



THE VALUE OF WIND ENERGY TO IRELAND

A report to Irish Wind Energy Association

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Front Cover Photo:
Entrant from Jack Brett to the IWEA Global Wind Day 2013 Photo Competition

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EXECUTIVE SUMMARY

Context and purpose

The Irish government has set a target of meeting 40% of electricity demand from renewable sources by 2020, as part of its obligation under the EU Renewable Energy Directive to source 16% of all energy consumed in the country from renewable sources. Northern Ireland (NI) has adopted the same 40% target for electricity and so significant growth in renewables across the Single Electricity Market (SEM) of the Island of Ireland is expected in the coming years.

The vast majority of the renewable electricity requirement is expected to be met through the development of indigenous wind power as Ireland has a strong wind resource potential, with one of the best onshore wind speed averages in Europe. The wind capacity installed on the island of Ireland as of the 10 March 2014 was 2632MW, meeting around 18% of SEM demand. Construction of another 2,600MW will be needed to meet the 2020 target and there is sufficient wind resource on the island of Ireland to more than double this capacity to deliver projects to export wind directly to GB.

While Europe has no clear target for renewable energy after 2020 it is clear that Ireland's development to deliver the 2020 commitment will mean the sector is well positioned to continue to grow through the 2020s with sufficient resource to meet any required renewable energy target.

Such a fundamental shift in the generation mix will not only have direct effects on the electricity market, but will have wider impacts on the economy. The aim of this study is to assess the overall economic impact of planned wind penetration on energy prices and macroeconomic performance in Ireland. To achieve this aim, the Irish Wind Energy Association (IWEA) commissioned Pöyry Management Consulting (Pöyry) and Cambridge Econometrics (CE) to examine different future pathways for wind development in Ireland combining Pöyry's detailed SEM market modelling and CE's macroeconomic modelling.

Wind Scenarios

To assess the economic impact of wind energy in Ireland, we have considered three distinct scenarios of wind capacity deployment on the island of Ireland and GB (see Table 1).

- **No Wind Effort (Post 2014) (No Wind)** is our baseline scenario in which no further wind development occurs in SEM beyond that which is already assumed to be under construction through to the end of 2014. GB continues wind deployment but does not meet its 2020 renewable target until 2025.
- **Domestic Wind Scenario (Domestic)** delivers sufficient wind capacity to meet the RoI and NI 2020 renewable targets. Wind capacity continues to grow through to 2030 proportionally with demand growth. GB continues wind deployment but does not meet its 2020 renewable target until 2025.
- **Export Wind Ambition (Export)** assumes domestic renewable targets are met as in the *Domestic Wind* scenario, and enables GB to hit its 2020 target through export wind capacity constructed in RoI.

Because of the nature of the SEM, each scenario defines wind penetration in both RoI and NI alongside GB renewable generation trends. It is important to consider deployment in GB because interconnection can have a material impact on observed prices in the

SEM. For detailed information on the split in capacity development between RoI, NI and GB see Annex B.1.5.

Table 1 – Wind capacity deployment in each scenario (GW)

	2012		2020		2030	
	SEM	GB	SEM	GB	SEM	GB
No Wind Effort (Post 2014)	2 GW	9.8 GW	2.4 GW	17.5 GW	2.4 GW	25 GW
Domestic Wind Scenario	2 GW	9.8 GW	5.2 GW	17.5 GW	7.9 GW	25 GW
Export Wind Ambition	2 GW	9.8 GW	5.2 GW	22 GW	7.9 GW	34 GW

Note: *Export Wind Ambition* builds wind capacity in RoI directly connected to GB market. This chart focuses on wind capacity on the island of Ireland (SEM) but the report focuses on the economic benefit of wind development in Ireland only.

Delivering Domestic Wind Scenario

A vibrant, growing, wind energy sector

In RoI, meeting the 2020 renewable target will see the wind sector more than double in size, adding just over 2.2 GW from the installed wind capacity at the end of 2012 to reach 3.8 GW by 2020. This sustained growth will see around 270MW of new capacity annually. Annual investment to 2020 of over €430m (1.2% of total Irish Investment) will support 12,390 jobs (person-years¹) during wind farm development and will support 920 permanent jobs in the O&M sector to support windfarms by 2020.

These figures translate to an estimated 5.74 direct jobs created per MW of wind capacity installed in the *Domestic* scenario plus 0.242 O&M permanent jobs per MW of cumulative capacity. In the absence of clear 2030 targets we assume wind capacity growth in Ireland slows in our *Domestic Wind Scenario* in the decade to 2030 while still capitalising on its development of a robust wind sector up to 2020 and maintaining Ireland’s commitment to a renewable and low carbon future with an additional 1.7GW of capacity. This growth supports a further 10,120 jobs (person-years) during development and construction and expands the O&M sector to support 1,340 permanent jobs by 2030.

Limited impact on consumer bills

The growth in wind generation will alter the generation mix in the SEM and the network infrastructure required to accommodate. We would expect this to be reflected in observed wholesale prices and in consumer bills. What we find are two effects lower wholesale prices and higher system costs which broadly offset each other to result in minimal impact on final consumer bills.

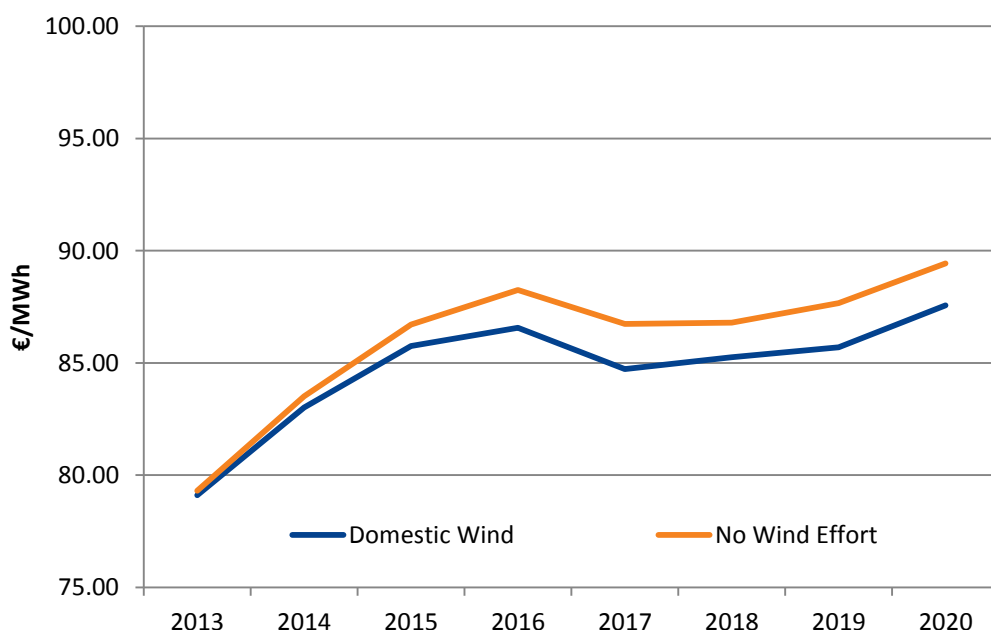
¹ Measured in person-years required to support planned growth in wind capacity with the assumption that one person-year is equivalent to one job

Wholesale prices

Our analysis shows that as Ireland deploys wind capacity to meet 2020 targets the wholesale price will fall by €2/MWh by 2020 compared with our baseline *No Wind Effort* scenario (see Figure 1). The price reduction is driven by the increased contribution from wind generation towards meeting energy demand, which replaces more expensive generation options, reducing the short run cost of system operation. This is commonly referred to as the merit order effect of wind.

Some studies have suggested that the merit order effect of wind could be even higher, but this outcome depends on the effect of interconnection with GB. Interconnection with GB dampens market price differentials, reducing the merit order effect of wind on SEM prices.

Figure 1 – SEM supplier wholesale price (€/MWh)



Note: includes System Marginal Price (SMP) and the capacity charge paid by suppliers

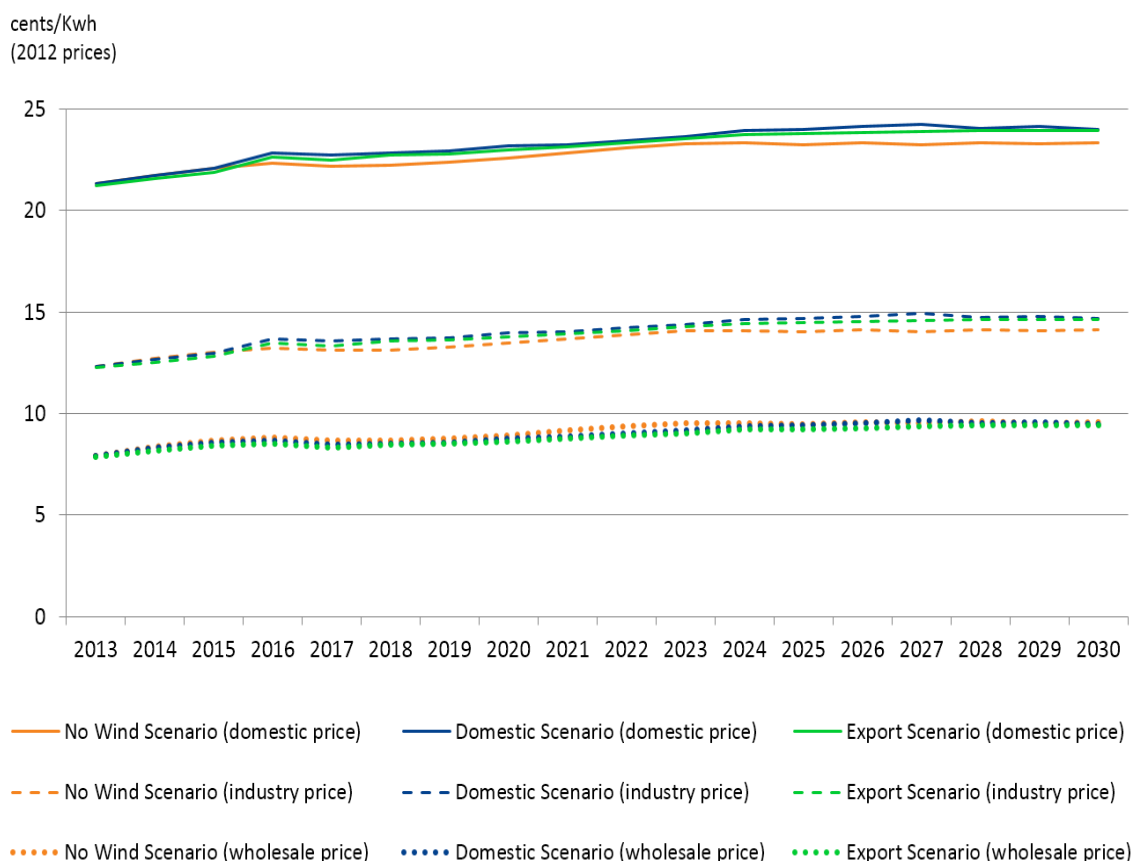
The carbon price has emerged as a key assumption impacting interconnector flows and SEM electricity prices. In our analysis we assumed a high carbon price differential emerges between SEM and the GB market as a result of the UK Government's planned trajectory for the carbon price floor (€90/tCO₂ by 2030) while SEM follows the IEA's central view for an EU carbon price (€30/tCO₂ by 2030). This underlying difference changes the magnitude and direction of interconnector flows as trades over the interconnector look to take advantage of wholesale electricity price differentials. Our modelling showed that this impact prevents the SEM wholesale price from falling as much as it would do from wind deployment if there was no carbon price difference between the markets. A narrower differential in carbon price between the two markets, as examined in our carbon sensitivity analysis, lowered the SEM wholesale price by a further 9% in 2020 relative to the *No Wind* scenario (see Annex B.8).

Retail prices

The reduction in wholesale prices will feed directly through into consumer bills. However, the overall impact on bills is limited as the bills reflect the impact of more wind generation on other system costs. Potential back-up requirements to maintain security of supply are already incorporated in wholesale prices. The additional costs are related to grid reinforcement and DS3 costs. It is not transparently clear what proportion of EirGrid’s planned investment in the electricity network is required solely for the development of wind capacity. Nor has it been determined how the system services outlined under the DS3 program will be paid for. But if all of these are passed through to consumers, they offset the wholesale price benefit, meaning household and industrial electricity prices rise slightly (see Figure 2).

While consumer bills may not fall as a result of meeting our 2020 target, the net benefits of wind development to GDP and economy wide employment levels as discussed below, results in an increase in household incomes suggesting that investment in a domestic Irish wind industry will not be carried by consumers.

Figure 2 – Industry and household electricity prices, 2013-2030



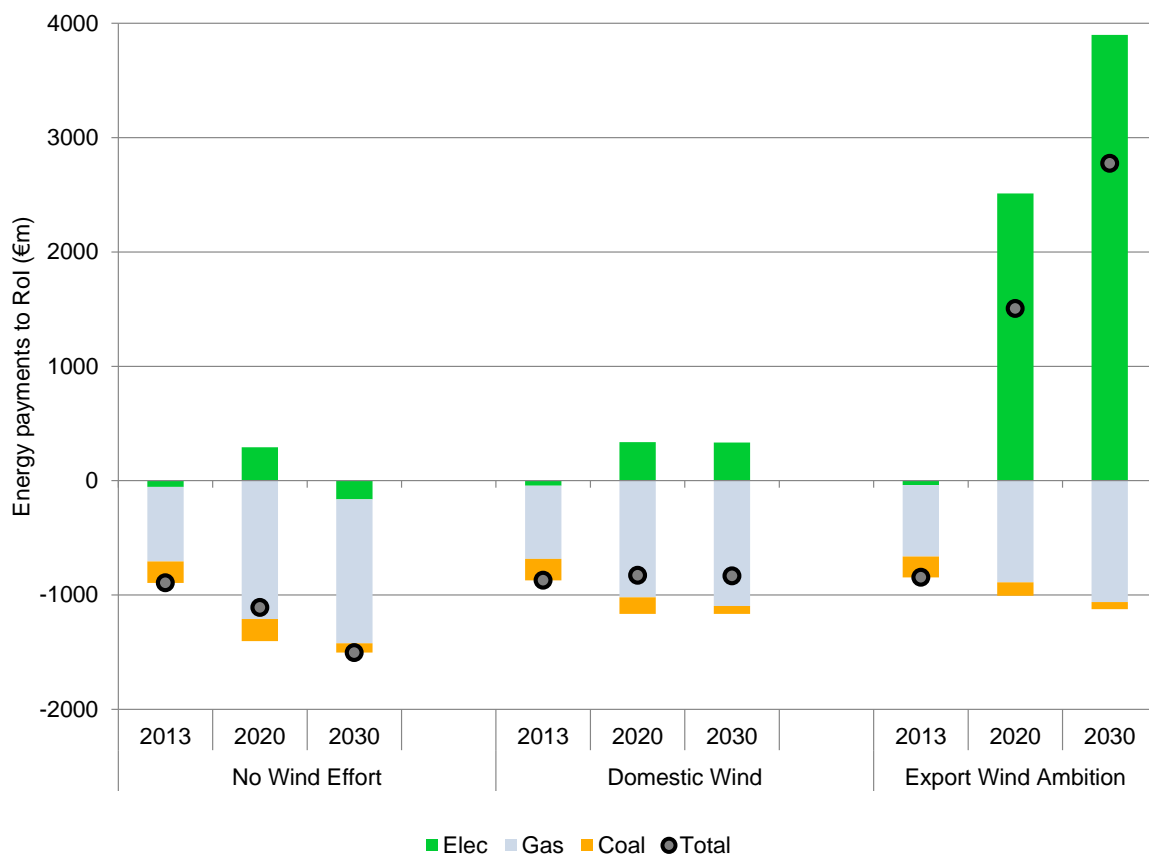
Improvement in the energy balance of payments

According to figures just published in February 2014 from the EU statistics agency Eurostat, Ireland ranks in the bottom 4 of the most energy dependent countries in the

EU28, trailing only behind Malta, Luxembourg and Cyprus. An energy dependence rate of 85% sees Ireland lagging 32% off the EU average of 53%. In contrast, Denmark, which has one of the highest wind penetrations in Europe, was the only EU net exporter of energy. The additional domestic wind capacity deployed in the *Domestic* scenario reduces annual gas imports by 15% relative to the *No Wind* scenario in 2020 and 2030. This not only contributes to security of supply but also results in a net transfer to the Irish economy, through a reduction in the energy import bill.

In our *No Wind* scenario, annual energy imports of coal, oil and gas will rise from €900m in 2013 to €1,100m in 2020 and €1,500m in 2030 (see Figure 3). Meeting 2020 targets in the *Domestic* scenario reduces dependence on these imported fuels, preventing this bill rising over time. This reduction in fuel imports not only benefits security of supply but also creates a net transfer to the Irish economy with the energy import bill falling by €282m in 2020 and saving almost €671m of expenditure on fuel imports per annum by the time we reach 2030.

Figure 3 – Rol balance of energy payments by type (€m)



Net economic benefits to the Irish economy

The major capital investment associated with the wind deployment programme (€3.5 billion) over the period to 2020 and €4.8 billion thereafter, together with the net transfers from the balance of payments, add an indirect stimulus to the Irish economy that increases total GDP, raises overall economy wide employment levels and delivers an impetus to disposable income.

An increase in wind investment in the RoI could create substantial benefits for associated industries, as well as increases in gross sector employment. Additional investment would lead to an increase in output and jobs in the planning and construction of new turbines, as well as permanent jobs in the operations and maintenance of these turbines.

Macroeconomic modelling using Cambridge Econometric's E3ME model shows the following net economic benefits:

- under this scenario, the model predicts annual GDP will increase by between €350m and €490m per annum, depending on how the investment is financed;
- overall economy wide employment levels rise by between 1,150 and 1,800 jobs per annum; and
- real household disposable income rises by €9 per annum to 2020.

Continued growth in wind capacity through to 2030 in our *Domestic* scenario reinforces the trends observed in the period to 2020, and total investment of €4.8 billion over the period 2021-2030 produces further gains:

- under this scenario, the model predicts annual GDP will increase by between €646m and €769m per annum, depending on how the investment is financed;
- overall economy wide employment levels rise by between 1,600 and 2,300 jobs per annum; and
- real household disposable income rises by €12 per annum to 2030.

The wind sector would also contribute in total €160m over the period 2013-2020 to government revenue through business rates with contributions from the sector continuing to grow through the 2020s with increasing wind deployment, reaching, on average, €57m annually over the period 2021-30.

By 2030, additional cumulative tax revenue could reach €1.8 billion in the *Domestic* scenario and €8.4 billion in the *Export* scenario, which is equivalent to 1% of current Irish government debt in the *Domestic* scenario and 4% of Irish government debt in the *Export* scenario. The increase in labour demand results in a fall in unemployment of 2,160 in the *Domestic* scenario and 9,840 in the *Export* scenario by 2030. This could reduce unemployment benefit payments by as much as €21m in the *Domestic* scenario and €96m in the *Export* scenario by 2030², and further relieve the strain on government debt.

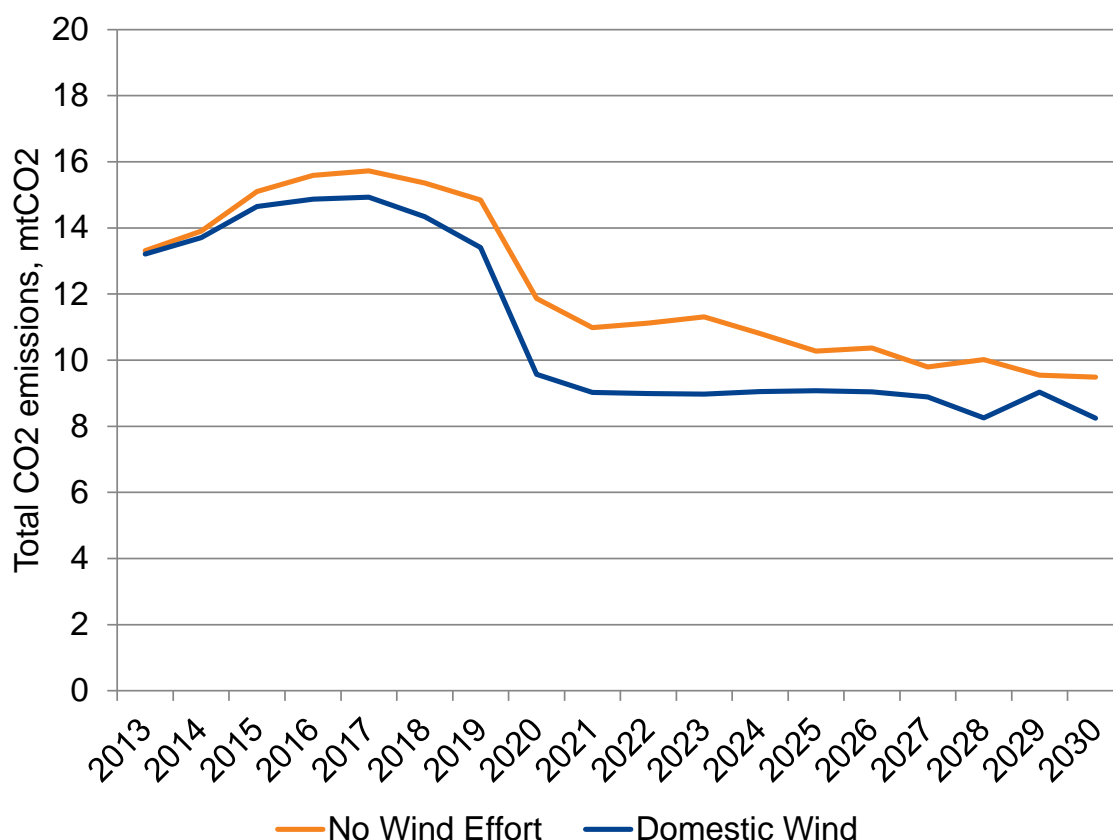
Maintains government commitment to addressing climate change

With no further renewable deployment the RoI power sector will still lower its total emissions (see Figure 4) from 13.5MtCO₂ in 2013 to 11.5MtCO₂ in 2020 due to the replacement of coal with gas from the generation output mix. However, by pursuing a domestic wind deployment programme much more substantive cuts can be made in power sector emissions with emissions falling to 9.5MtCO₂ by 2020. Emission benefits appear to decline between 2020 and 2030, but this is because RoI becomes more reliant on fossil fuel based generation imports in our *No Wind* scenario.

² Based on estimated reduction in unemployment of 2,158 in 2030 (compared with *No Wind* scenario) and average weekly unemployment payment of €188 per week, see: <http://www.welfare.ie/en/Pages/Jobseekers-supports.aspx>

There may be financial penalties imposed by the EU Commission on member states for failing to meet their 2020 renewable target. Although no formal infringement penalties have been associated with missing the targets, a recent referral of RoI to the European Court of Justice for failing to fully transpose into Irish law the Renewable Energy Directive could be an indicator of further penalties to come. Delivering the *Domestic* scenario mitigates this risk offering further economic benefit.

Figure 4 – Total RoI power sector emissions (tCO₂)



Export Ambition

Such is the potential of Ireland’s wind energy that the country could meet its domestic renewable target and also develop wind capacity directly for a new major export market. As proposed export projects to the UK would be financed by GB, the full benefit of this investment would be felt by the Irish economy. We have examined this under our Export Wind Ambition scenario.

The *Export* scenario changes the renewable capacity in the GB market and this has an impact on prices in SEM. The wholesale price in our *Export* scenario will fall by €1/MWh by 2020 compared with our *Domestic* scenario with a marginal price benefit in 2030 (see Figure 1).

If Ireland commits to allowing the industry to develop the capacity to export electricity to GB the wind capacity constructed in Ireland could more than double, dramatically increasing employment in the sector driven by high levels of foreign direct investment in

the Irish economy. To achieve the export ambition, we assume investment of €16.6 billion is required from 2013-20 and €14 billion from 2021-30. These values represent 5.5% and 3.2% of overall Irish investment.

During the development and construction phase of the export wind project, the number of jobs created in the wind sector could reach 47,240 by 2020, on a person-year basis. The net impact on GDP over the period 2021-2030 could be €5 billion higher on average, provided GB finances this capacity fully via CfDs.

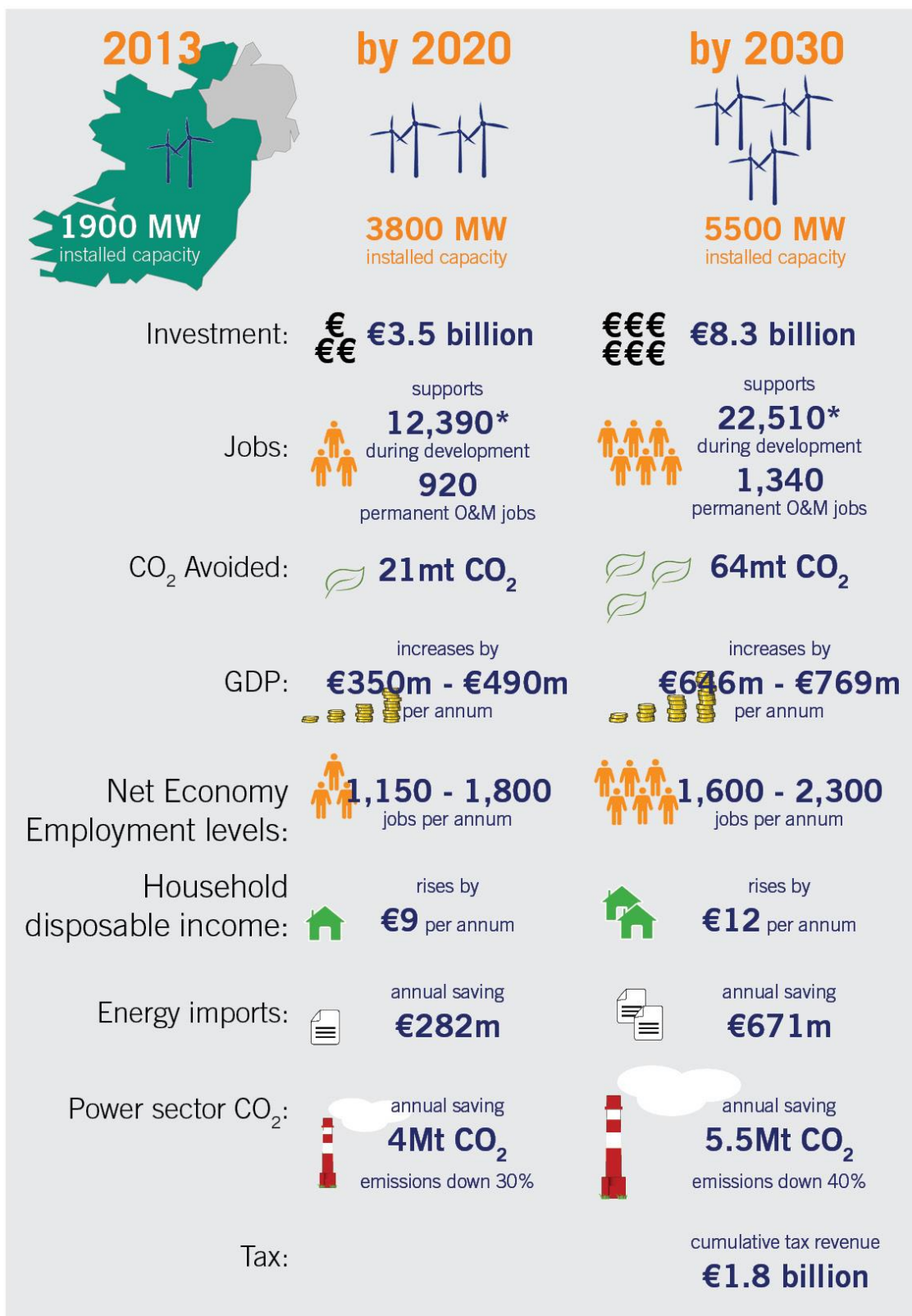
There is a large potential swing in the balance of energy payments in the *Export* scenario with RoI transforming from a net importer to a net exporter of energy within the electricity sector as shown in Figure 3. By 2020 RoI could net export €1.5B annually rising to €2.8B by 2030.

