation capacity on the island of Ireland can be increased by 1000 MW. It is reasonable to assume that this is provided by onshore wind, because this is the greatest available resource. Wave and offshore wind could also be assumed, but this would not make a great difference to the discussion. The other renewables are already assumed to be built out to the limits of the resource.

It is important to note that these assumptions inherently imply that ***the additional 1000 MW wind capacity becomes economic to build because it can find purchasers for at least some of its production through the additional interconnection capacity.*** This may not be the case, as the wind conditions and the underlying economic factors in GB are similar to those in Ireland.

From Table 5.3 it is seen that this additional wind capacity will only make a very small contribution (5% of 1000 MW) to security of supply during critical periods. The additional interconnection capacity to GB will also not make any significant contribution to security of supply, because it is reasonable to assume that the GB system will also have a large proportion of renewable generation in 2030, and there is a high risk of anticyclonic conditions affecting Ireland and GB at the same time. Therefore the gas-fired generation capacity is unchanged from Case A.

The effect of the increase in interconnection capacity is shown in Table 6.2. As before, the gas generation mix assumed is shown in Appendix 2. This is an indicative mix, and other mixes will also meet the requirements.

Table 6.2 and Appendix 2 show that the gas generation runs at lower capacity factors than in Case A. This will be a greater challenge for financing these projects.

The table shows that very little of the gas-fired generation capacity is required to be fitted with CCS in order to meet the decarbonisation target of 50 g/kWh.

Scenario	Central demand scenario	Ambitious demand scenario	Comments
Total renewables capacity	11,100 MW	9,500 MW	See text
Total gas generation capacity	7,900 MW	6,400 MW	See text
Annual electricity demand	46.1 TWh	36.9 TWh	From Section 3
Total renewables production	36.0 TWh	30.9 TWh	See Appendix 1.
Renewables production as fraction of demand	78%	84%	
Required output from gas generation	10.1 TWh	6 TWh	
Average capacity factor for gas generation	14.6%	10.7%	
Emissions from gas plant, assuming no CCS	3.8 mt $CO2_e$	2.3 mt $CO2_e$	Assume 376 kt/TWh: see Appendix 2
Overall emission intensity (gas plus renewables) assuming no CCS	82 g/kWh	62 g/kWh	
Emissions from gas plant, assuming all fitted with CCS	0.4 m t $CO2_e$	0.2 m t $CO2_e$	Assume 38 kt/TWh: see Appendix 2
Overall emission intensity (gas plus renewables) assuming all with CCS	8 g/kWh	6 g/kWh	
Gas generation required to have CCS in order to achieve emission intensity of 50 g/kWh	1.0 GW out of 7.9 GW	0.4 GW out of 6.4 GW	See Appendix 2

Table 6.2: Summary of renewable & gas generation capacity and emissions by scenario, Case B: 1000 MW additional interconnection capacity to GB

It is important to note that the figures presented here assume that there is still no substantial net annual import or export to the GB system. In reality, with interconnection capacity of roughly one quarter of all-island peak demand, it is highly likely that there would be substantial trading over the interconnectors: indeed, this would be necessary in order to make the additional interconnection capacity financially viable. Depending on the competing thermal generation on the GB system, this could result in the gas-fired generation in Ireland achieving higher or lower capacity factors than shown here.

Summary

Increasing interconnector capacity by 1000 MW allows a further 1000 MW of renewable generation capacity to be built, most likely onshore wind, because it provides access to a market for some if not all of the output.

This study does not attempt to establish if this would indeed be economic. In effect, wind generation capacity in NI or ROI would have to be able to pay for use of the interconnection and still undercut competing renewable generation in GB, for at least a large part of its output. It is not at all clear that this is feasible, though it is important to note that the competing renewable generation in GB is expected to include a large amount of offshore wind, which will be substantially more expensive than GB onshore wind.

6.2.2 Further interconnection to GB

Greater interconnection capacity to the GB system is entirely feasible. For example, the transmission capacity between Scotland and England is due to increase to 6000 MW shortly, and possibly around 8000 MW before 2020, primarily for the purpose of exporting large amounts of energy from hydro and wind generation to the load centres in England. This transmission capacity is roughly equivalent to peak demand in Scotland, and it is feasible to imagine a similar arrangement with the island of Ireland, i.e. connection capacity of 8000 or 9000 MW. The additional renewable generation capacity this might allow on the island of Ireland is still within the available resource discussed in Section 4, and is well within the UK's requirements for renewable generation to meet its obligations. Whether it will happen depends on whether Irish renewables, particularly onshore wind, can undercut GB options, particularly offshore wind. The likely evolution of regional rather than national energy markets in the EU should assist this.

