ALL ISLAND GRID STUDY

WORKSTREAM 2A

HIGH LEVEL ASSESSMENT OF SUITABLE GENERATION PORTFOLIOS FOR THE ALL-ISLAND SYSTEM IN 2020

January 2008

Department of Communications, Energy and Natural Resources
Roinn Cumarsáide, Fuinnimh agus Acmhainní Nádúrtha

Department of Enterprise, Trade and Investment
www.detini.gov.uk

A Report to

The Department of Enterprise, Trade and Investment

And

The Department of Communications, Energy and Natural Resources

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1. THE ALL-ISLAND GRID STUDY

1.1 This report describes the results of work-stream 2A of the All-Island grid study. The task of this work-stream is to make a high level assessment of suitable generation portfolios of the All-Island system in 2020. Work-stream 2A is one of several interacting studies undertaken as part of the All-Island grid study.

The All-Island Grid Study

1.2 The All Island Grid Study is the first comprehensive assessment of the ability of the electricity transmission network ("the grid") on the island of Ireland to absorb large amounts of electricity produced from renewable energy sources.

1.3 On July 25th 2005 the then Department of Communications, Marine and Natural Resources in the Republic of Ireland and the Department of Enterprise, Trade and Investment in Northern Ireland jointly issued a preliminary consultation paper on an all-island '2020 Vision' for renewable energy. The paper sought views on the development of a joint strategy for the provision of renewable energy sourced electricity within the All-island Energy Market leading up to 2020 and beyond, so that consumers, North and South, continue to benefit from access to sustainable energy supplies provided at a competitive cost.

1.4 It is within the context of the All-island Energy Market Development Framework agreed by Ministers and the undertaking to develop a Single Electricity Market that consideration was given to how the electricity infrastructure on the island might best develop to allow the maximum penetration of renewable energy.

1.5 A working group was established to specify and oversee the undertaking of studies that would provide more detailed information on the above issues. The working group recommended an "All Island Grid Study" comprised of 4 work-streams detailed below.

- Workstream 1 is a resource assessment study.

- Workstream 2 investigates the extent to which electricity generated from renewable energy sources can be accommodated on the grid system with regard to variability and predictability.

  This work study comprises two stages:

  (a) an initial high level modelling study to determine the portfolios to be studied.

- (b) a detailed modelling study of the impact of renewable generation on grid operation, costs and emissions.

- Workstream 3 looks at the engineering implications for the grid, in terms of the extent and cost of likely network reinforcements to accommodate the specified renewable inputs.

- Workstream 4 uses the outputs of earlier work streams to investigate the relative economic impact and benefits of various renewable generation levels for society as a whole. It also investigates the impacts on various stakeholder groups. It is the summary report which presents high-level results for policy makers.

Role of Work-stream 2A

1.6 The All-Island grid study was originally conceived without work-stream 2A. Initially it was proposed to examine the issues in work-streams 1-4 with a set of base renewable energy penetration scenarios ranging from 15 – 30%. These scenarios were presented at a public consultation in Dublin on the 22nd of November. Feedback was received from the public consultation questioning the basis and suitability of initial renewable energy scenarios. Some of the criticisms received were that there was no basis to how the scenarios were derived, that it may prove difficult to interpolate and extrapolate from results based on the scenarios and that that there were no higher renewable energy scenarios than 30%.

1.7 As a response to the feedback about the initial renewable energy scenarios the All-Island grid study working group decided the establish work-stream 2A. The work-stream is intended to explore in greater detail the make-up of a range of candidate generation portfolios for the All-Island system in 2020. The work-stream investigates not only renewable generation penetration but also the make-up of suitable complementary conventional generation in portfolios. It also examines the external factors, such as fuel prices which favour various generation portfolios. This analysis is intended to inform at a high level, a set of suitable scenarios to better frame the issues which must be addressed in the other work-streams of the All-Island grid study. The analysis also provides high level insight into generation planning and policy issues on the All-Island system.

Structure of this report

1.8 Section 2 gives a brief overview of the study. The approach taken to the work is outlined and some details of the methodologies used are introduced.

1.9 Section 3 details the inputs and assumptions used and also outlines the scenarios examined in the study.

1.10 Section 4 investigates and illustrates the relative effect that key factors have on the make-up of the least-cost generation portfolios.

1.11 Section 5 proposes five separate generation portfolios for the All-Island system in 2020 which are deemed suitable for further examination in the other work-streams of the All-Island grid study.

1.12 Some conclusions are given in Section 6.

1.13 The report contains four annexes:

- Annex A acknowledges the valuable contributions and inputs made to this work by a range of stakeholders.
- Annex B describes the capacity credit calculation used in this study.
- Annex C gives the formulation of the least-cost portfolio optimisation algorithm used in this study.
- Annex D formally gives the details of the 5 generation portfolios selected for use in the other work-streams of the All-Island grid study.

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2. WORK-STREAM 2A OVERVIEW

2.1 The aim of this study is to examine the range of candidate generation portfolios for the All-Island system in 2020. This task requires assessing generation portfolios for a range of influencing external factors such as fuel price and carbon cost. The role of renewable generation in the resulting least-cost portfolios is assessed and a suite of suitable generation portfolios are selected for further investigation in the other work-streams of the All-Island grid study.

2.2 To achieve this objective, the study utilises a least-cost generation portfolio optimisation algorithm developed by the author in the Electricity Research Centre, University College Dublin. Details of this methodology have been published in several places[1,2,3]. The methodology assesses the key high level factors which affect cost of electricity using a linear programming algorithm. This algorithm optimises the least-cost generation portfolio for the given conditions for a single year, in this case 2020.

2.3 The problem addressed in this study is subtly different and focused at a slightly higher level than a more conventional 5 to 10 year generation expansion problem. Established generation expansion software such as WASP[4] can be computationally intensive and models in a detailed way generation outage and dispatch features. The least-cost portfolio algorithm employed here uses simpler outage and dispatch approximations with the resulting benefit being a more flexible tool for the execution of multiple simulations to capture the large range of uncertainty surrounding many key inputs in 2020. The least-cost algorithm used here has also been developed specifically to handle the unique features of wind generation which is likely to be a significant contributor to the All-Island generation mix by 2020. Established generation expansion packages which have been developed around traditional thermal, hydro and nuclear generation options generally do not account for the features of wind generation.

2.4 The work in this study does not purport to produce the definitive least-cost generation portfolios to a precise resolution but rather assesses at a higher level the likely role of various generation options in desirable generation portfolio on the all island system in 2020. Assessments of the impact of key features such as fuel price and carbon costs on the resultant least-cost generation mix is undertaken

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[1] Doherty, R., Outhred H. and O'Malley, M., 2006, "Establishing the role that wind generation may have in future generation portfolios ", *IEEE Transactions on Power Systems*, (*in press*).

[2] Doherty, R., 2005, "New Methods for Planning and Operating Modern Electricity Systems with Significant Wind Generation", Ph.D. Thesis, University College Dublin.

[3] Doherty, R., Outhred H. and O'Malley, M., 2005, "Generation portfolio analysis for a carbon constrained and uncertain future", Proceedings of the International Conference on Future Power Systems, Amsterdam.

[4] International Atomic Energy Agency, 2001, "Wien Automatic System Planning (WASP), Package - A Computer Code for Power Generating System Expansion Planning", [Online] Available: http://www-pub.iaea.org/MTCD/publications/PDF/CMS-16.pdf

to better understand the extent of the role that renewable energy will play in desirable generation portfolios in 2020.

Features Included in the Analysis

2.5 The analysis attempts to include all the relevant features of the All-Island system in 2020. These include:

- Existing generation assumed to be still operational in 2020
- Annuitised capital costs & yearly operation and maintenance costs
- Fuel costs
- System generation adequacy
- Load growth to 2020 and load duration characteristics
- Unit merit order, unit utilisation and unit availability
- CO_2 emissions and costs
- Wind characteristics
- Network costs
- Reserve costs
- Wind generation curtailment
- Start-up costs and ramping costs
- Additional societal benefits of renewable energy

2.6 Further details of the values and assumptions made in relation to these features are given in Section 3 of the report and the formulation of the linear programming algorithm is included in Annex C.

Scenario Development and Sensitivities

2.7 The uncertainty that surrounds key factors such as future fuel price and carbon costs are probably the most challenging of the issues surrounding modern long term generation planning and policy. In recognition of this a large range of scenarios are examined in the analysis to account for aspects with which there is deemed to be a significant amount of uncertainty. In the analysis, the least-cost generation portfolio algorithm is run for all combinations of these uncertain factors within what is deemed appropriate ranges. The uncertain factors examined here are:

- Future gas prices
- Future cost of carbon in the European emission trading scheme
- Future wind turbine costs
- Weighted average cost of capital (WACC)
- The appetite for future investment in coal, lignite and peat generation
- The value placed by government on the additional benefits of renewable energy

2.8 Further details and the rationale for the range of values examined for these factors are given in Section 3

2.9 CO_2 emissions from the electricity generation sector are currently of concern to many countries. Each country may have separate emission reduction obligations under European and international agreements. The incentives to reduce emissions are dealt within this analysis solely using a European traded cost of carbon as a signal. This assumes that by 2020 the European emissions trading scheme will have established itself as the main mechanism for European countries to trade and provide cost reflective signals to its industries as to the value of CO_2 reductions. This assumption allows CO_2 emissions incentives to be treated uniformly across both the Republic of Ireland and Northern Ireland in the study. In the event that the European emission trading scheme fails to establish itself as envisaged here, the cost of carbon in this analysis acts as a proxy of the governments' willingness or necessity to reduce CO_2 emissions due to an alternative signal.

Structure of Analysis and Creation of Results

2.10 Figure 2-1 shows a broad outline of the structure of the analysis undertaken in this work. Information relating to the existing generation, load duration and system characteristics is fed, along with the costs and characteristics of new generation options, into the least-cost portfolio optimisation algorithm. For a given combination of uncertain factors the least-cost generation portfolio is found and stored in the results database. This process is repeated for all possible combinations of uncertain input factors over the relevant ranges examined. The database of results is then analysed to examine the range of different least-cost generation portfolio produced. The impact of altering each uncertain input factor on the resulting portfolios is also assessed. From the database of least-cost generation portfolios five suitable portfolios are selected for further analysis in the other work-streams of the All-Island grid study.

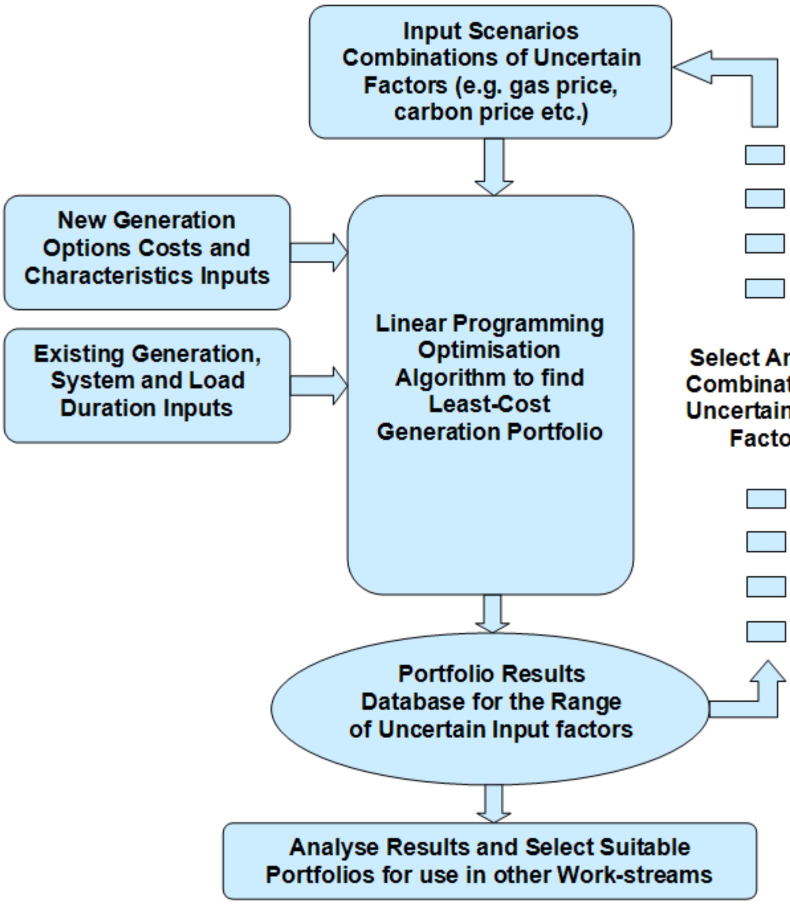

Figure 2-1. Structure of analysis undertaken

Limitations to the Analysis

2.11 The aim of this study is to examine the range of candidate generation portfolios for the All-Island system in 2020. This task requires high level analysis of the electricity system and the incorporation of the uncertainty associated with important external factors. It is thought that the analysis adopted here incorporates an appropriate and proportional level of detail with respect to what the study aims to achieve. However, as with any analysis of a highly complex system, the analysis here has limitations. Some of these limitations are as follows:

- The analysis focuses on least-cost generation portfolios for a single year and ignores any complexities involved with the evolution of the generation portfolio prior to 2020.
- The analysis is also based on a single year of wind output data.
- In the analysis the generation costs and carbon dioxide emission are based on the average efficiency of the units.
- The analysis here does not include a dispatch model for each hour but rather approximates the utilisation of the generation capacity based on a generation merit order and the system's load duration characteristics.
- The analysis does not explicitly cater for the variable nature of other renewable sources such as tidal, wave and photovoltaic.
- Average unit availability is used in the analysis, and the effect of simultaneous plant outages on the utilisation high merit plant is not included.
- Since a chronological dispatch model is not used, approximations of reserve, start-up and ramping costs have been included based on the best available information. The effect of increasing renewable generation on these costs and other costs such as network costs is not yet fully understood. These features are subject to more detailed analysis in work-streams 2B and 3.

Assessment of Least-Cost Portfolio Results

2.12 Section 4 of the report outlines examples of least-cost generation portfolios for the All-Island system in 2020. Section 4 presents a series of graphs and portfolios attempting to illustrate the effect varying each uncertain factor can have on the least-cost generation portfolio. The results from the sensitivity analysis show that the changes in the uncertain factors results in significant differences in the make up of the least-cost portfolios, specifically in relation to the levels of coal and renewable generation.

2.13 The study examines the impact of various factors on least-cost generation portfolios. Many of these factors were found to have a similar effect on the resultant least-cost generation portfolios. Examining the set of resultant least-cost generation portfolios produced for the various scenarios, provides insight into the range and variation of suitable generation portfolios for the All-Island system in 2020.

2.14 This work defines appropriate ranges over which the external factors will be examined. However, this work does not focus on providing forecasts or quantifying the likelihood of various factors taking up specific values within the ranges examined. The results in Section 4 however, do illustrate that the gas and carbon prices have the most significant impact on the make-up of the least-cost generation portfolios over the ranges examined.

Suitable Generation Portfolios for Examination within the All-Island Grid Study

2.15 Section 5 presents five generation portfolios which, after consultation with the All-Island grid study working group, were deemed suitable as a basis for the work carried out in the other work-streams. It is believed that these portfolios suitably represent the range of possible renewable energy penetrations on the All-Island system by 2020. It is believed that these portfolios also explore a suitable mix of the renewable generation technologies and the possible mix of conventional generation likely by 2020.

2.16 Some conclusions of the work are given in Section 6 and the complete generation portfolios for use in the other work-streams are detailed in Annex D

3. INPUTS AND SCENARIOS

Inputs

3.1 This section describes the various inputs and assumptions made for this work. Given here are the details of assumed existing generation in 2020, the assumed new generation options, their costs and characteristics, load growth to 2020 and other system assumptions.

3.2 All costs, prices and values in this section are expressed in current monetary value, € 2006.

Existing Generation in 2020

3.3 After consultation with the two system operators and the All-Island grid study working group, a set of existing generators assumed to be in operation in 2020 was chosen. This set of generators is shown in Table 3-1. It is assumed that there is 6106 MW of existing conventional generation and hydro capacity still available in 2020.

3.4 It was assumed that there would be a further 500 MW of interconnection to the Great Britain system by 2020, making a total of 1000 MW of interconnection between the two systems.

3.5 Prospective new generation projects which may be developed in the short-term such as the proposed new combined-cycle unit at Hunstown and other possible new generation facilities in the south were not included in the analysis here.

3.6 In early 2006 there was 600 MW of wind generation and other renewable generation connected to the All-Island electricity system. This capacity is not included directly in Table 3-1 but is considered later in the analysis.