Summary messages

Ireland currently imports 85% of its energy requirement, one of the highest ratios in Europe. There is an opportunity to develop a strong indigenous wind industry that will take advantage of Ireland's excellent wind resource reducing this import dependency while maintaining the Irish government's commitment to addressing climate change and delivering net benefits to the Irish economy (see Figure 5). Headline benefits include:

- The growth of the wind sector does not place a material burden on the Irish consumer as the energy bills are comparable across scenarios and disposable income increased.
- The wind sector could support 22,510 jobs (person-years) during wind farm development and an O&M sector that employs 1,340 by 2030. The level of employment in the Irish economy rises by between 1,150 and 1,800 jobs per annum in the period to 2020 and by between 1,600 and 2,300 per annum thereafter to 2030.
- If Ireland chose instead to build no more wind, then by 2030, we would be reliant on natural gas for most of our electricity generation, paying out €671m more per annum in fuel import costs. By maximising indigenous resource to meet renewable energy obligations, import dependency is reduced improving the security of supply and improving the energy balance of payments boosting the overall economic performance in terms of jobs and GDP.
- Ireland can contribute to a more cost effective delivery of EU climate goals by exporting to UK. This has no adverse impacts on the domestic economy and represents a major FDI stream that can boost jobs and GDP and establish a scale of activity more capable of supporting a larger domestic supply chain.
- The generation output of wind in Ireland is projected to double to 10TWh by 2020 in our *Domestic* scenario doubling the annual carbon emissions avoided and displacing over 21mtCO₂ up to 2020, a 35% increase over our *No Wind* scenario. Over the period 2021-30 over 43mtCO₂ is avoided totalling 64mt CO₂
- Wind growth supports €3.5 billion of direct investment to 2020, 1.2% of total Irish investment, and an additional €4.8 billion to 2030 totally €8.3 billion.
- By 2030, additional cumulative tax revenue could reach €1.8 billion in the *Domestic* scenario and €8.4 billion in the *Export* scenario. The increase in labour demand results in a fall in unemployment of 2,160 in the Domestic scenario and 9,840 in the Export scenario by 2030. This could reduce unemployment benefit payments by as much as €21m in the Domestic scenario and €96m in the Export scenario by 2030.

Figure 5 – Delivering a vibrant wind sector in Ireland



Note: *Measured in person-years required to support planned growth in wind capacity.

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1. INTRODUCTION

1.1 Background

At present, the majority of the electricity produced in Ireland (RoI) is from imported fossil fuels. The government has a target (as part of its obligation under the binding EU directive which set a target for Ireland to source 16% of its energy from renewable sources) to deliver 40% electricity from renewable sources by 2020. Because of its abundant natural resource, the majority of this is expected to come from wind and there is a healthy pipeline of projects that could see Ireland not only meets its domestic targets but create a significant export market for renewable power.

The focus of this report is to answer the question, **what is the economic impact of continuing to deploy wind generation at scale both to meet domestic needs and to realise Ireland's export ambition?**

To answer this question requires a combination of detailed assessment of the electricity market price effects and the wider macroeconomic impacts in terms of jobs and growth. In this study we use Pöyry Management Consulting (Pöyry) and Cambridge Econometrics (CE) modelling to address both questions.

Pöyry takes a fundamental market modelling approach to assess the impact of wind development in Ireland in the SEM and GB electricity markets. To undertake the analysis, we used our internally developed market model, **BID3**. BID3 is an economic dispatch model based around optimisation. The model balances demand and supply on an hourly basis by minimising the variable cost of electricity generation. The result of this optimisation is an hourly dispatch schedule for all power plant and interconnectors on the system. It takes account of all network infrastructure costs and ensures the security of supply standard is maintained.

CE use their **E3ME** model of Europe's economies, energy systems, and the environment to assess the impact of changes to the energy market on the wider Irish economy. The economic structure of E3ME is based on the system of national accounts, as defined by ESA95 (European Commission 1996), with further linkages to energy demand and environmental emissions. The economic model includes a full set of macroeconomic feedbacks at the sectorial level that capture supply chain impacts and multiplier effects. The model contains a total of 33 sets of econometrically estimated equations, covering the individual components of GDP (consumption, investment, and international trade), prices, the labour market, energy demand and materials demand.

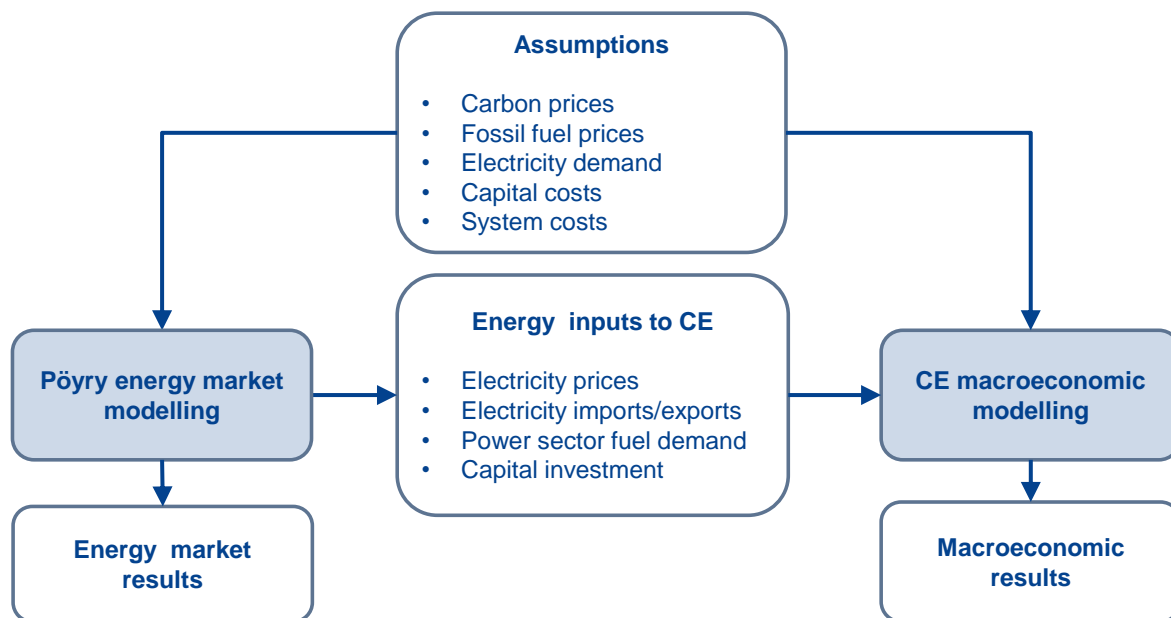
A consistent set of scenarios were defined as input to both Pöyry's and CE's modelling effort. The energy market modelling results were used as inputs to the macroeconomic modelling (see Figure 6).

Three separate scenarios were modelled and assessed across four dimensions:

- **power market performance** – including wholesale price levels, import/export of power, interconnector utilisation, generation and interconnector capacity investment costs;
- **macroeconomic impacts** – including GDP growth, labour market effects (employment levels), tax revenue and public sector balance and balance of energy payment effects;

- **security of supply** – including degree of power generation self-sufficiency, diversity of generation and import dependency; and
- **environmental targets** – including carbon emissions and renewable generation shares.

Figure 6 – Modelling interaction between Pöyry and CE



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- **power market performance** – including wholesale price levels, import/export of power, interconnector utilisation, generation and interconnector capacity investment costs;
- **macroeconomic impacts** – including GDP growth, labour market effects (employment levels), tax revenue and public sector balance and balance of energy payment effects;
- **security of supply** – including degree of power generation self-sufficiency, diversity of generation and import dependency; and
- **environmental targets** – including carbon emissions and renewable generation shares.

1.2 Scenario Overview

To assess the economic impact of wind energy in Ireland, we have considered three distinct scenarios of wind capacity deployment on the island of Ireland and GB (see Table 1).

- **No Wind Effort (Post 2014) (No Wind)** is our baseline scenario in which no further wind development occurs in SEM beyond that which is already assumed to be under construction through to the end of 2014. GB continues wind deployment but does not meet its 2020 renewable target until 2025.

- **Domestic Wind Scenario (*Domestic*)** delivers sufficient wind capacity to meet the RoI and NI 2020 renewable targets. Wind capacity continues to grow through to 2030 proportionally with demand growth. GB continues wind deployment but does not meet its 2020 renewable target until 2025.
- **Export Wind Ambition (*Export*)** assumes domestic renewable targets are met as in the *Domestic Wind* scenario, and enables GB to hit its 2020 target through export wind capacity constructed in RoI.

Because of the nature of the SEM, each scenario defines wind penetration in both RoI and NI alongside GB renewable generation trends. The latter is important since interconnection with the GB electricity market can have a material impact on observed prices in the SEM. For detailed information on the split in capacity development between RoI, NI and GB see Annex B.1.5.

Table 2 – Wind capacity deployment in each scenario (GW)

	2012		2020		2030	
	SEM	GB	SEM	GB	SEM	GB
No Wind Effort (Post 2014)	2 GW	9.8 GW	2.4 GW	17.5 GW	2.4 GW	25 GW
Domestic Wind Scenario	2 GW	9.8 GW	5.2 GW	17.5 GW	7.9 GW	25 GW
Export Wind Ambition	2 GW	9.8 GW	5.2 GW	22 GW	7.9 GW	34 GW

Note: *Export Wind Ambition* builds wind capacity in RoI directly connected to GB market. This chart focuses on wind capacity on the island of Ireland (SEM) but the report focuses on the economic benefit of wind development in Ireland only.

1.2.1 Capital Investment

We assume a level of investment in wind, network infrastructure (grid) and system services (DS3) through 2030. The wind investment is informed by our capacity build out rate defined in Table 2 and our assumptions on the cost of investment (see Annex B.1.4). The grid investment costs assume the full Grid 2025 investment plan is implemented and that 40% of this investment is required to support the 2020 renewable target³. The DS3 programme is assumed to cost €355m per year. We deduct €60 million for current system service payments covered in our market modelling and we deduct €100m as the assumed benefit to the capacity payment mechanism from the provision of the added system services under DS3. This leaves a net DS3 cost of €195m per year of which we assume 75% is attributable to RoI.

³ The grid investment costs would be recovered through transmission use of system (TUoS) charges which are currently split 75% Demand TUoS and 25% Generator TUoS. For transparency, we assume the full cost is applied to the consumer retail bill although in practice the generator portion is likely to be imbedded in generator profitability and may change the capacity pot calculation.

Table 3 – Total RoI capital investment in *Domestic* and *Export* scenarios (€ billion)

	<i>No Wind Effort</i>			<i>Domestic Wind</i>			<i>Export Ambition</i>		
	Wind	Grid	DS3	Wind	Grid	DS3	Wind	Grid	DS3
2013 - 2020	0.4	1	0	3.1	1.7	0.7	16.6	1.7	0.7
2021 - 2030	0	0.9	0	2.5	1.5	1.5	14	1.5	1.5

Note: Wind capex in *Export* scenario includes full capex requirement for export project including transmission infrastructure connecting wind capacity in RoI to GB grid.

1.2.1.1 Application of capital investment in macroeconomic modelling

We assumed that the capital cost of the grid investment would be financed over its lifetime, based on the assumption of a 40 year lifetime and a borrowing rate of 6.0%. The implication of this is that the grid investment is spread out over a 40 year period, and the grid cost component of the electricity price incorporates a borrowing cost payment. Therefore, not all of the grid investment is assumed to take place and be paid for over the period modelled (2013-2030), and we assume that some of this investment will be paid for in subsequent years.

In the *Domestic* scenario, the additional direct investment in wind amounts to around €335m per annum over the period 2013-2020 and €307m per annum over the period 2021-2030. We assume a 36% domestic share of capital investment, as the wind turbines themselves, which account for around 64% of costs, are not currently manufactured in Ireland. Therefore just over one third of the investment benefits the Irish wind sector.

In addition to this, there is, on average, an additional €99m per annum of electricity network and DS3 investment in the *Domestic* scenario over the period 2013-2020, and an average additional €175m per annum over the period 2021-2030.

In the *Export* scenario, additional to the domestic wind investment, there is new investment required to support the export wind project, which amounts to an average of €1.7 billion per annum over 2013-2020 and €1.2 billion per annum over 2021-2030. The new capacity is assumed to be constructed in two distinct phases (2016-2019 and 2023-2026) and is assumed to be financed by the UK government.

1.2.2 Input assumptions

A common set of input assumptions were devised to be internally consistent to enable comparison across scenarios and to gain understanding of how the future behaviour of energy markets is impacted by wind development. These include assumptions for:

- electricity demand;
- fuel and carbon prices; and
- SEM plant closures.

Pöyry's energy market modelling ensures an internally consistent approach is taken for the GB and mainland European electricity markets. Further information on all the fundamental modelling assumptions common across all scenarios can be found in Annex B.1. Further information on Pöyry's approach to modelling can be found in Annex A.

1.2.3 Carbon price sensitivity

For the main modelling runs we assumed that GB maintains a carbon price in line with DECC's projection for the UK carbon price underpinned by the carbon price floor which delivers a €90/tCO₂ price by 2030⁴ and the SEM maintains a carbon price in line with the EU carbon market, for which we take IEA's current policies scenario long term carbon price projections which delivers a €30/tCO₂ price by 2030⁵. This assumption impacts the balance of interconnector flows by building a fixed differential into the wholesale market price between the SEM and GB market.

We modelled a carbon price sensitivity in which the EU carbon price increases at a faster rate, closer to the UK ambition for the carbon price.

1.3 Structure of this report

This report contains four main sections which describe the main economic impacts of wind development in Ireland determined from this analysis followed by a section summarising the high level economic results:

- Section 2 – Growing Wind energy sector;
- Section 3 – Energy market effects;
- Section 4 – ROI energy balance of payments;
- Section 5 – Impact on Irish economy; and
- Section 6 – Summary of economic .

The results presented in the main body of the report are supported by a set of annexes which provide background on the modelling approach taken by both Pöyry and CE and more detailed results:

- Annex A – Pöyry's modelling approach;
- Annex B – Energy market results;
- Annex C – Cambridge Econometrics' modelling Approach; and
- Annex D – Macroeconomic results.

1.3.1 Conventions

All monetary values quoted in this report are in euros (€) in real 2012 prices, unless otherwise stated.

1.3.2 Sources

Unless otherwise attributed, the source for all tables, figures and charts is Pöyry Management Consulting.

⁴ Updated short-term traded carbon values used for modelling purposes, DECC, 16 Sept 2013.

⁵ World Energy Outlook 2012, IEA, 12 November 2012. The IEA projection is modified in the near term to take account of the current low EU carbon price.

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2. GROWING WIND ENERGY SECTOR

2.1 Introduction

An increase in wind investment in the RoI could create substantial benefits for associated industries, as well as increases in gross sector⁶ employment. Additional investment would lead to an increase in output and jobs in the planning and construction of new turbines, as well as permanent jobs in the operation and maintenance of these turbines.

This chapter of the report focuses specifically on the direct impacts of the scenarios on Ireland's wind sector, taking into account the effects of an increase in wind investment, DS3 and grid network investment. In this chapter we report the expected impact of wind investment on direct employment in the sector and briefly summarize the expected increase in business rates paid to local authorities.

Section 5 presents the net impact on the RoI economy after taking into account all other expected flows in the economy, and includes the effects of changes in electricity prices, electricity sector profits and the indirect and induced effects.

2.2 Gross sector employment

The increase in direct jobs in the wind sector can be separated into three broad categories:

- permanent direct jobs that are created due to an increase in operation and maintenance requirements for the wind turbines;
- transitory direct planning and development jobs that relate to the installation of the wind turbines; and
- transitory direct jobs associated with the required improvements to the grid and to support the DS3 programme.

The estimates for the wind operations and maintenance (OPEX) jobs are based on a literature review by Wei, Patadia and Kammen⁷. Their research includes details of jobs estimates for wind OPEX in five different studies. The average of these five estimates is 0.242 jobs/MW of installed wind capacity, and this is the figure that we use to estimate the OPEX jobs for this analysis.

Figure 7 shows the total OPEX jobs in the *Domestic* and *Export* scenarios in 2020 and 2030. In the *Domestic* scenario, the number of wind OPEX jobs doubles over the period 2013-2020 to reach 920 by 2020 and grow to 1,340 by 2030. In the *Export* scenario, a much greater increase in wind capacity sees the number of wind OPEX jobs in Ireland reach 2,130 by 2020 and grow to 3,520 by 2030. These OPEX jobs, which relate to the stock of installed capacity (rather than net additional capacity per annum) are long-term jobs that persist into the future for as long as the wind exists in the generation mix.

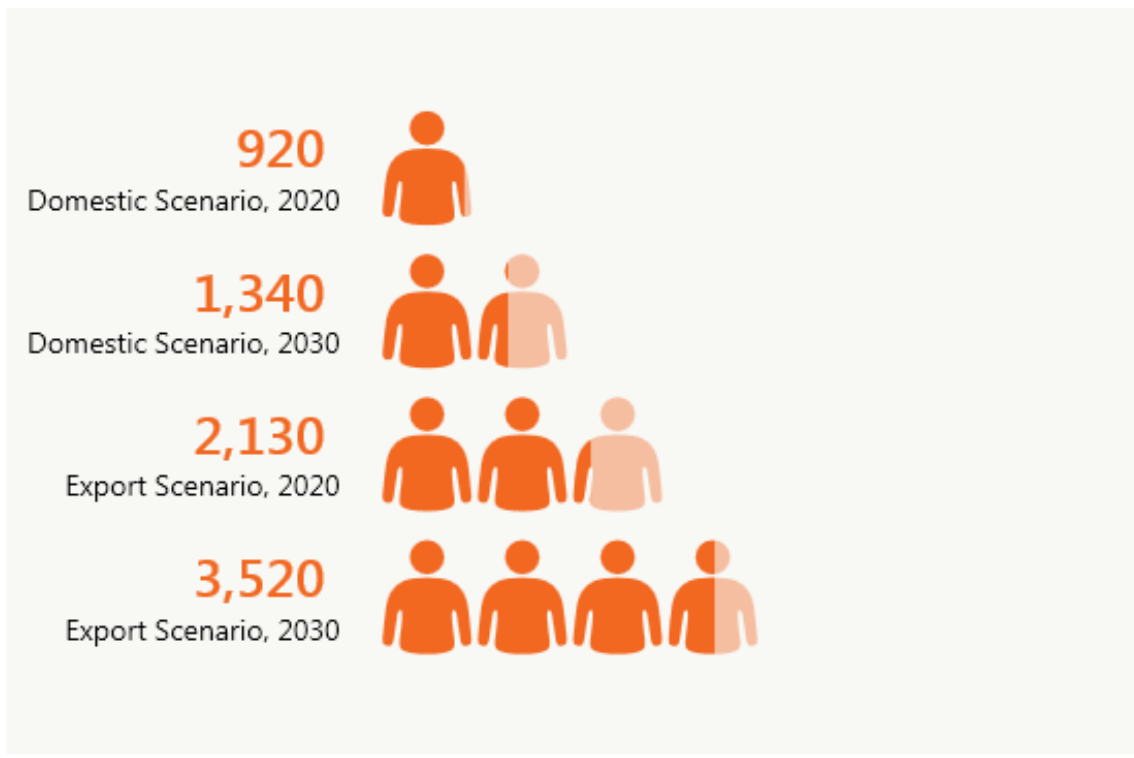
The OPEX jobs figures presented in Figure 7 are jobs that directly support the operation and maintenance of the wind turbines. In addition to these, there is also potential for the

⁶ The 'gross wind sector' is defined here as the operation of wind turbines and the manufacture/installation of new turbines.

⁷ Wei, Patadia and Kammen (2009), 'Putting renewables and energy efficiency to work: How many jobs can the clean energy industry generate in the US?'

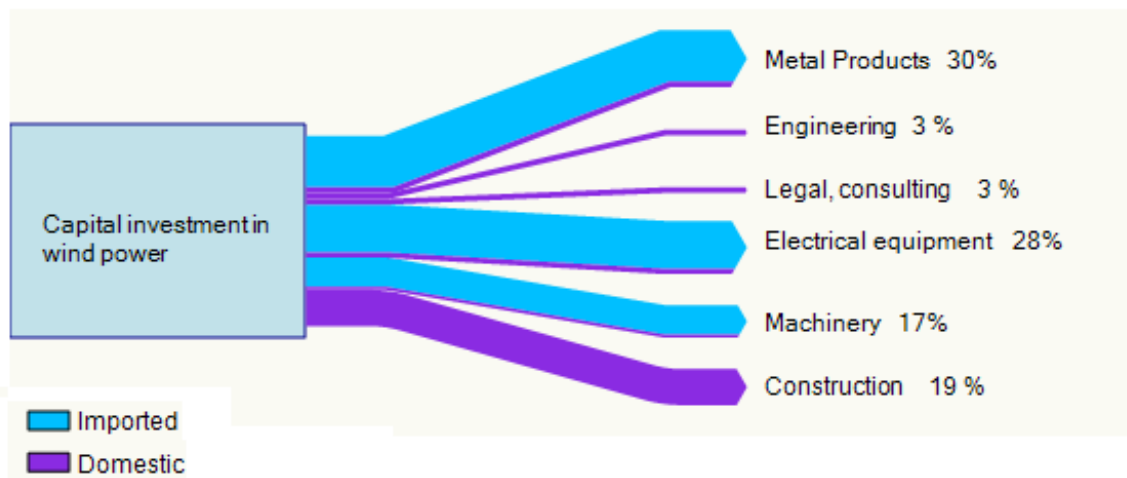
creation of OPEX jobs to support the grid expansion in the *Domestic* and *Export* scenarios.

Figure 7 – Total OPEX jobs in 2020 and 2030 in the *Domestic* and *Export* scenarios



The impact of increased wind investment on employment was estimated using a top-down modelling approach. The jobs figures are derived by combining empirically estimated levels of productivity with assumptions about the investment requirements, the sectors which benefit from this investment, and the domestic content of the investment. These assumptions are shown in Figure 8 below.

Figure 8 – Sectors that benefit from Irish wind investment



As all of the investment accrues to the construction, engineering, legal/consulting, electrical equipment, machinery and metals sectors, all of the jobs related to the installation of turbines are created in these sectors. Furthermore, we assume that no turbine manufacturing facilities are developed in Ireland over the period to 2030.

Our jobs estimates are based on average sector levels of productivity, and the construction sector, which is a relatively labour-intensive sector that also attains the highest share of domestic investment, sees the largest increases in employment.

Since investment in new capacity is lumpy over time (particularly in the *Export* scenario), the number of jobs created in a given year is of less interest than the total employment opportunity over the whole period. The cumulative number of jobs, measured in terms of person-years required to support a wind project pipeline, rather than jobs in a particular year, is therefore a better indicator of the direct employment opportunities related to the planning, manufacturing, construction and installation of turbines and supporting grid infrastructure.

Figure 9 shows the expected increase in jobs (measured in person-years⁸) in the *Domestic* and *Export* scenarios. If Irish wind capacity continues to grow at a rate similar to that observed in recent years, as represented by the *Domestic* scenario⁹, this would lead to the creation of 12,390 jobs (on a person-year basis) by 2020 and an additional 10,120 jobs (on a person-year basis) over the period 2021-2030.

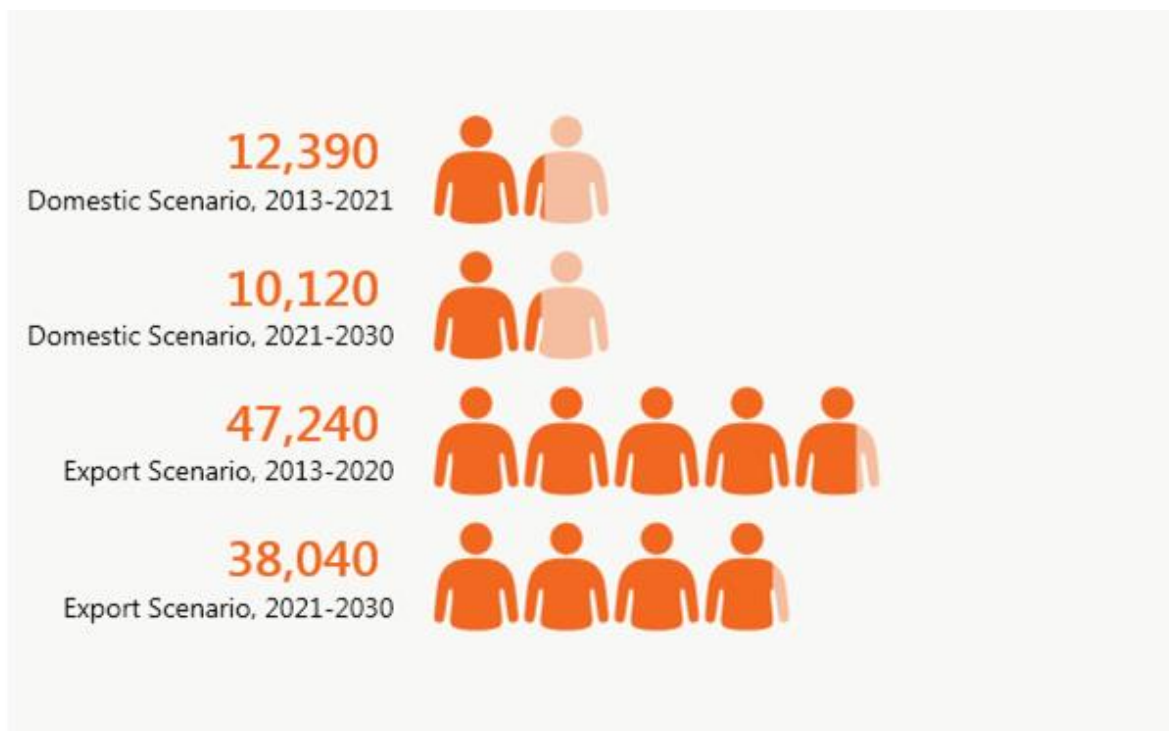
In the *Export* scenario, even more construction jobs required to support the additional export wind capacity, particularly over the two construction phases of the wind export project, running from 2016-2019 and 2023-2026. In this scenario, there will be 47,240

⁸ The direct construction and planning jobs are measured and reported in ‘person-years’. We assume that one ‘person-year’ is equivalent to one job lasting one year.

⁹ According to ‘EWEA Annual Statistics 2013’, 299MW of wind capacity was installed in Ireland in 2013; our *Domestic* scenario assumes 270MW is installed per annum in the period up to 2020.

construction-related jobs in the wind sector by 2020, and 38,040 over the period 2021-2030 (measured in person-years).

Figure 9 – Direct wind development, development and grid jobs (person-years) over 2013-2020 and 2021-2030 in the Domestic and Export scenarios



These figures translate to an estimated 5.74 direct jobs created per MW of wind capacity installed in the Domestic scenario. Note that these jobs are additional to the previously discussed 0.242 O&M jobs per MW of cumulative capacity.

Our jobs figures incorporate an estimated productivity improvement, due to improved labour efficiency of installing turbines. Due to the scale of the increase in capacity in this scenario, the estimated productivity improvement is higher in the Export scenario, compared with the Domestic scenario.

Our estimate for the number of jobs created per MW of capacity installed is higher in the Export scenario (6.60 person-years per MW installed), as the proportion of offshore wind capacity relative to onshore wind is higher in *Export* compared with *Domestic* scenario and the costs and labour requirements for offshore wind is higher.

A comparison of our direct jobs results with a number of other studies is shown in Table 4. The four comparison studies all use a bottom-up survey analysis to estimate the number of jobs in the wind sector. This methodology differs from our top down approach and we would therefore expect differences in the jobs estimates.

The Redpoint and Renewable UK studies both separate jobs relating to annual capacity installed and those relating to cumulative capacity. These results are therefore more comparable to the results presented for the *Domestic* and *Export* scenarios in this study. In the Renewable UK study, the jobs figure is towards the upper end of our range and in

the Redpoint study, it is even higher. One of the reasons for this is that the share of more labour-intensive offshore wind capacity installed (relative to onshore wind) is much higher in these studies than in our *Domestic* scenario, and is more closely comparable to the share in *Export* scenario. Furthermore the Renewable UK study includes jobs from turbine design and manufacture and decommissioning jobs that are not included in our analysis. Both the Redpoint and Renewable UK studies are based on UK surveys.

Table 4 – Comparison of jobs figures

Name of Study	Geographical coverage	Direct jobs (person-years) per annual MW installed	Direct jobs per cumulative MW	Number of indirect and induced jobs for each direct job created
Deloitte (2009) , 'Jobs and Investment in Irish Wind Energy' ¹⁰	ROI and Northern Ireland	-	1.5	-
ESRI (2014) , 'An Enterprising Wind: An economic analysis of the job creation potential of the wind sector in Ireland' ¹¹	ROI	-	1.66 - 1.89 ¹²	0.16-0.55 ¹³
Redpoint (2012) 'The economic effects of increasing wind deployment in Northern Ireland' ¹⁴	Northern Ireland	7.64 ¹⁵	0.31	0.66
Renewable UK (2013) , 'Working for a Green Britain & Northern Ireland 2013–23', Medium Growth scenario ¹⁶	UK	6.51	0.33	0.61
Study Results: Domestic and Export scenarios 2013-2030	ROI	5.74-6.60	0.24	0.33

The indirect jobs figures are roughly double our estimates, implying a ratio of 0.6 indirect jobs for each direct job created, compared with our figure of 0.3. Part of the reason for this

¹⁰ Deloitte (2009), 'Jobs and Investment in Irish Wind Energy'. Available online: http://www.iwea.com/contentFiles/Documents%20for%20Download/Publications/IWEA%20Policy%20Documents/2009_06_Deloitte_IWEA_Employment_in_Wind_Energy_Report.pdf?uid=1245768156894

¹¹ ESRI (2014), 'An Enterprising Wind: An economic analysis of the job creation potential of the wind sector in Ireland'. Available online: <http://www.esri.ie/UserFiles/publications/BKMNEXT250/BKMNEXT250.pdf>

¹² dependent on whether turbine manufacturing jobs are included

¹³ dependent on scenario

¹⁴ Redpoint (2012) 'The economic effects of increasing wind deployment in Northern Ireland'. Available online: http://www.ni-rig.org/wp-content/uploads/2012/07/Redpoint_NIRIG-NI-wind-report_final_20120329-2.pdf

¹⁵ Assumption of 3.82 construction and planning jobs per MW, that each last for two years- assumptions taken from a 2011 Renewable UK report, 'Working for a Greener Britain: Vol 2'.