At this stage it becomes meaningless to attempt to estimate the conventional generation capacity required in Ireland, and emissions, as the two systems will be close to behaving as one electrical system and one energy market.

6.3 Case C: increased interconnection capacity to continental Europe

6.3.1 Additional 1000 MW connection to continental Europe

Interconnections to continental Europe could be achieved by direct connections to France (~500 km) or northern Spain (~1000 km), or via GB.

These connections will be substantially more expensive than a direct connection to the GB system (~250 km) as discussed in Section 6.2. However they would offer significant benefits in geographic diversity of renewables production, and electricity demand.[36]

Because of this, the analysis produces different results than for the connection to GB in Case B.

As for Case B, it can be assumed that the renewable generation capacity on the island of Ireland can be increased by 1000 MW, most likely onshore wind. As before, this inherently assumes that ***the additional 1000 MW wind capacity becomes economic to build because it can find purchasers for at least some of its production through the additional interconnection capacity.*** This is more likely than for Case B.

As for Case B, this additional wind capacity will only make a very small contribution (5% of 1000 MW) to security of supply during critical periods. However unlike Case B, the additional interconnection capacity ***can*** be assumed to provide a contribution to security of supply during critical periods, because it is unlikely that the anticyclonic conditions will cover all of Europe, and because the generation mix is not so dominated by wind as it is assumed to be for GB. Therefore the gas-fired generation capacity can be reduced.

The effect is shown in Table 6.3. As before, the gas generation mix assumed is shown in Appendix 2. This is an indicative mix, and other mixes will also meet the requirements.

[36] Because of the effect of different working hours and different time zones.

Scenario	**Central demand scenario**	**Ambitious demand scenario**	**Comments**
Total renewables capacity	11,100 MW	9,500 MW	See text
Total gas generation capacity	6,900 MW	5,400 MW	See text
Annual electricity demand	46.1 TWh	36.9 TWh	From Section 3
Total renewables production	36.0 TWh	30.9 TWh	See Appendix 1.
Renewables production as fraction of demand	78%	84%	
Required output from gas generation	10.1 TWh	6 TWh	
Average capacity factor for gas generation	16.7%	12.7%	
Emissions from gas plant, assuming no CCS	3.8 mt $CO2_e$	2.3 mt $CO2_e$	Assume 376 kt/TWh: see Appendix 2
Overall emission intensity (gas plus renewables) assuming no CCS	82 g/kWh	62 g/kWh	
Emissions from gas plant, assuming all fitted with CCS	0.4 m t $CO2_e$	0.2 m t $CO2_e$	Assume 38 kt/TWh: see Appendix 2
Overall emission intensity (gas plus renewables) assuming all with CCS	8 g/kWh	6 g/kWh	
Gas generation required to have CCS in order to achieve emission intensity of 50 g/kWh	1.0 GW out of 6.9 GW	0.3 GW out of 5.4 GW	See Appendix 2

Table 6.3: Summary of renewable & gas generation capacity and emissions by scenario, Case C: 1000 MW additional interconnection capacity to continental Europe

As before, the figures presented here assume that there is no substantial net annual import or export. In reality, it is highly likely that there would be substantial trading over the interconnectors: indeed, this would be necessary in order to make the additional interconnection capacity financially viable. Depending on the competing thermal generation on the European system, this could result in the gas-fired generation in Ireland achieving higher or lower capacity factors than shown here.

Summary

Increasing interconnector capacity by 1000 MW allows a further 1000 MW of renewable generation capacity to be built, most likely onshore wind, because it provides access to a market for some if not all of the output. It also allows gas-fired generation capacity on the island of Ireland to be reduced by 1000 MW.

As for Case B, there is no attempt here to establish if this would indeed be economic. In effect, wind generation capacity in NI or ROI would have to be able to pay for use of the interconnection and still undercut competing renewable generation in Europe, for at least a large part of its output. It is not at all clear that this is feasible.

6.3.2 Further interconnection to continental Europe

Greater interconnection capacity to continental Europe is entirely feasible technically [61], up to the exploitable limit of Irish renewable generation. As for Case B, the fundamental issue is the cost of Irish renewables in comparison with the alternatives.

The cost of interconnection capacity should not be underestimated: as a rough guide, a subsea HVDC connection of 300 km length has approximately the same capital cost per MW as an onshore wind farm.

6.4 Other approaches

The analysis presented above requires a large amount of gas-fired generation capacity[37] (roughly equivalent to the total thermal generation capacity on the island today) in order to ensure a secure system. The average capacity factor for this generation is low, which will make its output relatively expensive in €/MWh terms, compared to the cost under present-day operating regimes. The gas generation also requires some CCS capacity in order to meet the decarbonisation target.

This option will also require substantial gas storage capacity, or alternatively robust supply contracts, to ensure availability of gas.