Table 3-1. Existing plant assumed to be available in on the All-Island system in 2020

Code	Unit	Capacity (MW)	Code	Unit	Capacity (MW)
AD1	Aghada Unit 1	258	PBC	Poolbeg Combined Cycle	480
AA1	Ardnacrusha Unit 1	21	RH1	Rhode Unit 1	52
AA2	Ardnacrusha Unit 2	22	RH2	Rhode Unit 2	52
AA3	Ardnacrusha Unit 3	19	TP1	Asahi Peaking Unit	52
AA4	Ardnacrusha Unit 4	24	SK1	Aughinish (Sealrock)	150
DBP	Dublin Bay Power	396	TE	Tynagh	404
ED1	Edenderry	117.6	TH1	Turlough Hill Unit 1	73
ER1	Erne Unit 1	10	TH2	Turlough Hill Unit 2	73
ER2	Erne Unit 2	10	TH3	Turlough Hill Unit 3	73
ER3	Erne Unit 3	22.5	TH4	Turlough Hill Unit 4	73
ER4	Erne Unit 4	22.5	WO4	West Offaly Power	137
LE1	Lee Unit 1	15	B31	Ballylumford CCGT 31	240
LE2	Lee Unit 2	4	B32	Ballylumford Unit 32	240
LE3	Lee Unit 3	8	B10	Ballylumford Unit 10	103
LI1	Liffey Unit 1	15	BGT1	Ballylumford GT1	53
LI2	Liffey Unit 2	15	BGT2	Ballylumford GT2	53
LI4	Liffey Unit 4	4	CPS CCGT	Coolkeeragh CCGT	404
LI5	Liffey Unit 5	4	CGT8	Coolkeeragh GT8	53
LR4	Lough Ree	91	K1	Kilroot Unit 1	201
HNC	Huntstown	342.7	K2	Kilroot Unit 2	201
MRT	Marina CC	112.29	KGT1	Kilroot GT1	29
MP1	Moneypoint Unit 1	282.5	KGT2	Kilroot GT2	29
MP2	Moneypoint Unit 2	282.5	Inter 1	Interconnector	500
MP3	Moneypoint Unit 3	282.5	Inter 2	Interconnector*	500

* second interconnector expected to be present in 2020

New Thermal Generation Options

3.7 After a review of the new thermal generation options, a list of credible new generation options were compiled. Oil fired generation, gas fired steam units, nuclear and coal fired integrated gasification combined cycle were all assumed to be either too expensive or not credible generation options on the island by 2020. The generation options, their cost and characteristics are shown in Table 3-2. These were compiled from a range of sources [5,6,7,8].

3.8 CO_2 emissions are expressed in tonnes of CO_2 per MWh generated. This is based on the typical carbon content of the fuels and the average efficiency of the plant.

Table 3-2. New thermal generation options, costs and characteristics

Generation Option	Coal 1	Coal 2	Lignite	Peat	CCGT	OCGT	ADGT
Max Size of Option (MW Installed)	1550	n/a	550	700	n/a	n/a	n/a
Plant Life (Years)	30	30	30	30	15	15	15
Build Time (Years)	4	4	4	4	2.5	1.5	1.5
Average Efficiency (%)	40	40	40	40	54	34	43
Capital Cost (€/MW Installed)	1,981,000	2,006,000	1,871,000	1,689,000	731,070	400,000	500,000
Op, Main and Network (€/MW p.a.)	43,811	55,750	72,697	55,000	46,000	36,000	40,000
CO2 Emissions (Tonne / MWh)	0.86	0.86	0.99	1.11	0.36	0.58	0.46
Averge Availability (%)	84	84	84	84	88	88	88

3.9 ***Coal 1* -** This option relates to the possibility of expanding the coal generation facility at Moneypoint by 1550 MW to a total capacity of 2400 MW. The efficiency of 40 % accounts for the extra load of flue gas desulphurisation. It is assumed that a €150 million port extension and new coal handling facilities will have to be developed. This is reflected in the capital cost. It is taken that the operation and maintenance cost is €35,000 per MW installed per year. It is assumed that a new 400kV line and other network facilities will have to be developed at a cost of €200 million. It is assumed that this cost is recovered over 30 years by the transmission asset owner with a rate of return of 5.63 %[9]. This cost is reflected in the operation, maintenance and network costs given in Table 3-2.

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[5] Royal Academy of Engineering, 2004, “The Costs of Generating Electricity”. [Online] Available: www.raeng.org.uk

[6] Commission for Energy Regulation, 2005, “Best New Entrant Price 2006”, [Online] Available: http://www.cer.ie

[7] General Electric – Energy, 2004, “New High Efficiency Simple Cycle Gas Turbine- GE’s LMS 100”, [Online] Available: http://www.gepower.com/home/index.htm

[8] ESBI – Gay Nolan, 2005, - *Personal Communication.*

[9] Commission for Energy Regulation, 2005, “2006-2010 Transmission Price Control Review”, [Online] Available: http://www.cer.ie

3.10 ***Coal 2*** **-** This option relates to the possibility of building any number of new coal facilities. It is assumed that a €150 million port and new coal handling facilities will have to be developed per 1000 MW. This is reflected in the capital cost. It is assumed that new 400kV transmission lines and other network facilities will have to be developed at a cost of €300 million per 1000 MW installed. This cost is again reflected in the operation, maintenance and network costs given in Table 3-2.

3.11 ***Lignite*** **-** This option relates to the possibility of building a 550 MW lignite plant and open cast mine in Ballymoney county Antrim. The plant is assumed to use fluidised bed technology with a cost of €1,689,000 per MW installed. The capital costs shown include an initial €100 million capital spend on the mine[10]. Operation maintenance costs are assumed to be €55,000 per MW installed per year. The operation, maintenance and network cost shown include further capital spend on the mine of €50 million over 30 years, and €100 million in network costs recovered over 30 years by the transmission asset owner with a rate of return of 5.63%.

3.12 ***Peat*** **-** This option relates to the possibility of building up to another 700 MW of peat plant. The plant is assumed to use fluidised bed technology and it is assumed that large deep network developments will not be necessary.

3.13 ***CCGT*** **-** This option relates to the possibility of building any number of combined cycle gas turbines on the island. The costs assumed here are similar to those in the CER best new entrant paper[11]. It is assumed that no significant deep network developments are necessary with this generation option.

3.14 ***OCGT*** **-** This option relates to the possibility of building any number of open cycle gas turbines on the island. It is assumed that no significant network developments are necessary with this generation option.

3.15 ***ADGT*** **-** This option relates to the possibility of building any number of aero derivative gas turbines on the island. This generation option is based on the General Electric LMS-100 plant which has a higher efficiency and capital cost than a standard gas turbine[12]. It is assumed that no significant network developments are necessary with this generation option.

[10] AuIron Energy, 2003 “Ballymoney Power – The Vision”, *Presentation*.

[11] Commission for Energy Regulation, 2005, “Best New Entrant Price 2006”, [Online] Available: http://www.cer.ie

[12] General Electric – Energy, 2004, “New High Efficiency Simple Cycle Gas Turbine- GE’s LMS 100”, [Online] Available: http://www.gepower.com/home/index.htm

3.16 As an illustration the cost of electricity from the new thermal generation options is shown Figure 3-1. Costs are shown for full load generation for maximum availability. The illustration assumes a Weighted Average Cost of Capital (WACC) of 8%, carbon price of 30 €/MWh and the following fuel prices: gas price = 6.55 €/GJ, coal price = 1.26 €/GJ, peat price of 3.57 €/GJ, lignite price of 0.77 €/GJ

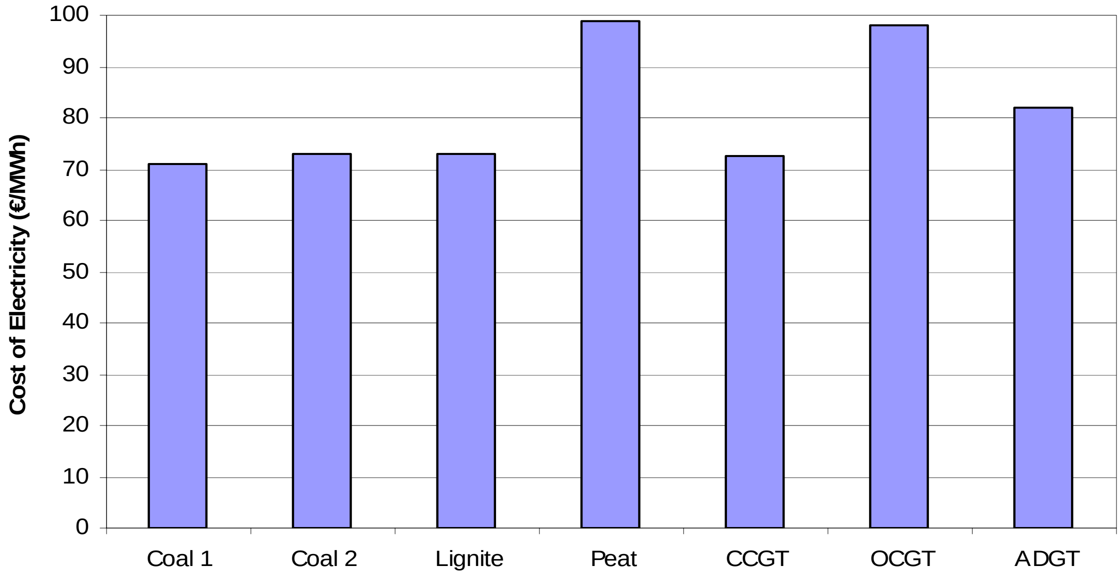

Figure 3-1. Cost of electricity illustration for new thermal generation options

Wind Generation Inputs and Assumptions

3.17 ***Capital Costs -*** The average cost of wind turbines increased by approximately 30% during 2005. This was mainly due a significant increase in global demand without a significant increase in manufacturing capability. It is likely, however, that manufacturing capacity will improve with respect to demand in the medium to long term. These events and other forecasts which predict a reduction in turbine costs highlight the uncertainly that surrounds wind generation costs in 2020. Therefore, it was decided to look at two wind cost scenarios. Both wind cost scenarios are based on on-shore wind development.

3.18 ***High Cost Scenario -*** This scenario uses the long term wind turbine costs similar to those in early 2005. This assumes that there will be no real cost reductions due to further technology advances, but that manufacturing capacity will keep up reasonably with demand. Here, capital costs are assumed to be €1.3 million per MW installed. This includes dedicated network asset costs. Operation and maintenance costs are assumed to be € 35,000 per MW per year. With a capacity factor of 0.345, a WACC of 8% and a plant life of 20 years, electricity cost would be 59 €/MWh in € 2006.

3.19 ***Low Cost Scenario -*** This scenario assumes that there will be cost reductions due to further technology advances by 2020 and that manufacturing capacity will keep up reasonably with demand. Here capital costs are assumed to be €1 million per MW installed. This includes dedicated network asset costs. Operation and maintenance costs are again assumed to be € 35,000 per MW per year. With a capacity factor of 0.345, a WACC of 8% and a plant life of 20 years, electricity cost would be 48 €/MWh.

3.20 ***On-Shore Vs Off-Shore -*** Off-shore wind generation technology has not matured to the same extent as the on-shore option and off-shore wind generation costs are not explicitly considered in the costs assumed here. Off-shore costs are generally accepted to be somewhat higher than on-shore, however, there are indications that developments in offshore technologies and project contracting are bringing these costs down. It may be the case, given the higher capacity factors available off-shore, that off-shore generation may be competitive with on-shore by 2020. If this is the case the costs assumed here can represent both on-shore and off-shore options.

3.21 ***Wind Profiles -*** The wind profiles used in this work are based on those used in a 2004 SEI report[13]. The wind profiles are based on real data grown to incorporate the effects and limits of geographical diversity on the All-Island system.

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[13] Sustainable Energy Ireland, 2004, "Operating Reserve Requirements as Wind Power Penetration Increases in the Irish Electricity System", [Online] Available: http://www.sei.ie

3.22 ***Capacity Factor -*** This study considers up to 9500 MW of installed wind generation on the island. Based on resource assessments[14] the assumed capacity factor of the wind generation versus the installed capacity is shown in Figure 3-2. The capacity factors shown do not include the possible impact of curtailment for system reasons.

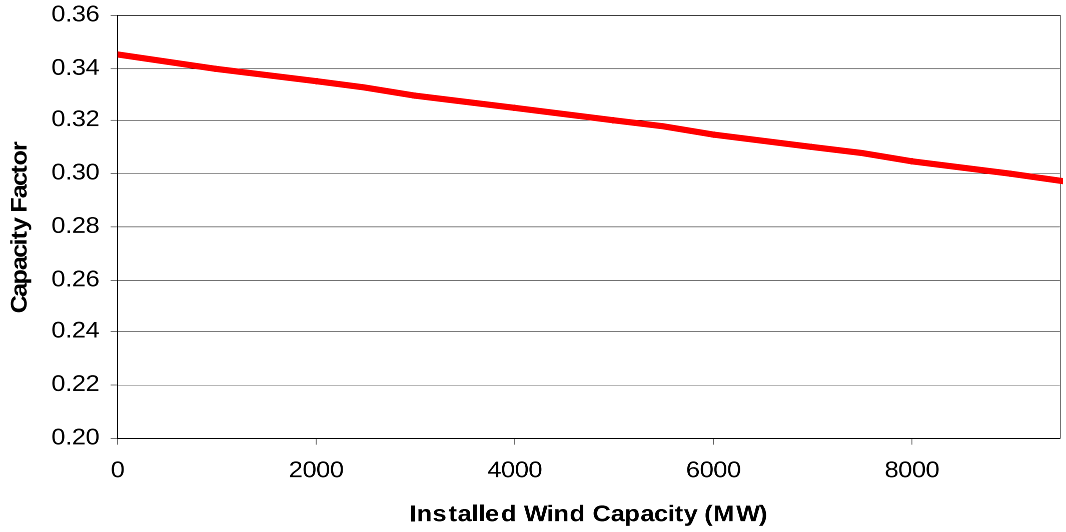

Figure 3-2. Wind generation capacity factor versus installed wind capacity

[14] Sustainable Energy Ireland, 2004, "Renewable Energy Resources in Ireland for 2010 and 2020 – A Methodology" [Online] Available: http://www.sei.ie

3.23 ***Deep Network Reinforcement Costs*** - It is envisaged that high penetrations of wind capacity may result in the need for greater deep network reinforcement. In the future more innovative network development methods considering the stochastic nature of the wind generation may mean that the deep network cost of wind generation may be less than envisaged now. Network development strategies and costs is the subject of work-stream 3 of the All-Island grid study, however, it is necessary for this work to make a preliminary assumption about these costs. After consultation with the two system operators the deep network reinforcement costs of wind generation, as illustrated in Figure 3-3 were assumed.

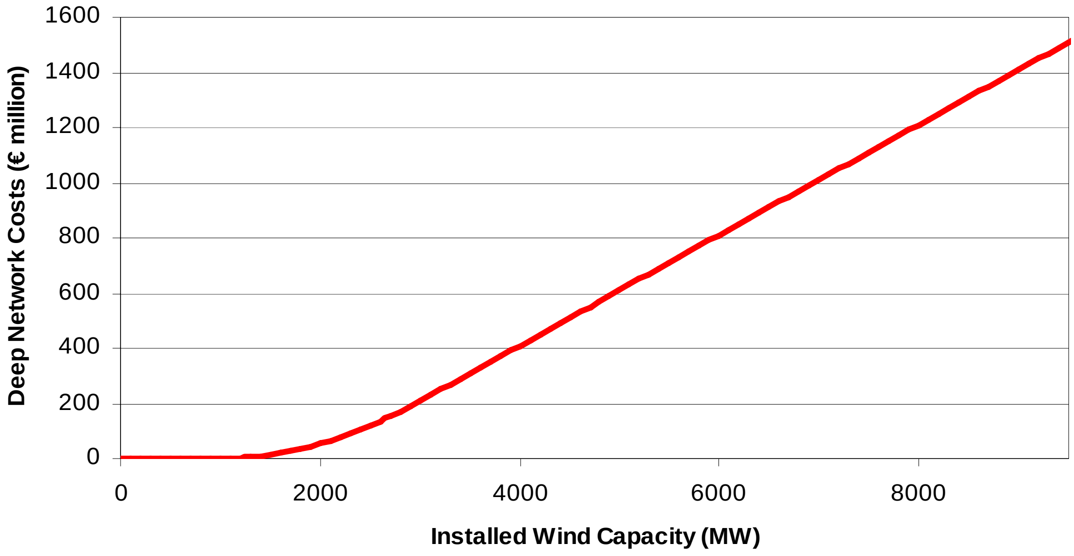

Figure 3-3. Assumed network reinforcement costs versus installed wind capacity

3.24 ***Wind Variability and Uncertainty System Costs*** **-** These costs will be the subject of detailed analysis in work-stream 2B of the All-Island grid study. However, an initial estimate of the costs is made here based on the best available information. Figure 3-4 shows the results from two previous studies. The first was carried out for SEI by a consortium lead by ILEX energy consulting[15].The second study was undertaken by Garth Bryans in the Electricity Research Centre, UCD using Plexos unit commitment software[16]. The assumed wind management costs used for this work are shown in green in Figure 3-4 and are based on results from the other studies with allowances made for the known shortcomings of each study.