¹⁶ Renewable UK (2013), 'Working for a Green Britain & Northern Ireland 2013–23', Medium Growth scenario. Available online: <http://www.renewableuk.com/en/publications/index.cfm/working-green-britain>

is that the share of imports to service domestic demand is twice as high in Ireland compared with the UK¹⁷, therefore we would expect that in Ireland, a higher share of the indirect supply chain demand will be met by imports from abroad. Our estimate of indirect and induced jobs (0.33) falls in the middle of the range (0.16-0.55) presented by the recent ESRI study which is the only other study specific to Ireland.

2.3 Contribution to government revenue

Onshore wind projects in the RoI are obliged to pay business rates to local authorities and these are intended to be re-invested in services that could directly benefit local communities. The business rates applicable are related to the annual sales of electricity from each wind farm. In 2013, the average annual contribution of Irish wind projects to local authorities was €6,750 per MW¹⁸. In addition to this, upon commissioning, each wind farm is required to pay an up-front fee averaging at about €4,922 per MW of installed wind capacity.

Based on these figures, local authorities could receive up to €20m per annum over the period 2013-2020 in the *Domestic* scenario and an annual average of almost €30m over period 2021-2030. In the *Export* scenario, the increase in local authority payments would be even greater, reaching almost €60m per annum over the period 2021-2030, as shown in Figure 10.

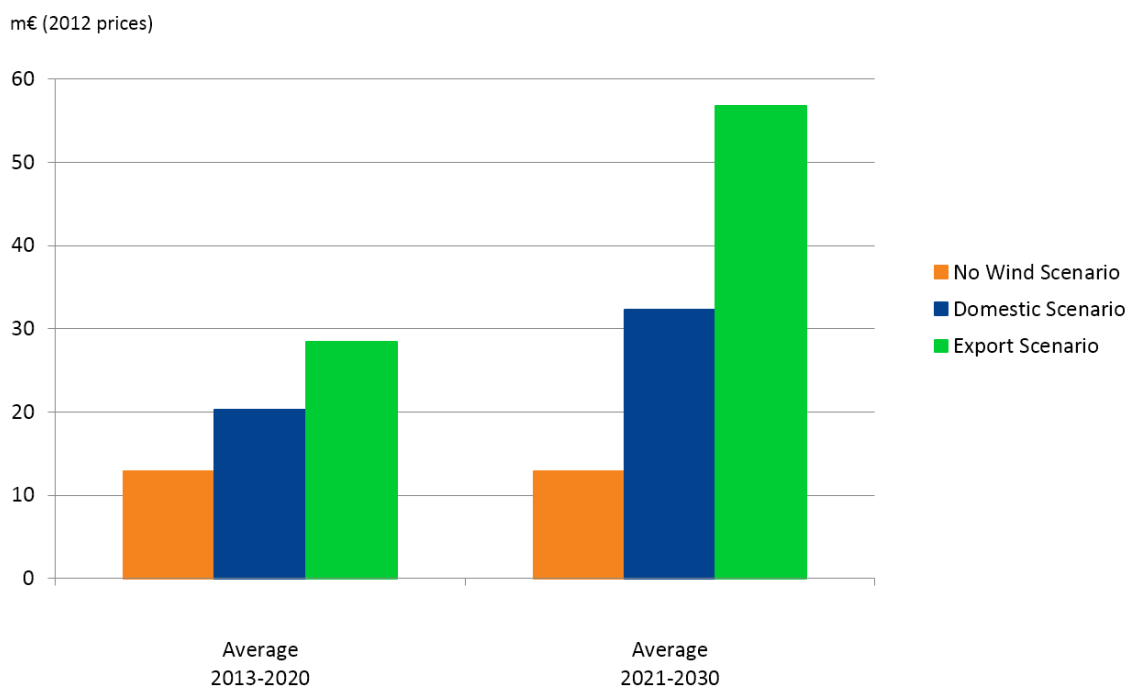
Although not studied in this report, in addition to the local authority payments shown in Figure 10, the local economy could also benefit from additional business rate contributions from the expanded grid network, rent payments on the land occupied by the wind farms, and an additional voluntary community benefit, which is currently estimated to be worth around €1,000 per MW annually¹⁹.

¹⁷ Based on Eurostat data (2012)

¹⁸ IWEA (2013)

¹⁹ IWEA (2013) Good Neighbour: IWEA Best Practice Principles

Figure 10 – Average annual revenue from business rates



2.4 Carbon emissions avoided

Wind generation output displaces a proportional quantity of output from the marginal source of generation in the market which is typically a CCGT in Ireland. Therefore as we increase the output from wind we also decrease the output from carbon emitting generation sources.

Wind output in 2013 in our three scenarios is 4.9TWh avoiding 1.7mtCO₂ annually. The generation output of wind in RoI is projected to double to 10TWh by 2020 in our *Domestic* scenario doubling the annual carbon emissions avoided and displacing over 21mtCO₂ up to 2020, a 35% increase over our *No Wind* scenario.

The annual quantity of CO₂ avoided continues to rise through the 2020s as additions to wind capacity continue. Wind output reaches 14.2 TWh in the *Domestic* scenario by 2030 with 5.1mtCO₂ avoided annually. Over the period 2021-30 over 43mtCO₂ is avoided.

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3. ENERGY MARKET EFFECTS

3.1 Changes to the SEM generation capacity mix

As electricity demand grows and older plant is retired due to age or on environmental grounds, new capacity is needed beyond our assumed renewable growth.

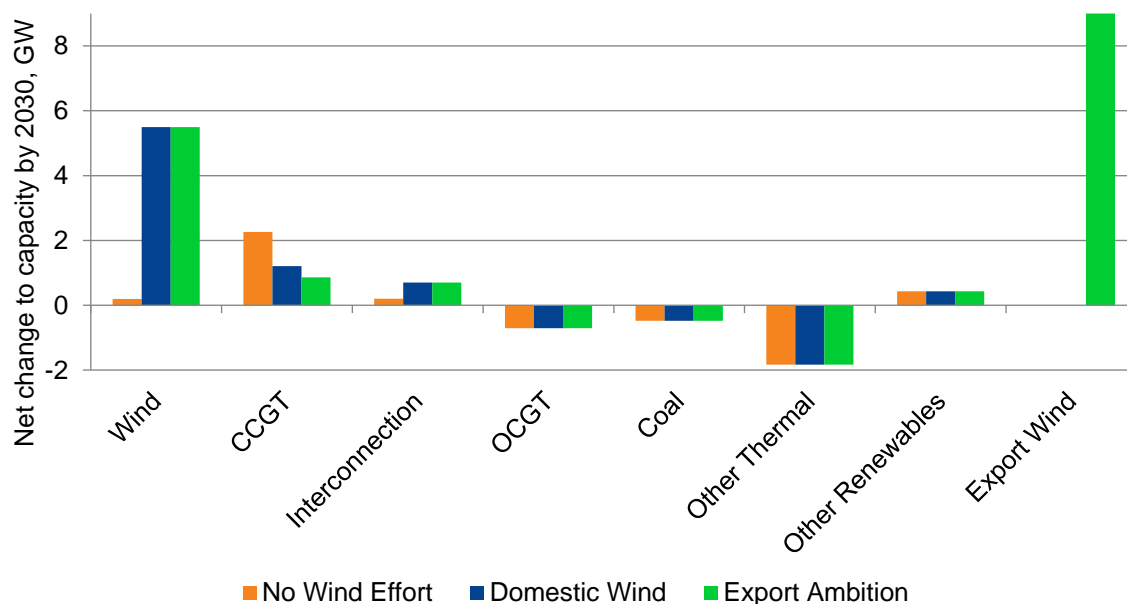
The growth in wind capacity is predetermined for each scenario as defined in Section 1.2. We assume in all scenarios that older thermal plant closes due to age and environmental restrictions imposed under the Industrial Emissions Directive (IED) and that renewables other than wind experiences modest growth. We assume that the Great Island CCGT (459MW) proceeds in 2014 in all our scenarios. Beyond this, new thermal capacity and new interconnection is added on an economic basis.

Figure 11 shows the net change in capacity by generation type in the SEM in each scenario. The market is currently well supplied and as a result, even if there is no new wind, we project that the first generic (uncommitted) new entrant does not occur until 2024 in *No Wind Effort* scenario. Our *No Wind* scenario builds 1800MW of new uncommitted CCGT, whereas our two wind scenarios build significantly less with 750MW in *Domestic* scenario and 400MW in *EWA*. If cheaper alternatives to new thermal emerge in the late 2020s such as demand side management and storage, there will be an added benefit.

In our *Domestic* and *Export* scenarios a new 500MW interconnector is constructed. Interconnection emerges as an important source of generation for the SEM in these scenarios and is cheaper than new build over some periods.

Figure 11 also shows us the wind capacity constructed in Ireland solely for export to the GB market in our *Export* scenario. This capacity is not connected to the Irish electricity grid and is considered part of the GB network in our modelling and therefore does not directly contribute to consumer prices in Ireland.

Figure 11 – Changes to installed capacity by generation type in SEM

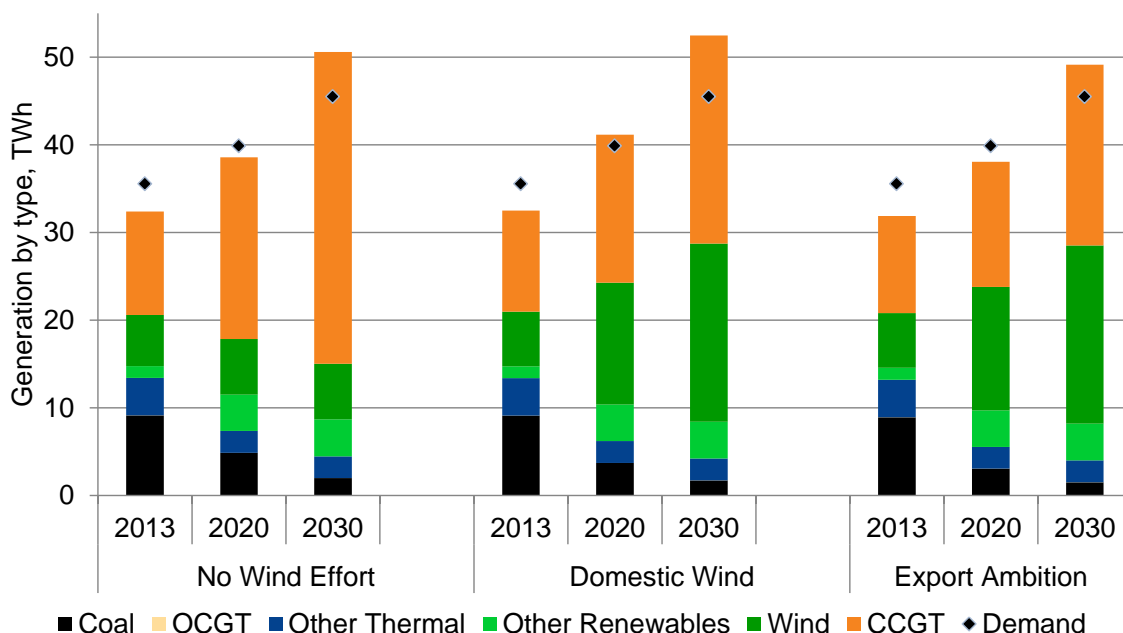


We assume that all new thermal capacity is constructed in NI due to the lower costs associated with gas capacity charges and business rates. We assume that the new interconnection is connected to GB from RoI. The location of these investments is important when examining the economic benefits to RoI.

3.2 SEM generation by type

The SEM demand requirement is indicated on Figure 12 by a blue diamond. Here we can see that generation output does not exactly match the demand requirement. Also, we can see that total SEM generation in specific modelling years is different across our three scenarios. This is due to the dynamics of interconnection with the GB market as generators import and export energy to take advantage of price arbitrage opportunities (see Section 4.3 for more detail).

Figure 12 – SEM generation output by type (TWh)



Note: Does not include output from export wind capacity

3.3 Interconnector flows

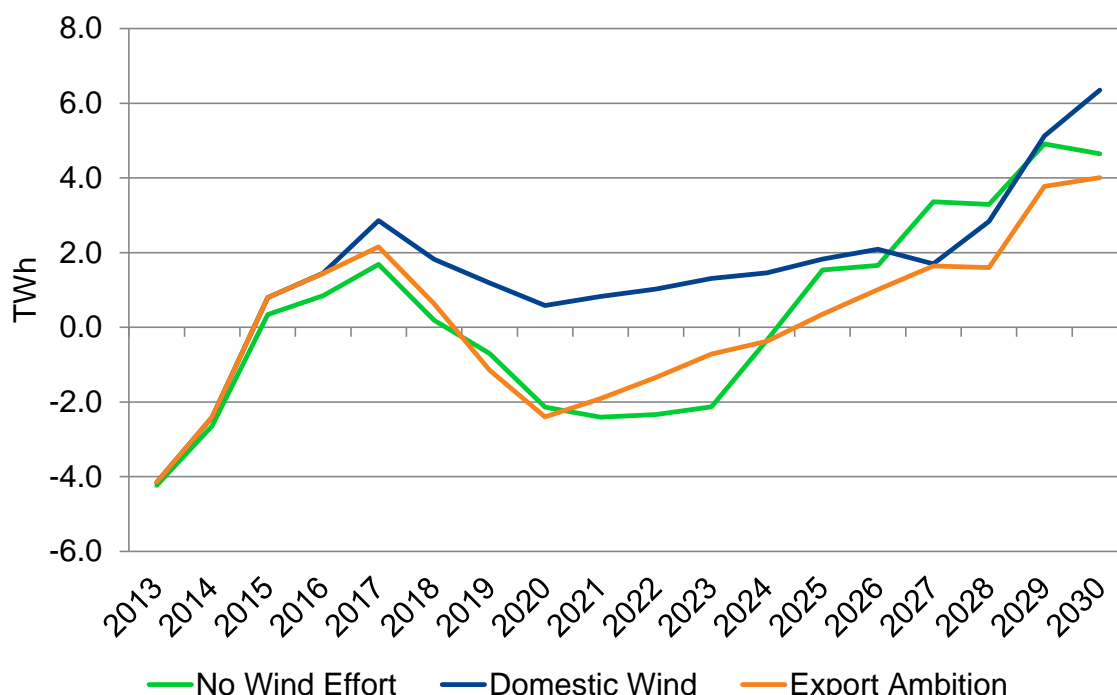
Figure 13 shows the net physical interconnector flows in our three scenarios. Tightness in the GB market drives export in the short term until differences between our three scenarios begin to emerge from 2017 onwards.

In the mid-term importing energy from GB is a cheaper way to meet SEM demand in *No Wind Effort* scenario than either increased running of domestic plant or new build thermal capacity. Our *Domestic* scenario keeps the SEM as a net exporter of electricity from 2015 onwards. This trend in the mid-term is driven by the high wind deployment in the Irish market which drives down the SEM price and increases the opportunity for exports to GB. Conversely this trend also prevents the SEM price falling as low as it might otherwise fall as the SEM wholesale price moves towards the higher GB price. The *Export* scenario results in a pattern similar to the *No Wind* interconnector flow pattern but for different reasons. In this scenario GB is deploying a much higher renewable capacity on its own

network in order to meet its 2020 target which counterbalances the high renewable deployment in the SEM and limits the opportunity to export from Ireland. Also, in periods of high wind, the output from domestic wind capacity and export wind capacity are both high. Flows over the new interconnector tie-line are constrained due to the carrying capacity of the export infrastructure link back to mainland GB grid.

In the long term the higher carbon price deployed in the GB market (driven by the carbon floor) relative to SEM (determined by EU carbon price) is the dominating factor in turning SEM into a net exporter in all three of our scenarios.

Figure 13 – Net electricity exports from SEM (TWh)



3.4 Wholesale prices

Wind development provides a wholesale price benefit in the SEM under the *Domestic* and *Export* scenarios. This is because wind has a zero short run marginal cost (SRMC) and therefore sits at the bottom of the merit order and displaces generation with positive SRMC higher up the order. This can change the marginal source of generation resulting in the wholesale price being set by the SRMC of a cheaper marginal source of generation than would otherwise be the case. This is commonly referred to as the merit order effect of wind.

3.4.1 System marginal price

In our scenarios, gas continues to be the marginal source of generation in the majority of periods between now and 2030. As a result, the system marginal price (SMP)²⁰ is closely linked to the running costs of a CCGT.

In all scenarios there is a general long-term upward trend in the annual average level of SMP. The general trend is due to the increasing prices of gas and carbon over the period to 2030. We assume the gas price rises from about €25/MWh to over €30/MWh and the carbon price impacting SEM generators rises from its low price today of €3/tCO₂e to €30/tCO₂e by 2030.

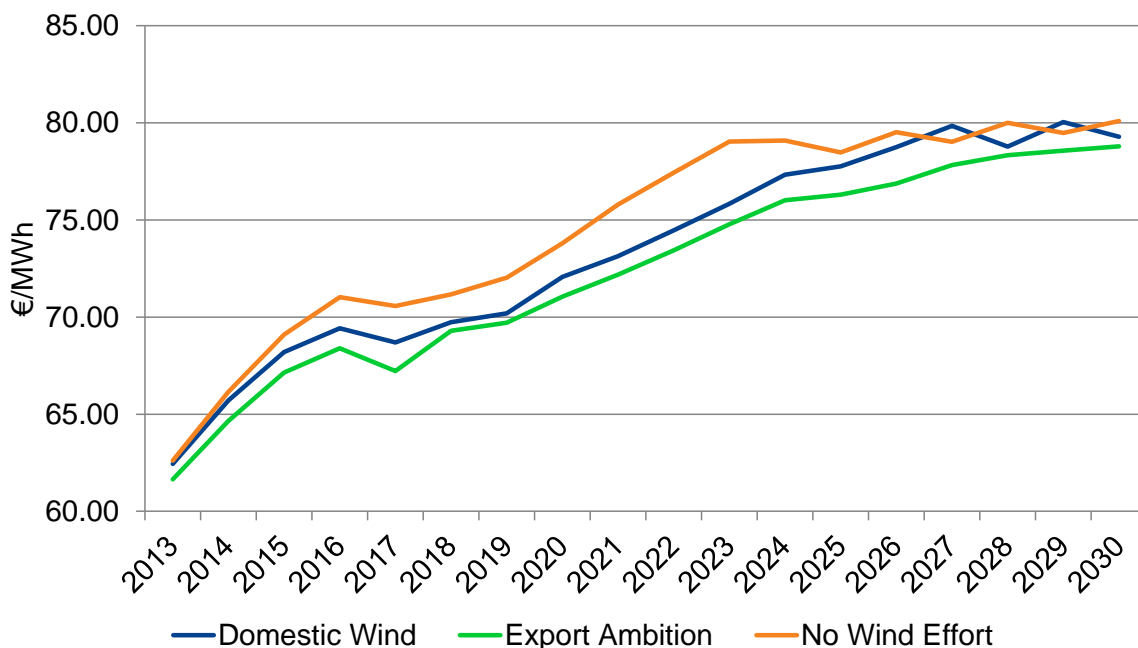
Our analysis finds that the required growth in wind to meet 2020 targets will reduce SMP by €2/MWh in 2020 when compared with our baseline *No Wind* scenario as shown in Figure 14 – Annual, time-weighted average SMP projections (€/MWh). The price benefit delivered by wind is projected to widen through the early 2020s.

In the longer term, the changes to the capacity mix through the closures of older less efficient thermal plant across our scenarios and the addition of new plant and interconnection tends to narrow any price differentials.

The wholesale price in the *Export* scenario is lower than the price in the *Domestic* scenario due to the different price point in GB between these two scenarios. In the *Export* scenario we assume that GB expands its renewable programme to meet its own 2020 targets through the deployment of export projects in Ireland. The higher level of renewable penetration in GB delivers a lower average GB price which impacts SEM through the available interconnection.

²⁰ Our system marginal price projection (SMP) is based on the principle of a market wide price for energy based on short run marginal cost. Our price projections are inclusive of transmission system losses and are therefore comparable to the prices from the SEM's market scheduling algorithm.

Figure 14 – Annual, time-weighted average SMP projections (€/MWh)

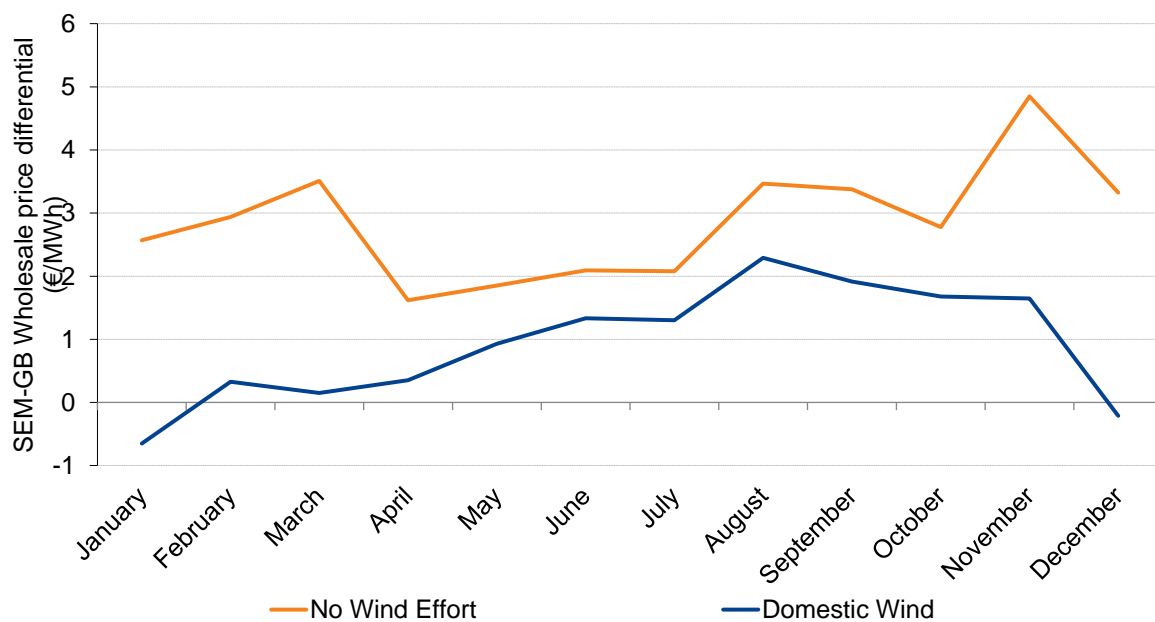


3.4.2 Impact of interconnector on wholesale price

The impact of the merit order effect of wind on the wholesale price is dampened by interconnection. Ireland tends to adopt a net export position in windy periods when SEM prices tend to be low and GB prices are at a higher price point. This prevents the SEM price from falling as low as it potentially could fall without the route to market offered by interconnection with GB. But interconnection with the GB market emerges as a key driver of economic benefit as the interconnector helps to maintain security of supply and provides a market for Irish power exports reducing Ireland’s energy import dependency.

Figure 15 illustrates the importance of the price differential between the SEM and GB markets in driving interconnector flows. This chart focuses the wholesale price differential between SEM and GB in 2020 in our *No Wind* and *Domestic* scenarios. In this year SEM is a net exporter of electricity in the high wind *Domestic* scenario while the market remains a net importer in the *No Wind* scenario when the price in GB is consistently lower than SEM.

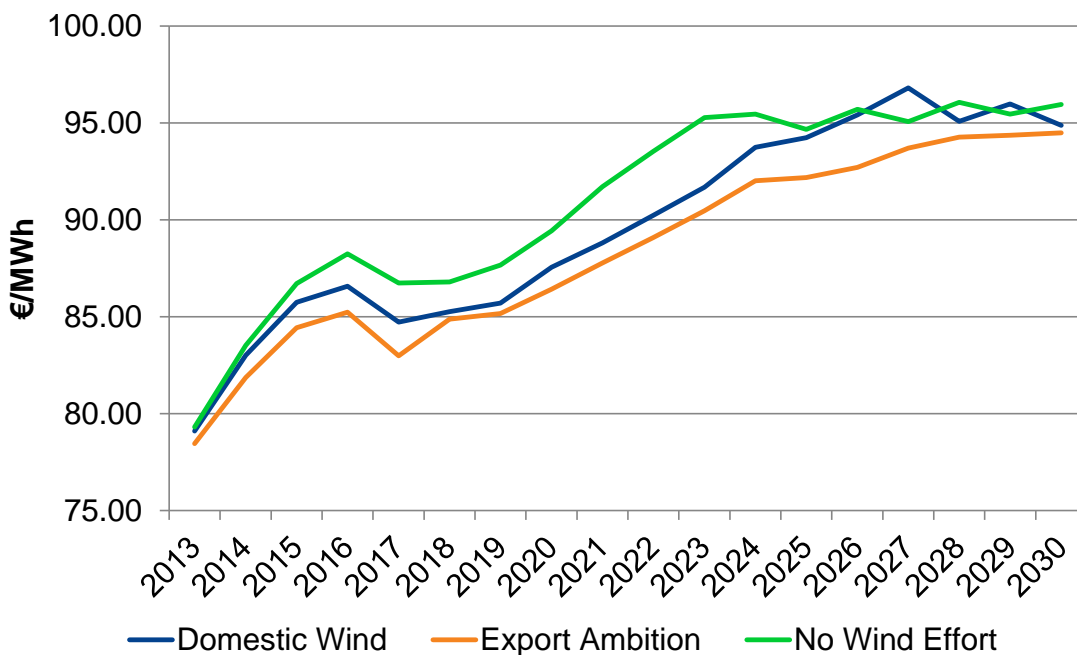
Figure 15 – Comparison between average monthly net physical interconnector flows and price differentials between SEM and GB in 2020



3.4.3 Wholesale prices paid by suppliers

The wholesale price paid by suppliers, and hence paid for by consumers, includes the SMP and the supplier capacity charge. The capacity payment mechanism is funded by suppliers with each entity contributing according to their total demand in terms of MWh. As a result, the wholesale price differentials between our scenarios are very similar to the differentials shown on SMP (see Figure 16).

Figure 16 – SEM supplier wholesale prices (€/MWh)

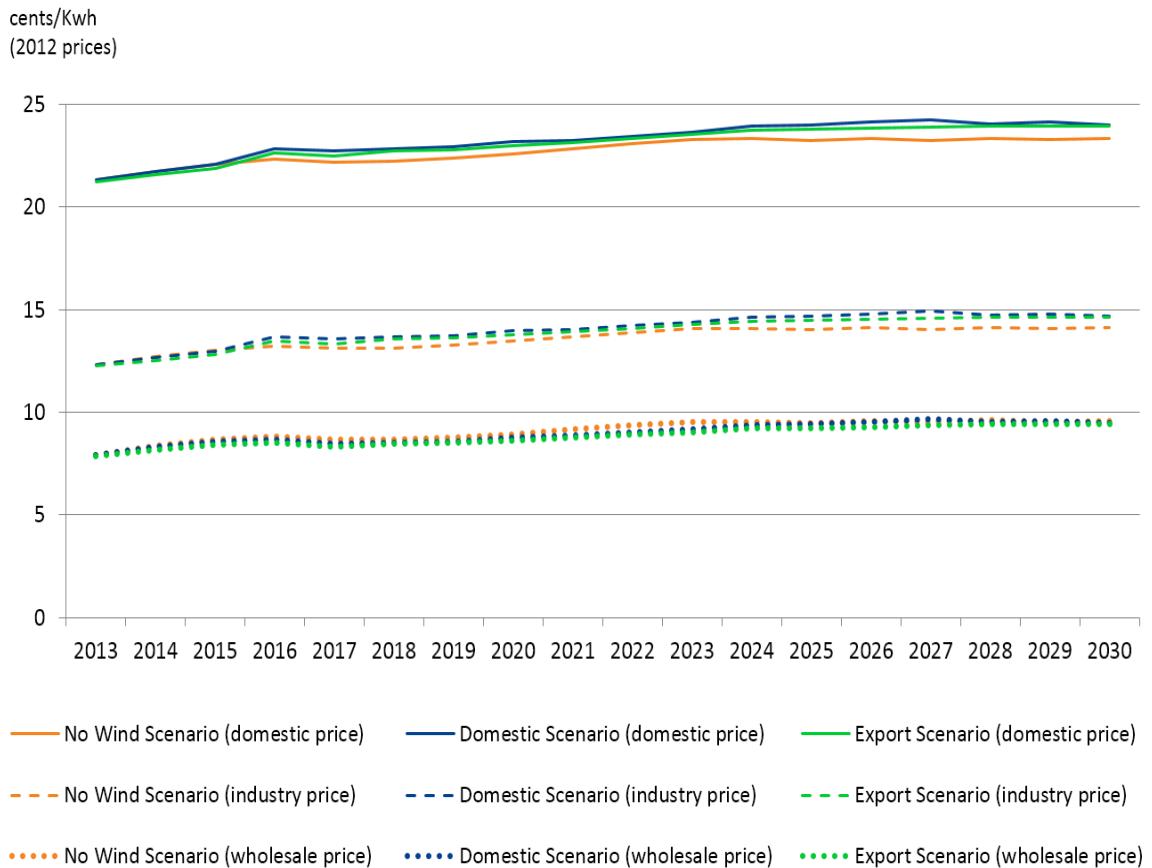


3.5 Retail electricity prices

Retail electricity prices were calculated by summing the annualised DS3 and grid investment costs, the REFIT wind subsidy, the distribution and supply costs, and the wholesale electricity price. We assume that retail margins and distribution costs are the same in each of the scenarios, but that the DS3 and grid investment costs are only applicable to the *Domestic* and *Export* scenarios. The VAT component of the household electricity price increases slightly in these scenarios due to an increase in the sale price of electricity.

