PÖYRY

LOW CARBON GENERATION OPTIONS FOR THE ALL-ISLAND MARKET

A report to EirGrid
March 2010

LOW CARBON GENERATION OPTIONS FOR THE ALL-ISLAND MARKET

PÖYRY

LOW CARBON GENERATION OPTIONS FOR THE ALL-ISLAND MARKET

A report to EirGrid
March 2010

LOW CARBON GENERATION OPTIONS FOR THE ALL-ISLAND MARKET

Contact details

Name	Email	Telephone
Dr. Phil Hare	phil.hare@poyry.com	+44(0) 1865 722660

Pöyry Energy Consulting is Europe's leading energy consultancy providing strategic, commercial, regulatory and policy advice to Europe's energy markets. The team of 250 energy specialists, located across 15 European offices in 12 countries, offers unparalleled expertise in the rapidly changing energy sector.

Pöyry is a global consulting and engineering firm focusing on the energy, forest industry, water and environment, transportation and construction service sectors, with over 7,500 staff operating from offices in 49 countries.

Foreword

I am pleased to have the opportunity to present this report on future low carbon portfolio options for the All-Island system. The report describes the various power generation technology options that are likely to be available to help deliver sustainable power in the future.

A global consensus that decarbonisation of the power sector will be one of the key objectives in achieving a sustainable future is beginning to crystallise. The means of achieving this are still being debated but what is certain is that the power sector is set to undergo significant change over the next few decades. Ireland and Northern Ireland have already begun this process, for example by setting targets for electrical energy from renewables, establishing energy efficiency plans and making preparations for the roll out of electric vehicles. There is now a need to extend this outlook to delivering low carbon power by the middle of this century. EirGrid are pleased to contribute to the debate by having commissioned Pöyry to study and report on technology options for the island's low carbon future.

Renewables and gas generation look set to play a part in all future portfolio options. There are wide and varying options for how the remainder of the portfolio will be made up. All options have shared themes of large capital expense, an increased requirement for flexibility to support intermittent renewables and increased integration with neighbouring markets to ensure security of supply and to help renewables integration. There is now a need for a wider debate on the development of a low carbon power system.

EirGrid will continue to build on our work to date of operating and planning a secure and economic transmission system with emphasis on integrating renewables and exploring the potential to increase our interconnection with neighbouring electricity markets. In tandem with this, we will continue to develop the electricity transmission infrastructure to ensure security of supply, maximise the island's renewables potential and to place the island in a position to deliver on generation portfolio developments.

I hope that readers can draw on the factual and objective information contained in this high level report to help form their own views on future generation portfolio options. I would welcome any feedback on the report and I look forward to future debate in the area.

Dermot Byrne

Dermot Byrne

Chief Executive, EirGrid Group

[This page is intentionally blank]

TABLE OF CONTENTS

[This page is intentionally blank]

EXECUTIVE SUMMARY

Across the world policymakers are facing the challenge of dramatically reducing carbon dioxide emissions. A significant part of the reduction must be found from the electricity sector – some systems aspiring towards complete decarbonisation by the middle of this century. While complete decarbonisation may seem too ambitious, many observers have suggested that electricity systems should be aiming for carbon intensities (the amount of CO_2 emitted per unit of electricity generated) of below 100g/kWh towards the middle of this century. As the carbon intensity of the generation sector in Ireland stood well over 500g/kWh in 2008, dramatically reducing it will have to involve radical changes from the current generation portfolio. However, electricity systems also need to factor in many other concerns: affordable and competitive prices, exposure to international fuel markets, reliability and diversity of fuel sources, and public acceptance are all important considerations.

Our analysis examines the main generator technologies that could be deployed on the island of Ireland ('the island') in the next twenty years. A description of each technology, their characteristics and likely technical development is our starting point. We recognise that there are many potential developments which can impact on the demand for electricity: improvements in energy efficiency, the development of smart grids, as well as changes in the heating and transportation sectors. It is clear that there are a range of possible outcomes that will become more apparent in time but our results would indicate that the magnitude of renewable intermittency will overshadow any foreseeable developments on the demand side.

The next step of our work was to examine how the very different characteristics of the generator technologies need to combine together to meet the electricity system needs of the island. To do this we modelled six possible generation portfolios, each with a particular technology theme for a study year of 2035. All scenarios build on the current 2020 renewables policy targets while also recognising that in this time frame the existing coal, oil and peat fired stations will have reached end of life: therefore two are focused on fossil fuel based alternatives (gas and coal); one centres on nuclear generation; and three on far higher renewables deployment.

While we have created six balanced generator portfolios that contain a mixture of baseload, mid-merit and peaking plant it must be noted that further work will have to be carried out to examine detailed technical issues. It is not the intention of this report to advocate one option over another.

In developing a comparison between the different portfolios, we have factored in investors' expectations on returns; although there is much important detail a general picture begins to emerge and we are able to make the following observations:

- Significant emissions reductions can be achieved with all portfolios compared to the present day portfolio, and they represent feasible points on a trajectory towards carbon neutrality by the middle of this century.
- Recognising that the *Gas* portfolio is the most likely outcome based on the current policies, we observe that although it has lowest costs, it suffers from the highest reliance on gas and has the highest emissions (in fact it could not meet our 100g/kWh target). While not a sustainable solution in itself, any trajectory towards this portfolio could be considered as a transitional step towards other lower emission options and carbon neutrality by 2050.

- Our *Coal CCS* portfolio exhibits the lowest overall emissions. However, CCS is not a proven commercial technology and it is expected that it will be at least 2018 before the technology becomes commercially available. Even then, suitable local sites for storage must be located. CCS stations currently have high project risk due tonew technology development issues.
- The *Nuclear* portfolio exhibits low emissions similar to the *Coal CCS* portfolio but would have high project risk associated with it because of public acceptance issues and the complexity of the overall project. The construction of a green-field nuclear power station is a complex process, with long lead times required for resolving public acceptance issues and policy decisions. A domestic nuclear regulatory and supporting industry would have to be established. Commercially available nuclear stations are large for the size of the electricity system on the island of Ireland and we have assumed that a high system cost is required to integrate nuclear generation. More detailed technical feasibility studies and a full project risk assessment will be needed to develop this option. Nuclear feasibility could be re-examined in a different light at a future date if smaller nuclear generators become commercially available.
- The high renewables options can meet very low emission targets and reduce the net amount of energy imports but they have higher capital costs. All of these portfolios require more capital investment than the thermal portfolios because there:
  - is a requirement to maintain conventional backup capacity for managing renewable intermittency; and,
  - high costs for achieving higher renewable penetrations (because of the development of offshore wind, marine and biomass plant and higher network management costs).
- Further Interconnection helps integrate the island with the British and continental European systems. This aids renewable integration and helps the island benefit from combined regional advantages. It will also tend to bring wholesale prices on the island in line with those across the region and therefore contribute to competitiveness.
- Storage, by itself, is insufficient to manage intermittent renewable generation because of its power and energy capacity constraints but it can make a contribution towards managing intermittency as part of a portfolio with interconnection and flexible generation. There are also capital cost, environmental and technical issues that need to be examined further to develop this concept.
- All portfolios are susceptible to price volatility due to the significant amounts of gas-fired generation and due to large amounts of wind generation in each portfolio with their inherent variations in wind patterns.
- They also have higher capital costs and lower running costs relative to today. While this drives down market prices, generators may not earn sufficient income in the market to cover their costs. This suggests that market design changes or price support mechanisms may be required to encourage investment in new low carbon generation.

While some of these conclusions are intuitive, others are much less so. The report provides the detailed costs and performance data used in the analysis of the generation portfolios. As a global engineering and consulting company operating in the power sector, Pöyry is able to draw on firsthand experience to estimate the costs and performance of future power sources. However, the data is provided to allow the reader to assess the validity of data and to draw their own conclusions.

Our hope is that this report will contribute to an informed debate on the shape of the future generation portfolio on the island of Ireland, and will input into energy policy formation in both jurisdictions.

1. INTRODUCTION

1.1 Introduction

Both jurisdictions in the Island of Ireland ("the island") have ambitious targets to significantly reduce their greenhouse gas emissions. As in many other countries the brunt of effort to decarbonise the energy sector is most likely to fall on the electricity sector – yet the emissions from existing power stations on the island are far higher than the future demands. Many observers suggest that in order for climate change targets to be met, the electricity sector may have to decarbonise completely by the middle of this century.

The island is not well endowed with fossil fuel resources and apart from gasfields off the southern and western coasts, imports coal by sea and natural gas through three pipelines from Scotland. In recent years electricity generation from gas and coal has been running at around 55% and 25% respectively. Gas supplies to the island have proved reliable even in the recent volatile markets.

In electricity terms the island is not entirely isolated: links to GB will total 1,000MW when the East-West interconnector is completed in 2012.

Both jurisdictions have already taken significant steps to reduce greenhouse gas emissions: an early harbinger of the trend towards electricity decarbonisation was the introduction of renewable support schemes. Recent years have witnessed considerable construction of windfarms in both the Ireland and Northern Ireland: by the end of 2010 it is expected that over 2GW will be in operation. Around 5GW more windfarm applications are currently involved in Gate 2 and Gate 3 grid connection processes in Ireland.

Prices paid by electricity customers on the island are well reported to be higher than the European average[1], in part reflecting the island's location on the furthest reaches of the continent's gas pipeline network. The recent downturn in economies throughout the world has served to re-emphasise the economic value in having competitive electricity prices.

On a more general note, despite well over a hundred years of continuous improvement, generating technologies are continually evolving – new approaches to old systems, as well as radically new ideas.

1.2 A look into the future?

The purpose of this independent report, commissioned by EirGrid, is to seek insights into the challenges of dramatically reducing the carbon intensity of the electricity sector, and evaluate the many trade-offs that this inevitably involves.

Such a task is not without its difficulties. Nearly all parts of the equation represent a moving picture: new technologies that have potential to greatly cut emissions are now only just on the drawing board, and the rate of developing existing ones is far from clear. Gas and coal markets, as witnessed by recent years have proved remarkably volatile – the prices and sourcing patterns even in the medium term remain uncertain.

While wind power is a growing force around Europe, the intermittent output of windfarms is challenging the nature of power systems everywhere. In our experience, while many have speculated on the likely patterns of the wind, properly understanding how the impact

[1] http://www.sei.ie/Publications

of wind on the rest of the system requires detailed quantitative models – and ones that are able to include the inevitable interaction with the electricity system in Great Britain.

Many countries' approach to decarbonisation includes a growing nuclear component. Although nuclear power stations are not currently a legal option in Ireland, we believe that due consideration of them as an option is worthwhile.

Factoring in their impact is, however, not straightforward. Purchasers of conventional thermal power stations understand the costs and performance of these well. However, nuclear projects have additional cost and timescale risks: in particular from arising from project construction as well as the vagaries of licensing and construction controls.

Additional complexities arising from decommissioning, spent fuel disposal and other safety concerns have been prominent in the debate over deployment in many countries.

There is potential for further electrical interconnectors between the island and GB as well as possibly France and it would seem sensible to understand the added value they can give to security of supply as well as the market interactions that they inevitably increase.

Lastly, it is not clear just how the different generating technologies best fit together, and in what proportions.

The aim of this report is to examine the following questions:

- What is the outlook for the various generating technologies, both commercially and technically?
- How do the different sources of power compare against each other, particularly in terms of their costs, emissions, fuel sources but also with due consideration of Health and Safety?
- How might portfolios of generating technologies reach far lower emissions than today...?
- and then how do the portfolios compare against each other?

1.2.1 Structure of this report

We aim to answer these questions above by first discussing the individual generating technologies before comparing them to each other.

The larger part of this report will be devoted to examining a set of possible low carbon portfolios and discussing their relative merits.

Annexes set out more detail of the generating types' economic and operating characteristics.

1.2.2 Pöyry

Pöyry is particularly well placed to comment on the challenges described above: on the engineering side, the company has been involved in the construction of over 40,000MW of thermal plant in many parts of the world in the last ten years. In 2009 we published the report "The Impact of intermittency in Ireland and GB", available on our website, which examined the market impact of wind generation on these places.

1.2.3 Sources

Where tables, figures and charts are not specifically sourced they should be attributed to Pöyry Energy Consulting.

2. GENERATING TECHNOLOGIES

2.1 Preamble

Electricity generation technology's history dates back to the nineteenth century and the development of steam and water turbines. In those parts of the world where large scale deployment of hydro-schemes were not an option, the predominant fuels were historically coal and heavy fuel oil.

Over time the general trend for coal and oil stations was one of increasing size as engineers sought to capture economies of scale and turn more of the energy in the fuel into electricity. The advent of nuclear reactors in the 1950s brought a very different type of technology into play, although many of the same components were used in the steam turbine part of the plant.

Up to the 1980s, natural gas had only featured as a fuel in steam-cycle power stations in a few parts of the world where gas was particularly cheap. However, the 1990s witnessed a transformation in many countries' electricity systems as the newly available combined-cycle gas turbine (CCGT) technology was widely deployed. Indeed, Ireland was one of the first countries to deploy this technology.

Power companies are responding to the challenge of reducing their carbon emissions in the last decade which has prompted far greater emphasis on the carbon intensity, and the consequent development and deployment of many new technologies: ranging from wind to solar. The older technologies are not standing still either – rising to the low carbon challenge by increasing further their efficiencies, and both operability and flexibility, combining with district heating systems or potentially capturing and storing the carbon dioxide deep underground.

The purpose of this Chapter is to briefly review the key technologies that might be available in the future and compare them. Numerical assumptions for each of them in our modelling are contained in Annex A. As this report is concerned with generation costs and technologies it must be noted that network costs are excluded from our analysis.

2.2 Coal- and gas-fired power stations

Coal-fired

Since Kilroot and Moneypoint were built, coal-fired technology has taken a considerable leap forward in terms of the thermal efficiency. Nowadays, nearly all new coal stations are so-called 'supercritical' which means that the temperature (374 °C or higher) and pressure (221 bar or higher) in the boiler are so high that the distinction between water and steam is lost. This means that the thermal efficiency is as high as 44%[2] - considerably above the mid-thirties for the existing coal-fired plant on the island. This increased efficiency has also resulted in reduced emissions (CO_2, SO_2 and NO_x). Fitting emissions control technologies such as flue gas desulphurisation and selective catalytic reduction further reduce SO_2 and NO_x emissions to levels of around 100mg/Nm^3 and 40mg/Nm^3 respectively, well within European large combustion plant limits but at the cost

2 We quote thermal efficiencies in this report on a Higher Heating Value (HHV) basis for a new plant. Over a plant's lifetime, its efficiency is likely to degrade by a few percentage points.

of a loss in overall efficiency. The design of supercritical boilers is such that they have a high degree of operational flexibility and can adjust their output up or down to match changes in demand.

Generally a new coal-fired power station is sized between 1,000 – 2,000MW, with three or four separate units. Such a configuration appears to optimise the economies of scale with the practicalities of incorporating them into the electrical system.

The quest for increased thermal efficiency continues, although engineers know that in order to raise the temperature and pressure of the boiler further, they will have to use cutting edge alloys. A flagship development in this direction is the AD700 project which is currently aiming to start a unit operating by 2014. Materials tests are currently being carried out at the Scholven plant in Western Germany. If successful, the unit might have a thermal efficiency similar to current gas-fired plant.

Although not modelled specifically in this report our projections for coal-fired plant costs are €1,450/kW for capital costs and €40/kW pa for fixed costs with a thermal efficiency of 44%.

Figure 1 – AD700 Project, Denmark

Source: Elsam Engineering

Combined cycle gas-fired power stations (CCGTs)

CCGTs burst on the scene in the 1990s as a result of the lifting of restrictions on the use of gas for power generation in Europe, and a step change in the turbine technology in terms of both reliability and efficiency. The key to improving the thermal efficiency of a CCGT is to run the gas turbine at even higher temperatures: successive improvements are known by their 'Frame' type. Thus in the 1990's the E-frame types were deployed with a thermal efficiency of 46-48%, while from the mid-90's onwards the F-frame type, with a thermal efficiency of 50-51% has been commonplace.

Even higher thermal efficiencies are expected from development of H-frame technology, and there are a few demonstration plants now in operation, but these have been plagued with technical difficulties and not seen major uptake in global markets to date. If designers' aspirations are achieved, thermal efficiencies close of 54-55% might be achieved.

It is likely that CCGTs in power markets with large amounts of wind generation will not be able to run at baseload. However, the technical capability and cost implications of CCGTs having to operate more flexibly (in terms of numbers of starts, part loading and varying output) remain contentious issues with a wide range of views.

As in many other countries, in Ireland there is a licence requirement for CCGT plant to carry backup supplies of distillate liquid fuel (5 days) to deal with potential interruptions in gas supply – changing over fuels does require some time, but it is relatively simple.

CCGTs major attraction economically is their lower capital costs compared to coal plant: in this study we take €750/kW for the capital costs and €35/kW for the annual fixed costs. In general the energy price of gas is higher than for coal (although there is a seasonality that can make gas much cheaper in the summer), but this is mitigated by CCGTs' higher thermal efficiency compared to coal.

