ALL ISLAND GRID STUDY

WORK STREAM 4

ANALYSIS OF IMPACTS AND BENEFITS

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

Executive Summary

The All Island Grid Study is the first comprehensive assessment of the ability of the electrical power system and, as part of that, the transmission network ("the grid") on the island of Ireland to absorb large amounts of electricity produced from renewable energy sources. The objective of this five part study is to assess the technical feasibility and the relative costs and benefits associated with various scenarios for increased shares of electricity sourced from renewable energy in the all island power system.

Study Methodology

Six generation portfolios were selected for investigation comprising a range of different renewable and conventional technologies in varying compositions. The assessment considers certain elements of cost and benefit for a single year (2020). Specialist consultants with relevant expertise for each area carried out a screening study, a resource assessment, a dispatch study, and a network study, which provided information for assessment in the cost benefit study.

This document reports on the final work stream which brings some of the costs and benefits identified within each of the prior work streams together to consider an aggregate picture of the relative positions of each of the generation portfolios.

Work stream 2A selected the portfolios of generation to be further examined in later work streams using a linear programming optimisation model with a simplified treatment of dispatch and network issues to produce least cost generation portfolios over a wide range of cost scenarios for: fuel, carbon, renewable resource, conventional generation, and network reinforcement. The portfolios selected cover a range of renewable energy penetration with renewable electricity providing from 17% to 54% of energy demand in portfolios 1 to 6 respectively. These were subsequently adjusted in work stream 2B to ensure a comparable level of system security across all portfolios.

The six portfolios were then populated by specific renewable generation projects through the resource study analysis in **work stream 1**. This study included the establishment of resource cost curves for each technology using cost assessments including investment and both fixed and variable operating costs. Investment costs included the cost of network connection to the closest connection point on the 110 kV network. The population of the renewable generation for each portfolio gave priority to those projects that had already submitted applications for grid connection or had received planning permission. The remainder of the allocation was based on least cost projects as identified on the resource cost curve. A spatial allocation of all generation plants and the costs of energy for each renewable project were provided to work stream 2B and work stream 3, and the renewable generation costs were a key input to work stream 4.

Work stream 2B used a scenario tree tool to provide continuous forecast scenarios of wind power, load, forced outages and required reserves for the year 2020. Based on the forecast scenarios a scheduling model minimised the expected operating costs across the portfolios. The model provided dispatch information on all plants for the year 2020 for each portfolio considered, including fuel consumption, reserve allocation, electricity imports and exports, and CO_2 emissions. A number of assumptions made in this study are important to any interpretation of the results, including: the dispatch assumed no network restrictions because iteration between the work streams was not possible; total interconnection to Great Britain was assumed to be 1000MW; 100MW of interconnection was assumed available for spinning reserve; CO_2 costs were assumed to be €30/tonne and gas costs assumed are €22/MWh thermal.

Work stream 3 used the spatial allocation of the generation portfolios provided by **work stream 1** to assess the extent and cost of the required additional transmission network development to accommodate the renewable generation in the different portfolios. Distribution connections and extension of distribution networks was not included explicitly within the scope of this study, however distribution connections were considered in the renewable energy cost analysis in work stream 1. Specific dispatches representing winter peak, summer maximum and summer night valley, with high and low wind generation were used to test the load flow simulations. Some additional dispatches from work stream 2B were also considered. The network development was done initially with a DC load flow model and then refined with an AC model to address voltage and reactive power issues[1]. The study methodology incorporated a number of limitations that should be noted by the reader, namely: the network developed allowed for the unexpected loss of a *single transmission line* at any one time but did not include provision to take lines out of service for maintenance, which may have understated the required instances of generation constraint; the studies were steady-state calculations meaning dynamic issues such as frequency stability and transient stability were not considered, which may have understated dispatch restrictions, resulting in an underestimation of operational costs, required wind curtailment, and CO_2 emissions.

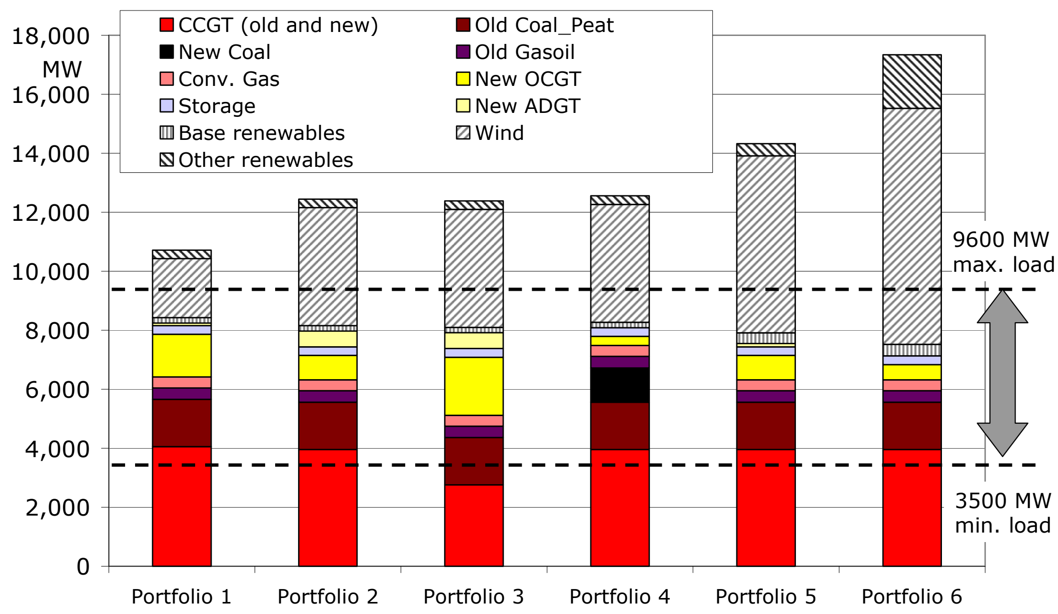
Work stream 4 analysed the information provided from each of the previous work streams to present a comparison across the portfolios of certain costs and benefits associated with each. The work stream included a stakeholder analysis of the key

[1] A D.C. (Direct Current) load flow model is a simplified computational model for network analysis which simulates direct current electricity flow within the modelled electricity network to initially establish the direction and magnitude of power flows and estimate the required conductor sizes. A more complex A.C. (Alternating Current) network model is then applied to simulate the actual operation of the system under steady state conditions, allowing accurate assessment of power flows and selection of the required network components.

stakeholder classes across the electricity sector: conventional generators, renewable generators, network operators and owners, system operation and interconnector operation. The key findings from the previous work streams in relation to each stakeholder group were discussed and quantified in cost and benefit terms where the Study scope and methodologies facilitated such quantification. The costs associated with electricity generation for most stakeholder classes were then aggregated to provide a relative cost comparison across generation portfolios for the year 2020. The capital cost for existing conventional generators was not included in the aggregation analysis as they would be the same across all portfolios and thus do not impact on the relative cost comparison. It is critical to note that work stream 4, as well as work stream 2B, abstracted from real-world market designs, i.e. the study assumed market and support mechanisms without imperfections and a strictly marginal cost pricing principle.

Results and Conclusions

Portfolios selected (results of work stream 2A)



Share of renewable capacity	23 %	36 %	36 %	36 %	47 %	59 %

Figure E-1: Composition of 2020 generation portfolios, renewable share of total installed capacity

Work stream 2A assumed that approximately 1,800MW of the existing generation units will be retired by 2020. The figure above shows the installed capacities of conventional generation (solid areas) and renewable generation (hatched) in the 2020 scenario. The term “base renewables” characterises all renewable technologies capable of contributing to base load such as biomass or biogas plants. “Other renewables” comprises wave and tidal energy.

Portfolios 2 to 4 vary the amounts and technologies used to satisfy the requirement for new conventional generation with the same amount of renewable generation: Portfolio 2 uses a large proportion of combined cycle gas turbines; Portfolio 3 uses a large proportion of open cycle gas turbines and aero-derivative gas turbines; Portfolio 4 uses a new large coal plant. The amount of renewable generation across the portfolios is as follows:

- Portfolio 1 – 2000MW wind energy, 182MWMW base renewables, 71MW variable renewables
- Portfolios 2 to 4 – base and variable renewables as in Portfolio 1 but increasing to 4000MW wind energy
- Portfolio 5 – 6000MW wind energy, 360MW base renewables, 200MW variable renewables
- Portfolio 6 – 8000MW wind energy, 392MW base renewables and 1600MW variable renewables

These portfolios are used throughout the remainder of the work streams in the All-Island Grid Study.

Portfolio 6

In the course of the analysis of the dispatch and the network implications, portfolio 6 exceeded the limitations of the methodologies applied. In the dispatch study a significant number of hours characterised by extreme system situations occurred where load and reserve requirements could not be met. The results of the network study indicated that for such extreme renewable penetration scenarios, a system redesign is required, rather than a reinforcement exercise.

At this point, the determination of costs and benefits had become extremely dependent on the assumptions made for extreme situations, which adversely affected the robustness of the results. As a consequence, throughout the Study, results of portfolio 6 were only included for illustrative purposes in selected circumstances.

Geographic distribution of generation and renewable energy investment costs (results of work stream 1)

Work stream 1 analysed the geographic spread of wind energy in key zones. Wind energy projects are mapped on a grid of 200 meter spacing for analysis based on wind speed mapping, and transmission system planning as well as connection costs based on distance to the nearest 110kV connection point.

Similar geographic distribution information was prepared for the other renewable energy technologies. This information is a key contribution to the network development study in work stream 3, where planning was based on project location in relation to 110kV nodes, and to the scenario tree tool used in work stream 2B for determining the power output from all variable renewables to feed in to the scheduling model.

Work stream 1 also generated levelised cost curves for each technology. The levelised cost represents the total discounted capital and operating cost divided by the total output in kWh over the life of a project. The result represents the average price a renewable generator would have to receive, in euro per kWh, for power produced to make an assumed amount of profit[2]. The levelised cost curve ranks projects by their levelised cost. Renewable projects in each portfolio were selected on the basis of the levelised cost rankings, except where preference was given to projects with planning permission and grid connection contracts.

The same cost information as used in the levelised cost calculations were used to calculate the total investment cost for the renewable projects included in the portfolios. This information is annualised for inclusion in the overall results of work stream 4.

Dispatch results: revenues and short term costs for conventional generators, and CO_2 reduction benefits (results of work stream 2B)

The dispatch model produced hourly dispatches with associated operating costs in each period. These system operating costs, representing total fuel cost, cost of carbon, and net import payments for the year 2020 resulting from the dispatch of conventional generators, is a key input to the aggregation analysis of work stream 4[3]. The difference of operating cost between the portfolio with the highest cost (portfolio 1) and the lowest cost (portfolio 5) is about 30% or €740 million. At higher proportions of renewable capacity installed, less conventional capacity is required to run and thus the operational cost decreases. The operating costs required vary in portfolios 2 to 4 as a result of the various new conventional generation mix technologies employed.

The dispatch model also produced hourly system marginal prices, reflecting the operating cost of the most expensive generator called on to dispatch during the period. The resulting weighted average price varied from €51/MWh to €61/MWh across portfolios 1 to 5. The dispatch results are used in work stream 4 as a proxy market

---

[2] Assumed profit was based on an 8% weighted average cost of capital for the Study.

[3] Note that other variable operating costs, such as variable maintenance costs, and fixed operating costs, such as payroll costs, for conventional generators are excluded.

price to consider the revenues possible for energy output for the different types of generators operating in the market. It is important to note that this is only a proxy and modelling a real market price would require modelling a market, which was out of the scope for this study.

Network reinforcement cost annualised (work stream 3 results)

The existing all island transmission network, all reinforcements that had received internal approval within EirGrid or NIE, the assumption of some additional reinforcement to accommodate additional generation in Cork and the construction of an additional 500MW interconnector to Great Britain formed the "baseline" for the evaluation of network reinforcements in work stream 3. The study only considered transmission system costs and did not consider distribution system impacts. The total required capital investments in both the Republic of Ireland and Northern Ireland, and the total length of transmission network that needs to be reinforced due to the addition of renewable energy generators to the system in both jurisdictions for each portfolio are calculated in work stream 3. Total investment required varies from €92 million for portfolio 1 to €1,007 million for portfolio 5, including the cost for an additional 75 kilometres to 845 kilometres of transmission lines respectively. The incremental cost to incorporate 6000MW (portfolio 5) rather than 4000MW (portfolios 2 to 4) is roughly half the amount required to incorporate 4000 compared to 2000MW (portfolio 1) of wind.

It should be emphasised that work stream 3 assumed an integrated planning process with a predefined renewable capacity target per portfolio. Initially planning and building for 4000MW of wind and then deciding later on to increase the network capacity to accommodate 6000MW of wind would likely result in a requirement for more lines and higher costs than would be required if the decision at the outset was to build to accommodate 6000MW of wind. In the former case, the costs incurred would likely be higher for the accommodation of 6000MW than those shown above.

Planning and permitting of these new lines represents a major challenge for the network operators and the authorities. As public acceptance for overhead lines is problematic, planning procedures may be very time consuming and availability of the complete infrastructure as identified in work stream 3 by the year 2020 is questionable.

Total capital cost for new generation (work stream 4 analysis)

The analysis of the relative cost of generation in work stream 4 requires consideration of the investment costs for new conventional generation. Because the new conventional generation requirements are different for each portfolio, the investment costs will be different for each. The investment cost for existing conventional generators are the same across all portfolios; as such, their inclusion is not required in analysing the relative cost of generation across the portfolios, however it will add to the cost of all portfolios equally.

It is important to consider the investment cost of conventional generators, both existing and new, as only the variable operating costs have been considered thus far (i.e. the cost of fuel and carbon). Conventional generators will need to recover their investment costs as well through revenue received in periods when they are not the marginal generator, and via payments for ancillary services and/or capacity payments. Because the study of a market was out of scope for work stream 4, a full analysis of the revenue available was not possible.

Aggregate additional costs and selected benefits

The figure below provides an aggregation of the additional costs to society considered in the study in millions of euro for the year 2020 for the five portfolios. It has to be pointed out that the given cost figures do not reflect the full cost of electricity supply but rather indicate the relative relationship between the elements of the costs of generation investigated in this study in the different portfolios.

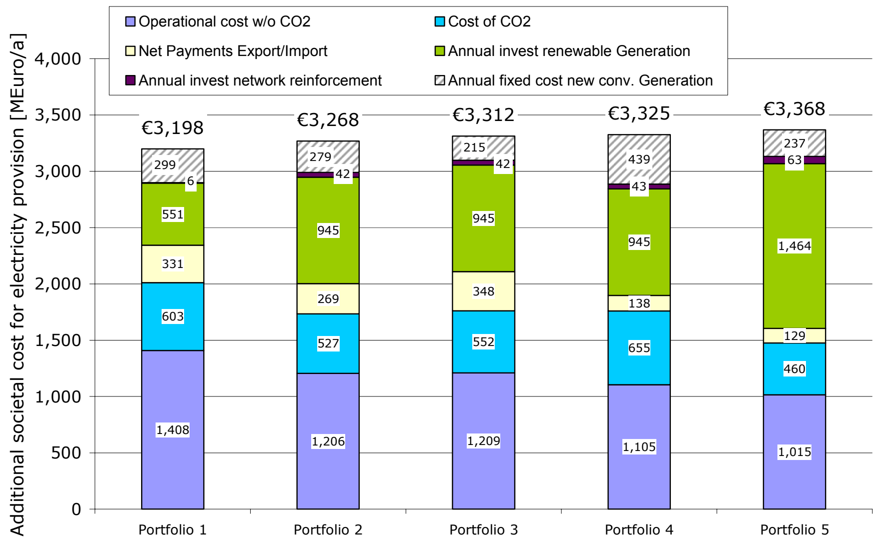
The additional cost to society is defined as the sum of the operating costs of the power system and varies with the generation portfolios. These costs include:

- The operational costs of generation consisting of the fuel costs and the cost of CO_2;
- The charges for the net imports over the interconnector;
- The total annual investment costs for all renewable generation, existing and new;
- The annual investment in network reinforcements;
- Investment in new conventional generation. Under market rules these costs would typically be covered by revenues from energy markets (infra marginal rents) as well as by those from ancillary services and capacity payments where in place.

The following costs were excluded from the analysis:

- the historic investment costs of existing conventional generation as well as for the base case transmission assets and additional 500MW interconnector. As these cost components apply identically to all portfolios it does not compromise a comparison between the portfolios.
- variable maintenance costs

These additional costs will need to be recovered within the price of electricity charged to end users.



RE share of demand	16%	27%	27%	27%	42%
CO_2 emissions [Mt/a]	20	18	18	22	15

Figure E-2: Additional societal cost for electricity provision in M€/annum

The information presented illustrates the order of magnitude of the change of the cost components examined between the portfolios. It shows that the total cost to end users varies by at most 7% between the highest cost and lowest cost portfolios. Thus the presented results indicate that the difference in cost between the highest cost and the lowest cost portfolios are low, given the assumptions made in this Study.

The resulting relative carbon emissions from each portfolio again show that at higher proportions of renewable capacity installed, less carbon is emitted. Portfolio 4, with the new coal plant utilised, has the highest emissions.

Work stream 4 also considers the annual fuel consumption by the all island power system of those fuels that, for the most part, have to be imported. It identifies that the total amount of imported fuels declines with increasing shares of renewable generation by as much as 23% between portfolio 1 and portfolio 5.

All but portfolio 4, which is substantially coal based, lead to significant reductions of CO_2 emissions compared to portfolio 1. Compared to portfolio 1 (2000MW) wind, 25 % of the total CO_2 emissions from the electricity sector can be avoided by incorporating the renewable generation of portfolio 5 (including 6000MW wind). Additionally, they reduce the dependency of the all island system on fuel and electricity imports. However, the construction of a second interconnector to the GB system is a precondition for the feasibility of the portfolios.

A precondition for implementation of the portfolios, in particular in the case of high renewable shares, is a substantial reinforcement of the existing transmission networks. This is a substantial planning challenge and the typically long lead times require an immediate policy response if the study-year 2020 is accepted as target date.

More actions have to be taken in order to support the portfolios with increased renewable energy shares and to facilitate the respective transition processes. Sufficient investment in and appropriate operation of the generation plant relies on adequate framework conditions and underlying policies. Despite the snapshot character of the study, the results indicated a number of key issues likely to be relevant during this transition.

The dispatch results of workstream 2B are used in work stream 4 as a proxy market price to consider the revenues possible for energy output for the different types of generators operating in the market and to assess the required support payments for renewable generators. The analysis shows that 70% to 80% of the total investment cost for renewable generation can be recovered by these generators in the electricity market. It is important to note that this figure is only a proxy and modelling a real market price and cost of support would require modelling a market, which was out of the scope for this study. However, it was shown that the required cost of support depends not only on the renewable generation portfolio but also on the structure of conventional generation that influences the electricity price level.

Key conclusions

- The presented results indicate that the differences in cost between the highest cost and the lowest cost portfolios are low (7%) for the costs considered
- All but the high coal based portfolio lead to significant reductions of CO_2 emissions compared to portfolio 1
- All but the high coal based portfolio lead to reductions on the dependency of the all island system on fuel and electricity imports
- The limitations of the study may overstate the technical feasibility of the portfolios analysed and could impact the costs and benefits resulting. Further work is required to understand the extent of such impact.
- Timely development of the transmission networks, requiring means to address the planning challenge, is a precondition for implementation of the portfolios considered.
- Market mechanisms must facilitate the installation of complementary, i.e. flexibly dispatchable plant so as to maintain adequate levels of system security.

Further work required

All efforts, within the resources of the study, were directed at developing results which are as realistic as possible using state-of-the art methodologies. However, in particular within the high penetration portfolios, a number of limitations of the study's methodologies have to be acknowledged. These limitations may affect the technical feasibility of the dispatches and consequently the economic performance of the portfolios.

The focus of technical follow up studies should be on the dynamic behaviour of the system accommodating high portions of renewable generation. These should be accompanied by detailed network planning studies assessing the challenges associated with the development of the transmission system and generator connections.

Additionally, an evaluation of the portfolios under the conditions of real markets will be required in order to specify the conditions under which sufficient returns will be available for existing and new conventional and renewable generators. Consequently these studies should sufficiently reflect risk perception and investment behaviour of stakeholders. In that way, also the potential societal cost of imperfections of market and support mechanisms can be assessed.

Table of contents

List of figures

List of tables

1 Introduction

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.

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.

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.

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.

- Work stream 1 is a resource assessment study.
- Work stream 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 stream 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 system operation, costs and emissions.

- Work stream 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.

- Work stream 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.

2 Methodology and basic assumptions of the study

Important framework conditions influencing the methodology and interrelations between the work streams were defined during the initial design of the study. These are outlined below.

2.1 Basic assumptions

Snapshot nature of study

The All Island Grid Study carried out an analysis of the performance of various generation portfolios for one particular year in the future (2020). Assumptions were made about which existing conventional generators would remain in operation in the year 2020 and which generators will have ceased operation by this date. At the same time, a scenario for network development independent from the development of renewable generation was assumed. However, an examination of the transition to the generation and network configurations was not carried out. This transition activity is likely to pose significant challenges.

Analysing a specific year in the future allows the analysis to be based on a specific time series for load and for a series representing the variable generation of all renewable energy systems. The load for the all island system time series was based on joint projections of the system operators of both jurisdictions.

The assumed time series for the all island system load in 2020 has the following properties (see also Figure 2-1):

- Total electricity demand: 54 TWh
- Minimum load: 3500MW[4]
- Maximum load: 9600MW

[4] Please note that for the network studies a minimum load of 3000 MW was assumed.

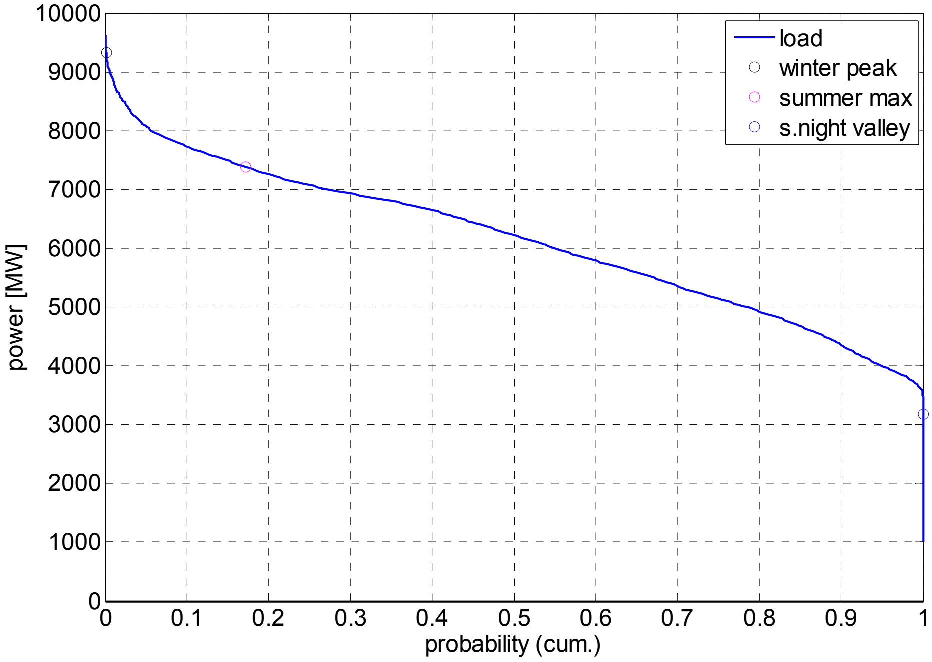


Figure 2-1: Load-duration-curve of the all island load in the year 2020; (specific points indicating the three basic operational conditions used in the network study in work stream 3)

The time series for renewables used in work stream 2B is an amalgam of the series for the different technologies. The dominating component in this is the wind time series. This is based upon an extrapolated set of wind power data which has been recorded by meters for billing purposes over a limited period of approximately one year.

Cost based study

Throughout the study, a strictly cost-based approach was applied. The study did not incorporate a specific market design, market power and strategic bidding behaviour or other elements that are associated with real-world markets. In addition, no specific regulatory framework was considered, for example, incentive regulation was not incorporated into the methodologies applied. However, for the analysis of revenues of generators within work stream 4, price setting by system marginal prices, based on marginal costs, was assumed. Details on these assumptions can be found in section 2.7.

Interconnection to the system of Great Britain

The study assumed that in 2020 the all island electricity system will be connected via two interconnectors with a total capacity of 1000MW to the system of Great Britain (GB). To model the interactions of both electricity systems, certain assumptions about the future generation structure of GB had to be made. A simple approach was applied to modelling the GB generation system.[5]

Treatment of co-firing

Co-firing of biomass in peat and coal plants is an option to increase renewable energy generation on the basis of (modified[6]) plants of conventional technology. Although some of the possibilities to apply co-firing were evaluated in the resource assessment carried out in work stream 1, the treatment of co-firing in work stream 2B did not allow a complete analysis of associated costs and benefits within the study.

Interest rates

Within work stream 1, 2A and 4 a Weighted Average Cost of Capital (WACC) of 8 % was assumed for the calculation of the levelised cost of both renewable and conventional generation. For the calculation of annual cost of network assets, discount rates were defined by the regulators. A rate of 6.41 % was applied for Northern Ireland and 5.63 % for the Republic of Ireland. A discussion of the impact of specific technological risks can be found within Section 3.4.1.

Cost assumptions

All cost assumptions were based on cost data for the year 2006 and results are reflected in 2006 values. Specific assumptions for costs can be found in the relevant work streams: new conventional generation costs are found in work stream 2A, renewable generation costs can be found in work stream 1, and transmission network equipment and construction costs can be found in work stream 3.

---

[5] Detailed information about the approach to model the Great Britain system can be found in the appendix of the work stream 2B final report (Appendix 1.5.2).

[6] New existing peat plants can co-fire up to a certain percentage of biomass without material modification.

2.2 Work streams and their interactions

Figure 2-2 depicts the work streams of the study and their most important interactions. The following sections briefly describe the objectives, methodologies and the key assumptions made for each of the work streams.

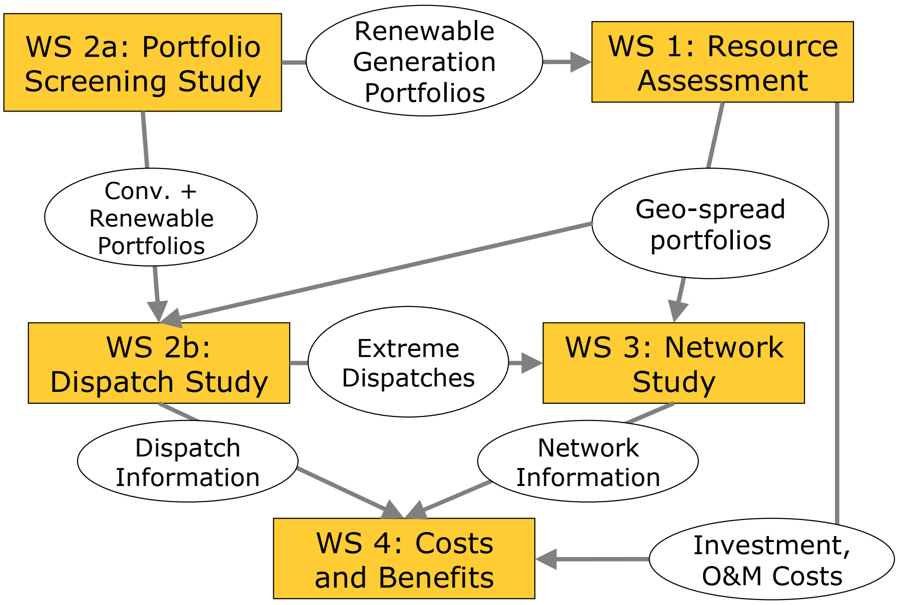


Figure 2-2: Work streams of the Study and their interactions

2.3 Work stream 2A: High level portfolio assessment

Work stream 2A, "High Level Assessment of Suitable Generator Portfolios for the All-Island System in 2020", was designed to generate a number of suitable generator portfolios for detailed study in work streams, 1, 2B, 3 and 4.