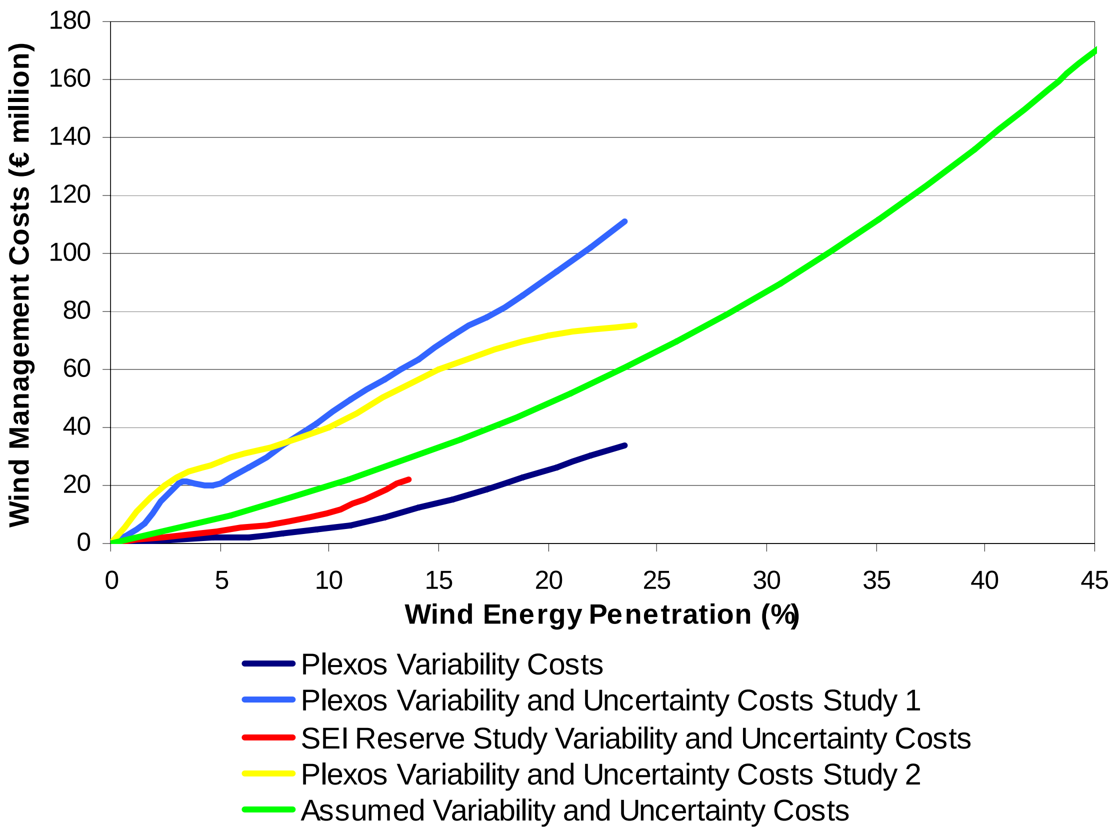

Figure 3-4. Wind variability and uncertainty costs versus wind energy penetration

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[15] Sustainable Energy Ireland, 2004, "Operating Reserve Requirements as Wind Power Penetration Increases in the Irish Electricity System", [Online] Available: http://www.sei.ie

[16] Bryans, A.G., Fox, B, O'Malley, M. and Crossley, P., 2006, "The Predictability and Variability Effects of Renewable Generation", (*in review*).

3.25 To illustrate the relative effect on overall cost of the assumed capacity factors, network costs and wind management costs, Figure 3-5 shows the generation costs for the high wind turbine cost scenario with the above factors taken into account.

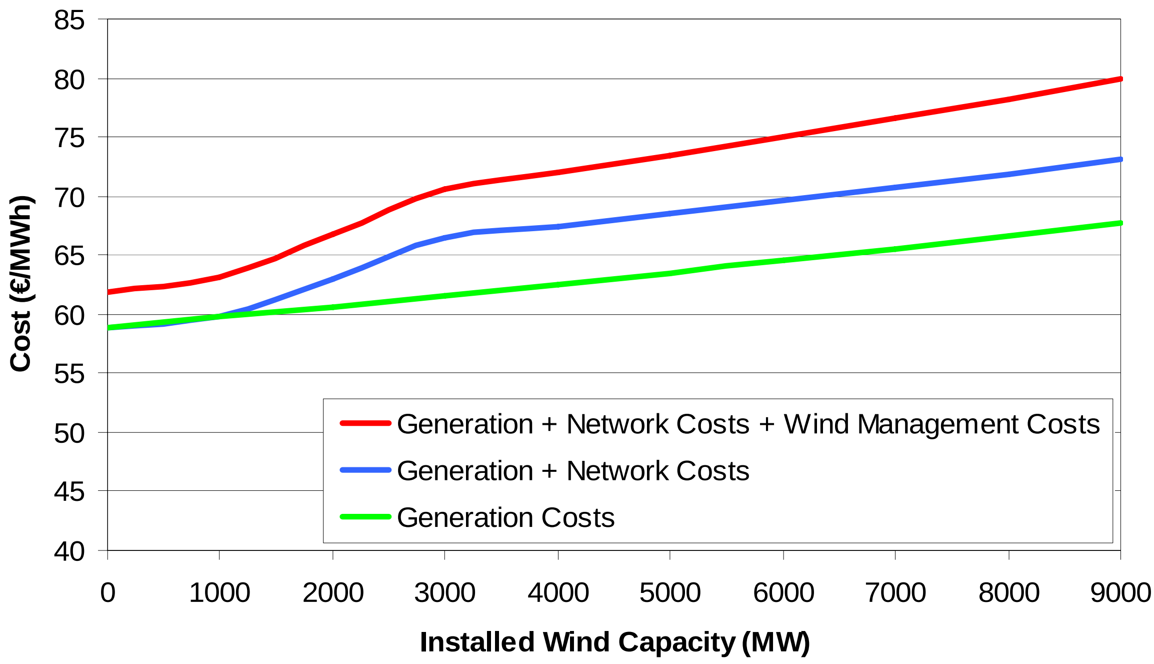

Figure 3-5. Wind generation costs versus wind generation capacity including effect of capacity factor, network costs and wind management costs assumptions.

3.26 ***Curtailment* -** With high penetrations of wind generation it is conceivable that generation may have to be curtailed from time to time. However, given that wind generation has basically a zero incremental energy cost then the only valid reason for curtailment would be if the marginal cost of the system service being acquired by curtailment was greater than the marginal cost of energy. Work-streams 2B and 3 will examine this topic further, but for the purposes of this study a simple assumption has to be made. Given the increased interconnection capacity and a complementary portfolio of generation then it is assumed that at least 33.3% of the load at all times must be served from conventional dispatchable generation. Any excess wind generation, i.e. greater than 66.6 % of the load in any hour, is assumed to be curtailed. Under this assumption no meaningful curtailment occurs until the wind capacity increases beyond 5000 MW and at 9500 MW, 14.4 % of all available wind energy is being curtailed.

3.27 ***Capacity Credit –*** It is generally accepted that wind generation due to its variable nature makes a different contribution to generation adequacy than dispatchable generation. This trait is generally described by way of a capacity credit. Figure 3-6 shows the assumed capacity credit of the wind generation for the All-Island system in 2020. Further details of the capacity credit calculations can be found in Annex B.

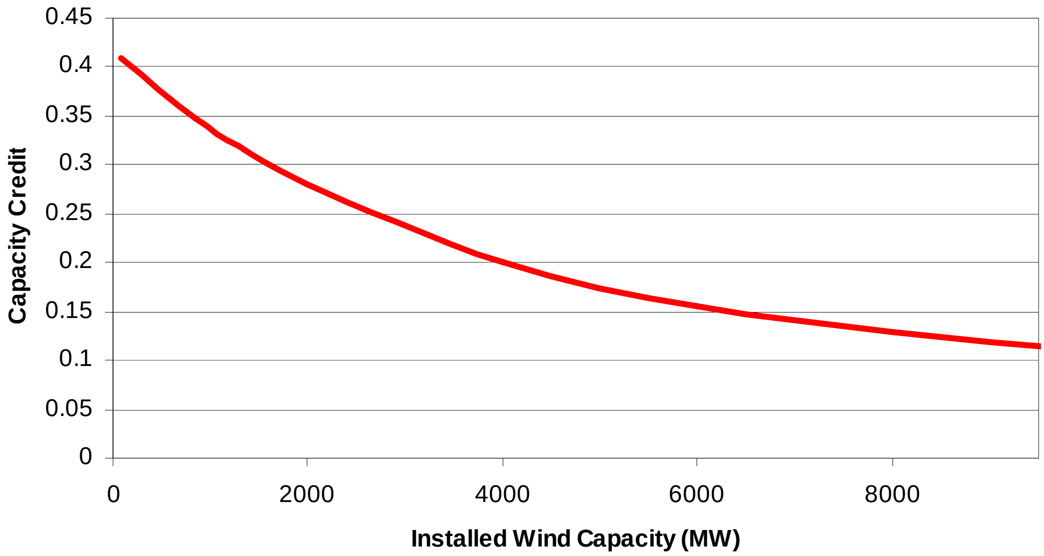

Figure 3-6. Capacity credit versus wind capacity

Base Load Renewable Resources and Costs

3.28 Various sources of renewable energy are categorised in this work as “base load renewables”. These include biomass and biogas, land fill gas, agricultural waste and others. An assessment was made of the available resource and respective costs from the best available literature[17,18,19]. Figure 3-7 summarises the assumed base load renewable resource and costs for the island in 2020.

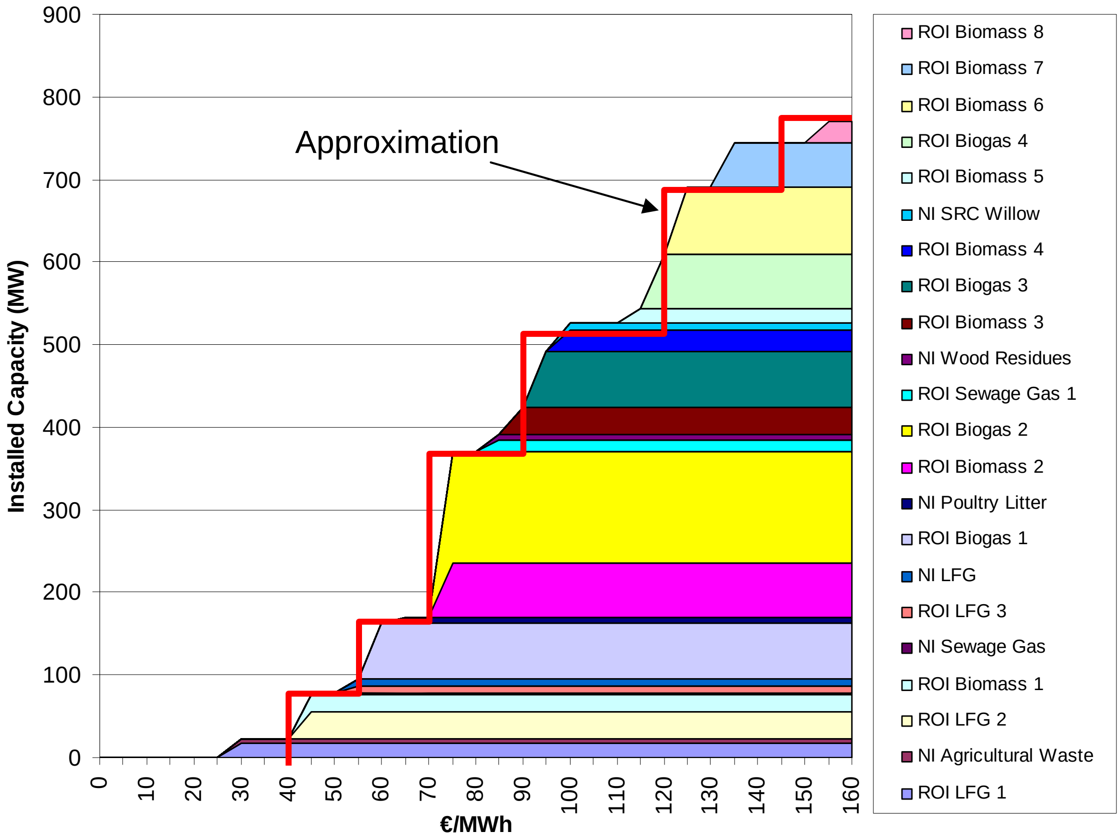

Figure 3-7. Base load renewable resource and cost curve.

[17] Sustainable Energy Ireland, 2004, “Renewable Energy Resources in Ireland for 2010 and 2020 – A Methodology” [Online] Available: http://www.sei.ie

[18] Department of Enterprise, Trade and Investment Northern Ireland, 2003, “A study into the economic renewable energy resource in Northern Ireland and the ability of the electricity network to accommodate renewable generation up to 2010”, [Online] Available: www.energy.detini.gov.uk.

[19] Sustainable Energy Ireland, 2004, “Annex II, Database for Res-E in Ireland, Study on the Economic Analysis of RE Support Mechanisms in the electricity generation sector” [Online] Available: http://www.sei.ie

3.29 For easier inclusion of the base load renewable cost curve into the portfolio optimisation algorithm, the curve was approximated into 6 separate resource/cost levels. This is illustrated in Figure 3-7 by the red line.

3.30 With various different technologies, transport cost models and interactions with the agricultural sector it is difficult to break down the base load renewable costs curve into more specific capital, fixed and variable costs. Given this and the uncertainty that surrounds these cost in 2020, it was decided to use the approximated base load resource cost curve for all scenarios, regardless of the weighted average cost of capital.

3.31 Base load renewable energy is assumed to have an availability of 0.85 and a capacity credit of 0.99. It is assumed that no deep network reinforcement costs or system management costs will result from the development of base load renewables at the levels considered here.

Variable Renewable Resource and Costs

3.32 Tidal stream generation, wave generation and photovoltaic generation are categorised in this work as “variable renewables”. An assessment was made of the available resource and respective costs from the best available literature[20,21,22]. Figure 3-8 summarises the assumed variable renewable resource and costs for the island in 2020.

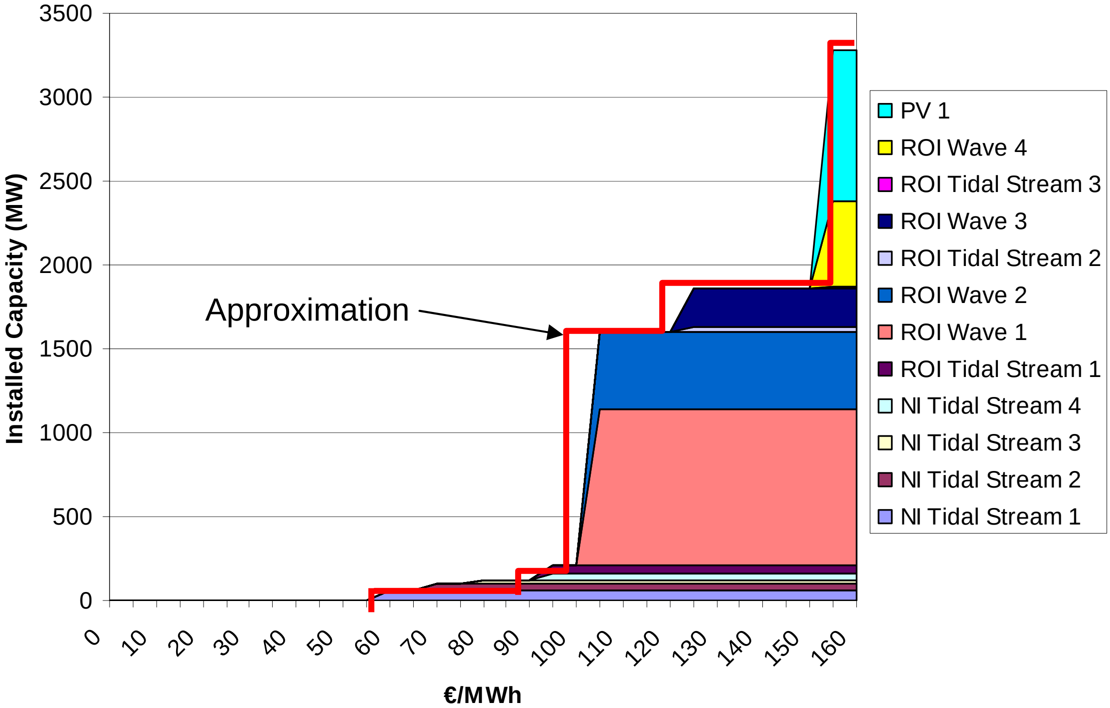

Figure 3-8. Variable renewable resource and cost curve.