Open cycle gas-fired power stations (OCGTs)

While also running on natural gas, modern open cycle plants are designed for much more flexible operation – typically as peaking plant – albeit at the cost of a somewhat poorer thermal efficiency than CCGTs. As a result of their typical operating mode OCGTs are often fuelled with gasoil, or are built to switch between gas and gasoil.

In economic terms, because OCGTs run for fewer hours in each year, the cost of electricity production is less influenced by thermal efficiency and more strongly driven by capital costs. This trade-off has led to a rather wide range of offerings from the manufacturers.

GE's LMS 100 is a typical example of a higher efficiency OCGT, with an efficiency of around 40%. An often encountered competitor is Alstom's GT13E2 which has a 33% efficiency, but is significantly cheaper; we use a capital cost for OCGTs of €500/kW and fixed annual costs of €25/kW and €30/kW for natural gas and gasoil fuel respectively.

2.2.1 Carbon capture and storage (CCS)

The idea of capturing the carbon dioxide from fossil fuel power stations and then storing it in geological rock formations has been gaining ground since it was first mooted in the early 1990s. Historically the main focus has been on applying CCS to coal-fired power stations, but gas-fired projects are also being developed, most notably by Hydrogen Energy in Abu Dhabi and California.

One of the key attractions of coal-fired CCS technology is that can maintain diversity of the fuel mix in a country's electricity system, yet at the same time have a much lower carbon footprint than existing power stations: designers estimate that around 90% of the CO_2 will be captured and stored.

However, much remains to be proved that CCS will feature in the low carbon electricity systems of the future: a full-scale CCS plant has yet to be put into operation anywhere in the world. As many of the components of an integrated CCS system are in existence as individual operations, albeit at somewhat lower scale, the challenges on this technology are to prove its technical feasibility at scale, and then achieve the cost and performance levels projected by designers.

Figure 2 below shows the location of selected projects.

Figure 2 – Location of selected CCS projects and pilots in Europe and N America

The likely availability of CO_2 storage in Ireland has been the subject of a recent report published by SEI which concluded that the potential for CCS was viable, but subject to further geological and economic analysis, as well as the continued development of CCS technology.

As a way of moving the prospective technology to deployment the European Commission announced in early 2009, its intention to fund 12 – 15 demonstration projects. Many of these are now moving forward with the aim of starting in the middle of the next decade.

In the absence of an operational track record, the likely costs and performance of commercial scale CCS plant continue to be based on calculations and estimates – our analysis later in this chapter is based on these. CCS plants are likely to have higher capital costs (we use €2,200/kW) than their conventional counterparts because of the greater complexity of the process, and a lower thermal efficiency (general expectations are that it will be ten percentage points below conventional plant) because of the energy required to run both the additional processes and compress the CO_2 to pipeline pressures.

Although not considered in detail in this study, gas-fired CCS presents an interesting prospect. Hydrogen Energy is currently advancing projects in Abu Dhabi and California based on a chemical process to turn the natural gas into a mixture of CO_2 and hydrogen. The two gases would then be separated and the hydrogen used to fuel a CCGT. Other observers have suggested alternatives in which the capture plant is effectively added to an existing CCGT (so-called 'retrofit') or more complex arrangements involving coal-gasification systems to capture the CO_2 and fuel the CCGT on coal. We do not include these approaches in any of the portfolios, but do conclude that there may be longer term potential to capture the CO_2 from gas-fired CCGTs.

2.2.2 Combined Heat and Power

In general large power stations are designed with electricity production in mind, with 'waste' heat being absorbed in either the large concrete cooling towers or to the sea where the power station is coastal.

However the 'waste' heat from power stations can be used for residential heating – as in the district heating systems in many Nordic towns, or in energy intensive businesses such as refineries and pulp mills where the power station is very much integrated into the business.

We recognise that the Irish government has set targets for CHP deployment: such 'combined heat and power' (CHP) schemes, with parallels to Nordic countries, would have lower carbon emissions than conventional power stations, but there would also be many complications in developing the infrastructure. As our focus is on the electricity system we do not consider it further in this report.

2.3 Nuclear power stations

Although Ireland has statutory provisions that do not allow nuclear power stations to be built in the country, no description of power generation technologies would be complete without a discussion of nuclear sources.

With hindsight, the first generation of nuclear reactors, and some of the later ones were designed with priorities very different to those expected nowadays. Nowhere is this more true than the areas of the 'spent' fuel and decommissioning at the end of the life of the station: while still 'nuclear' in name, the designs available today bear little resemblance to their forebears.

One of the most informed reviews of nuclear technology was published by MIT, and we would refer interested readers to this document for far more detail than we can include in this report[3].

Fission

All nuclear fission power stations all work on the principle of capturing the heat from splitting uranium atoms into lighter elements – hence the term 'fission' reactor. When an atom is split it emits neutrons that in turn split more uranium atoms – the so-called 'chain reaction'. Nuclear reactors work by controlling the chain reaction: this is done by moderating the speed of the neutrons through a medium such as graphite. The speed of the neutrons also determines to some extent the composition of the 'fission products', and therefore the characteristics of the spent fuel. Previous designs of reactor have produced spent fuel far less amenable to management than those currently marketed.

The nuclear reactor designs work by taking the heat of the nuclear reaction into a steam turbine cycle in much the same way that the heat from a coal-fired boiler is fed via the steam into the turbine.

Fusion

Nuclear fusion is very different to fission – although both involve nuclear reactions, the principal behind fusion is that lighter elements like hydrogen 'fuse' together at temperatures of millions ºC. This is exactly the same process by which stars like the sun create heat – and the technical challenges of harnessing it are enormous. Although

3 The Future of Nuclear Power http://web.mit.edu/nuclearpower/

research programmes continue, the earliest deployment of any commercial application will not be until the middle of this century[4] at the earliest.

Fission technologies

Since the 1950s nuclear technology has developed in distinct phases, each with evolutionary improvements in both safety and design (with an eye on the entire life cycle of the plant and fuel). While there was a distinct stage of development (typified by the Advanced Gas Cooled reactor design in the UK) which aimed to maximise the energy conversion and output, the 'Generation III' reactors have quite a different design philosophy, factoring in the entire life-cycle and fuel cycle.

In contrast to CCGTs, nuclear power stations have inherently high capital costs and the additional dimensions of designing in safety systems only add to that. In order to mitigate these costs, there has been a natural progression to larger and larger units and there are currently over fifteen different reactor designs being marketed around the world. For example even in a small country like Lithuania some ten designs are mentioned in the Environmental Impact Assessment (EIA) for a project there.

In Europe there are currently almost 200[5] nuclear power stations in operation. While many more are in various stages of planning consent, two reactors are currently under construction: Unit 3 at the Olkilouto power station in Finland (illustrated below in Figure 3 below as a graphic alongside the existing units 1 and 2), and Unit 3 at Flamanville in France.

Figure 3 – Olkiluoto Power Plant

Source: Teollisuuden Voima Oy

Integral to the development of Unit 3 at Olkiluoto is the construction of an underground repository for the spent fuel only a few miles from this project, in which it is envisaged that all Finland's nuclear waste will be stored.

4 http://www.parliament.uk/post/pn192.pdf

5 European Nuclear Society

New projects may soon start elsewhere: Lithuania and Switzerland have completed the important EIA stages for new projects to replace existing nuclear capacity in those countries and may soon invite tenders.

Both Flamanville and Olkilouto are of the 'European Pressurised water Reactor' (EPR) design, around 1,600MW capacity. While the larger unit sizes have advantages in terms of reducing costs, they can also have some practical disadvantages: reliance on single large projects to deliver future electricity needs can add undue levels of risk, and in smaller electricity systems the sheer size can be difficult to accommodate. In any electricity system enough back up needs to be available within seconds to deal with the largest possible fault – usually breakdown of the largest unit.

To deal with these market issues, suppliers have been developing many designs for smaller reactors, for example the Pebble Bed Reactor, and the IRIS reactor (325MW). Although smaller reactor designs continue to evolve, none are in commercial operation yet. Other developments continue to focus on safety and efficiency – and initiatives towards new designs like the High Temperature Reactor and 'Generation IV' continue.

Nuclear reactors have also been widely deployed for submarines and aircraft carriers. Such designs are not suitable for civilian use, with the main factors in their design being to physically fit inside the vessel and work under military conditions. As such issues of cost and fuel cycle have been far less of a priority. Despite the attractiveness of their small size, the military designs' unit costs are probably very high, and we therefore do not include them in our analysis.

The two main types of unit being advanced for UK deployment before 2025 are, the 'European Pressurised Water Reactor (EPR)' and the Westinghouse AP1000 are 1,600 and 1,100MW respectively, and we have considered these as the most likely candidates for the island in this report.

Economics

It is certainly not true that nuclear power will be too cheap to meter, but the debate over the cost of nuclear power continues to rage, especially when comparison is made to other low carbon technologies.

Several reasons account for the difficulty in making the assessment – the high capital costs, the unknown costs of fuel reprocessing or spent fuel storage, and potentially long lifetime of nuclear stations mean that the calculation of lifetime generation cost is far more sensitive to the discount rate and the owner's view of economic lifetime than the other technologies. This is also true of the costs of decommissioning the stations – in practice the time for this is so far away that on a discounted basis it does not materially add to the lifetime generation cost in full economic assessments.

Estimation of the actual costs of building a nuclear station in Europe is clouded by the lack of recent case histories – and like many of the UK's nuclear stations in the past, the Olkiluoto project has suffered from cost overruns and large construction delays. In contrast recent construction history in the Far East (Japan's ABWR projects and China's Candu projects) has shown that it is possible to hit targets.

Nevertheless, all of these lead to a wide range of estimates for new European nuclear projects – for our analysis in this report we use €3,000/kW). We note that smaller reactor designs may incur less system costs, but these savings may be offset by their loss of the economies of scale that have driven up the size.

The underlying figures we have used in our economic comparison later in this chapter are based on our experience of the commercial environment and are broadly in line with other observers' views of the likely costs.

Spent nuclear fuel

Nuclear fission by its very nature produces highly radioactive materials – the most radioactive of which is the spent fuel, but necessarily there are also so-called 'Intermediate-level' and 'Low-level' wastes.

Each of these materials arise in different quantities and need to be dealt with in highly specialised ways – for example the spent fuel may require constant cooling either by air or by placing it in water (so-called cooling ponds).

Spent nuclear fuel is often transferred across international borders for further treatment, or managed within a country in either centralised or decentralised storage facilities. In many countries the location of storage facilities has been highly contested and subject to many changes – although in Finland the country appears to have a strong national consensus and in 1994 passed specific laws to create a national repository.

Safety issues

It is worth pointing out that the latest nuclear power station designs all claim to exceed international safety standards (risk targets) by some margin and have enhanced accident prevention and mitigation features. We expect the 'Generation IV' plants, with likely deployment after 2030 to present even lower operational risks.

No doubt the memory of the incident at Chernobyl continues to haunt the industry – but the reactor designs currently being deployed are based on very different philosophies and there is far greater oversight of safety issues.

2.4 Renewables

2.4.1 Wind

Since the 1980s wind power has evolved dramatically to being an important component of many power systems. This has largely been because technical developments have provided economies of scale; with a typical turbine size growing from 2-3MW to 5MW and the industry is now developing even larger units. Clipper, for example, announced funding by the UK government to develop a 10MW offshore wind turbine prototype, scheduled for deployment in late 2011[6].

While the early deployment was in the form of onshore projects with up to five turbines, the industry is now turning towards offshore applications with larger turbines in arrays where the project size will be generally 1,000MW scale. Industry development is likely to move towards more mass-production and more standardisation to lower production costs.

Although the economics of wind generation appear to be competitive with many other forms of low carbon generation, it is worth mentioning that in recent years the costs of the equipment rose with growing global demand – the fundamental laws of supply and demand affect wind farms as much as anything else. Offshore wind farms tend to be significantly more expensive than those onshore: for this report we draw on our

[6] Clipper press release, 16 September 2009

experience of financing windfarms, and therefore use capital costs of €2,150/kW and €1,050/kW respectively.

Wind output is also intermittent. Hitherto any additional costs to the system of intermittency have been absorbed by the system, but as deployment grows to 2020 targets and beyond, any comprehensive view of costs needs to take into account the provision of back up when the wind is not blowing.

2.4.2 Wave

The Irish Government's Energy White Paper in 2007 set an initial target of at least 500MW of installed ocean energy capacity by 2020.

Marine energy has a long history of development but hitherto has not been deployed in any large scale around the world. Nevertheless many companies are highly active in this area and the purpose of this section is to give an overview of the different approaches.

Wave power broadly divides into fixed or floating, the latter being moored offshore. The actual devices come in a number of different configurations: Oscillating Water Columns use wave energy to create pressure inside an air column, which in turn drives a turbine to generate electricity; Trapped Channel systems use a method not unlike hydro power where the kinetic energy of waves is converted into potential energy stored in a water reservoir, then fed through a turbine. Finally, systems that capture oscillating motion of waves can convert this to electrical energy using hydraulic pumps or magnets and coils.

Figure 4 – Marine generating technology: Wavebob

The Wavebob is an example of a floating device that uses a hydraulic system to generate electricity. Average electrical power of 500kW and more expected from North Atlantic sites.

Source: Wavebob

As might be expected of a technology without a commercial track record, there is a wide range of cost estimates. For this report we use capital costs of €3,500/kW in our analysis.

2.4.3 Tidal

The majority of tidal power technologies use turbines that spin on either a horizontal or vertical axis. They use a similar concept to wind turbines but because ocean power has a higher energy density than air, turbines can be much smaller than their wind equivalent. For example, a unit with diameter of 10-15m can produce between 200kW and 700kW. A recent alternative to turbines is hydrofoil tidal power technology, which use blades attached to an oscillating arm that rise and fall with the tides.

The simplest generating systems use a barrage to fill a tidal basin on incoming high tides and generate on the outgoing ebb tide. The world's first tidal power system, the 240MW La Rance plant in France, uses such a system. However, there is little global deployment of barrage systems, due to environmental concerns.

The Open-Centre turbine developed by OpenHydro (see Figure 5) is the only tidal power technology to receive funding from the SEI.

Figure 5 – Open-Centre Turbine

OpenHydro announced in October 2009 that it secured a research & development grant of up to €2m. These turbines will be mounted directly onto the sea bed and claim less environmental impact due to their large open centre and outer housing. A 1MW turbine has already been successfully installed at a site in Canada.

Source: OpenHydro

We use capital costs of €3,500/kW in our analysis of the costs of tidal generation.

Marine technologies will, to differing extents, exhibit 'intermittent' characteristics like wind generation – we have modelled this at a very high level in our analysis.

2.4.4 Dedicated biomass

Dedicated biomass-to-electricity plants around the world have historically been limited to relatively small units which take the biomass fuel from a local catchment area.

A very different approach is being advanced by several developers in the UK at the moment in which the unit scale is around 300MW. Such schemes would take typically 2.4m tonnes of woodchips per year[7] (similar to the tonnage of coal consumption for Moneypoint) and have a dedicated biomass-fired power plant to convert it to electricity. The wood material would probably be sourced from regions like Eastern Canada or the Southern US and transported by freighter to coastal power station sites. Although not the specific focus of this report, our work in the Forest Industry sector, suggests a considerable sustainable resource is available for such projects globally.

Such plant will be considerably more expensive than its coal-fired equivalent (we use €2,150/kW and the fuel is likely to cost more – however the advantages are that the plant would have a virtually invisible carbon footprint (the transport of the biomass is relatively small).

A biomass fired power station might also have some advantages in terms of being able to deliver firm power and its flexibility – economics aside, such plant ought to have flexibility comparable to conventional steam plant.

Figure 6 – Proposed 300MW biomass plant at Teesside

Source: Renewable Energy Association

[7] Renewable Energy Association

2.4.5 Solar technology

Solar technology includes Photovoltaic (PV) and Concentrated Solar Power (CSP). While the latter is only likely to be economically viable in Southern European or North African locations, photovoltaics are in widespread use, notably in Germany where lucrative feed-in tariffs have encouraged developers.

Technically, and economically they continue to improve: thin film PV technology, for example, uses less silicon and is cheaper to manufacture than conventional photovoltatics. However, even the most promising PV technologies are considerably away from competing economically with the other technologies outlined in this section of the report.

While we recognise the potential for further advancement to close the economic gap, we have not included PV in the modelling as a large scale generation technology for the island in 2035.

2.5 Hydro

2.5.1 Conventional generation

Hydro-electric generation is one of the oldest forms of large scale electricity production; in more mountainous parts of the world it is often the dominant source of power.

There are two main forms of hydro power – often combined in complex schemes. Dam-based schemes are centred on an artificial lake which can store several months' (in some cases over a year's) water: in this way production can be maintained against variable amounts of rainfall. Run-of-river schemes simply operate on the natural flow of the water and therefore are much more prone to interruption on account of the weather.

There are four major dam-based hydro stations in Ireland, all of which were first commissioned a number of years ago. Ardnacrusha is the largest hydro plant in Ireland and contributes 85MW to a total conventional hydro capacity of 220MW.