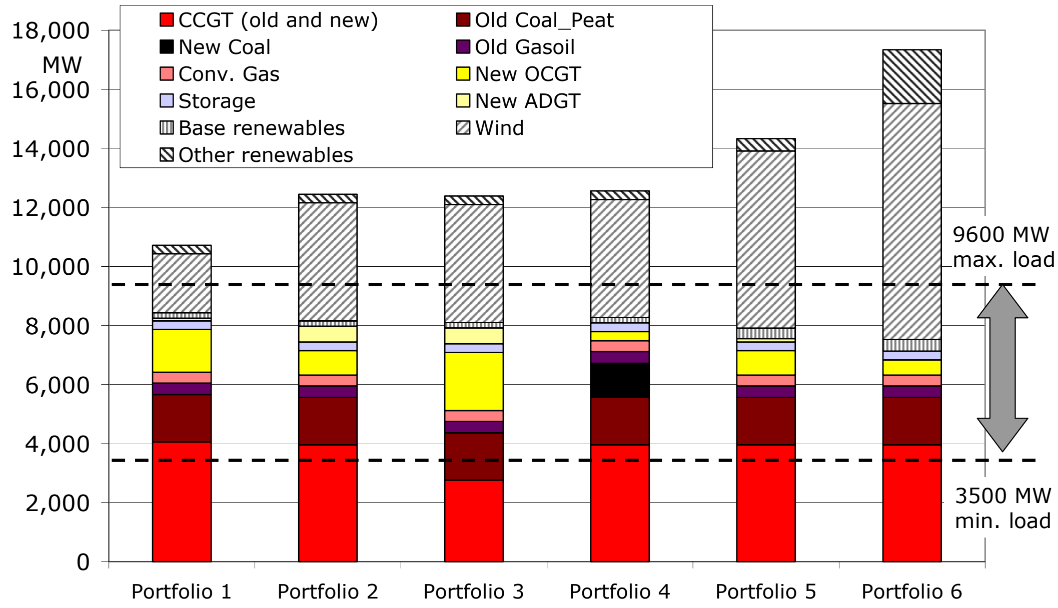
The methodology is based on a linear programming optimisation with dispatch and network issues represented in a simplistic manner that produces least cost generation portfolios for a very wide range of future cost scenarios. The cost scenarios included varying fuel costs, carbon costs, renewable resource costs, conventional generation costs, investment costs, network costs etc. The resulting generator portfolios in conjunction with their associated cost scenarios were examined and five of these were chosen (later increased to six) for further study in the other work streams. The criteria for choosing these five portfolios included the need to cover as wide a range of cost scenarios and as wide a range of renewable energy penetrations as is practical. The modelling limitations did not allow some issues to be included e.g. storage and demand side response. For completeness some further study on these topics may be justified.

The chosen generation portfolios are depicted in Figure 2-3. This figure shows the output of work stream 2A after some adjustments in a subsequent step to reach an acceptable and comparable loss of load probability for all portfolios.

The figure shows the installed capacities of conventional generation (solid areas) and renewable generation (hatched) in the 2020 scenario. The term “base renewables” characterises all renewable technologies capable of contributing to base load such as biomass or biogas plants. “Other renewables” comprises wave and tidal energy.

Solar photovoltaic technology and small hydro were considered in work stream 2A but were excluded from the final portfolios due to the high levelised cost of solar photovoltaic generation, and the low future resource potential from small hydro. Electricity generation from deep geothermal plants was excluded due to lack of resource and cost data for Ireland. The potential contribution from each of these technologies was deemed to be immaterial to the calculation of the percentage share of renewable electricity in final demand in the time frame of the study.

The work stream assumed that approximately 1,800MW of the existing generation units will be retired by 2020. Those capacities are not shown in Figure 2-3.



Share of renewable capacity	23 %	36 %	36 %	36 %	47 %	59 %

Figure 2-3: Composition of 2020 generation portfolios, shares of renewable capacity as of total installed capacity

The resulting total amount and shares of conventional and renewable energy produced by these portfolios will be discussed in section 3.1.1.

The portfolios can be characterised as follows:

- Portfolio 1 consists of 2000MW of wind, 180MW of renewable generation capacity with baseload characteristics and 71MW of tidal energy.
- Portfolio 2 contains 4000MW of wind, and the same other renewable generation capacity as portfolio 1. The conventional generation in this portfolio includes a relatively high proportion of combined cycle gas capacity. Portfolios 2 to 4 have an equal share of renewable energy in total installed capacity (36 %);
- Portfolio 3 is a variation of portfolio 2 with a higher share of flexible gas turbines (Open Cycle Gas Turbines (OCGTs) and Aeroderivative Gas Turbines (ADGTs)) and less combined cycle capacity;
- Portfolio 4 is another variation of portfolio 2 but with new coal capacities included;
- In portfolio 5 wind capacities are increased to 6000MW and additional baseload and tidal energy systems added;
- Portfolio 6 was generated as a result of applying different gas and CO_2 price assumptions to those used to generate portfolios 1 - 5 (high gas and CO_2 price and

lower prices for wind generators). In this portfolio 8000MW of wind is installed. Additional tidal and wave energy capacities are included to take account of these framework conditions. Here, almost 60 % of the demand is covered by renewable energy.

The study analysed two variants of portfolio 6. Whereas the first contained a share of 70MW of offshore wind in the total wind capacity resulting from work stream 1 methodology (see section 2.4 below), the second assumed a share of 1000MW wind installed offshore. The main purpose of this variation was to illustrate the impact of differing installed capacities of off shore wind on network planning and operation (work stream 3). Within the dispatch part of the study (work stream 2B) an installed capacity of 1000MW offshore was assumed.

Figure 2-4 shows the duration curves of the wind generation of portfolios 1 to 5.

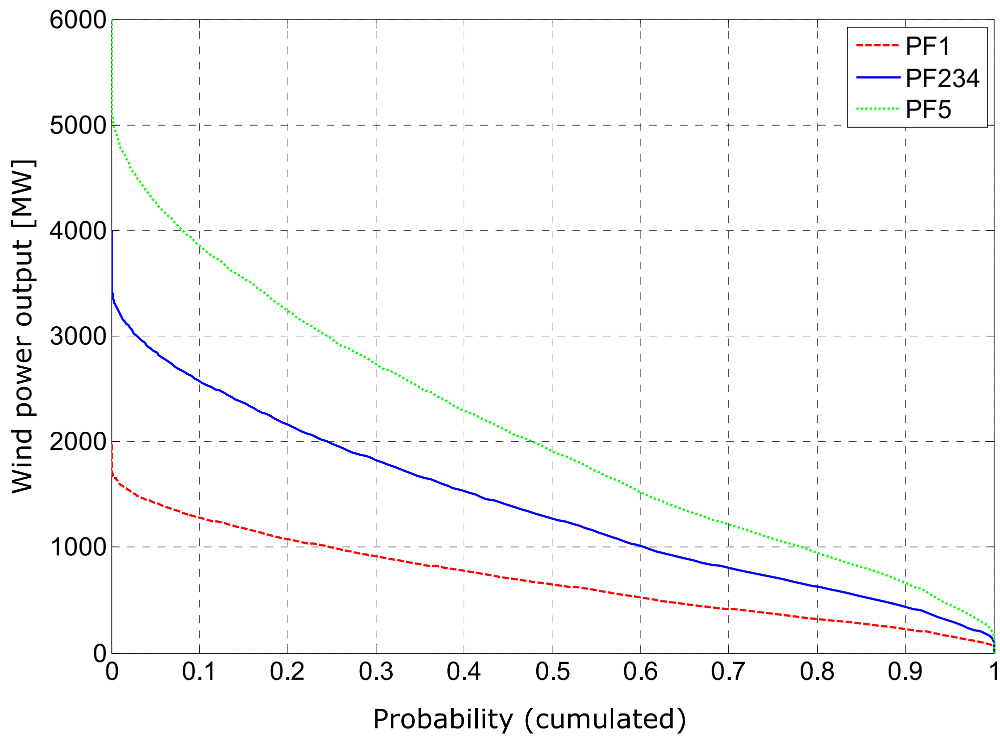


Figure 2-4: Duration curves of wind power output of the 2020 portfolios 1 to 5

2.4 Work stream 1: Resource assessment

Based on generation portfolios defined by work stream 2A, a detailed assessment of renewable energy projects and their associated costs was executed within this work stream. The assessment comprised projects in various project development stages and made assumptions about prospective projects required to reach the higher renewable energy penetration portfolios. The cost assessment included investment and operational cost. Investment costs included the cost of network connection to the closest connection point at the 110 kV network. For the evaluation of the connection cost a simplified approach was chosen, based on average connection cost per km. Depending on the actual connection point, the associated route and terrain conditions those costs may deviate from the assumed cost.

Resource curves were constructed by sorting projects by levelised cost in ascending order and selecting the projects with the lowest cost according to the portfolio composition provided by work stream 2A.[7] Throughout this process projects already in advanced stages of development (i.e. those that had submitted applications for grid connection or had received planning permission) were given priority.

The assessment comprises cost evaluation of innovative technologies. However, no special interest rate was applied to reflect developer risk. This may result in an underestimation of costs for the initial deployments of certain, immature renewable technologies as developers of such technologies may factor in higher rates to reflect risk perception. It should be noted in this regard that learning curve effects were employed for certain technologies which serves to reduce costs with an increasing number of installations. This is briefly discussed in section 3.4.

The main outputs from this work stream are the spatial allocation of generation plants, in particular renewable electricity generators, and the respective levelised electricity generation costs. For the generation of aggregated wind output in work stream 2B, the installed wind capacity was allocated to a number of "generation zones" across the island (see Figure 2-5 from the work stream 1 report below).

[7] Levelised costs are calculated dividing the net present value of all costs associated with the project by the net present value of the annual energy production of the renewable energy plant using the same predefined discount rate. See report of work stream 2A, section 2.5.3.

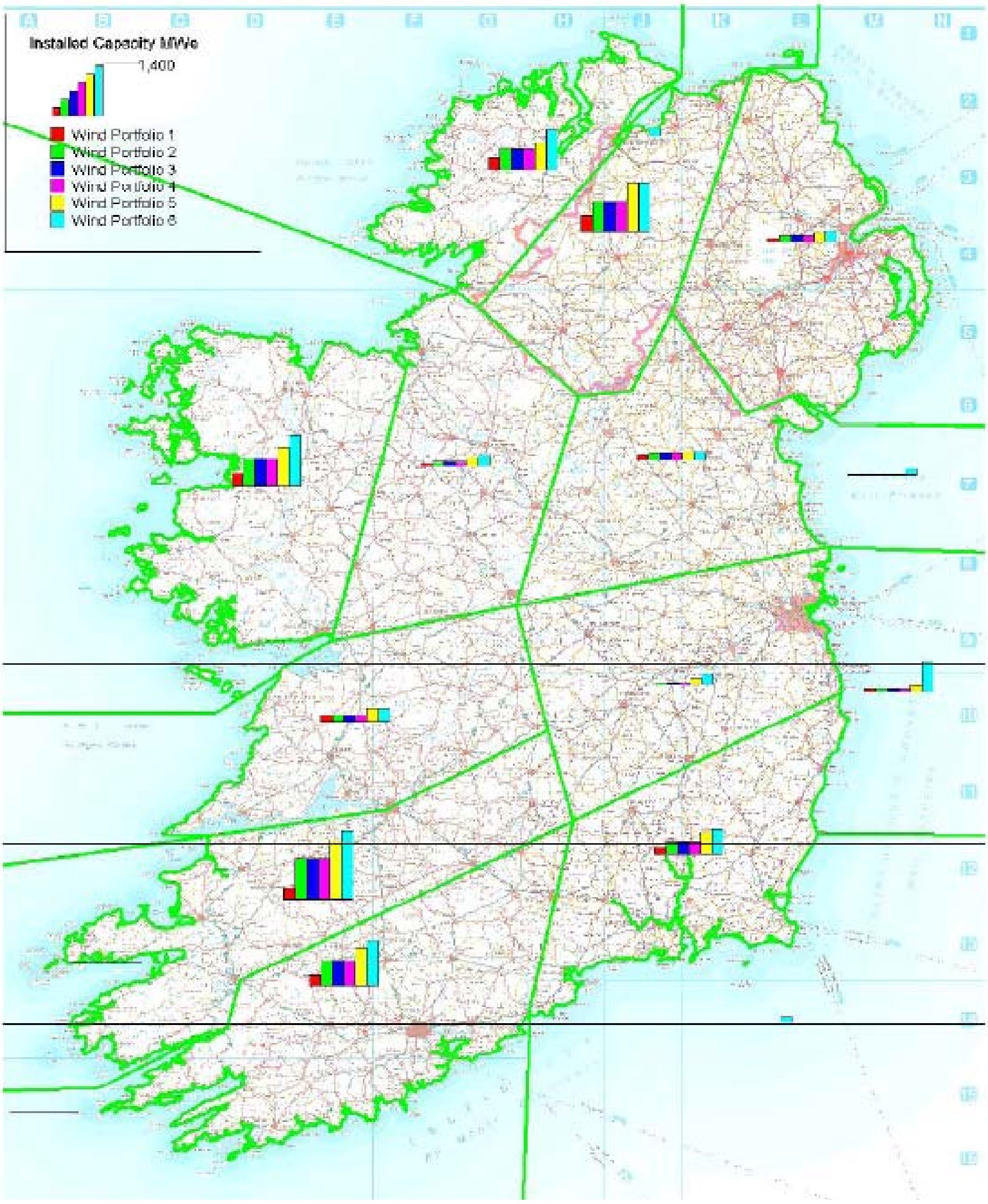


Figure 2-5: Illustration of wind generation zones for installed wind capacity defined in work stream 1 and used in the study

2.5 Work stream 2B: Dispatch Study

Work stream 2B simulated the load, renewable generation and the resulting dispatch of each of the previously identified generation portfolios for every hour in the year 2020.

The simulation was done using the Wilmar planning tool[8] adapted to the specific requirements of the all island power system. In particular the stochastic scheduling model

[8] The WILMAR (Wind Power Integration in Liberalised Electricity Markets) planning tool is the result of a research project supported by the European Commission under the Fifth Framework

and an associated scenario tree tool, was upgraded to include the integer nature of the unit commitment problem which can be important when studying small systems. The scenario tree tool was populated with historical demand and renewable generation (forecasts and actual) time series. The scenario tree tool generates multiple demand and renewable generation scenarios weighted according to their probability of occurrence. The scheduling model minimizes the expected scheduling cost across the scenarios subject to the operational constraints.[9]

An important category of operational constraints are reserve requirements. Reserve constraints, spinning and replacement, are dynamically derived from forecast information and dispatch information. Spinning reserve requirements are depending on the largest online unit and the wind power forecast for the respective hour.[10] From the resulting figure 150MW of spinning reserve was deducted to account for the provision from the GB system (100MW) and 50MW provision from the demand side. The replacement reserve requirements correspond to the total forecast error of the power system (load and wind forecast errors, forced outages of conventional power plants).[11] The scheduling model refines its schedule every three hours to account for the most up to date information (in particular updated wind forecasts).

All operational constraints act as a restriction on the dispatch of plant and therefore, give a different dispatch than would otherwise be the case. For example, the requirement to have a certain amount of spinning reserve provided by the portfolio of plant in a given hour will mean that certain plant therein will be dispatched differently than would have been the case in the absence of this requirement. Section 2.7 discusses the methodology for the interpretation of the value of the restrictions and the changes of the dispatch.

The output of the work stream was dispatch information of all plants for the assumed year 2020, including fuel consumption, reserve allocation, electricity imports and exports and CO_2 emissions.

The dispatch simulation of Work stream 2B assumed no transmission network constraints. It is recognised that this is not a realistic assumption given the outputs of work stream 3. However, it was not possible to do an iteration on work stream 2B with results from work stream 3. It was assumed that a second interconnector to the GB power system will be functional in 2020 to reach a total capacity over both interconnectors of 1000MW. 100MW of the interconnector import capacity is kept available for spinning reserve, i.e. not used for electricity import. The interconnector is dispatched day ahead and not every three hours as is the case for generation as set out above.

Programme. For more detailed information see MEIBOM et al. 06 and related publications (listed for example at http://www.wilmar.risoe.dk/Results.htm).

[9] The operational constraints are explained in the appendix of the work stream 2B report (sections A 1.4.5 to A 1.4.15)

[10] For details on spinning reserve demand, see section 4.6.1. of the work stream 2B report.

[11] Replacement reserve requirements are explained in section 4.6.3. of the work stream 2B report.

An important assumption is that with the exception of one plant, no further restriction on the minimum number of conventional plants online was applied in the study. With the chosen hourly resolution of the simulation, only one unit has a restriction in ramp up and ramp down rates. While the analysis recognised limited flexibility of conventional plants, and included start-up fuel costs of conventional plants, no cycling costs (mainly increased maintenance costs) were included in the analysis of operational cost.

The cost for CO_2 emission certificates was assumed to be 30 €/t CO_2 for all portfolios, except for portfolio 6 where a price of 80 €/t was assumed. Fuel price assumptions for portfolios 1 to 5 are shown in Table 2-1. The table gives average numbers. However, the prices have been modelled with a seasonal variation.

Table 2–1: 2020 Central fuel price assumptions for dispatch simulation in the All Island system used by work stream 2B (annual averages)

Fuel	**Fuel Price Assumption**	
	[€/MWh$_{th}$]	**Common Units**
Coal	6.9	52.9 €/tonne
Gas (baseload)	21.3	248 €/10^7kcal
Gas (midmerit)	22.0	256 €/10^7kcal
Gasoil	32.3	389.77 €/tonne
Peat	13.4	28.81 €/tonne

2.6 Work stream 3: Network study

The aim of the network study is to assess the extent and cost of the required network development to accommodate the renewable generation in the different portfolios. The assessment was based on spatial allocation of the resources identified in work stream 1 and generation portfolios identified in work stream 2A.

To evaluate the required network development a two-step approach was chosen. In the first step, a DC load flow model was used to identify the critical line overloads and bottlenecks. After refinement of the network configuration, these results were used as an input for the second step. In this step, the analysis covered the complex nature of AC networks and thus addressed voltage and reactive power issues, including voltage stability.

In line with industry practice, load flow simulations of work stream 3 were based on a limited set of specific cases, rather than on dispatches of work stream 2B. These cases were combinations of winter peak, summer maximum as well as summer night valley from the load perspective with low and high wind situations from the generation perspective. For plausibility checks, some extreme dispatch situations simulated in work stream 2B were checked for compatibility with the proposed network reinforcements.

The study differs from industry practice in several ways. Under industry practice extreme generation positions are explored to gain an understanding of the robustness of the network. This means that all generation in a zone which has access rights will be assumed to be simultaneously in operation when the load is lowest in the region. This tests the ability to exit power from the region under the most arduous generation and load conditions. This study assumed that the other generation dispatch would respect the generation economics. The limitations of this are that if traditional generation was re-planted with efficient plant, the network capacity would be inadequate.

The network development identified is sufficient only to deal at any time with a single contingency, i.e. the unexpected loss of any one single transmission line, transformer or other transmission element. It does not, as industry practice would dictate, include any provision to take transmission lines out of service for maintenance or other work. Whilst constraining generation may be an economically effective approach to accommodate outages due to maintenance, if a particular generator is liable to constraint for an outage of just one line, it could be unacceptable if the outages of a considerable number of lines required the constraining down or off of the same generator. In both senses the study represents the most optimistic view.

All studies carried out within this work stream were steady-state calculations. No dynamic studies (frequency stability, transient stability, etc.) have been executed.

The identified network reinforcements were valued with specific average costs, agreed between both system operators.

The high level approach to the cost analysis distinguished a limited set of cost components (lines, transformers, substations, bays and reactive compensators). Other cost components related to network reinforcement were excluded or included implicitly (acquisition of land, buildings, etc.).[12] This causes an underestimate of costs, but has limited impact on the overall results. It should be pointed out that land acquisition, land damage and civil engineering costs are so variable depending upon site conditions, that any estimate is likely to be a meaningless number.

The network study focused on the transmission network. No analysis of the distribution network was executed as solutions are very dependant upon projects and timing. However, some details regarding necessary network connections on the distribution level were reported. The distribution level impacts are analysed and discussed in work stream 1.

---

[12] A detailed breakdown of the network reinforcement costs can be found in section 7.10 of the work stream 3 report.

2.7 Work stream 4: Cost benefit analysis

Work stream 4 focuses on the costs and benefits to stakeholders from the RES-E Scenarios at different aggregation levels. This use of aggregation levels helps to structure stakeholder implications in a consistent way and to highlight the distribution of costs and benefits within a certain subgroup.

Figure 2-6 depicts the stakeholder structure used throughout this work stream. Wherever possible and appropriate, costs and benefits are differentiated between the two jurisdictions.

The electricity sector level is divided into the main components of the electricity value chain: Generation, Transmission/Distribution and the Market. As this study is cost-based, only general conclusions with respect to the electricity market and its design can be drawn. Further work may be required to examine any implications for market design.

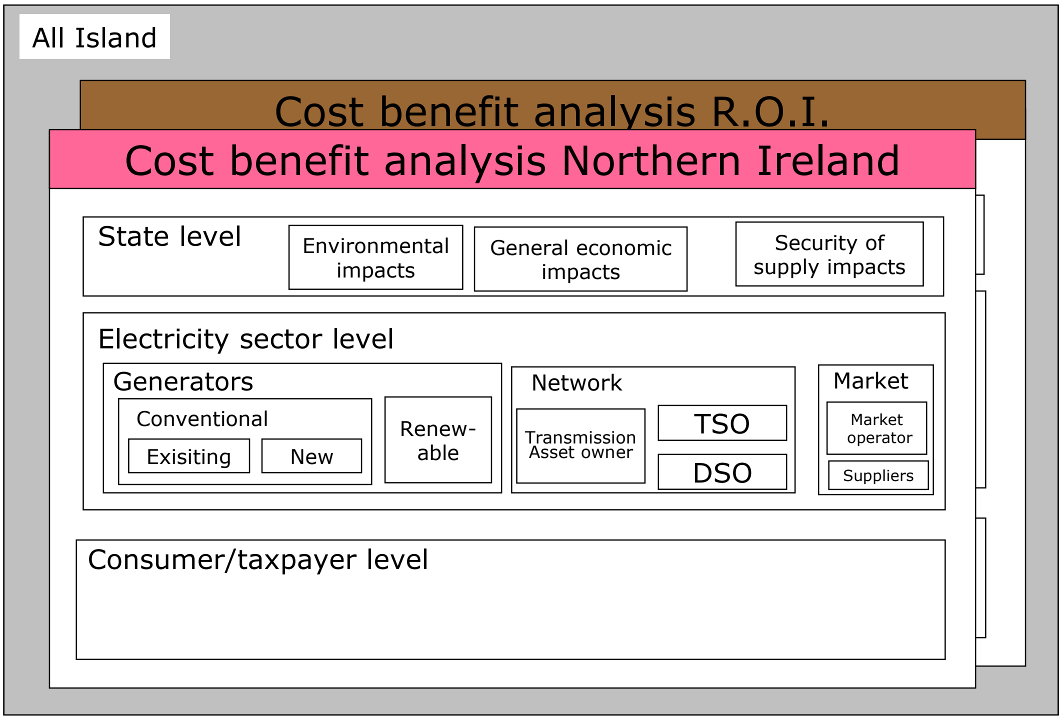


Figure 2-6: Stakeholder levels of cost-benefit analysis

On the highest level, the electricity sector can be viewed as a 'black box'. In 2020 the sector delivers a given load profile at a given reliability level to all end-users The scenarios can now be analysed by comparing the costs implied by the specific electricity payment and the necessary cost of RES-E support with the impacts at the state level such as the associated CO_2 emissions or fuel imports.

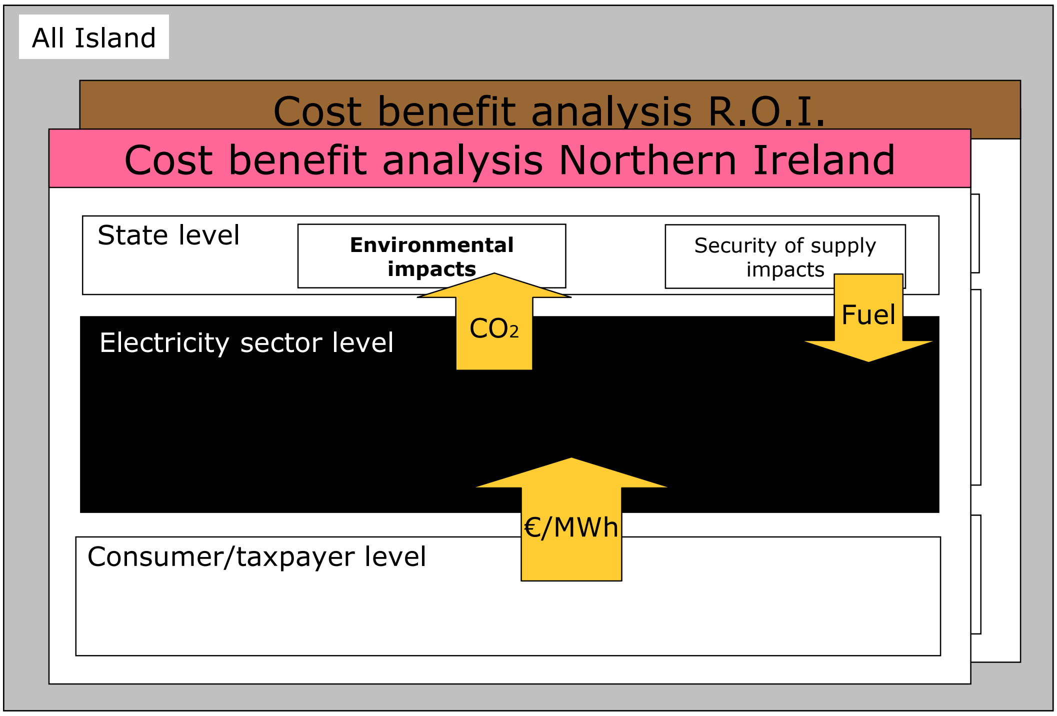


Figure 2-7: High-level cost-benefit analysis

To examine the implications in further detail, the electricity sector is disaggregated and impacts on stakeholders are analysed. This view is depicted in Figure 2-8.