It is therefore worth considering other approaches.

Additional output from gas generation with CCS capability

The power required to operate CCS plant is currently understood to be high: perhaps 20% of the output of the generation plant. As there is no CCS plant operating at anything near commercial scale, this figure is approximate. It would be possible to shut down the CCS plant at times when very high output of the generating plant is required. This would result in additional electricity output of possibly 25% of the rated capacity of the plant.

[37] Though as noted earlier, some coal-fired generation may be justified instead.

Provided this mode of operation is used for very limited periods during the year, the additional CO_2 released may be acceptable. This can be seen as a lower-cost alternative to providing a peaking gas plant (OCGT) without CCS.

Demand management

This study already assumes that there will be substantial management of deferrable demands within-day, primarily heating and EV charging. This will bring benefits in a situation of high renewables penetration, in particular by reducing the fraction of the renewables production that would otherwise be lost by curtailment. However, deferral of demand over longer periods, particularly within the week, should offer substantial further benefits, particularly as wind variability in northern Europe is strongly affected by passage of depressions, generally with periods of the order of 3 or 4 days.

The most likely contributor to demand management on timescales of several days is EV charging. This requires that cars and vans (which will make up the vast majority of the EV stock) have sufficient battery capacity to allow charging roughly once a week. This also fits with usage patterns. However, two factors work against this:

- Battery capacity for a week rather than a day will be significantly more expensive and heavier;
- Vehicle owners may only use their vehicles for 20 km per day or 200 km per week, but may wish to have the full battery capacity available to them at all times in case of unforeseen events.

The other major deferrable demand is heat. Improvements to building insulation will make deferral within-day feasible, but it is not at all clear that deferral for longer periods is feasible or desirable.

The fundamental issue with demand management when considering security of supply is that the critical cold calm period may last several weeks. Therefore demands that can be deferred for several weeks are required in order to replace the need for gas generation capacity, and there seems little prospect of such deferrable demands appearing.

The major benefit of deferrable demands in a high-renewables situation is in reducing the curtailment of renewables. This in itself is valuable, and therefore understanding the effects of EV charging and heat loads on timescales of a day and longer is an important issue.

Energy storage

In this context, energy storage has the same characteristics as deferrable demand. Irrespective of the energy storage technology, it offers significant benefits in managing high renewables penetration, but in order to substitute for gas generation capacity to deal with long cold calm periods, it has to have a storage capacity very much greater than existing facilities such as pumped storage. Further, this storage capacity has to be provided economically while perhaps only being used (i.e. paid for its full energy storage range) a few times per year, or perhaps even per decade.

Dispatchable renewables

Reservoir hydro would be a great advantage, but there are insufficient sites in Ireland for any significant increase in capacity.

Underground compressed-air storage, as currently proposed in Larne, would also be a great advantage.

Biomass is the main option here. Biomass generators are generally designed and sized to be run as baseload generation, and this has been assumed in the analysis so far, but there is no fundamental reason (other than economics) why biomass could not be used to replace some of the low-capacity-factor gas generation assumed in this study. In other words, the biomass generation capacity assumed here could be increased, without increasing the electricity production or biomass requirements on an annual basis.

Like gas generation, biomass also may have an advantage in producing heat at a time of high heat demand, if sited close to heat loads.

6.5 Employment effects

The potential for job creation is an important argument for renewables. Known information on employment effects is summarised in Appendix 3. Although subject to large uncertainties, a figure of 3 jobs (Full Time Equivalent, FTE) per MW of cumulative installed wind capacity based on current market structure and industry maturity appears reasonable to apply to the case of Ireland, from UK experience.

It is reasonable to assume considerable learning and efficiency gains by 2030, so a figure of 2 FTE/MW may be appropriate.

In the absence of relevant data, the same figure is assumed to apply to wave and tidal stream technologies. No allowance is made for additional employment from hydro or biomass, as explained in Appendix 3.

Therefore, direct and indirect employment in 2030 from around 10,000 MW of wind, wave and tidal capacity is estimated at around 20,000 FTE.

If Ireland managed to establish a manufacturing capability for wind turbines, wave or tidal stream devices, employment could be substantially higher. Note however that by 2030 the installation rate of new renewable capacity is likely to have fallen to close to replacement levels: assuming a 20-year device life, the replacement installation rate will be of the order of 500 MW per year.

7 SUMMARY AND CONCLUSIONS

This study has shown that it is technically feasible for the island of Ireland to have a secure electricity system in 2030 with a high level of decarbonisation (50 g/kWh), based on a high fraction of renewables generating capacity, conventional thermal generation (mostly gas), and possibly increased interconnection capacity. The study has not attempted to show that this is the cheapest or least risky way of achieving the objective.