Inevitably there is a conflict with other land uses in developing large scale hydro schemes: it is generally accepted that the most suitable sites in Western Europe have been exploited – the mountainous terrain required to give the water enough height drop is often in environmentally sensitive areas. Ireland is no different to other countries in this regard.

2.5.2 Pumped Storage

Pumped storage schemes represent a very specialised form of hydro power scheme: they pump water electrically from a lower lake to a reservoir high up a mountain, and then generate electricity by flowing it back down. In general, such plant is constructed because it can turn on and off extremely fast – enabling the system operator to manage situations like television peaks or failure of other power stations. Few such schemes are constructed with large scale storage in mind – the volumes of water needed and the height required are too much (as an indication 1m^3 of water falling 100m will only generate around 0.2kWh)

As the pumping efficiency is not 100%, pumped storage schemes actually are net consumers of electricity – although because overnight prices are lower than daytime, they can compensate somewhat.

The 290MW Turlough Hill station (see Figure 7) is the only pumped storage on the island of Ireland; it was deliberately designed to be obscured from public view by building an artificial lake on the top of this hill and using a natural glacial corrie as the lower lake. Its maximum storage capacity is 1,800MWh - approximately 6 hours at full output.

Figure 7 – Turlough Hill

Source: ESB

Pumped storage continues to attract developer interest, with some considering development of large storage schemes.

One such proposal is to develop sea water based pumped storage schemes in the U-shaped valleys on the west coast to create relatively large amounts of storage capacity and then be run to offset the intermittency of wind and marine generation. Plans include up to 2GW of generating capacity with up to 200GWh of storage, enough to run the plant at full load for 100 hours. This compared to the 1.8GWh (6 hours) available at Turlough Hill. Using the sea as the lower reservoir could help lower costs – we have based our analysis on capital costs of €1,200/kW but in our experience each project has very individual cost characteristics.

By way of example, an 85MW seawater scheme with an artificial upper reservoir has been operating at Okinawa, Japan (shown in Figure 8 below) for over 10 years.

Figure 8 – Okinawa seawater pumped storage plant

Source: IEA

2.6 Other alternative generation forms

Innovation in sources of electrical generation continues in many other areas, particularly those in which the generation can be combined with heating uses, or act as potential storage. While we recognise these, their contribution to power systems is highly uncertain, and this report does not examine them in great detail.

2.7 Comparisons

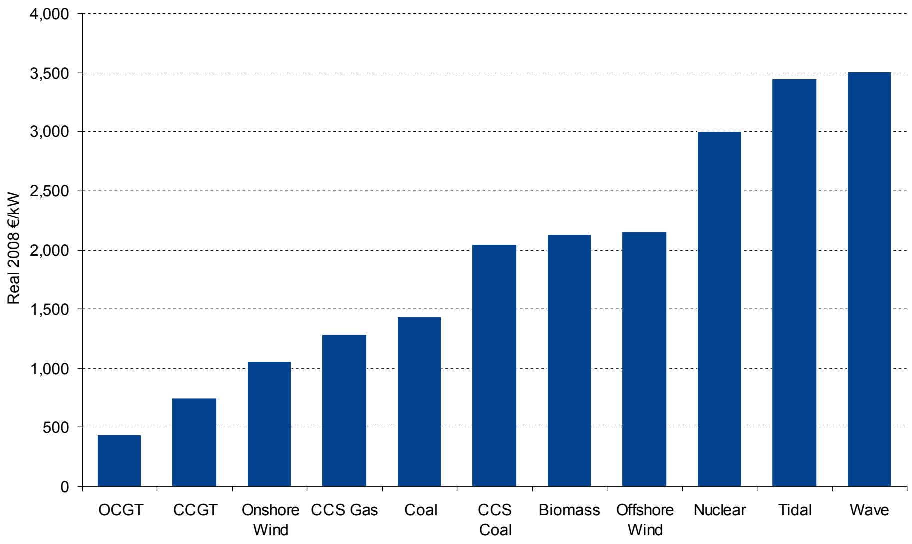
Having described the many types of generation technology that could contribute to the power system in the 2030s, we now aim to compare and contrast them from several different points of view. Our aim is to set the background for our analysis later on this report of the characteristics of complete portfolios and to help understand the many trade-offs involved. We have selected technologies that are either in or close to deployment and also included CCS given current interest. Details of our views on commodity prices, which form an important part of this analysis, are contained in the Annex; they are broadly in line with other commentators. We have also separately analysed each of the portfolios under a High fuel cost scenario, where the cost of fossil fuels and carbon are significantly increased.

2.7.1 Economics

2.7.1.1 Capital costs

A major component of generating costs is the initial capital requirement. Figure 9 below shows the capital costs by generation type. In order to account for the different sizes in which the units are deployed, this is shown in terms of €/kW.

Figure 9 – Capital costs by generation type



In general this shows how much greater the initial capital outlay is for all renewables, apart from onshore wind (we have not included on- or offshore grid costs in this analysis). Gas plant is much cheaper than coal plant, with the more simple OCGT being considerably cheaper than Combined Cycle plant. Carbon capture and storage plant is more expensive than its conventional equivalent because of the extra capture equipment and the CO_2 compressors. We recognise that there is some uncertainty about the nuclear capital costs, but it in our experience it is likely to have this position relative to the other technologies given their state of development.

2.7.1.2 Total generation costs

Over the lifetime of a power generation project the capital costs are amortised over the generation output and the initial hierarchy above changes significantly. When due consideration of an appropriate economic lifetime (i.e. the number of years that the investor evaluates the project financially), output and other operating costs such as fuel are also taken into account we are able to compare the ‘total’ generation costs of the various technologies.

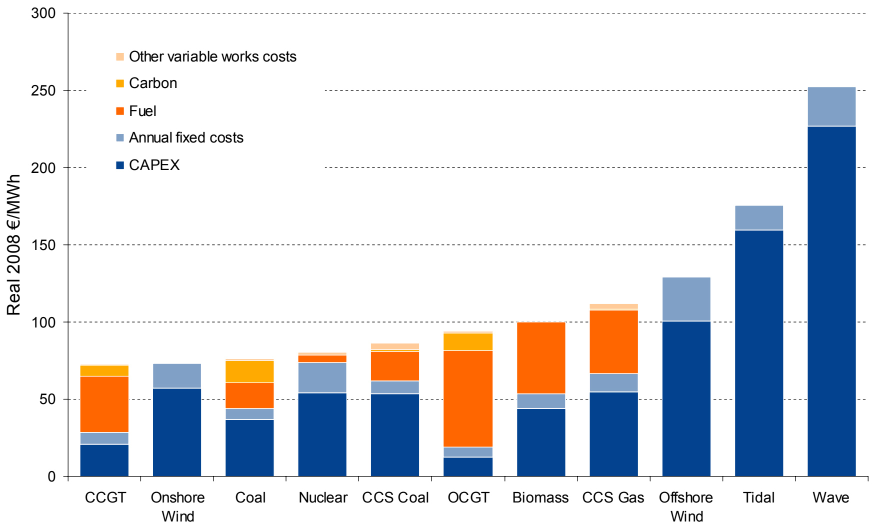
Figure 10 shows our calculations of the lifetime generation costs for different generating technologies. A picture emerges of a significant range: from CCGTs, onshore wind and conventional coal to wave power at the higher end.

However there are some important nuances in this picture too. Figure 10 also shows the proportions the main cost elements: initial capital outlay, annual variable costs and fixed costs based on typical lifetime outputs. These proportions are very important to investors when they consider such issues as the time it takes to get back the money initially invested in the project (so-called capital intensity) and the exposure to fuel prices.

OCGTs and CCGTs have amongst the lowest capital intensity, but high exposure to gas prices. In contrast to this, the majority of onshore wind costs are incurred in the initial capital investment and the remainder through fixed costs not dependent on generation. Nuclear generation has many parallels with the wind economics: a high proportion of capital costs and high fixed costs, which are not affected to a large degree by the generation levels.

Coal-based technologies have lower fuel costs than gas fired plants, though they have a much higher capital element (particularly for CCS coal) or higher carbon costs (e.g. for non-CCS coal).

Figure 10 – Lifetime generation costs by technology (€/MWh)



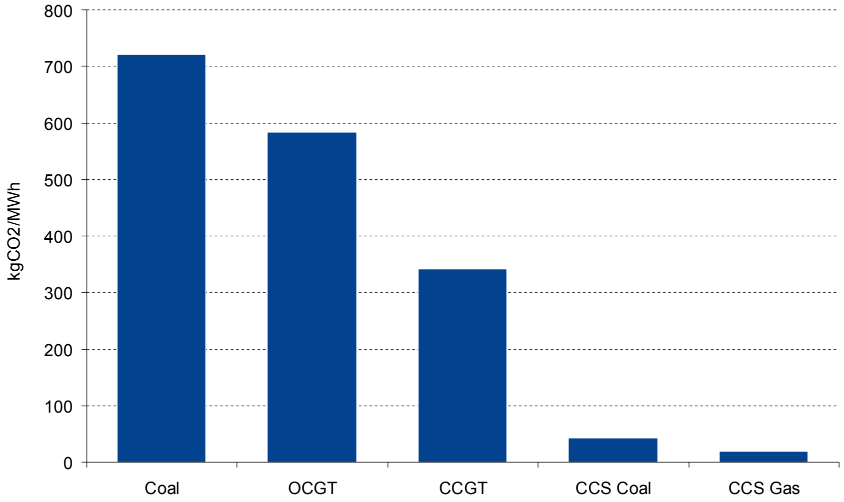
Adding CCS to both conventional coal- and gas-fired plant increases their lifetime costs considerably as expected from both higher capital costs and lower thermal efficiency.

Other renewable technologies, like offshore wind and marine, have much a higher capital element, which overall makes their lifetime generation costs significantly higher despite relatively low variable costs.

2.7.2 *Environmental performance*

Our analysis in this report about environmental performance is concerned with carbon dioxide emissions, and for those with material emissions these are shown in Figure 11 below.

Figure 11 – Carbon dioxide emissions by generating type



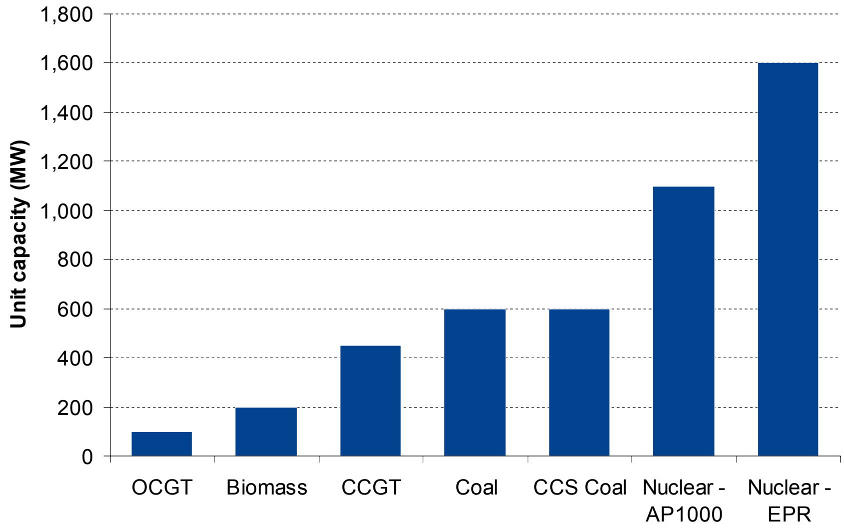
Gas-fired generation has inherently lower emissions than coal plant mainly because a higher proportion of the energy in natural gas is in the form of hydrogen rather than carbon – the hydrogen simply burns to form water, while the carbon turns into carbon dioxide. Secondarily, the thermal efficiency has an effect, with the higher thermal efficiency of CCGTs further improving the gap with coal plant.

Adding carbon capture and storage to either a gas-fired or a coal-fired plant does not completely remove all the CO_2 emissions as the most likely designs will run at a 90% capture rate.

Thermal power stations also have other atmospheric emissions e.g. sulphur dioxide, nitrous oxides, and particulates, as well as water emissions. This report does not discuss these in detail, although we have assumed compliance with known environmental standards.

2.7.3 Unit sizes

Figure 12 – Minimum unit size commitment by technology type



While there are strong drivers on many technologies to improve their performance or reduce costs by building bigger units, this can have drawbacks.

Figure 12 above shows typical unit sizes for commercially available units. Large units can have their drawbacks – a single project can carry a disproportionate amount of risk, and in a relatively small system like the island, the system operator will permanently need to manage potential failure at that site. In much larger systems the proportional impact is far less. The two designs of nuclear plant with reactor sizes of 1,100MW and 1,600MW would present the most concern, although primarily from the project risk point of view.

3. THE ISLAND OF IRELAND

3.1 Preamble

In this section we review electricity demand, the outlook for fuel prices, as well as the potential for storage of both natural gas and carbon dioxide.

Understanding the outlook for all these has its challenges, particularly with the recent extraordinary economic growth and decline, but also the turbulent times in not only oil markets but also those for gas and coal.

Fuel prices are important in understanding the economic shape of possible generation portfolios for the island: relative costs as well as the exposure of these to world markets need to be understood.

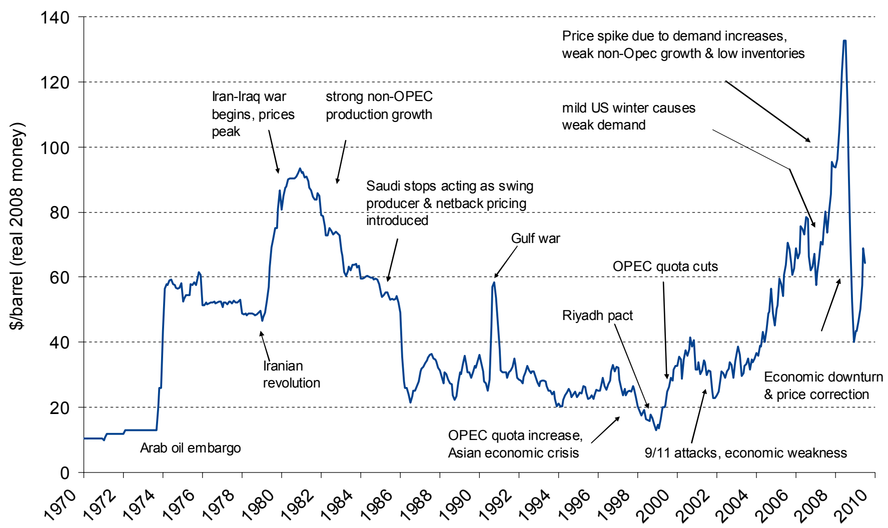
Furthermore, prices for carbon dioxide emission allowances (which can be considered as an addition to the fuel costs of power stations) only date from 2005, and for most of that time have tracked far below expectations of many policymakers.

3.2 Fuel prices

The island of Ireland stands at an almost unique geographic point in the energy supply compared to other parts of Europe: its deep water ports give it amongst the best access to internationally traded coal, while it stands on a distant edge of Europe's gas supply system. So compared to many other countries, the relative expense of gas compared to coal in the island is high.

As crude oil prices have been a major bellwether of other energy sources we show the historical picture in Figure 13 below.

Figure 13 – Historic crude oil prices ($/barrel, real 2008 money)

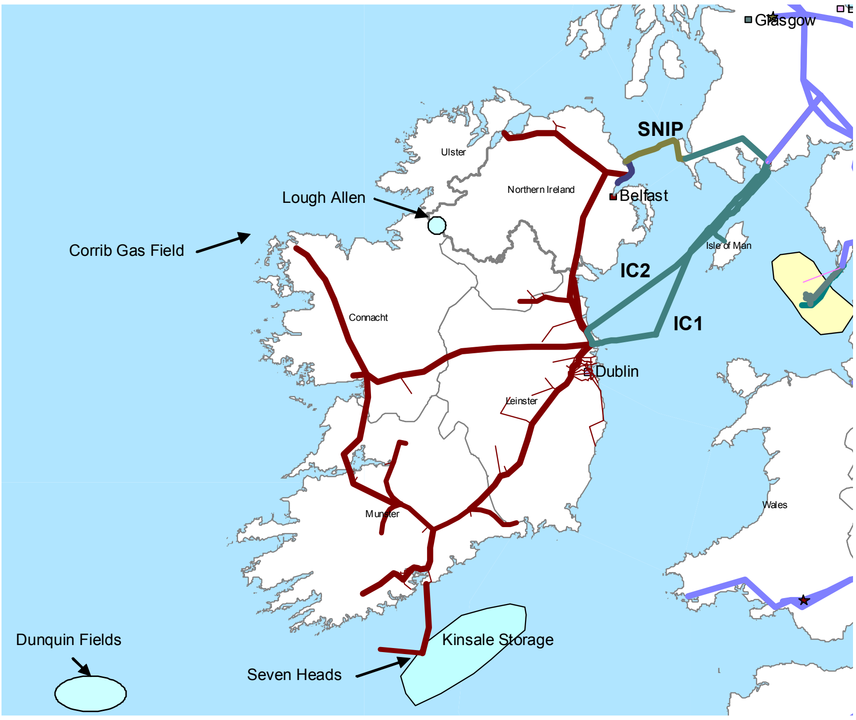


Source: EIA, Reuters, Pöyry

International gas and coal prices have historically shown some correlation with those of oil over the long term. The island does have fossil fuel sources of its own in the gas fields of the south coast and in due course from the Corrib gasfield off the coast of County Mayo, and possibly from the exploration at Lough Allen. Three gas interconnectors bring piped gas from the UK system to the island. Despite having significant gas reserves, the island is likely to remain a net importer of gas, and therefore prices are likely to continue to be referenced to the National Balancing Point (NBP) in the UK (slightly higher to allow for the transportation cost).