3.33 Tidal stream, wave and photovoltaic generation are non-dispatchable forms of generation similar to wind generation. However, to treat them as such in the analysis would introduce an unnecessary level of complexity given the likely penetration these technologies may reach by 2020. Therefore, the variable renewable category is treated as a form of base load renewable generation in the analysis. This simplification may have the effect of slightly overestimating the benefits of this category of generation within generation portfolios.

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[20] Sustainable Energy Ireland, 2005, “Tidal and Current Energy Resources in Ireland”, [Online] Available: http://www.sei.ie

[21] Photovoltaic Technology Research Advisory Council, 2005 “A Vision for Photovoltaic Technology”, [Online] Available: http://europa.eu.int

[22] Sustainable Energy Ireland, 2005, “Accessible Wave Energy Resource Atlas Ireland”, [Online] Available: http://www.sei.ie

3.34 Again, for easier inclusion of the variable renewable cost curve into the portfolio optimisation algorithm, the curve was approximated into 5 separate resource/cost levels. This is illustrated in Figure 3-8 by the red line.

3.35 It is assumed that tidal stream generation and wave generation have a capacity factor of 0.31, while photovoltaic generation has a capacity factor of 0.1. The variable renewable generation category is assumed to have a capacity credit of 0.2. The network costs of the variable renewable technologies are reflected in the costs in Figure 3-8.

3.36 Again, given the uncertainty that surrounds the cost of these forms of renewable energy in 2020, it was decided to use the approximated variable renewable resource cost curve for all scenarios regardless of the weighted average cost of capital.

Co-Firing of Existing Peat Capacity with Biomass

3.37 A report commissioned for SEI[23] examined the potential of co-firing biomass fuel in the existing peat and coal generation facilities. The report found that there is significant scope for co-firing the existing peat capacity with wood biomass up to about 30% of the installed capacity (i.e. approx 104 MW in total). Based on this report, Figure 3-9 shows the assumed biomass co-firing potential for the island in 2020. It can be seen that the maximum amount of 30% co-firing with biomass is feasible when the Short Run Marginal Cost (SRMC) of peat generation is 45 €/MWh and above.

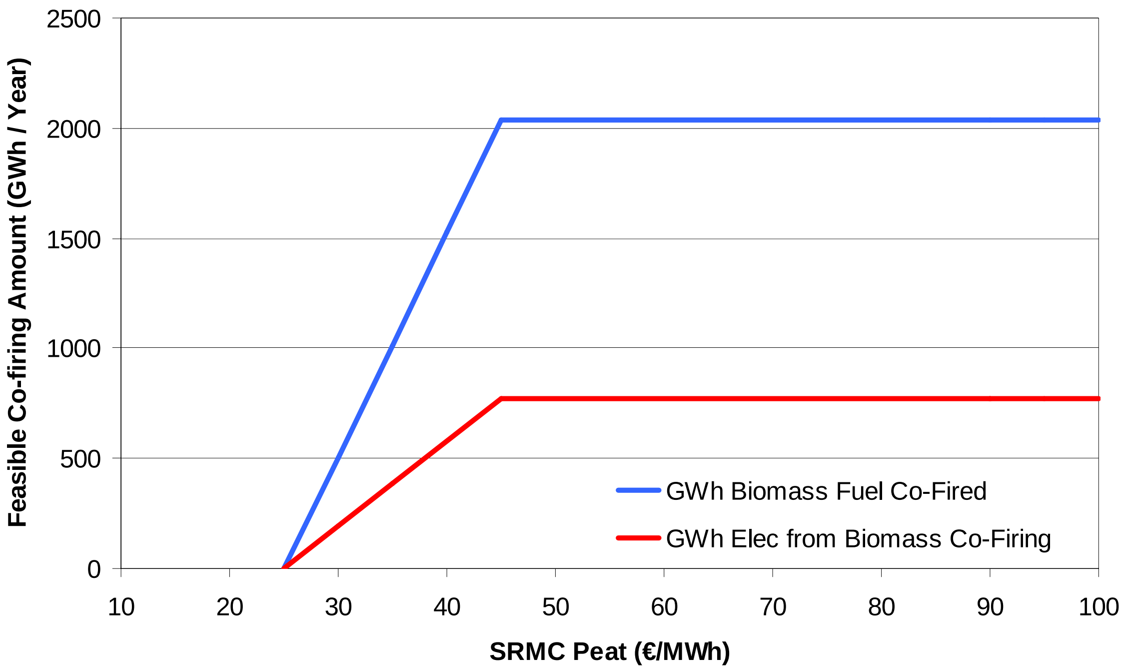

Figure 3-9. Assumed economically and technically feasible co-firing amount in existing peat plants versus the short sun marginal cost (SRMC) of peat generation.

3.38 Short run marginal cost of the peat generation here includes the cost of carbon. Results showed only limited potential for co-firing in the Moneypoint units. For this reason co-firing of coal capacity has been ignored.

3.39 It is assumed that the co-firing of wood biomass is the most efficient use of this resource. Consequently, this amount of wood biomass resource has been removed from the biomass resource assumed available for dedicated biomass plant detailed in Figure 3-7. The work here does not consider the possibility of building new coal or peat plant specifically as a co-firing facility.

[23] Sustainable Energy Ireland, 2005, "Co-Firing with Biomass ", [Online] Available: http://www.sei.ie

Load Growth and Load Duration Characteristics

3.40 This work assumes an average annual load growth of 3% for the All-Island system between for the period 2003 – 2020. An hourly load profile was created for the All-Island system for the year 2003 using data supplied by ESB National Grid. From this series the 2020 All-Island hourly load profile was created based on the 3% annual growth rate.

3.41 In planning generation portfolios, it is of the utmost importance that consideration is given to the duration characteristics of the load. It is crucial for finding the appropriate mix of base-load, mid-merit, and peaking type plant in the portfolio. For inclusion in the least-cost portfolio algorithm the load was broken up into 18 separate load duration bins. Each bin is 500 MW wide and records the number of hours during the year when the load fell within the range of the bin. The load duration characteristics as expressed by the load duration bins are incorporated into least-cost portfolio optimisation algorithm as 18 separate constraints.

3.42 For inclusion into the least-cost portfolio algorithm, the effect of the wind generation on the net-load (load minus wind) profile was expressed in terms of the changes it caused to the load duration bins. Wind profiles ranging from 500 MW – 9500 MW of installed capacity were examined and corresponding sets of net-load duration bins were created. Further details of this technique can be found in following publications[24,25,26].

Hydro, Pumped Storage and Interconnection

3.43 It is assumed here that Ireland's hydro generation potential is already fully exploited and further hydro projects are not considered in this work. The All-Island system has approximately 508 MW of installed hydro and pumped storage capacity at present. The effect of these plant are incorporated into the model using their historic operation profile[27].

3.44 The All-Island system currently has one 500 MW interconnector to Scotland. There are plans for a similar interconnector from the Republic of Ireland system to Wales in the near future. In this work it is taken that there will be two interconnectors resulting in 1000 MW of interconnection in total to Great Britain in 2020.

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[24] Doherty, R., Outhred H. and O'Malley, M., 2006, "Establishing the role that wind generation may have in future generation portfolios ", *IEEE Transactions on Power Systems*, (*in press*).

[25] Doherty, R., 2005, "New Methods for Planning and Operating Modern Electricity Systems with Significant Wind Generation", Ph.D. Thesis, University College Dublin.

[26] Doherty, R., Outhred H. and O'Malley, M., 2005, "Generation portfolio analysis for a carbon constrained and uncertain future", Proceedings of the International Conference on Future Power Systems, Amsterdam.

[27] Electricity Supply Board National Grid, 2005, Download Centre, [Online] Available: http://www.eirgrid.com

3.45 Modelling fully the possible import/export potential of the interconnectors is a difficult task which would involve not only estimating the All-Island plant mix in 2020 but also the Great Britain plant mix along with assessing the hours where sufficient price arbitrage exists for trades between the two systems. This is outside the scope of this study and a simplier assumption is made here. It is assumed that the interconnectors can import energy at a price which is 4% greater than the costs of energy from a new CCGT on the All-Island system. As the interconnector thus far has been almost entirely used as an importer to the All-Island system, the possibility of exporting on the interconnectors was not considered in this work. The energy imported over the interconnector is assumed to be non-renewable.

Scenarios and Sensitivities

3.46 ***Gas Price –*** Significant uncertainty surrounds the future gas price in the All-Island system. In this work a wide range of conceivable gas prices is examined. These range from 2 €/GJ to 12 €/GJ. These prices indicate the delivered cost of fuel on the All-Island system in net calorific value. Assuming that transport from the Great Britain adds 10 % to the cost of gas, the range examined here roughly corresponds to a traded cost of gas of about 12 p/therm to 73 p/therm in Great Britain.

3.47 ***Other Fuel Prices –*** Other fuel prices in this work were taken to be: coal = 1.26 €/GJ, lignite = 0.77 €/GJ, peat = 3.57 €/GJ and distillate = 7.99 €/GJ [28]. It was decided not to undertake a sensitivity analysis specifically to in relation to coal price as coal prices are generally though be less volatile than gas prices. Also, the carbon price sensitivity mimics the effect of changing the cost of electricity from coal relative to that of gas.

3.48 ***Carbon Price –*** Like gas price, considerable uncertainty surrounds the future price of carbon in the European emissions trading scheme and indeed the future form of the scheme itself. In this work it was decided to examine a range of carbon prices from 0 €/Tonne CO_2 – 100 €/Tonne CO_2. It has been indicated 100 €/Tonne of CO_2 will be the fine imposed for participants exceeding their allowances in phase two of the scheme.

3.49 ***Wind Turbine Costs -*** As highlighted in section 3.17 it was decided to examine two wind turbine cost scenarios, one to reflect the cost of turbines at the beginning of 2005 and a second to factor in possible cost reductions due to further technology advances by 2020.

3.50 ***Weighted Average Cost Capital (WACC) -*** The weighted average cost of capital in 2020 is uncertain and can be affected by changes in underlying interest rates and the perception of risk on investments in the electricity sector in the All-Island system. It was decided in this work to examine three WACC scenarios 6%, 8% and 10%. It is assumed in this work that the WACC applies equally to all

[28] All-Island Project, 2005, "Fuel Price and Generator Maintenance Assumptions for use in SEM Modelling", [Online] Available: http://www.allislandproject.org

generation options in 2020 except for the base load and variable renewable categories.

3.51 ***Societal Benefits of Renewable Energy*** **-** It is generally accepted that renewable energy has other societal benefits which are not normally reflected in the electricity industry marketplace. These benefits include but are not limited to: increasing the security of supply of primary energy to a system, acting as a natural hedge against volatile fuel prices, net new job creation, rural economic development etc. It is outside the scope of this study to quantify these benefits; however, previous government support structures in the Republic of Ireland provided a subsidy to peat generation citing benefits similar to those listed here. In 2005 peat generation may have been receiving about 25 €/MWh extra from this support scheme. In this work, three scenarios are explored in relation to the societal benefits of renewable energy. The first is where there is no value placed on the benefits of renewable generation, the second is where these benefits are valued at 5 €/MWh, and the third is where these benefits are assumed to be worth 10 €/MWh.

3.52 ***No New Coal, Lignite or Peat Scenario*** **–** New coal, lignite and peat generation require a relatively large capital spend and long plant life. With considerable uncertainty surrounding future fuel and carbon prices there is a risk that new coal, lignite and peat generation, as based load type plant, may become stranded in the market. This risk may mean that new coal, lignite and peat plant are not credible generation investment options on the All-Island system in the future. For this reason it was decided to examine scenarios where new coal, lignite and peat plant were assumed not to be generation options.

3.53 Variations in many of the factors listed here have a similar impact on aspects of the least-cost generation portfolios. For example, increased gas price and carbon prices both serve to increase the amount of renewable energy that it is desirable to have in generation portfolios. However, variations in these factors do not necessarily impact all aspects of the portfolio similarly, i.e. increased gas prices increase the amount of coal generation that it is desirable to have in generation portfolios while increased carbon price decrease its role in portfolios. One of the tasks of this work is to explore the effect that variations and combinations of these uncertain factors have on the range and variety of resultant least-cost portfolios.

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4. LEAST-COST PORTFOLIO ANALYSIS

4.1 This section presents some of the results from the least-cost portfolio optimisations. Illustrations are given of the relative effect of each of the scenarios and sensitivities on the least-cost generation portfolios for the All-Island system in 2020.

4.2 Sections 3.46-3.53 outlined the scenarios and sensitivities to be tested. Running the least-cost portfolio algorithm for all combinations of scenarios and sensitivities resulted in a database of over 16,000 separate portfolio results. Many portfolios in the database are duplicated due to the similar effects several combinations of scenarios and sensitivities can have on the outcome. This section aims to convey the range of outcomes possible and isolate and illustrate the relative effect of each scenario and sensitivity.

Example of Least-Cost Portfolio Results

4.3 Least-cost portfolio results are presented here in tables which show the amount of megawatts installed of each new generation option. This capacity along with the existing capacity assumed to be present in 2020, shown in Table 3-1, makes up the total All-Island generation portfolios. Table 4-1 shows examples of such least-cost portfolios. Also, shown is the resultant energy mix from each portfolio expressed in terms of energy source.

Tables 4-1. Portfolios A and B - Examples of least-cost generation portfolios.

Portfolio A	MW Installed
Coal 1	0
Coal 2	0
Lignite	0
Peat	0
CCGT	694
OCGT	1761
ADGT	89
Base Load Renewables	370
Variable Renewables	70
Wind	2000
Co-fired Capacity (of peat)	104
Resultant Energy Mix	**%**
Coal/Lignite Energy	17.09
Peat Energy	3.40
Gas Energy	51.89
Interconnection	8.24
Hydro	1.64
Base Load Renewables	5.10
Variable Renewables	0.35
Wind Energy	10.83
Co-fired Capacity (of peat)	1.46
Total Renewables	**19.38**

Portfolio B	MW Installed
Coal 1	1550
Coal 2	0
Lignite	0
Peat	0
CCGT	0
OCGT	681
ADGT	0
Base Load Renewables	370
Variable Renewables	70
Wind	5000
Co-fired Capacity (of peat)	104
Resultant Energy Mix	**%**
Coal/Lignite Energy	38.28
Peat Energy	3.40
Gas Energy	23.91
Interconnection	0.14
Hydro	1.64
Base Load Renewables	5.10
Variable Renewables	0.35
Wind Energy	25.73
Co-fired Capacity (of peat)	1.46
Total Renewables	**34.28**

4.4 Portfolio A is the least-cost generation portfolio for a gas price of 5.5 €/GJ (33p/therm), a carbon price of 50 €/Tonne CO_2, a WACC of 8%, high wind turbine costs and assuming no addition benefits of renewable energy. These conditions are labelled here as “Scenario A”. This portfolio results in a renewable penetration of about 19%. It can be seen that a significant amount of new peaking capacity is required in this portfolio. This feature is prominent throughout a large range of portfolios in the database. This is due to the assumption that a significant portion of the existing peaking capacity will be retired by 2020. Along with the replacement of the peaking capacity, increased wind generation in portfolios alters the shape of the net-load duration curve which can cause a further increase in the need for peaking capacity[29]. It can be seen that in the above scenario there appears to be only a limited need for further CCGT capacity on the All-Island system by 2020. This trend is also prominent throughout a large range of portfolios in the database.

4.5 Portfolio B is the least-cost generation portfolio for a gas price of 8 €/GJ (49p/therm), a carbon price of 50 €/Tonne CO_2, a WACC of 6%, high wind turbine costs and assuming no addition benefits of renewable energy. These conditions are labelled here “Scenario B”. It can be seen that under these circumstances that it is desirable to have a significant portion of new coal and wind generation in the portfolio. It can be seen that a much smaller proportion of new peaking capacity is required in this case as the existing mid-merit capacity gets pushed higher up the merit order due to the introduction of the new coal and wind capacity.

Effect of Increasing Wind Capacity in Portfolios

4.6 Portfolios A and B show the installed capacity of generation in the least-cost portfolios for the conditions defined as scenarios A and B respectively. For scenario A it was found that the least-cost portfolio included 2000 MW of wind capacity. Scenario B found that 5000 MW of wind capacity was optimal. Figure 4-1 shows the minimum cost of electricity possible from portfolios which include a range of installed wind capacities. This is shown for both scenario A and B. It can be seen that increasing wind generation in the portfolios initially causes a reduction in the cost of electricity from the portfolios until the optimal level is reached. It is the generation portfolios at these points which are presented in this work as being the least-cost generation portfolios. It can be seen that a further increase in wind capacity beyond this point causes an increase in the cost of electricity from the generation portfolio.