The total renewable resource available to the island of Ireland is many times greater than its electricity demand.

A likely mix of renewable generation technologies has been selected for 2030, dominated by onshore and offshore wind. However onshore wind, offshore wind, wave and tidal stream share similar characteristics in the context of this study, and other mixes of these technologies would not greatly affect the conclusions.

Renewables production reaches around 70% to 80% of total electricity demand (but see qualifications below).

Despite the large contribution from variable renewable generation, a secure[38] electricity system is provided by gas-fired generation capacity, roughly equivalent to the current thermal generation capacity. This gas generation has a very low average capacity factor, which may require a specific incentive mechanism to help attract finance.

To meet the decarbonisation target, some of the gas generation capacity is fitted with CCS.

The critical issue for a secure electricity system with a high proportion of variable renewables, especially wind, is an extended period of anticyclonic conditions in winter, with very low renewables production and high heat demand. The possible length of this period is such that conventional energy storage solutions and deferrable demand are unlikely to make a contribution. This is a challenging ‘stress test’ for any electricity system, and has been used in order to ensure the conclusions of this work are robust.

An increase in interconnector capacity to the electricity system of Great Britain could provide a market for the output of renewable generation on the island of Ireland, and therefore increase the renewable generation capacity. This is most likely if Irish onshore wind, including interconnector costs, is cheaper than GB offshore wind. However interconnection capacity to GB does not reduce the need for gas-fired generation in Ireland.[39]

Interconnector capacity to continental Europe (France, Spain or via GB) would also allow renewable generation capacity on the island of Ireland to increase. However, unlike connection to GB, it is likely to allow gas generation capacity in Ireland to be reduced, because anticyclonic conditions in Ireland

[38] I.e. providing a satisfactory level of security of electricity supply.

[39] Because it is assumed that in the worst case of low renewables production, GB will be in a very similar situation. Weather patterns may extend over very large areas.

will not correlate strongly with renewables production in continental Europe. The costs will be significantly higher than connection to GB.[40]

There are several important qualifications to these conclusions, the methodology and the input assumptions:

- It is assumed that the technical issues associated with running an electricity system with very high levels of renewable generation (up to 100% instantaneous penetration, i.e. periods with no conventional generation in operation) can be resolved, though it will not be straightforward and the costs may be high. Analysis of the known technical issues indicates that with technology development, especially of wind turbines, satisfactory operation should be feasible, including control of voltage and frequency. However operation at or close to 100% instantaneous penetration will result in curtailment of the output of variable renewables such as wind. This curtailment could be substantial, in effect increasing the Cost of Energy for these renewables.

- The reduction in renewables production due to curtailment is not quantified in this study, and therefore the figures for renewables production, production from gas generation, and emissions reduction shown in Table 6.1 should be regarded as indicative.

- The impact of curtailment of renewables production is expected to be mitigated by substantial deferrable demands, especially electric vehicle (EV) charging, and heat. The major impact will be from deferral within-day, but if longer periods are possible (such as with EV charging), there could be further substantial benefits.

- Developments in other forms of energy storage could also reduce the impact of curtailment, if economic.

- There are very substantial uncertainties in predicting electricity demand and generation options in 2030.

There are several issues which should be considered by policymakers, to allow further understanding and development of policy in this area:

- Understanding the likely capacity for deferring electricity loads would be very useful, especially EV charging and heat, for periods of 3-4 days (a typical depression cycle, driving wind production), or a week (to take advantage of the reduction in underlying demand at weekends). This should encompass user behaviour and the contractual, regulatory and

[40] As a rough guide, HVDC subsea cable costs including installation are of the order of €1.5M per km for 1000 MW capacity. So the additional costs of a 1000 MW HVDC connection to France rather than GB (at least a further 300 km) will be of the order of €500M.

administrative arrangements by which consumers can be incentivised to achieve substantial demand management.

- The costs and resource size for anaerobic digestion (AD).

- The use of biomass generation capacity including AD in ‘peaking’ rather than baseload operation should be considered. If feasible, this could substitute for some of the gas-fired generation capacity. It is also worth investigating whether the economics of biomass generation compared to gas-fired generation would encourage it to be used in this way.

Further, policymakers should keep abreast of development in energy storage technologies, and interconnector costs.

Cooperation with operators of other electricity systems with low levels of interconnection and high renewables penetration (such as Spain and Portugal) is likely to be beneficial.