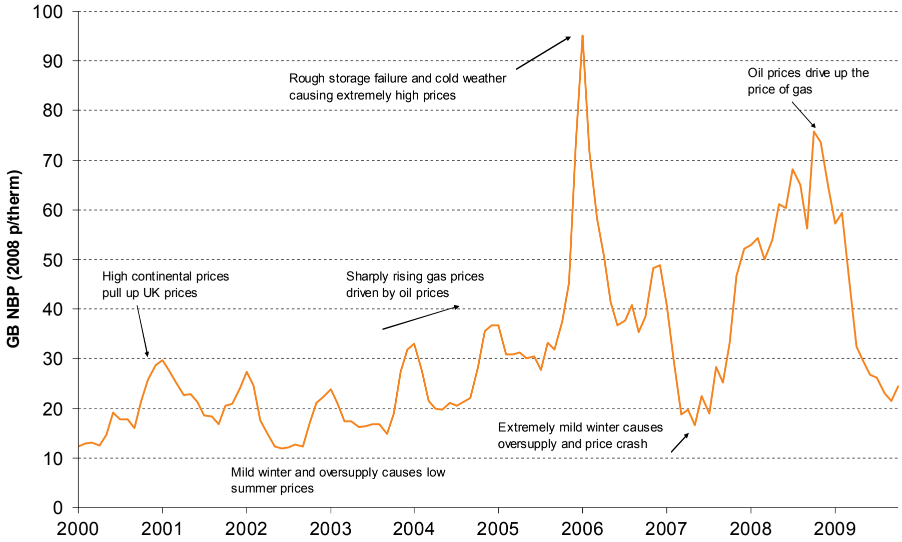
Figure 14 below shows the major features of the gas supply to the island.

Figure 14 – Gas infrastructure and sources



As the gas supply is effectively referenced to the gas market in the UK, we show historical prices in Figure 15 below. In practice the market has been influenced by underlying supply demand balance in the UK and continental Europe, overlain by some short term events (like the temporary closure of the Rough storage facility in February 2006).

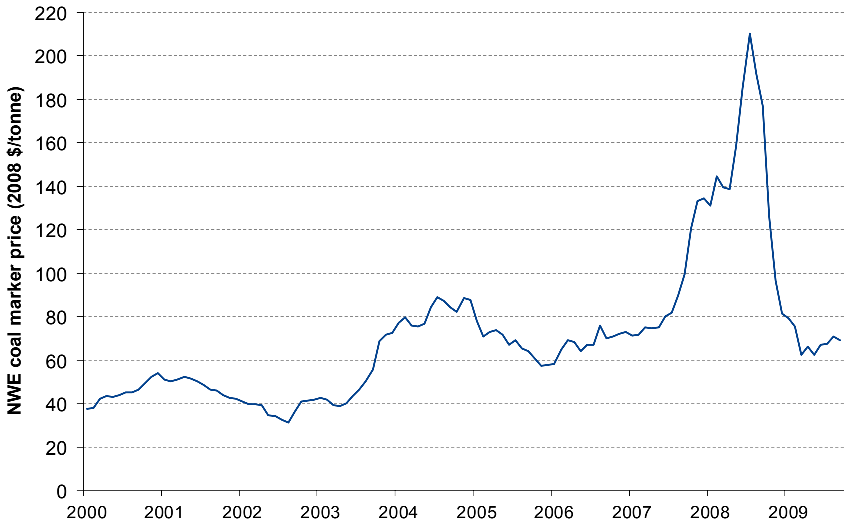
Figure 15 – Historical gas prices to National Balancing Point (GB)



Source: Heren

Figure 16 below shows historical coal prices delivered to North West Europe, typical of the prices that would be paid for coal delivered to the island. Recent price increases were initially due to a rising cost of seabourne transportation, however significant tightening of the coal supply/demand balance pushed prices up even further to record levels in 2008. Prices have since decreased back to pre-2008 levels as a result of the economic climate and a moderation in worldwide coal demand.

Figure 16 – Historical coal prices



Source: Reuters, McCloskey, ARA CIF basis 6000kcal/kg

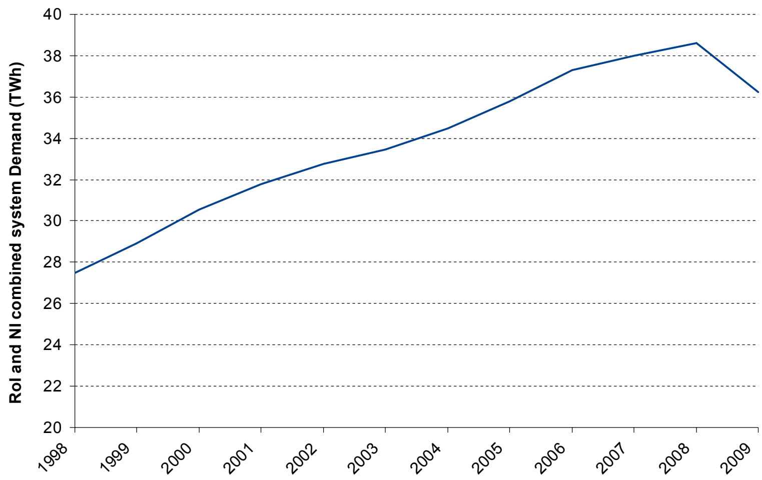
Uranium prices, pertinent to the discussion on the possible future generation portfolios are discussed in the Annex. While the price for uranium oxide ('yellow cake') have ranged between US$20-60/lb it briefly peaked at US$140/lb in 2007 because of various operational problems at certain mines. However, because the fuel component of the lifetime nuclear generating cost is only a minor proportion (as shown in Figure 10), even the higher price has little impact on the total. A recent report by MIT concluded that there is an abundance of uranium reserves, with current estimates that there are sufficient supplies for 800 1,000MW reactors for 80 years (the current fleet totals 436 reactors with a combined capacity of 370,000MW[8]).

In the later part of this report we factor in the impact of different fuel prices by considering a Base case and a High case for fuels using our own scenarios. Details of these are contained in the Annex.

3.3 Demand for electricity

After a number of years of strong growth, 2009 demand in Ireland is expected to show an annual decrease of -5.5%[9] compared to 2008.

Figure 17 – Historical and system operator projected electricity demand



Source: EirGrid, SONI

In this report, which looks to likely demand in 2035, we will base the demand on a long term trend of 0.7% annual growth, very much in line with other commentators.

While it is possible that changes in the pattern of demand, or more sophisticated and extensive control of demand at the end consumers' premises could also change the daily pattern of demand, to simplify our analysis we assume that the 'shape' of demand is unchanged.

As will be shown later in Chapter 4, while energy efficiency measures could result in a lower absolute growth rate and novel ways to change end customers consumption patterns may be developed, the intermittency of the wind will continue to be a dominating influence on the electricity market.

8 European Nuclear Society.

9 EirGrid Generation Adequacy Report (GAR) 2010-2016.

3.4 Natural gas storage

Changing and uncertain demand for natural gas is met in many parts of the world by a combination of altering the producing fields' output, and combined with use of storage facilities near the demand. Often the storage is designed to reduce a country's dependence on a few, critical, pipelines or to provide some kind of leverage against a dominant supplier. As will be discussed later, one of the consequences of large amounts of wind power is that the island's gas-fired power stations will increasingly have to run at the will of the wind, or lack of it. Having large amounts of gas storage on the island may mitigate the inevitable market consequences.

Natural gas storage sites divide themselves by the nature of the storage they provide, especially their ability to 'turn on' to the system. Typically depleted gasfields provide seasonal storage – they inject during the summer and produce during the winter when demand is higher. However such fields are not able to provide large amounts of gas at very short notice, such as less than twenty-four hours' notice. So-called 'fast' storage is typically constructed in 'salt caverns' where hollows are made in underground salt deposits. Liquefied Natural Gas (LNG), stored in tanks at -196ºC can also able to provide 'fast' storage.

The island has only one significant natural gas storage facility at the moment, at the site of the depleted Kinsale field run by Marathon. The licence, which was awarded in 2006, means that it can store up to 198mcm, with a delivery rate of 2.8mcm per day. To give some context, if all of the gas was used on CCGT generation this would provide enough gas to run about one and a half CCGT stations at full output.

There is also a potential new depleted salt cavern storage facility under evaluation at Islandmagee, Co. Antrim with storage of 500mcm and withdrawal rate of over 20mcm per day. The caverns would be created within the salt sequence below Larne Lough but accessed from directionally drilled boreholes on the land.

A second potential 500mcm storage development in Larne, the North East Storage project, is being considered by a joint venture between Bord Gáis and Storengy (a GDF-Suez company). Both of these projects are not expected to be commercially operational until 2016 at the earliest (neither of them are assumed to impact our fuel price assumptions)

3.5 CO_2 storage

Adoption of CCS schemes in the island will require a matching amount of storage.

In anticipation of potential CCS developments various studies have attempted to characterise the geological formations which might be used to store the CO_2 emissions from future projects of comparable size to Moneypoint.

An 800MW coal-fired power station would produce around 10mt CO_2 pa and therefore likely to require storage capacity of 300–400mt CO_2 over its physical lifetime. In relative terms, the technical and commercial challenges of moving the CO_2 from that site to possible storage sites in waters around the island would be straightforward.

Recent research by SEI estimated the island of Ireland's[10] storage capacity at over 90,000 million tonnes of CO_2.

However, much of this volume is speculative, and the 'practical' category totalled almost 1,500 million tonnes of CO_2 including the Kinsale formation which, if converted to storing CO_2, is estimated to have storage potential of 330 mtCO_2.

At this stage, it would appear that there are no definite grounds to rule out CCS as a viable option for the future, recognising the discussion earlier that much also remains to be proven.

10 Assessment of the Potential for Geological Storage of CO_2 for the Island of Ireland, SEI, September 2008

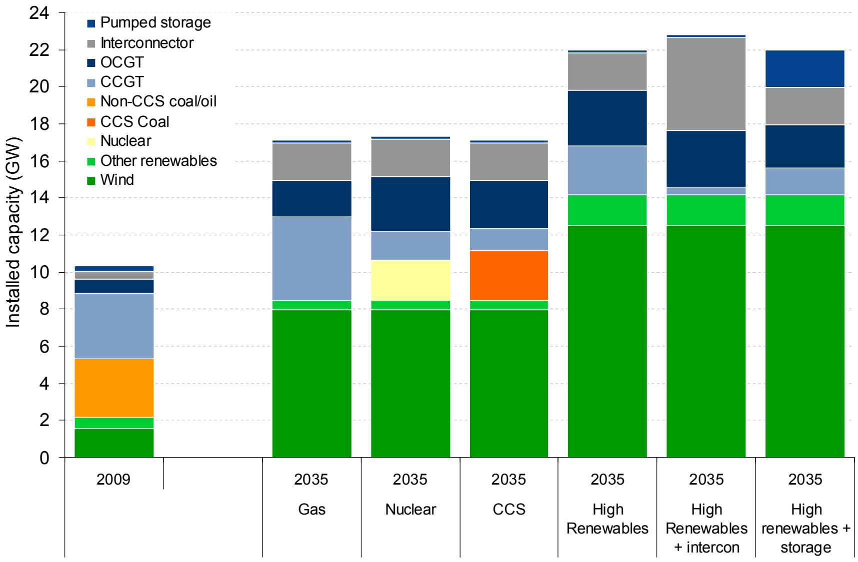
4. GENERATING PORTFOLIOS

4.1 Introduction

In order to understand and analyse the issues involved in reducing the carbon intensity of the island's electricity generation down towards 100g/kWh, we have constructed six different portfolios comprising different proportions of generating technologies. All are aimed to push at boundaries while still remaining feasible and credible points on a path towards further decarbonisation.

All of the portfolios build on the current targets in both Ireland and NI to reach 40% renewables by 2020, but in different ways so that we can compare and contrast their characters. Figure 18 below shows their composition in terms of generation capacity. Although it might appear that the amount of generation capacity is different, all six are serving the same system demand and deliver the same security but the higher wind capacity in three of the portfolios does not obviate the requirement for other types of plant.

Figure 18 – Overview of portfolio capacity composition



In this chapter we make some comments on each of these; Chapter 5 then examines them against each other. In all scenarios we assume an increase of interconnection capacity to GB to 2,000MW – based on the 1,000MW already built or in advanced planning, and an expectation of a further 1,000MW by 2035 on the basis of further electricity market integration.

For general consistency in our analysis we have assumed a single relatively decarbonised GB electricity system; further details are contained in the Annex.

‘Gas focused portfolio

Gas-fired CCGT appears to be the economic choice of new build for thermal plant at the moment, and as CCGTs have considerably lower carbon emissions than coal plant, the carbon intensity of the overall portfolio is lower than present. In many ways, this portfolio might represent the natural direction of the current policy environment, as it has even higher deployment of renewables than the 2020 targets.

‘Nuclear focused portfolio’

While recognising that such an option is not possible in Ireland at the moment, this portfolio includes 2,200MW of nuclear plant. This would be possible using two Westinghouse AP1000 reactor designs.

The levels of renewables are the same as the ‘Gas’ portfolio, and the balance of thermal generation is a combination of gas-fired OCGT and CCGT.

‘CCS focused portfolio’

This portfolio assumes that by 2035, coal-fired CCS has moved into widespread commercial deployment. We have assumed inclusion of 2,700MW of such plant because the smaller unit size (and consequent lower reserve costs) makes greater deployment more practical. Renewable capacity is the same as the ‘nuclear’ focused portfolio.

‘High renewables portfolio’

As an alternative to reducing carbon emissions with thermal generating technologies, all three ‘high’ renewables portfolios are centred on much higher deployment of renewables at 80% of total generation. These portfolios will enable us to examine alternatives in dealing with the high levels of intermittency associated with the wind and marine sources.

We have limited wind generation to 60% because beyond this point, the requirements for additional firm capacity backup appear to be onerous. A further 20% of renewables is delivered by dedicated biomass-fired plant and a combination of marine and tidal generation.

Gas-fired plant has been deployed only to levels necessary to maintain the same system security standards as the other portfolios.

‘High renewables with higher interconnection portfolio’

This portfolio has the same renewables plant as the ‘high renewables’ portfolio, but it has a significantly increased interconnection to GB and France. Again gas-fired thermal plant is only deployed as necessary to maintain system security standards, recognising that the interconnection also gives a certain capacity credit.

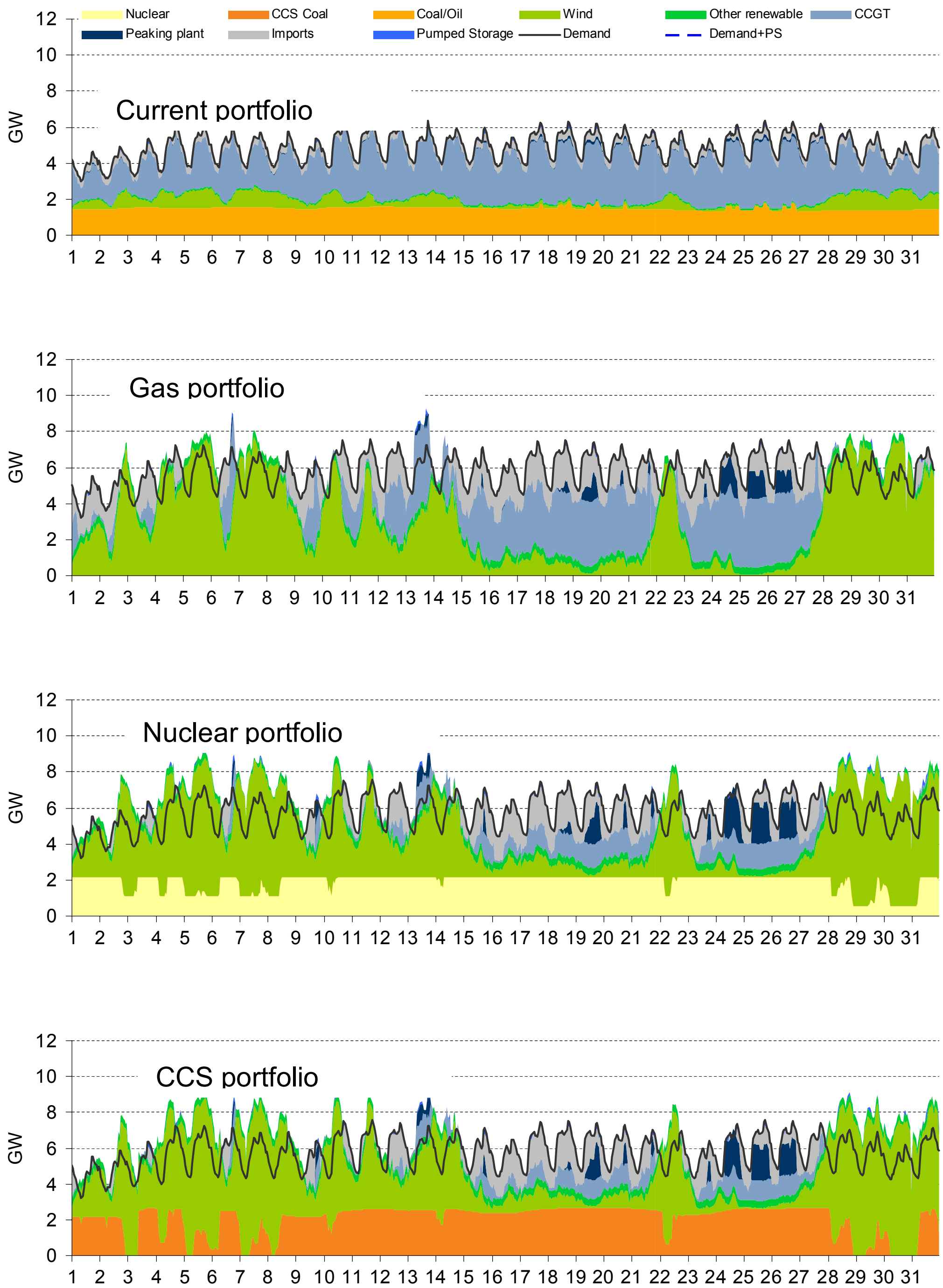
‘High renewables with large scale storage portfolio’

In order to tackle the combined challenges of wind intermittency and dependency on imported fuels, we have constructed one final portfolio to examine the degree to which these can be mitigated.