[29] The analysis in this work is pitched at a high level, lower level system considerations such as the impact of simultaneous unit outages on the utilisation of peaking plant and unit start-up and ramping limitations of units have not been included. These considerations may have an impact on the least-cost mix of peaking and mid-merit capacity.

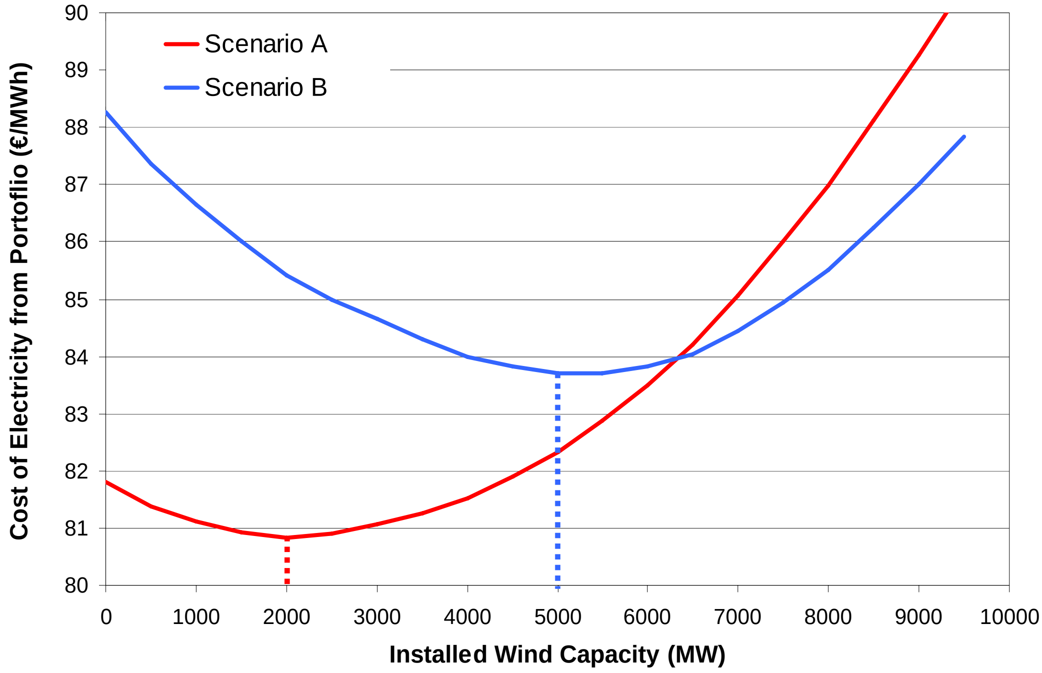

Figure 4-1. Cost of electricity versus installed wind capacity in generation portfolios

4.7 It can be seen from Figure 4-1 that the curve of the cost function around the optimal wind generation penetration is relatively gradual. This is an important point to note as it indicates that there would not be severe cost implications of only having a wind penetration within a reasonable range (e.g. ± 1000 MW) of the optimal penetration.

Impact of uncertain factors on least cost-portfolios

4.8 Table 4-1 simply shows examples of two portfolios from the database of least-cost portfolios. Further analysis sought to isolate the effect which the main factors had on the make up of future least-cost portfolios. The future gas price and carbon prices were found to have the biggest effect on the least-cost portfolios over the ranges examined. Both of these factors also have a significant level of uncertainty associated with them. Figures 4-2 and 4-3 attempt to illustrate the effect of gas price and carbon price on the penetration of renewable energy in the least-cost portfolios over the ranges examined. Other values in the scenario are WACC of 8%, low wind turbine cost, and a 5 €/MWh additional benefit of renewable energy.

4.9 It can be seen, that over the ranges examined the gas and carbon prices can cause the renewable energy penetration in least-cost portfolios to vary between about 5% and 60%.

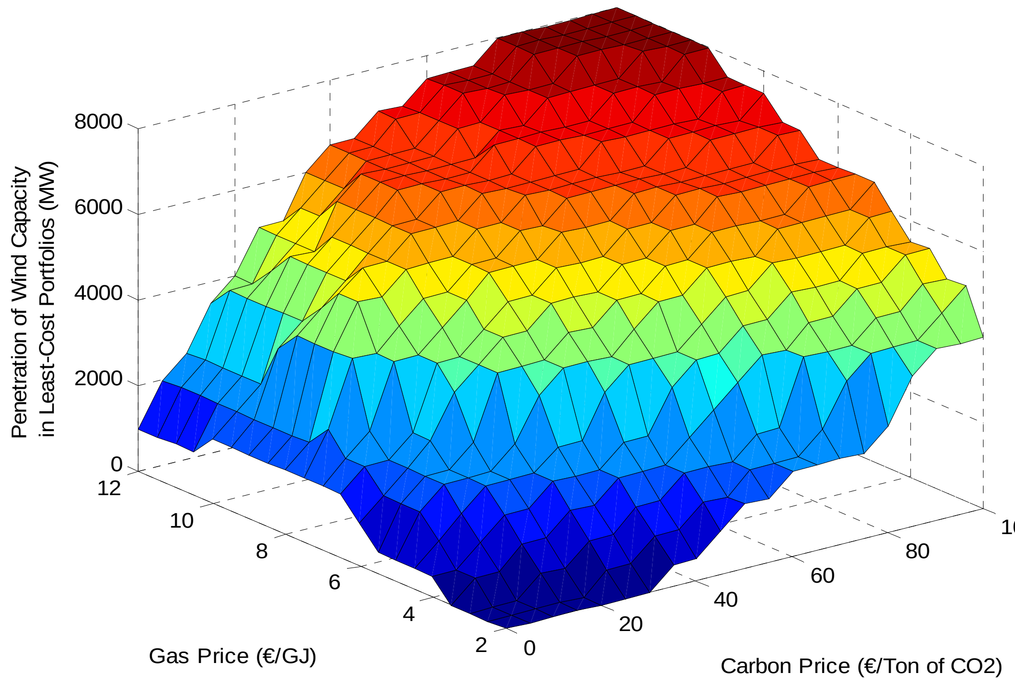

Figure 4-2. Effect of gas and carbon prices on wind capacity in least-cost generation portfolios

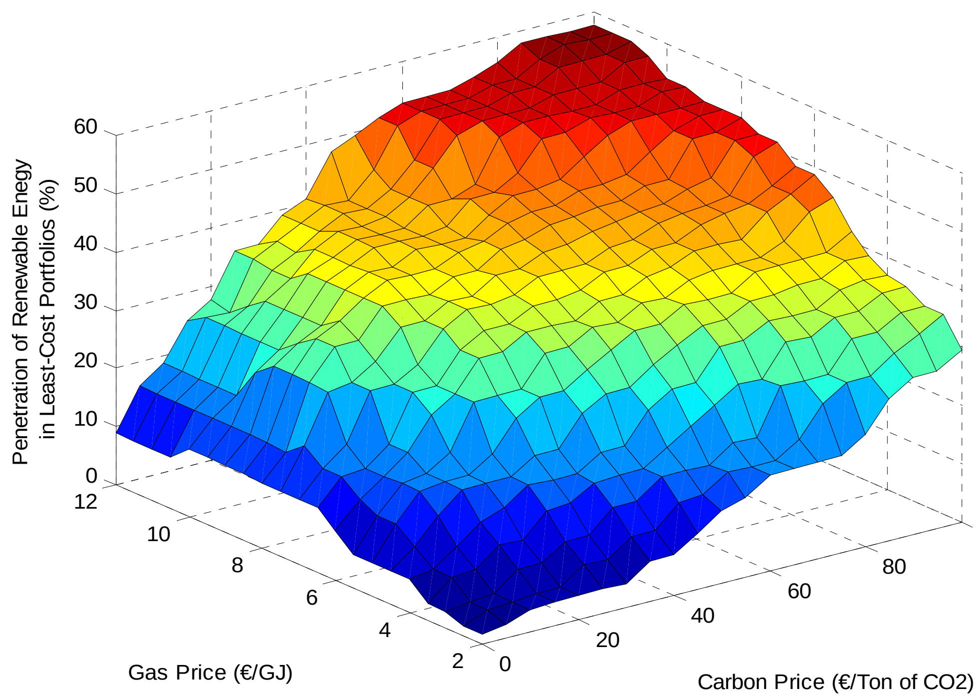

Figure 4-3. Effect of gas and carbon prices on renewable energy penetration in least-cost generation portfolios

4.10 ***Central Scenario*** **-** The many different scenarios and sensitivities make illustrating the effect of each individual input difficult. For this reason it was decided to pick a central scenario which can be used as a reference and then alter each individual input to illustrate the effect it has on the least-cost generation portfolio. The central scenario conditions for the All-Island system in 2020 are taken to be: a gas price of 5.5 €/GJ (33p/therm), a carbon price of 30 €/Tonne CO_2, a WACC of 8%, low wind turbine costs and the additional benefit of renewable energy valued at 5 €/MWh. Portfolio C shown in Table 4-2 shows the make up of the new capacity in the least-cost generation portfolio for this central scenario.

Table 4-2. Portfolio C – Central scenario

Portfolio C	MW Installed
Coal 1	0
Coal 2	0
Lignite	0
Peat	0
CCGT	0
OCGT	1968
ADGT	535
Base Load Renewables	170
Variable Renewables	70
Wind	4000
Co-fired Capacity (of peat)	104
Resultant Energy Mix	**%**
Coal/Lignite Energy	17.09
Peat Energy	3.40
Gas Energy	43.76
Interconnection	8.88
Hydro	1.64
Base Load Renewables	2.34
Variable Renewables	0.35
Wind Energy	21.09
Co-fired Capacity (of peat)	1.46
Total Renewables	**26.88**

4.11 It can be seen that this scenario produces a renewable energy penetration of about 27%. This comprises 4000 MW of wind capacity, 170 MW of base load renewable energy capacity, 70 MW of variable renewable capacity and the maximum amount of biomass co-firing in the existing peat generation stations (i.e. 104 MW of peat capacity). It can be seen that no CCGTs were deemed necessary above the existing CCGTs assumed to be present in 2020.

4.12 ***Wind Turbine Costs –*** The central scenario assumes the low wind turbine costs by 2020. Portfolio D in Table 4-3 shows the least-cost portfolio for the same conditions as the central scenario expect for the high wind turbine costs.

Table 4-3. Portfolio D – Central scenario with high wind costs

Portfolio D	MW Installed
Coal 1	0
Coal 2	0
Lignite	0
Peat	0
CCGT	492
OCGT	1850
ADGT	402
Base Load Renewables	170
Variable Renewables	70
Wind	2000
Co-fired Capacity (of peat)	104
Resultant Energy Mix	**%**
Coal/Lignite Energy	17.09
Peat Energy	3.40
Gas Energy	50.58
Interconnection	12.31
Hydro	1.64
Base Load Renewables	2.34
Variable Renewables	0.35
Wind Energy	10.83
Co-fired Capacity (of peat)	1.46
Total Renewables	**16.63**

4.13 It can be seen that the high wind turbine costs result in a reduction in the amount of wind capacity in the least-cost portfolio relative to Portfolio C. This reduction in wind capacity is replaced basically by CCGT capacity and a slight reduction in the amount of peaking capacity required can also be seen due to the reduced penetration of wind generation.

4.14 ***Weighted Average Cost of Capital (WACC)* –** The central scenario assumes WACC of 8% in 2020. Portfolios E and F in Table 4-4 show the least-cost portfolios for WACC of 6% and 10% respectively. All other conditions are the same as the central scenario.

Table 4-4. Portfolios E and F– Central scenario with WACC of 6 % and 10 % respectively

Portfolio E	MW Installed
Coal 1	0
Coal 2	0
Lignite	0
Peat	0
CCGT	0
OCGT	1941
ADGT	490
Base Load Renewables	170
Variable Renewables	70
Wind	5000
Co-fired Capacity (of peat)	104
Resultant Energy Mix	**%**
Coal/Lignite Energy	17.09
Peat Energy	3.40
Gas Energy	42.32
Interconnection	5.67
Hydro	1.64
Base Load Renewables	2.34
Variable Renewables	0.35
Wind Energy	25.73
Co-fired Capacity (of peat)	1.46
Total Renewables	**31.52**

Portfolio F	MW Installed
Coal 1	0
Coal 2	0
Lignite	0
Peat	0
CCGT	261
OCGT	1795
ADGT	408
Base Load Renewables	370
Variable Renewables	70
Wind	2500
Co-fired Capacity (of peat)	104
Resultant Energy Mix	**%**
Coal/Lignite Energy	17.09
Peat Energy	3.40
Gas Energy	46.80
Interconnection	10.71
Hydro	1.64
Base Load Renewables	5.10
Variable Renewables	0.35
Wind Energy	13.46
Co-fired Capacity (of peat)	1.46
Total Renewables	**22.01**

4.15 Wind generation is a relatively capital intensive generation option and it can be seen in Portfolio E that a reduction in the WACC results in an increase in the amount of wind generation in the least-cost generation portfolio. It can be seen that an increase in the WACC to 10 % in Portfolio F results in decrease in the amount wind capacity in the least-cost portfolio to 2500 MW. Portfolio F also shows an increase in the amount of base load renewable capacity. This is a result of assuming a single resource/cost curve for base load renewables which is not altered by the WACC.

4.16 ***Additional Benefits of Renewable Generation*** **–** The central scenario assumes that the additional benefits on renewable generation equates to 5 €/MWh in 2020. Portfolios G and H in Table 4-5 shows the least-cost portfolios for the case where there is no value placed on the additional benefits on renewable generation and where they are valued at 10 €/MWh. All other conditions are the same as the central scenario.

Table 4-5. Portfolios G and H – Central scenario with the additional benefits from renewables valued at 0 €/MWh and 10 €/MWh respectively

Portfolio G	MW Installed
Coal 1	0
Coal 2	0
Lignite	0
Peat	0
CCGT	461
OCGT	1795
ADGT	408
Base Load Renewables	170
Variable Renewables	70
Wind	2500
Co-fired Capacity (of peat)	104
Resultant Energy Mix	**%**
Coal/Lignite Energy	17.09
Peat Energy	3.40
Gas Energy	49.66
Interconnection	10.60
Hydro	1.64
Base Load Renewables	2.34
Variable Renewables	0.35
Wind Energy	13.46
Co-fired Capacity (of peat)	1.46
Total Renewables	**19.25**

Portfolio H	MW Installed
Coal 1	0
Coal 2	0
Lignite	0
Peat	0
CCGT	0
OCGT	1948
ADGT	317
Base Load Renewables	370
Variable Renewables	70
Wind	4500
Co-fired Capacity (of peat)	104
Resultant Energy Mix	**%**
Coal/Lignite Energy	17.09
Peat Energy	3.40
Gas Energy	42.21
Interconnection	5.31
Hydro	1.64
Base Load Renewables	5.10
Variable Renewables	0.35
Wind Energy	23.45
Co-fired Capacity (of peat)	1.46
Total Renewables	**32.00**

4.17 It can be seen that placing no value on the additional benefits reduces in role of wind generation in the least-cost portfolio to 2500 MW. Valuing the additional benefits at 10 €/MWh increases the role of wind generation to 4500 MW and increases the role of base load renewables to 370MW in the least-cost portfolio.

4.18 ***New Coal, Lignite and Peat Generation -*** As outlined in section 3.52, the risk associated with investment in capital intensive coal lignite and peat generation in an environment of uncertain fuel and carbon prices may prevent investment in such plant in the future on the All-Island system. Therefore, a set of scenarios were run assuming new coal, lignite and peat generation options were not available.

4.19 Portfolios I and J in Table 4-6 show the least-cost portfolios with and without new coal, lignite and peat options for a scenario of gas price of 6.5 €/GJ (40p/therm), a carbon price of 0 €/Tonne CO_2, a WACC of 8%, low wind turbine costs and the additional benefit of renewable energy valued at 5 €/MWh.