8 REFERENCES

1. Irish Government, *National Renewable Energy Action Plan Ireland*. Submitted under Art.4 of Directive 2009/28EC, accessed at http://ec.europa.eu/energy/renewables/transparency_platform/action_plan_en.htm

2. UK Government, *National Renewable Energy Action Plan UK*. Submitted under Article 4 of Directive 2009/28/EC, accessed at http://ec.europa.eu/energy/renewables/transparency_platform/action_plan_en.htm

3. Department of Communications, Energy and Natural Resources (2009). *Maximising Ireland's Energy Efficiency. The National Energy Efficiency Action Plan 2009 – 2020*, accessed at http://www.dcenr.gov.ie/NR/rdonlyres/FC3D76AF-7FF1-483F-81CD-52DCB0C73097/0/NEEAP_full_launch_report.pdf.

4. Department of Communications, Marine and Natural Resources (2007). *Delivering a Sustainable Energy Future for Ireland. The Energy Policy Framework 2007 – 2020*, accessed at http://www.dcenr.gov.ie/Energy/Energy+Planning+Division/Energy+White+Paper.htm.

5. SONI/EirGrid (2010). *All Island Generation Capacity Statement 2011-2020*, accessed at http://www.eirgrid.com/media/GCS%202011-2020%20as%20published%2022%20Dec.pdf.

6. Sustainable Energy Authority Ireland (SEAI) (2010). *Energy Forecasts for Ireland to 2020*, accessed at http://www.seai.ie/Publications/Statistics_Publications/Energy_Modelling_Group/Energy_Forecasts_for_Ireland_to_2020.pdf.

7. SEAI (2008). *Demand Side Management in Ireland. Evaluating the Energy Efficiency Opportunities*, accessed at www.seai.ie/Publications/Energy_Efficiency_Policy_Publications/KEMA_Full_Report.pdf.

8. SEAI (2009). *Energy in Transport*, accessed at http://www.seai.ie/Publications/Statistics_Publications/EPSSU_Publications/Energy_in_Transport/Energy_In_Transport_2009_Report.pdf.

9. EirGrid (2008). *Generation Adequacy Report 2009-2015*, accessed at http://www.eirgrid.com/media/GAR%202009-2015.pdf.

10. EirGrid (2009). *Generation Adequacy Report 2010-2016*, accessed at http://www.eirgrid.com/media/GAR%202010-2016.pdf.

11. Department of Enterprise, Trade and Investment (2010). *Energy. Strategic Energy Framework for Northern Ireland*, accessed at http://www.detini.gov.uk/energy-consultations-31.

12. European Commission/DG Energy (2009). *EU Energy Trends*, accessed at http://ec.europa.eu/energy/observatory/trends_2030/doc/trends_to_2030_update_2009.pdf.

13. Department of Energy and Climate Change (DECC) (2010). *Energy Trends*. December 2010, accessed at http://www.decc.gov.uk/en/content/cms/statistics/publications/trends/trends.aspx.

14. Renewable Energy Directive (28/EC/2009), 23 April 2009.

15. SEAI. *Renewable Energy Resources in Ireland for 2010 and 2020 – a methodology*. 2004, accessed at http://www.seai.ie/Archive1/Files_Misc/REResources20102020MainReport.pdf.

16. SEAI. *Industrial Development Potential of Offshore Wind in Ireland*. GL Garrad Hassan on behalf of SEAI, 2011, accessed at http://www.seai.ie/Renewables/Ocean_Energy/Ocean_Energy_Information_Research/Ocean_Energy_Publications/Offshore_Wind_Study.pdf.

17. SEAI. *Offshore Wind Energy and Industrial Development in the Republic of Ireland*. Risø National Laboratory on behalf of SEAI. 2004, accessed at http://www.seai.ie/Archive1/Files_Misc/Offshore_Wind_Energy.pdf.

18. SEAI. *SEA Scoping Report. Scoping for the Strategic Environmental Assessment on Plans to Develop Offshore Renewable Energy*. 2009, accessed at http://www.seai.ie/Renewables/Ocean_Energy/Strategic_Environmental_Assessment_of_the_OREDP/.

19. SEAI/IMDO. *Assessment of the Irish Ports & Shipping Requirements for the Marine Renewable Energy Industry*. 2011, accessed at http://www.seai.ie/Renewables/Ocean_Energy/Ocean_Energy_Information_Research/Ocean_Energy_Publications/Assessment_of_the_Irish_Shipping_and_Ports_Requirements_for_the_Marine_Renewable_Energy_Industry.pdf.

20. SEAI. *Ocean Energy Roadmap*. 2010, accessed at http://www.seai.ie/Renewables/Ocean_Energy_Roadmap.pdf.

21. Department of Communications, Energy and Natural Resources (DCENR)/Department of Enterprise, Trade and Investment (DETI). *All Island Grid Study. Workstream 1. Renewable Energy Resource Assessment.* ESBI, 2008, accessed at http://www.dcenr.gov.ie/Energy/North-South+Co-operation+in+the+Energy+Sector/All+Island+Electricity+Grid+Study.htm.