We take an approach of deploying sea-water based pumped storage schemes in parallel with the wind while recognising that the feasibility of such a scheme is yet to be proven. As with other portfolios, we have used gas-fired plant to balance the system to meet the same system security levels.

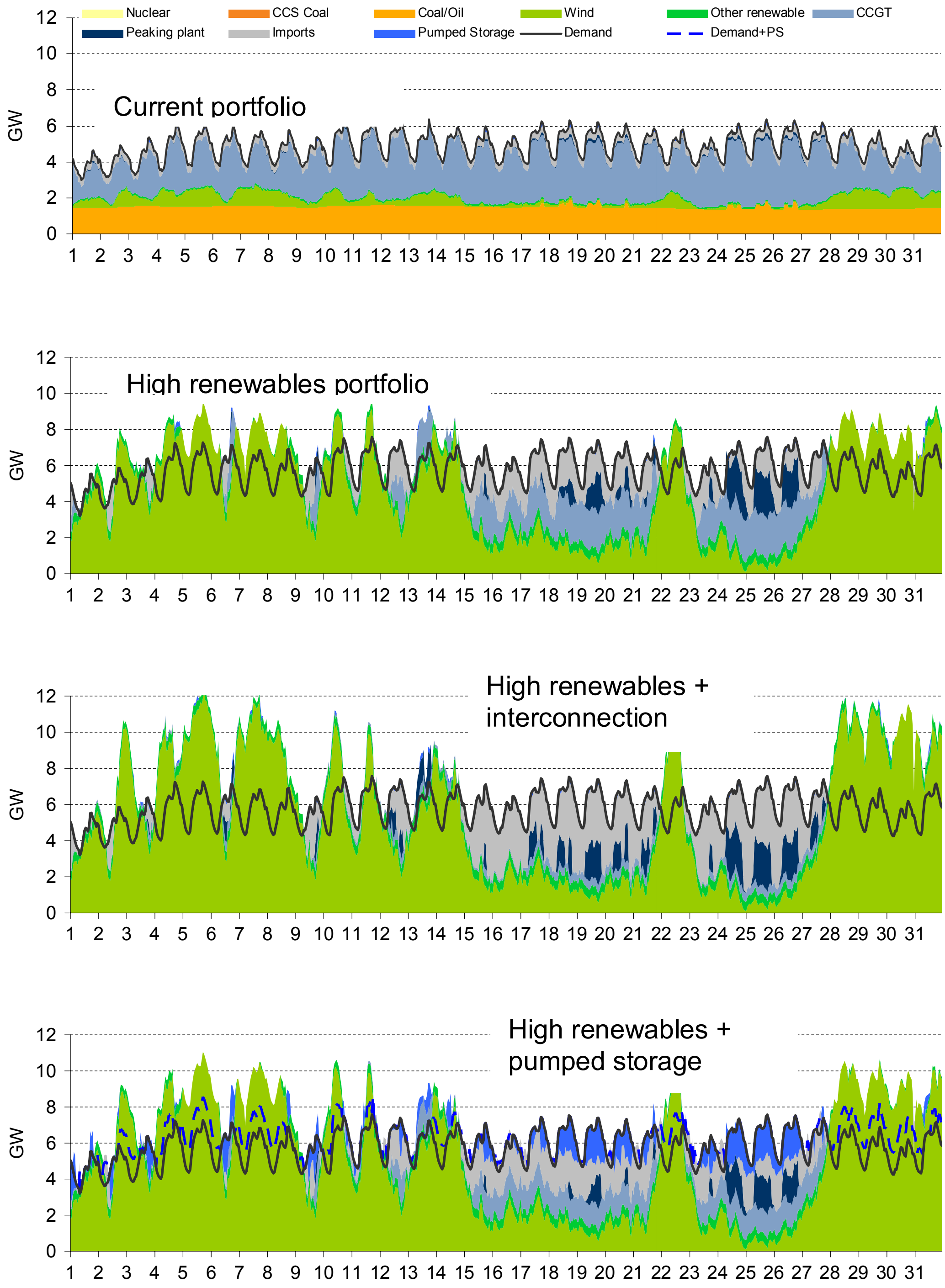
Figure 19 on this page and Figure 20 on the following page compare the dispatch patterns[11] of the portfolios if they experience the weather of January 2000.

Figure 19 – Generation portfolio dispatch patterns (I)



11 Dispatch patterns shown do not consider system reserve/response constraints. However we have considered these additional costs in Section 5.7

Figure 20 – Generation portfolio dispatch patterns (II)



The dispatch pattern of the current portfolio shows how the coal plant largely runs at baseload with the CCGTs largely supplying the remaining system demand (as shown by the black line) once wind generation is accounted for.

All the portfolios analysed in this report have the same projected system demand for 2035, but very different mixes of generation capacity.

The gas portfolio shows how the gas plant is called on to operate very much in response to the output of the wind, with open cycle plant dealing with short peaks and CCGTs otherwise. Interconnectors too are highly active: output above the black demand line is exported to GB while interconnector imports are shown in grey.

Both the nuclear and CCS portfolios show the role expected of these types of plant in the system, largely running at full capacity. Our modelling suggests that there are times when the wind output is so large that they have to reduce output.

All three of the higher renewables portfolios show how the intermittency of the wind becomes even more of a dominant feature in the market. The period when the wind output is low between the 15th and 22nd of the month well illustrates how gas-fired plant – both CCGTs and OCGTs – combined with interconnectors operates to supply demand in this situation. Note that there are also times, like on the 14th, when the OCGTs operate profitably to export power to the GB market because prices are even higher there.

That greater interconnection allows more exports to GB and France is seen by the far higher wind output, on for example both the 5th and 8th, compared to the 'high renewables scenario. The interconnectors also import far more at times of low wind: so in these periods, instead of gas-fired generation being the principal source of generation, the interconnectors provide the power.

We have illustrated the high renewables plus storage portfolio by showing the additional demand when the pumped storage is pumping as the dashed line above the basic level of system demand, and its output as a solid blue. To a significant extent the pumped storage is working to mitigate the intermittency of the wind, pumping when the wind output is high and generating when the wind output is low. However, the variations in the wind output are far greater than the capacity of the pumped storage, so interconnectors and gas-fired generation are called to meet demand at times of low wind output, as can be seen in the period between 15th and 22nd of the month when the pumped storage is mainly used to deal with the diurnal demand rising and falling. By the 27th the wind output has been low for long enough for the model to conserve the remaining water – although rising wind output on 28th and for the remainder of the month means that the pumped storage is able to pump continually.

These charts illustrate just a particular month and while they serve to illustrate the complex dynamics of the system on an hour by hour basis, wider reaching conclusions need to take a view over a longer timescale. In the next Chapter we show average annual statistics for the system when taken over eight years' wind patterns.

[This page is intentionally blank]

5. COMPARISONS BETWEEN PORTFOLIOS

5.1 Introduction

Earlier in 2009, we developed a new economic model of the future power systems in the island and GB. It included an analysis of the behaviour of wind farms in both systems, and provided for the first time a view on the likely market prices, power station profitability and plant operating regimes with large amounts of wind generation.

We have used the same modelling platforms to compare the six portfolios outlined in Chapter 4 from a variety of different viewpoints.

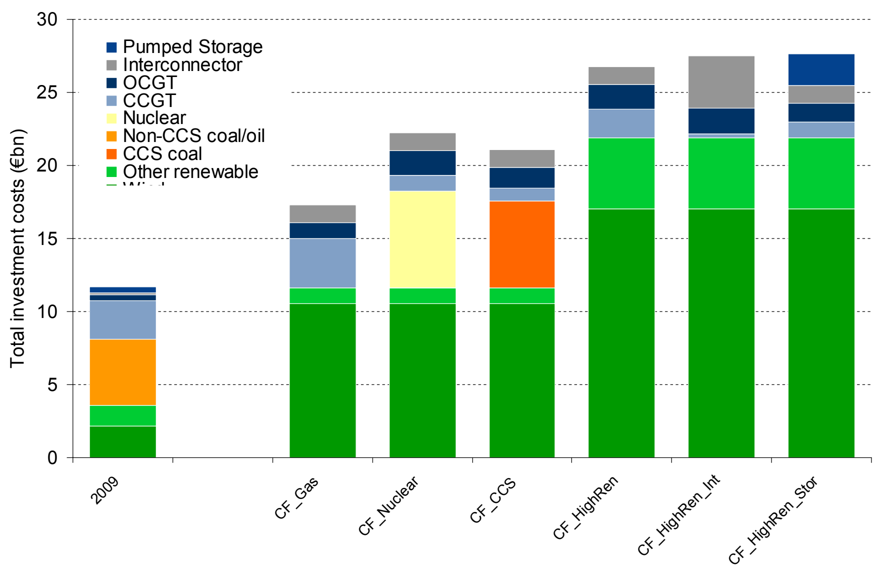
The analysis presented in this Chapter focuses on a generation portfolio for 2035 and excludes onshore transmission and distribution costs and also excludes CO_2 transport and storage costs. Likewise we exclude the costs of possible transmission constraints in recognition that the network would have developed accordingly.

5.2 Generation costs

Figure 21 below shows the total capital costs at today's money of each of the portfolios, and compares the current generation portfolio on the island on the same basis[12].

The figure illustrates the greater capital costs of higher renewables penetration. In relative terms, we would add that all six portfolios would be characterised as relatively capital intensive as we would expect from systems with a high proportion of renewables.

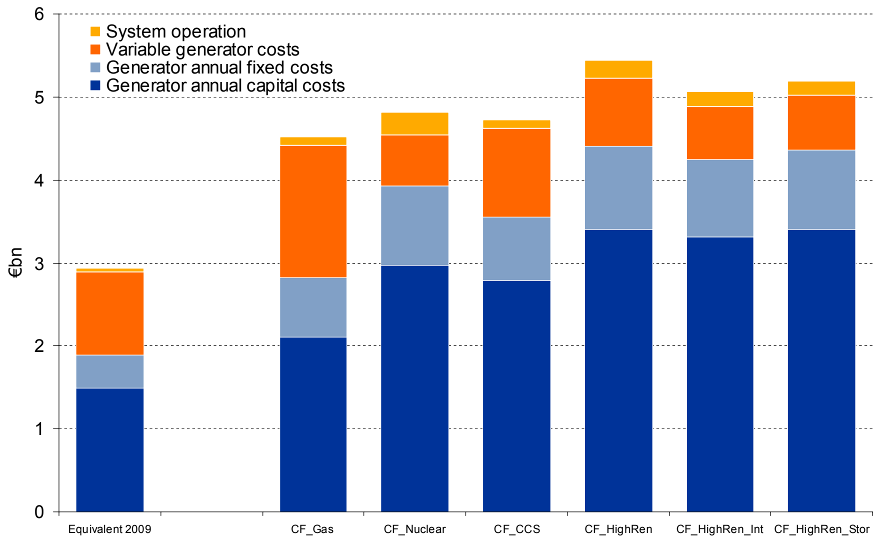
Figure 21 – Total capital investment



12 For the 2009 equivalent we have assumed that all generating units have an associated capital cost, based on our assumptions for capital investment, economic life and discount rate. This enables us to compare the costs more effectively with the 2035 portfolios.

Figure 22 below shows the portfolios in terms of their annual generation costs, including the amortised capital. These are broken down into the four main components: capital, fixed annual costs, variable costs (which include fuel), and system operating costs. Each of these elements make a material contribution to the overall cost of running the system, and the Figure serves well to illustrate their economic character. We are grateful to EirGrid for its advice for the system operation costs (which include reserve).

Figure 22 – Annualised generation costs (central fuel basis)



We have used our view on appropriate discount rates and economic lifetimes to make this comparison, and details are contained in the Annex. Different views of discount rates and economic lifetimes would change the picture somewhat, but we believe that the comparison in Figure 22 is realistic and appropriate.

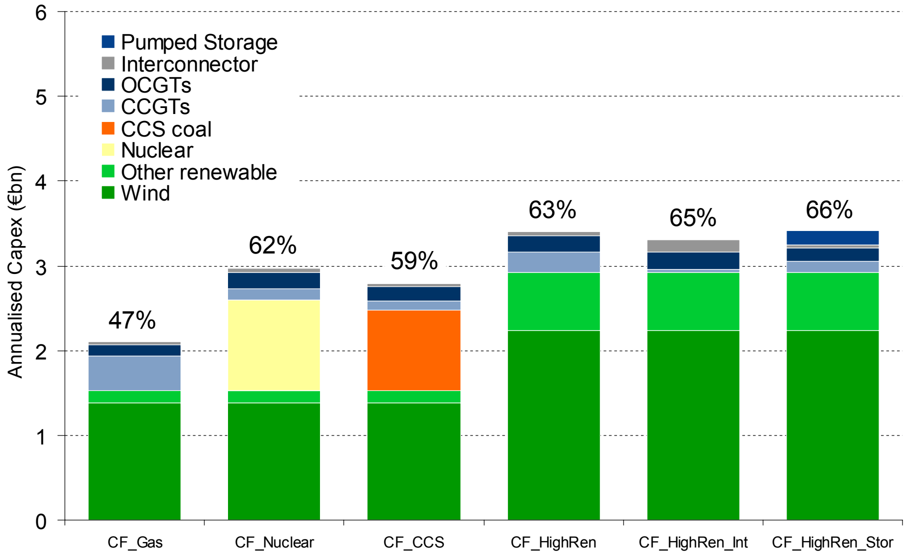
The fixed annual costs include all elements of the generator operation which are not strictly related to running hours i.e. network charges, staff salaries, statutory maintenance, rates, insurance, market operator charges.

Despite the higher capital costs of the higher renewables portfolios their lower variable costs considerably reduce the overall difference between their total annualised costs – a picture emerges of them all being quite close.

It is also notable that even in the higher renewables portfolios, there remains a considerable variable cost – largely associated with gas-fired generation, biomass or interconnector flows.

Figure 23 below shows how renewables constitute the largest component of the annualised capital costs.

Figure 23 – Renewables capital costs dominates all scenarios' annualised costs

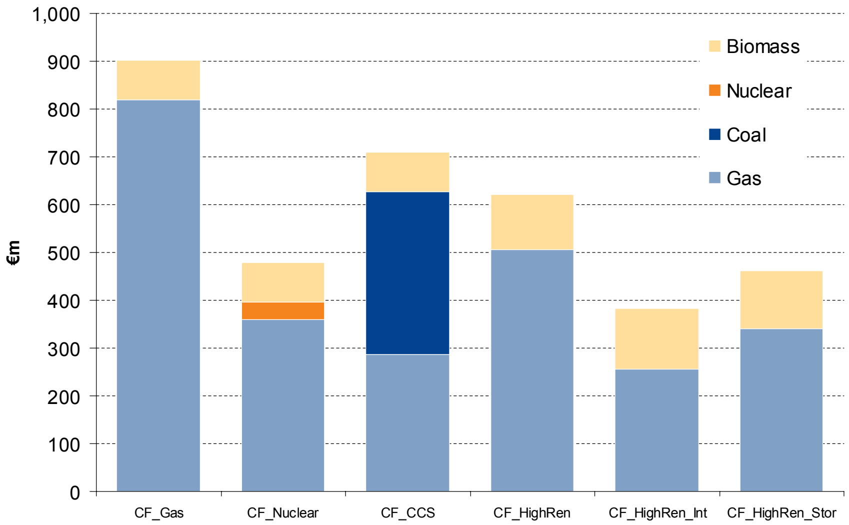


* Label shows the annualised capital costs as a percentage of total generation costs

The variable costs are primarily made up of two components: fuel and interconnector flows.