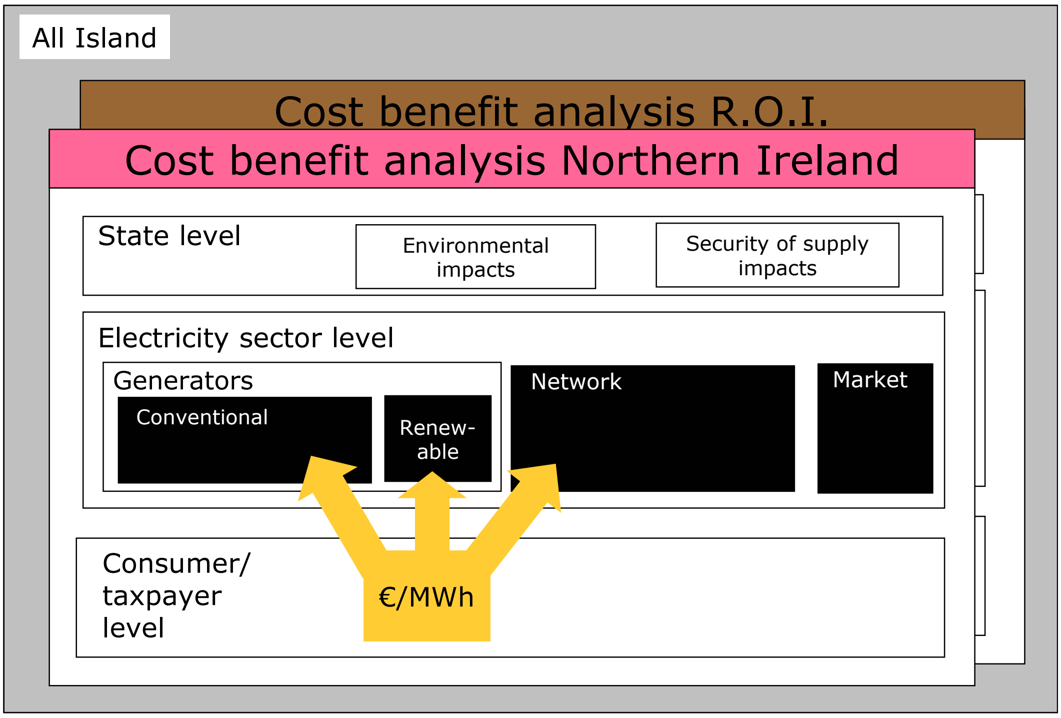


Figure 2-8: Disaggregation of electricity costs

The above figure shows the main components of the cost for the consumer or taxpayer. It will be analysed with respect to the following components, which are dependent on the chosen portfolios:

- total operational cost of the conventional power system, as represented by the cost of fuel and carbon for new and existing conventional generators,
- cost of electricity imports to and exports from the GB system,
- costs of required network reinforcement,
- investment costs of new conventional generators,
- required costs of support for existing and new renewable generators.

The stakeholder impact analysis does *not* include

- additional capital requirements of existing assets such as conventional generation or network assets,
- the effect of the implementation of portfolios on fiscal or regulatory instruments currently in place (e.g. the climate change levy),
- other markets, such as primary fuel markets,
- macro-economic analysis of demand response to electricity price changes.

Market assumptions

The objective of the dispatch model applied in the study is to minimise expected cost with no specific market mechanism or behaviour of market actors being defined. However, for the calculation of revenues for conventional and renewable generators assumptions had to be made. Therefore, the principle of system marginal cost pricing was used for pricing electricity and reserves. For every hour the marginal system cost was calculated and interpreted as the system price. This represents the cost of generating one MWh of additional electricity. In most of the cases, this cost is equivalent to the incremental operating costs, representing fuel and carbon cost, of the most expensive generator online[13]. System marginal cost pricing implies that those generators pricing below the system price will receive infra marginal rents[14], meaning the system price will exceed their variable operating costs in the respective hour.

Extreme prices for electricity and reserves may occur, if the generators are not able to cover electricity demand or reserve requirements. In those rare cases, prices rise to a maximum level. This maximum level is usually defined within the market design of an

[13] Start up costs were not included in setting the system marginal price. Because the generators typically required to start up had low start up costs (OCGT), this exclusion is not material. Fuel costs associated with start up are included in the analysis of costs to society.

[14] The infra marginal rent a generator receives in a certain hour is the difference between the market clearing price of electricity in this hour and its operational cost in the respective hour.

electricity market. It is fixed at a very high value, which is intended to represent the value of lost load to consumers. In this study, the maximum price when load is not met was assumed to be 4000 €/MWh. This situation rarely occurs in the analysis undertaken (see Figure 3-3).

Generators provide spinning or replacement reserve to enable the Transmission System Operator (TSO) to provide short-term balancing actions to adjust supply with demand. In line with real market designs the study assumes that generators can earn additional revenues on separate markets for spinning and replacement reserve. As described in section 2.5 the dispatch model incorporated the allocation of spinning and replacement reserve requirements as restrictions for the optimisation model. The influence of these restrictions on the dispatch can be very different in certain dispatch situations: Reserve requirements may lead to the dispatch of a plant in the model to be less than otherwise optimal in order to make it available to ramp up if required. In other dispatch situations, spinning reserve can be provided without any extra cost e.g. from the Turlough Hill pumped hydro storage plant. The dispatch model places a value on the operational restrictions e.g. to provide reserve. For this study, the common practice which is adopted is to interpret the value of the restriction as the marginal cost of providing the reserve. To illustrate the consequences, typical dispatch situations and resulting reserve price levels are described below:

- Reserve prices are very low (close to zero), if the reserve demand is low and units are operating partly loaded due to reasons other than reserve provision (e.g. high load ramps ahead): As nearly the whole demand for replacement reserves is provided by offline OCGTs in all portfolios, no extra costs occur for the provision of these reserves and hence the marginal cost of provision is mostly zero.
- If the reserve requirement forces infra marginal generators from full load into part load operation, reserve prices are the lost profit (lost revenue – fuel savings). In those cases reserve prices are between zero and the system marginal price
- In some cases the reserve requirements require the start of an additional expensive plant. In this case the reserve defines a new price for energy. Here, the reserve price sets the system marginal price.
- If the available capacity is not sufficient to provide the required amount of reserve, prices on these markets rise to a level that is typically fixed within the market design. If demand for reserve can not be covered, reliability (operational security of supply) decreases but this has no direct impact on the load/demand balance. In this study, this ceiling on reserve prices implied by market design is assumed to be 120 €/MWh, which is in the range of the marginal cost of the most expensive generator. If reserves are scarce, prices rise on both the reserve and electricity markets to this level. Again, Figure 3-3 shows the number of hours, in which this situation occurs.

While the assumption of marginal cost pricing is applied in most electricity markets and verified by empirical evidence, pricing of spinning and replacement reserves applied in real-world markets can deviate significantly from marginal cost based principles applied in this study. In particular, market designs may provide fixed payments for generators for the being available to provide reserve and additional payments in cases where the generator is called on to provide reserve (sometimes linked to their bid-price in the balancing service market). As described within the examples above, the marginal cost pricing principle of this study does not foresee a flat or fixed payment for reserve provision but a marginal cost-based payment specific to the respective dispatch situation. If reserves are called they would receive the system marginal price for energy rather than a distinguished energy payment.

The applied optimisation methodology of the unit commitment problem limits the accuracy of the correct interpretation of the values of the restrictions as marginal reserve prices.[15] This limitation is recognised and its implications are highlighted in the relevant sections of the study. These assumptions have relevance for the determination of average system marginal prices and the required support for renewable generators. They do not materially affect the analysis of total operational cost of the all island power system however because the fuel (and related CO_2) costs incurred by generators required to run to provide reserve is included in the operational cost analysis reflected in Figure 3-10.

No price was assigned for the provision of 50MW of spinning reserve from the demand side and 100MW from the interconnector.[16] In practise, these services may be priced under long term contracts. The determination of these long-term prices is out of the scope of the study.

---

[15] The unit commitment problem solved within work stream 2B is formulated as a linear, mixed integer optimisation problem. For details, see the Appendix to the work stream 2B report.

[16] The average spinning reserve demand ranges between 450 and 500 MW (see work stream 2B report, Figure 13).

Generator cost recovery assumptions

For a complete stakeholder impact analysis a cost recovery requirement for all generators would have to be assumed. Given the market assumptions discussed before, the following issues emerge for the different types of generators:

- To examine the cost recovery for **existing, conventional generators** an assessment of the status of depreciation of the assets would be necessary. Furthermore the reserve pricing assumptions are especially relevant to determine the revenues of this group. Hence, no further analysis of this issue is conducted in this study.
- For **new conventional generators** investment cost assumptions were made within work stream 2A. Those assumptions were used to draw a very indicative picture of cost recovery for various conventional generation technologies (see section 3.3.4). A detailed assessment of cost recovery on a generator-by-generator basis is not supported by the methodology of this study.
- For **renewable generators** revenues for reserve provision provide only an insignificant share of their revenues. This reduces the impact of market assumptions on results of a cost recovery analysis and calculation of required support payments. Hence, this study gives an indication as to what extent the calculated investment cost can be recovered by renewable generators on the electricity market (see section 3.4.4).

However, it should be noted that in all cases where the marginal cost pricing results are used in the analysis of required support or revenue adequacy for renewable and new conventional generators, the results reflect unrealistic market conditions where perfect efficiency and transparency are assumed due to the fact that no specific market design or behaviour of market actors was incorporated in the analysis.

2.8 Key Limitations

As with any study, the All Ireland Grid Study and the underlying work streams are based on inputs and assumptions and employ certain methodologies. These necessarily give rise to a number of limitations which should be considered when interpreting the Study. A number of those were mentioned in the description of the individual work stream methodologies in the paragraphs above. In summary, the key limitations and uncertainties to be considered by the reader when interpreting the results of the All Island Grid Study are set out below:

Snapshot character of input data

Work stream 2B used a wind and load a chronological dataset of hourly values over one year of data. From a power systems perspective, extreme but unlikely events are important for system design. Of course, one year of data does not contain all possible combinations of load and wind generation and all operational conditions. As a consequence, operational conditions may exist which were not covered by the dispatch study. In turn this might affect the loss of load expectation (LOLE) of particular portfolios. As a consequence, a quantitative comparison of the LOLE levels between portfolios is not supported by model output.

To an important extent the wind power dataset relies on (partially) synthesized data: the wind data have been extrapolated from a limited set of monitoring data. Thorough validation of these data with real world measurements is impossible given the current availability of measurements. Further work aimed at increasing the reliability of the assumed input data is recommended.

Additionally, the snapshot nature of the study also limits the interpretation of cost results to those occurring during the single year modelled. It is possible that the comparison of costs amongst the portfolios would show a certain variance for other sample years, in particular as wind data may vary significantly from year to year.

Model resolution and methodology

Work stream 2B was limited to a one hour time resolution. Therefore, constraints that may be binding within sub one hour time scales have not been fully modelled.

In addition, no dynamic studies (transient behaviour in case of disturbances, steady state frequency stability, etc.) were conducted. As a consequence, additional restrictions may apply to the dispatch, rendering some of the operational regimes assumed in work stream 2B technically unfeasible. In the end, this would result in an underestimation of operational costs, required wind curtailment and CO_2 emissions.

Lack of iteration and resulting inconsistencies

An iteration, allowing a feed back of work stream 2B and 3 results to work stream 1 and subsequent adjustment of models and output data proved to be impossible in the given timeframe. As a consequence, certain constraints identified, by e.g. work stream 3, have not been reflected in the other sub models and an optimisation of the overall study results (e.g. reallocation of RES-E generation capacities) has not been performed.

In addition, work stream 3 analysed only a limited set of cases and used a very simplified model for merit order and allocation of reserves, deviating from respective dispatches in work stream 2B. Additionally, the exporting capability of the interconnector has not been included in the dispatch model of work stream 3. For that reason, work stream 3 results do not provide complete evidence that the dispatches derived from work stream 2B are really feasible from a network perspective. Additional restrictions to work stream 2B dispatch may apply, resulting in an increase of operational costs (redispatch) or further costs for network reinforcement. A full iteration between the work streams would be required to ensure consistent treatment. Further modelling would be required to examine the above issues.

Assumptions of interconnector operation

The study assumes substantial participation of the interconnector in system operations, e.g. by the constant provision of 100MW of spinning reserve. This assumption differs substantially from common practice. For actual future interconnector operation to mirror that assumed in the study substantial changes in market arrangements and possibly contracts, as well as some technology upgrade may be required. The capability of the existing interconnector to provide this kind of system services in the assumed manner has not been verified.

Results and treatment of portfolio 6

Portfolio 6 implies shares of renewable generation and capacity that go beyond what has been studied in other integration studies (see section 2.9). In the course of the analysis of the dispatch and the network implications, portfolio 6 reached the limits of the methodologies applied.

In the dispatch study, portfolio 6 required a wind curtailment of 2.3% of annual wind production. Furthermore the results show generation adequacy to be critical (see section 3.1.2). A significant number of hours characterised by extreme system situations occurred, implying extreme system marginal costs and hence extreme instantaneous prices. At this point, the determination of revenues becomes extremely dependent on the assumptions made for extreme situations, which adversely affects the robustness of the results.

During the network study, the renewable generation of this portfolio could not be studied correctly. For renewable capacities over 6900MW, the number of overloaded circuits was unmanageably large. This indicates that for such extreme renewable penetration scenarios, a system re-design is required, rather than a reinforcement exercise.

As a consequence, in this report, results of portfolio 6 are only included for illustrative purposes.

2.9 Comparison with other integration studies

The methodology of the All Island Grid Study is innovative in nature, particularly due to the application of a stochastic dispatch simulation. Further, the application of the concept of security constraint optimum power flow in work stream 3 allowed that n-1 requirements were satisfied with minimum network reinforcements.

Integration of renewable energies has been the subject of a variety of international studies, mainly from the perspective of the integration of wind energy. The wind portfolios defined for the All Island Grid Study cover the full range of wind penetration levels being treated in other wind integration studies. Figure 2-9 depicts the penetration levels, investigated energy metrics (annual TWh production by wind generation as a percentage of gross national electricity demand) versus capacity metrics (installed wind capacity as a percentage of instantaneous minimum system load plus nominal export capability of interconnectors). These figures may be considered as rough indicators of the "integration challenge".

The studies shown in Figure 2-9 have been evaluated with respect to simulation methodologies in IEA wind agreement Task 25 "Design and operation of power systems with large amounts of wind power". Portfolio 5 of the All-Island Grid Study reaches the highest energy share levels of all studies evaluated in IEA Task 25 and Portfolio 6 goes beyond all penetration and energy share levels studies thus far.

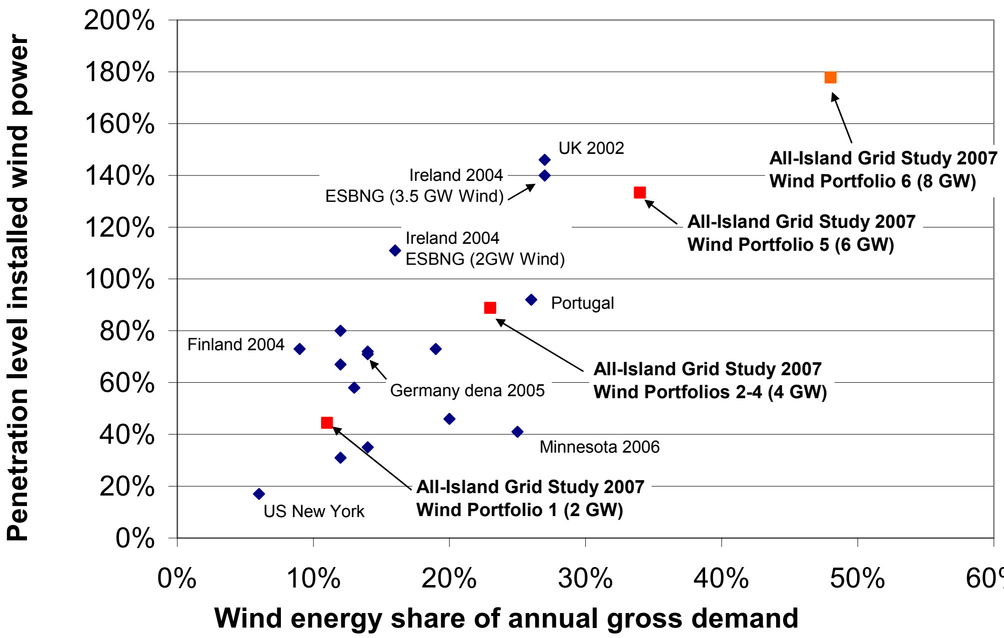


Figure 2-9: Comparison of wind penetration levels in various integration studies, (penetration level here defined as installed wind capacity in relation to minimum system load plus nominal export capacity of interconnectors); other renewable sources ignored

It has to be emphasised that Figure 2-9 reflects wind power only. In line with most studies referred to in this illustration, other renewable generation is not taken into account here. This also explains the differences compared to the figures provided in Figure 3-1.

3 Stakeholder impacts

In this section, the implications of the portfolios for the most important stakeholders within the electricity system are evaluated. This section starts with the description of issues common or relevant for all stakeholders.

3.1 Common issues

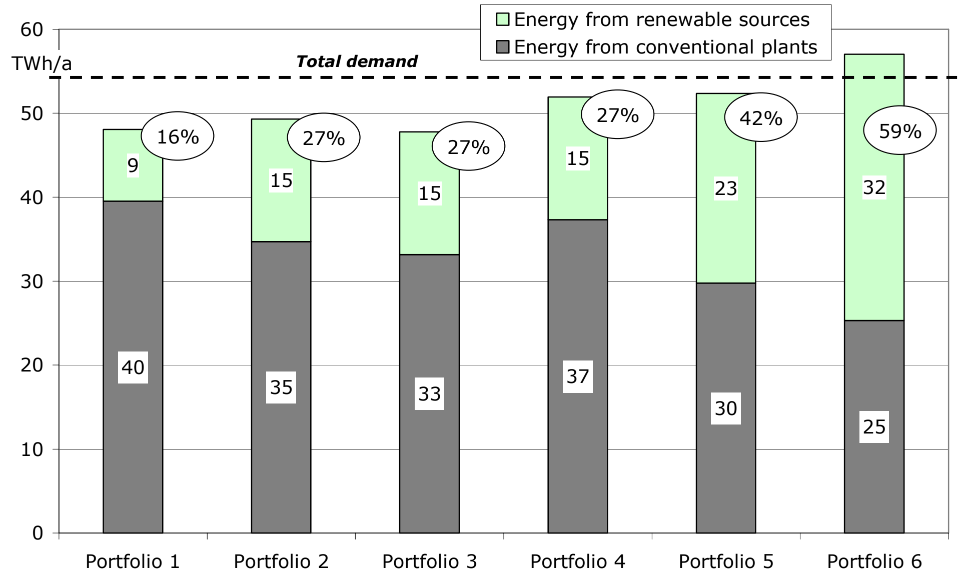
3.1.1 Renewable and conventional energy production

Figure 3-1 gives an overview of shares of energy production from renewable and conventional generators as a result of the dispatch simulation. This section also discusses average capacity factors.[17] A detailed discussion of capacity factors of conventional generation can be found in section 3.3.3.

- In portfolio 1, 9 TWh of renewable energy is produced. Compared to the total demand of the all island system the share of renewable energy is 16% . The average capacity factor of all conventional power plants is 55%, and 39% for renewable plants.
- The 2000MW additional wind capacity in portfolio 2 leads to a decrease in the capacity factor for renewables from 39% to 37%. The share of renewable energy in total demand rises to 27%. The capacity factor of conventional generators decreases to an average of 50%.
- As portfolio 2, 3 and 4 assume the same renewable generation, 15 TWh, energy production and capacity factors generation are the same at 27% of demand and 37% capacity factors. However, the capacity factor of conventional generation differs considerably. The higher share of gas turbines leads to higher imports from the GB system and thus lower capacity factors for conventional generation in portfolio 3.
- The new coal capacities in portfolio 4 with low variable cost lead to a higher capacity factor of conventional generation and lower imports.
- The increased wind capacities in portfolio 5 (total 6000MW) leads to an increase of the share of renewables in demand to 42%. Since additional renewable baseload capacities are added, the capacity factor of renewable generation remains at about the same level as in portfolios 2 to 4. The high share of renewables leads to a decrease of the capacity factor of conventional generation to 45 %.

[17] The capacity factor of a power plant is the ratio of the actual output of a power plant over a period of time and its output if it had operated a full capacity of that time period. This is calculated by totaling the energy the plant produced and dividing it by the energy it would have produced at full capacity

- In Portfolio 6 almost 60% of the demand is covered by renewable energy. The increased share of wind and wave energy leads to a decrease of the capacity factor of renewables to 35%. The decrease of this factor would be higher if 1000MW onshore wind capacity rather than offshore wind capacity was added to the portfolio. The high share of renewable capacity leads to a further decrease of the capacity factor of conventional generators and to net exports to the GB system.



Capacity factor ren. generators	39 %	37 %	37 %	37 %	38 %	35 %
Capacity factor conv. generators	55 %	50 %	48 %	62 %	45 %	41 %

xx % Renewable energy share in total annual demand

Figure 3-1: Conventional and renewable energy production, total annual demand of the all island system and capacity factors.

Figure 3-2 shows the relative share of renewable energy production in the respective demand both jurisdictions. These figures were calculated using the geographic information assessed in work stream 1 and the dispatch data of work stream 2B. It shows that the relative share does not change substantially in the portfolios, except in portfolio 6 where the effect of 1400MW of wave energy located off the west coast results in a higher proportion of renewable generation in the Republic of Ireland.

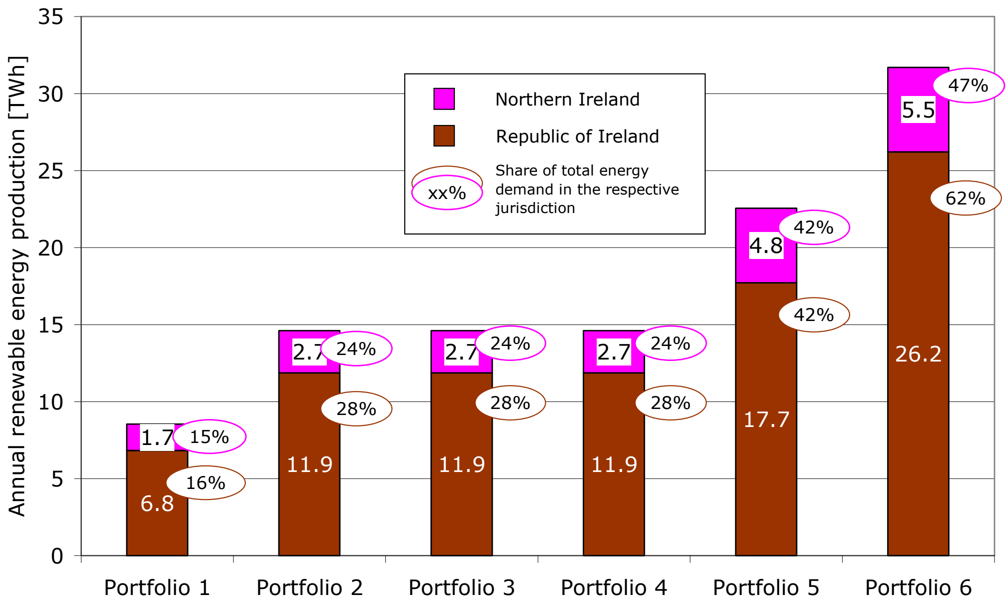


Figure 3-2: Breakdown of annual renewable energy production to jurisdictions

3.1.2 Generation adequacy

No technical system is 100% reliable. There is always a chance that components and sub-systems fail. Redundancy, as provided by overcapacity in generation reduces the risk of underperformance of the total system, possibly to very low levels, but cannot avoid it completely.

In this study reliability analysis is performed from the generation perspective in work stream 2B and from the network perspective in work stream 3.

In this section some general conclusions on generation reliability are drawn. Specific operational aspects are treated in section 3.5.1 under the discussion on the system operators.

In order to make the portfolios comparable from a reliability perspective, the compositions of generation plants in the work stream 2B portfolios were tuned such that each would meet the same, predefined standard for Loss of Load Expectation (LOLE). The Loss of Load Expectation is a quantitative expression of the adequacy of the generation plant with respect to the load. The LOLE gives the number of hours in a year during which the available generation plant will be inadequate to meet the instantaneous demand.

In line with current practice, work stream 2B required that LOLE should be not more than 8 hours annually. As LOLE is a statistical measure, this does not mean that during this limited period a deficit affecting end users actually occurs in every year.

During the stochastic dispatch simulation the number of critical hours was identified. Figure 3-3 compares this number between the portfolios.

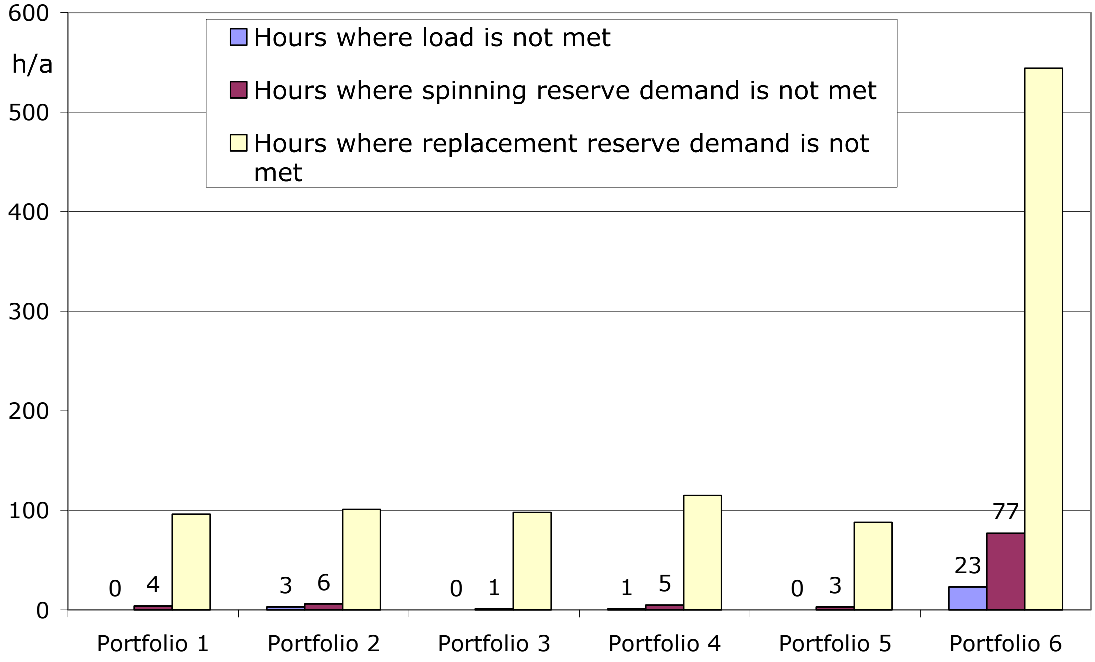


Figure 3-3: Number of hours with system reliability problems[18]

The methodology applied in the model makes it difficult to rank the reliability levels of the portfolios. First of all, the datasets for load and wind power contain exactly one year, i.e. 8760 samples. This is a quite limited dataset, particularly when trying to evaluate differences in the sub-‰ range. The combinations between wind power output and load values in the model do not cover the complete range of possible data and, hence, with other input data the outcome of the LOLE assessment may easily vary by a magnitude that would change the order between portfolios.

It can be concluded, on the basis of the data available, that portfolios 1-5 have approximately the same reliability level. Portfolio 6 is seen to be the most unreliable on the basis of the output of the methodology applied. However, it is acknowledged that this methodology was inappropriate to analyse portfolio 6.