Table 4-6. Portfolios I and J – Scenario with and without new coal, lignite and peat generation options

Portfolio I	MW Installed
Coal 1	1550
Coal 2	843
Lignite	550
Peat	0
CCGT	0
OCGT	0
ADGT	0
Base Load Renewables	85
Variable Renewables	0
Wind	1500
Co-fired Capacity (of peat)	20
Resultant Energy Mix	**%**
Coal/Lignite Energy	57.31
Peat Energy	4.57
Gas Energy	26.87
Interconnection	0.02
Hydro	1.64
Base Load Renewables	1.17
Variable Renewables	0.00
Wind Energy	8.13
Co-fired Capacity (of peat)	0.28
Total Renewables	**11.23**

Portfolio J	MW Installed
Coal 1	0
Coal 2	0
Lignite	0
Peat	0
CCGT	461
OCGT	1795
ADGT	408
Base Load Renewables	170
Variable Renewables	70
Wind	2500
Co-fired Capacity (of peat)	20
Resultant Energy Mix	**%**
Coal/Lignite Energy	17.09
Peat Energy	4.57
Gas Energy	49.66
Interconnection	10.60
Hydro	1.64
Base Load Renewables	2.34
Variable Renewables	0.35
Wind Energy	13.46
Co-fired Capacity (of peat)	0.28
Total Renewables	**18.08**

4.20 It can be seen in Portfolio I that there is a significant amount of new coal and lignite capacity in the least cost portfolio. In this scenario the existing mid-merit gas capacity assumed available in 2020 is pushed up the merit order toward the role of peaking generation. With the coal and lignite generation options removed it can be seen in portfolio J that the least-cost solution involves higher levels of renewable generation along with new CCGT and peaking capacity.

4.21 To further illustrate the role of new coal and lignite generation in least-cost portfolios Figure 4-4 shows the total (existing and new) installed capacity of coal and lignite generation in least-cost portfolios for a range of gas and carbon prices. The lowest value shown in Figure 4-4 is 1250 MW which corresponds to the existing coal generation facilities assumed available in 2020. Other values in the scenario are WACC of 8%, low wind turbine cost, and a 5 €/MWh additional benefit of renewable energy.

4.22 Figure 4-5 shows the percentage of energy served by coal and lignite generation for the range of gas and carbon prices. Most of this surface reflects the energy generated by the capacity showed in Figure 4-4 running as base load plant. However, also highlighted in Figure 4-5 is a dark blue region which corresponds to a case where, due to a combination of relatively low gas prices and high carbon prices, the existing coal capacity moves above the gas capacity in the merit order. These type of conditions result in fewer running hours for the coal generation and may result in the coal generation assets becoming stranded. It is possible that the perceived risk of this occurring at some stage during the life time of a plant may discourage investment in new coal and lignite generation.

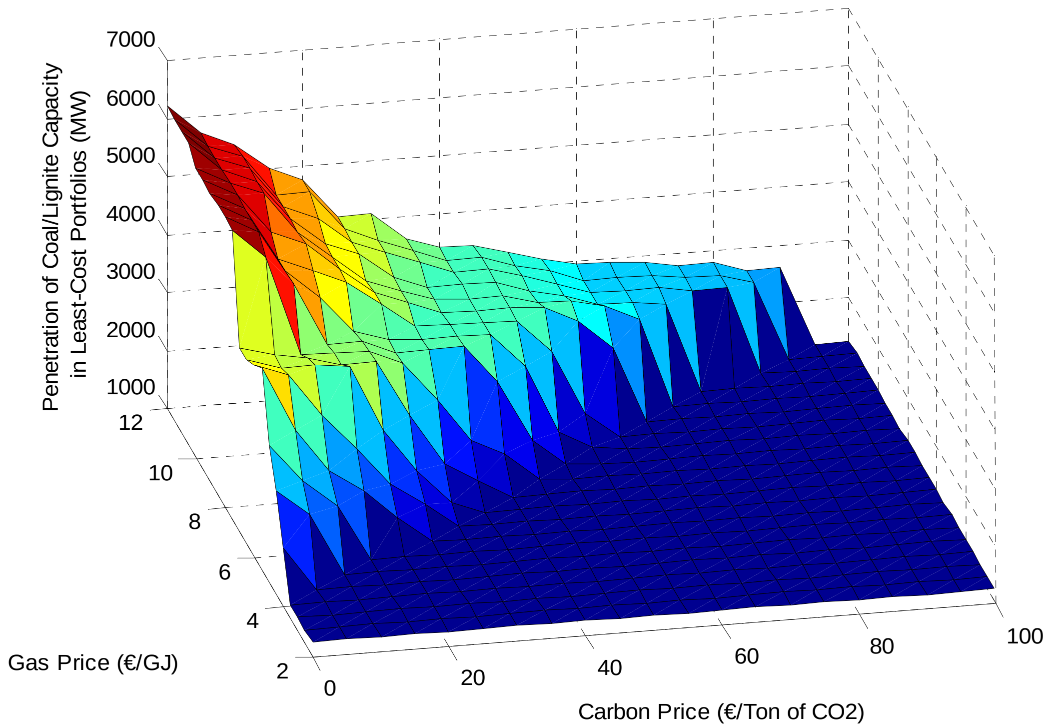

Figure 4-4. Effect of gas and carbon prices on the amount of coal and lignite capacity in least-cost generation portfolios

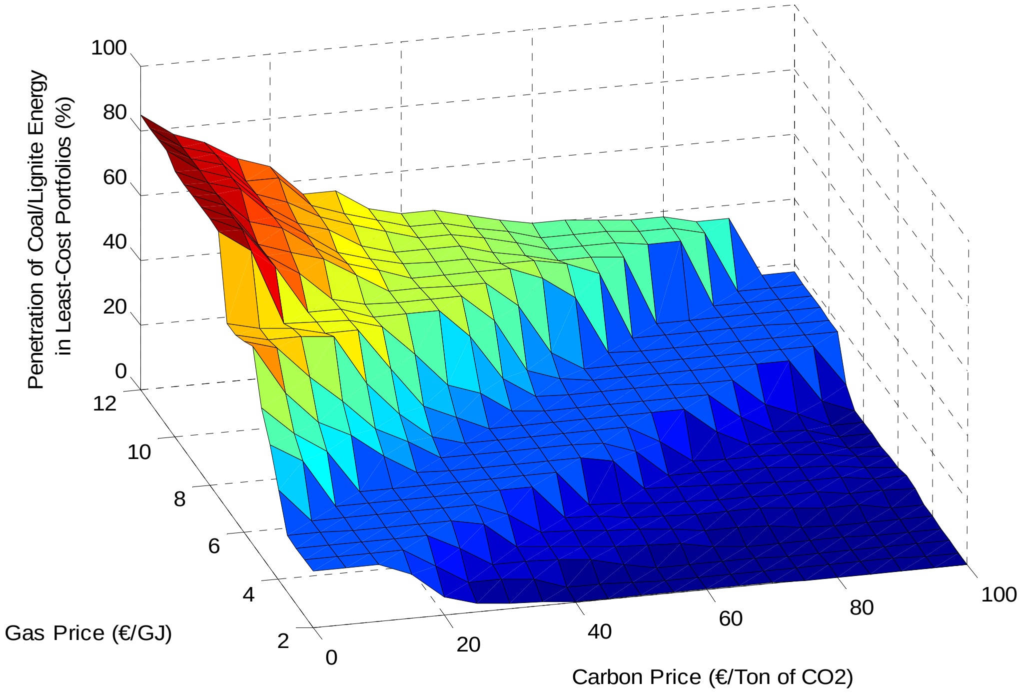

Figure 4-5. Effect of gas and carbon prices on the coal and lignite energy penetration in least-cost generation portfolios

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5. SUITABLE PORTFOLIOS FOR ANALYSIS IN THE ALL-ISLAND GRID STUDY

5.1 This section outlines five generation portfolios which have been deemed suitable as a basis for assessments which will be carried out in other work-streams of the All-Island grid study. These portfolios were deemed suitable on the basis that they explore the range of conceivable and reasonable future generation portfolios without significant duplication.

5.2 With many different dimensions to generation portfolios it is difficult to convey the extent of the variations in the database of least-cost portfolios. Figure 5-1 attempts to illustrate this variation by showing a scatter plot of the installed coal and renewable capacity in the least-cost portfolios. Also shown in Figure 5-1 is the frequency of occurrence of different renewable and coal capacities in portfolios in the results database.

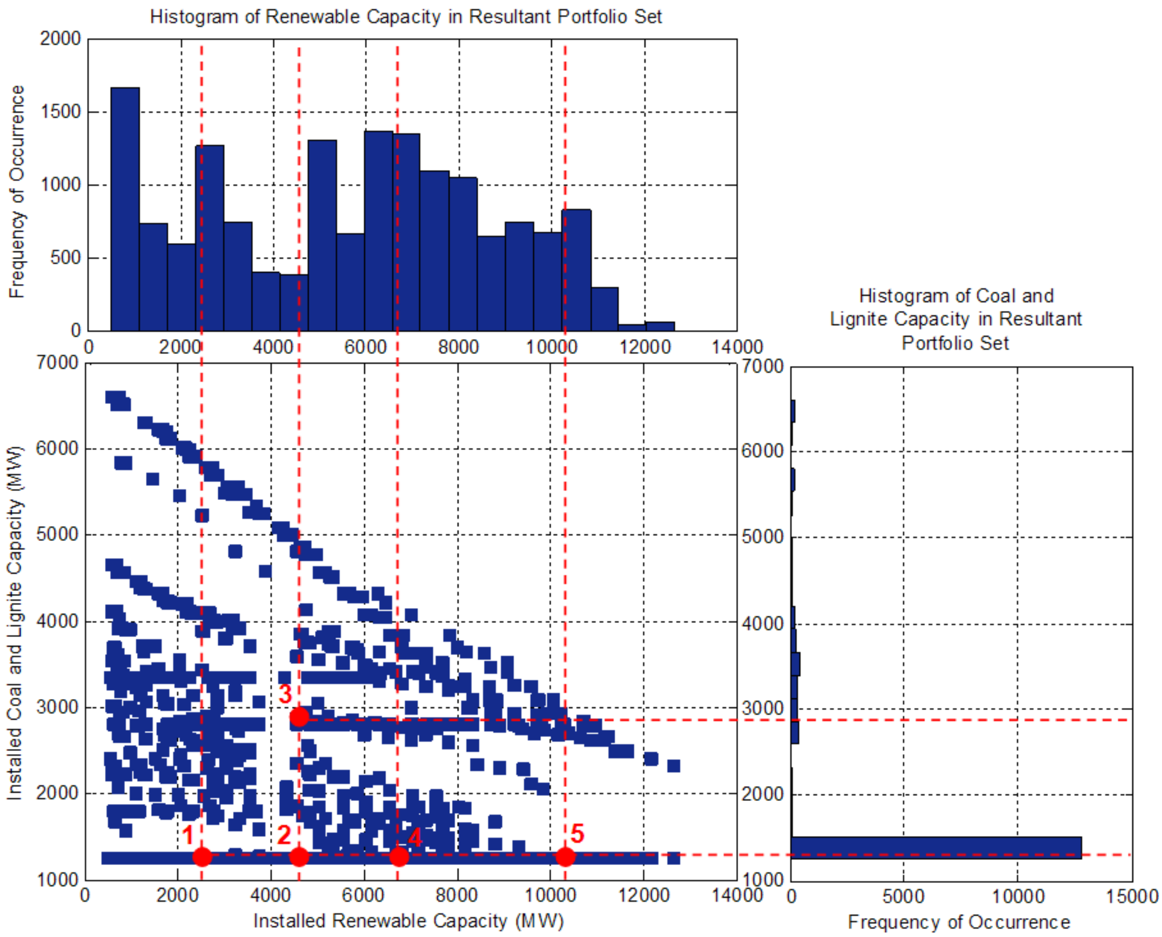

Figure 5-1. Occurrence of various penetrations of coal and renewable capacity in the least-cost generation portfolio results database

5.3 It can be seen that over all the scenarios tested the majority of the least-cost generation portfolios included just the existing 1250 MW of coal capacity which is assume to still be present in 2020. It can also be seen that the resultant database of least-cost portfolios shows a relatively even distribution of installed renewable capacity between 1000 MW and 11,000 MW.

5.4 From this database of portfolios, five portfolios were selected as being suitable for further analysis in other work-streams of All-Island grid study. The five portfolios are indicated in red (1-5) in Figure 5-1. It was thought that these portfolios reasonably explore the likely range of renewable penetration on the All-Island system by 2020. A portfolio with the same renewable penetration as another portfolio but with and increased amount of coal capacity was also selected. This will allow comparisons to be made in work-stream 2B as to the impacts of operating a system with renewable energy and an increased amount of coal capacity. Further details of these portfolios follow.

Portfolio Scenario 1

5.5 In addition to the existing capacity assumed available in 2020, see Table 3-1, Table 5-1 outlines the additional capacity necessary in portfolio 1. As with all the selected scenarios several combinations of future conditions can result in this portfolio being optimal. One such combination is a gas price of 5.5 €/GJ (33p/therm), carbon price of 30 €/Tonne CO_2, WACC of 6% and high wind turbine costs.

Table 5-1. Installed capacity of new generation and resultant energy mix for Portfolio Scenario 1

Portfolio 1	MW Installed
Coal 1	0
Coal 2	0
Lignite	0
Peat	0
CCGT	894
OCGT	1761
ADGT	89
Base Load Renewables	170
Variable Renewables	70
Wind	2000
Co-fired Capacity (of peat)	104
Resultant Energy Mix	**%**
Coal/Lignite Energy	17.09
Peat Energy	3.40
Gas Energy	54.76
Interconnection	8.13
Hydro	1.64
Base Load Renewables	2.34
Variable Renewables	0.35
Wind Energy	10.83
Co-fired Capacity (of peat)	1.46
Total Renewables	**16.63**

5.6 The Republic of Ireland has a renewable energy target of approximately 13% by 2010 and Northern Ireland has a renewable energy target of approximately 12 % by 2012. With over 600 MW of wind generation already installed on the All-Island system and much more in various stages of the planning and development process, portfolio 1 represents a low renewable energy penetration scenario by 2020.

Portfolio Scenario 2

5.7 Table 5-2 outlines the new capacity necessary in portfolio 2. This is the mid-range renewable energy portfolio scenario and is identical to the central scenario presented in Section 4. This portfolio is optimal for a gas price of 5.5 €/GJ (33p/therm), carbon price of 30 €/Tonne CO_2, WACC of 8% and low wind turbine costs and a 5€/MWh additional benefit of renewable energy.

Table 5-2. Installed capacity of new generation and resultant energy mix for Portfolio Scenario 2

Portfolio 2	MW Installed
Coal 1	0
Coal 2	0
Lignite	0
Peat	0
CCGT	0
OCGT	1968
ADGT	535
Base Load Renewables	170
Variable Renewables	70
Wind	4000
Co-fired Capacity (of peat)	104
Resultant Energy Mix	**%**
Coal/Lignite Energy	17.09
Peat Energy	3.40
Gas Energy	43.76
Interconnection	8.88
Hydro	1.64
Base Load Renewables	2.34
Variable Renewables	0.35
Wind Energy	21.09
Co-fired Capacity (of peat)	1.46
Total Renewables	**26.88**

Portfolio Scenario 3

5.8 Table 5-3 outlines the new capacity necessary in portfolio 3. This is the mid-range renewable energy portfolio scenario similar to portfolio scenario 2 but with a significant portion of new coal generation plant. This portfolio will allow system operational issues to be investigated in other work-streams with respect to operating generation portfolios with significant renewable energy penetration and coal penetration. This portfolio is optimal for a gas price of 6.5 €/GJ (40p/therm), carbon price of 30 €/Tonne CO_2, WACC of 6% and high wind turbine costs and a 5 €/MWh additional benefit of renewable energy.

Table 5-3. Installed capacity of new generation and resultant energy mix for Portfolio Scenario 3

Portfolio 3	MW Installed
Coal 1	1550
Coal 2	0
Lignite	0
Peat	0
CCGT	0
OCGT	953
ADGT	0
Base Load Renewables	170
Variable Renewables	70
Wind	4000
Co-fired Capacity (of peat)	104
Resultant Energy Mix	**%**
Coal/Lignite Energy	38.28
Peat Energy	3.40
Gas Energy	30.69
Interconnection	0.76
Hydro	1.64
Base Load Renewables	2.34
Variable Renewables	0.35
Wind Energy	21.09
Co-fired Capacity (of peat)	1.46
Total Renewables	**26.88**

Portfolio Scenario 4

5.9 Table 5-4 outlines the new capacity necessary in portfolio 4. This portfolio is optimal for a gas price of 8 €/GJ (49p/therm), carbon price of 30 €/Tonne CO_2, WACC of 8% and low wind turbine costs, a 5 €/MWh additional benefit of renewable energy and no new coal, lignite or peat generation options.

Table 5-4. Installed capacity of new generation and resultant energy mix for Portfolio Scenario 4

Portfolio 4	MW Installed
Coal 1	0
Coal 2	0
Lignite	0
Peat	0
CCGT	0
OCGT	2031
ADGT	111
Base Load Renewables	370
Variable Renewables	200
Wind	6000
Co-fired Capacity (of peat)	104
Resultant Energy Mix	**%**
Coal/Lignite Energy	17.09
Peat Energy	3.40
Gas Energy	36.62
Interconnection	3.89
Hydro	1.64
Base Load Renewables	5.10
Variable Renewables	1.01
Wind Energy	29.81
Co-fired Capacity (of peat)	1.46
Total Renewables	**39.01**

5.10 This is a relatively high renewable energy portfolio scenario. However, the conditions which make this the least-cost generation portfolio are very conceivable by 2020. Because of the perceived probability of these conditions occurring by 2020 it was decided to choose another portfolio scenario with an even higher renewable energy penetration.