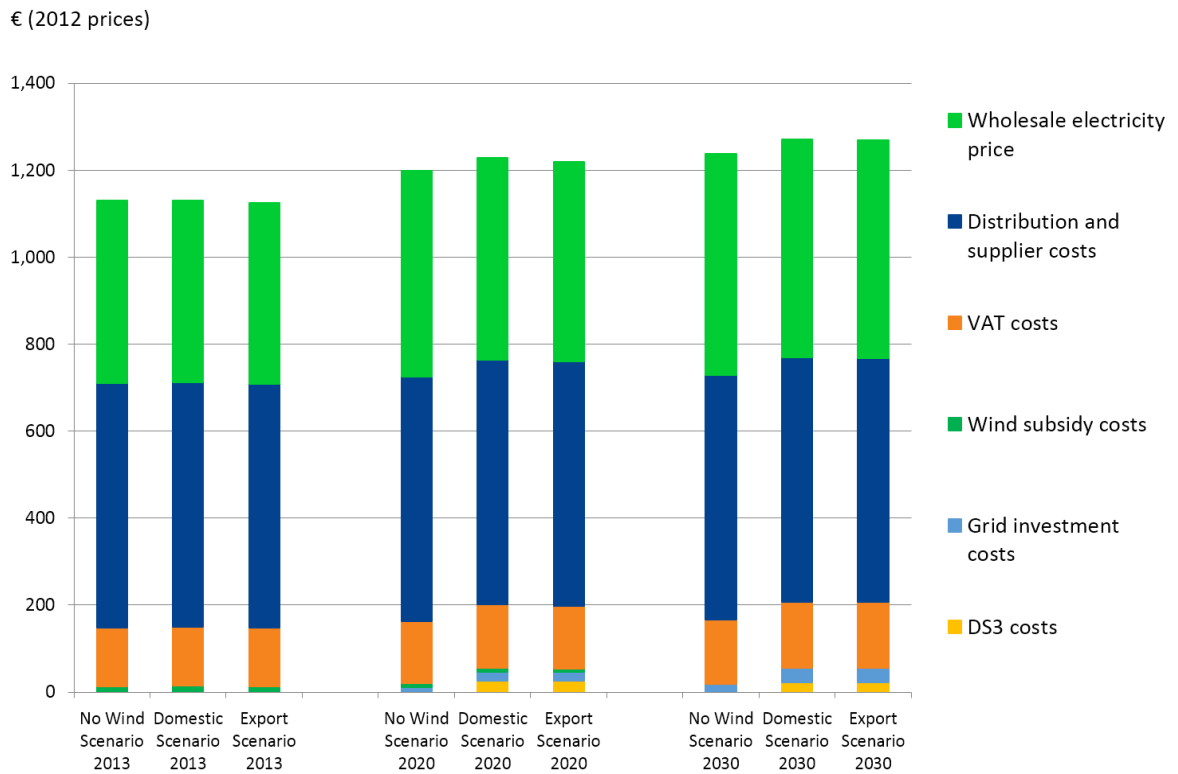
The marginally higher prices faced by domestic and industrial consumers are shown in Figure 17 below.

Figure 17 – Industry and household electricity prices, 2013-2030



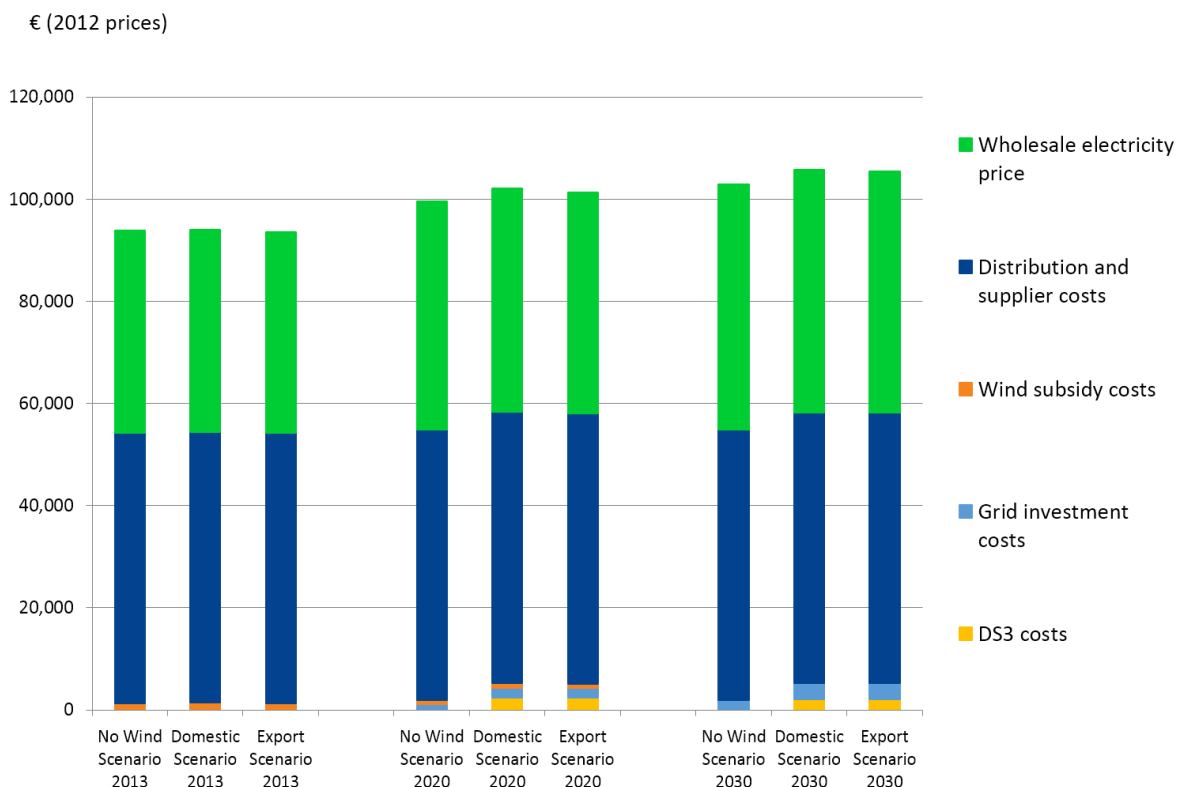
It is assumed that electricity demand is the same in each of the scenarios (growing over time by around 1.5% p.a.). However, as consumers in the *Domestic* and *Export* scenarios face higher retail electricity prices, their overall spending on electricity is higher in these scenarios. Figure 18 shows household electricity bills in each of the three scenarios, based on an average 2013 electricity consumption of 5,300 KWh, and Figure 19 shows electricity bills for an illustrative small industry in Ireland, that consumes 500 MWh of electricity per annum.

Figure 18 – Household electricity bills



Note(s): based on 2013 average household electricity consumption of 5,300 KWh

Figure 19 – Industry electricity bills



Note(s): based on illustrative electricity consumption in a small industry in Ireland of 500 MWh per annum

A small increase in industry electricity bills would lead to a marginal increase in production costs, particularly in electricity-intensive industries. To ensure profitability in the long run, some, perhaps all, of these costs would be passed on, thus marginally raising the price of consumer goods and services. Higher goods prices would reduce competitiveness slightly in international markets. However, the increase in demand in the Export and Domestic scenarios leads to an increase in industry output and sales revenue and the results show that there is a net small positive impact on industry profits in the Domestic and Export scenarios, relative to No Wind.

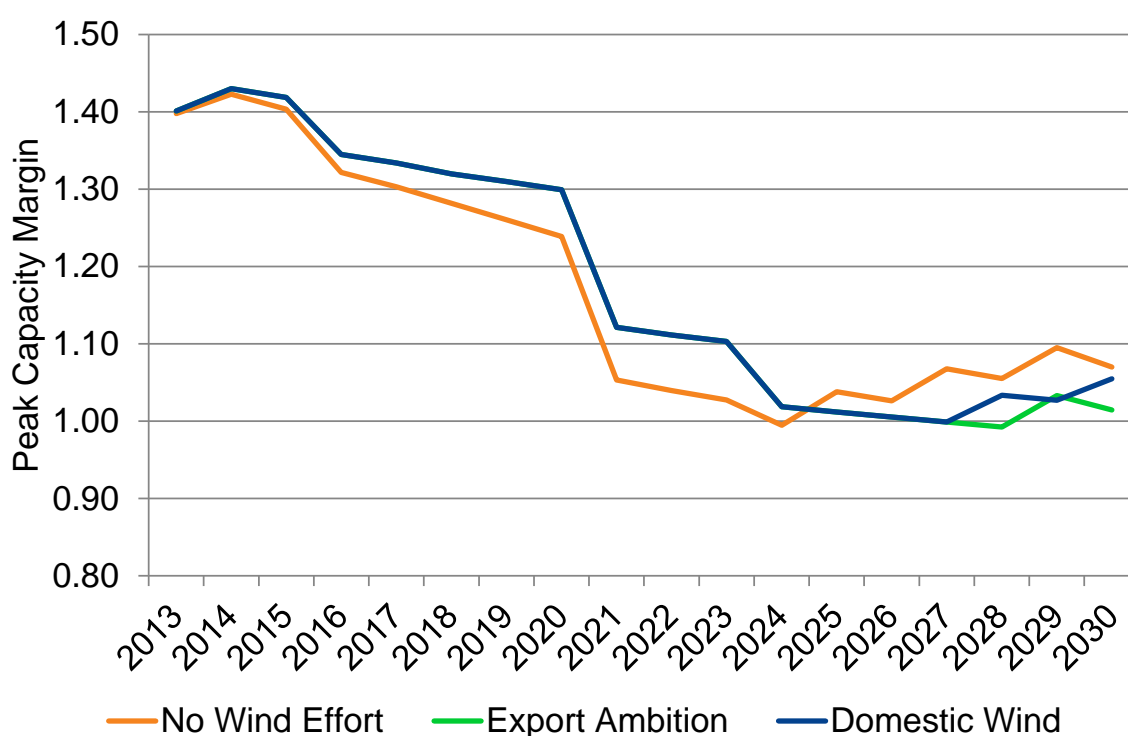
Higher electricity and goods prices faced by households would slightly reduce real disposable income, consumption and savings. However, after considering the increase in output and employment to support the wind investment, we find that household incomes do not change between the *No Wind* and *Domestic* scenarios. In the *Export* scenario, however, households are better off overall, compared with the *No Wind* baseline. **The larger investment stimulus leads to a greater increase in employment that more than offsets any negative consequences brought about by slightly higher electricity prices.**

3.6 Security of supply

The security standard is maintained in all scenarios. The peak capacity margin depicted in Figure 20 tightens across all three scenarios, most noticeably in the early 2020s due to

the restricted running of older plant (under the IED) and the closure of Kilroot. The security standard is protected, despite a gradually increasing demand due to the excess capacity currently available in the market. The security margin is wider in our *Domestic* and *Export* scenarios until 2024 due to the growth in wind capacity. New CCGTs are constructed, as they become economic across all scenarios, predominately in the late 2020s. The tighter peak capacity margin shown in Figure 20 in the *Domestic* and *Export* scenario post 2025 can be explained by the addition of an additional 500MW interconnector in these scenarios. The security of supply standard in the model allows for contribution from interconnectors and the security standard of 8 hours of loss of load probability is protected across our scenarios. The margin is broadly comparable between cases indicating that increased wind deployment does not reduce security.

Figure 20 – Peak capacity margin (excluding Interconnectors)²¹



3.7 Environmental impacts

In RoI in 1990 annual Irish emissions of CO₂ were 31 Mt. According to the latest statistics published by SEAI, the level of emissions has grown to 41Mt in 2012. The energy sector in RoI contributes approximately 30% to overall emissions and therefore has a major role to play in facing up to the challenge of reducing emissions relative to this 1990 benchmark.

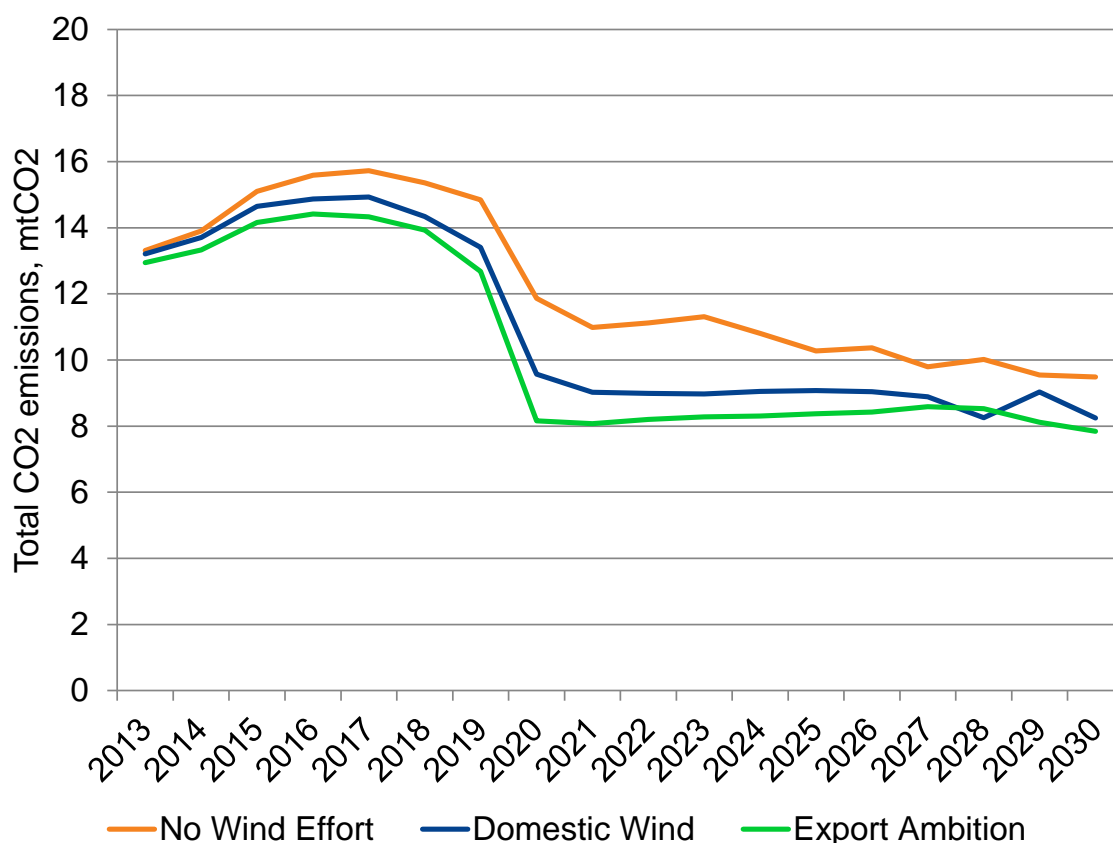
²¹ The peak capacity margin is calculated by dividing the annual peak demand by the capacity credit for each generation source installed in SEM. The capacity credit derates the installed capacity by the forced outage probability. We assume a forced outage probability for thermal generation of 5.91% and a capacity credit of 15.8% for wind capacity.

$$Peak\ capacity\ margin = [Nameplate\ capacity] \times [Derating\ factor] \div [Peak\ demand]$$

With no further renewable deployment the ROI power sector will still lower its total emissions (see Figure 21) relative to 2013. By 2020, they will have fallen by around 2MtCO₂. However, by pursuing a domestic wind deployment programme much more substantive cuts can be made in power sector emissions falling a further 2MtCO₂ to 9.5MtCO₂ by 2020²². Emission benefits appear to decline between 2020 and 2030, but this is because ROI becomes more reliant on fossil fuel based generation imports in our *No Wind* scenario.

Both *Domestic* and *Export* scenarios deliver the requisite level of renewable output required by NREAP targets. The level of emissions in the *Export* scenario remains marginally lower than *Domestic* due to the higher level of thermal generation requirements in the *Domestic* scenario. This implies that the price differential that exists between the GB and SEM markets drives the export of gas fired generation in the *Domestic* scenario increasing domestic production to serve the export market.

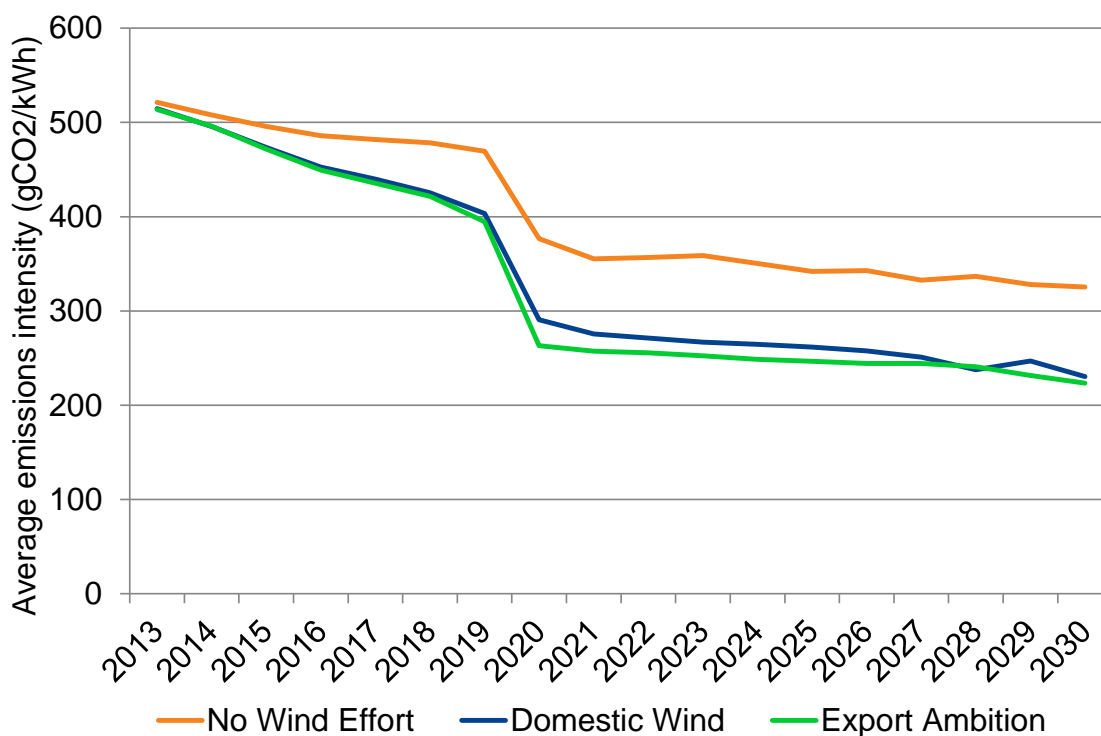
Figure 21 – Total ROI power sector emissions (tCO₂)



ROI emissions intensity from power generation falls with a high wind roll-out to about 230gCO₂/kWh as shown in Figure 22. This is predominately driven by the switch from coal, oil and peat generation to gas and wind with the major fall in emissions intensity occurring in 2019/20 when these higher emitting fuels fall out of the merit order.

²² Our analysis of carbon emissions from the power sector takes account of inefficiencies in thermal plant operation caused by start-up costs and part loading.

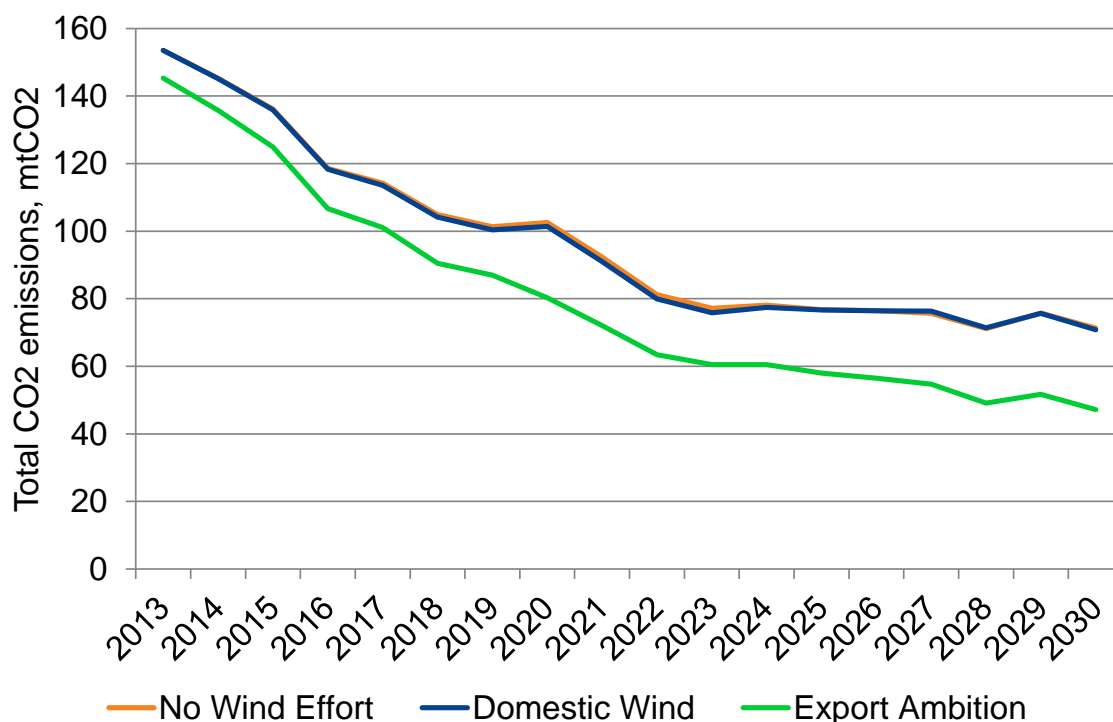
Figure 22 – Average ROI emissions intensity (gCO₂/kWh)



Although not considered within the scope of this project, lowering the emissions intensity of the electrical power generation system could have knock on benefits if and to the extent electrification of heat (heat pumps, storage heaters) and transport (electric vehicles) occurs at significant scale.

GB meets 2020 renewable target for power generation in *Export* scenario delivering a reduction in emissions compared with the baseline for GB deployed in both *No Wind* and *Domestic* scenarios as shown in Figure 23. There is a marginal decrease in GB emissions in *Domestic* scenario due to the importation of power from SEM.

Figure 23 – Total GB emissions (tCO₂)



3.8 Concluding remarks

The merit order effect of wind could be even higher but is limited by a number of factors. First, even with increased wind output, gas-fired generation generally remains the marginal generation source. This means that that the costs of gas-fired generation continue to set the wholesale price of electricity in most periods throughout the year and so the Irish electricity price is driven by fuel and carbon markets. Second, interconnection with GB serves to dampen price differentials between the two markets and so reduces the downward impact of Irish wind generation on wholesale prices. Third, our approach to modelling the SEM market schedule assumes that the maximum contribution wind can make towards meeting demand in the price setting algorithm used to set the wholesale price in the SEM from 2018 onwards is 75% in any given time period²³. This approach ensures that projected restrictions on variable generation, to maintain grid stability, are taken into account.

Although wholesale prices fall, the costs to consumers do not fall because of the additional system costs required to integrate wind on the system including DS3 and grid investment costs. It is not yet clear how the system services will be priced and procured, and how costs will be allocated across generators, system operations and consumers,

²³ The DS3 programme aims to increase the current limit for non-synchronous sources of generation in the SEM from 50% to 75%. We model this limit in our market schedule modelling as we do not consider this limitation to be a network constraint which can be resolved with grid investment. There is however no current limit applied in the real market schedule today.

and therefore efforts to reduce the cost to consumers of such measures could help to deliver benefits of consumer price reductions.

While consumer bills rise marginally, overall disposable income is not adversely affected and in fact experiences improvement due to the net gains to the wider economy from investment in wind. The energy price paid by consumers in our *No Wind* scenario is very similar to the price paid in our high wind scenarios. And, our analysis shows that future growth in the wind sector will not need support from the REFIT scheme, the government levy designed to support wind, and will in fact become competitive with other generation sources competing in the wholesale market. This suggests that the required investment for the development of an indigenous Irish industry in the wind sector will not be carried by consumers.

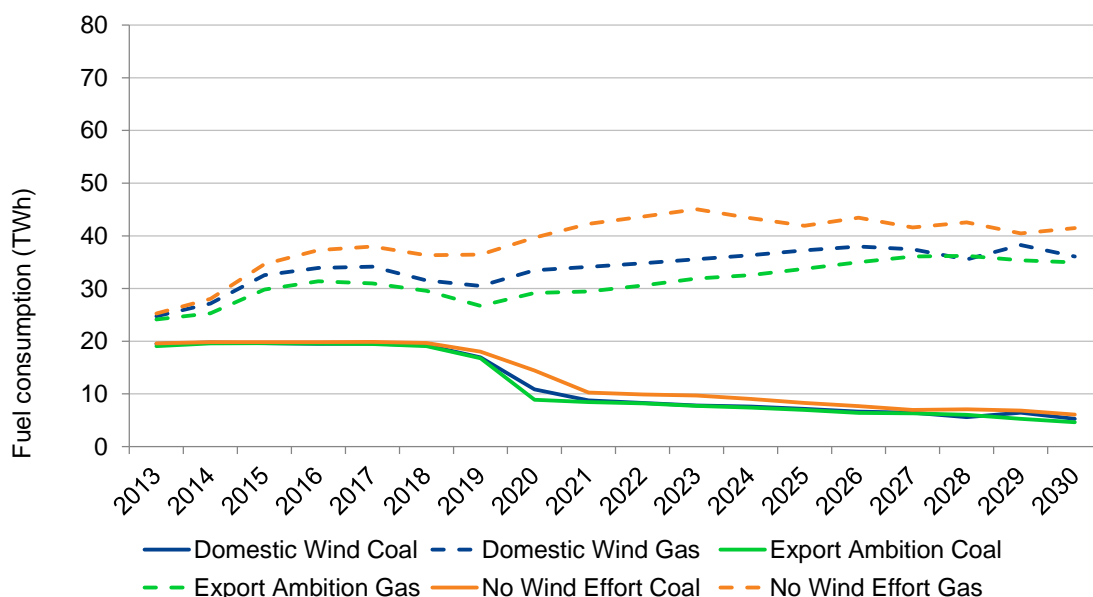
There may be financial penalties imposed by the EU Commission on member states for failing to meet their 2020 renewable target. Although no formal infringement penalties have been associated with missing the targets, a recent referral of RoI to the European Court of Justice for failing to fully transpose into Irish law the Renewable Energy Directive could be an indicator of further penalties to come. Delivering the *Domestic* scenario mitigates this risk offering further economic benefit.

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4. ROI ENERGY BALANCE OF PAYMENTS

The growth of wind capacity in the *Domestic* and *Export* scenarios displaces the marginal sources of generation from the merit order curve proportional to the wind power output and hence reduces the generation output from fossil fuel powered generation. Gas fired generation increases across all of our scenarios as output from other thermal fuel sources diminish although this trend is curtailed in the high wind scenarios *Domestic* and *Export* due to the contribution of wind to meeting demand as shown in Figure 24. It is worth noting that in our scenarios, gas use in RoI is kept lower than SEM as we assume new uncommitted CCGT is constructed in NI.

Figure 24 – RoI fuel demand (TWh, fuel)



4.1 Balance of payments

The total energy import bill for coal, gas and electricity in 2013 is approximately €0.9 billion. This payment remains relatively flat with a high wind rollout in our *Domestic* scenario as while it rises to €1.1 billion by 2020 and €1.5 billion by 2030 in our *No Wind* scenario. Therefore the benefit of wind to the RoI economy is worth €671m annual by 2030 in terms of improved balance of payments for energy imports.

Figure 25 shows the payment balance in ROI for coal, gas and electricity, which is improved with the deployment of wind capacity in both our *Domestic* and significantly in our *Export* scenarios.