[18] See Table 16, report of work stream 2B

3.1.3 Price duration, average prices

Figure 3-4 shows the weighted average price occurring in the dispatch from work stream 2B based on system marginal costs.

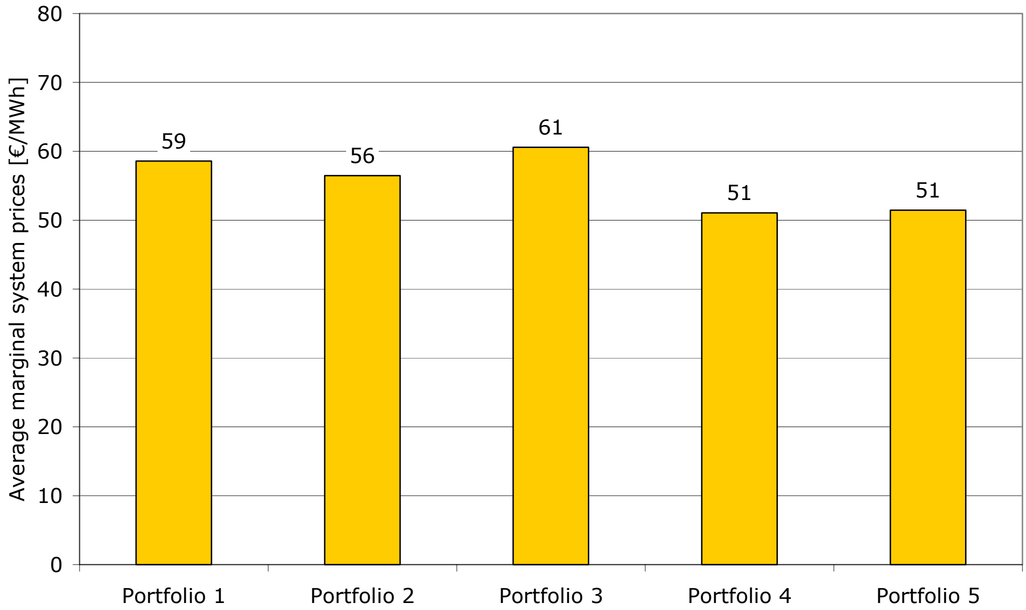


Figure 3-4: Average "price" levels in the different portfolios (volume-weighted marginal system price as calculated on a cost basis)

It has to be pointed out, that the absolute values have to be interpreted with extreme care and no judgement on the suitability of portfolios can be made without consideration of the limitations of the study. Firstly, they do not represent the full cost for society since investments in network or generation are not included in the analysis at this point. Secondly, a number of effects that influence prices in the real world are excluded from the model. Some of them will be discussed below.

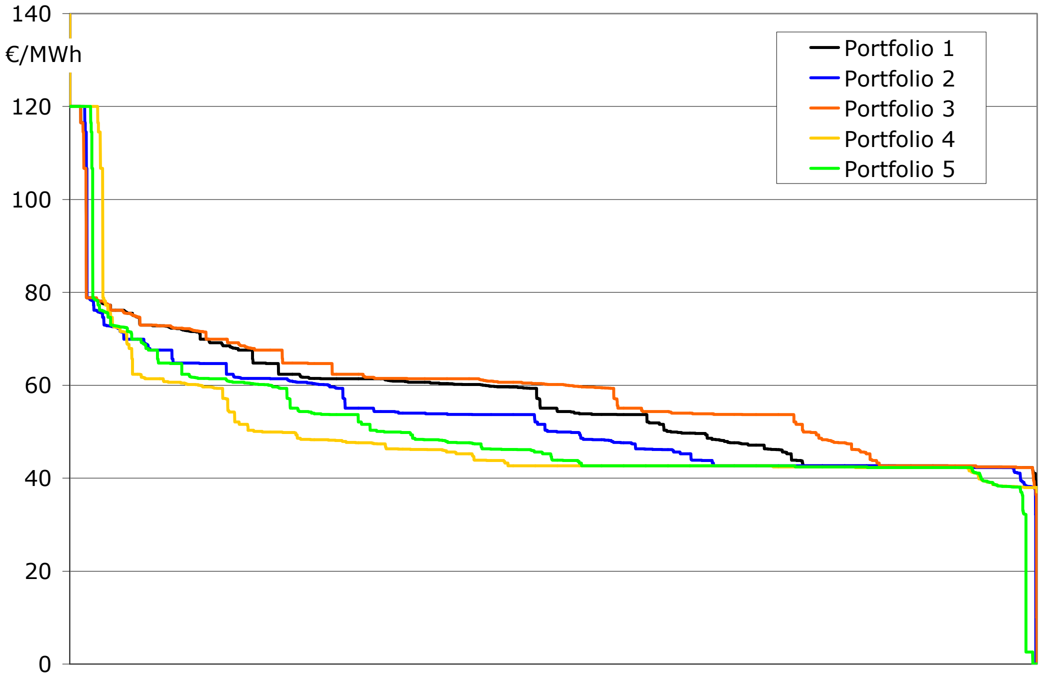


Figure 3-5: Price duration curves for Portfolios 1-5

Figure 3-5 takes a closer look at the market prices that define the revenues of all generators. It shows the cumulated hourly prices in descending order for all scenarios for all 8760 hours of the year.

Looking from left to right, we observe a number of high or even extreme prices. As shown in Figure 3-3 within portfolio 3 we find three hours and in Portfolio 5 one hour where load is not met. Consequently, prices in those hours reach the price assumed for the value of lost load (€4000/MWh) in the dispatch; however these hours are not graphically represented due to the scaling of the graphic.

The next price level, of 120 € applies to hours when reserve capacities are not met and the market price is driven up to the reserve price, and occurs in portfolios 1 to 5 depending on the reliabilities of the portfolios. The variation between the portfolios is limited. The frequencies of these hours are depicted in Figure 3-3.

In the large middle section of the duration curves, the portfolios range between portfolio 4 as the cheapest and portfolio 3 as the most expensive. The price ranges can be explained by reference to the generation structure in each case, since both portfolios contain the same amount of wind. Portfolio 4 contains new coal plants with relatively low marginal generation costs, thus prices tend to be low. On the other hand, portfolio 3 has a high share of OCGT with high fuel costs, which influences the marginal cost.

3.2 Price volatility

Since this study is cost based and does not consider a specific market design only general consequences of each portfolio can be considered in relation to price volatility.

The optimisation methodology applied in the dispatch model represents a continuous re-dispatch every three hours. In contrast, most real-world electricity markets are based on day-ahead power auctions, in some cases in combination with one or several intraday-markets. Therefore the following observations are not necessarily applicable for real markets.

For participants in the electricity market the risk of changing prices has to be managed. The effects of increased penetration of variable renewable electricity on price volatility are manifold. Two main effects are:

- Portfolios with higher shares of renewable electricity result in higher price risk due to variations of the resource;
- On the other hand, renewable electricity lowers overall exposure to the risk of price fluctuations of conventional fuels, especially gas price fluctuations.

The risk of extreme price fluctuations primarily depends on the availability of replacement reserve. Figure 3-6 shows the standard deviation of the marginal system price. The standard deviation is considerably higher in portfolios 2 and 4 where reserves tend to be scarce.

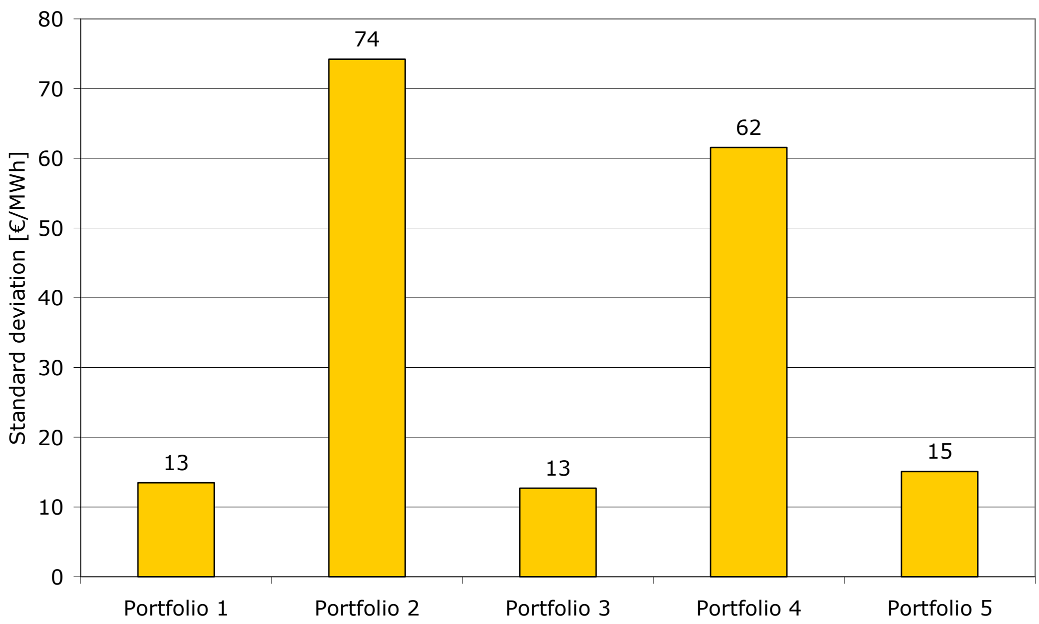


Figure 3-6: Standard deviation of marginal system costs (electricity "prices")

3.3 Impact on conventional Generators

3.3.1 Characteristics of conventional generation units

For this analysis, generators are grouped according to technical characteristics such as plant efficiency and plant flexibility. The flexibility of conventional units is defined by factors such as ramp rates (MW/min), minimum up- and downtimes, startup fuel consumptions as well as synchronisation times. Furthermore, conventional units have different capabilities to provide operating reserves.[19]

The following groups were defined to facilitate the description of the impacts on conventional generators:

- **Existing Coal and peat**: The existing coal and peat plants have average maximum efficiencies of 37 %. Peat plants in particular have relatively low ramp rates (about 1-2MW/min, old coal plants can ramp at 4-6MW/min).
- **New Coal**: New coal-fired plants have an efficiency which is increased to approximately 41 %. Coal plants consume about 6 times the amount of fuel to start up than new Combined Cycle Gas Turbine (CCGT) plants. Their ramp rates are about 8MW/min. Hence, a single plant could theoretically change its output by 480MW within an hour.
- **Existing Gasoil:** These open cycle gas turbines run on gasoil and reach maximum efficiencies of only 30 %. Therefore they are mainly used for the provision of replacement reserve. Ramp rates for these plant range between 5 and 10MW/min.
- **Conventional Gas:** These are two existing condensing thermal plants running with gas. They reach maximum efficiencies of up to 40 % and ramp rates of 2 and 4MW/min.
- **CCGT**: Combined cycle gas turbine plants (both existing and new) have a maximum efficiency in excess of 50 %. New CCGT plants are assumed to reach ramp rates of about 11MW/min.
- **New OCGT**: Open cycle gas turbines are inexpensive peaking plants with capacities close to 100MW but with maximum efficiency limited to 36 %. They ramp at 10MW/min.
- **New ADGT**: Aeroderivative gas turbines are very similar to OCGT, but have higher efficiencies of up to 46 % and the same ramp rates as new OCGT (10MW/min). The start-up fuel consumption of OCGT and ADGT when cold is only about 0.25 % of the start-up fuel consumption of a CCGT plant. Due to their flexibility, they can offer a higher share of their capacity as spinning reserve.

Unit groups with higher operational efficiencies tend to have higher investment costs. Assumptions on investment costs are given in Figure 3-12.

[19] Detailed technical characteristics of existing and new plants can be found in the tables 31-33 of the Appendix to the work stream 2B report.

3.3.2 Total investment volume for new conventional units

The annuity for the investment in new conventional generation, calculated on the basis of cost assumptions made in work stream 2A[20] is depicted in Figure 3-7. The coal-dominated portfolio 4 has the highest investment cost. The figures include annual fixed operating cost. These annual costs such as maintenance and payroll costs do not depend on energy output.

In a later step, these investment costs are aggregated with the other cost components to be carried by the final customer.

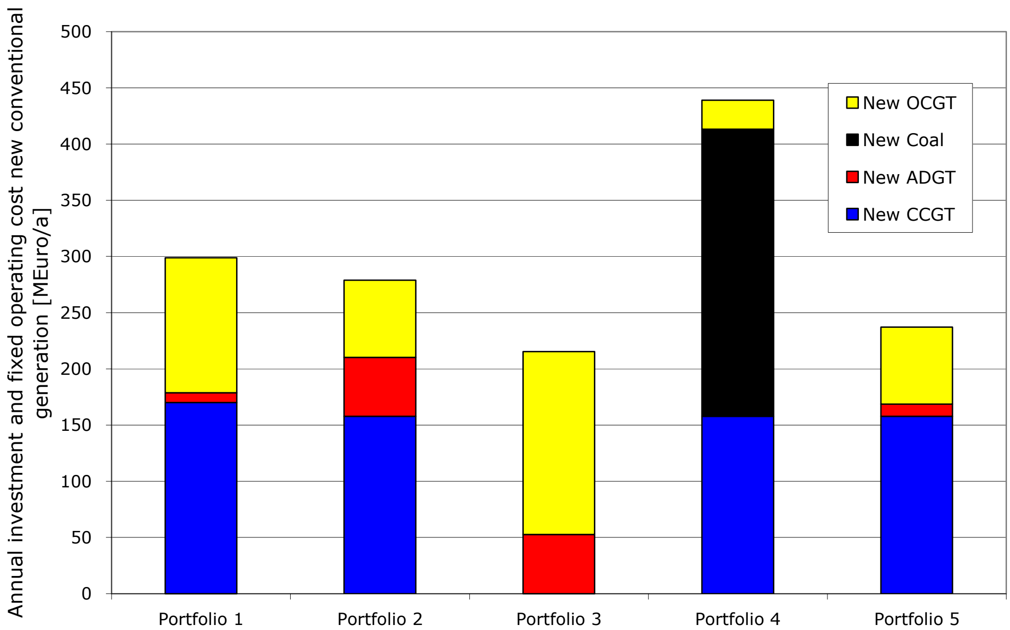


Figure 3-7: Investment annuity and annual fixed operating costs for new conventional generation

Both investment and fixed operating costs need be recovered from payments received in the energy markets as well as those in reserve markets and from payments under a capacity payment mechanism.[21]

3.3.3 Dispatch of conventional units

The hourly dispatch calculated by work stream 2B takes all technical characteristics, as per the All-Island System simulation data, of conventional plants into account. However, due to the hourly resolution of the dispatch, only one peat fired unit has restricting ramp

---

[20] Those assumptions are shown in Figure 3-12.

[21] This topic is further explained in section 3.6.3.

up and ramp down rates. Considering the variation of the resulting power production from one hour to the next for all portfolios, almost the whole operating range is utilised by all units aside from the installed wind capacity.

Figure 3-8 shows the capacity factors for the defined generator groups that result from the dispatch simulations of portfolio 1-5 in work stream 2B. The capacity factor describes the fraction of the available time the plant is generating electricity weighted against its full capacity. The following observations can be made:

- The combined cycle, gas-based generation (CCGT) has a capacity factor in the range of 70% to 80% in portfolios 1 to 3 and can therefore be regarded as a baseload capacity. The high capacity factor results from the high efficiency of the units. In portfolio 4 the new coal plants take over a part of their base load role, hence the capacity factor decreases. In portfolio 5 the high share of renewable generation leads to their decreased capacity factor.
- The low efficiency of the existing conventional (condensing) gas plants means they play only a minor role in the dispatch and have capacity factors ranging from 4% to 25 %.
- The higher efficiency of the aeroderivative gas turbine plants enables them to gain capacity factors from 17% up to 45%, which compares favourably to the conventional gas turbines, which achieve between 3% and 10%.
- New coal plants exist only in portfolio 4 but gain a capacity factor of 87% due to the high efficiency of the modern plants.
- Because of their relatively low fuel costs, the capacity factor of existing coal and peat plants is relatively high. They act as baseload units.
- The extremely low capacity factors of the old gasoil plants reflect their role as providers of reserve capacity in all portfolios.

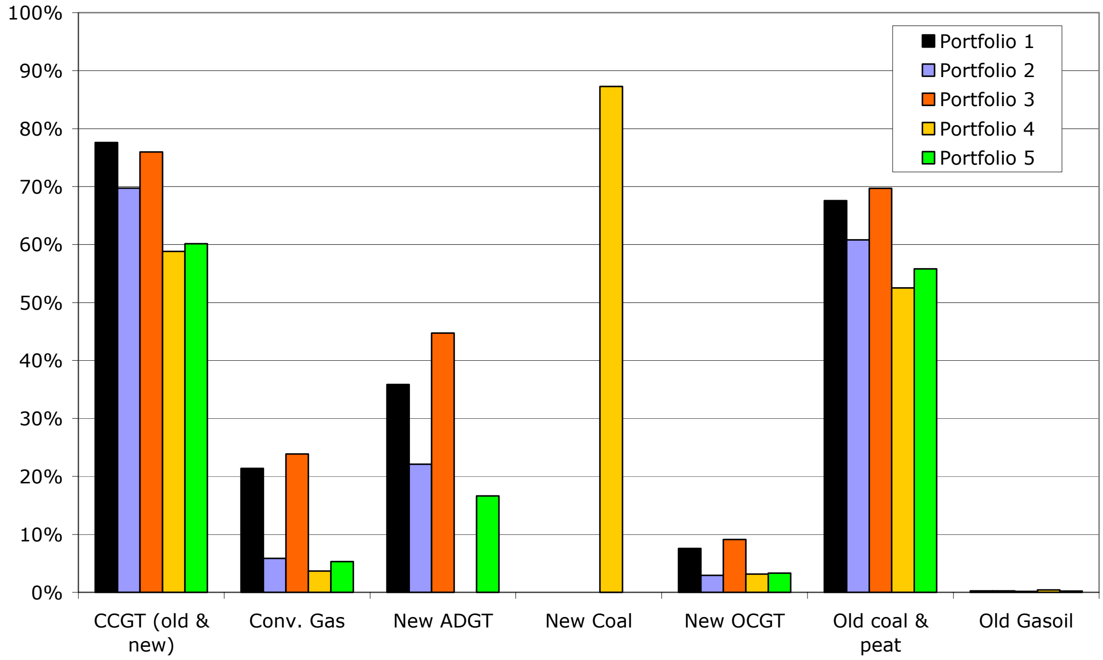


Figure 3-8: Capacity factors of conventional generators

To further illustrate the operational behaviour of the generation groups, Figure 3-9 shows the composition of the capacity factors for portfolios 2, 3 and 5. The figure illustrates that baseload units mostly deliver electricity (CCGT, existing coal and peat plants) and, hence, achieve high capacity factors. In opposite, peaking units with low capacity factors (e.g. OCGTs and old gasoil units) serve one of the reserve categories during a substantial share of time, but do not generate much electricity.

Although the composition of the generation portfolios is very different, the operational behaviour of the generators shows a similar pattern. The most obvious observable effect is higher electricity production from ADGT and OCGT in portfolio 3. A reduced number of full load hours for electricity production in portfolio 5 can also be observed. This is due to a higher percentage of the energy requirement being met by non-fossil fuel options. Despite the relative similarity of the operation patterns, the financial results can vary significantly, as will be demonstrated in the following section.

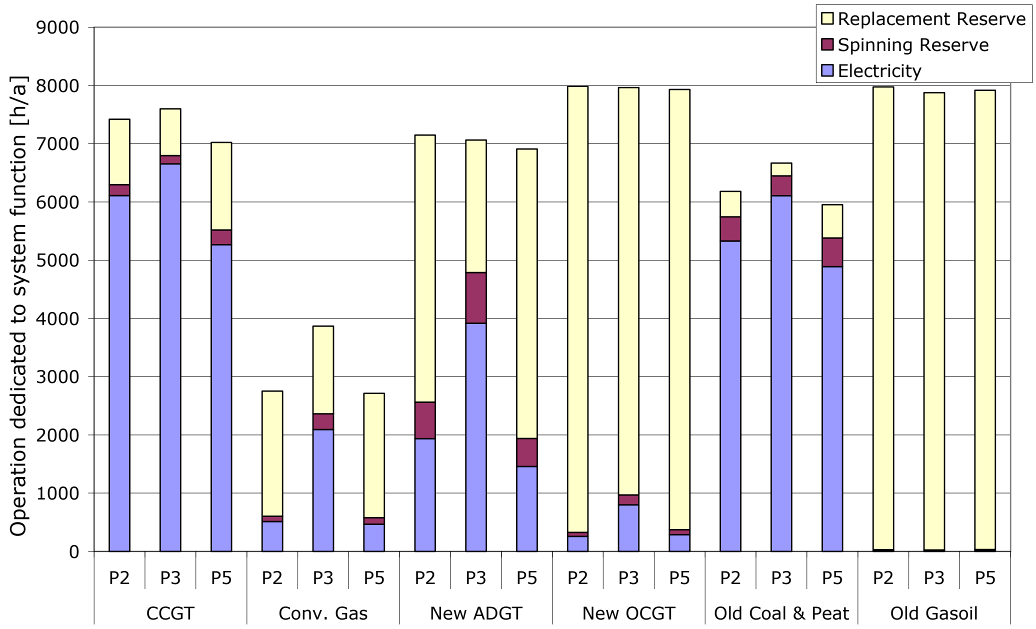


Figure 3-9: Operational modes of conventional generation portfolios 2, 3 and 5

When interpreting these outcomes of work stream 2B care is required, taking into account the assumptions and limitations of the study. The unit data applied in the dispatch model may require further elaboration and modification at detail level. Examples of those aspects are start-up time restrictions, additional O&M cost as a function of enhanced operational dynamics or extended low load operation, must run requirements, availability of the interconnector for provision of reserves etc.

Based on the dispatches identified in work stream 2B, Figure 3-10 shows the resulting total operational costs of the power system, including payments related to import and export of power to/from Great Britain divided by the total demand. The costs of CO_2 are separated from the fuel prices. The figure shows, that an increased share of renewable generation in the all island electricity generation portfolio leads to both, decreased CO_2 Emissions (with the exception of coal-based portfolio 4) and decreased fuel costs, implying decreased cost to society from conventional generation. Both effects persist with an increase of the share of renewable electricity penetration up to 42% (portfolio 5).

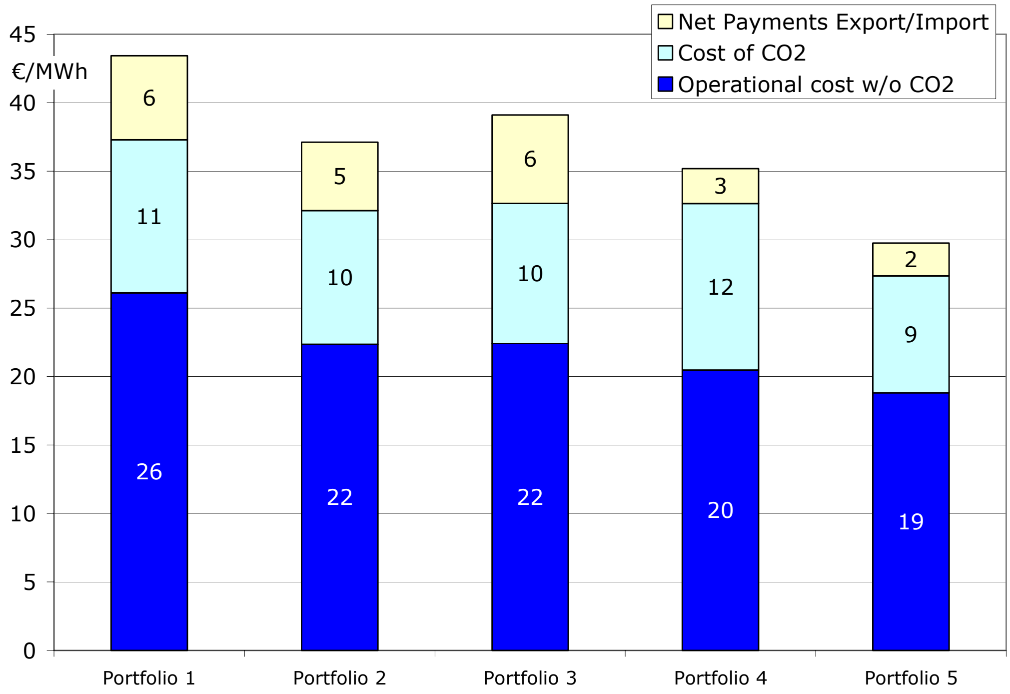


Figure 3-10: Total operational costs of power production in the All Island power system, including payments related to power exchange with Great Britain[22]

[22] See work stream 2B report, table 6.

3.3.4 Revenues of conventional generators

The source of revenues for conventional generators, based on system marginal cost pricing can be broken down into the revenues from electricity generation and the provision of spinning and replacement reserves. The revenue breakdown is depicted in Figure 3-11. The figure shows that the applied methodology for pricing of reserves implies only marginal contributions from these services to the total revenues of conventional generators. Again, it has to be noted that, in particular the accuracy of reserve revenues is limited by methodology restrictions. What is more, within some market designs payments outside of energy payments like capacity payments are made to ensure a sufficient investment in generation capacity (generation adequacy). As no specific design was assumed in this study, such payments are not calculated. The decreasing revenues within portfolio 1 to 5 reflect the higher shares of revenues captured by renewable generators.

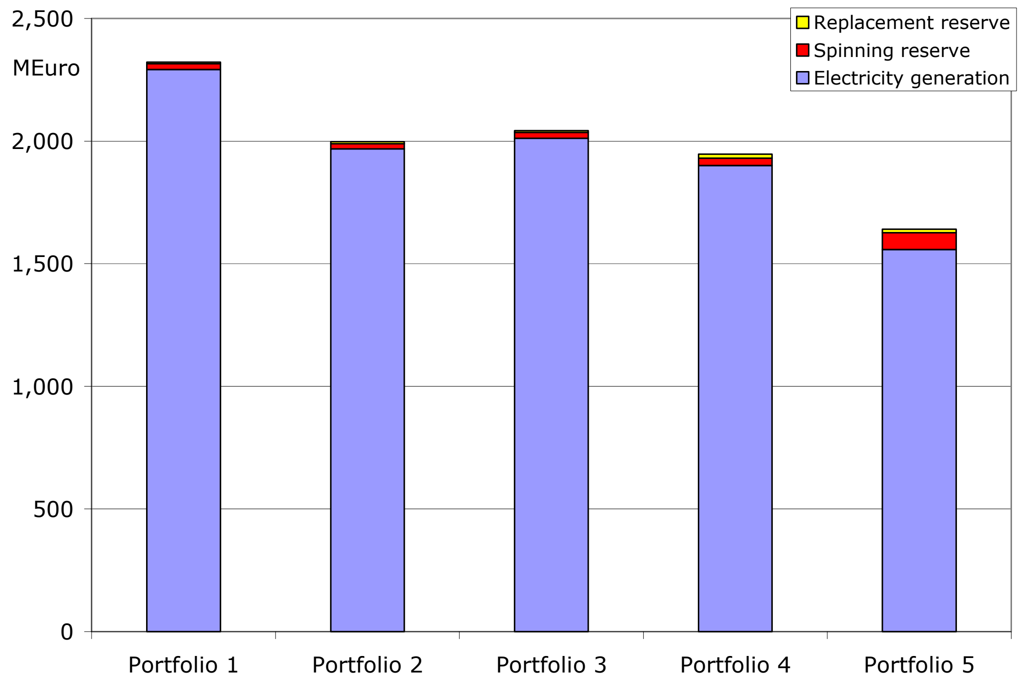


Figure 3-11: Revenue distribution of conventional generators, excluding storage

The total generator revenues are used to cover the operating cost components (fuel-, O&M and startup-cost), investment cost and applicable network tariffs.