Portfolio Scenario 5

5.11 Table 5-5 outlines the new capacity necessary in portfolio 5. This is a very high renewable energy portfolio scenario. The wind energy resource assumed to be exploited here may even exceed the physically realisable resource on the island. This issue will be examined in work-stream 1. This scenario will require the development of robust strategies in work-streams 2B and 3 with respect to the operation and network development. The results should highlight in detail the implications of operating a system with over 50 % renewable energy. This portfolio is optimal for a gas price of 9 €/GJ (55p/therm), carbon price of 80 €/Tonne CO_2, WACC of 6% and low wind turbine costs and a 10 €/MWh additional benefit of renewable energy.

Table 4-5. Installed capacity of new generation and resultant energy mix for Portfolio Scenario 5

Portfolio 5	MW Installed
Coal 1	0
Coal 2	0
Lignite	0
Peat	0
CCGT	0
OCGT	1598
ADGT	0
Base Load Renewables	520
Variable Renewables	1600
Wind	8000
Co-fired Capacity (of peat)	104
Resultant Energy Mix	**%**
Coal/Lignite Energy	17.09
Peat Energy	3.40
Gas Energy	25.22
Interconnection	0.00
Hydro	1.64
Base Load Renewables	7.16
Variable Renewables	8.04
Wind Energy	35.99
Co-fired Capacity (of peat)	1.46
Total Renewables	**54.30**

6. CONCLUSION

6.1 This work strove to investigate at a high level the likely range and variation of desirable generation portfolios for the All-Island system in 2020. The aim was to inform a suitable and representative suite of generation portfolio for further analysis in the All-Island grid study.

6.2 Linear programming optimisation was deemed to be a flexible and suitable platform on which to assess the many variables and trade-offs involved in the generation portfolio planning problem. The existing generation plant assumed to operational in 2020 and other system features were included in the analysis. The analysis also specifically encapsulates the variable nature of the wind generation.

6.3 Uncertainty surrounds several important factors in 2020, these include gas price, carbon price, wind turbine costs, WACC, the value placed on the additional benefits of renewable generation, and the appetite to invest in new coal generation facilities. These factors were varied over what was deemed a suitable range and the effect on the resultant least-cost portfolios in 2020 was assessed. Although no consideration was given to the probability of specific future values of these variables it would appear that the future gas price and carbon costs have the largest impact on the make-up of desirable generation portfolios in the future. The inherent uncertainty of these factors again highlights the additional benefits that renewable generation brings to a system.

6.4 Results showed the renewable energy penetration range between about 10 % and 60 % in the least-cost portfolios depending on the conditions. The renewable energy penetration in general ranged between 20% and 40% for the more conceivable sets of future conditions. A large range of results showed the need for a significant amount of new peaking capacity. This is partially due to an increase in wind generation in portfolios and partially due to the retirement of most of the existing peaking capacity by 2020.

6.5 It was illustrated that there was minimal cost implications of having a sub-optimal wind capacity within a certain range. (i.e. ±1000 MW from optimal penetration). Results also showed that co-firing biomass to the maximum extent possible in the existing peat generation stations is desirable for almost all future scenarios.

6.6 Most of the scenarios tested found that the least-cost generation portfolios included the existing coal capacity running as base-load plant with no new coal generation capacity necessary. Some scenarios did show that new coal capacity was desirable, while other scenarios with low gas and high carbon prices showed the possibility of coal generation assets becoming stranded due to it marginal cost increasing beyond that of gas plant.

6.7 Five generation portfolios were decided as suitable and representative of the likely range of future desirable generation portfolios for the All-Island system in 2020. These portfolios have a renewable energy penetration ranging from about 17% to 54 % in 2020 and a wind penetration ranging from 2000 MW to 8000 MW. These portfolios will be the subject of further and more detailed analysis in other work-streams of the All-Island grid study.

ANNEX A– ACKNOWLEDGEMENTS AND CONSULTATION

A.1 This study has only been made possible thanks to the inputs, effort, time and data provided by a large number of stakeholders. The author would like to gratefully acknowledge the input and time given by the All-Island Grid Study Working Group:

Prof. Mark O’Malley – Electricity Research Centre, University College Dublin

Paul Smith – ESB National Grid

Leslie Bryans – System Operator of Northern Ireland

Ivan Jackson – Action Renewables

Fiona Johnson – Action Renewables

John McCann – Sustainable Energy Ireland

David Stanley – Department of Enterprise, Trade and Investment

Bob Hanna – Department of Marine, Communication and Natural Resources

Martin Finucane – Department of Marine, Communication and Natural Resources

A.2 The author would also like to gratefully acknowledge the input and time given by:

Gay Nolan – ESB International

Garth Bryans – Electricity Research Centre, University College Dublin

Morgan Bazilian – Sustainable Energy Ireland

Katrina Polaski – Sustainable Energy Ireland

Pearse Buckley – Sustainable Energy Ireland

Roy Foreman – Northern Ireland Electricity

Bill Cargo – Premier Transmission

Paddy O’Kane – Airtricity

Dermot O’Kane – Airtricity

Mark Fogarty – Airtricity

Fergus Shiels – Airtricity

Michael Kelly – ESB National Grid

Cormac McCarthy – ESB National Grid

Philip O Donnell – ESB National Grid

Doireann Barry – ESB National Grid

Louis Fisher – ESB National Grid

Farah Mydin – Trinity College

ANNEX B – CAPACITY CREDIT CALCULATIONS

B.1 This annex includes details of the generation adequacy assessment for the All-Island system in 2020 and outlines how the capacity credits were derived for the various generation options. A more detailed description of these calculations can be found in the following thesis[30].

B.2 It is essential that any power system have enough capacity to serve the load to the extent defined by a system reliability criterion. In this work the system reliability criterion used is the Loss of Load Expectation (LOLE) which is defined as the number of hours in a year when there is insufficient generation to meet the demand. In the Republic of Ireland the system operator aims to have enough generation capacity to maintain a LOLE of 8 hours per year[31]. The method of deriving capacity credits which proportionality reflects the value of each type of generation capacity in achieving the LOLE of 8 hours is shown in this section. The capacity credits are then incorporated into the least-cost portfolios optimisation.

Capacity Credit Methodology

B.3 There are several ways to calculate a system's LOLE and generation capacity credits. The approach adopted here is a Monte Carlo method similar to that used by Fitz Gerald[32]. Typical forced outage probabilities, the number of days needed each year for scheduled maintenance and the number of days needed for short-term maintenance outages were used for the dispatchable generation.

B.4 In power systems capacity is generally scheduled out for maintenance during periods of lower load when the system is assumed to have sufficient capacity. In the All-Island system this is generally during the summer. The scheduling of units for maintenance here was based on the daily peak load profile. Generation is scheduled as being out on maintenance in order of size, starting with the largest. Units are scheduled out at a time period were the minimum megawatt difference between daily peak load and the remaining capacity is largest.

B.5 In order to assess the generation adequacy of a system and to find capacity credits, a base case portfolio is needed as an initial point of reference for the analysis. For the 2020 All-Island hourly load profile a base case generation portfolio was created which gave a LOLE of 8 hours per year. This portfolio was made up of entirely dispatchable generation in what is thought to be a reasonable mix of base-

[30] Doherty, R., 2005, "New Methods for Planning and Operating Modern Electricity Systems with Significant Wind Generation", Ph.D. Thesis, University College Dublin.

[31] ESB National Grid, 2003, "Generation adequacy report 2004-2010," [Online] Available: http://www.eirgrid.com

[32] Fitz Gerld, J.,2004, "Generation Adequacy in an Island Electricity System", [Online] Available: http://www.esri.ie

load, mid-merit and peaking plant. It was found that the system required 10101 MW of dispatchable generation to have an LOLE of 8 hours. This is approximately 108% of the peak load. The final capacity credits and portfolio results were found not to be sensitive to the make-up of this initial portfolio.

B.6 For any portfolio of plant scheduled for maintenance by the method described above, a Monte Carlo simulation can then calculate the LOLE of the system. For each hour of the year the units that are deemed available by the maintenance schedule can find themselves on forced outage in accordance with the forced outage probabilities. If in any hour there is insufficient capacity to meet the load the system LOLE is increased by 1 hour. At the end of the year the LOLE is the number of hours where the capacity was insufficient to meet the load. The year was then run many times and the average of the yearly LOLEs was found. It was decided to calculate capacity credits based on LOLE calculations run over 1000 years.

B.7 In order to find the capacity credit of the generation considered in this study, the impact of the installed capacity of the generation must be related to the LOLE of the system. To find the capacity credit of certain type of dispatchable generation, extra units of that type of generation were added to the base portfolio. The portfolio of plant was then scheduled out on maintenance and the LOLE was calculated for the 2020 All-Island load profile. An increase in the system LOLE could be measured due to the increase in generation capacity. The load was then increased uniformly in increments of 1 MW during the year until the LOLE returned to 8 hours per year. The capacity credit was then found by dividing the amount of generation capacity added by the increase in load that it could serve at a LOLE of 8 hours per year.

B.8 It was found that all the dispatchable generation had a capacity credit of approximately 0.99. This implies that 1 MW of conventional generation allows almost 1 MW of extra load to be served every hour in the year without decreasing system reliability. Despite having availabilities of around 86 % the fact that the units can be scheduled out on maintenance at times of low load means that they have a high capacity credit.

B.9 To find the capacity credit of the wind generation the various wind profiles ranging from 77 MW to 9500 MW of installed wind capacity were subtracted in turn from the load profile. The LOLE calculations were carried out as before using the base case generation portfolio and the capacity credit was again found by dividing the corresponding installed wind capacity by the increase in load. Figure B-1 shows the capacity credit for the wind capacity at different penetrations. It can be seen that the capacity credit of the wind generation is initially about 0.4 for low penetrations of wind generation. However, this decreases as the penetration of wind generation increases and is about 0.2 for a wind capacity of 4000 MW and 0.11 a wind capacity of 9500 MW. The wind generation’s capacity credit at low penetrations exceeds its capacity factor of 0.35. This is because there are strong seasonal and diurnal elements to the wind generation output. At times of system peak demand during winter daytime hours the wind can in general be expected to be producing more than its average yearly output. The decrease in the capacity credit as wind capacity increases is due to the correlated nature of individual wind farm outputs. Hours of high load and relatively low wind production are likely to also have relatively low wind production with large amount of wind capacity. These type of hours become more significant to the LOLE calculation as the wind capacity increases and this causes a decrease in the wind generation capacity credit.

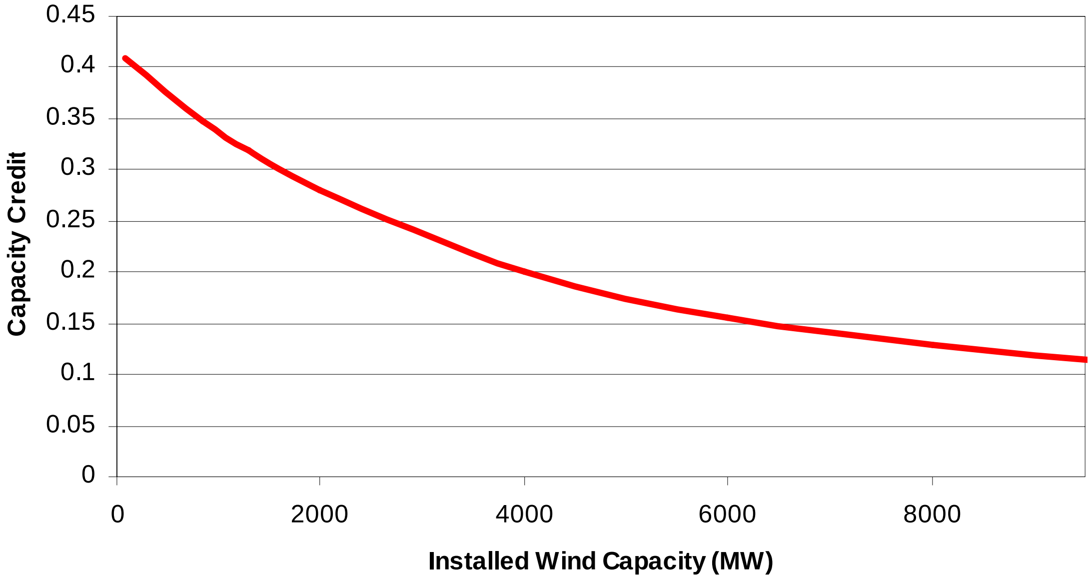

Figure B-1. Wind generation capacity credit versus increasing wind capacity.

B.10 Calculations of capacity credits for wind generation will vary from system to system as the nature of load profiles and wind generations profiles will differ. The capacity credit of wind generation in this work was found to be similar to those calculated in various studies in the Great Britain electricity system[33].

[33] Sustainable Development, Commission, 2005, "Wind Power in the UK", [Online] Available: http://www.sd-commission.org.uk

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ANNEX C – PORTFOLIO OPTIMISATION ALGORITHM

C.1 This annex includes formal details of the portfolio optimisation algorithm. The objective of the algorithm is to assess the portfolio of generation that will deliver electricity at the least-cost. The methodology considers the cost issues described in Section 3, issues of system capacity, plant utilisation and net-load duration characteristics. Rather than solving for the installed capacity of the various types of generations in the portfolio while trying to approximate when they may be used during the year, the approach adopted here is to optimize the installed capacities and when they are used.

C.2 The approach solves for a least-cost generation portfolio for a given wind penetration WP. The level of wind generation is altered between 0 and 9500 MW in 500 MW steps and the level that results in the least-cost electricity indicates the optimal portfolio for the given input conditions.

C.3 In a similar way to wind generation, the variable renewable generation option introduces its own unique features into the generation planning problem. However, given the smaller role that this generation option appears to have in generation portfolios, specific consideration of these features has not been included in the algorithm. Instead, the variable renewable generation option is been included in the algorithm in a similar way as base load generation.

C.4 In this formulation the control variables are:

I_n the installed capacity of each type of dispatchable generation n in MW.

$E_{b,n}$ the amount of energy delivered in MWh by each type of dispatchable generation n in each net-load duration bin b.

C.5 The optimization algorithm allows the installed capacity of each technology to be a continuous variable from 0 to infinity or its limited amount as shown in Table 3-2. This allows the problem to be formulated as a linear program and the complications of discrete integer optimization to be avoided. The energy served in each load bin by each technology, $E_{b,n}$ is linked to the installed capacity, I_n, with the use of constraints. The aim is to minimize the objective function in the equation below. This is the cost of supplying the All-Island net-load for a given wind penetration.

$$min \quad WPCc_{WP} + \sum_{n \in N} Cc_n I_n + \sum_{n \in N} \sum_{b \in B_{WP}} Cf_n E_{b,n}$$

N is the set of dispatchable generation technologies being considered.

B_{WP} is the set of net-load duration bins corresponding to a wind penetration of WP megawatts.

Cc_n is the annuitised capital cost and annual operation and maintenance cost of the dispatchable generation in € per MW installed / year.

Cc_{WP} is the annuitised capital cost and annual operation and maintenance cost of WP megawatts of wind capacity in € per MW installed / year.

Cf_n is the fuel cost of the dispatchable generation in €/MWh.

C.6 This is subject to the capacity constraints which ensures every portfolio will have a LOLE of 8 hours per year.

$$\sum_{n \in N} I_n 0.99 \geq 10000 - WPCapC_{WP}$$

$CapC_{WP}$ is the capacity credit corresponding to a wind penetration of WP.

0.99 is the capacity credit of the dispatchable generation.

The value of 10000 in the constraint comes from 10101×0.99 and is coincidental.

C.7 The constraint in the equation below ensures that there is sufficient energy for the generation to serve the demand in each net-load bin.

$$\sum_{n \in N} E_{b,n} = H_b M_b \quad \forall \;\; b \in B_{WP}$$

H_b is the number of hours in each net-load bin.

M_b is the centre value of each net-load bin.where

C.8 The energy served by each generation technology must not be greater than the installed capacity of that technology multiplied by its availability in hours per year, $Avail_n$.

$$\sum_{b \in B_{WP}} E_{b,n} \leq I_n Avail_n \quad \forall \;\; n \in N$$

C.9 The constraint in the equation below is used to ensure that that one MW of installed capacity does not provide more than one MWh at a time.

$$E_{b,n} \leq I_n H_b \quad \forall \;\; b \in B_{WP}, \quad \forall \;\; n \in N$$

The formulation given by equations above solves, for each wind penetration, the installed capacity of each generation option and the amounts generated from the capacity that will result in the load being supplied at least-cost. This approach takes into account the nature of the load duration curve, the changes wind generation causes to the net load duration and respects the need to have sufficient capacity to maintain a LOLE of 8 hours per year. The optimization algorithm is run several times for different wind penetrations producing a series of portfolios. The portfolio that results in the least-cost is then selected as the optimal.