Figure 25 – Balance of payments ROI (€m)

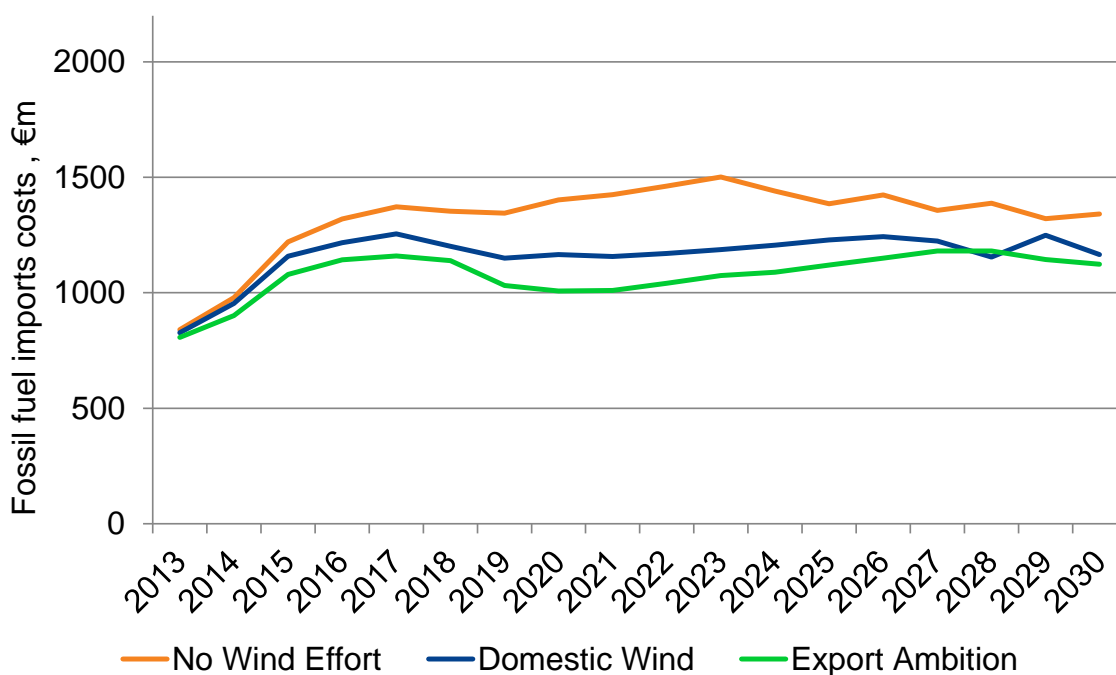


Note: This chart shows the balance of payments accrued to ROI only and includes revenue from the export project in *Export* scenario

4.2 Fossil fuel payments

ROI depends on fuel imports for most of its thermal generation. The gas import requirement is projected to increase in all our scenarios due to the replacement of other thermal fuels (oil, peat, coal) from the merit order. But as shown in Figure 26 wind development in Ireland in both the *Domestic* and *Export* scenarios will reduce the import payments for coal and gas relative to our *No Wind* scenario. The reduced dependency on imported fossil fuels improves the security of supply for ROI.

Figure 26 – ROI power generation gas and coal costs (€m)



4.3 Net interconnector payments

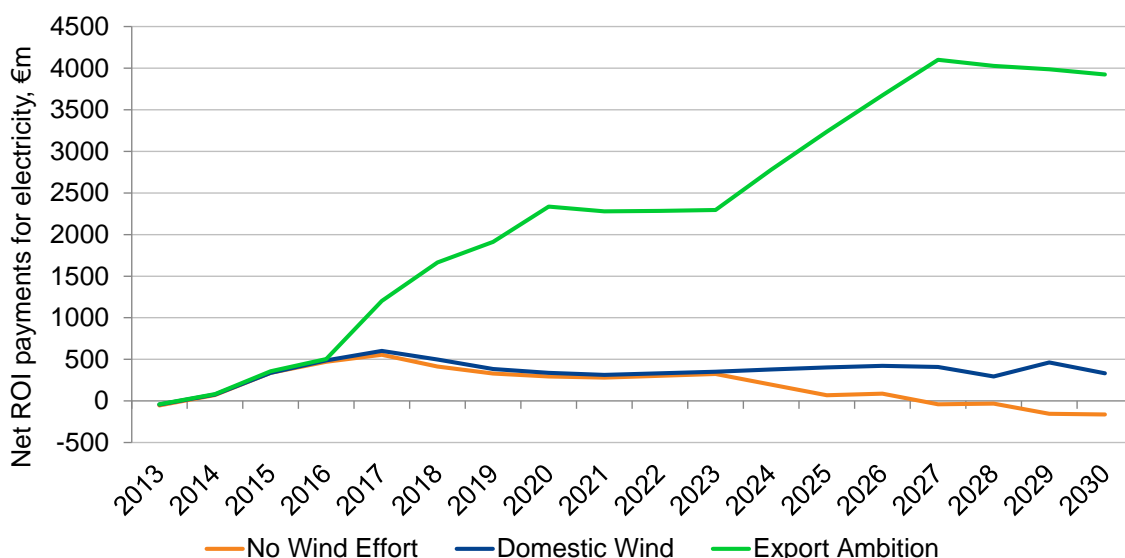
The balance of electricity payments to Rol is shown in Figure 27. This includes payments over interconnection with the GB system and assumed transfer of payments between Rol and NI over the North-South tie-line.

The net electricity payments are currently balanced with Rol a net importer from GB and a net exporter to NI. This balance improves for Rol as GB supply tightens and Rol exports in more periods. The *No Wind* and *Domestic* scenarios remain closely matched until new CCGT capacity is added in NI reducing exports from Rol to meet NI demand.

The *Export* scenario shows how significant value can accrue to Rol from the export project. The first export project creates €2 billion of annual payments coming into Ireland, which increases to €3.8 billion after the second export project is completed. We calculated the export project balance of payment value for Ireland as follows:

$$[Export\ Output] \times [CFD] - [Gross\ imports] \times Max[SEM_{price}, GB_{price}]$$

Figure 27 – Net ROI payments for electricity (€m)



Note: The *Export* scenario includes review accrued to Ireland for the export wind project which we assume is fully funded under the UK government sponsored FIT CfD scheme.

4.4 Concluding remarks

Ireland currently has one of the highest energy import dependencies in Europe importing 85% of its demand requirement²⁴. The development of indigenous wind generation reduces the reliance on fuel imports as electricity generated from fossil fuels are displaced from the merit order. Security of supply refers to both the reliability of the power system over both short and long term periods and the insulation from world gas and carbon prices. Wind does contribute to both, but more the latter.

The additional domestic wind capacity deployed in the *Domestic* scenario reduces reliance on imported energy sources with a 15% reduction in annual gas imports relative to *No Wind* in 2020 and 2030. This not only benefits security of supply but also creates a net transfer to the Irish economy with the energy import bill falling by €282m in 2020. Therefore as Ireland capitalises on its natural resource by making an investment in the wind sector, this financial outlay is mitigated by a reduced import requirement for gas relative to our low wind *No Wind* scenario. In addition to reducing import dependency and improving energy balance of payments, security of supply standards is improved.

²⁴ Energy in Ireland, Key Statistics 2013, SEAI

5. IMPACT ON IRISH ECONOMY

5.1 Introduction

This chapter presents the main results from the macroeconomic analysis of the two scenarios, specifically focusing on the net change in GDP and jobs. The figures presented in this chapter consider the Irish economy as a whole. They incorporate:

- the gross sector effects of an increase in wind deployment (as outlined in Section 2);
- the indirect and induced effects due to higher employment and higher overall demand in the economy;
- the impact on the balance of trade as a result of higher electricity exports, higher imports of wind turbines and lower gas imports;
- the effects of marginally higher retail electricity prices in the *Domestic* and *Export* scenarios; and
- the impact on consumer disposable income.

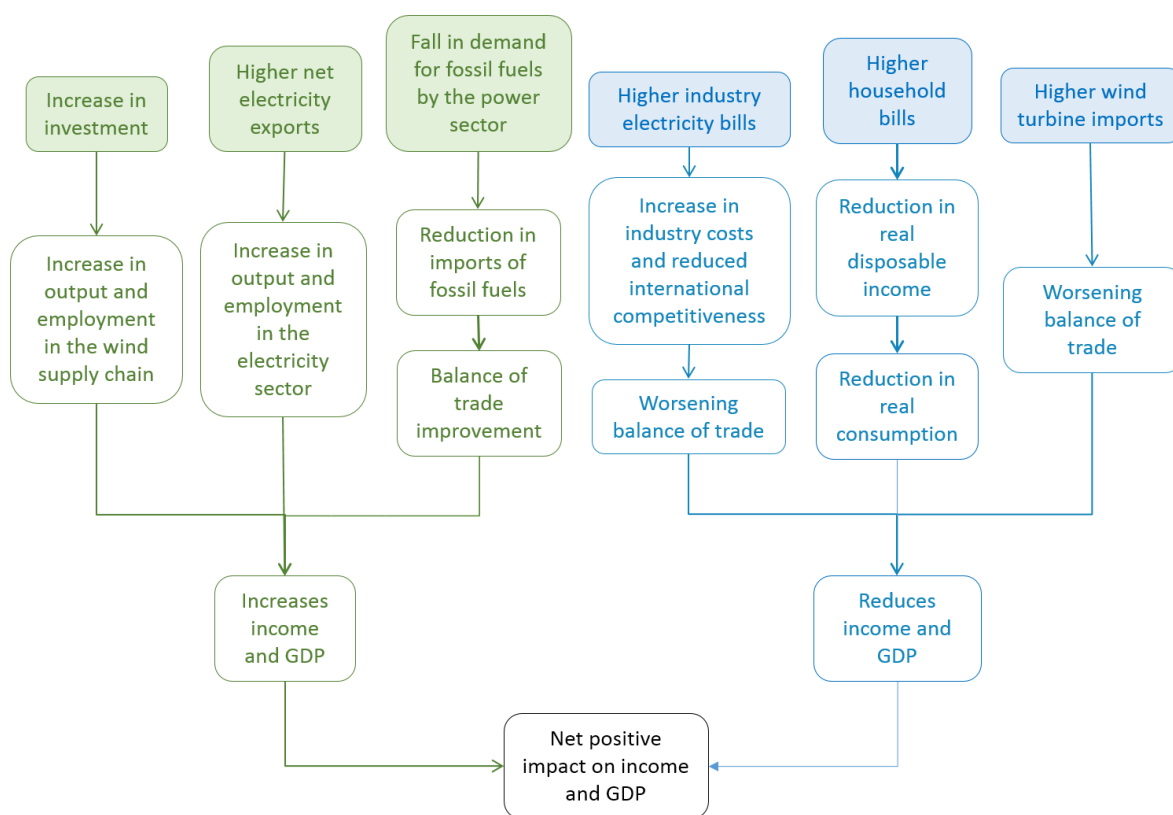
5.2 Key elements of the economic impact

There are four key elements that determine the economic impact of wind energy generation in the RoI:

- investment and specifically the level of investment; the share that goes to other domestic industries and, indirectly, to associated supply chains in the domestic economy; and the effects of wind energy investment on other types of investment;
- the effects on the value of exports and imports of electricity;
- the extent to which the additional wind generation displaces fossil fuel imports; and
- the impact on electricity prices and the extent to which households and industries are affected by or respond to these price changes.

The expected economic consequences of the *Domestic* and *Export* scenarios are summarized in Figure 28 and discussed in more detail in Section 5.2.1 to Section 5.2.4 below.

Figure 28 – Expected economic consequences of the Domestic and Export scenarios



5.2.1 Investment

The defining feature of the *Domestic* and *Export* scenarios is increased investment into wind capacity and the supporting transmission and grid infrastructure. In the *Domestic* scenario, there is an additional annual average of €434m investment in the wind sector and grid network over the period 2013-2020 and this increases slightly to average additional investment of €482m per annum over the period 2021-2030. In this scenario, the investment is broadly stable from year to year. In the *Export* scenario, there is an annual average of €2,036m of additional investment over the *No Wind* baseline in the period 2013-2020, and an additional €1,458m per annum over 2021-2030, but the build phase is concentrated in two periods, the first from 2016-19 and the second from 2023-26.

There are three interrelated factors that are crucial to assessing the economic impact of this investment:

- the share of investment that accrues to domestic producers;
- the distribution of the domestic share across industry sectors; and
- how the investment is financed and the extent to which this investment ‘crowds out’ other forms of investment.

We have based our allocation of investment to the domestic economy on a study by IRENA²⁵, which found that the manufacture of the wind turbine accounts for approximately 64% of total capital costs. As there are currently no turbine manufacturing facilities in the RoI, we have assumed that the wind turbine themselves are imported from abroad, but that the remaining 36% of capital investment is met by domestic suppliers. This implies that just over one-third of the total investment can be treated as creating a direct stimulus to the Irish economy. Of the total investment stimulus, 19% of the investment goes to the domestic construction sector (mainly associated with building the foundations and installing the turbine) and the remainder of the domestic share of investment is split between the machinery, metal and electrical equipment manufacturing sectors; the engineering sector; and the legal, consulting and planning sector.

Higher investment in the wind sector in the *Domestic* and *Export* scenarios leads to an increase in output and employment in construction and, to a lesser extent, in the other domestic sectors that the investment goes to. It would also lead to an increase in demand further down the supply chain, referred to as the 'indirect effect'. For example, the construction sector would require more cement and building materials in order to install the wind turbine, and demand from the other sectors for intermediate goods and services would also increase. This indirect effect would lead to a further increase in output and jobs. This increase in economic activity and employment would lead to an increase in average household incomes, which would, in turn, lead to an increase in consumer demand and thus to further increases in output and employment in the economy (the 'induced effect'). In these ways, the increase in domestic production from the investment in wind generation has a multiplier effect.

The domestic construction sector, which is assumed to receive 19% of total wind investment (and over half of the domestic share of investment), is a relatively labour-intensive sector. Consequently, the domestic share of the wind investment would have a relatively large impact on employment and real incomes and, subsequently, a considerable induced effect.

The investment under the *Domestic* and *Export* scenarios falls into four broad categories:

- DS3 investment;
- grid investment;
- additional wind investment to meet domestic targets (in both scenarios); and
- export project investment (in *Export* scenario only).

All the investment that takes place must be paid for. In practice, the two most likely options are that it could be financed by the government or by the electricity companies (through higher prices). In order to ensure the scenarios are unbiased, we have to make further assumptions about how the government or the electricity companies would raise the funds. For example, the government could increase taxes or reduce other expenditure, while electricity companies could increase prices or cut other investments. Our assumptions for the source of financing to support the additional investment in the *Domestic* and *Export* scenarios vary for each of the four broad categories of investment (see Table 5).

²⁵ IRENA (2012), "Renewable Energy Technologies: Cost Analysis Series, Volume 1: Power Sector, Issue 5/5: Wind Power".

Table 5 – Summary of investment financing assumptions

Investment category	Financing assumption
DS3 investment	Financed by higher retail electricity prices
Grid investment	Financed by higher retail electricity prices
Additional wind investment to meet domestic targets	Financed by Irish electricity companies
Export project investment	Financed by UK government revenue from CFDs

It is assumed in the scenarios that the DS3 and grid investment costs would be added to the price of electricity faced by households and industrial users. These costs are therefore effectively paid for by domestic consumers of electricity. The additional investment costs to fund the export project in the *Export* scenario are assumed to be financed by GB electricity consumers, by means of revenues from the Contracts for Difference payments.

On the assumption that the electricity sector meets the costs of domestic wind investment, the appropriate treatment in the model is more complex.

- Wholesale electricity prices are slightly lower in the *Domestic* and *Export* scenarios than in the *No Wind* scenario, but domestic electricity consumption is the same in all three scenarios. The consequence is that overall domestic sales revenues are marginally lower in the *Domestic* and *Export* scenarios.
- Capital investment costs are higher in the *Domestic* and *Export* scenarios than in the *No Wind* scenario, due to the large amount of additional wind capacity built in these scenarios.

If all other aspects of the scenarios were equal, these assumptions about financing would imply a relative reduction of electricity sector profitability in the *Domestic* and *Export* scenarios (compared with the *No Wind* scenario). There would be an increase in costs (due to the additional wind investment) but slightly lower revenues (due to the lower wholesale electricity price). In macroeconomic terms, this introduces a bias between scenarios in the modelling, since the lower revenues lead to a shortfall of economy-wide funding for investment. However, there are some other factors that will also affect electricity sector profitability.

- In particular, the *Domestic* scenario has higher electricity exports. This means that, overall, average annual electricity sector revenue is €136m²⁶ higher in the *Domestic* scenario.
- Annual costs faced by the electricity sector are €310m²⁷ higher in the *Domestic* scenario.

²⁶ Average annual sales of exported electricity are €174m higher in the *Domestic* scenario compared with the *No Wind* scenario, but average annual revenues from domestic electricity sales are €38m lower than in *No Wind*.

²⁷ Although annual fuel costs in the *Domestic* scenario are €151m lower than in *No Wind*, average annual capital investment costs are €292 higher and annual operation and maintenance costs are €169m higher than in *No Wind*.

- Therefore, overall annual average profits for the sector are €174m lower in the *Domestic* scenario than in the *No Wind* baseline scenario.

In order to avoid the bias in the modelling described above (a shortfall of economy-wide funding for investment), we assume that part of the wind investment (corresponding to the €174m of lower average annual profits) would displace other investment in the *Domestic* scenario. In the *Export* scenario, by contrast, the additional export sales of electricity are sufficient to cover the domestic wind capital investment costs; and so we do not model any displacement of investment in this scenario (see Figure 27).

It should be noted that there are some circumstances under which there would not be a reduction in electricity sector profits in the *Domestic* scenario. For example, if Ireland was able to secure external financing for the wind investment, then the electricity companies would not necessarily need to cover the investment costs (at least in the short term).

For the *Domestic* scenario, a sensitivity analysis under the assumption that external financing would be available to fund the wind investment illustrates the most wind-optimistic case, and shows that external financing would have a small positive impact on the results (see Annex D.4.1.4).

5.2.2 Imports and exports of electricity

The SEM in Ireland is currently connected to the GB market via one interconnector in Northern Ireland and one in the RoI. A new 500MW interconnector between GB and RoI is added in both the *Domestic* and *Export* scenarios. There are no interconnectors linking the SEM directly to the European continent and therefore it is the difference between the GB and Irish wholesale electricity price that drives the electricity trade flows in Ireland. The lower wholesale electricity prices in the *Domestic* and *Export* scenarios lead to a widening of this difference in price, to the advantage of exports of Irish-generated electricity.

The electricity market modelling shows net annual electricity exports are €50m higher in the *Domestic* scenario compared with the *No Wind* scenario by 2020. This difference increases to €495m by 2030. In the *Export* scenario, there is additional €2,137m of net electricity exports in 2020, rising to €4,247m by 2030.

5.2.3 Fossil fuel imports

Domestic electricity demand is assumed to be the same in each of the three scenarios modelled, and the majority of the additional wind generation in the *Domestic* and *Export* scenarios is assumed to displace gas-fired power generation. By 2030, annual imports of gas into Ireland are €165m lower in the *Domestic* scenario and €199m lower in the *Export* scenario (compared with the *No Wind* baseline). This reduces the amount of money flowing out of the Irish economy.

5.2.4 Electricity prices

Household and industry electricity prices are marginally higher in the *Domestic* and *Export* scenarios, relative to *No Wind*. The consequences of this and the impact on household and industry electricity bills are discussed in Chapter 3.

5.3 Macroeconomic results

5.3.1 GDP

The macroeconomic results show that GDP is, on average €350m (0.2%) higher per annum in the *Domestic* scenario over the period 2013-2020 and €650m (0.3%) higher on average per annum over the period 2021-2030 (compared with the *No Wind* baseline).

If Ireland could secure funding for substantial export wind projects, the positive economic impacts are much greater: in the *Export* scenario, annual GDP is on average €2.52 billion (1.3%) higher than in the *No Wind* baseline over the period 2013-2020 and €5.02 billion (2.1%) higher over the period 2021-2030. The breakdown of the GDP impact into its component parts is shown in Figure 29.

Figure 29 – Breakdown of economic impact (average per annum over the specified period)

		Domestic Scenario 2013-2020	Domestic Scenario 2021-2030	Export Scenario 2013-2020	Export Scenario 2021-2030
Increase in wind and grid investment	Increase in output and employment in the wind sector supply chain	+€434m (domestic share = €156m)	+€482m (domestic share = €174m)	€2,036m (domestic share = €733m)	€1,458m (domestic share = €525m)
Increase in net electricity exports	Increase in output and employment in the electricity sector	+€36m	+€285m	+€719m	+€3,276m
Reduction in demand for gas imports	Balance of trade improvement	+€103m	+€190m	+€181m	+€274m
Multiplier and induced effect	Increase in output and employment drives further increases in demand	+€253m	+€245m	+€895m	+€754m
Loss of electricity sector profits	Reduction in investment	-€174m	-€174m	-€0m	-€0m
Increase in household and industry electricity bills	Reduction in disposable income, increase in industry costs	-€24m	-€70m	-€11m	-€50m
Net impact on GDP	Taking account of all of the above	+€350m	+€650m	+€2,517m	+€5,015m

Note(s): we assume that the electricity sector balances profits over the period 2013-2030, and therefore the reduction in baseline investment is equal in each year (-€174m)

5.3.2 Net employment

The net impact on employment incorporates the following factors:

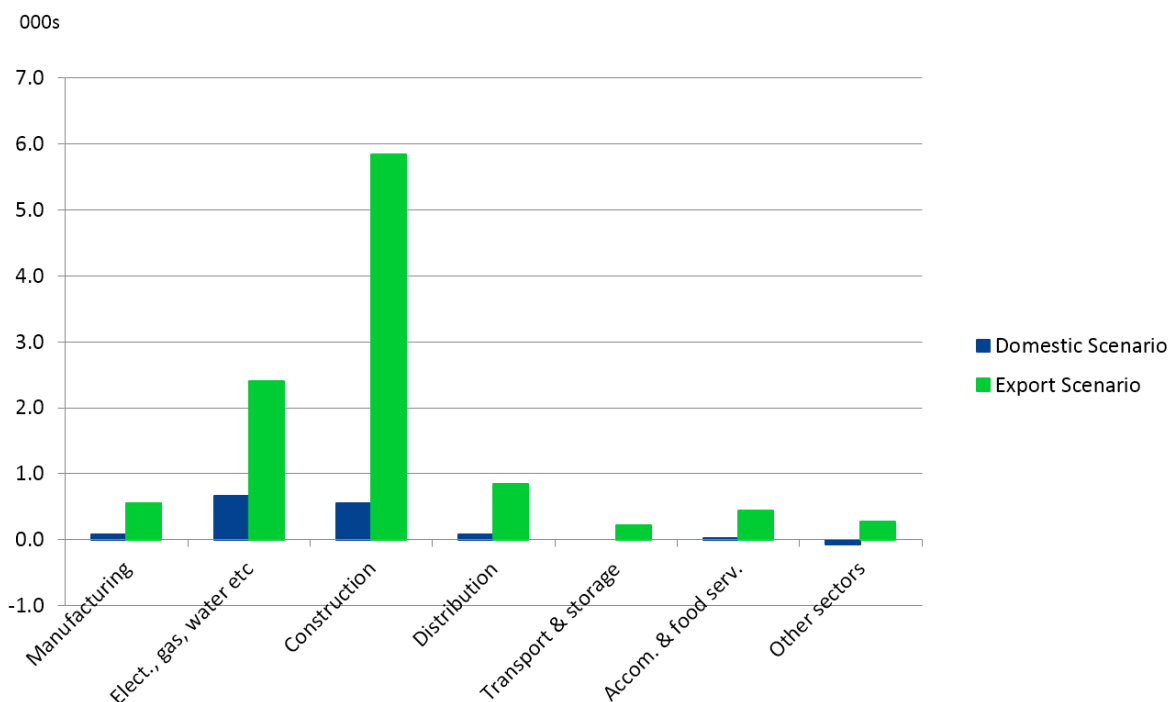
- an increase in direct jobs created in the wind sector due to an increase in capital investment in wind power and an increase in operations and maintenance requirements;
- an indirect increase in employment to support the increase in supply chain demand;
- an induced effect due to higher incomes and consumer demand that drives further increases in employment; and
- the effect of marginally higher retail electricity prices that may lead to a reduction in consumption, output and employment.

Importantly, in the *Domestic* scenario, these figures also take account of displaced investment, which is the assumption we make to maintain electricity sector profit neutrality and in order to ensure our scenarios are unbiased. The corollary of this is that, in the *Domestic* scenario, the net economy-wide jobs result is lower than the number of direct jobs created in the wind sector (as outlined in Chapter 2). Despite the fact that the economy-wide impact includes indirect and induced jobs, it also incorporates the effects of our assumption that some of the wind investment would displace other investment.

Taking account of the direct, indirect and induced jobs in the scenarios, as well as the assumption of a loss of investment in order to maintain electricity sector profit neutrality in the *Domestic* scenario, the overall impact in the *Domestic* scenario is an average additional 1,150 jobs over the period 2013-2020, and, on average, an additional 1,600 jobs over the period 2021-2030 compared with the *No Wind* baseline. In the *Export* scenario there are an additional 7,450 jobs, on average, over the period 2013-2020, rising to 11,850 additional jobs compared with the *No Wind* baseline over the period 2020-2030.

Figure 30 shows the employment results by sector. The Construction sector and the Electricity sector see the largest increase in employment as a direct result of the installation and maintenance of the wind turbines. Employment in the manufacturing and service sectors increases due to the indirect and induced effects.

Figure 30 – Net impact on employment by sector, annual average 2021-2030



5.3.3 Household income

Despite a marginal increase in household electricity bills in the *Domestic* and *Export* scenarios, the average Irish household is still better off in both scenarios. The additional direct employment in the wind investment sectors and the indirect employment in these sectors’ supply chains result in an increase in average real personal incomes. In the *Domestic* scenario this increase is sufficient to offset the negative impact of marginally higher electricity prices. In the *Export* scenario, household incomes are, on average, €380 higher per annum over the period 2013-2020 and €640 higher per annum over 2021-2030.

5.3.4 Impact on government revenue

The consequences for three separate tax revenues were assessed and the results show that:

- higher income tax revenues and Universal Social Charge payments than in the *No Wind* baseline, due to an increase in employment and incomes;
- higher corporation tax revenue than in the *No Wind* baseline, due to an increase in industry output and a net increase in industry profits; and
- higher VAT revenue than in the *No Wind* baseline, due to an increase in consumer spending.

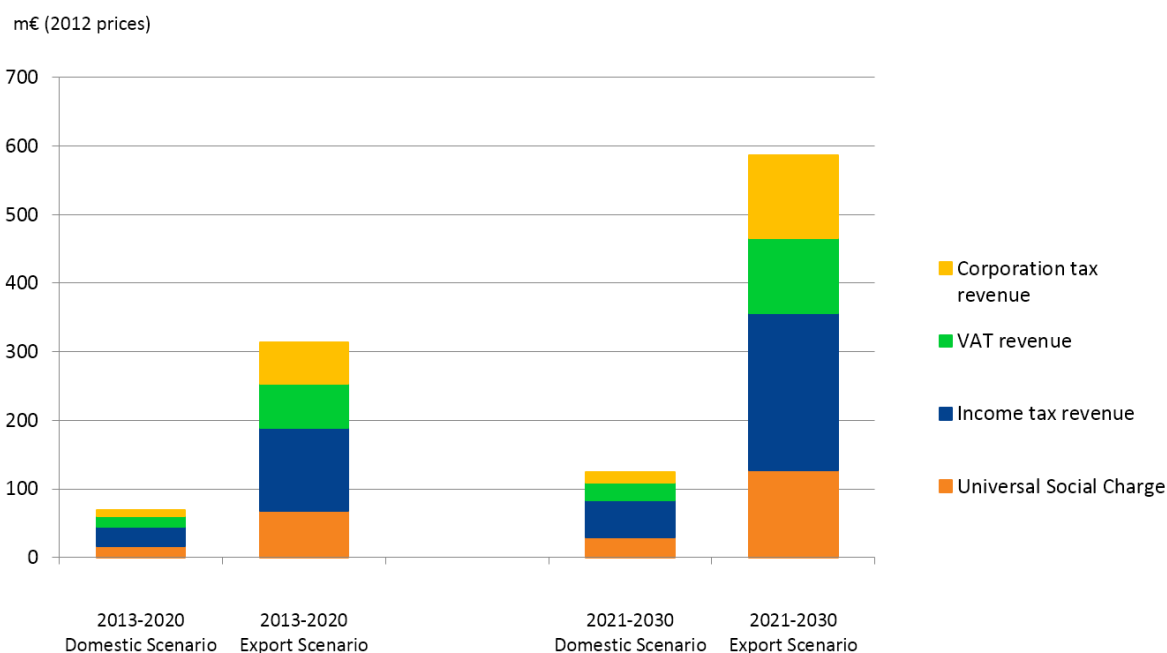
The estimated increase in tax revenue is show Figure 31. By 2030, additional cumulative tax revenue could reach €1.8 billion in the *Domestic* scenario and €8.4 billion in the *Export*

scenario, which is equivalent to 1% of current Irish government debt²⁸ in the *Domestic* scenario and 4% of Irish government debt in the *Export* scenario.

To assess the net effect on the government budget balance, it is necessary to consider the impact on welfare payments as well as on fiscal revenues. This is a particularly important consideration in Ireland, where unemployment benefit payments as a percentage of GDP have recently been amongst the highest in the EU (over 3% of GDP in 2011²⁹). A policy that can stimulate output and employment in the economy will not only be effective because of the spare capacity and under-employment in the economy, it will also have the potential to reduce the government’s budget deficit.