Figure 3-12 shows for every generation group and portfolio, which investments could be financed from the cash flow available after operating cost components are covered.[23] In

[23] Fixed operating costs, such as maintenance and payroll costs, (as explained in section 3.3.2) were excluded.

this graph an annuity factor of 10.2 % was assumed that reflects an interest rate of 8 % and a plant lifetime of 20 years. It also shows the relative investment costs of conventional plants, as assumed in work stream 2A, to indicate where revenue adequacy issues arise. The figure should be interpreted in consideration of these simplifications and the specific market assumptions that have been made.

The following observations can be made:

1. The gaps between specific capital investments that can be financed from available cash flow and the actual investment cost of new plants show, that in almost all cases, new plants would require additional (capacity) payments to cover the cost of the investment. Figure 3-10 illustrates that only ADGT plant in portfolio 5 can fully cover their investment costs in the absence of such additional payments.
2. The higher revenue deficits of CCGT plants in portfolio 4 and 5 are caused by low average prices (see Figure 3-4) combined with lower capacity factors due to the fact that they are displaced by coal in portfolio 4 and wind in portfolio 5.
3. The single cycle gas turbines benefit from higher spinning reserve requirements in portfolio 5. This is due to the provision of spinning and replacement reserve which accounts for 34 % of the revenues of ADGT and 63 % of OCGT.[24]
4. The new ADGT technology seems to be a promising technology in the "high-wind" portfolio 5.
5. The new coal plants are likely to face severe profitability problems without additional payments, since their infra marginal rent is only about 10 €/MWh.[25] This is due to the high investment cost of modern coal-fired plant and the relatively low energy prices.

In a theoretical equilibrium of an electricity market, the infra marginal rents of each plant are just sufficient to recover its fixed cost. It can be inferred from Figure 3-10 that there is scope to refine the portfolios to arrive at or closer to this perfect equilibrium. For example, portfolio 5 foresees 1200MW of new CCGT. Figure 3-12 shows that in this portfolio CCGT will not be able to recover their fixed cost. Among the reasons are a lower capacity factor (see Figure 3-8) and lower market prices (see Figure 3-4) than in portfolios 1 to 3. Hence, different plant types might be more appropriate to use (e.g. a higher share of OCGT/ADGT) to accompany the renewable capacities of portfolio 5. These observations indicate further optimisation potential in the portfolios studied. Furthermore they underline the importance of a market design that remunerates appropriately for provision of capacity and reserves as distinct from energy.

---

[24] Analysis based on dispatch data of work stream 2B.

[25] Analysis based on dispatch data of work stream 2B.

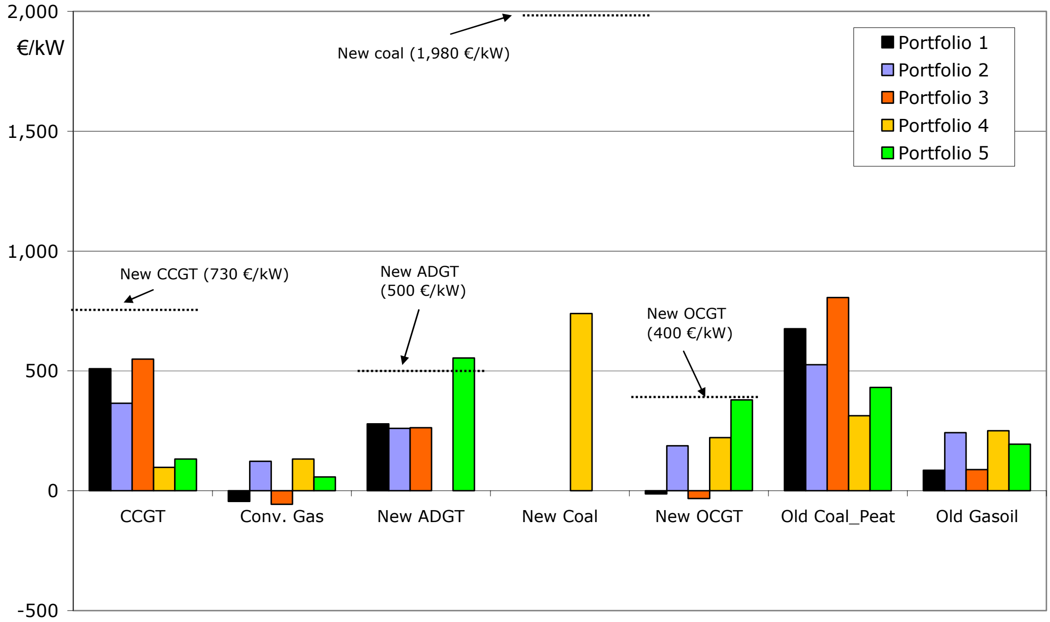


Figure 3-12: Specific capital investments in generation plants that can be financed from available cash flow and indicative investment cost for new plants

3.3.5 Applicable Network tariffs for Generators

Necessary grid reinforcements lead to additional network charges. These charges are distributed between generators (G-component) and load (L-component).

Within the process of European harmonisation of the structure of transmission tariffs, the G-component is likely to become less important as it is applied in very few European jurisdictions.[26] The value of the 'annual national average G' within Great Britain, Ireland and Northern Ireland will be at maximum 2.5 €/MWh. [ERGEG 05].

Currently, EirGrid applies the G-component of the tariffs according to a generator's ability to offset flows to the direction of the dominant flow on the transmission system. The G-component can be negative if a generator delivers such benefits and therefore avoids future network investments. However, wind energy is not regarded as being able to deliver such benefits due to its variable nature. Hence, the transmission tariff for wind energy can not become negative (see also [CER 06]).

To reduce the complexity of the analysis, a uniform G-component is calculated for all generators (conventional and renewable), on the basis of the average G/L distribution (ROI: 25 % generators, 75 % load, NI: 27 % generation, 73 % load).

[26] See [ERGEG 06], [ETSO 2006]

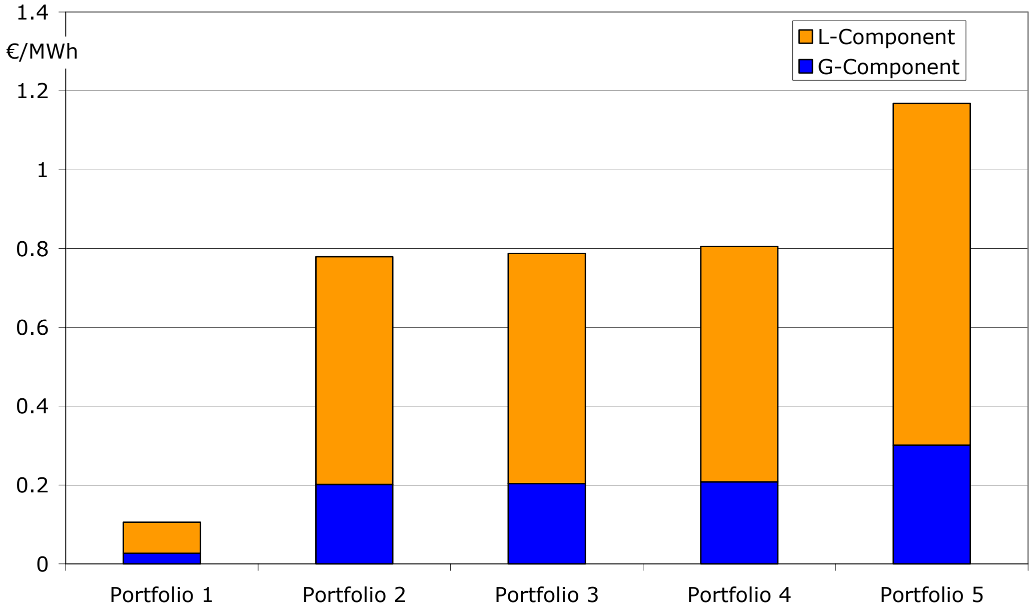


Figure 3-13: Additional use of system charges for generators and load (G and L-component)

Figure 3-13 shows the average additional use of system charges generators and load would have to carry in both jurisdictions to finance the required network reinforcements. Irrespective of the distribution of the use of system charges between generators and load, both components will ultimately be paid by the final customer.

3.3.6 Sensitivity analysis

Figure 3-14 shows the three basic critical factors influencing the total annual system cost: the conventional generation portfolio, the load and RES-E characteristics (in particular the wind power feed-in) and the fuel and CO_2 prices. As load and RES-E characteristics are similar in portfolios 2 to 4, the impact of fuel and CO_2 prices can be analysed for the different plant mixes of portfolio 2 to 4 to evaluate their advantages.

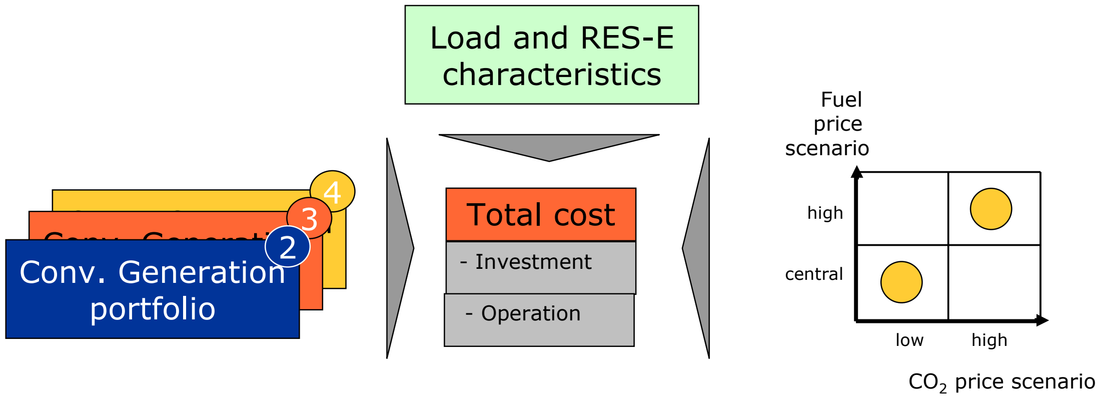


Figure 3-14: Scheme for Sensitivity runs to evaluate the optimal plant mix

In this analysis, two combinations of fuel and CO_2 prices are compared: The central fuel price scenario is combined with the central-CO_2-price scenario (30 €/t) and the high fuel price scenario is combined with a high-CO_2 price scenario (80 €/t). This reflects the assumption that the demand for gas would rise in times of high CO_2 prices and therefore limit the substitution of coal with gas.

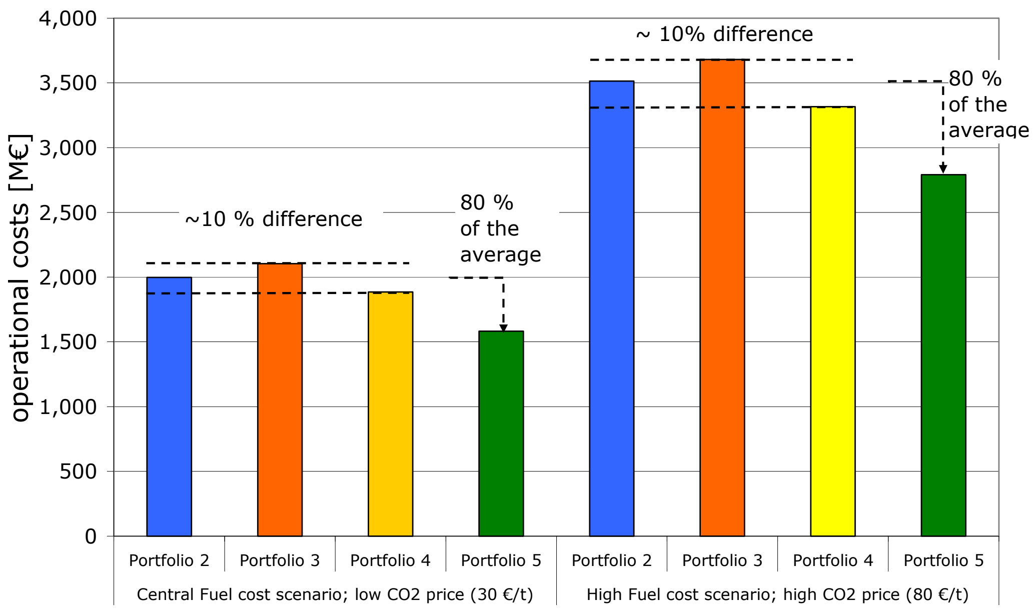


Figure 3-15: Differences in operation cost of power production for portfolio 2 to 5 in one fuel/CO2 cost scenario and portfolio 2 to 5 in a higher fuel/CO2 cost scenario

Figure 3-15 shows the operational cost for the directly comparable portfolios 2 to 4. To compare the impacts of fuel and CO2 prices of portfolios with different wind energy shares, portfolio 5 was added to the chart.

The sensitivity runs conducted by work stream 2B using the high fuel/high CO_2 cost scenario confirmed the relationships of the operational cost as shown in Figure 3-10.[27] This means that for portfolios 2 to 4 with an identical share of renewable generation capacity in the system a combined increase of gas and CO_2 prices do not affect the conclusions of this work stream in relation to portfolios 2 to 4. The total cost of Portfolio 5 increases proportionally to the other portfolios. This means that a higher share of wind in the generation mix does not change the relative order of portfolios as well. However, the absolute cost savings associated with higher shares of renewables will increase.

As a second step the portfolios 2 to 4 are analysed applying a set of other criteria:

1. New generation investment cost
2. Grid connection (and possible reinforcement) cost
3. Environmental impacts (CO_2 and other emissions)
4. Operational flexibility and security
5. Long-term security of supply

The generation portfolios 2-4 will be discussed qualitatively in relation to these criteria.

1. Generation investment would be lowest for portfolio 3 (high shares of OCGT) and highest for portfolio 4 (high shares of new coal). Portfolio 2, with high shares of CCGT, is in between the two other portfolios
2. As Table 3-1 indicates, portfolio 3 will have the greatest number of new conventional units. The distribution of a greater number of smaller units can be more easily aligned with the network flows than a smaller number of large units. Therefore, Portfolio 3 is superior to the other portfolios and portfolio 2 better than portfolio 4 as regards grid connection and reinforcement costs.

[27] See work stream 2B report, Figure 36.

Table 3–1: Number of new units installed in Portfolio 2 to 4[28]

Unit type	Number of new units, portfolio 2	Number of new units, portfolio 3	Number of new units, portfolio 4
New CCGT	3	-	3
New ADGT	5	5	-
New Coal	-	-	3
New OCGT	8	19	3
Total Number	**16**	**24**	**9**

3. As shown in section 3.6.1, portfolio 4 has the highest CO_2 emissions and portfolio 2 the lowest.
4. A larger number of distributed units implies the highest operational security, therefore the order is as with regard to the grid issues raised in the second point
5. The long-term security of supply is higher with systems that depend on coal rather than on gas, since the coal reserve will last longer than gas reserves and coal can be stored more easily. Portfolio 4 is regarded as being superior to the other portfolios in relation to long term security of supply. Portfolio 3 relies more on electricity import from GB than Portfolio 2 (see Figure 3-34), therefore it is rated lower than Portfolio 2.

Table 3–2: Summary of evaluation of generation portfolios 2-4

Criterion	Portfolio 2	Portfolio 3	Portfolio 4
Operational cost	√√	√	√√√
1. New generation investment cost	√√	√√√	√
2. Grid connection (and possible reinforcement) cost	√√	√√√	√
3. Environmental impacts (CO_2 and other emissions)	√√√	√√	√
4. Operational flexibility and security	√√	√√√	√
5. Long-term security of supply	√√	√	√√√

Legend: least preferable = √, most preferable = √√√

The overall picture (see Table 3–2) indicates that the conventional generation mix of portfolio 3 appears to provide more advantages than portfolio 2 and 4 regarding the crite-

[28] Based on portfolios documented in work stream 2B report, Appendix 2.

ria 1-5. Furthermore, the coal-dominated portfolio appears to be the one with most disadvantages.

3.4 Renewable Generators

This section starts with a listing of renewable energy plant types and the ranges of levelised costs as analysed within work stream 1. The next sections cover the dispatch of these technologies and the total expected investment costs.

3.4.1 Renewable technologies and cost ranges

Wind energy

Levelised costs for wind energy range from €0.04 to €0.47 per kWh for those projects considered in this study. Levelised costs are below €0.06 per kWh up to a total capacity of about 4000MW. The capacity requirements established by the portfolio composition in work stream 2A were fulfilled using known site locations and projects in various stages of development. For portfolios 5 and 6 new sites were identified using the wind resource maps.[29] Some projects at new sites have lower costs than the projects already under development. Because work stream 1 prioritised those projects already in development in fulfilling the various portfolios, some projects in portfolios 1 – 4 have higher levelised costs than projects in portfolios 5 and 6.

Bioenergy

A wide variety of materials and seven conversion pathways were covered in the analysis of work stream 1. Within this analysis, electricity from bioenergy was classified in to three categories as follows:

- *Landfill gas* representing biological municipal waste anaerobic digestion;
- *Biogas* from wet agricultural or food waste as well as municipal solid waste;
- "*Biomass*", which includes the following resource and technology combinations:
    - Dry agricultural waste incineration
    - Woody crop/residues combustion, gasification, pyrolysis
    - Municipal solid waste incineration

Sewage sludge aerobic digestion was not included as it is assumed that this technology will not be extended beyond the existing installation

Levelised cost from bioenergy vary significantly between and within categories and specific assumptions apply for each technology. Details can be found in the detailed report of work stream 1.

---

[29] The detailed methodology for the assessment of the wind resource can be found in Appendix 7 of the Work stream 1 report.

Ocean energy: Wave

Wave energy will have similar resource characteristics to wind energy, although it is expected to be more predictable. Portfolio 6 included a requirement of 1,400MW of wave energy. Wave energy was excluded from other portfolios in the work stream 2A study due to cost expectations relative to the cost of biomass resources. Sites have been identified of the Mayo, Galway and Kerry coasts. Levelised costs range between €0.10 and €0.15/kWh on the presumption that at this level of deployment, technical risks and price will be substantially reduced.

Ocean energy: Tidal

Tidal energy is also a variable resource, however it is predictable. For portfolios 1-4 a first-generation technology was assumed, which has levelised cost that range between €0.22 and €0.25/kWh. Second generation tidal technology is expected to overcome limitations on the depth at which tidal devices can be deployed, allowing access to more energetic resources. As such, a cost decrease for the second generation technology to about €0.10/kWh was assumed for installations applied in portfolios 5 and 6.

3.4.2 Total investment volume of renewables

Work stream 1 assessed the investment cost requirements for the existing and new renewable plants required in portfolios 1 - 6. The total investment volume is shown in Figure 3-16 and ranges from €4 bn to €11 bn. The investment requirements are dominated by wind energy investments which are between €3 bn and €9 bn. It should be noted that this figures includes existing projects as well as projects already in various stages of project development. The inclusion of existing projects reflects the fact that most renewable projects have a shorter economic life than conventional generation, and may be repowered between now and 2020.

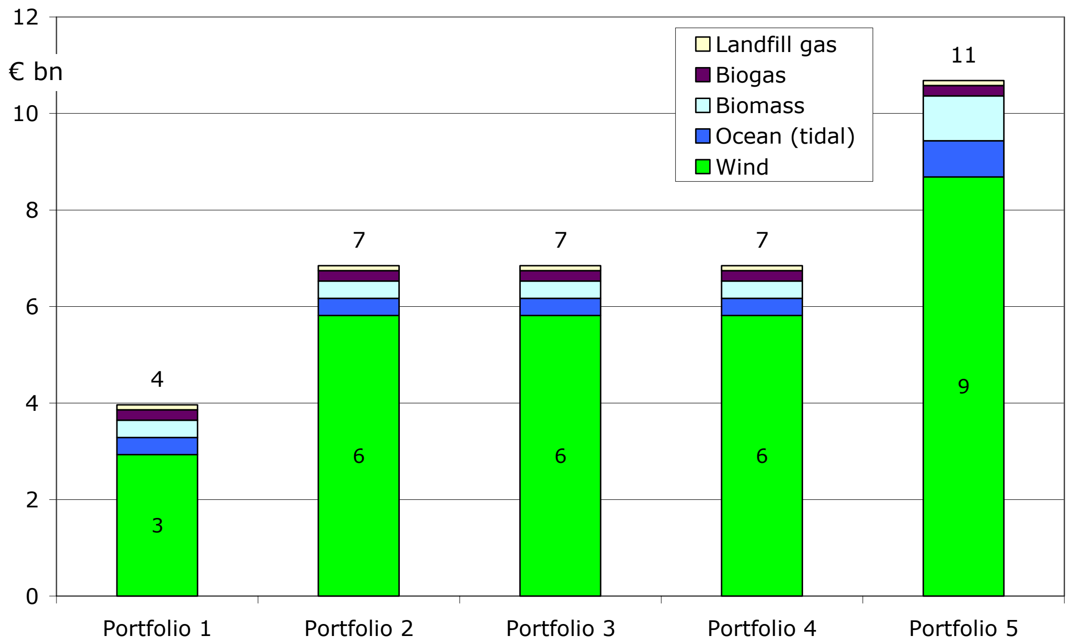


Figure 3-16: Total investment volumes in renewable energies

3.4.3 Dispatch of renewable generators

All renewable technologies with the exception of bioenergy have operational costs close to zero. Hence, the generation of variable renewable electricity is dispatched according to the given time series of electricity generation with no consideration of operational costs. Bioenergy resources ("baseload renewables") are treated as must-run units, since their variable operational costs are very low (assumed to be 10 €/MWh).

Levels and effects of wind curtailment

Curtailment of variable renewable energy is considered in two situations: as an alternative to the extension or reinforcement of the network, and to enable system balancing.

The economic risks associated with curtailment and its yield losses will be an important factor influencing investment behaviour. The experience from other countries shows that if the risks are unclear or perceived as high they may preclude investment in renewable energy systems. Dedicated policy instruments may be required to make these risks manageable for project developers and investors.

Within the network study, the network reinforcements were calculated without considering long-term wind curtailments as an option, yet temporary curtailment of wind power is often suggested as a cost effective alternative to the extension or reinforcement of the network. The study results indicated that at transmission level curtailment for such reasons is justified economically only in exceptional cases. In all portfolios, the fraction of network reinforcement cost in the total societal costs associated with electricity supply is so low that they are simply not decisive for strategic choices.

At distribution level and in the case of individual projects it may be that the energy yield does not justify respective infrastructure investments. In those cases it may be reasonable to apply temporary curtailment of wind farm output. This has to be evaluated in individual case studies. Additionally, curtailment may be a suitable transitional instrument allowing accelerated implementation of wind power compared to network reinforcement.

Curtailment may also be required from a systems operations perspective. This possibility has been partly considered in the work stream 2B methodology in which the simulation of the dispatch included the possibility of wind curtailments. However, the necessity of curtailments was found to be low with only 0.5% of the annual wind production possible in portfolio 5 requiring curtailment due to dispatch and must run requirements.

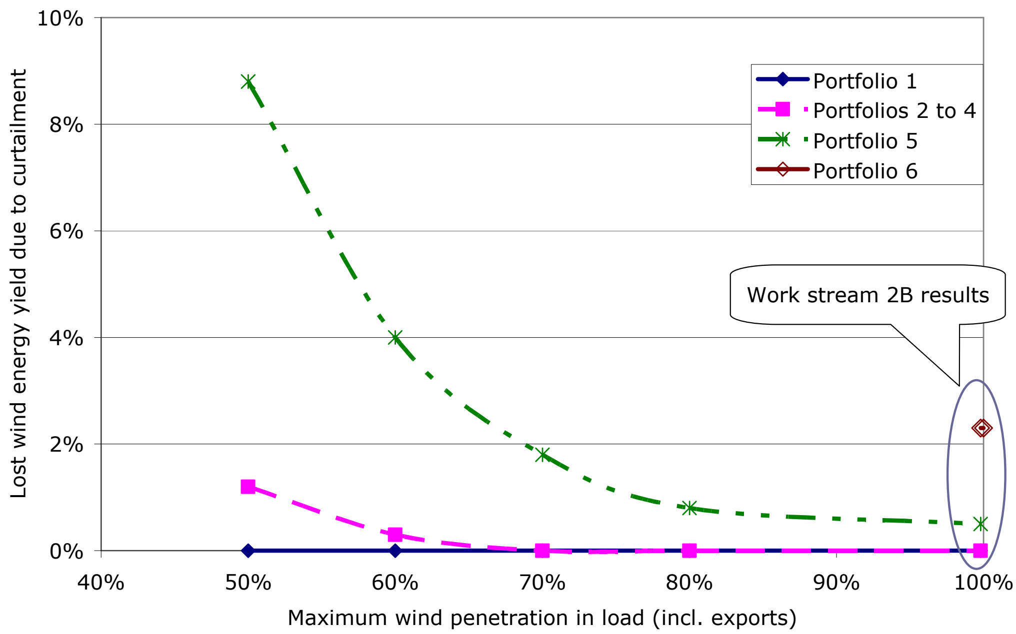
The penetration levels of wind power in the simulation runs resulting from work stream 2B exceed what has been empirically demonstrated to date as being technically feasible. From that perspective, it may appear that in a number of scenarios and under specific conditions additional constraints in wind generation will be required for secure system operation. Further research will be required in this field.

Wind curtailment for system operational reasons

As a consequence of the limitations of the study's methodology the need for wind curtailment in work stream 2 results may be underestimated. Considering, for example, frequency stability and fault issues wind curtailment for operational reasons should be approximately correlated with the instantaneous levels of wind generation with respect to the load. As instantaneous levels of wind generation increase it becomes increasingly likely that curtailment may be necessary in order to maintain system reliability. It is recognized that technical improvements in wind turbine technology may reduce the need for curtailment in the timeframe covered by the study.

Here a very simple illustration is given which demonstrates how curtailment may grow with wind penetration if a limit on instantaneous value became a necessary operational constraint.

As the figure below shows, the impact on the portfolios 1 to 4 is limited in the range considered. As a consequence of the relatively low installed wind capacity, critical penetration levels hardly occur and, hence, related yield losses are negligible. With higher installed wind capacities, as in the case of portfolio 5, the impact becomes more severe. For higher installed wind capacities the relation between maximum acceptable wind penetration and yield losses is highly non-linear and for that reason the outcome will be highly sensitive to this maximum. It has to be emphasized that from the current perspective a penetration level of 50% has to be seen as quite challenging.



3.4.4 RES-E support requirements

This section analyses the financial position of renewable generators, both existing and new, that emerges from the dispatch simulations of the year 2020. In the dispatch simulation all renewable plants of one technology are aggregated and treated as one large plant. The annual revenues for a renewable generator are calculated on the basis of their power output multiplied by marginal electricity prices per the work stream 2B dispatch. It should be noted that these prices are generated from a cost based dispatch where no market model was assumed (see Section 2.7). Marginal electricity prices in an actual market would differ. From these revenues, the annualised investment costs are subtracted. For bio-energy plants operational costs are also subtracted. The remainder is considered annual profit or, when a loss, annual support requirement. This methodology takes account of the correlation of the time series of electricity production with electricity prices and the influence of renewable generation on the marginal electricity (market) price.