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ANNEX D – COMPLETE PORTFOLIOS FOR USE IN THE ALL-ISLAND GRID STUDY

D.1 This annex presents in detail the five generation portfolios to be used in the other work-streams of the All-Island grid study.

PORTFOLIO 1					
Code	Unit	Capacity (MW)	Code	Unit	Capacity (MW)
AD1	Aghada Unit 1	258	B10	Ballylumford Unit 10	103
AA1	Ardnacrusha Unit 1	21	BGT1	Ballylumford GT1	53
AA2	Ardnacrusha Unit 2	22	BGT2	Ballylumford GT2	53
AA3	Ardnacrusha Unit 3	19	CPS CCGT	Coolkeeragh CCGT	404
AA4	Ardnacrusha Unit 4	24	CGT8	Coolkeeragh GT8	53
DBP	Dublin Bay Power	396	K1	Kilroot Unit 1	201
ED1	Edenderry *	117.6	K2	Kilroot Unit 2	201
ER1	Erne Unit 1	10	KGT1	Kilroot GT1	29
ER2	Erne Unit 2	10	KGT2	Kilroot GT2	29
ER3	Erne Unit 3	22.5	Inter 1	Interconnector	500
ER4	Erne Unit 4	22.5	Inter 2	Interconnector	500
LE1	Lee Unit 1	15	NCT1	New CCGT (2+1)	480
LE2	Lee Unit 2	4	NCT2	New CCGT	414
LE3	Lee Unit 3	8	NOT1	New OCGT	103.58
LI1	Liffey Unit 1	15	NOT2	New OCGT	103.58
LI2	Liffey Unit 2	15	NOT3	New OCGT	103.58
LI4	Liffey Unit 4	4	NOT4	New OCGT	103.58
LI5	Liffey Unit 5	4	NOT5	New OCGT	103.58
LR4	Lough Ree *	91	NOT6	New OCGT	103.58
HNC	Huntstown	342.7	NOT7	New OCGT	103.58
MRT	Marina CC	112.29	NOT8	New OCGT	103.58
MP1	Moneypoint Unit 1	282.5	NOT9	New OCGT	103.58
MP2	Moneypoint Unit 2	282.5	NOT10	New OCGT	103.58
MP3	Moneypoint Unit 3	282.5	NOT11	New OCGT	103.58
PBC	Poolbeg Combined Cycle	480	NOT12	New OCGT	103.58
RH1	Rhode Unit 1	52	NOT13	New OCGT	103.58
RH2	Rhode Unit 2	52	NOT14	New OCGT	103.58
TP1	Asahi Peaking Unit	52	NOT15	New OCGT	103.58
SK1	Aughinish (Sealrock)	150	NOT16	New OCGT	103.58
TE	Tynagh	404	NOT17	New OCGT	103.58
TH1	Turlough Hill Unit 1	73	NAT1	New ADGT	89
TH2	Turlough Hill Unit 2	73	LFG	Total Landfill Gas	68
TH3	Turlough Hill Unit 3	73	BG	Total Biogas**	73
TH4	Turlough Hill Unit 4	73	BM	Total Biomass***	25
WO4	West Offaly Power *	137	SG	Total Sewage Gas	4
B31	Ballylumford CCGT 31	240	TS	Total Tidal Stream	70
B32	Ballylumford Unit 32	240	WD	Wind Generation	2000

* Indicates 30% co-fired with wood biomass

** Biogas category includes farm slurries, agricultural residues and residues from pasture land

*** Biomass category includes forestry residues and products, agricultural residues and products and biodegradable fractions of municipal waste

PORTFOLIO 2					
Code	Unit	Capacity (MW)	Code	Unit	Capacity (MW)
AD1	Aghada Unit 1	258	BGT2	Ballylumford GT2	53
AA1	Ardnacrusha Unit 1	21	CPS CCGT	Coolkeeragh CCGT	404
AA2	Ardnacrusha Unit 2	22	CGT8	Coolkeeragh GT8	53
AA3	Ardnacrusha Unit 3	19	K1	Kilroot Unit 1	201
AA4	Ardnacrusha Unit 4	24	K2	Kilroot Unit 2	201
DBP	Dublin Bay Power	396	KGT1	Kilroot GT1	29
ED1	Edenderry *	117.6	KGT2	Kilroot GT2	29
ER1	Erne Unit 1	10	Inter 1	Interconnector	500
ER2	Erne Unit 2	10	Inter 2	Interconnector	500
ER3	Erne Unit 3	22.5	NOT1	New OCGT	103.56
ER4	Erne Unit 4	22.5	NOT2	New OCGT	103.56
LE1	Lee Unit 1	15	NOT3	New OCGT	103.56
LE2	Lee Unit 2	4	NOT4	New OCGT	103.56
LE3	Lee Unit 3	8	NOT5	New OCGT	103.56
LI1	Liffey Unit 1	15	NOT6	New OCGT	103.56
LI2	Liffey Unit 2	15	NOT7	New OCGT	103.56
LI4	Liffey Unit 4	4	NOT8	New OCGT	103.56
LI5	Liffey Unit 5	4	NOT9	New OCGT	103.56
LR4	Lough Ree *	91	NOT10	New OCGT	103.56
HNC	Huntstown	342.7	NOT11	New OCGT	103.56
MRT	Marina CC	112.29	NOT12	New OCGT	103.56
MP1	Moneypoint Unit 1	282.5	NOT13	New OCGT	103.56
MP2	Moneypoint Unit 2	282.5	NOT14	New OCGT	103.56
MP3	Moneypoint Unit 3	282.5	NOT15	New OCGT	103.56
PBC	Poolbeg Combined Cycle	480	NOT16	New OCGT	103.56
RH1	Rhode Unit 1	52	NOT17	New OCGT	103.56
RH2	Rhode Unit 2	52	NOT18	New OCGT	103.56
TP1	Asahi Peaking Unit	52	NOT19	New OCGT	103.56
SK1	Aughinish (Sealrock)	150	NAT1	New ADGT	106.97
TE	Tynagh	404	NAT2	New ADGT	106.97
TH1	Turlough Hill Unit 1	73	NAT3	New ADGT	106.97
TH2	Turlough Hill Unit 2	73	NAT4	New ADGT	106.97
TH3	Turlough Hill Unit 3	73	NAT5	New ADGT	106.97
TH4	Turlough Hill Unit 4	73	LFG	Total Landfill Gas	68
WO4	West Offaly Power *	137	BG	Total Biogas**	73
B31	Ballylumford CCGT 31	240	BM	Total Biomass***	25
B32	Ballylumford Unit 32	240	SG	Total Sewage Gas	4
B10	Ballylumford Unit 10	103	TS	Total Tidal Stream	70
BGT1	Ballylumford GT1	53	WD	Wind Generation	4000

* Indicates 30% co-fired with wood biomass

** Biogas category includes farm slurries, agricultural residues and residues from pasture land

*** Biomass category includes forestry residues and products, agricultural residues and products and biodegradable fractions of municipal waste

PORTFOLIO 3					
Code	Unit	Capacity (MW)	Code	Unit	Capacity (MW)
AD1	Aghada Unit 1	258	WO4	West Offaly Power *	137
AA1	Ardnacrusha Unit 1	21	B31	Ballylumford CCGT 31	240
AA2	Ardnacrusha Unit 2	22	B32	Ballylumford Unit 32	240
AA3	Ardnacrusha Unit 3	19	B10	Ballylumford Unit 10	103
AA4	Ardnacrusha Unit 4	24	BGT1	Ballylumford GT1	53
DBP	Dublin Bay Power	396	BGT2	Ballylumford GT2	53
ED1	Edenderry *	117.6	CPS CCGT	Coolkeeragh CCGT	404
ER1	Erne Unit 1	10	CGT8	Coolkeeragh GT8	53
ER2	Erne Unit 2	10	K1	Kilroot Unit 1	201
ER3	Erne Unit 3	22.5	K2	Kilroot Unit 2	201
ER4	Erne Unit 4	22.5	KGT1	Kilroot GT1	29
LE1	Lee Unit 1	15	KGT2	Kilroot GT2	29
LE2	Lee Unit 2	4	Inter 1	Interconnector	500
LE3	Lee Unit 3	8	Inter 2	Interconnector	500
LI1	Liffey Unit 1	15	NCG1	New Moneypoint Coal Unit	387.5
LI2	Liffey Unit 2	15	NCG2	New Moneypoint Coal Unit	387.5
LI4	Liffey Unit 4	4	NCG3	New Moneypoint Coal Unit	387.5
LI5	Liffey Unit 5	4	NCG4	New Moneypoint Coal Unit	387.5
LR4	Lough Ree *	91	NOT1	New OCGT	95.25
HNC	Huntstown	342.7	NOT2	New OCGT	95.25
MRT	Marina CC	112.29	NOT3	New OCGT	95.25
MP1	Moneypoint Unit 1	282.5	NOT4	New OCGT	95.25
MP2	Moneypoint Unit 2	282.5	NOT5	New OCGT	95.25
MP3	Moneypoint Unit 3	282.5	NOT6	New OCGT	95.25
PBC	Poolbeg Combined Cycle	480	NOT7	New OCGT	95.25
RH1	Rhode Unit 1	52	NOT8	New OCGT	95.25
RH2	Rhode Unit 2	52	NOT9	New OCGT	95.25
TP1	Asahi Peaking Unit	52	NOT10	New OCGT	95.25
SK1	Aughinish (Sealrock)	150	LFG	Total Landfill Gas	68
TE	Tynagh	404	BG	Total Biogas**	73
TH1	Turlough Hill Unit 1	73	BM	Total Biomass***	25
TH2	Turlough Hill Unit 2	73	SG	Total Sewage Gas	4
TH3	Turlough Hill Unit 3	73	TS	Total Tidal Stream	70
TH4	Turlough Hill Unit 4	73	WD	Wind Generation	4000

* Indicates 30% co-fired with wood biomass

** Biogas category includes farm slurries, agricultural residues and residues from pasture land

*** Biomass category includes forestry residues and products, agricultural residues and products and biodegradable fractions of municipal waste

PORTFOLIO 4					
Code	Unit	Capacity (MW)	Code	Unit	Capacity (MW)
AD1	Aghada Unit 1	258	BGT1	Ballylumford GT1	53
AA1	Ardnacrusha Unit 1	21	BGT2	Ballylumford GT2	53
AA2	Ardnacrusha Unit 2	22	CPS CCGT	Coolkeeragh CCGT	404
AA3	Ardnacrusha Unit 3	19	CGT8	Coolkeeragh GT8	53
AA4	Ardnacrusha Unit 4	24	K1	Kilroot Unit 1	201
DBP	Dublin Bay Power	396	K2	Kilroot Unit 2	201
ED1	Edenderry *	117.6	KGT1	Kilroot GT1	29
ER1	Erne Unit 1	10	KGT2	Kilroot GT2	29
ER2	Erne Unit 2	10	Inter 1	Interconnector	500
ER3	Erne Unit 3	22.5	Inter 2	Interconnector	500
ER4	Erne Unit 4	22.5	NOT1	New OCGT	101.57
LE1	Lee Unit 1	15	NOT2	New OCGT	101.57
LE2	Lee Unit 2	4	NOT3	New OCGT	101.57
LE3	Lee Unit 3	8	NOT4	New OCGT	101.57
LI1	Liffey Unit 1	15	NOT5	New OCGT	101.57
LI2	Liffey Unit 2	15	NOT6	New OCGT	101.57
LI4	Liffey Unit 4	4	NOT7	New OCGT	101.57
LI5	Liffey Unit 5	4	NOT8	New OCGT	101.57
LR4	Lough Ree *	91	NOT9	New OCGT	101.57
HNC	Huntstown	342.7	NOT10	New OCGT	101.57
MRT	Marina CC	112.29	NOT11	New OCGT	101.57
MP1	Moneypoint Unit 1	282.5	NOT12	New OCGT	101.57
MP2	Moneypoint Unit 2	282.5	NOT13	New OCGT	101.57
MP3	Moneypoint Unit 3	282.5	NOT14	New OCGT	101.57
PBC	Poolbeg Combined Cycle	480	NOT15	New OCGT	101.57
RH1	Rhode Unit 1	52	NOT16	New OCGT	101.57
RH2	Rhode Unit 2	52	NOT17	New OCGT	101.57
TP1	Asahi Peaking Unit	52	NOT18	New OCGT	101.57
SK1	Aughinish (Sealrock)	150	NOT19	New OCGT	101.57
TE	Tynagh	404	NOT20	New OCGT	101.57
TH1	Turlough Hill Unit 1	73	NAT1	New ADGT	111
TH2	Turlough Hill Unit 2	73	LFG	Total Landfill Gas	68
TH3	Turlough Hill Unit 3	73	BG	Total Biogas**	206
TH4	Turlough Hill Unit 4	73	BM	Total Biomass***	92
WO4	West Offaly Power *	137	SG	Total Sewage Gas	4
B31	Ballylumford CCGT 31	240	TS	Total Tidal Stream	200
B32	Ballylumford Unit 32	240	WD	Wind Generation	6000
B10	Ballylumford Unit 10	103			

* Indicates 30% co-fired with wood biomass

** Biogas category includes farm slurries, agricultural residues and residues from pasture land

*** Biomass category includes forestry residues and products, agricultural residues and products and biodegradable fractions of municipal waste

PORTFOLIO 5					
Code	Unit	Capacity (MW)	Code	Unit	Capacity (MW)
AD1	Aghada Unit 1	258	B32	Ballylumford Unit 32	240
AA1	Ardnacrusha Unit 1	21	B10	Ballylumford Unit 10	103
AA2	Ardnacrusha Unit 2	22	BGT1	Ballylumford GT1	53
AA3	Ardnacrusha Unit 3	19	BGT2	Ballylumford GT2	53
AA4	Ardnacrusha Unit 4	24	CPS CCGT	Coolkeeragh CCGT	404
DBP	Dublin Bay Power	396	CGT8	Coolkeeragh GT8	53
ED1	Edenderry *	117.6	K1	Kilroot Unit 1	201
ER1	Erne Unit 1	10	K2	Kilroot Unit 2	201
ER2	Erne Unit 2	10	KGT1	Kilroot GT1	29
ER3	Erne Unit 3	22.5	KGT2	Kilroot GT2	29
ER4	Erne Unit 4	22.5	Inter 1	Interconnector	500
LE1	Lee Unit 1	15	Inter 2	Interconnector	500
LE2	Lee Unit 2	4	NOT1	New OCGT	99.88
LE3	Lee Unit 3	8	NOT2	New OCGT	99.88
LI1	Liffey Unit 1	15	NOT3	New OCGT	99.88
LI2	Liffey Unit 2	15	NOT4	New OCGT	99.88
LI4	Liffey Unit 4	4	NOT5	New OCGT	99.88
LI5	Liffey Unit 5	4	NOT6	New OCGT	99.88
LR4	Lough Ree *	91	NOT7	New OCGT	99.88
HNC	Huntstown	342.7	NOT8	New OCGT	99.88
MRT	Marina CC	112.29	NOT9	New OCGT	99.88
MP1	Moneypoint Unit 1	282.5	NOT10	New OCGT	99.88
MP2	Moneypoint Unit 2	282.5	NOT11	New OCGT	99.88
MP3	Moneypoint Unit 3	282.5	NOT12	New OCGT	99.88
PBC	Poolbeg Combined Cycle	480	NOT13	New OCGT	99.88
RH1	Rhode Unit 1	52	NOT14	New OCGT	99.88
RH2	Rhode Unit 2	52	NOT15	New OCGT	99.88
TP1	Asahi Peaking Unit	52	NOT16	New OCGT	99.88
SK1	Aughinish (Sealrock)	150	LFG	Total Landfill Gas	68
TE	Tynagh	404	BG	Total Biogas**	269
TH1	Turlough Hill Unit 1	73	BM	Total Biomass***	167
TH2	Turlough Hill Unit 2	73	SG	Total Sewage Gas	16
TH3	Turlough Hill Unit 3	73	TS	Total Tidal Stream	200
TH4	Turlough Hill Unit 4	73	WE	Wave Energy	1400
WO4	West Offaly Power *	137	WD	Wind Generation	8000
B31	Ballylumford CCGT 31	240			

* Indicates 30% co-fired with wood biomass

** Biogas category includes farm slurries, agricultural residues and residues from pasture land

*** Biomass category includes forestry residues and products, agricultural residues and products and biodegradable fractions of municipal waste