Figure 24 below examines the make up of the fuel costs (these include EU ETS carbon allowances). As might be expected, gas is the largest component in all portfolios apart from the Coal CCS portfolio; however it is also clear that all three high renewables scenarios still need considerable amounts of gas.

Figure 24 – Proportions of components of the fuel costs



Interconnectors effectively reduce the amount of physical generation plant needed on the island, but the part that they play in the system is highly complex. Figure 25 shows the gross position based on market price and volume.

Figure 25 – Interconnector costs for the portfolios

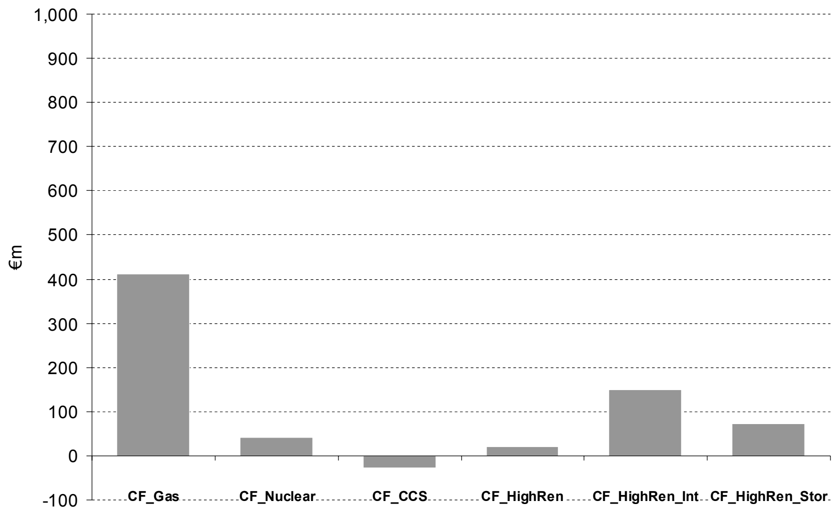
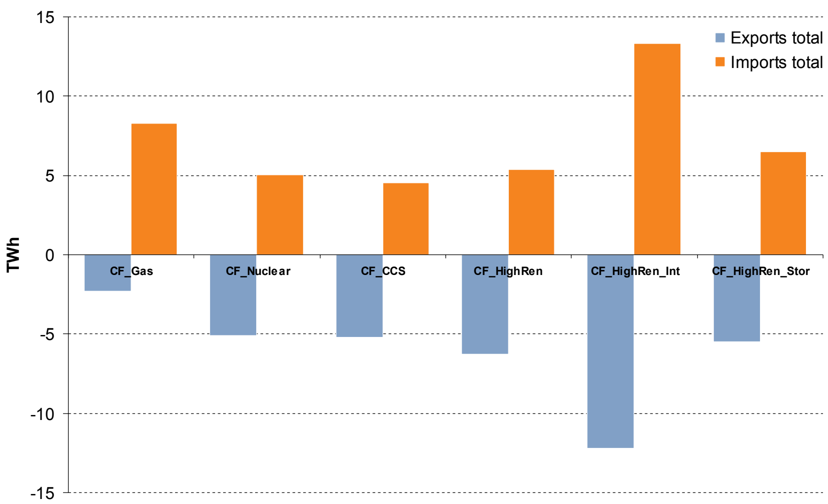


Figure 26 below shows the gross physical interconnector flows for each portfolio; there is significant interconnector use in all portfolios.

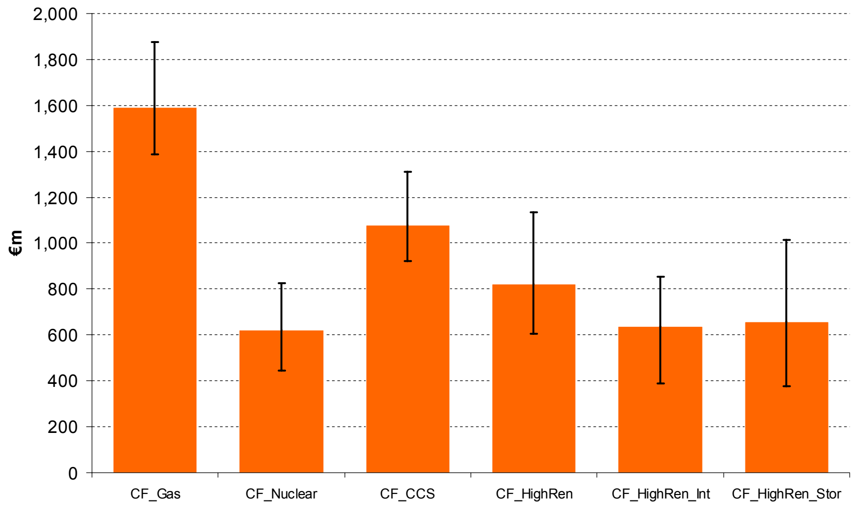
Underlying these flows is a picture of the island being a net exporter at times of high wind or low demand, but an importer at times of low wind or high demand. The financial consequences of these situations are asymmetric because market prices tend to be lower when the interconnectors are exporting but higher when importing (and often at prices set by the GB market).

Figure 26 – Gross physical interconnector flows



Two factors can significantly impact the variable costs of the system: wind and gas prices. All the views above are based on an averaging of all eight year's wind, but in practice there is a considerable year on year variability. Figure 27 shows how the total system costs range across the eight years.

Figure 27 – Impact of wind variability on total system variable costs



However, to understand the drivers behind this picture, it is important to separate out the two parallel components of gas costs and interconnector costs. Figure 28 below shows the range of fuel costs and Figure 29 shows the range of interconnector costs. In a high wind year the net interconnector costs actually become negative in all portfolios except the gas i.e. there is a net export of power in value terms, but in a low wind year the net annual costs of the interconnector flows are approximately €200m greater because of greater imports.

Figure 28 – Impact of wind variability on fuel costs

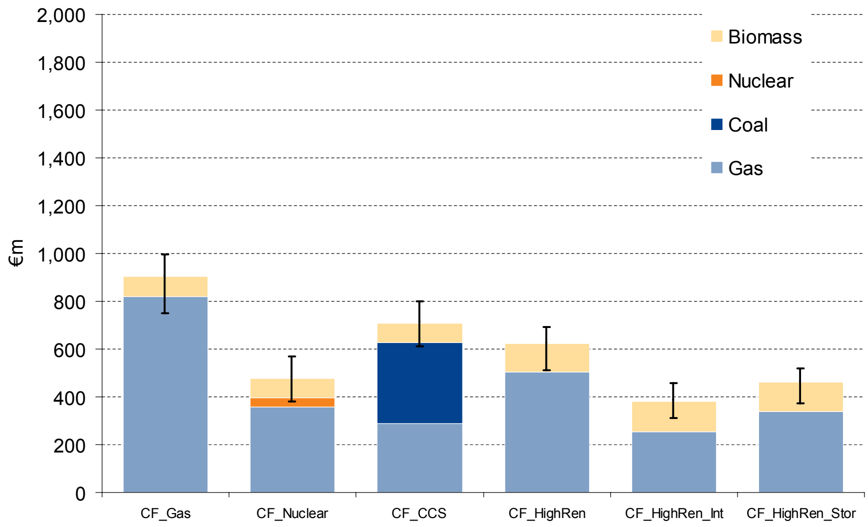
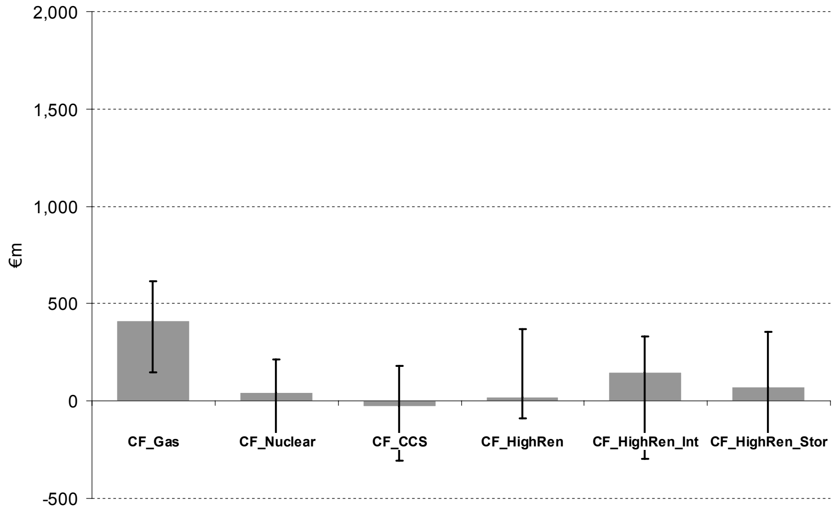
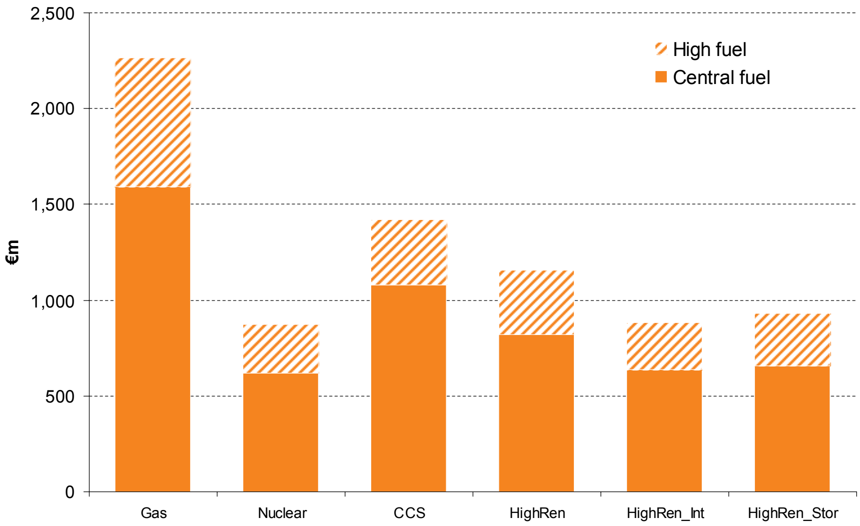


Figure 29 – Impact of wind variability on interconnector costs



Each of the portfolios is impacted by higher gas prices in very different ways. Figure 30 below shows our analysis of the variable costs in the high fuel cost scenario. While changes to the gas market price directly affect the variable costs of the gas-fired plant, they also have an indirect impact through the interconnectors. Higher gas prices disproportionately affect market prices in the GB market, which means that the higher cost of imports to the island are much greater than the value of exports.

Figure 30 – Impact of higher gas prices



5.3 Market prices

While the above section has described the *costs* of each of the portfolios, the *market prices* that they set are somewhat different. Figure 31 below shows the SEM generation-weighted average annual wholesale prices[13] produced by each portfolio; in contrast to the pattern in Figure 22, the portfolios with a higher proportion of renewables (with their lower variable generation costs) typically set lower market prices. In the high interconnection scenario we observe the impact of greater exposure to the GB market prices, and hence observe somewhat higher prices.

Figure 31 – Wholesale market prices

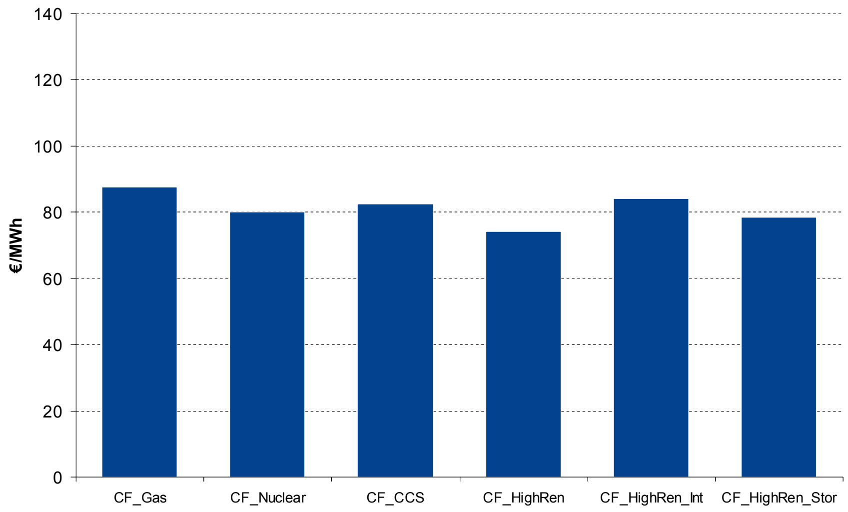
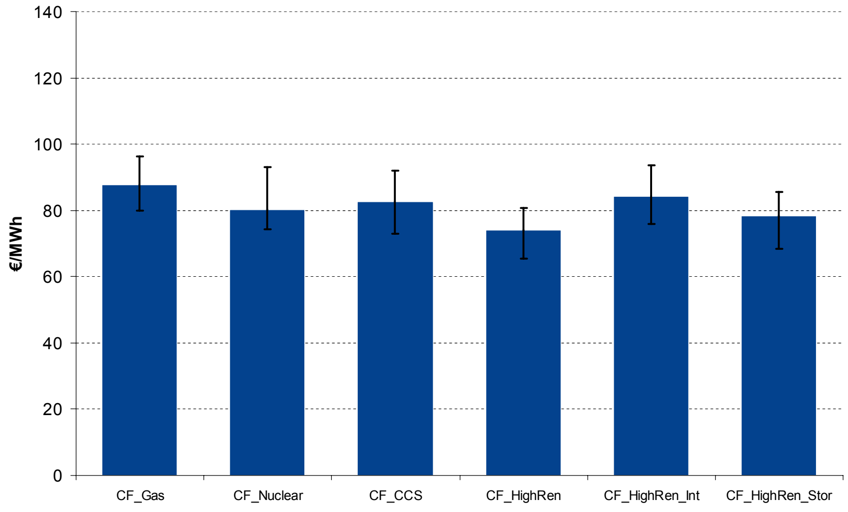


Figure 32 and Figure 33 show the susceptibility of the wholesale prices to wind variability and higher gas prices respectively. The relativity of the levels of prices is not altered by the variation in wind despite the higher proportion of wind generation in all three high renewables scenarios.

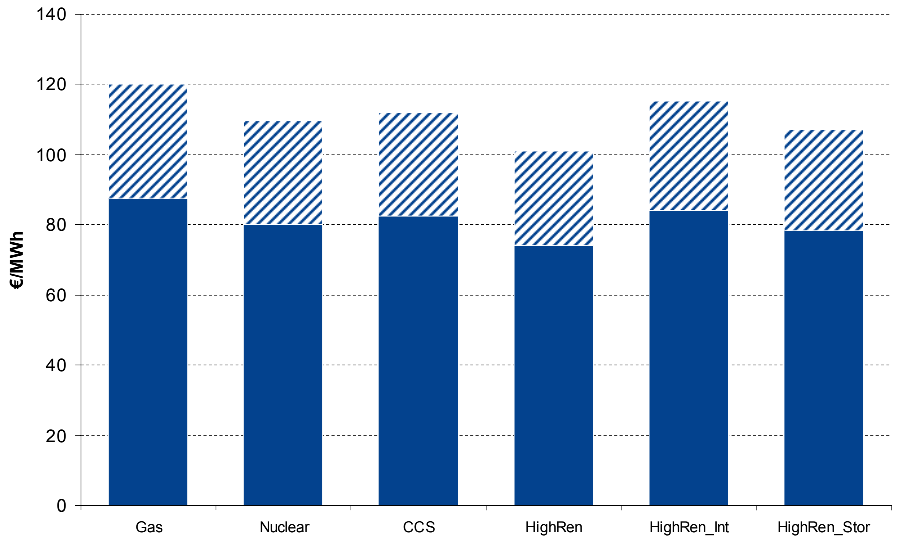
13 i.e. It covers all generator SMP revenues and capacity payments weighted by SEM electricity generation.

Figure 32 – Impact of wind variability on wholesale market prices



The full bars in Figure 33 show the wholesale prices with our central gas price scenario, and the shaded bars show the higher wholesale prices in our high gas price scenario. All scenarios show similar variation, which is basically a result of gas-fired plant setting the market price on the island for a large proportion of the time, as well as in the GB market.