The profit or support requirement for all renewable generators can be aggregated to a "profit-resource curve", similar to a cost-resource curve, to show which generators would require support payments in 2020 and to what extent.

Figure 3-17 shows the profit –resource curve for all renewable generators of portfolio 1. The x-axis shows the cumulated amount or renewable energy, produced by existing and new renewable units. On the y-axis, the profit or loss per MWh is depicted. Consequently, the filled area shows the total profit of a unit. If the area is below the x-axis, the plant requires a support payment. The total filled area below the x-axis depicts the total required amount of support. Since the colours depict technologies the required support payments per technology are made evident.

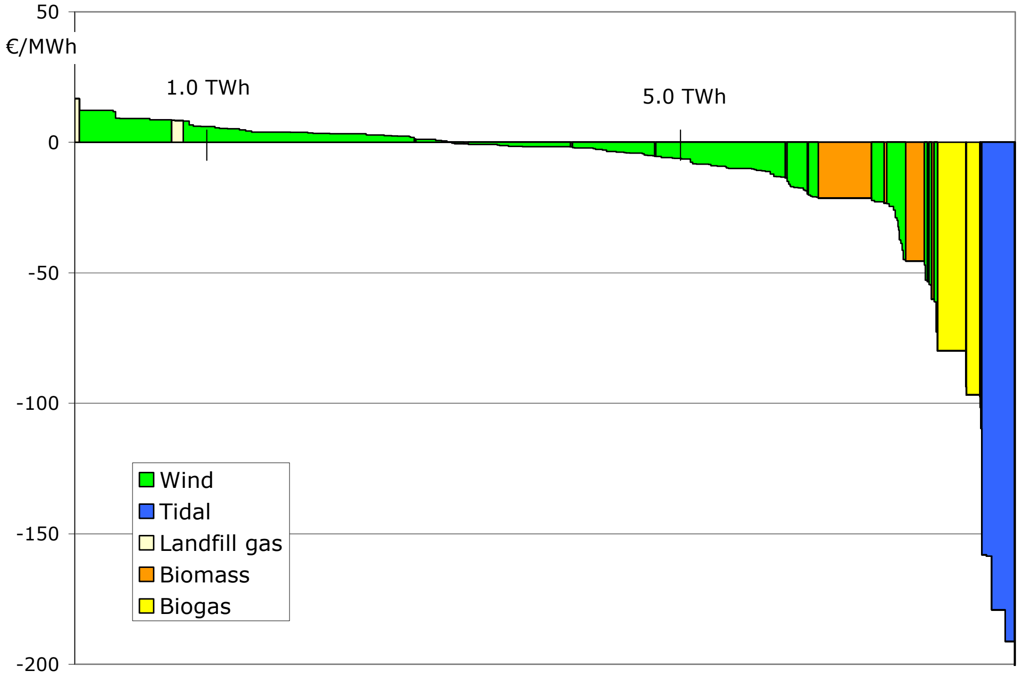


Figure 3-17: 2020 profit resource curve for portfolio 1 (2251MW renewable energy capacity, 16% RES-E penetration)

Figure 3-17 shows that wind energy is by far the cheapest renewable resource in Ireland. Only a few landfill gas units have profits in the range of wind energy. More than two TWh of renewable energy can be provided from wind projects that do not require support payments but can refinance their costs from electricity market revenues under the cost based market assumptions included in the study. Only moderate support payments are required for nearly 6 TWh of renewable energy. With biomass and biogas projects, the curve becomes steeper and reaches to tidal projects which require the most support.

Figure 3-18 depicts the profit resource curve of portfolio 2. The obvious difference to the previous figure is the higher amount of wind energy. Although 2 GW of wind capacity are added, the additional wind energy requires less additional support than the remaining technologies. Since portfolios 3 and 4 have the same renewable energy capacities installed the profit resource curve do not differ substantially from the figure shown. The difference is that higher price levels in portfolio 3 lead to a lower levels of required support for all technologies.

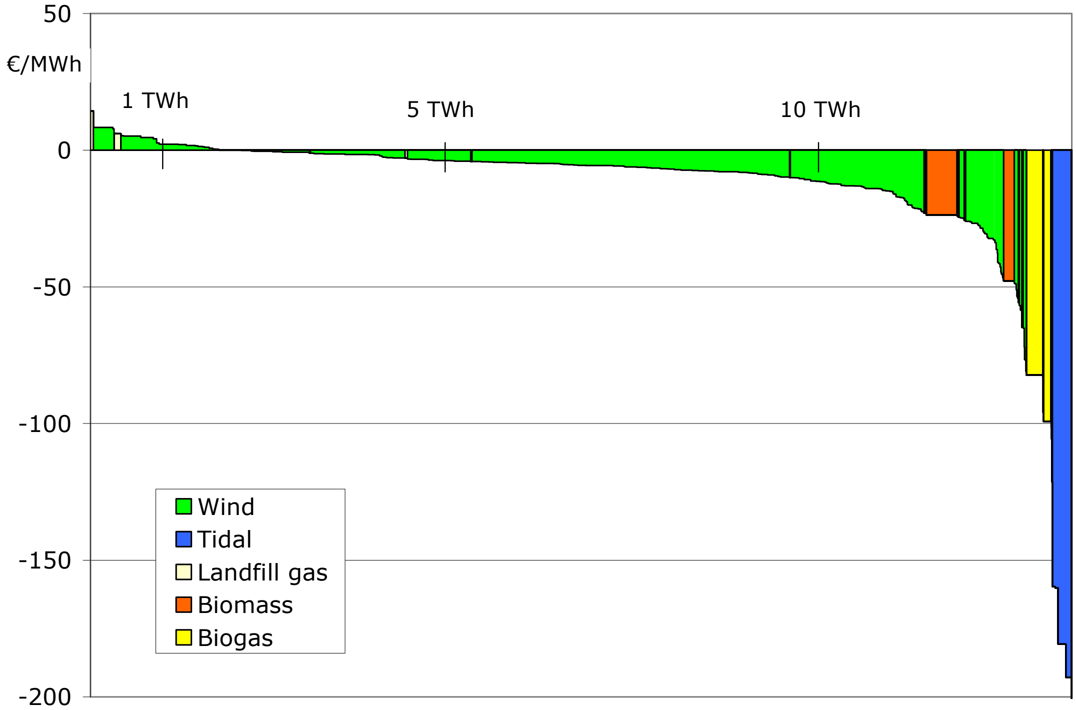


Figure 3-18: 2020 profit resource curve for portfolio 2 (4251MW renewable energy capacity, 27% RES-E penetration)

Finally, Figure 3-3-19 shows the profit resource curve for portfolio 5. This portfolio shows the support required for the production of almost 23 TWh of renewable energy. Here, second generation tidal technology, which benefits from the access to better tidal resources, are able to compete with the more expensive wind resources and landfill gas. Wind energy remains the technology that requires the least support.

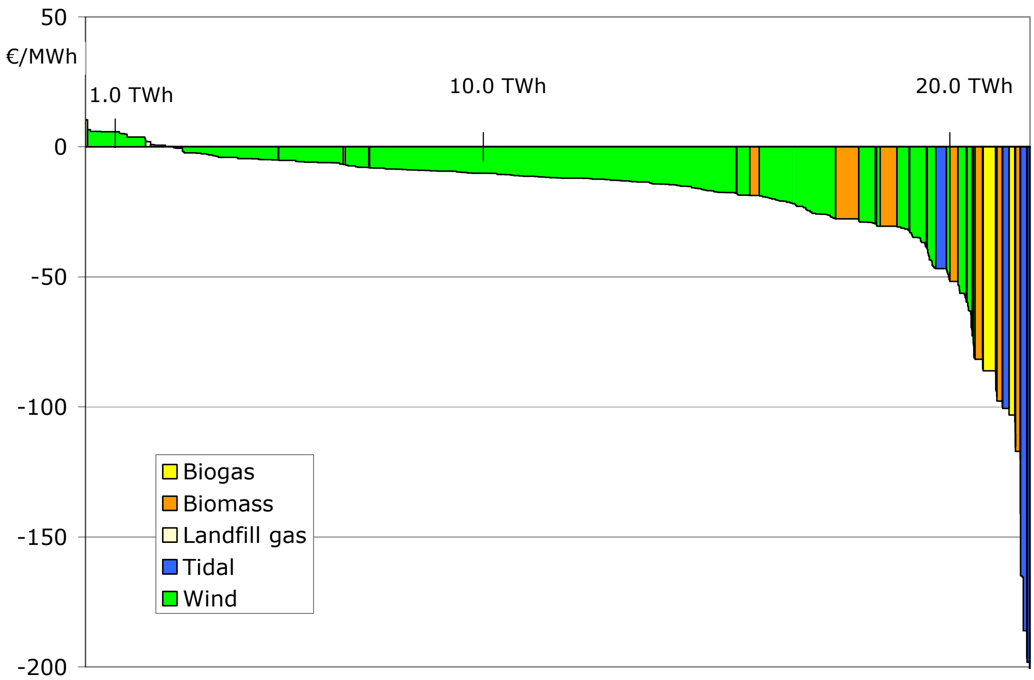


Figure 3-3-19: 2020 profit resource curve for portfolio 5 (6572MW renewable energy capacity, 42% RES-E penetration)

The profit resource curves show that, especially for the portfolios with lower shares of renewable electricity, an increased reliance on wind energy could decrease the required support. However, it has to be kept in mind, that an increased application of wind energy requires substantial network connections (included in the cost calculation) but also additional network reinforcements (treated in section 3.5.3) below.

Ocean wave energy was only included in portfolio 6. As it was mentioned in sections 2.5, 2.6 and 2.8, the dispatch and network assessment of portfolio 6 indicated that any system marginal prices resulting from the system dispatch model would entail such uncertainties as to make the analysis unreliable. In order to view the financial position of wave generators without relying on the results of portfolio 6, the technology was integrated into portfolio 5 for an alternative profit resource curve. Note that separate dispatches with ocean wave generation were not done; rather the presumed revenue on the basis of output was compared to the levelised costs for the wave generators to estimate the required support. Figure 3-20 shows the indicative results of the integration of 1400MW of ocean wave generators in portfolio 5. They generate about 4 TWh of electricity and would require approximately the same amount of support as the technologies they replace.

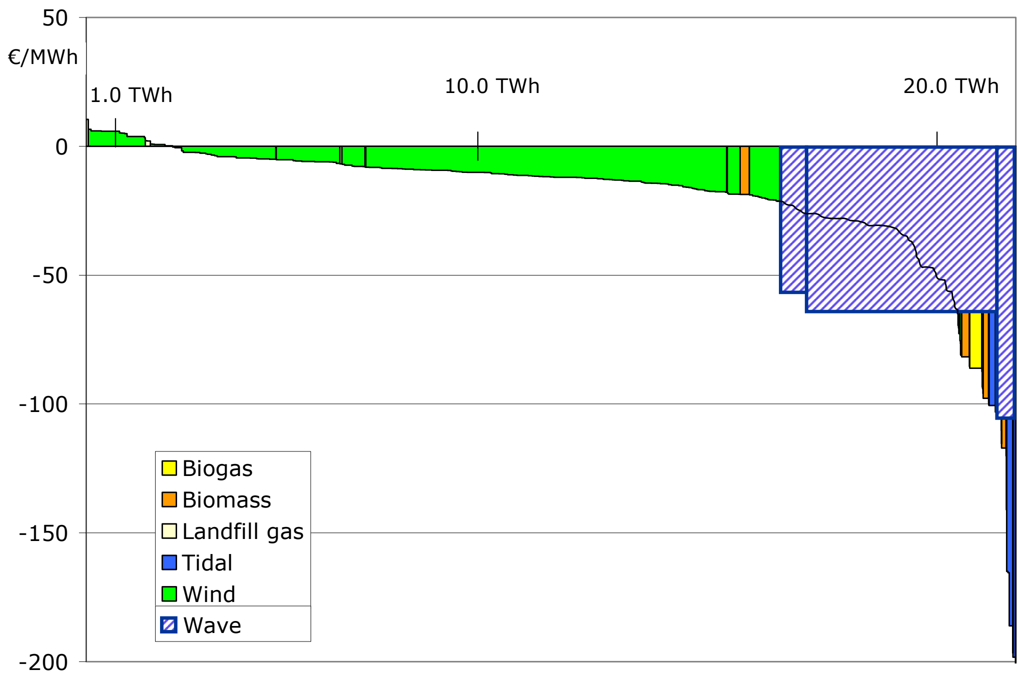


Figure 3-20: 2020 profit resource curve for portfolio 5, including wave energy

Figure 3-21 shows the total required support payments for portfolios 1-5 based on the previous analysis. The positive profits some wind generation plants earn are not deducted from the calculated support payments, thus the support payment figure represent the total area under the x axis in each of the profit resource curves in the previous graphs Figure 3-17 to Figure 3-20.

When interpreting the figures illustrated in Figure 3-21, one has to reflect the ideal character of the model and its underlying methodologies. All support mechanisms incur some inefficiencies, where the support level provided to some renewable energy generators exceeds their requirements to break even. The support cost estimated by this analysis represents that which would incur if a perfectly efficient support mechanism were employed. As such it is possible that this analysis underestimates the support costs that would be incurred.

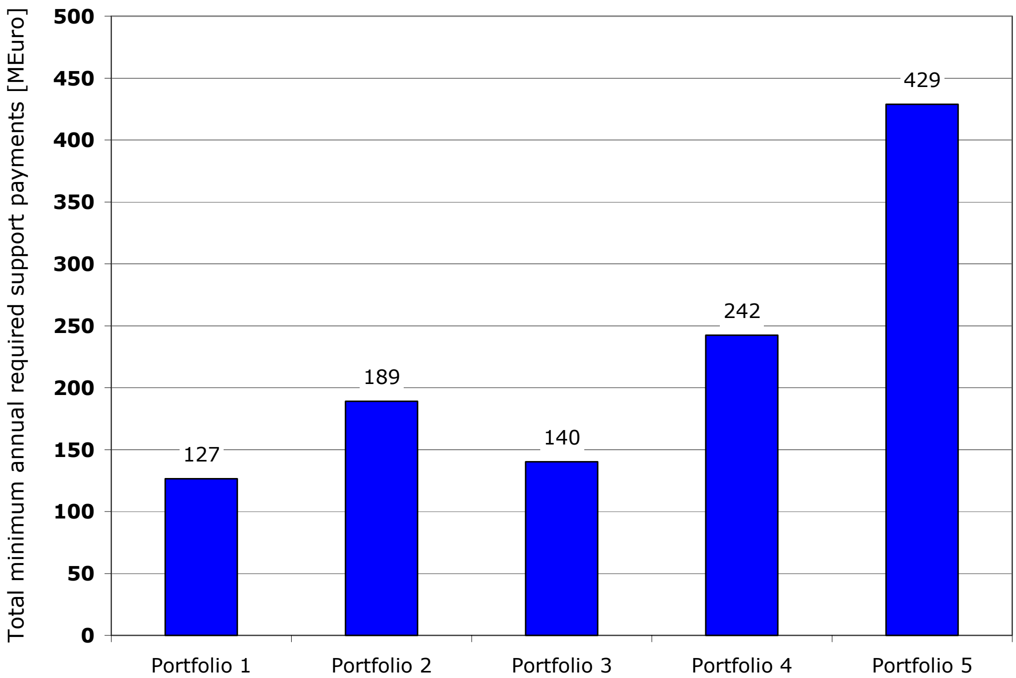


Figure 3-21: Total minimum annual required support payments assuming a perfectly efficient support mechanism

The total required support payments shown in Figure 3-21 are further disaggregated in Figure 3-22 to show the relative support requirements for the technologies. This figure shows that the relative support requirements vary considerably. The variation occurs even in the portfolios with a similar portfolios of renewable generation, which can be explained by different correlations between system marginal prices and wind generation.

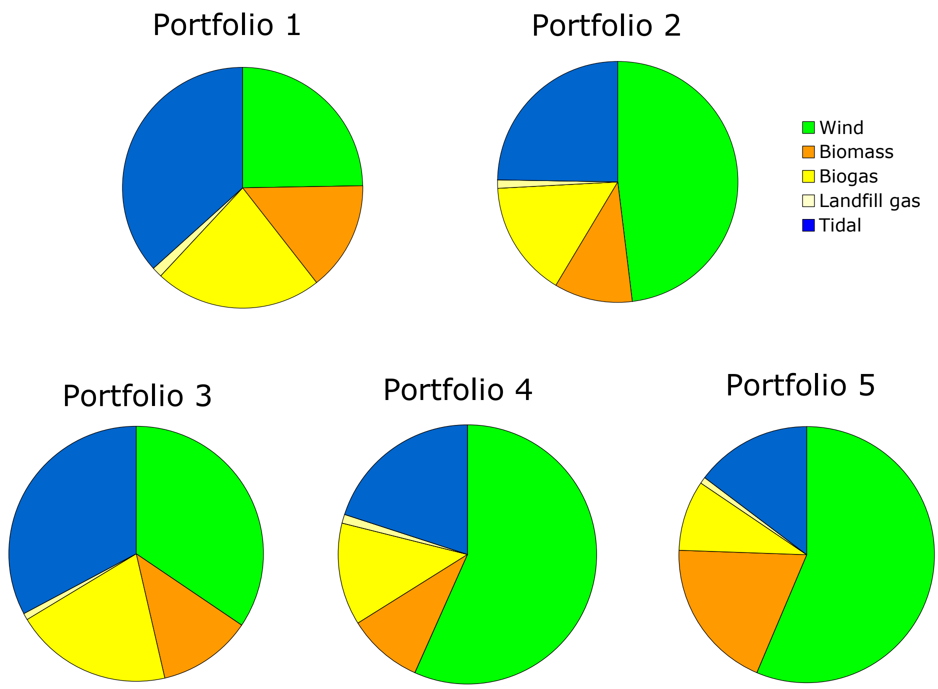


Figure 3-22: Distribution of minimum required support payments by technologies

3.5 Network operators and –owners

The analysis of the impacts on network operators and owners distinguishes between issues affecting system operation of a future system, and issues that affect the construction and maintenance of the transmission network. This Section also includes some analysis regarding network connections and the operation of the interconnector.

3.5.1 System operation

Provision of reserves

An important aspect of reliable system operation is the availability of reserves in generation. Reserves are required to cope with imbalances between load and generation. Those imbalances may be caused by errors in the predicted levels of loads and or wind power output. They may be caused also by large power fluctuations. These can be the consequence of changes in load as well as (wind) generation but also tripping of generation units. As an example: the steepest change in net load in portfolio 5 according to the results of work stream 2B amounts to more than 3 GW in one hour. To maintain the balance during these hours, the system operator needs generation capacity that is effectively immediately dispatchable. Likely levels and the dynamics of respective imbalances differ, as do the levels and specifications of respective reserve categories.

Work stream 2B distinguished between spinning reserves and replacement reserves being available after 5 minutes. Deficits of reserve capacity in terms of hours and MW have been compared (see also Figure 3-3). The outcomes suggest that portfolios 3 and 5 perform best in terms of availability of reserves. However, the differences between the portfolios are partly related to model limitations, most significantly in portfolio 6, and their statistical significance is difficult to evaluate. Based on the existing data, a robust ranking of the portfolios according to this criterion is impossible.

The delivery of reserves in all cases requires special attention. From a techno-economic perspective it is clearly feasible to tackle related challenges, e.g. by addition of further peaking capacity. This may require appropriate efforts in regulation such as provision of capacity payments.

Also from the perspective of reserve markets, capacity extensions may be desirable. Otherwise there is a clear risk for high volatility in power prices. The outcomes of work stream 2B indicate that this may apply to a substantial fraction of time.

Forecasting

The methodology of the dispatch simulation in work stream 2B allows for an assessment of the value of forecasting wind energy output. Work stream 2B concludes that cost reductions due to perfect forecasts of load and wind power production are relatively small in comparison to the total system operation cost of the all island power system. However, the absolute sum of the cost reductions is not negligible and increases with higher shares of wind energy.

Operation of the storage facility (Turlough Hill)

Work stream 2B concluded that increasing wind penetrations did not materially alter the operation of the pumped hydro storage facility, Turlough Hill.

An increased use was observed for portfolio 6.

Reliability issues

As stated in the assumptions the loss of load expectation was a major design criterion for the portfolios. From the perspective of generation capacity available to meet the instantaneous demand the portfolios are comparable. However, additional restrictions in system operation may apply, directly affecting the feasibility of operational configurations and reliability levels. The methodologies employed in the All Island Grid Study did not cover all of these issues. As an example the technically feasible penetration of instantaneous wind power with respect to load is not addressed, i.e., dynamic or, fault issues.

As Figure 3-23 shows, except for portfolio 1, wind penetration in the island load achieves levels in excess of 50% of instantaneous load. This is much higher than what has ever been demonstrated to be manageable on a single synchronous system. With existing technology concepts, those instantaneous penetration levels will clearly challenge the capability of the system to maintain frequency stability and synchronism and to recover from system disturbances.

It is important to realize that the duration of the undemonstrated situations is an order of magnitude higher than the accepted LOLE level. For portfolio 5 this applies to at least 20% of the year.

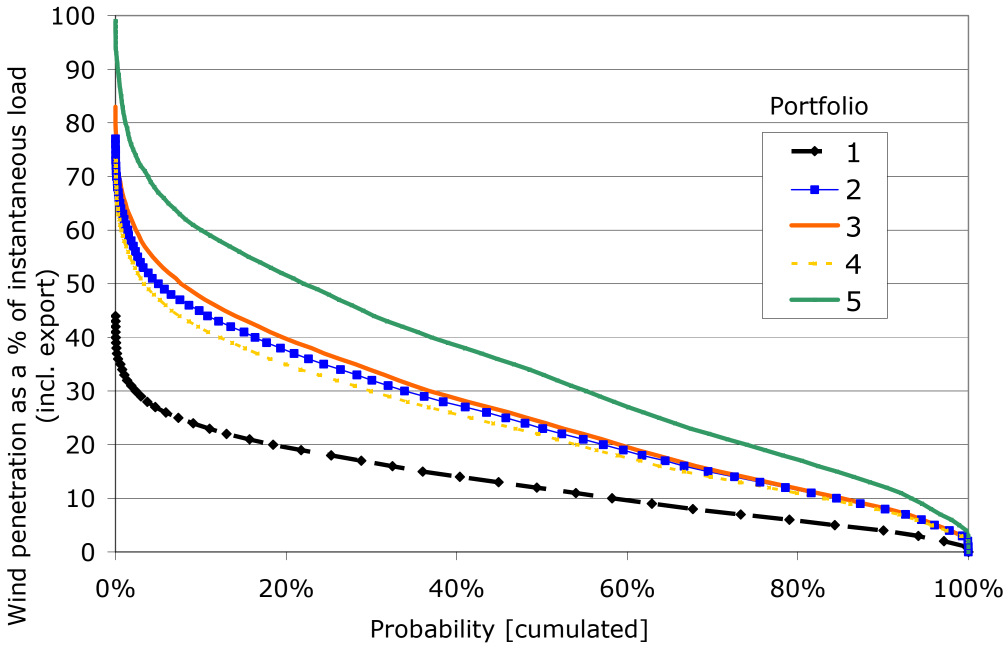


Figure 3-23: Duration curves of instantaneous penetration of wind power in the All-Island load (including exports to the UK) for portfolios 1-5

The methodology of the All Island Grid Study did not cover relevant investigations and hence, these issues clearly require further investigation in the domain of dynamic studies. In the context of the study and for the time being one can conclude that, given the above reported results, all portfolios perform similarly with regard to LOLE requirements.

3.5.2 Interconnector operation

For 2020, two interconnectors from the All Island System to the power system of Great Britain with a total capacity of 1000MW are assumed. While 100MW are reserved for the provision of spinning reserve, the remaining capacity is used to optimise both generation systems.

The pattern of the energy transports via the interconnector changes with the renewable electricity share of the all island generation and is also influenced by the structure of the conventional generation. Figure 3-24 shows that exports become more important with an increasing share of electricity sourced from renewables in the portfolio. Portfolio 3, with many gas turbines that have low investment costs but high operating costs, requires high imports comparable to that required in Portfolio 1.

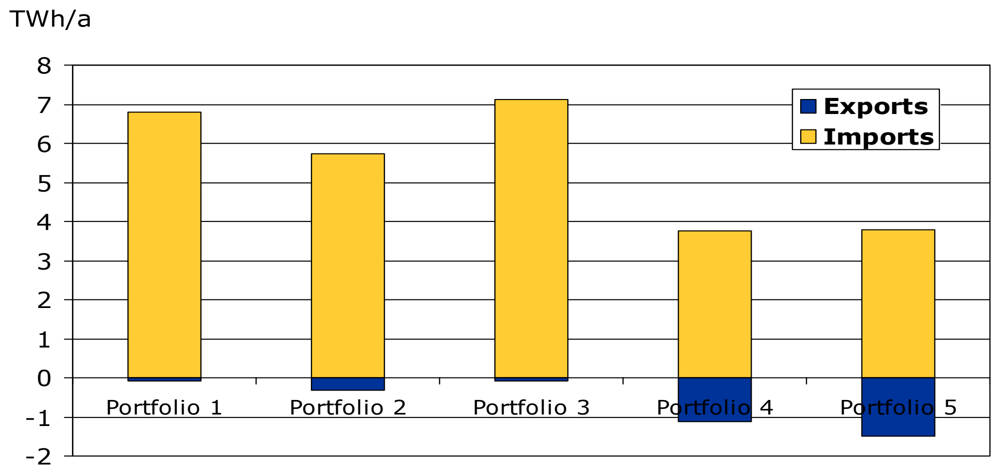


Figure 3-24: Expected annual energy flows via the interconnectors

The absolute amount of energy transported does not allow a statement about its economic importance. The economic value of an interconnector is determined by the price differences on both sides and the amount of energy transferred at this price difference. Because the (operational) generation cost in Ireland tend to decrease with an increased share of renewable generation in the portfolio, the net payments for imports of electricity tend to decrease from portfolio 1 to 5.