The increase in employment in the *Domestic* and *Export* scenarios comprises people that are drawn into the labour market due to higher wage rates, and people who would otherwise be unemployed but are able to secure jobs in these scenarios. The increase in labour demand results in a fall in unemployment of 2,160 in the *Domestic* scenario and 9,840 in the *Export* scenario by 2030. This could reduce unemployment benefit payments by as much as €21m in the *Domestic* scenario and €96m in the *Export* scenario by 2030³⁰, and further relieve the strain on government debt.

Figure 31 – Average additional tax revenue per annum (relative to *No Wind Effort* scenario), 2013-2020 and 2021-2030



²⁸ 'Provision of deficit and debt data for 2012', Eurostat, April 2013

²⁹ Eurostat

³⁰ Based on estimated reduction in unemployment of 2,158 in 2030 (compared with *No Wind*) and average weekly unemployment payment of €188 per week, see: <http://www.welfare.ie/en/Pages/Jobseekers-supports.aspx>

5.4 Concluding remarks

The analysis in this chapter of the report shows that developing wind capacity in Ireland has the potential to bring both transitional and long-term economic benefits. In the transition phase, investment in new sites will create jobs in the construction and engineering sectors. In the long term, the benefits will come from higher exports of electricity to GB. This export income is expected to provide finance for the initial investment and will also contribute to GDP and employment and ongoing O&M in the longer run.

In the *Domestic* scenario, in which Irish wind capacity, grows to reach 3.8 GW by 2020, there is an increase in annual GDP of €352m on average over the period 2013 to 2020 and around 1,150 additional jobs, even if turbines are imported from other European countries.

In the more ambitious *Export* scenario, the new wind projects are financed by the UK's Contract for Difference payments. Under these assumptions, GDP could increase by €2,517 per annum on average over the period 2013-2020 and €5,015 over 2021-2030. This would lead to an additional 7,450 jobs each year over 2013-2020 and 11,840 over 2021-2030.

As with any economic modelling exercise, it is important to be aware of the underlying assumptions. In this case the key assumption is the development in the UK market, which was a result of the energy market analysis (see Annex B). Under these conditions, the increased demand for electricity generated from renewable sources in Ireland creates the additional employment opportunities that we see in our results. The available capacity in the Irish economy (e.g. as demonstrated by high unemployment rates) means that this demand stimulus results in an overall increase in output and employment levels.

6. SUMMARY OF ECONOMIC BENEFITS

Wind sector direct effects

The wind industry would make a valuable contribution to the Irish economy by meeting the 2020 renewable target and provide a good platform for continued growth during the 2020s compounding the benefit to the economy.

- 12,390 jobs (person-years) are supported during construction to deliver the 2020 renewable target; a further 10,120 jobs (person-years) are supported during construction through to 2030.
- O&M sector is projected to more than double to 920 permanent jobs by 2020 and rise to 1,340 by 2030.
- Wind growth supports €3.5 billion of direct investment to 2020, 1.2% of total Irish investment, and an additional €4.8 billion to 2030.
- Wind output avoids carbon emissions by displacing the marginal thermal source of generation (gas CCGT). This delivers 21mtCO₂ avoided through 2020 and another 43mtCO₂ through 2030, doubling the tonnes of CO₂ avoided in this time period.

Energy market effects

- There is a merit order effect on wholesale prices leading to a reduction of €2/MWh. This reduction is limited because of the impact of interconnection on market performance.
- Annual consumer bills are marginally higher as they reflect additional network costs of accommodating renewables although the increase in bills is offset by the wider benefits to the economy driven by the investment stimulus which delivers an increase to consumer disposable income.
- By pursuing a domestic wind deployment programme the cut in power sector emissions can be doubled falling to 9.5MtCO₂ by 2020 (from 13.5MtCO₂ today).
- Gas imports fall by 15% relative to *No Wind* scenario delivering an annual reduction of fossil fuel imports of €282m by 2020.

Whole economy impacts

- Net GDP is on average €350m (0.2%) higher per annum in the *Domestic* scenario over the period 2013-2020 and €650m (0.3%) higher on average per annum over the period 2021-2030 (compared with the *No Wind* baseline).
- In the *Domestic* scenario, there are, on average, an additional 1,150 jobs over the period 2013-2020, rising to an additional 1,600 jobs, on average, over 2021-2030.
- Boost to government revenue through an estimated cumulative increase in tax revenue by 2030 in the *Domestic* scenario of €1.8 billion which is equivalent to 1% of current Irish government debt and a reduction in unemployment benefit payments by as much as €21m.
- By 2030, additional cumulative tax revenue could reach €1.8 billion in the *Domestic* scenario and €8.4 billion in the *Export* scenario, which is equivalent to 1% of current Irish government debt in the *Domestic* scenario and 4% of Irish government debt in the *Export* scenario.

- The increase in labour demand results in a fall in unemployment of 2,160 in the *Domestic* scenario and 9,840 in the *Export* scenario by 2030. This could reduce unemployment benefit payments by as much as €21m in the *Domestic* scenario and €96m in the *Export* scenario by 2030³¹, and further relieve the strain on government debt.

Export Wind Ambition

- Achieving domestic targets can deliver material benefits to the Irish economy. However, the scale of wind resource provides further opportunities to grow the industry and provide a boost to the wider economy.
- Because these projects would be export focused and hence funded externally, the potential benefits are much larger. If the export projects modelled in this study were delivered then there is potential for:
 - By 2030, the creation of 85,28032 jobs, on a person-year basis to support construction for each export project as well as the domestic wind capacity installed in this scenario.
 - O&M sector could rise to support 2,130 permanent jobs by 2020 and grow to 3,520 by 2030.
 - Net GDP, on average €2.52 billion (1.3%) higher than in the No Wind baseline over the period 2013-2020 and €5.02 billion (2.1%) higher over the period 2021-2030.
 - There are an additional 7,450 jobs, on average in the Irish economy, over the period 2013-2020, rising to 11,850 additional jobs compared with the No Wind baseline over the period 2020-2030.

³¹ Based on estimated reduction in unemployment of 2,158 in 2030 (compared with *No Wind*) and average weekly unemployment payment of €188 per week, see:
<http://www.welfare.ie/en/Pages/Jobseekers-supports.aspx>

³² 47,240 jobs created over 2013-2020 and an additional 38,040 created over 2021-2030, on a person-year basis.

ANNEX A – PÖYRY'S MODELLING APPROACH

A fundamental market modelling approach was taken to assess the impact of wind development in Ireland in the SEM and GB electricity markets. To undertake the analysis, we used our internally developed market model, **BID3**.

A.1 Evolution of Pöyry market models

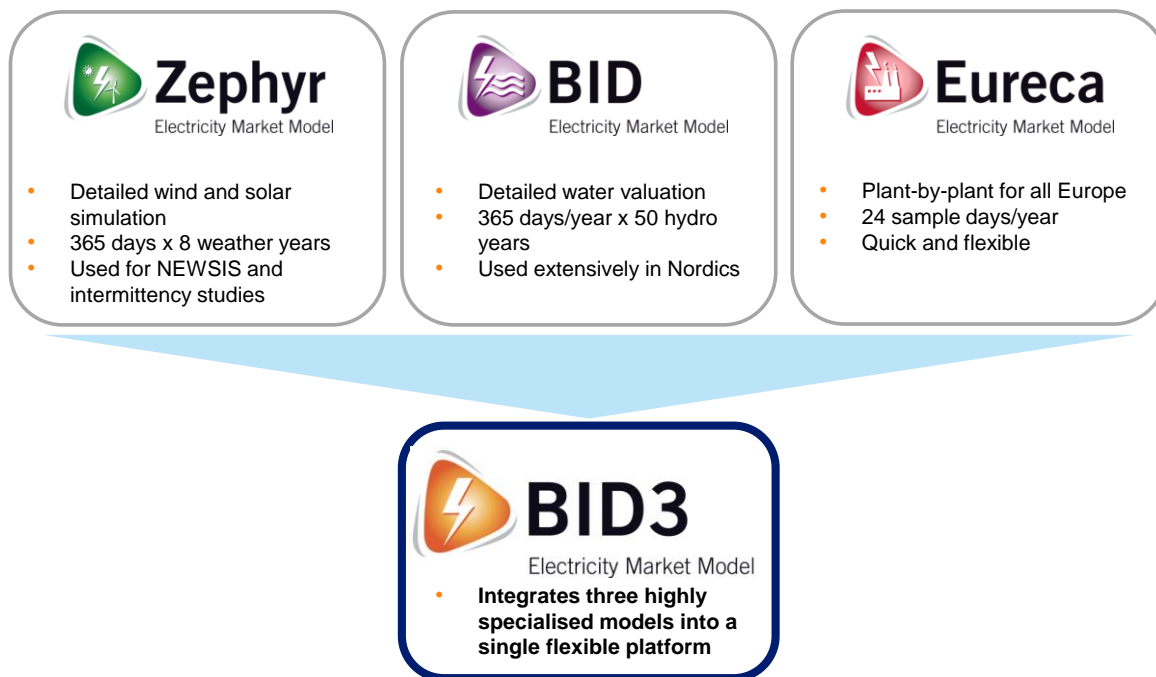
BID3 is Pöyry's power market model, used to model the dispatch of all generation on the European network. We simulate all 8760 hours per year, with multiple historical weather patterns, generating hourly wholesale prices for each country for each future year and dispatch patterns and revenues for each plant in Europe.

As illustrated in Figure 32 we have developed **BID3** out of our previous power market models: BID 2.4 which has sophisticated treatment of hydro dispatch, using Stochastic Dynamic Programming to calculate the option value of stored water; and Zephyr, which has underpinned our ground-breaking studies quantifying the impacts of intermittency in European electricity markets and the role flexibility could play in meeting the challenges of variable generation. **BID3** is highly flexible to use and incorporates the best aspects of our previous models. Since **BID3** is based upon the same underlying dispatch algorithm as Zephyr, there is no fundamental basis shift in projections when moving between the two

BID3 is:

- the modelling platform used for Pöyry's *Electricity Market Quarterly Analysis* reports, giving European power price projections used by major banks, utilities, governments and developers;
- used for bespoke projects for a wide range of clients; and
- available to purchase – deployed in-house by Energinet, Fingrid, Hydro, NVE, Statnett, and Svenska Kraftnät.

Figure 32 – Evolution of Pöyry electricity market models



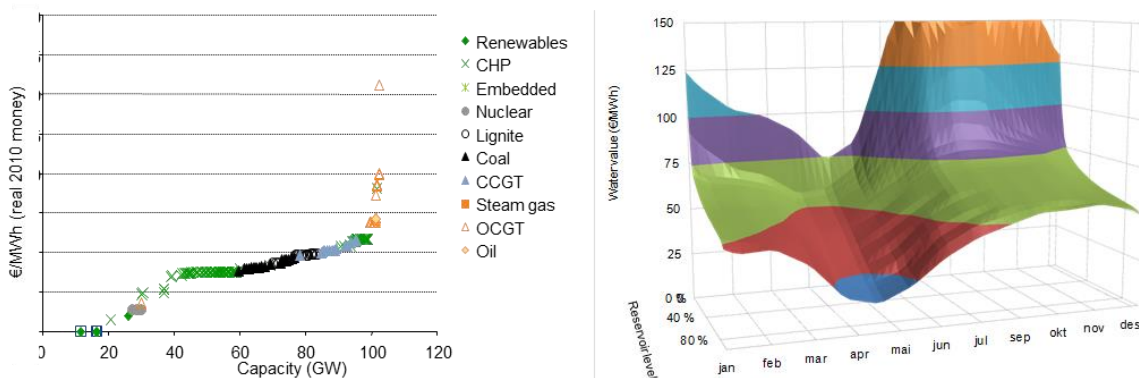
A.2 Modelling methodology

BID3 is an economic dispatch model based around optimisation. The model balances demand and supply on an hourly basis by minimising the variable cost of electricity generation. The result of this optimisation is an hourly dispatch schedule for all power plant and interconnectors on the system. At the high level, this is equivalent to modelling the market by the intersection between a supply curve and a demand curve for each hour. Producing the system schedule:

- **Dispatch of thermal plant.** All plants are assumed to bid cost reflectively and plants are dispatched on a merit order bases – i.e. plants with lower short-run variable costs are dispatched ahead of plant with higher short-run variable costs. This reflects a fully competitive market and leads to a least-cost solution. Costs associated with starts and part-loading are included in the optimisation. The model also takes account of all the major plant dynamics, including minimum stable generation, minimum on-times and minimum off-times. Figure 33 below shows an example merit order curve for thermal plant.
- **Interconnector flows.** Interconnectors are optimally utilised – this is equivalent to a market coupling arrangement.
- **Dispatch of hydro plant.** Reservoir hydro plants can be dispatched in two ways:
 - A simple perfect foresight methodology, where each reservoir has a one year of foresight of its natural inflow and the seasonal power price level, and is able to fix the seasonality of its operation in an optimal way.
 - The water value method, where the option value of stored water is calculated using Stochastic Dynamic Programming. This results in a water value curve where the option value of a stored MWh is a function of the

filling level of the reservoir, the filling level of competing reservoirs, and the time of year. Figure 33 below shows an example water value curve.

Figure 33 – Thermal plant merit-order and water value curve



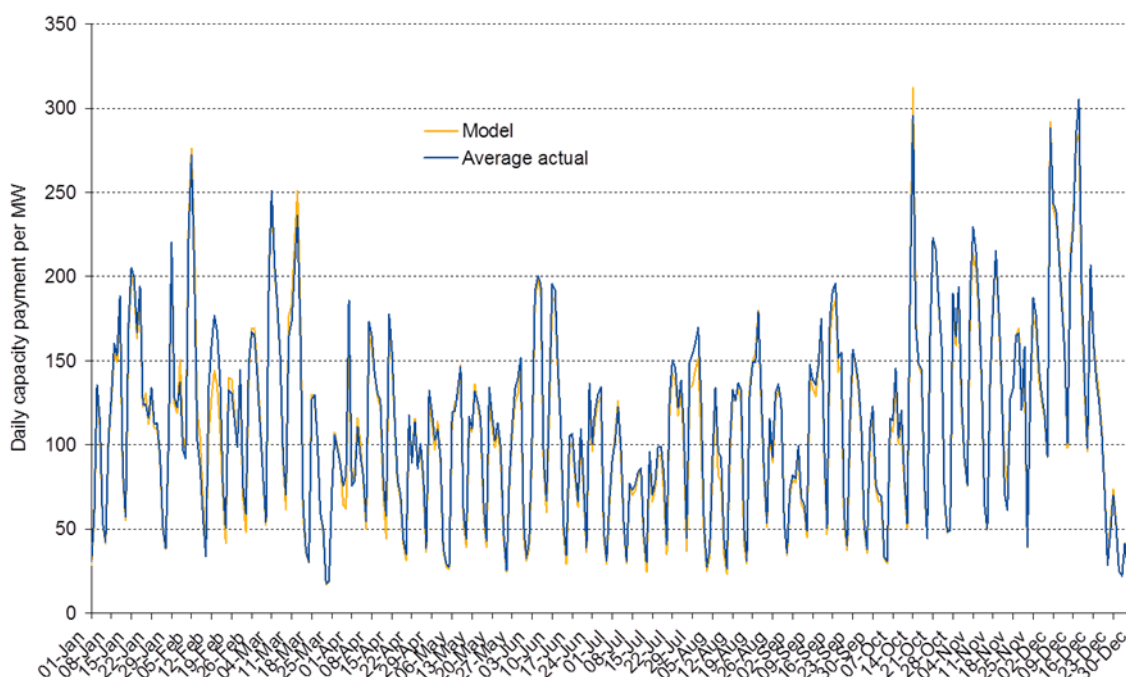
A.3 Power price

The model produces a power price for each hour and for each zone (which may be smaller than one country, for example the different price-zones within Norway). The hourly power price is composed of two components:

- **Short-run marginal cost.** The SRMC is the extra cost of one additional unit of power consumption. It is the minimum price at which all operating plant are recovering their variable costs. Since the optimisation includes start-up and part-load costs all plant will fully cover their variable costs, including fuel, start-up, and part-loading costs.
- **Scarcity rent.** A scarcity rent is included in the market price – we assume power prices are able to rise above the short-run marginal cost at times when the capacity margin is tight. In each hour the scarcity rent is determined by the capacity margin in each market. It is needed to ensure that the plants required to maintain system security are able to recover all of their fixed and capital costs from the market. The SEM has an explicit payment for available generation capacity through the Capacity Payment Mechanism (CPM).

We have developed a detailed model of the CPM, which can replicate the market rules with a high degree of accuracy, shown in Figure 34. The distribution of the annual sum within the year is based on a blend of projected demand, projected system margin and outturn system margin. The impact on the CPM of the increased level of wind on the system, as well as potential changes to the CPM can be modelled on a bespoke basis for clients if required.

Figure 34 – Comparison of the CPM model with actual data



A.4 Input data

Pöyry’s power market modelling is based on Pöyry’s plant-by-plant database of the European power market. The database is updated each quarter by Pöyry’s country experts as part of our *Electricity Market Quarterly Analysis*.

- **Demand.** Annual demand projections are based on TSO forecasts³³ up to 2022 and assumed to grow by 1.3% thereafter according to the EU PRIMES growth rate for Ireland³⁴. For the within year profile of demand we use historical demand profiles – for each future year that is modelled we use demand profiles from a range of historical years.
- **Variable generation.** We use historical wind speed data and solar radiation data as raw inputs. We use consistent historical weather and demand profiles (i.e. both from the same historical year). This means we capture any correlations between weather and demand, and can also example a variety of conditions – for example a particularly windy year, or a cold, high demand, low wind period.
 - Our wind data is from Anemos and is reanalysis data from weather modelling based on satellite observations. It is hourly wind speeds at grid points on a 20km grid across Europe, at hub height. Figure 35 below shows average wind speeds based on this data. Hourly wind speed is converted to

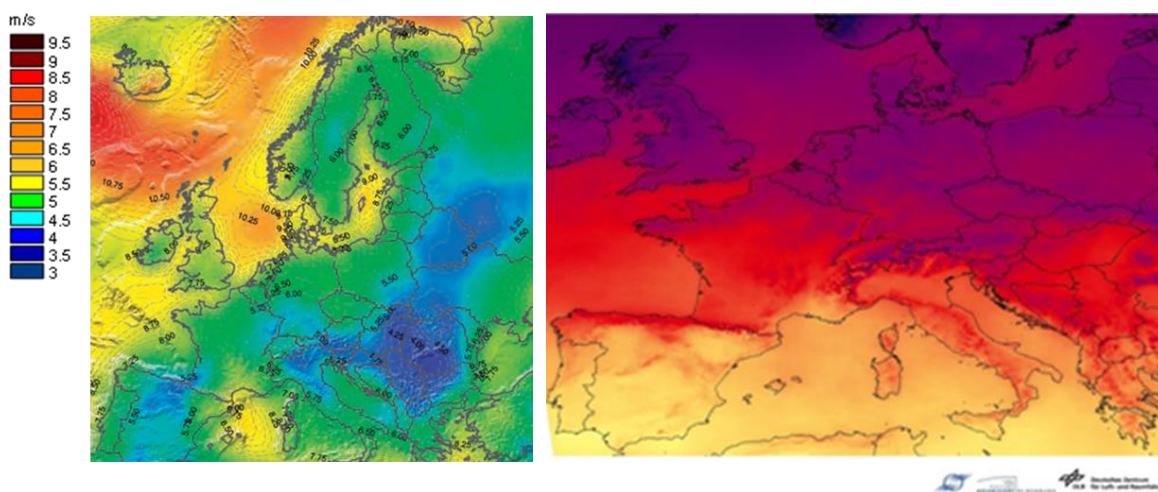
³³ All Island Generation Capacity Statement (2013-2022), TSOs (EirGrid and Soni), December 2012

³⁴ EU PRIMES reference scenario growth rate for Ireland, EU energy trends to 2030 update 2009, European Commission, August 2010

hourly wind generation based on wind capacity locations and using appropriate aggregated power curves.

- The solar radiation data is from Transvalor, and is again converted to solar generation profiles based on capacity distributions across each country. Figure 35 below shows average solar radiation based on this data.
- **Fuel prices.** The latest DECC fuel price projections³⁵ for oil, gas and coal were used in conjunction with BID3 to produce input fuel prices consistent with the scenarios developed.
- **Carbon prices.** EU carbon price projections formulated using short term DECC36 (central) projections and long term IEA37 projections. The main modelling scenarios assumed the IEA current polices price trajectory whereas the carbon price sensitivity assumed the IEA 450 scenario price trajectory for carbon.

Figure 35 – Average wind speeds and solar radiation in Europe



Source: Anemos, data resolution 20km by 20km Source: Transvalor, data resolution 2km by 2km

³⁵ Reference scenario, Updated Energy and Emissions Projections, DECC, September 2013

³⁶ Updated short-term traded carbon values used for modelling purposes, DECC, September 2013

³⁷ World Energy Outlook 2012, IEA, November 2012

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ANNEX B – ENERGY MARKET RESULTS

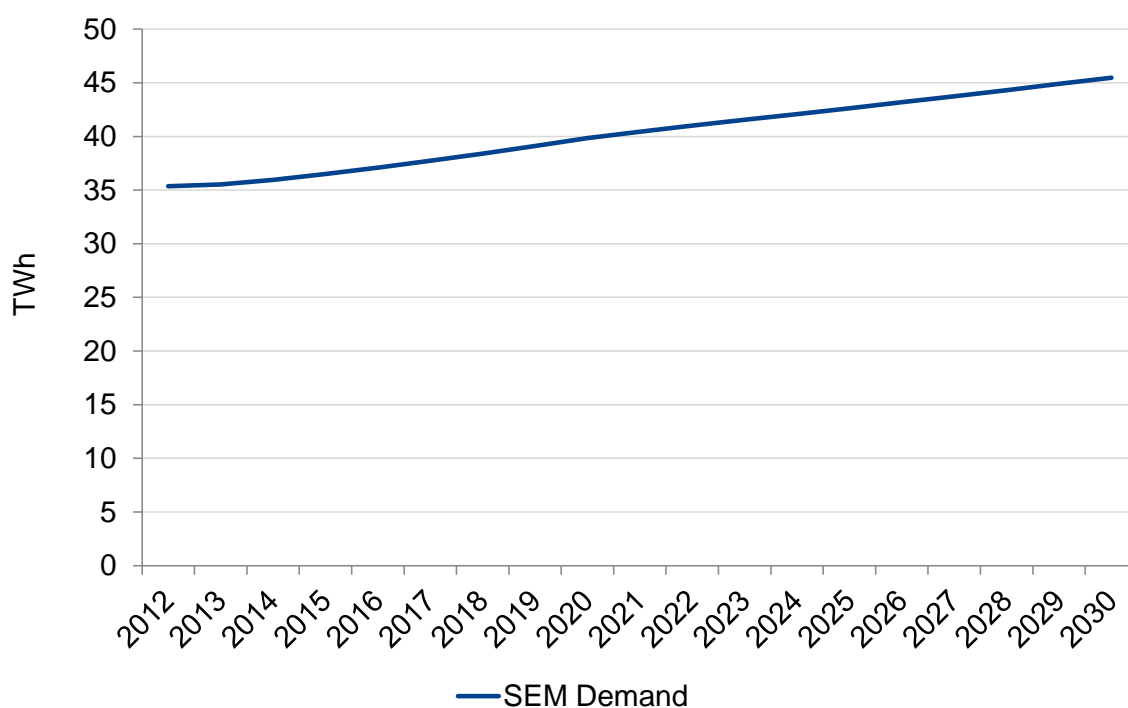
B.1 Common Input assumptions

A common set of input assumptions were devised which are internally consistent to enable comparison across scenarios and to gain understanding of how the future behaviour of energy markets is impacted by wind development.

B.1.1 Electricity demand

We used EirGrid's central projection for electricity demand in our modelling scenarios as shown in Figure 36. EirGrid only publish demand projections as far as 2022 and so we have used EU primes central projection of 1.3% annual growth in demand for electricity to inform our annual demand requirement from 2023 to 2030.

Figure 36 – Annual electricity demand in SEM

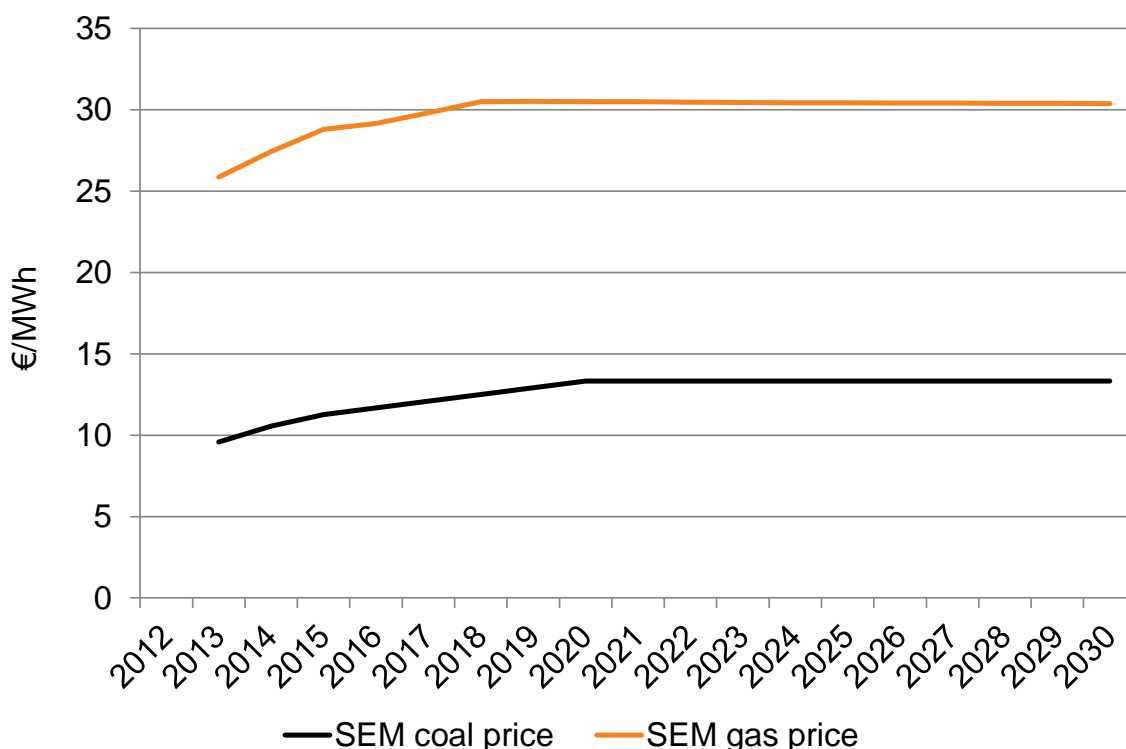


Source: EirGrid's All-Island Capacity Statement (2013-2022); EU Primes

B.1.2 Fuel price

We used DECC's reference scenario for fossil fuel price projections (Crude Oil Brent, Natural gas NBP and Coal ARA) to derive our prices for coal and gas in SEM as shown in Figure 37.

Figure 37 – SEM Fuel price projections



Source: Reference scenario, Updated Energy and Emissions Projections, DECC, September 2013

B.1.3 Carbon price

We used IEA projections for the EU carbon price. Ireland maintains a carbon price in line with the EU carbon market and in our core scenarios we take IEA’s ‘current policies’ long term carbon price projections which deliver a €30/tCO₂ price by 2030³⁸.

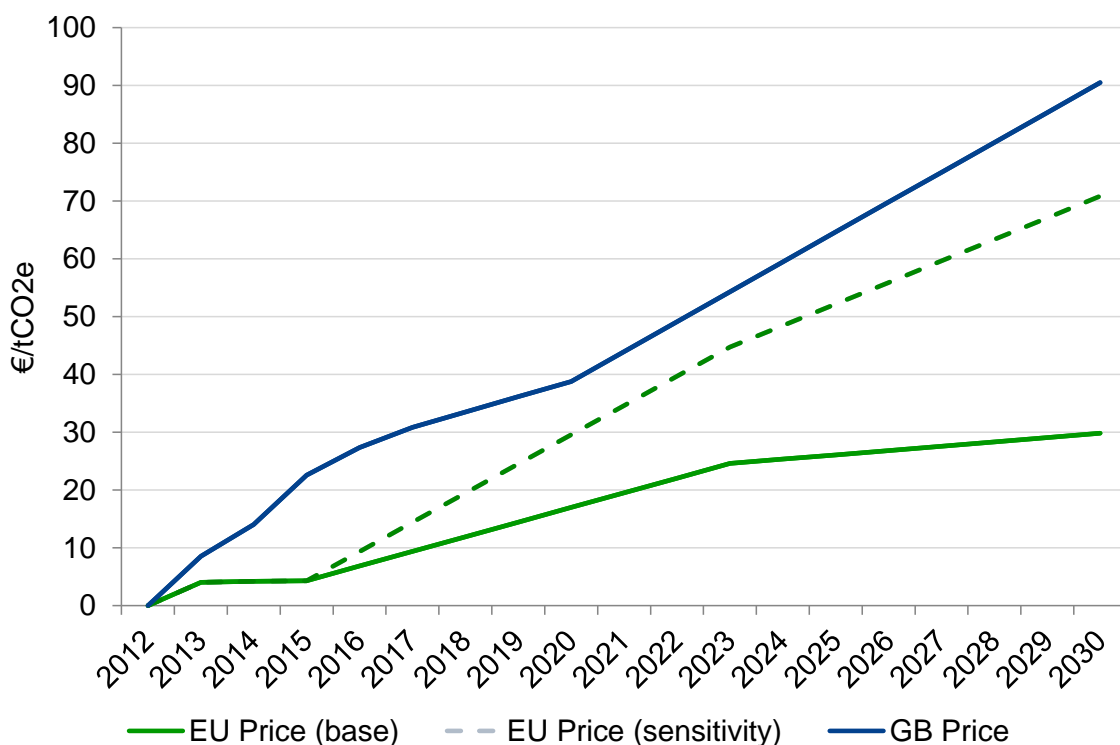
We used DECC projections for the GB carbon price which is underpinned by the carbon price floor and delivers a €90/tCO₂ price by 2030³⁹.