Figure 33 – Impact of high fuel prices on wholesale market prices

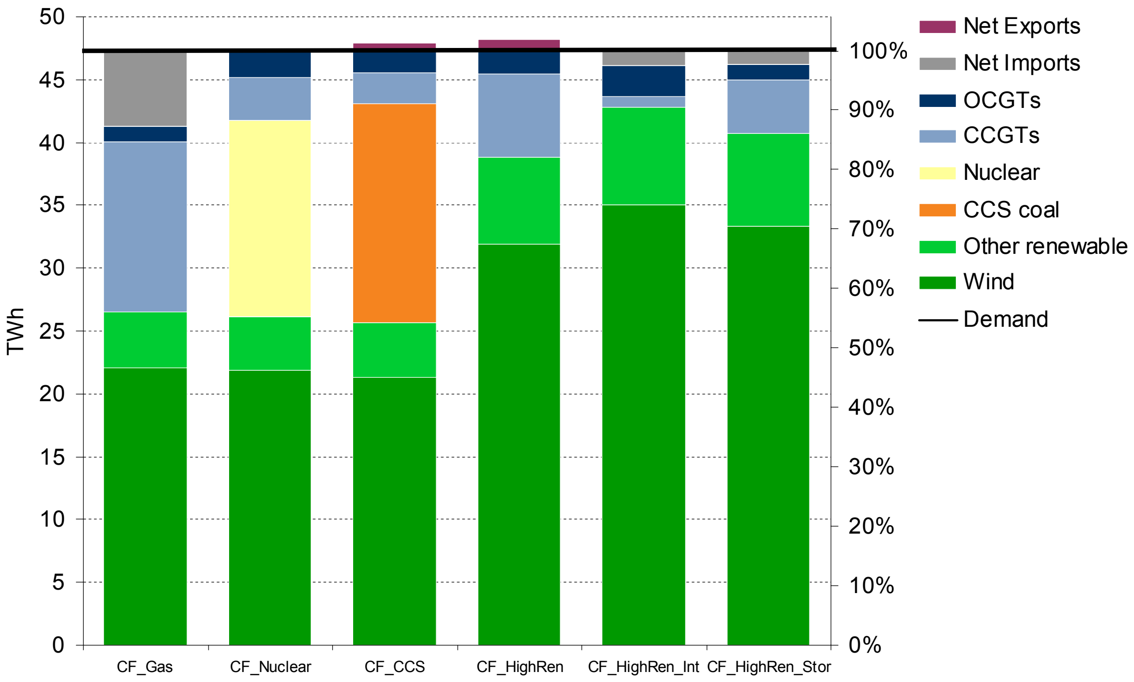


At the start of this work, we had thought that the high renewables portfolios would have a reduced exposure to volatile gas market prices, but perhaps at the cost of being more exposed to the vagaries of the wind. This does not seem to be the case: the high renewables portfolios exhibit similar exposure to gas market and wind output at the others. This may be because in relative terms, all these portfolios have a high proportion of wind generation, and equally gas-fired generation features significantly in all of them.

5.4 Generation components

Figure 34 below shows the generation output of each of the scenarios. To simplify this diagram we show the net interconnection flow, recognising that underlying the net position is a large amount of import and export in all the scenarios.

Figure 34 – Generation by type



While the gas portfolio has the highest dependency on imported gas, with the exception of the 'high renewables with interconnection' portfolio, gas-fired generation still represents a considerable proportion in all of them. When the slight capacity differences of the nuclear plant and the CCS plant in their respective scenarios is taken into account, the amount of gas-fired generation in these two is close.

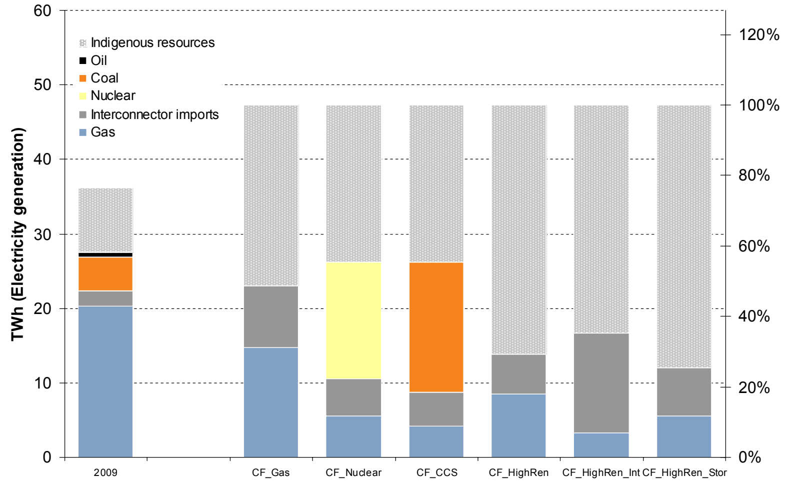
5.5 Reliance on imported energy

One aspect of the generation portfolio we wished to explore is the degree to which they reduce the island's dependence on imported fuels. Figure 35 below shows this picture compared to now. We recognise that some of the gas may be supplied from Irish gasfields, but for simplicity show the total amount.

In general, regarding issues of security of supply, coal and nuclear are relatively secure because the fuel can be relatively easily stockpiled to provide at least some months' supply. Taking just gas and interconnector imports shows how all portfolios feature reliance on import-sourced electricity to a significant degree.

Nevertheless the nuclear and CCS portfolios do have by far the lowest reliance, and the gas portfolio the highest. All three of the high renewables portfolios have lower reliance than the gas portfolio, but they are relatively close to each other.

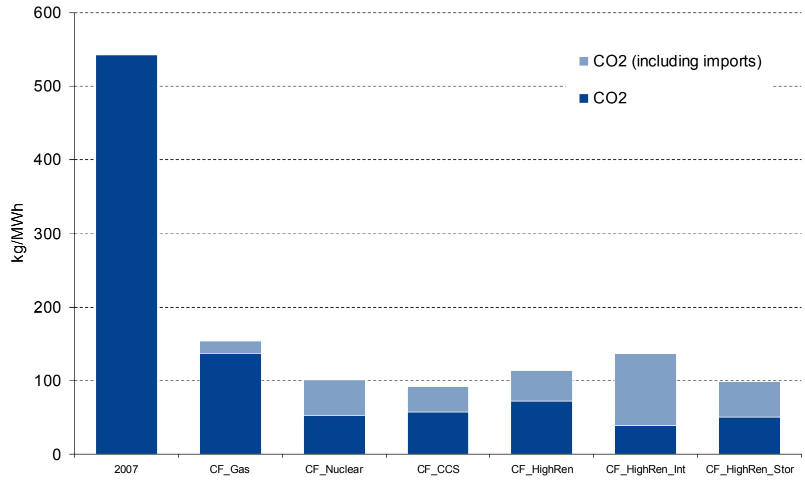
Figure 35 – Amounts of imported energy



5.6 Environmental Performance

Figure 36 shows the carbon intensities that each portfolio produced; each one is shown on a standalone basis as well as with interconnector (basing interconnection imports on the likely situation of CCGT being the marginal plant in GB and France[14]).

Figure 36 – Carbon intensities



14 For the purposes of this analysis we draw on our general experience that for the majority of times, the marginal plant in both the GB and the North-West continental markets is likely to be CCGT. In other words, we base our analysis that marginal changes in the island are reflected in marginal changes in the other two markets.

This picture shows a generic problem with the gas portfolio: while all the other portfolios have standalone carbon intensities well below the target assumed in this report, the gas portfolio is well above it. When interconnector volumes are included only two portfolios, the CCS and the High Renewables-High Storage are below 100g/kWh.

5.7 System operational issues

The system operator dispatches conventional generation over time to meet changing demand and to manage changing power sources such as hydro and wind. For simplicity, we can categorise three types of conventional generation. Base-load plant is typically on-load 24 hours a day; mid-merit plant runs during daytime to meet the higher demand and can operate more flexibly to manage daily variations in demand; finally there is peaking plant which may run for only a few hours per day at times of highest demand but can respond quickly to demand changes. In building of the portfolios, we have been cognisant for the need for a balanced portfolio of the generation types that is appropriate for each portfolio.

As well as capacity and energy to meet demand, there are additional support services required to ensure a safe and secure power system such as frequency response, load following capability, fast-acting power reserves to manage loss of generation, voltage support, short-circuit current and inertia. Mostly these services are provided by generators but interconnectors, network devices and demand can also contribute to them. These issues are outside the scope of this report.

Introduction of a large single power source relative to the system size and/or the increasing amounts of intermittent, decentralised generation will impact on a wide range of power system issues including system dynamics, power quality, and short circuit levels. It is likely that the All-Island system will be the first to encounter these issues and will have to overcome them through a combination of innovations in system operation and operational experience of these conditions over time. These complex issues are not studied in this work. However, in our costing of the different portfolios, we do recognise that the grid may need to carry different levels of spare capacity to cater for the uncertain output of the generating plant – in exactly the same way that happens now. Typically the system operator manages the system to maintain frequency and voltage over various time horizons, ranging from fractions of a second to minutes and hours – and this is often done by carrying ‘spare’ plant on the system which is part-loaded. We have taken advice from EirGrid on these complex issues to add additional costs of providing system support for different portfolios.

5.8 Deployment paths

This section outlines our thinking on the potential issues of deployment that arise in moving from where the island's portfolio is now towards those described in this report.

Nuclear

We have outlined earlier in this report that nuclear plant in Ireland will need law change and public acceptance in order to proceed. Even if these obstacles are been overcome there will also be significant lead times that will be needed for planning and construction. In essence, nuclear plant on the island will require setting up a complete new 'industry' – oversight bodies, constructors, as well as operations.

Furthermore, in practice a decision to go down this route by definition means a moratorium on construction of other power stations, particularly those which would run at baseload (as they would become redundant when the nuclear stations are built). In our opinion, given this level of commitment, it suggests that a 'halfway house' situation is untenable – in other words, any move in the direction of the nuclear portfolio will also need to be done wholeheartedly. For these reasons there is a large project risk associated with the Nuclear option.

Without being prescriptive, we would suggest that if a nuclear plant is to start operating on the island by 2035, the process of communicating information, public debate and policy formation should be starting now, and that further delays will simply push back on a possible future commissioning date.

CCS

While Carbon Capture and Storage as a process appears to be promising, it is not commercially proven, and until full storage site characterisation has been carried out question marks must remain about the suitability of this option for the island.

Given the progress in Europe and elsewhere, there are clear prospects for many of the technical and commercial issues surrounding CCS to be resolved in the next ten years. There is a real danger that construction of a new coal-fired power station before then would simply leave a legacy of an unabated coal station with many years of operational life ahead of it.

In the light of this it probably would make sense to reconsider CCS when the performance of demonstration plants becomes evident.

Gas

Gas-fired plant, both CCGT and OCGT can be deployed relatively quickly – it is not unknown for plant to be running within a couple of years of financial commitment. In terms of deployment, therefore, the gas portfolio has considerable flexibility. This flexibility might be further enhanced if more gas storage options were available.

We note that the carbon intensity of this portfolio is somewhat above our self-imposed target of 100g/kWh and raises the question 'Is this a potential dead end?' In our opinion this is not necessarily the case: in the longer term, older gas-fired could be phased out and the portfolio is shifted towards the higher renewables end of the spectrum; the possibility of retrofitting the gas plant with carbon capture and storage may also become clearer over time.

Renewables

Other than the market implications of renewables described in this report, the deployment of renewables is unlikely to be constrained by the industry with the exception of the marine technologies which have not yet reached commercial deployment.

Where there are conflicts with environmentally sensitive land use, there can be considerable delay – the pumped storage schemes may fall into this category. It may well be prudent to consider a lead time of ten years for public acceptance for this.

Interconnectors

Interconnectors can be delivered reasonably quickly in the context of 2035 and towards the middle of the century, although this is to some extent constrained by the willingness of organisations in the other country.

Mutual exclusivity

While this report does not specifically address issues of deployment, the question arises as to at what point the pathway to them becomes mutually exclusive?

As the discussion above shows, in some cases, considerable lead times are required to allow nuclear and coal-CCS to be viable options. In the case of nuclear this probably needs to start soon to be in place for 2035.

However, in more general terms, the point at which clear choices need to be made is not until the 2020s, and pursuit of the deployment of renewables to the levels in current policy to meet the 2020 renewables directive would not rule out any of the portfolios described in this report.

In the longer term there will reach a point in the evolution of the generation portfolio on the island which firmly points towards a certain direction.

This is likely to be most marked for the nuclear direction where even the signalling of the clear intent to explore nuclear plant will be, de facto, signalling a direction away from CCS-coal and may well delay any gas plant investments.

5.9 Energy costs for end users

Based on our modelling of the wholesale prices, we have estimated the equivalent energy costs for end users (excluding networks charges, and therefore not directly comparable to household bills) as shown in Figure 37 below. The wholesale price paid by end users covers the payments made to generators in the SEM[15] and a small premium to cover higher costs of the domestic demand profile.

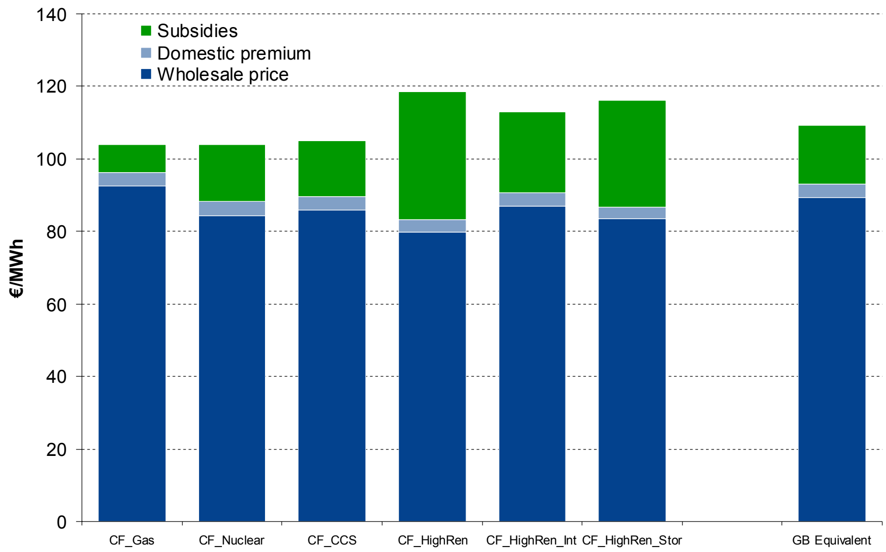
In order to calculate the energy costs for end users, we also need to add the likely renewable support costs. In order to do this we make the assumption that all types of generation plant need to earn at least compensatory levels of return; for renewables, where this level is not met by their income from the electricity market, we have assumed that this additional income would be funded by support mechanisms. We adopt a similar methodology for nuclear and CCS, though proportionally much smaller subsidies are required.

---

15 I.e. It covers all generator SMP revenues and capacity payments weighted by electricity demand.

While there is not a substantial variation between them in each portfolio, the three high renewables portfolios are somewhat higher because the non-market subsidies for low carbon plant more than offset the lower wholesale prices.

Figure 37 – Residential retail prices



The GB prices reflect a somewhat higher wholesale price in general, but a lower renewables support cost per unit as a result of the cost differentials between GB offshore wind in relatively shallow water and the portfolios of renewables we have considered.

6. CONCLUDING REMARKS

The aim of our report was to examine the possibility, and then the consequences, of the island moving its electricity sector dramatically towards decarbonisation – to the levels being suggested by many leading environmentalists and policy makers.

Generating technologies already exist that individually meet these targets, but this report has examined how they might fit together and the natural consequences of dealing with wind's intermittency and other system limitations.

To some extent we have made some large simplifications: our analysis is based on the system demand having the same characteristics as today, and is based more or less on generating technologies available today, with the exception of CCS and the marine technologies. It does, however, properly account for the way in which the wind behaves and the way in which the GB market will interact through the interconnectors. While costs are an important part of the analysis, our calculations are based on experience of working with investors in many countries and while there may be some uncertainty about the absolute level of costs we have far greater confidence in the relative costs between the different technologies.

It is not the purpose of this report to suggest an ideal portfolio – indeed, the analysis suggests that all of them have their merits. Nevertheless, we believe that there are some important observations to be had.

- Significant emissions reductions[16] can be achieved with all portfolios compared to the present day portfolio, and they represent feasible points on a trajectory towards carbon neutrality by the middle of this century.
- Recognising that the *Gas* portfolio is the most likely outcome of the current policies, we observe that although it has lowest costs, it suffers from the highest reliance on gas and has the highest emissions (in fact it could not meet our 100g/kWh target). While not a sustainable solution in itself, any trajectory towards this portfolio could be considered as a transitional step towards other lower emission options and carbon neutrality by 2050.
- The *Coal CCS* portfolio exhibits the lowest overall emissions. However, Coal CCS is not a proven commercial technology and it is expected that it will be at least 2018 before plants become commercially available. Even then, suitable local sites for storage must be located. Coal CCS stations have high project risk associated with them because of new technology development issues.
- The *Nuclear* portfolio exhibits low emissions similar to the Coal CCS portfolio but would have high project risk associated with it because of public acceptance issues and the complexity of the overall project. The construction of a green-field nuclear power station is a complex process, with long lead times required for resolving public

[16] There is uncertainty as to how emissions will be attributed to imports and exports. In this report, we have assumed that renewable energy exports do not count to the islands renewable energy targets. Imports are assumed to come from a system where gas-fired CCGTs are the marginal units and thus have carbon associated with them. This is a conservative approach but we consider it appropriate while there is uncertainty over the rules that apply to interconnector trading of renewable energy.

acceptance issues and policy decisions. A domestic nuclear regulatory and supporting industry would have to be established. Commercially available nuclear stations are large for the size of the island's power system and we have assumed that a high system cost is required to integrate nuclear generation. More detailed technical feasibility studies and a full project risk review would be needed to develop this option. Nuclear could be re-examined in a different light at a future date if smaller nuclear generators become commercially available.