22. Marine Institute/SEI. *Accessible Wave Energy Resource Atlas Ireland*. 2005, accessed at http://www.marine.ie/NR/rdonlyres/90ECB08B-A746-4247-A277-7F9231BF2ED2/0/waveatlas.pdf.

23. Marine Institute/SEAI. *Ocean Energy in Ireland. An Ocean Strategy for Ireland* submitted to the Department of Communications, Marine and Natural Resources. 2005, accessed at http://www.marine.ie/NR/rdonlyres/86491414-3E7E-48E5-A0E1-287CA9191C61/0/OceanEnergyStrategy.pdf.

24. SEAI. *Tidal & Current Energy Resources in Ireland*. 2004, accessed at http://www.seai.ie/Publications/Renewables_Publications/Tidal_Current_Energy_Resources_in_Ireland_Report.pdf.

25. Department of Energy Ireland. *Small Scale Hydro-Electric Potential of Ireland*. 1985, on file with author.

26. Action Renewables. *Report on the Potential for Deep Geothermal Energy in Northern Ireland*. 2008, accessed at http://www.detini.gov.uk/deti-energy-index/deti-energy-sustainable/energy-sustainable-8.htm.

27. SEAI web page, http://www.seai.ie/Renewables/Geothermal_Energy/Geothermal_Maps/

28. SEAI. *Energy forecasts for Ireland to 2020. 2011 Report*. Dec 2011, accessed at http://www.seai.ie/Publications/Statistics_Publications/EPSSU_Publications/Energy%20Forecasts%20for%20Ireland%20%20for%202020%20-2011%20Report.pdf

29. WWF UK, *Positive Energy: how renewable electricity can transform the UK by 2030*. Oct 2011, accessed at http://assets.wwf.org.uk/downloads/positive_energy_final_designed.pdf

30. GL Garrad Hassan, *UK generation and demand scenarios for 2030*. Document 108646/GR/02 revision I, Sep 2011, accessed at http://assets.wwf.org.uk/downloads/positive_energy_glgh_technical_report.pdf

31. IEA Wind Implementing Agreement, Task 25, *Design and operation of power systems with large amounts of wind power*. Several reports, see http://www.ieawind.org/AnnexXXV.html

32. IEA, *Harnessing variable renewables – a guide to the balancing challenge*, May 2011. http://www.iea.org/w/bookshop/b.aspx

33. Rogers A, O'Sullivan J, Coughlan P, Kennedy A, *Managing wind penetrations of 50% and higher*, 10th International workshop on large-scale integration of wind power into power systems, Oct 2011. http://www.windintegrationworkshop.org/index.html

34. Speckmann M, Baier A, *Provision of frequency control by wind farms*, 10th International workshop on large-scale integration of wind power into power systems, Oct 2011. http://www.windintegrationworkshop.org/index.html

35. Christensen PW, Tarnowski GC, *Inertia for wind power plants – state of the art review – year 2011*, 10th International workshop on large-scale integration of wind power into power systems, Oct 2011. http://www.windintegrationworkshop.org/index.html

36. Knüppel T et al, *Frequency activated fast power reserve for wind power plant delivered from stored kinetic energy in the wind turbine inertia*, 10th International workshop on large-scale integration of wind power into power systems, Oct 2011. http://www.windintegrationworkshop.org/index.html

37. Nielsen HA et al, *An overview of wind power forecast types and their use in large-scale integration of wind power*, 10th International workshop on large-scale integration of wind power into power systems, Oct 2011. http://www.windintegrationworkshop.org/index.html

38. Revuelta J, *Limits to integration of renewable energy sources. The Spanish experience and challenges*, 10th International workshop on large-scale integration of wind power into power systems, Oct 2011. http://www.windintegrationworkshop.org/index.html

39. Windpower Monthly, November 2011. http://www.windpowermonthly.com/go/wpdaily/article/1103222/?DCMP=EMC-CONwindpowerdaily

40. Department of Energy and Climate Change (DECC), *2050 Pathways Analysis*, accessed at http://www.decc.gov.uk/en/content/cms/tackling/2050/2050.aspx

41. EWIS, *European Wind Integration Study*, April 2010. http://www.wind-integration.eu/downloads/

42. Offshore Grid project, *Offshore electricity infrastructure in Europe, a techno-economic assessment*, Oct 2011. Published by EWEA. http://www.ewea.org/fileadmin/ewea_documents/documents/publications/reports/OffshoreGrid__report.pdf

43. Tradewind study, *Integrating wind – final report*, May 2009. http://www.trade-wind.eu/fileadmin/documents/publications/Final_Report.pdf