A carbon price differential between the SEM and GB market can have a significant impact on the direction of flow over the interconnectors due to its impact on domestic wholesale electricity prices and the resulting arbitrage opportunities. It is therefore an important underlying assumption for the analysis of the impact of wind development in Ireland and so we modelled a sensitivity using the IEA 450 scenario EU price which reaches €70/tCO₂ by 2030. Figure 38 charts the carbon price trajectories modelled in our scenarios.

³⁸ World Energy Outlook 2012, IEA, 12 November 2012. The IEA projection is modified in the near term to take account of the current low EU carbon price. We used the DECC projection for EU carbon price 2013-15 and trend to IEA projections by 2023.

³⁹ Updated short-term traded carbon values used for modelling purposes, DECC, September 2013

Figure 38 – Carbon price assumptions



Source: World Energy Outlook 2012, IEA, 12 November 2012; Modelled carbon prices, DECC, September 2013

B.1.4 Generation entry/exit decisions

The following plant retirements up until 2024 are assumed totalling 2.2GW of capacity closures:

- Great Island’s oil capacity and the Ballylumford steam units are assumed to close by 2013 and 2015 respectively, due to the requirements of the Large Combustion Plant Directive (LCPD), based on published information from EirGrid;
- Aghada steam unit, Marina, North Wall and the Tarbert units are all assumed to enter Ireland’s Transitional National Plan (TNP) and therefore close in 2020; and
- Kilroot coal plant is assumed to close in 2023 as a result of the Industrial Emissions Directive (IED).

Only one named plant is added to thermal capacity and that is a 460MW CCGT at Great Island in 2014.⁴⁰

Table 6 shows our assumptions for the capex, opex and required rate of return on investment for each of the generation assets we construct in our scenarios. Note that we do not judge the investment decision for wind capacity as the wind rollout is exogenous to the modelling effort. The cost of interconnection depends on whether we are talking about a standard interconnector similar to building another East-West 500MW interconnector (*Domestic* scenario), building transmission capability to transport wind energy from

⁴⁰ SSE latest public statement indicates commissioning by 2H2014

Ireland’s geography back to the main GB network (*Export* interconnection), or whether we are building an interconnection tie-line to connect the Irish transmission network to the export wind infrastructure (*Export* tie-line).

Table 6 – Generation asset and interconnection cost assumptions

	CCGT	Interconnector (Domestic)	Interconnector (Tieline)	Interconnector (Export)	Onshore wind	Offshore wind (2020)
CAPEX (€/kW)	840	1000	340	833	1450	2780
OPEX (€/kW/year)	52	3	1	3	44	150
IRR (%)	8.5%	5.6%	5.6%	na	7%	10%

Source: Pöyry analysis and IWEA project council input; Interconnection economic feasibility report, EirGrid; Review of generation costs, ARUP

B.1.5 Wind capacity in each scenario split by Rol, NI and GB

Table 7 – Wind capacity deployment in each scenario (GW)

	2012		2020		2030	
	SEM	GB Market	SEM	GB Market	SEM	GB Market
No Wind Effort (Post 2014)	Rol: 1.6 NI: 0.4	GB: 9.8	Rol: 1.9 NI: 0.5	GB: 17.5	Rol: 1.9 NI: 0.5	GB: 25
Domestic Wind Scenario	Rol: 1.6 NI: 0.4	GB: 9.8	Rol: 3.8 NI: 1.4	GB: 17.5	Rol: 5.5 NI: 2.4	GB: 25
Export Wind Ambition	Rol: 1.6 NI: 0.4	GB: 9.8	Rol: 3.8 NI: 1.4	GB: 17 Rol: 5	Rol: 5.5 NI: 2.4	GB: 25 Rol: 9

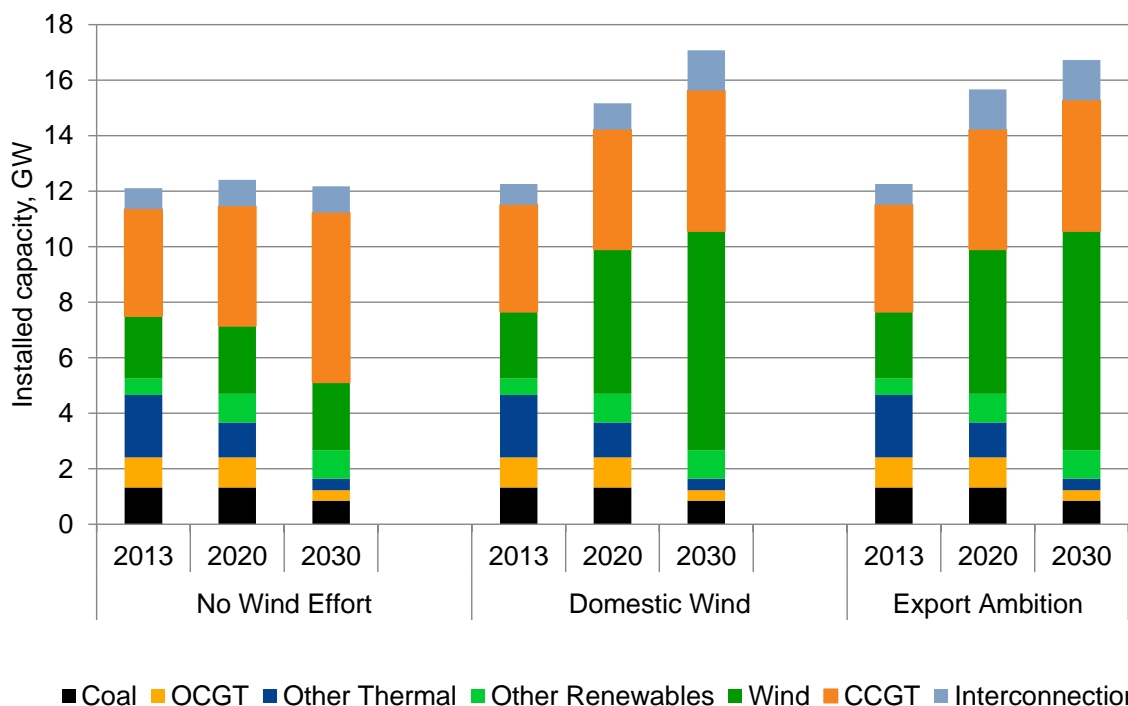
Note: *Export* scenario builds wind capacity in Rol directly connected to GB market. *No Wind* scenario rollout stops in 2014.

B.2 Impact on physical flows

B.2.1 SEM generating capacity

The total capacity installed in SEM changes over the period of analysis. Older thermal plant powered by oil, peat and coal is expected to close in the time period to 2030 and this is replaced by new gas powered generating capacity, wind capacity and interconnection capacity with the GB electricity system. Figure 39 shows the total installed capacity in SEM by type of generation across our three scenarios. Figure 40 shows net capacity additions made by 2030 for each generation type.

Figure 39 – Total SEM capacity (MW)



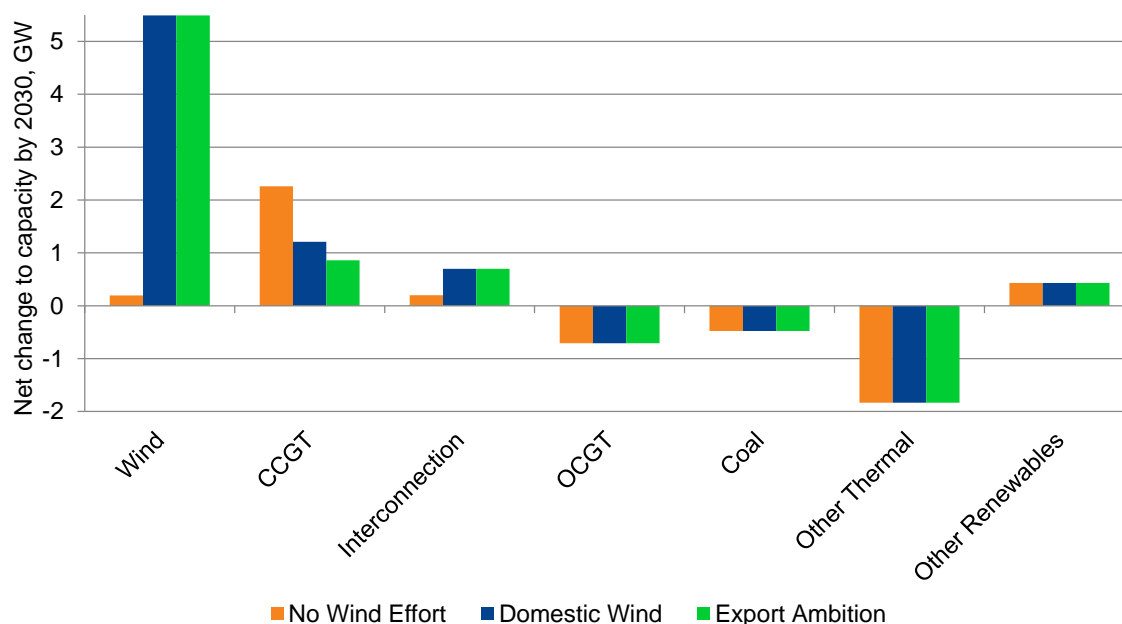
Note: This chart only shows capacity directly connected to SEM and hence excludes export wind capacity

In our base *No Wind* scenario with minimal growth in wind capacity, overall capacity levels remain steady as closing thermal plant is replaced by new gas capacity which offers a similar level of capacity credit to the market. Rising demand does not merit an overall growth in market capacity due to the fact that the market is currently over supplied and hence higher levels of installed capacity are not required. The marginal growth in interconnector capacity represents the expectation for Moyle to be restored to full capacity once the faults on the line are repaired.

In our *Domestic* scenario the strong deployment of wind capacity results in a higher total capacity due to the lower capacity credit provided by wind relative to thermal. A new 500MW interconnector is constructed as the market moves to take advantage of price differentials between SEM and GB market. 50% less new gas capacity becomes economic compared with the *No Wind* scenario.

Our *Export* scenario delivers a similar total system capacity to our *Domestic* scenario with two differences. The new 500MW interconnector becomes economic much earlier in this scenario due to the cheaper capital cost requirement of interconnection through the export wind infrastructure. And 350MW less new CCGT capacity becomes investible due to the different flow dynamics over the interconnector.

Figure 40 – Changes to SEM capacity by fuel type

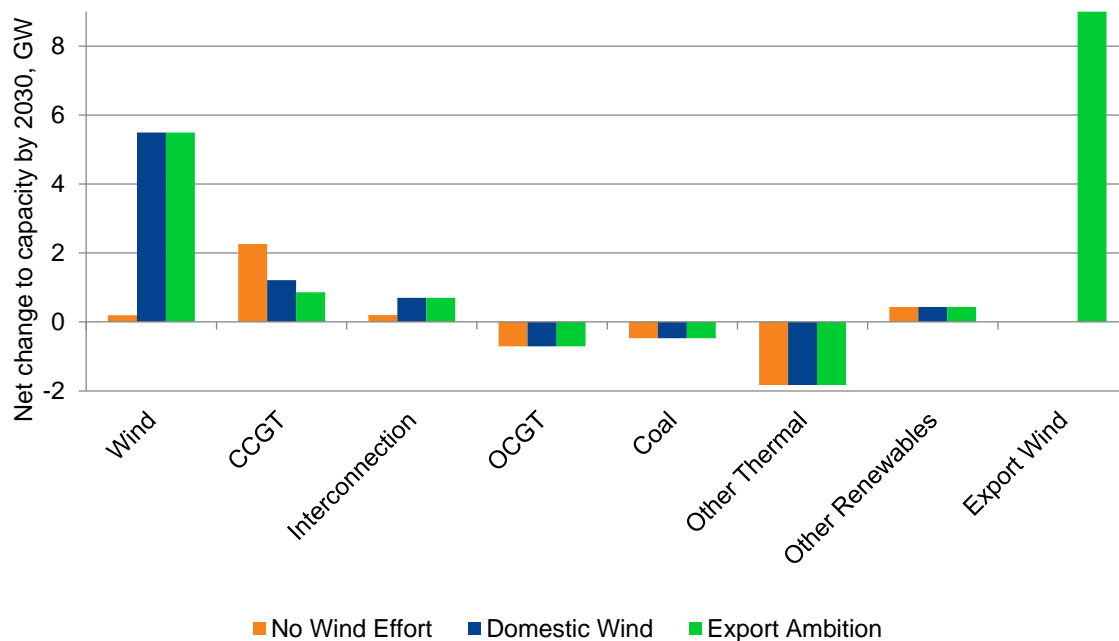


B.2.2 Export wind generating capacity

The export wind capacity of 9GW constructed in Ireland for the GB market in the *Export* scenario, and delivered over two distinct project phases, is more than double the total wind capacity deployed in Ireland in the *Domestic* scenario over the time period to 2030 (ROI capacity moves from 1.8GW today to 5.5GW in 2030). The export project is electrically and commercially isolated from SEM and the expectation is that the full export wind output will earn a GB CFD rate.

- **Export phase 1 (2017-2020).** Project assumed to include 3GW of onshore capacity spread across midland counties and 2GW of offshore capacity located in the Irish Sea. The onshore capacity is connected to GB via three separate substations each with a 1GW HVDC carrying cable. The offshore capacity is connected via the GB OFTO network regime.
- **Export phase 2 (2024-2027).** Project includes 1GW onshore and 3 GW offshore.

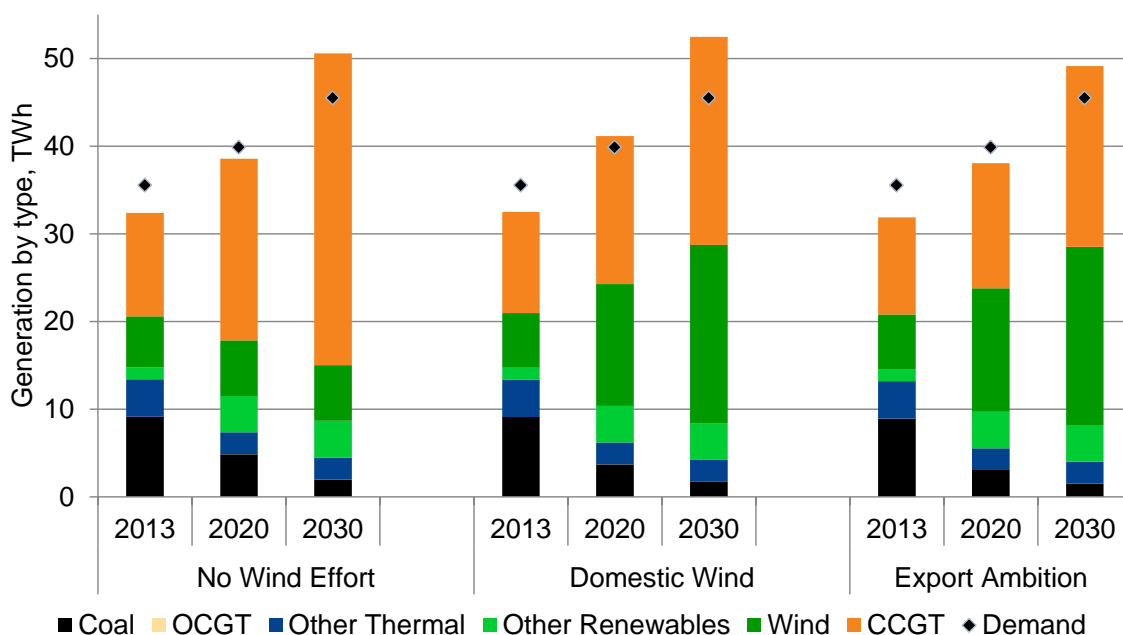
Figure 41 – Changes to capacity constructed on the Island of Ireland



B.2.3 SEM generation output

The use of gas increases in all scenarios as shown in Figure 42 to meet rising demand and falling output from other thermal fuel source due to closures of oil, coal and peat plant. The high level of wind deployment in the *Domestic* and *Export* scenarios displaces the less efficient sources of gas generation from the merit order curve. But gas fired generation remains the marginal source of generation in all scenarios in most time periods and so sets the wholesale price for electricity.

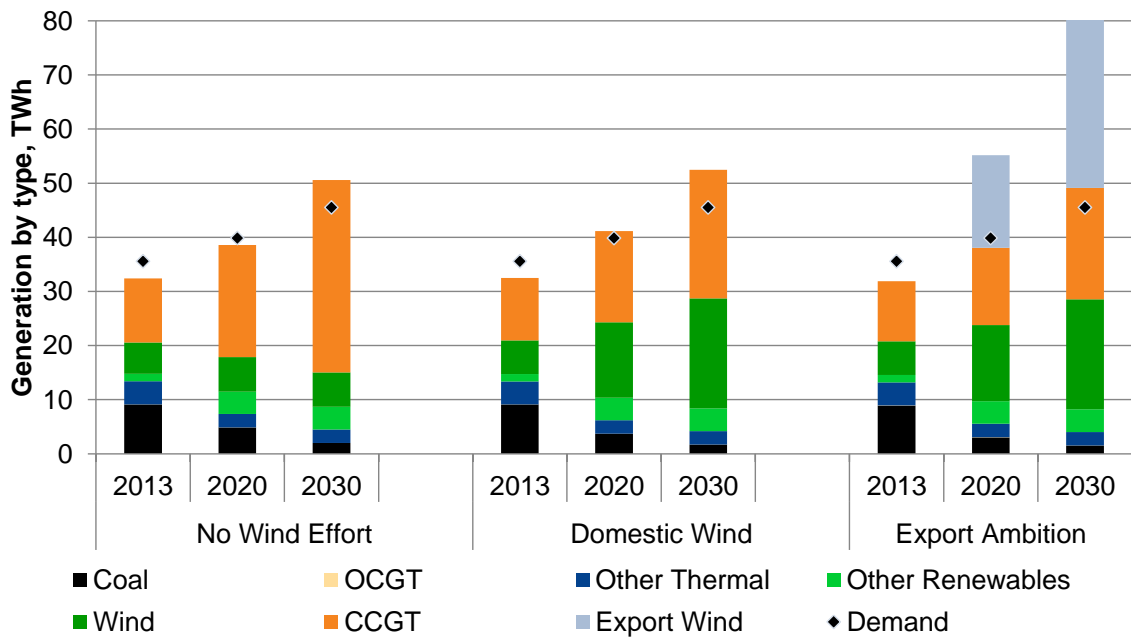
Figure 42 – SEM generation output by type (TWh)



The SEM demand requirement is indicated on Figure 42 by the blue diamond. Where the generation output is lower than SEM demand, the interconnectors net import energy and when generation is higher than SEM demand the interconnectors net export.

Figure 43 shows the same SEM generation output results but also charts the output from the export wind projects. While these outputs are electrically isolated from SEM and fully funded through the GB market, the chart gives a sense of the potential scale of wind development in Ireland.

Figure 43 – SEM generation output by type compared with export wind output (TWh)

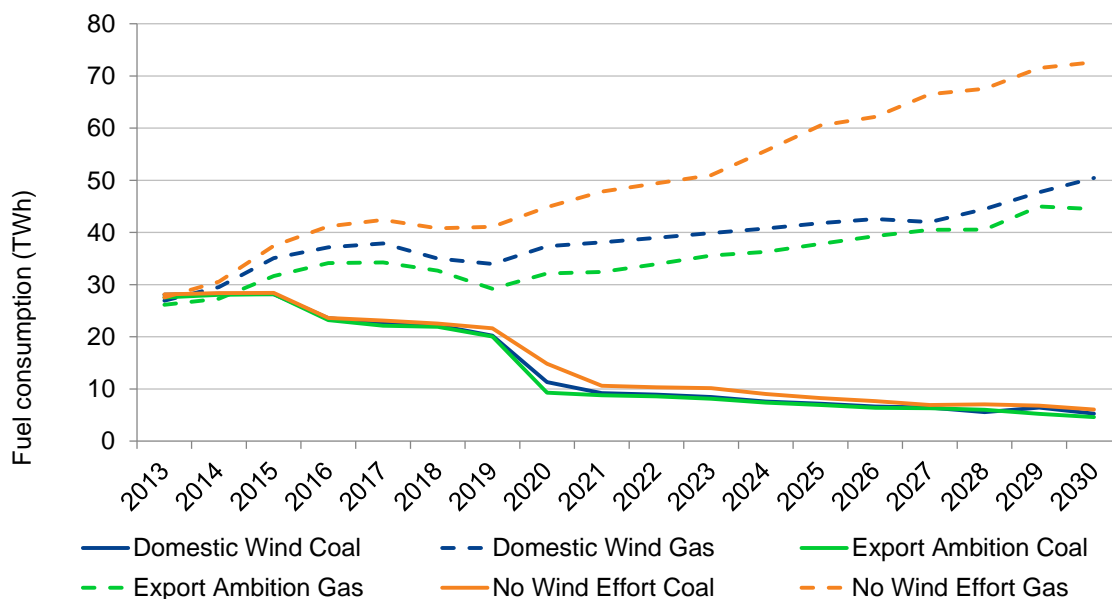


B.2.4 Fuel demand by the power generation sector

Gas demand rises as other thermal (coal, oil, peat) power capacity either closes due to age or is forced to reduce running hours due to the environmental constraints of IED. The demand for coal falls in 2015/16 as IED restricted running comes into effect and dramatically falls in 2023 when coal plant at Kilroot is assumed to close. Coal demand tapers off at Ireland’s only other coal plant, Moneypoint, driven out of the merit order principally by a rising price for carbon.

The fuel demand trends for SEM are shown in Figure 44. The ROI gas demand does not rise in the long term as we assume new gas capacity is constructed in NI. The gas transportation and capacity charge is cheaper in NI which drives this assumption and it is consistent with best new entrant (BNE) assumptions made by the RAs which place a new entrant in NI.

Figure 44 – SEM fuel demand (TWh, fuel)

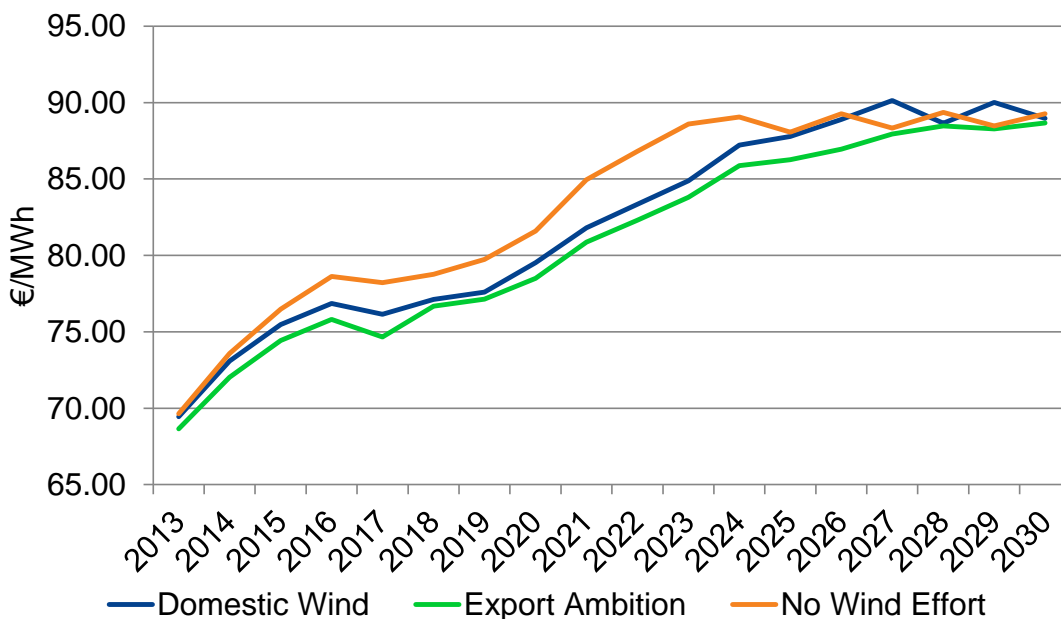


B.3 Impact on wholesale prices

Our wholesale electricity price projections in each scenario are constructed by combining two elements – the projected system marginal price and the projected capacity payment. The time-weighted average (TWA) wholesale electricity price projections of our three scenarios are presented in Figure 45.

In the scenarios presented, gas continues to be the marginal source of generation in the majority of periods between now and 2030 and as a result, the TWA SMP is closely linked to the running costs of a CCGT. The rising trend in wholesale prices across all three scenarios is driven by the assumptions made for gas and carbon prices. Further information on our gas and carbon prices is presented in B.1.

Figure 45 – Wholesale TWA prices (€/MWh)



Wind development provides a price benefit as wholesale prices are comparatively lower in the *Domestic* and *Export* scenarios with respect to the *No Wind* scenario in the short to mid-term. Wind has a zero short run marginal cost (SRMC) and therefore sits at the bottom of the merit order and displaces generation with positive SRMC higher up the merit order. This can change the marginal source of generation resulting in the wholesale price being set by the SRMC of a cheaper marginal source of generation than would otherwise be the case. This is commonly referred to as the merit order effect of wind. However, in the long term new CCGTs become economic and are constructed in all three scenarios. These new CCGTs displace older less efficient thermal plant from the merit order curve and tend to set the marginal price for energy which has the impact of neutralising price differentials between our low and high wind deployment scenarios.

The wholesale price in the *Export* scenario is lower than the price in the *Domestic* scenario due to the different price point in GB between these two scenarios. In the *Export* scenario we assume that GB expands its renewable program to meet its own 2020 targets through the deployment of export projects in Ireland. The higher level of renewable penetration in GB delivers a lower average GB price which impacts SEM through the available interconnection.

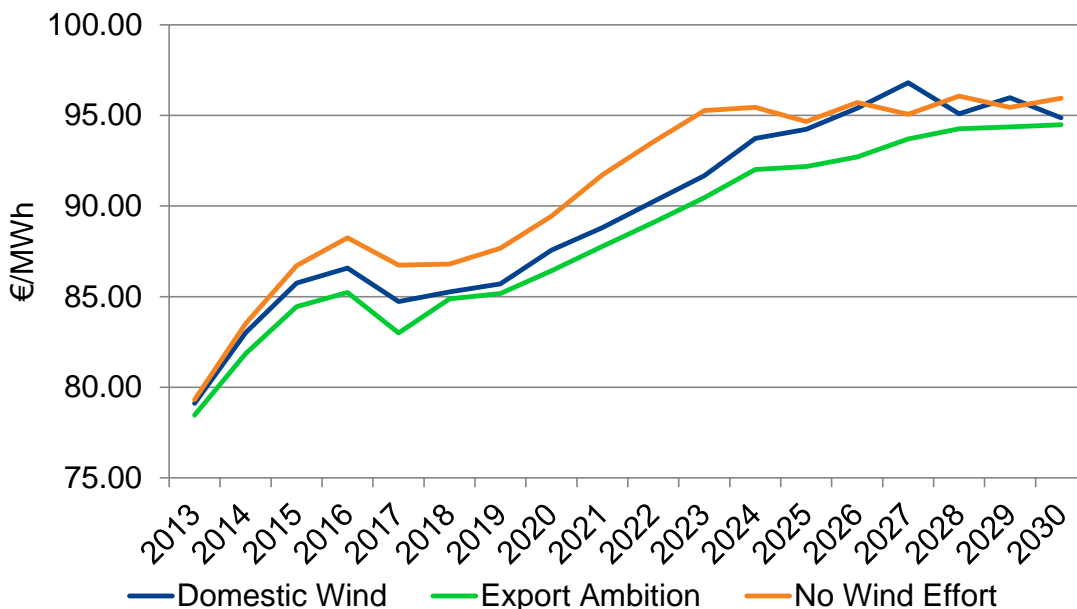
Wholesale prices are lower in higher wind cases but not significantly. The relative wholesale price differential by 2030 between the three scenarios is quite small suggesting that a major wind rollout will not lead to higher prices for consumers.

B.3.1 Supplier wholesale prices

The wholesale price paid by suppliers to meet their customer’s demand for energy is better represented as an average weighted by demand rather than time. Figure 46 shows the demand weighted average wholesale price composed of two elements – the system marginal price and the capacity charge faced by suppliers. The price pattern is similar to

the TWA price but due to the higher capacity charge faced by suppliers than earned by generators through the capacity payment per MWh, the price point is €7-8 higher.