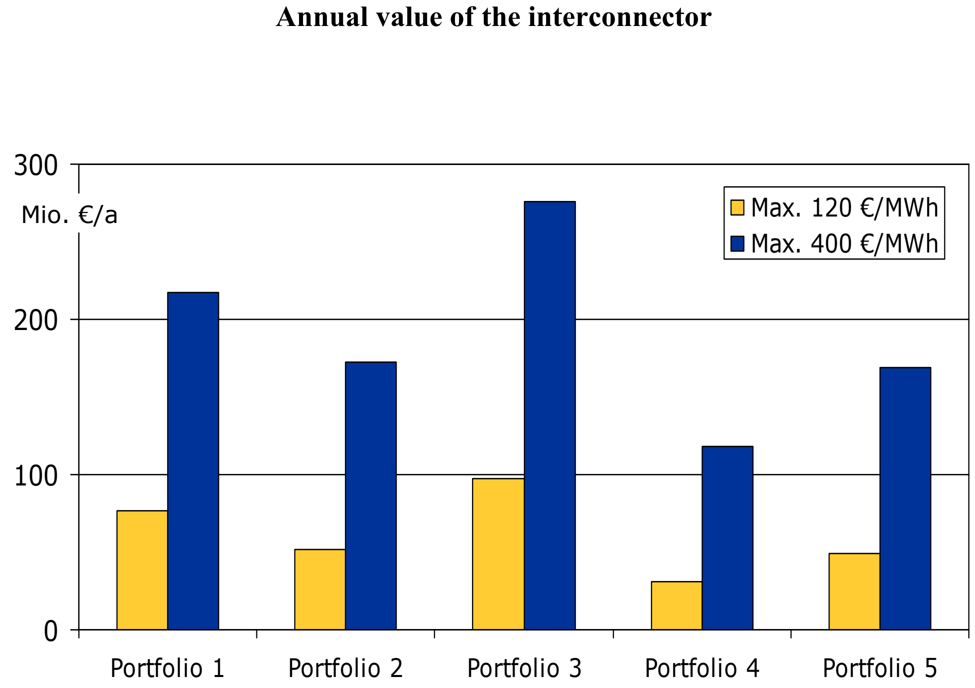


Figure 3-25: Annual value of the interconnectors

For the calculation of annual values it is assumed that prices in both systems do not exceed 120 €/MWh. Figure 3-25 shows the results of the calculations in the yellow bars. Additionally a scenario was calculated assuming a maximal price of 400 €/MWh, which is depicted in the blue bars. The results underline the importance of the interconnector in Portfolio 3. Since the value of the interconnector is dominated by the values of the hours where prices in the All Island System are very high and the interconnectors are transmitting at full capacity, the maximum price and therefore the market design influences heavily the results of the calculation.

The figure does not indicate a strong dependency of the value of the interconnector on the share of renewables in the system. However, the hourly load fluctuations on the interconnector increase.[30]

The annual values are also an upper limit on network charges that a merchant transmission company might be able to charge. For the calculation of the total societal cost as shown in Figure 3-36 it is assumed that no transmission charges apply and the energy is purchased at the system marginal cost on the "cheap side" of the interconnector.

[30] See paragraph 4.9. in the work stream 2B final report.

3.5.3 Transmission System reinforcement

Transmission Network reinforcements

Necessary network construction associated with the exploitation of renewable energy sources may be considered an external effect, but is still of decisive importance. This Section examines the transmission network reinforcement requirements.

Distribution connections and extension of distribution networks was not included explicitly within the scope of this study. Nevertheless work stream 1 provided important information which will be reflected in the Section on network connections for renewable generators below.

The existing planning for the development of the all island transmission system formed the baseline for the evaluation of network reinforcements in work stream 3. Specifically, the base case represents the existing all island transmission network with the assumption of some additional reinforcement to accommodate additional generation in Cork and the construction of an additional 500MW interconnector to Great Britain. Figure 3-26 shows the total length of transmission network that needs to be reinforced due to the addition of renewable energy generators to the system in both jurisdictions for each portfolio. For comparison: the total length of the transmission system of Eirgrid in 2007 is 5800 km[31].

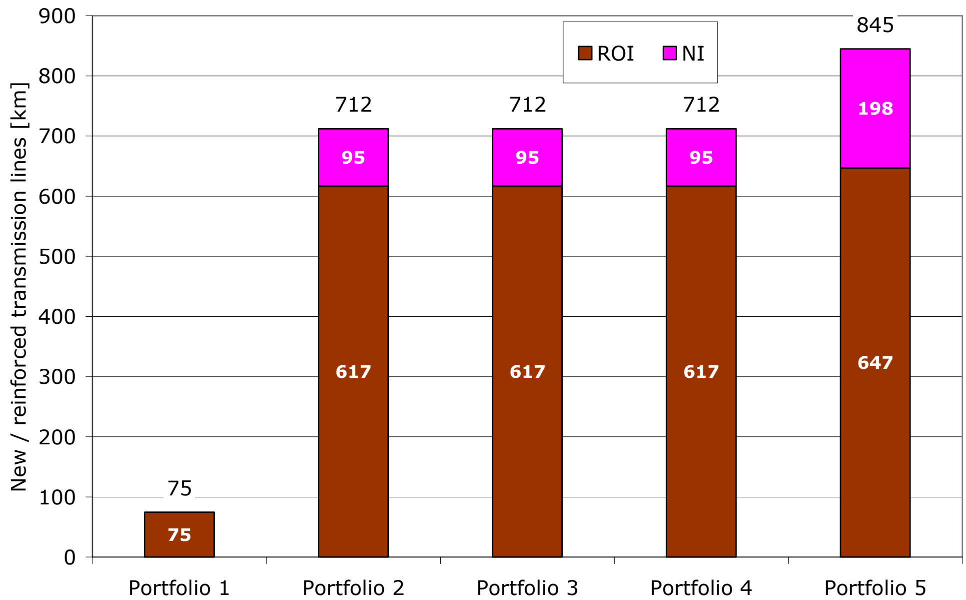


Figure 3-26: Total length of transmission lines to be reinforced

Obviously, there is a great difference in required network reinforcement between Portfolio 1 and the others.

---

[31] See http://www.eirgrid.ie, October 2007

It should be emphasised that work stream 3 assumed an integrated planning process with a predefined renewable capacity target per portfolio. In case of changing ambition levels the moderate increase from portfolios 2-4 to portfolio 5 as suggested in Figure 3-26 may not be applicable. In other words: initially planning and building for 4000MW of wind and then deciding later on to increase the network capacity to accommodate 6000MW of wind would likely result in a requirement for more lines and higher costs than would be required if the decision at the outset was to build to accommodate 6000MW of wind. In the former case, the costs incurred would likely be higher for the accommodation of 6000MW than those shown above.

To a certain extent these reinforcement measures may use existing network routes. However, in many cases reuse or extension of existing corridors will be impossible. Planning and permitting of these new lines represents a major challenge for the network operators and the authorities. As public acceptance for overhead lines is problematic, planning procedures may be very time consuming and availability of the complete infrastructure as identified in work stream 3 by the year 2020 is questionable. From that perspective, the outcomes of work stream 3 highlight one of the major challenges associated with all portfolios except portfolio 1: adopting the network to the changing generation plant is a major development activity affecting the whole country.

The specification of assets and estimation of the required investment volume for the transmission network reinforcement up to 2020 was calculated in work stream 3. The environmental impact of the required additional lines will be discussed in section 3.6.1.

Figure 3-27 shows the total required capital investments in both jurisdictions. These figures also represent the expansion of the regulated asset base of the transmission system owners.

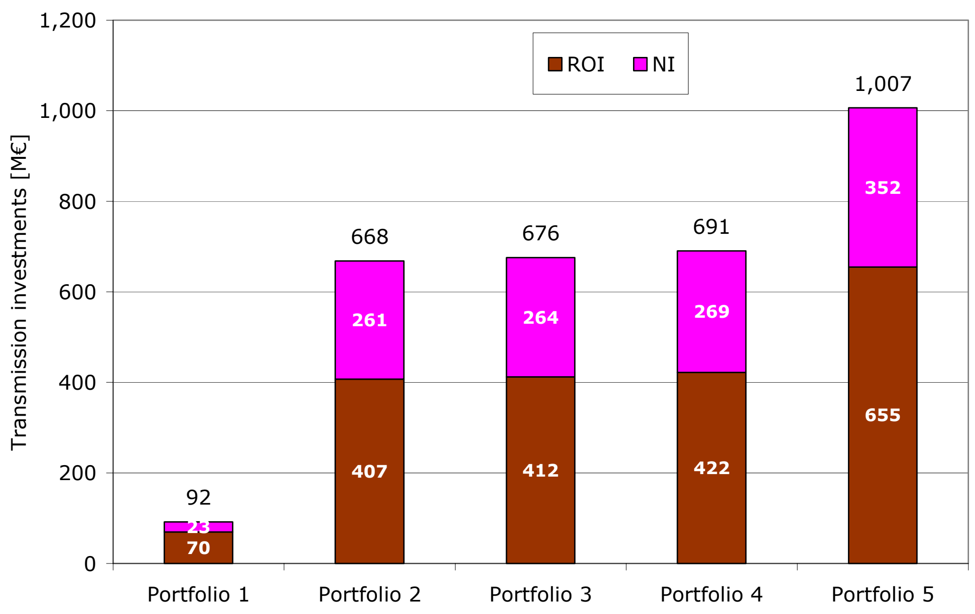


Figure 3-27: Total investments in transmission line reinforcements, including additional capacitors taking account of unplanned outage events only

The relevant impact category for the TSO is the allowed revenue that emerges from the increased additional network charges. The allowed revenue is determined by, among other factors, the capital employed and this is used to calculate tariffs and charges to users of the transmission system.

There are other costs related to land and civil works which are unquantifiable until routes and substation sites are selected. Hence, these costs are not included in this analysis.

For the calculation of additional charges to customers, an asset lifetime of 50 years and interest rates used by the respective regulators are applied.[32] Based on the resulting annuity factors, investments were annualised. The annual numbers are shown in Figure 3-28.

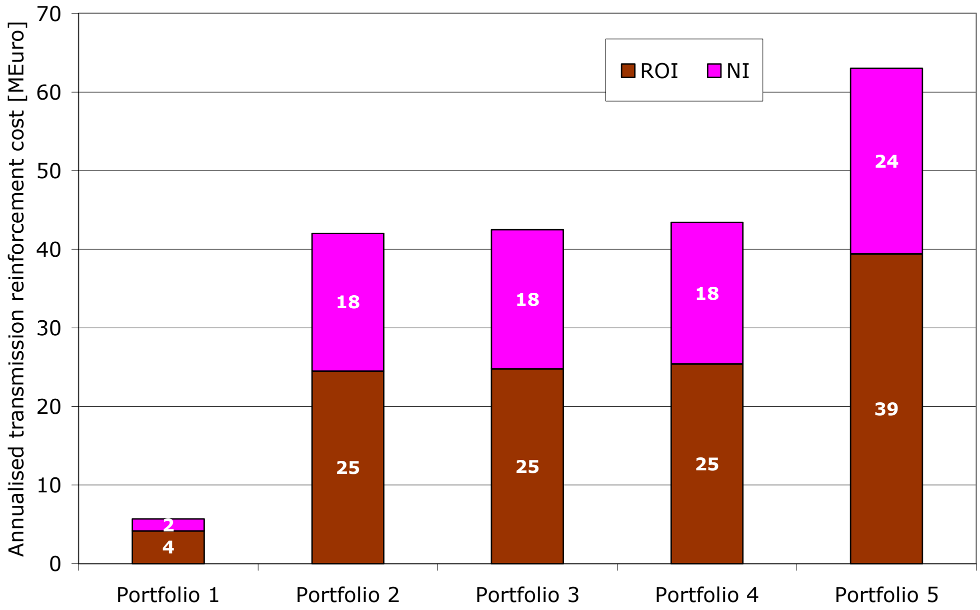


Figure 3-28: Annualised cost for transmission network reinforcement (including cost of capacitors)

Annual maintenance costs also have to be considered. Based on historic maintenance costs of approximately 1700 €/km, the annual expected costs will range between 1.2 – 1.5 Mio. €[33] for the Republic of Ireland (portfolio 2/3/4 - 5) and 0.2 and 0.4 Mio. € for

[32] For NI a rate of 6.41 was used, for the ROI 5.63, resulting in annuity factors of 6.7 % for NI and 6.0 % for ROI.

[33] The historic maintenance costs of the Transmission Asset Owner for ESB range between 11 and 13 M€/a (2004 prices) for the whole network., see CER transmission

Northern Ireland.[34] Thus, the annual values given before can be augmented by approximately 5%.

It is important to note that the studies screened for reinforcements as defined in the base case, and then isolated developments necessary for renewable generation only. Network costs discussed here are therefore in addition to the base case reinforcements.[35]

---

[34] These are maximum values, since maintenance costs for lines with conductor upgrades are not likely to rise.

[35] See chapter 2.9 of the work stream 3 report.

Network connection of Renewable Generators

The TSO, and partially the Distribution System Operator (DSO) are responsible for the administration of the network connection process. They charge the applicable investment cost as well as an ongoing service charge (OGSC) attributable to maintaining the asset. [EirGrid/ESB Networks 07].

The total of the required network connection line investment until 2020 for the connection of renewables was assessed within work stream 1 and is depicted in Figure 3-29. The costs are part of the levelised cost calculations in work stream 1 as explained in section 2.4.

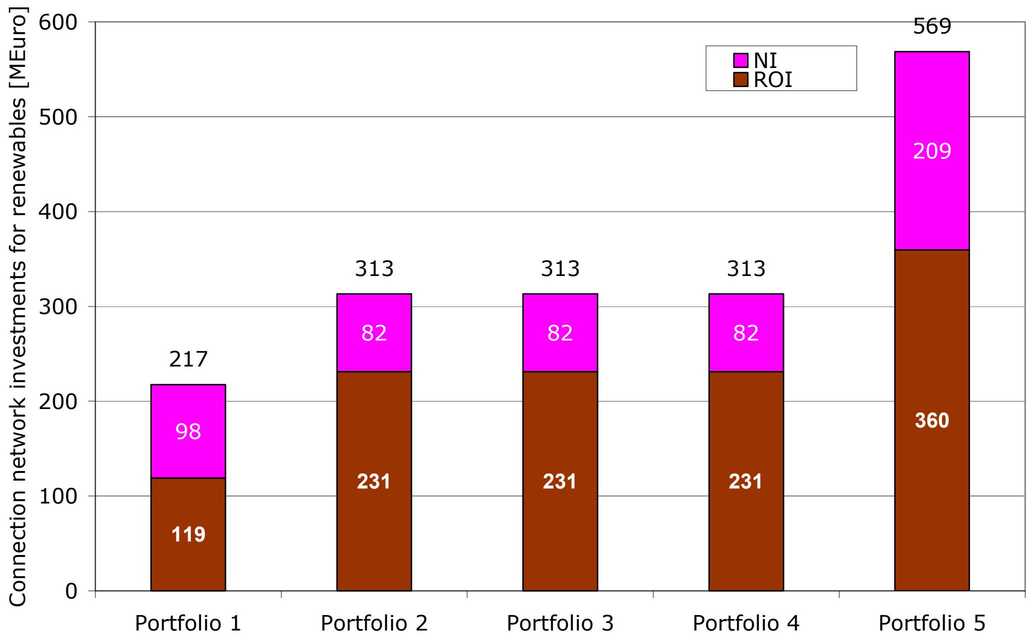


Figure 3-29: Total investments in connection lines for renewable energies

It is assumed that the investment requirement will lead to a revenue requirement that is approved by the regulators. Presently (7/2007), about 30-40 % of the connections will be in the domain of the TSO, the remainder will be handled by the DSO.[36]

[36] See http://www.eirgrid.com/EirgridPortal/uploads/Customer%20Relations/Summary(Wind)July07.pdf

Network connections

The network reinforcements described before refer to the existing transmission network. This paragraph describes the necessary connections of plants to the closest 110 kV network nodes. These figures, evaluated by work stream 1, describe the geographical distance between the project and the connection point, which is not necessarily the actual route of the line. Therefore the figures represent a lower bound of the required line lengths. On the other hand, in the case of the extension of an existing site a new line does not need to be built. Hence, the values represented in Figure 3-30 serve only as an approximation.

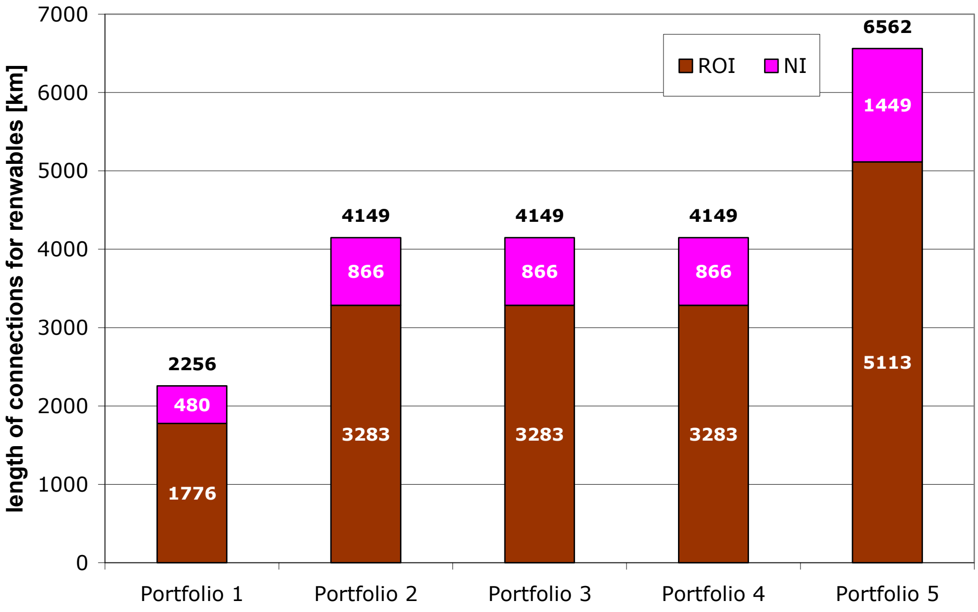


Figure 3-30: Total length of new network connections for renewables plants in both jurisdictions

Figure 3-30 shows that the total network length for network access is about 2200 km for portfolio 1 and roughly doubles for portfolio 2-4 and again for portfolio 5. The figures are dominated by connections of wind projects (about 90 % of the total length), which have an average distance to the connection point of about 15 km.

Depending on the size and the distance of the plant to the connection point, different voltage levels are applied. A large portion of the connections have been identified as being medium voltage (20-38 kV, see Figure 3-31). These connections can be realised as overhead lines with poles of 10-15 m, or via underground cable. Cable connections are associated with higher costs. This has not been taken into account in the economic evaluation.

The connection estimates are based on the assumption of a separate connection to an existing 110 kV node for each renewable project. In practice, it is probable that these connections will be optimised, leading to some sharing of connection assets, and the possible introduction of new 110 kV nodes where appropriate. This optimisation process is likely to lead to an increased length of 110 kV lines and a reduction in the total length at 20 kV and below.[37]

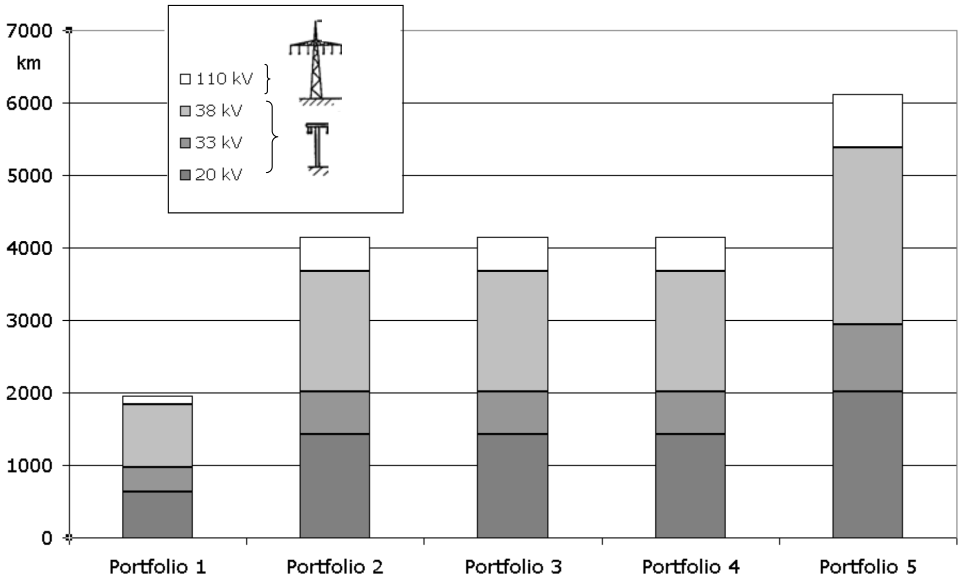


Figure 3-31: Distribution of windfarm connections on voltage levels

[37] Such connection optimisation occurs through the existing group connection process for wind in the Republic of Ireland.

3.6 Societal impacts and costs to end-users

Societal impacts are environmental impacts and long-term implications of the security of fuel supply.

3.6.1 Environmental impacts

CO_2 Emissions

Figure 3-32 shows the relative differences of CO_2 emissions of the portfolios as compared to portfolio 1. The green bars show the change of CO_2 Emissions in the All Island system. The changes observed for portfolios 2-4 (with a similar share of renewables) make it obvious, that emissions are heavily influenced by the plant mix of conventional generators. In portfolio 4, the emissions reduced by the higher proportion of renewable generation are more than offset by emissions from the carbon-intense, coal-based generation. Portfolio 3 has a greater import share and therefore lower emission reductions than gas-based portfolio 2. Portfolio 5, with a 42 % share of renewable generation, may achieve a CO_2 reduction of almost 25 % over portfolio 1.

Additionally, in all scenarios small reductions in the GB power system are achieved. Thus, emission reductions in the All Island power system are not offset by emission increases in the GB system.

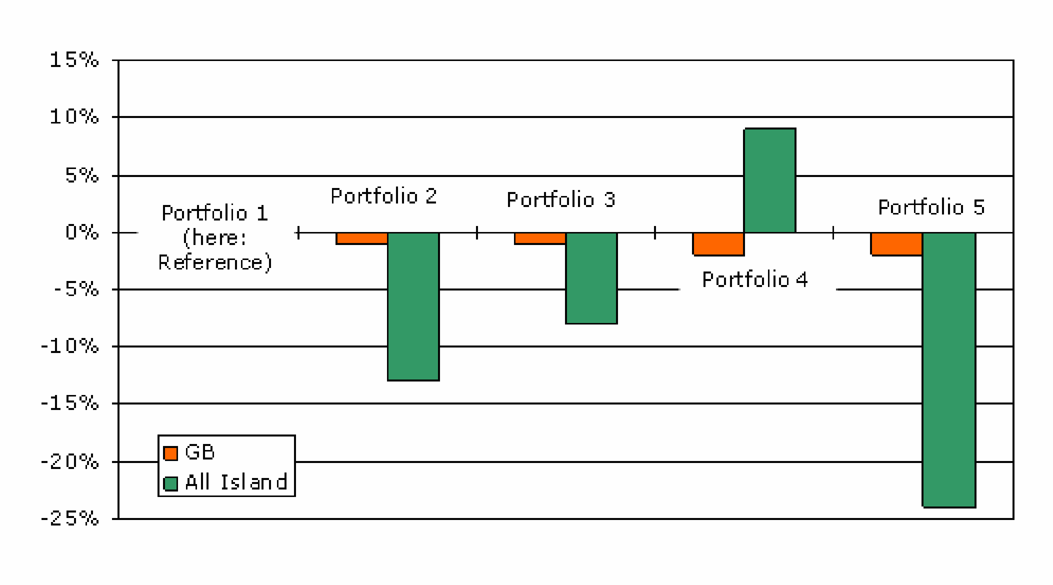


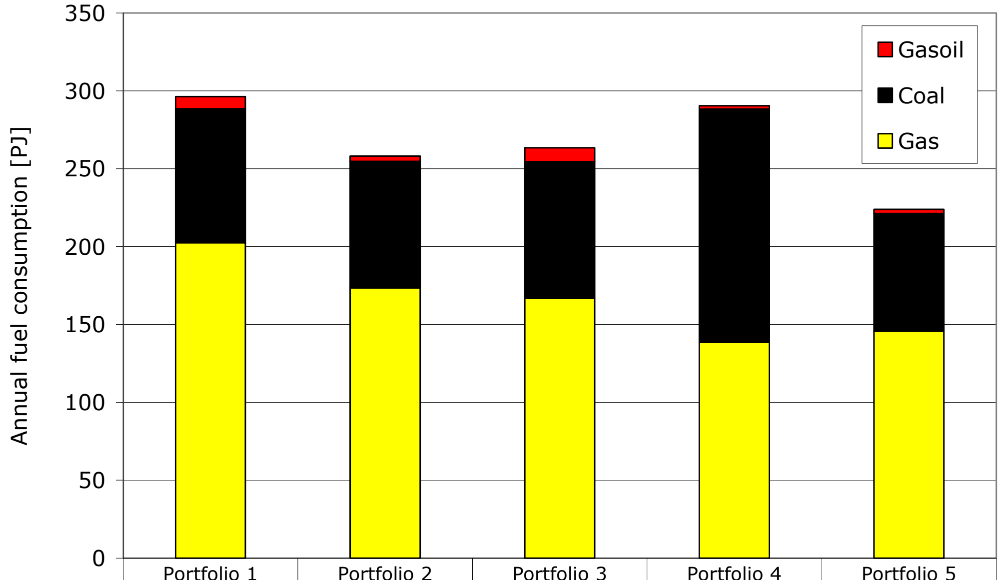
Figure 3-32: Percentage change in CO_2 emissions relative to Portfolio 1

Network reinforcements and network connections

The analysis of required network reinforcements and network connections in section 3.5.3 revealed a substantial requirement for the construction of new lines both at distribution and transmission level. The requirement is driven mainly by the development of wind and other variable renewable energy. For both network connections and reinforcements the visual impacts and the impact on the surroundings can be very diverse. The evaluation of these effects is beyond the scope of the study and will require, in addition to detailed case-by-case analyses, consideration of the broader planning implications of generation portfolios with large amounts of wind energy.

3.6.2 Long-term security of supply

The composition of generation units in the portfolios has a significant impact on the amount of conventional fuels employed.



	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
Gasoil	8	3	9	2	3
Coal	86	81	88	150	75
Gas	203	174	167	139	146

Figure 3-33: Structure of annual fuel consumption of fuels with high import shares[38]

[38] Baseload gas and Midmerit gas are aggregated

Figure 3-33 shows the annual fuel consumption by the all island power system of those fuels that, for the most part, have to be imported. It can clearly be seen that the total amount of imported fuels declines with increasing shares of renewable generation. However, the effect is relatively small comparing Portfolio 1 (renewable energy share of 16%) with Portfolio 2-4 (27% renewable energy share). Portfolio 5 (renewable energy share of 42%) shows a more dramatic decrease of required imports of fuels. Comparing portfolios 2-4, the impact of higher shares of coal fired units replacing gas baseload units is indicated.

As the study assumes two large electricity interconnections with the GB power system, the analysis needs to include the consideration of exports and imports to and from the all islands power system. As Figure 3-34 depicts, the reduced fuel imports are not offset by increased electricity imports; rather the opposite appears to occur. Electricity imports are reduced with increased renewable energy penetration and lead to a net-export in the extreme case of portfolio 6. Note that the results for portfolio 6 are included for illustrative purposes only, given the challenges that this portfolio posed as discussed in Section 2.8.