44. Pricewaterhouse Coopers/European Climate Forum, *100% renewable electricity – a roadmap to 2050 for Europe and North Africa*, 2010. http://www.pwc.co.uk/eng/publications/100_percent_renewable_electricity.html

45. European Climate Foundation, *Roadmap 2050*, Vol 1, April 2010. http://roadmap2050.eu/attachments/files/Volume1_fullreport_PressPack.pdf

46. SKM, *Offshore grid development for a secure renewable future – a UK perspective*. June 2010, for DECC. Accessed at http://www.decc.gov.uk/assets/decc/what%20we%20do/uk%20energy%20supply/futureelectricitynetworks/800-offshore-grid-development-secure-renewable.pdf

47. Renewable UK, *Working for a Green Britain: Employment and skills in the UK wind and marine industries*. Feb 2011. Accessed at http://www.bwea.com/pdf/publications/Working_for_Green_Britain.pdf

48. Danish Wind Industries Association, *Denmark – wind power hub*, 2009. Accessed at. http://www.e-pages.dk/windpower/21/

49. Bundesministerium für Umweltschutz, *Gross employment from renewable energy in Germany in 2010 – a first estimate*. March 2011. Accessed at http://www.bmu.de/english/renewable_energy/downloads/doc/47242.php

50. UK Energy Research Centre, *Making the transition to a secure and low-carbon energy system: synthesis report*, 2009. http://www.ukerc.ac.uk/Downloads/PDF/U/UKERCEnergy2050/0906UKERC2050.pdf

51. SEAI, *Wind Energy Roadmap*, Dec 2011

52. SEAI, *Bioenergy Roadmap*, Dec 2011

53. Department of Enterprise, Trade and Investment, *Draft Onshore Renewable Electricity Action Plan 2011-2020*, 2011. http://www.nigridenergysea.co.uk/wp-content/uploads/2011/10/Draft-OREAP-Oct-2011.pdf

54. Department of Enterprise, Trade and Investment: *Offshore Renewable Energy StrategicAction Plan 2012-2020*, 2012.

http://www.detini.gov.uk/ni_offshore_renewable_energy_strategic_action_plan_2012-2020__march_2012_.pdf

55. EirGrid, *Grid Code Version 4.0*, Dec 2011. http://www.eirgrid.com/operations/gridcode/

56. Gaelectric Ltd. See http://www.gaelectric.ie/inside.asp?id=3

57. Frost P, Agricultural Research Institute of Northern Ireland, 2005, *Opportunities for anaerobic digester CHP systems to treat municipal and farm wastes*, http://www.afbini.gov.uk/frost-2005-anaerobic-digestion-chapter7.pdf

58. Joint Committee on Communications, Energy and Natural Resources, 2011, *Fourth report: The development of Anaerobic Digestion in Ireland*, http://www.oireachtas.ie/viewdoc.asp?DocID=17463&CatID=78

59. EirGrid, *Delivering a Secure Sustainable Electricity System*, http://www.eirgrid.com/operations/ds3/

60. SONI Grid Code 2012, http://www.soni.ltd.uk/upload/SONI%20Grid%20Code%20-%2020%20July%202012.pdf

61. EirGrid 2011, *Offshore Grid Study: Executive Report*, http://www.eirgrid.com/media/EirGrid%20Offshore%20Grid%20Study.pdf

APPENDIX 1

CALCULATION OF RENEWABLES PRODUCTION

The output of renewables is calculated in the table. Capacity factors assumed are as in Table 4.4.

Technology	**Capacity [MW] – Central demand scenario**	**Production [TWh] – Central demand scenario**	**Capacity [MW] – Ambitious demand scenario**	**Production [TWh] – Ambitious demand scenario**
Onshore wind	4,000	10.5	4,000	10.5
Offshore wind	3,700	14.0	2,700	10.2
Wave	1,000	2.2	400	0.9
Tidal stream	700	2.5	700	2.5
Sustainable biomass	400	3.2	400	3.2
Hydro	300	1.0	300	1.0
Totals	**10,100**	**33.4**	**8,500**	**28.3**

APPENDIX 2

INDICATIVE MIX OF GAS GENERATION

An indicative mix of gas generation is defined in the table for each scenario. This mix is chosen to match the required total capacity and energy production, and to meet the limit of 50 gCO_2/kWh. Other alternative mixes that meet these aims are of course also possible, though the end results will not be markedly different.