- The *high renewables* options can meet very low emission targets and reduce the net amount of energy imports but they have higher capital costs. All of these portfolios require more capital investment than the thermal portfolios because:
  - There is a requirement to maintain conventional backup capacity for managing renewable intermittency; and,
  - There are high costs for achieving higher renewable penetrations (because of the need to develop offshore wind, marine and biomass generation as well as potentially higher system costs);
- Further Interconnection helps integrate the island with the British and Continental European systems. This aids renewable integration and helps the island benefit from combined regional advantages. It will also tend to bring wholesale prices on the island in line with those across the region and therefore contribute to competitiveness.
- Storage, by itself, is insufficient to manage intermittent renewable generation because of its power and energy constraints but it can make a contribution towards managing intermittency as part of a portfolio with interconnection and flexible generation. There are also capital cost, environmental and technical issues that need to be examined further to develop this concept.
- All portfolios are susceptible to price volatility due to the significant amounts of gas-fired generation and due to large amounts of wind generation in each portfolio with the inherent annual variations in wind patterns.
- All portfolios have higher capital costs and lower running costs relative to today. While this drives down market prices, generators may not earn sufficient income in the market to cover their costs. This suggests that market design changes or price support mechanisms may be required to encourage investment in new low carbon generation.

It seems that almost inevitably electricity systems are subject to many forces, sometimes opposed, and sometimes reinforcing. In our experience each country and each market also carries its own unique identity, be those its geography, or its natural resources, or its politics.

In this regard the island of Ireland is no different to elsewhere. Our experience suggests that consideration of the long term outlook can often put into perspective short term issues, and we hope that the deeply analytical and quantitative material in this report will enrich the many current debates on the island's electricity future.

ANNEX A – DATA TABLES

A.1 Technology assumptions

Table 1 – Selected assumptions for different technologies

Cost assumptions	Capital Costs (€/kW)	Discount rate[17]	Economic lifetime (years)
CCGT	750	10%	20
LMS100	600	10%	20
OCGT (gas)	500	10%	20
OCGT (gasoil)	500	10%	20
Conventional coal	1450	10%	20
Coal CCS	2200	12%	20
Nuclear	3000	12%	25
Onshore wind	1050	10%	20
Offshore wind	2150	12%	20
Biomass	2150	12%	20
Wave	3500	12%	20
Tidal	3450	12%	20
Interconnector	1200[18]	6%	40
Pumped storage	1200	11%	30

[17] Real pre-tax project hurdle rate

[18] Total capital cost, in our modelling we assume Ireland pays for 50% of this figure

A.2 Fuel scenarios

Table 2 – Fuel and carbon price assumptions in 2035

Cost assumptions	Price (Central)	Price (High)
Oil[19]	$80/barrel	$127/barrel
Gas[20]	58p/therm	88p/therm
Coal[21]	$70/tonne	$100/tonne
Carbon	€40/tonne	€60/tonne

A.3 Portfolios

Table 3 – SEM capacity assumptions (Data from Figure 18)

		Gas	Nuclear	CCS	High Ren	High Ren (Int)	High Ren (Stor)
Capacity (MW)	2009	2035	2035	2035	2035	2035	2035
Wind	1.5	7.9	7.9	7.9	12.5	12.5	12.5
Other renewables	0.6	0.5	0.5	0.5	1.7	1.7	1.7
Nuclear	0.0	0.0	2.2	0.0	0.0	0.0	0.0
CCS Coal	0.0	0.0	0.0	2.7	0.0	0.0	0.0
Non-CCS coal/oil	3.2	0.0	0.0	0.0	0.0	0.0	0.0
CCGT	3.5	4.5	1.6	1.2	2.6	0.4	1.4
OCGT	0.7	2.0	2.9	2.6	3.0	3.1	2.3
Interconnector	0.5	2.0	2.0	2.0	2.0	5.0	2.0
Pumped storage	0.3	0.2	0.2	0.2	0.2	0.2	2.0

19 Brent crude

20 GB NBP

21 ARA CIF

Table 4 – GB capacity assumptions

Capacity (GW)	2009	2035
Wind	4.1	28.1
Other renewables	8.1	21.8
Nuclear	10.0	8.0
CCS Coal	0.0	8.8
Non-CCS coal/oil	30.1	1.7
CCGT	27.0	36.1
OCGT	1.2	2.0
Interconnector	2.5	5.0
Pumped storage	2	1.8

A.4 Results

Table 5 – Total capital investment (Data from Figure 21)

€bn	Gas	Nuclear	CCS	High Ren	High Ren (Int)	High Ren (Stor)
CCS coal	0.0	0.0	5.9	0.0	0.0	0.0
Nuclear	0.0	6.6	0.0	0.0	0.0	0.0
CCGT	3.4	1.1	0.9	2.0	0.3	1.1
OCGT	1.1	1.7	1.4	1.7	1.7	1.3
Wind	10.6	10.6	10.6	17.0	17.0	17.0
Other renewable	1.0	1.0	1.0	4.9	4.9	4.9
Interconnector	1.2	1.2	1.2	1.2	3.6	1.2
Pumped Storage	0.0	0.0	0.0	0.0	0.0	2.2

Table 6 – Annualised generation costs, Central fuel (Data from Figure 22)

€bn	2009	Gas 2035	Nuclear 2035	CCS 2035	High Ren 2035	High Ren (Int) 2035	High Ren (Stor) 2035
Generator annual capital costs	1.0	2.1	3.0	2.8	3.4	3.3	3.4
Generator annual fixed costs	0.4	0.7	1.0	0.8	1.0	0.9	1.0
Variable generator costs	1.5	1.6	0.6	1.1	0.8	0.6	0.7
System operation	0.1	0.1	0.3	0.1	0.2	0.2	0.2

Table 7 – Fuel costs, Central fuel, (Data from Figure 24)

€m	Gas	Nuclear	CCS	High Ren	High Ren (Int)	High Ren (Stor)
CCS Coal	0	0	340	0	0	0
GasOil	5	5	6	5	7	6
Gas	820	359	287	505	256	340
Nuclear	0	37	0	0	0	0
Biomass	83	82	83	116	126	121

Table 8 – Interconnector costs, Central fuel, (Data from Figure 25)

€m	Gas	Nuclear	CCS	High Ren	High Ren (Int)	High Ren (Stor)
Net Interconnector costs	412	42	-28	22	149	73

Table 9 – Gross physical interconnector flows, Central fuel, (Data from Figure 26)

TWh	Gas	Nuclear	CCS	High Ren	High Ren (Int)	High Ren (Stor)
Total imports	8.3	5.0	4.5	5.4	13.3	6.5
Total exports	2.3	5.1	5.2	6.3	12.2	5.5

Table 10 – Generation by type, Central fuel, (Data from Figure 34)

TWh	Gas	Nuclear	CCS	High Ren	High Ren (Int)	High Ren (Stor)
CCS coal	0.0	0.0	17.4	0.0	0.0	0.0
Nuclear	0.0	15.7	0.0	0.0	0.0	0.0
CCGTs	13.5	3.4	2.5	6.7	0.9	4.3
OCGTs	1.2	2.1	1.8	1.8	2.5	1.3
Wind	22.1	21.8	21.3	31.9	35.0	33.3
Other renewable	4.5	4.3	4.3	6.9	7.8	7.4
Net Imports	6.0	0.0	0.0	0.0	1.1	1.0
Net Exports	0.0	0.1	0.7	0.9	0.0	0.0

Table 11 – Residential retail prices (Data from Figure 37)

€/MWh	Gas	Nuclear	CCS	High Ren	High Ren (Int)	High Ren (Stor)	GB Equivalent
Wholesale price	92.4	84.2	85.8	79.7	87.1	83.4	89.3
Domestic Premium	4.0	4.1	3.9	3.6	3.7	3.3	3.8
Subsidies	7.7	15.8	15.4	35.2	22.3	29.4	16.2
Total	104.1	104.1	105.1	118.6	113.1	116.1	109.3

[This page is intentionally blank]

ANNEX B – METHODOLOGY

B.1 Overview of methodology

The modelling outputs outlined in this report have come through a four stage process.

1. Portfolio construction;
2. Capital cost assumptions
3. Market modelling; and
4. Results comparison against a number of metrics.

B.2 Portfolio construction

The theme of each generation portfolio was decided through discussion between EirGrid and Pöyry. As described in Chapter 4, we developed the 2035 portfolios with an aim of reducing carbon towards a level of 100g/kWh and assuming that renewable growth would remain a strong policy driver.

In each portfolio, we initially determined the generating capacity of the individual technology that was the focus of the portfolio, together with the level of renewables capacity. The intention was to maximise the differences between portfolios and push the boundaries of renewable development, while remaining realistic about likely technologies and the impact they would have on the electricity system.

Additional capacity required to meet the Loss of Load Expectation (LOLE) constraint within the model was provided by adding CCGTs, advanced OCGTs, OCGTs running on gas, and OCGTs running on distillate to the capacity mix. The level of capacity from each technology choice was dependent on the level of plant generation and projected plant revenues.

B.3 Capital cost assumptions

For each generation technology, we used the cost assumptions for each technology shown in Table 1 to calculate an annualised capital cost. The assumptions used are Pöyry estimates for the capital costs of each type of generator technology together with an appropriate discount rate and economic lifetime for the type of technology. We have assumed no major reduction in costs for newer technologies, due to the uncertainty of future development.

B.4 Zephyr model structure

The projected revenues and variable costs for each portfolio in 2035 were determined using our *Zephyr* electricity market model. The model simulates the dispatch of each unit on the GB and the combined Ireland/NI systems for each hour of every day – a total of 8760 hours per year. The model is based on a mixed-integer linear programming platform. This allows us to optimise to find the least-cost dispatch of plant accounting for fuel costs, the costs of starting plant and the costs of part-loading, in aggregate. For example, it may mean that the model will reduce the output of wind generation to avoid shutting down a nuclear plant and incur the cost of restarting it later. The model also accounts for minimum stable generation and minimum on and off times, which allows more realistic operational simulation of plant such as large coal or nuclear sets that, once running, must remain on for a certain number of hours, or, once shut down, cannot restart for a long period.

For the year that was modelled (2035), nine iterations are carried out, which represent the wind, availability and demand for the historical years 2000 - 2008. This means that for any given future year, a total of 78,840 prices are created (8760 x 9), giving a good representation of possible interactions between wind, availability and demand. The prices that result from the model are the result of the interaction of supply and demand in any given hour.

The model optimises the use of pumped storage across each month, so that it generates when prices are high and pumps when prices are low. The model also accounts for interconnection between GB and the island of Ireland, so that flows between the two countries are optimised. Interconnection flows between GB and Continental Europe are modelled with an hourly price profile of the Continental countries, based on the underlying commodity values and prices from our pan-European Eureca model.

Generation from wind is based on actual hourly wind speeds at 35 locations across the UK and the island of Ireland plus an offshore site using 'reanalysis' of wave data, which are converted to generation using an aggregated power curve.

Figure 38 – Overview of Zephyr model framework

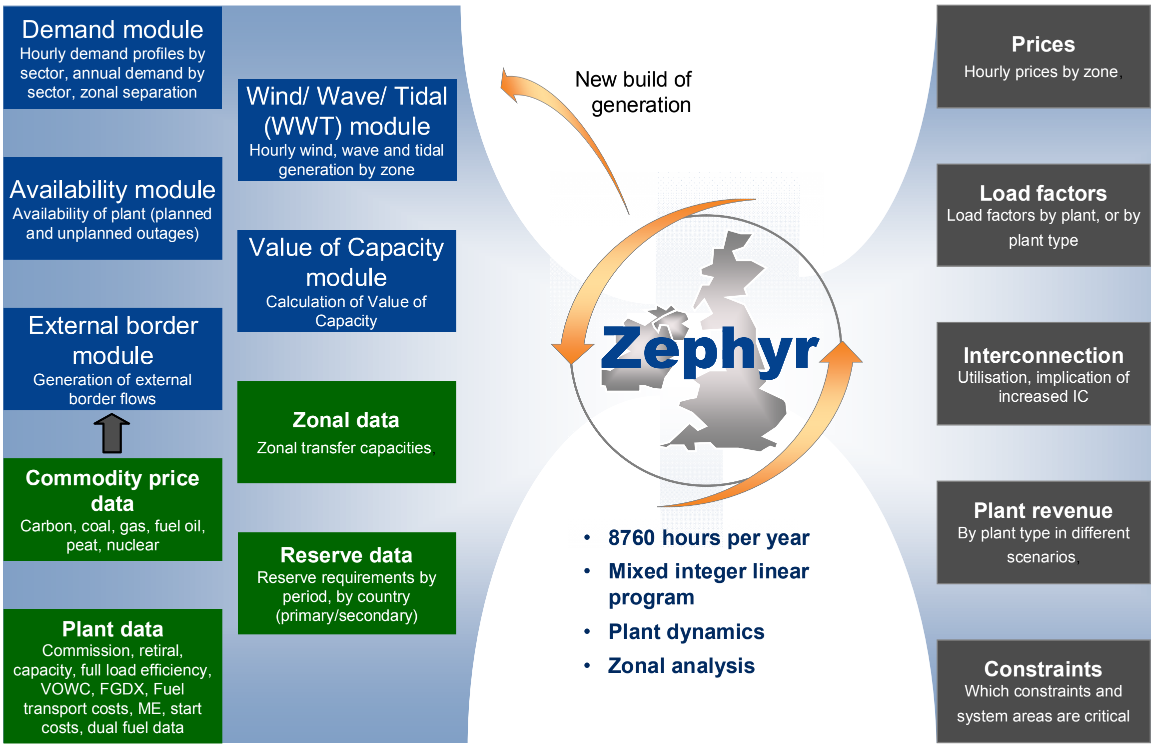


Figure 38 above illustrates the model structure. The inputs to the model can be classified under the following headings:

- demand and availability;
- wind, wave and tidal;

- commodity prices; and
- plant data.

B.5 Comparison of results

B.5.1 Generation Costs

For each portfolio, the annual capital costs, the variable costs from *Zephyr*, assumptions for plant fixed costs[22], and non-locational system costs were combined to calculate to the total annual generation cost for comparison.

Variable costs were also calculated based on high fuel costs (as opposed to Central) and high and low wind profiles (as opposed to an average of the 8 historical years in Zephyr) to enable us to evaluate the impact on total generation costs in these scenarios.

B.5.2 Plant generation and market prices

Zephyr optimises the generation of plant to produce the lowest cost generation schedule across GB and the island of Ireland. This enables us understand the likely running regime of each technology type, based on their short-run variable costs.

Annual wholesale market prices[23] were established by adding the System Marginal Price (SMP) to our estimate of the capacity value. These prices were calculated for each of the modelled portfolios.

B.5.3 Plant revenues and required subsidies

The high capital cost of a number of the technologies meant that not all plants were able to recover their capital costs by relying on revenues from the energy market (SMP and capacity payment). We assumed that these plants received additional subsidies to support capital investments and achieve the rate of return given in Table 1. The additional cost has been added to the end user price for comparison.

B.5.4 Emissions data

Emission data was from generation according to in-house emissions factors, including starts and part loading. Imported power was assumed to have emissions based on a CCGT plant, while exports were assumed to be wind and have no associated emissions.

---

22 The annual costs of a plant that are not related to the initial capital cost and are not affected by the level of generation.

23 Average wholesale prices were calculated on a demand-weighted average (DWA) basis.

[This page is intentionally blank]

QUALITY AND DOCUMENT CONTROL

Quality control		Report's unique identifier: 2010/085
Role	Name	Date
Author(s):	James Marshall Kapil Kulkarni	22 February 2010
Approved by:	Phil Hare	22 February 2010
QC review by:	Beverly King	22 February 2010

Pöyry is a global consulting and engineering firm.

Focusing on the energy, forest industry, water and environment, transportation and construction service sectors, Pöyry employs over 7,500 experts globally and has annual net sales of over €800million.

Pöyry PLC is listed on NASDAQ OMX in Helsinki.

Pöyry Energy Consulting is Europe's leading energy consultancy providing strategic, commercial, regulatory and policy advice to Europe's energy markets. The team of 250 energy specialists, located across 15 European offices in 12 countries, offers unparalleled expertise in the rapidly changing energy sector.

Pöyry Energy Consulting
King Charles House
Park End Street
Oxford, OX1 1JD
UK

Tel: +44 (0)1865 722660
Fax: +44 (0)1865 722988
www.ilexenergy.com
E-mail: consulting.energy.uk@poyry.com

Pöyry Energy (Oxford) Ltd, Registered in England No. 2573801
King Charles House, Park End Street, Oxford OX1 1JD, UK

www.poyry.com