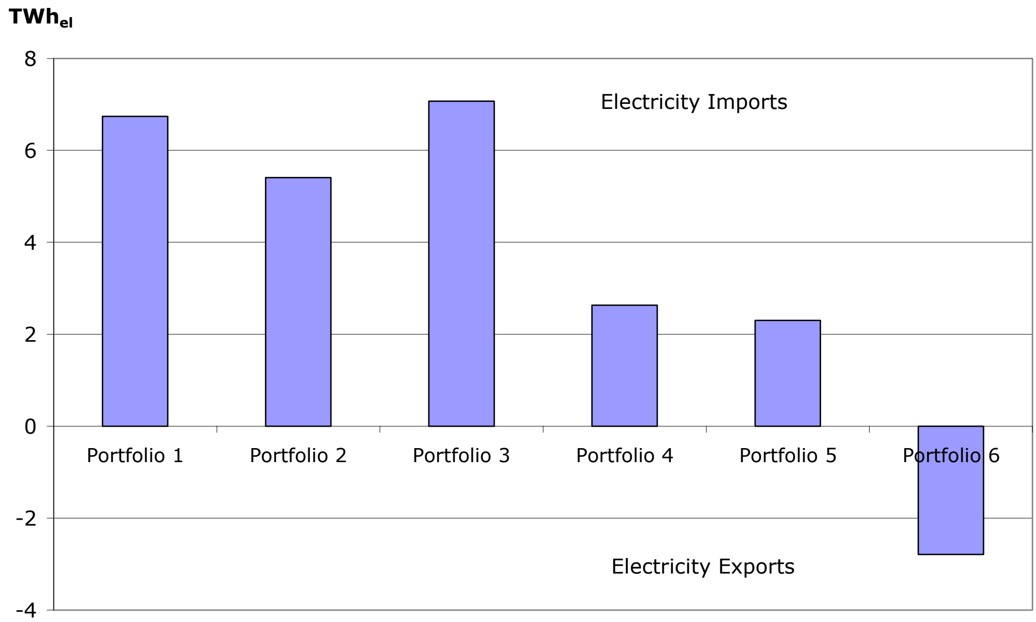


Figure 3-34: Annual net electricity exports and imports to the all island power system

Since the gas import capacity is limited by available transmission pipelines and the capacity of terminals to handle Liquefied Natural Gas, the maximum required daily capacity is analysed. Figure 3-35 shows that the maximum demand does not differ significantly between the portfolios. Existing variations have to be evaluated in the perspective of the snapshot character of the study. With the limited period covered by the simulation, the particular day of maximum gas import and the associated import volume per portfolio is subject to possibly arbitrary coincidences in the input data. Therefore no robust relationship between the amount of renewables employed and the maximum daily gas demand can be derived from this exercise. Portfolio 4 has the lowest gas capacity requirement, which is expected given the high share of coal-fired units.

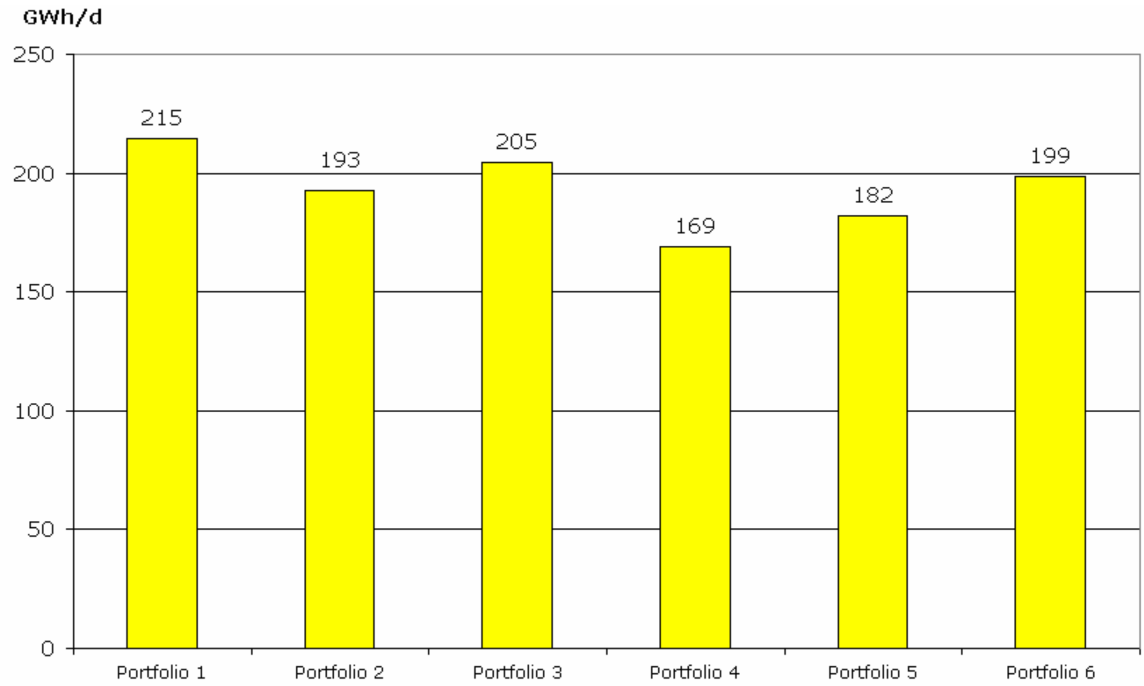


Figure 3-35: Maximum daily gas demand of the All Island system (baseloadgas and midmeritgas)

Three main conclusions can be drawn with respect to long-term security of supply:

- In portfolios 1 to 5, the all island power system will rely on net electricity imports from the GB system.
- The application of high amounts of RE (Portfolio 5, 42 % renewable based electricity) leads to a significant decrease in the dependency on fuel imports of the all island power system. Additionally, the electricity imports from the GB system are reduced.
- There is no significant relationship between the amount of renewable generation employed and the maximum daily gas demand.

3.6.3 Additional costs to society

The key cost and benefit categories discussed up to this point are aggregated and illustrated in Figure 3-36 for the first five portfolios. This figure depicts the annual CO_2 emissions, thus illustrating the reduction achieved in portfolios 2, 3 and 5. But most of all, the figure provides an aggregation of the costs to society considered in the study in millions of euros for the year 2020 for the five portfolios. It has to be pointed out that the given cost figures do not reflect expected electricity prices but rather indicate the relative relationship between the elements of the costs of generation investigated in this study in the different scenarios.

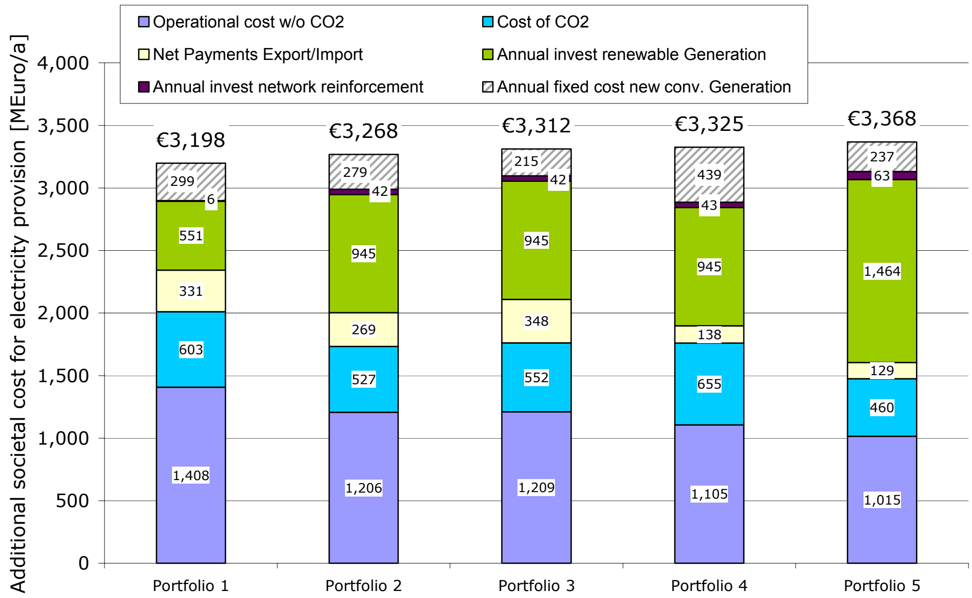
The additional cost to society is defined as the sum of the operating costs of the power system and varies with the generation portfolios. The costs are additional to the investment costs of existing conventional generators and existing and base case transmission asset costs. These costs include:

- The operational costs of generation consisting of the fuel costs and the cost of CO_2 , including fuel and CO2 costs incurred in start up, as discussed in section 3.3 and illustrated in Figure 3-10;
- The charges for the net imports over the interconnector as discussed in section 3.5.2;
- The total annual investment costs for all renewable generation, existing and new, as identified in section 3.4.2;
- Investment in new conventional generation as described in section 3.3.2. Under market rules these costs would typically be covered by revenues from energy markets (infra marginal rents) as well as by those from ancillary services and capacity payments where in place.
- The annual investment in network reinforcements as discussed in section 3.4.3.

The following costs were excluded from the analysis:

- the historic investment costs of existing conventional generation as well as for the existing transmission assets. As these cost components apply identically to all portfolios it does not compromise a comparison between the portfolios.
- variable maintenance costs

These additional costs will need to be recovered within the price of electricity charged to end users.



	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Portfolio 5
RE share of demand	16%	27%	27%	27%	42%
CO_2 emissions [Mt/a]	20	18	18	22	15

Figure 3-36: Additional societal costs for electricity provision, renewable energy share in total demand and annual CO_2 emissions associated with electricity provision

The impact of the portfolios studied on the prices charged to end customers cannot be determined as the study of markets was out of scope for this study. However, this study identified differences arising in certain price components that make up the final price charged to end users on their electricity bills, the following of which are included in the analysis:

- electricity wholesale prices (section 3.1.3);
- transmission use-of-system charges (L-component directly, G-component indirectly via generators) due to the network reinforcement (section 3.5.3);
- cost of ancillary services included in the use of-system charges (not discussed in detail) , and
- support payments for renewable generators (see section 3.4.4).

The following components of the electricity price have not been included in the analysis:

- distribution charges, and
- capacity payments for generators.

The information presented in Figure 3-37 is based on the same cost information as that used in Figure 3-36. Figure 3-37 displays these costs in €/MWh based on annual electricity consumption of the all island system to illustrate the order of magnitude of the change of the cost components examined. It shows that the total cost to end users varies by at most 7% between the highest cost and lowest cost portfolios. Thus the presented results indicate that the difference in cost between the highest cost and the lowest cost portfolios are low.

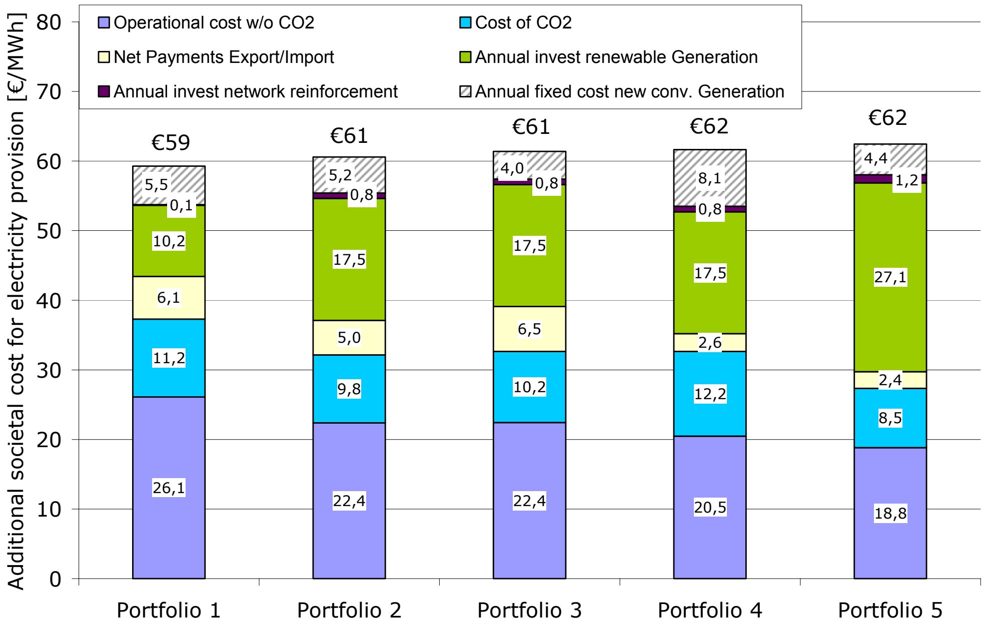


Figure 3-37: Overview of portfolios 1 to 5 indicating specific additional societal costs for electricity provision

Figure 3-38 includes a breakdown of annual investment costs for renewable generation shown in Figure 3-37, by costs covered by revenue and costs requiring a support mechanism. The revenue share depends on the electricity price level in the respective portfolio (see Figure 3-4). It becomes obvious, that a great share of the required investment cost can be recovered from revenues on the electricity market as part of the electricity wholesale prices. This is due to the fact that the levelised cost of renewable generation is in many cases close to the cost of conventional generation.

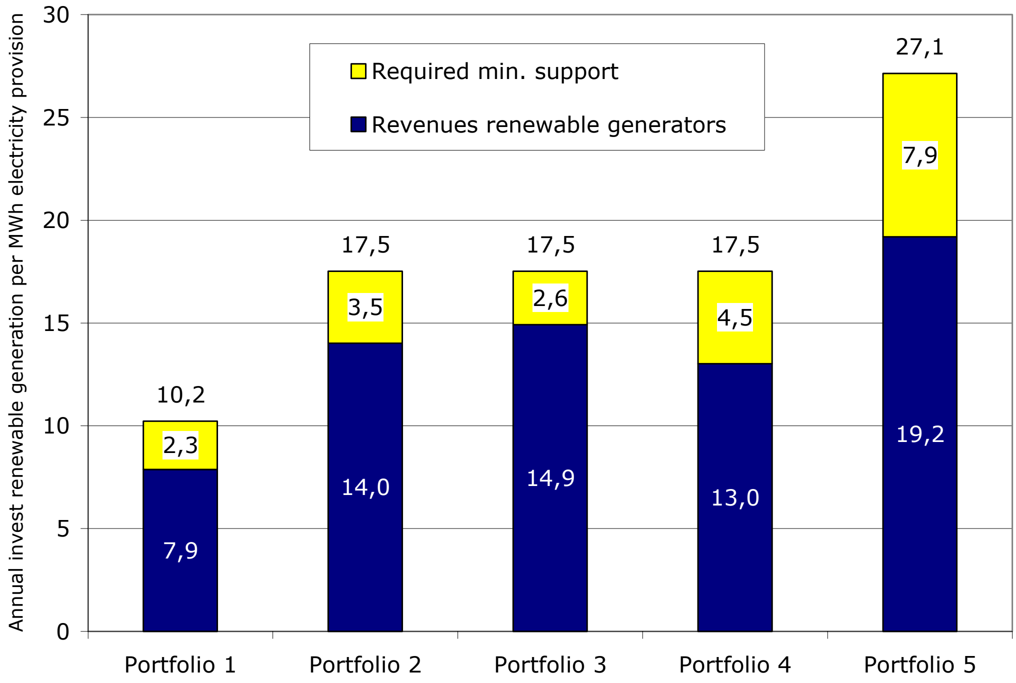


Figure 3-38: Financing of the investment cost for renewable generators

It was explained in section 3.3.4 that within the assumed methodology conventional generation also requires payments additional to system marginal costs. The calculation of those payments is clearly outside the scope of this study. Depending on the electricity market design renewable generators may be able to benefit from those payments as well. This applies especially for firm renewable baseload capacity such as biomass plants. Hence, required support payments can be further reduced.

On the other hand, the study assumed an ideal support mechanism without windfall profits arising to renewable generators as explained in section 3.4.4. In reality, support mechanisms can over compensate relative to costs incurred. Both of the above effects have an impact on the required share of support, the impacts being in opposing directions.

Given the above mentioned limitations of the analysis it can be seen that the order of magnitude of additional support for renewables ranges between €2.3 and €7.9 /MWh total energy supplied or, if applied to the MWh of renewable generation only, from €9.6 to €19.0/MWh.

4 Recommendations for further work

Although the All Island Grid Study covered the most important aspects of the integration of high shares of renewables in the power system, further research is necessary, to cover implications of high penetration scenarios in greater detail. This future work has to improve understanding of

- technical issues related to the planning, design and operation of power systems and its components,
- economical and regulative issues in relation to market design as well as
- the fundamentals of the renewable resource base and its behaviour from a power systems perspective.

Dynamic power system studies

The methodology of the All Island Renewable Grid Study allows conclusions regarding the feasibility and limitations of portfolios with high penetration of renewable based and dispersed generation technologies only to a very limited extent. Further analysis allowing insight into the interaction of the generators and the network under steady state conditions as well as in case of system disturbances are an inevitable precondition for further system planning and ex ante policy evaluation.

Further research should not only focus on the feasibility of a portfolio itself but should also provide information regarding the likelihood and economic impact of critical situations, allowing an evaluation and comparison of corrective measures. Curtailment of wind power and its economic impact is one of the key aspects to be covered by such studies. For that reason, dynamic studies should not be restricted to singular cases (winter peak, summer night valley, etc) but cover a specified operational area applying appropriate probabilistic concepts.

Strategic network planning, design and operation and application of innovative technologies

The required additional network reinforcements to take account of the need to provide for network outages for maintenance or other work have to be identified and prioritised. The impacts of the studied generation portfolios on the design and development of the distribution networks and the associated costs should be studied more in detail. In order to facilitate the necessary network development, the cost allocation options need to be explored. There is a need to concurrently review network planning standards and network access contracts in the context of the greater range of operational characteristics of the individual plant types in the future generation mix. Additional network studies are required to identify measures and investment which may be required to address the effects on the network of a high renewable energy penetration that were not comprehensively studied in work stream 3 (reactive power, voltage rise, stability, fault level, quality of supply, etc.)

Technological concepts that serve to optimise both yield from wind generation and network investments have been discussed elsewhere in relation to wind energy, but are not yet common practice in the power industry. Examples are dynamic line ratings, rewiring of existing lines with high temperature conductors or DC (underground) transmission. The potential benefits of these technologies are not only the cost savings associated with reduced network reinforcement but in many cases the significant acceleration of the possible implementation of renewable energy capacities. Technology assessments containing cost benefit analysis may help to identify promising near and long term options for accelerated and cost efficient integration of renewable based and dispersed generation capacity and should allow integration of these concepts in the abovementioned studies.

Long-term wind power time series

There is still potential to improve existing methodologies to synthesize wind power time series. Uncertainties of the performance of the total wind farm population distributed across the island directly translate to uncertainties in the dispatch model and economic output data. Accurate, representative long-term wind (power) time series reflecting the geographical dispersion of the generation plant still have to be validated. All available data sources (monitoring data from wind farms, wind measurements as well as weather models, etc.) and their combinations should be considered. Findings should inform future research in wind forecasting.

Optimisation of the plant mix and scheduling at higher penetrations and generation adequacy

Further analysis should be carried out on the results of this study, or on data from other sources, on the optimal plant mix and on the specific plant performance required (max. aggregate up and down ramping over various time intervals, max replacement reserve being provided by off-line plants, min capacity that must be capable of frequent stops and starts etc.) with a view to refining plant portfolio requirements. Any additional costs, for example increased operation and maintenance costs, associated with altered operational regimes should be identified and quantified.

Paradigms for generation scheduling and dispatch in a system with a very high penetration of variable, non-dispatchable renewable generation should be investigated.

Appropriate measures of generation adequacy in a system with high penetration of renewable electricity generation need to be developed. These should allow comparison of portfolios and thus definition of appropriate adequacy standards of generation adequacy.

Co-combustion

The possibilities for co-combustion of biomass in conventional generation units was assessed in work stream 1 but not carried throughout the study. Thus, the implications of including co-combustion into generation portfolios should be assessed.

Electricity market design

As an increased variability of the net load requires power plants to react more flexible, market mechanisms become more important to guarantee an efficient dispatch. As reserve requirements increase with increased variable renewables the design of reserves market has an increased importance. The fact that the marginal values of reserves are very low compared to system marginal electricity prices emphasises the requirement of an efficient design of the ancillary service market to avoid windfall profits. Hence, market design options need to be examined with a special focus on the reserve requirements of wind energy penetrations as in portfolios 2-5.

Further work is required on the development of electricity markets to encourage investment in the appropriate plant. The impact of different renewable electricity support mechanisms and of the interaction between the two existing support mechanisms on the island, requires detailed study. This work should progress to research on the design of support mechanisms to optimally facilitate the growth in renewable electricity generation. Consideration needs to be given to the question of revenue adequacy for existing non-renewable generation and to the financial impact of changes to the operating regime of conventional plant.

Gas market implications

Changes in the use of gas resources in the various generation scenarios has implications for the gas market which have not been addressed, but which might influence the cost of gas and possibly the necessary gas infrastructure. In particular the impact on the gas interconnector flows with G.B. should be investigated further.

Demand-side management and storage

Based on the dispatch information generated within work stream 2B the economic viability of demand-side measures can be evaluated for different portfolios to assess information about their potential for a further cost reduction in the different scenarios. Further investigation and validation of the study results regarding the operation of pumped storage, in scenarios with high penetration of variable renewable generation, may be appropriate.

5 Conclusions

The All Island Grid Study was an ambitious and far reaching study. The stakeholder implications of various scenarios for future shares of renewable energies and conventional generation of the all island power system were considered. The analysis included an extensive assessment of resources, power system operation and required network upgrades.

The benefits of increased shares of renewable energy

Based on the parameters used in the study, investment in renewable energy technology allows meeting up to 42% (portfolio 5) of the all island electricity demand with renewable generation in 2020. In turn, this allows a 25% reduction in CO_2 emissions associated with power generation and a 28% reduction in gas imports for electricity generation when compared to a 16% renewable energy share (portfolio 1) which may be used as a reference case in the study. Additional total costs are estimated to be about €216 million in the year 2020 when compared with portfolio 1. This represents a 7% difference in the additional costs included in the study to achieve a 25% reduction in CO_2 emissions. This is equivalent to additional specific costs of about €4 per MWh generated in all of Ireland in 2020, compared to the first portfolio with a 16% renewable share. These are significant results illustrating that for a relatively small additional cost for society, large CO_2 and security of supply benefits could be achieved.

However, there are uncertainties with some risk that the additional cost could be significantly higher (see below).

The more moderate portfolios investigated allow a renewable energy share in electricity demand of 27%, a reduction of CO_2 emissions related to the electricity sector up to 10% and a 15% reduction of gas imports against additional specific costs of about €2 per MWh compared to the reference case. As an exception, the portfolio substantially relying on new coal plants ends up with an increase of CO_2 emissions.

The uncertainties associated with these portfolios are lower.

The overall result is relatively robust with respect to the price of gas and carbon, with the reasonable assumption that these are correlated.

Challenges and supportive action required

In order to achieve this very high level of renewable energy penetration in the range from about 30% to more than 40% of total demand and in order to deliver the related benefits, the following complementary **actions**, which may imply additional costs, are essential:

- The transmission network development required is extensive. Though the cost related to reinforcement are in acceptable ranges (0.8…1.2 €/MWh), the developments will require considerable resources to be deployed by the transmission owners and operators, in addition to the work necessary to implement the east-west and north-south interconnectors, and other extensive transmission infrastructure development required to accommodate non-renewable generation and growth in demand. As existence of sufficient transmission capacity is a precondition for planning and development of any new generation capacity, successful and timely development of the infrastructure is a precondition for implementing the portfolios envisaged in the study. The lead times for the individual transmission reinforcements envisaged will be considerable – in many cases 7-10 years. Therefore work on identifying the detailed scope and timing of the transmission reinforcements and their subsequent implementation must commence without delay.

- Though not within the scope of the study, the results indicate that the challenges related to the development of the distribution networks connecting renewable generation are at least as ambitious. To connect wind to the transmission network, 4000 – 5500 km of new lines need to be built. This number may change substantially when transmission voltages and/or connection points are changed during a detailed planning process.
- The assumed 1000MW of interconnector capacity must be available to be used as envisaged in the study. This includes flexible dispatch and participation in reserve markets. The costs associated with the incremental 500MW of interconnector capacity have not been included in this analysis nor have the cost of technology upgrades potentially required for the existing interconnector.
- The installation of complementary, i.e. flexibly dispatchable plant must be effectively incentivised so as to maintain adequate levels of system security. From the current perspective, such plant will be dominated by non-renewable options for technical and economical reasons.
- With increasing electricity supply from renewable plant, revenues for certain non-renewable generation technologies from electricity markets and capacity factors of respective units tend to decrease. Nevertheless, availability of these generation capacities is essential for maintaining generation adequacy. Mechanisms such as capacity payments and/or ancillary service payments will be required to supplement the energy market income of all generators and ensure that they can earn sufficient revenue to remain in business. Analysis of any support mechanisms for renewable generators is needed.

Cautions

The benefits of renewable electricity generation may be lower than estimated and some associated costs are likely to be higher than estimated by this study. There is a risk that, due to the limitations of the models used, in particular the instantaneous amount of wind under dynamic conditions, the extent of curtailment of renewable generation, especially wind, at times of low demand has been underestimated significantly. The effect of such an underestimate is to overstate the CO_2, fuel usage and cost benefits of renewable generation and to underestimate the cost of renewable support payments required. The network model in work stream 3 did not account for the need for maintenance, which will have the effect of increasing reinforcement costs and/or curtailing wind. The model for evaluating the cost of support assumed a perfectly efficient support mechanism. In practice there are certain inefficiencies inherent in support mechanisms and thus the results may underestimate the costs associated with the support required.

Characteristics of generation portfolios and their components

- Wind energy is by far the cheapest renewable energy source for electricity generation. Some wind farms are able to compete economically with conventional plants.
- Evaluating the different portfolios with respect to optimal plant mix, a mixture of new gas-based conventional generation (single and combined cycle) seems to be superior to new coal plants with respect to both, costs and CO_2 emissions.
- Within the assumptions and limitations of the methodologies applied, the examined portfolio with 8 GW of wind installed is not a feasible option. Both the dispatch and network study showed severe reliability problems. Given the fact, that the methodology of the study did not reflect all issues and most likely further operational restrictions apply, such a portfolio has to be considered more or less speculative.

In summary, the Study indicates the potential to achieve significant environmental and fuel security benefits for little additional cost to society and thus to electricity customers. The limitations of the study may mean that, on further analysis it is found that the benefits are not as great as indicated and the costs are higher. Finally, the benefits will not be achieved without the complementary actions listed above being addressed.

6 References

CER 06: Determination of transmission allowed revenue and use of system tariffs, CER/06/199, 10th October 2006, Appendix 1.

Doherty, R. and O'Malley, M.J., "Establishing the role that wind generation may have in future generation portfolios", IEEE Transactions on Power Systems, Vol. 21, pp. 1415 - 1422, 2006.

EirGrid/ESB Networks 07: Joint TSO/DSO Group processing Approach Pricing Principles Guidelines, published 27/02/2007

ERGEG 05: Guidelines on transmission tarification, 18 July 2005, explanatory note

ERGEG 06: Application of G-charge across EU according to draft Guidelines on Transmission Tarification, ERGEG Ref: E06-CBT-12-04, 6 December 2006

ESBI 06: All Island Grid Study - work stream 1, Interim Report, January 2006, Information Freeze: 2/1/07

ETSO 2006: ETSO Overview of transmission tariffs in Europe: Synthesis 2005, June 2006

Meibom et al. 06: WILMAR - Wind Power Integration in a Liberalised Electricity Market, Final Technical Report, RISOE, January 2006

OPTRES 06: Assessment and optimisation of renewable support schemes in the European electricity market, Interim report, January 06.

RISOE 06: Methodology Report for All Island Grid Study, Work-stream 2B: Wind Variability Management Studies., October 2006, paragraph 4.6.

UK 2002: Ilex Energy, Strbac, G., Quantifying the system costs of additional renewables in 2020. DTI, 2002. STRBAC 07: Strbac, Goran, Shakoor, Anser, Black, Mary, Pudjianto, David, Bopp, Thomas, 2007. Impact of wind generation on the operation and development of GB electricity systems, Electrical Power Systems Research, Volume 77, Issue 9, Pages 1214-1227, Elsevier 2007.