Case A: conventional generation capacity

1. Central demand scenario

Gas generation technology	Emissions intensity [kt/TWh]	Capacity [GW]	Assumed CF	Production [TWh]	Emissions [MT CO_2]	Net emission intensity [kt/TWh]
OCGT	440	6.2	0.07	3.8	1.67	
CCGT without CCS	376	0	0.5	0	0	
CCGT with CCS	38	1.7	0.6	8.94	0.34	
Totals		7.9		12.74	2.01	43.7

2. Ambitious demand scenario

Gas generation technology	Emissions intensity [kt/TWh]	Capacity [GW]	Assumed CF	Production [TWh]	Emissions [MT CO_2]	Net emission intensity [kt/TWh]
OCGT	440	5.2	0.07	3.2	1.4	
CCGT without CCS	376	0	0.5	0	0	
CCGT with CCS	38	1.2	0.51	5.4	0.2	
Totals		6.4		8.6	1.6	43.5

Case B: additional 1000 MW interconnection capacity to GB

1. Central demand scenario

Gas generation technology	Emissions intensity [kt/TWh]	Capacity [GW]	Assumed CF	Production [TWh]	Emissions [MT CO_2]	Net emission intensity [kt/TWh]
OCGT	440	6.4	0.04	2.2	1.0	
CCGT without CCS	376	0.5	0.6	2.6	1.0	
CCGT with CCS	38	1.0	0.6	5.3	0.2	
Totals		7.9		10.1	2.2	47.2

2. Ambitious demand scenario

Gas generation technology	Emissions intensity [kt/TWh]	Capacity [GW]	Assumed CF	Production [TWh]	Emissions [MT CO_2]	Net emission intensity [kt/TWh]
OCGT	440	5.4	0.038	1.8	0.79	
CCGT without CCS	376	0.6	0.4	2.1	0.79	
CCGT with CCS	38	0.4	0.6	2.1	0.08	
Totals		6.4		6.0	1.66	45.0

Case C: additional 1000 MW interconnection capacity to continental Europe

1. Central demand scenario

Gas generation technology	Emissions intensity [kt/TWh]	Capacity [GW]	Assumed CF	Production [TWh]	Emissions [MT CO_2]	Net emission intensity [kt/TWh]
OCGT	440	5.9	0.09	4.7	2.05	
CCGT without CCS	376	0	0.6	0	0	
CCGT with CCS	38	1.0	0.62	5.4	0.20	
Totals		6.9		10.1	2.25	48.9

2. Ambitious demand scenario

Gas generation technology	Emissions intensity [kt/TWh]	Capacity [GW]	Assumed CF	Production [TWh]	Emissions [MT CO_2]	Net emission intensity [kt/TWh]
OCGT	440	4.6	0.045	1.8	0.80	
CCGT without CCS	376	0.5	0.6	2.6	0.99	
CCGT with CCS	38	0.3	0.6	1.6	0.06	
Totals		5.4		6.0	1.85	50.0

APPENDIX 3

ESTIMATION OF EMPLOYMENT EFFECTS

Employment effects are best estimated by comparison with experience from the renewables industries in other countries. Comparison with other industries is likely to give misleading results, because of the relative immaturity of the renewables industries, and their specific characteristics (for example, the concentration of wind turbine manufacturing in a few countries).

Onshore and offshore wind

Information on employment is available for Denmark [48], Germany [49] and Spain. However, these countries have large wind turbine manufacturing industries, with significant exports. Therefore, the figures cannot be applied to the case of Ireland.

The most relevant experience is for the UK, which currently has no substantial wind turbine manufacturing industry. Employment there is in project development, construction, operation and maintenance, which is similar to the likely future profile of onshore wind energy on the island of Ireland.

The UK wind and marine trade body, Renewable UK, published an analysis of employment in wind and marine energy in 2010 [47]. This showed 6,000 direct jobs (Full Time Equivalent, FTE) in onshore wind and 3,100 in offshore wind. Using information from other studies, a figure of 1.8 can be applied to scale up to include indirect jobs, resulting in a figure of 16,380 FTE.

When scaled by the wind capacity in the UK, the result is a figure of 3 FTE per MW of cumulative installed capacity, or 17 FTE per MW of additional capacity installed in the year. The first figure is more relevant to analysis of long-term development of employment in Ireland.

Wave and tidal stream

No satisfactory information exists. The Renewable UK study [47] included marine energy, and reports over 800 FTEs in the UK in 2010. However, the current activity in wave and tidal stream energy in the UK cannot be considered to be representative of a mature industry, as is shown by the finding that around one third of the jobs are in 'support services/other'.

Therefore in this analysis it is assumed that mature wave and tidal stream industries would have employment effects similar to offshore wind. The environment and unit sizes are similar.

Hydro

Very little further development of hydro in Ireland is expected, so employment effects are ignored.

Biomass

No satisfactory information on biomass employment has been found. Biomass as baseload displaces the requirement for an equivalent amount of conventional generation capacity, with a similar requirement for operational and maintenance staff, so the employment effects are limited to the fuel production and handling.

As a relatively small biomass capacity is assumed in this study, employment effects are ignored.