Figure 46 – Supplier wholesale Domestic scenario prices (€/MWh)



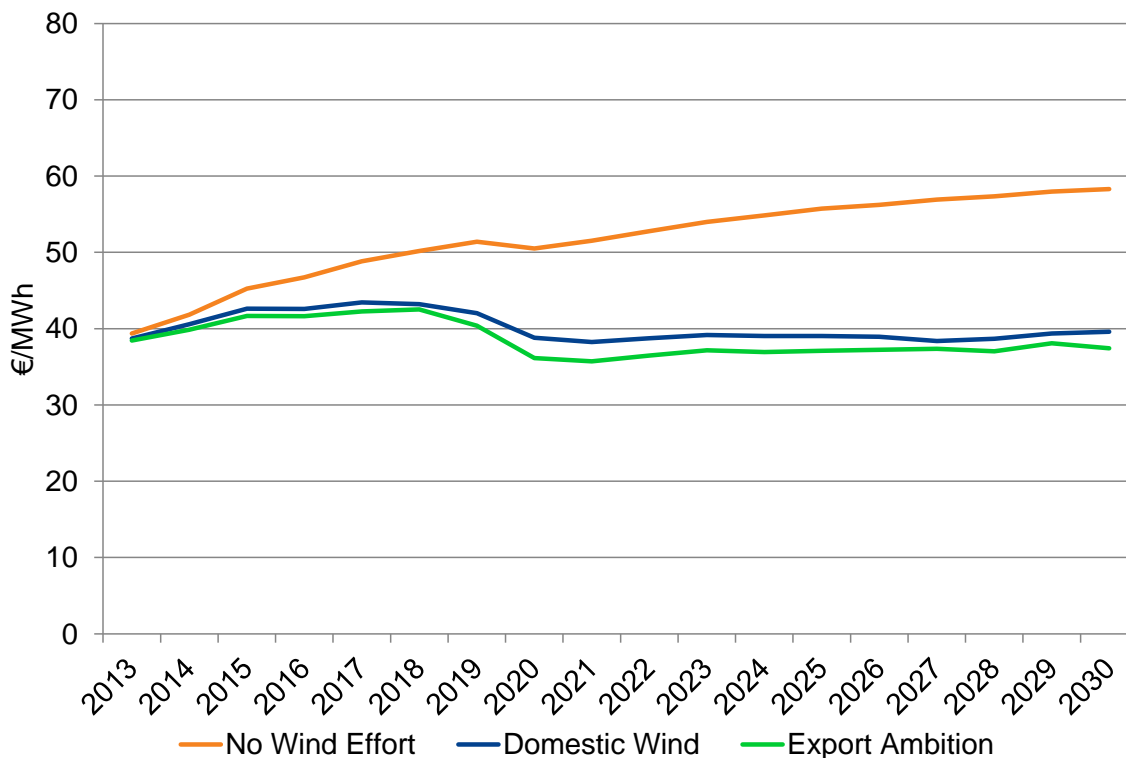
B.4 Impact on production costs

The SEM wholesale price is set through a marginal price approach, meaning that the price is set by the short run marginal cost of the marginal generating unit required to meet demand. This approach means that even with a large deployment of wind on the Irish grid the full benefit of wind’s negligible running costs do not translate into a proportional fall in wholesale prices as shown in Section B.3. This section explores the overall generation production cost of our three scenarios to investigate whether there is a cost benefit which does not translate into the wholesale power price.

B.4.1 Production cost of generation

Figure 47 shows the difference in SRMC between our three scenarios. The *Domestic* and *Export* scenarios deliver a system that has almost a €20/MWh lower cost of producing power in 2030. This outcome is driven by the negligible running costs of wind capacity and its higher contribution displacing thermal capacity from the merit order.

Figure 47 –Variable cost of generation



Note: Only includes cost estimates for fuel, carbon and VOWC

Once we add in the fixed costs of the full generating capacity in each scenario the cost picture changes marginally, tightening the differential between our wind scenarios (*Domestic*, *EWA*) and *No Wind* scenario. This is due to the fact that wind capacity does have a fixed annual cost to maintain its operation; we assume this to be €44/kW.

In a production cost view of generation we cannot only consider the operational cost of running generating capacity, we must also consider the recovery of capital investment. For simplicity, we have assumed that all pre-existing capacity has already fully recovered their capital requirements and therefore must only cover their operational costs. Figure 48 charts the costs including capital recovery for all new wind and CCGT capacity. In this case the cost benefit of a wind rollout is eroded with the *No Wind* scenario operating on a lower cost basis in the mid-term. This result is driven by the steady annual addition to wind capacity in our *Domestic* and *Export* scenarios set against no new build in the *No Wind* scenario until new CCGT capacity comes online in the mid-2020s.

The broadly comparable production cost of the wind scenarios does not affect the wholesale price for electricity as wind is able to recuperate its cost of investment through the inframarginal rents available in the market and so there is no risk of this cost being passed on to consumers.

Figure 48 – Fixed and variable cost of generation

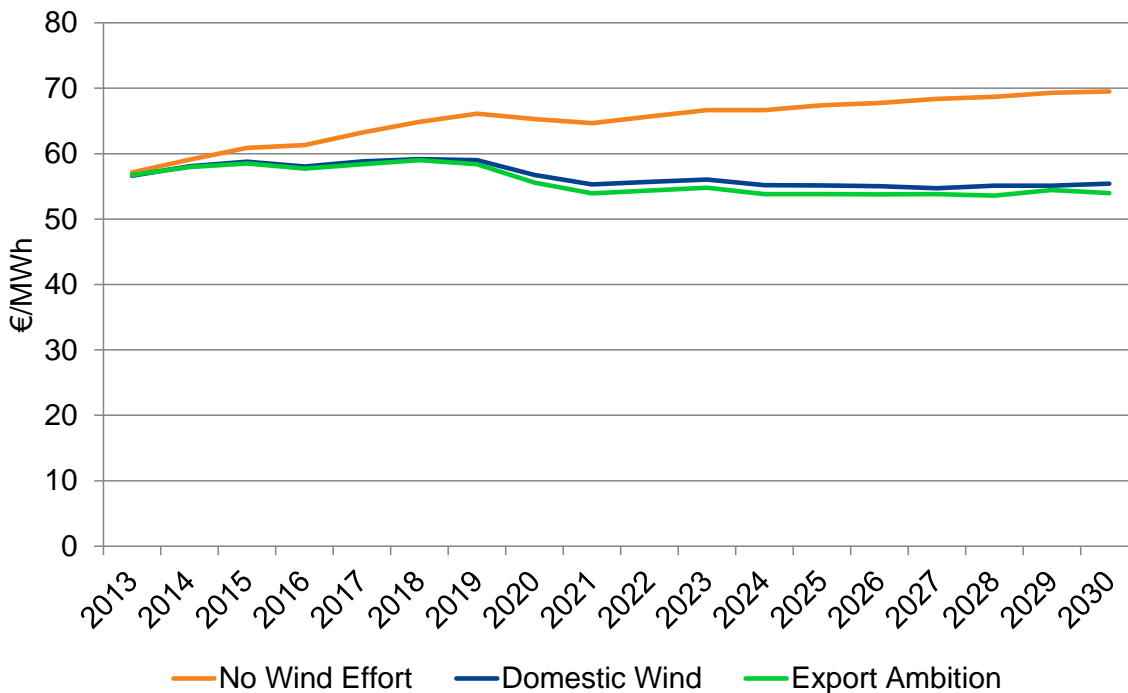
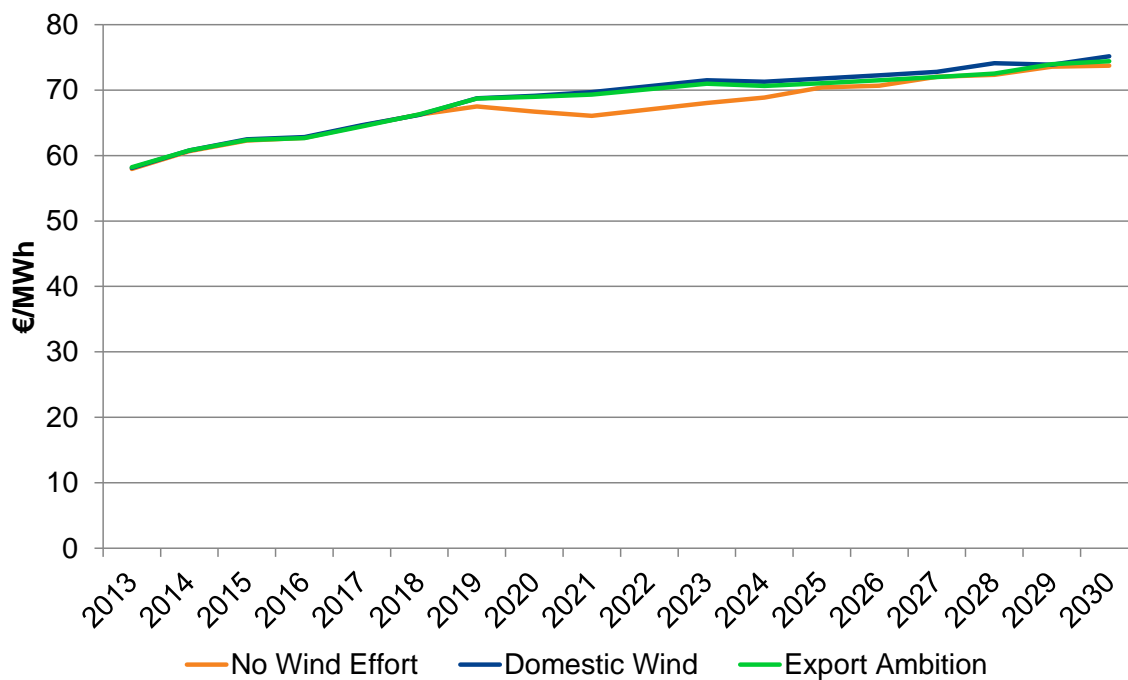


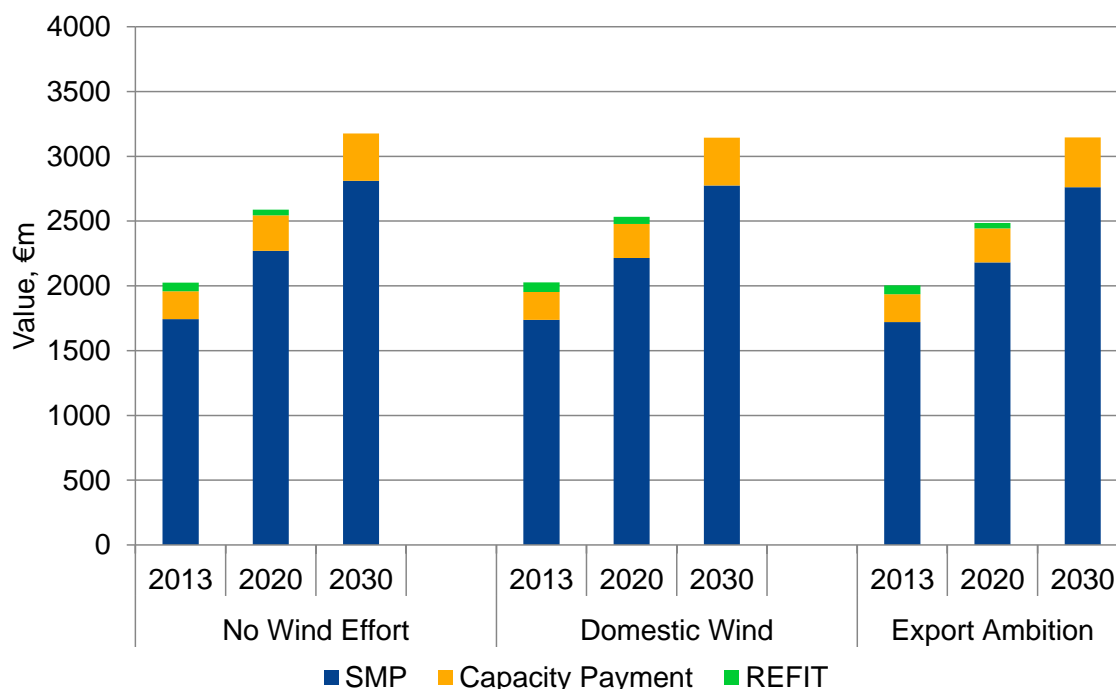
Figure 49 – Fixed and variable cost of generation including capex recovery



B.4.2 Actual total cost of generation

Our analysis projects that all wind in ROI will become self-financing from mid 2020s onwards and will not require payment through the REFIT scheme assuming the current scheme is extended in its current format beyond REFIT 2. This is due to the projected rise in wholesale price above the REFIT 2 payment threshold and expiry of REFIT 1 contracts. Figure 50 shows the total cost of generation in terms of revenues earned from the wholesale market SMP, capacity payment mechanism and wind support costs. The costs are marginally lower in our scenarios that deploy an ambitious wind program in Ireland. Price differentials are minimised due to interconnection and price arbitrage.

Figure 50 – Total cost of generation in ROI including REFIT payments



Note: Includes revenue from wholesale market price, capacity payment mechanism and REFIT payments. Excludes capital costs and export wind project which we assume is covered by the GB CFD price

B.5 Impact on interconnector flows

Interconnector usage is primarily determined by the wholesale price in both SEM and GB markets. Competing pressures drive the direction of flow between GB and SEM markets as operators move to take advantage of price differentials to capture inframarginal rent. The drivers include:

- SEM capacity payments;
- any difference in carbon price between GB market and SEM;
- GB renewable rollout strategy;
- tightness of GB capacity margin; and
- the closures of coal plant in SEM.

Figure 51 shows the net electricity flows between SEM and GB with negative flows indicating SEM as a net importer and positive flows indicating SEM as a net exporter.

Today the interconnectors on average across the year import energy to SEM due to the higher price on offer in SEM relative to GB. In the short term the anticipated tightness of the GB market drives a change in direction with SEM becoming a net exporter across all three of our scenarios.

In the mid-term importing energy from GB is a cheaper way to meet SEM demand in our *No Wind* scenario than either increased running of domestic plant or new build thermal capacity. Our *Domestic* scenario keeps the SEM as a net exporter of electricity from 2015 onwards. This trend in the mid-term is driven by the high wind deployment in the Irish market which drives down the SEM price and increases the opportunity for exports to GB. Conversely this trend also prevents the SEM price to fall as low as it might otherwise fall as the SEM wholesale price moves towards the higher GB price. The *Export* scenario results in a pattern similar to the *No Wind* interconnector flow pattern but for different reasons. In this scenario GB is deploying a much higher renewable capacity on its own network in order to meet its 2020 target which counterbalances the high renewable deployment in the SEM and limits the opportunity to export from Ireland. Exports in *Export* constrained by a correlation between high wind periods in both markets, and the limited connection capacity between the export projects constructed in Ireland and GB mainland.

In the long term the higher carbon price deployed in the GB market (driven by the carbon floor) relative to SEM (determined by EU carbon price) is the dominating factor in turning SEM into a net exporter in all three of our scenarios.

Figure 52 shows the balance of interconnector payments between SEM and GB. The net payments match trend in net flows closely and shows that in our *Domestic* scenario with a high domestic wind deployment, Ireland can improve its payments balance with GB. The *Domestic* scenario payments in mid-term are lower than flows because the SEM tends to export in windy periods and hence at lower prices. The trends are dependent on the carbon markets and changes in the GB capacity mix, as can be seen in our *Export* scenario.

Figure 51 – SEM net exports (TWh)

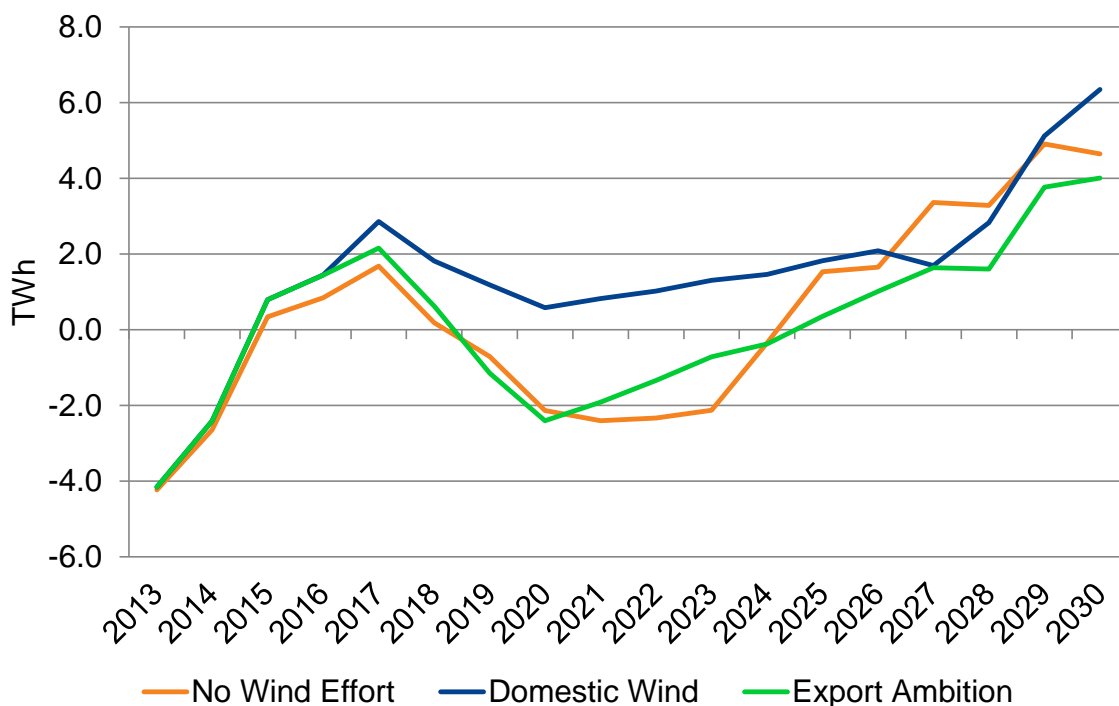
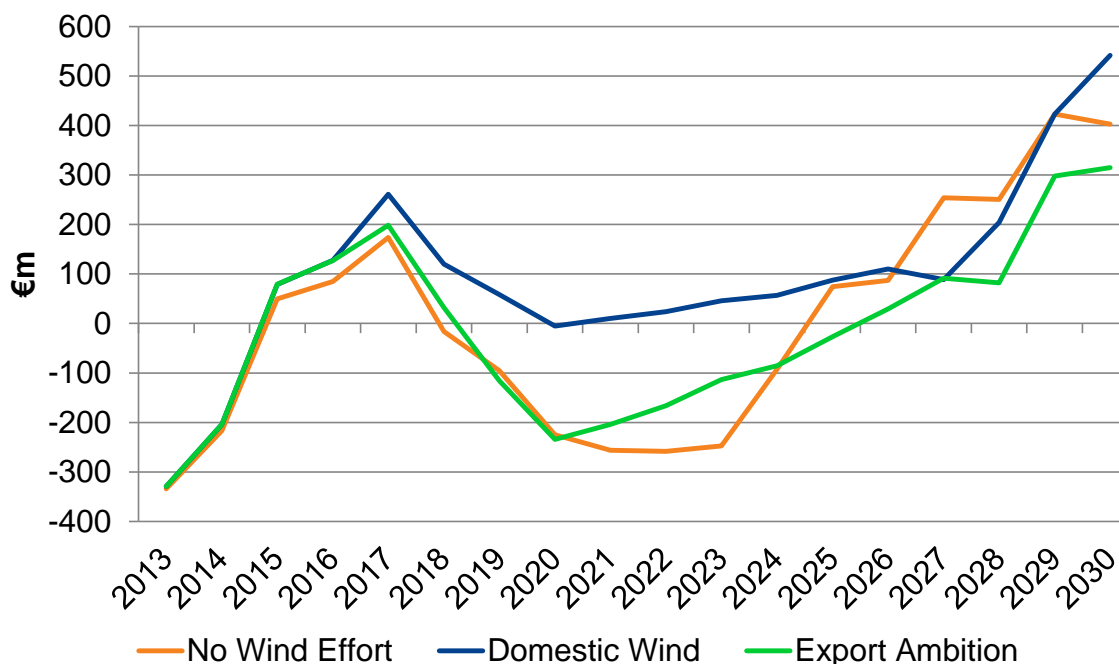


Figure 52 – Interconnector payments between SEM and GB (€m)



Note: Assumes SEM exports earn GB price and SEM imports earn SEM price in each trading period

The charts presented above consider the net flows and net payments between the SEM and GB markets. It is worth noting here that the data provided to the macro-economic analysis only included the net flows and net payments between ROI and the UK. To calculate the flows for ROI only, we made a post model calculation of the cross border flows between ROI and NI. The net flow and net payment charts for ROI only has the same shape as those presented above, albeit with a smaller magnitude.

B.6 Impact on security of supply

B.6.1 Capacity Payment Mechanism and generic capacity additions

Figure 53 summarises our modelling approach to the Capacity Payment Mechanism and the addition of generic new entry in the SEM. Our assumptions on the costs of generic (or uncommitted) new entrants are given in Table 8.

Table 8 – Commercial assumptions for new entrant generation in the SEM⁴¹

	CCGT	Coal	BNE OCGT
Capital cost (2012 €/kW)	840	1,941	616
Fixed other works costs (2012 €/kW/yr)	52	60	28
Variable other works costs (2012 €/MWh)	2.4	2.6	0.8
Required rate of return	8.5%	9.0%	7.5%
Economic lifetime (years)	20	20	20

We see a tension between the following components of the CPM calculation methodology:

- For the calculation of the **capacity requirement** (and so capacity pot), wind capacity is **de-rated**. Currently wind is de-rated to 17% of its installed capacity.
- For the calculation of the **distribution of capacity pot**, wind capacity is paid on its **output**. Wind’s average load factor in 2012 was 28% and therefore it received a higher level of capacity payments than the de-rating to 17% of its installed capacity would imply (though this doesn’t take account of the fact that the ex-post element of payment is based on out-turn system margin and will be lower at times of high wind availability).

As a result of these differing treatments of wind in different components of the CPM methodology, there is a risk that even at very tight capacity margins a BNE peaker will not make a sufficient IRR to justify new build. This is because wind capacity may be distributed a greater fraction of the pot compared with the de-rated contribution used in the calculation of the pot. This effect becomes greater at higher wind penetrations.

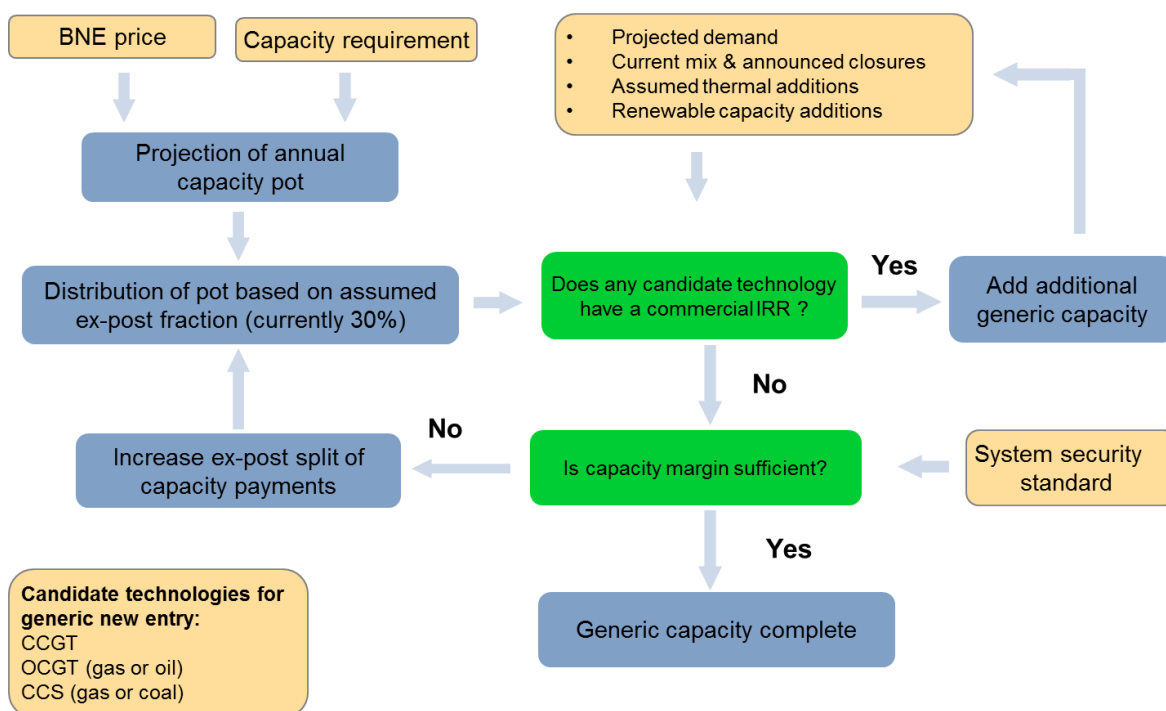
One straightforward measure that the RAs could use to solve this inconsistency is to adjust the fraction of capacity pot which is distributed based on the ‘ex-post’ capacity margin. We have assumed in our modelling that this is the approach that is taken if thermal new entry is required (based on an assumed market security standard) but does

⁴¹ Due to the smaller unit size of CCGTs in the SEM, we assume a capital cost which is €50/kW higher than in other European electricity markets. Also, we do not consider the investment of new unabated coal in Ireland due to current environmental policy

not achieve a commercial IRR. However, we note that there are a number of alternative approaches available to solving this issue.

We also note that the methodology to calculate the level of IMR received by the BNE peaker assumes a Loss of Load Probability (LOLP) of eight hours a year. The IMR is deducted from the BNE price and therefore has an impact on the level of capacity payments. In practice, the RAs may be uncomfortable allowing eight hours of LOLP and would intervene in the market to prevent this. However, we do not consider the potential for the RAs to intervene and impose a tighter security standard and we model the capacity payment using the stated methodology. Actual decrease in the LOLP (if it was implemented through the existing framework) would be an upside for thermal plant.

Figure 53 – Generic new build methodology

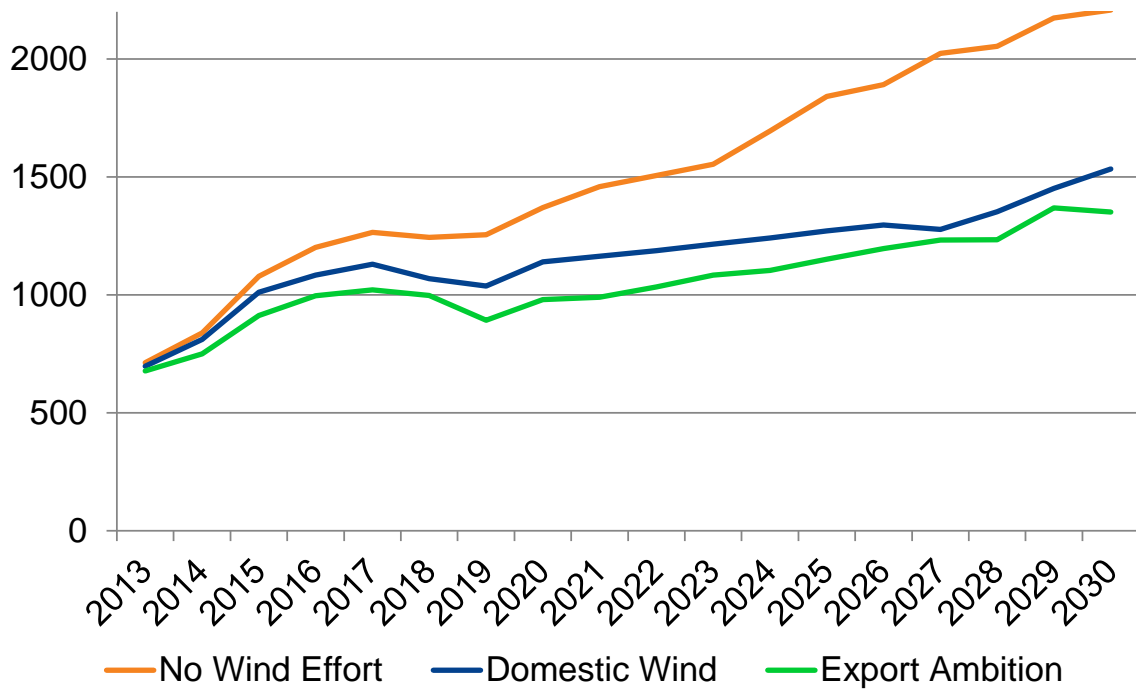


B.6.2 Gas import dependency

Ireland depends on fuel imports for most of its thermal generation. The gas import requirement is projected to increase in all our scenarios due to the replacement of other thermal fuels (oil, peat, coal) from the merit order. But as shown in Figure 54 wind development in Ireland in both the *Domestic* and *Export* scenarios will significantly reduce the gas import dependency.

A reduction in gas consumption coupled with higher interconnection capacity as delivered in both our high wind scenarios delivers a security of supply benefit. The percentage of domestic generation relying on imported fuel sources drops in the higher wind cases (although imported gas still remains important at the margin)

Figure 54 – SEM power generation gas costs (€m)



In our scenarios gas use in ROI is kept lower than SEM average as new CCGT is constructed in NI.

B.7 Impact on environment

Figure 55 – Total SEM power sector emissions (tCO₂)

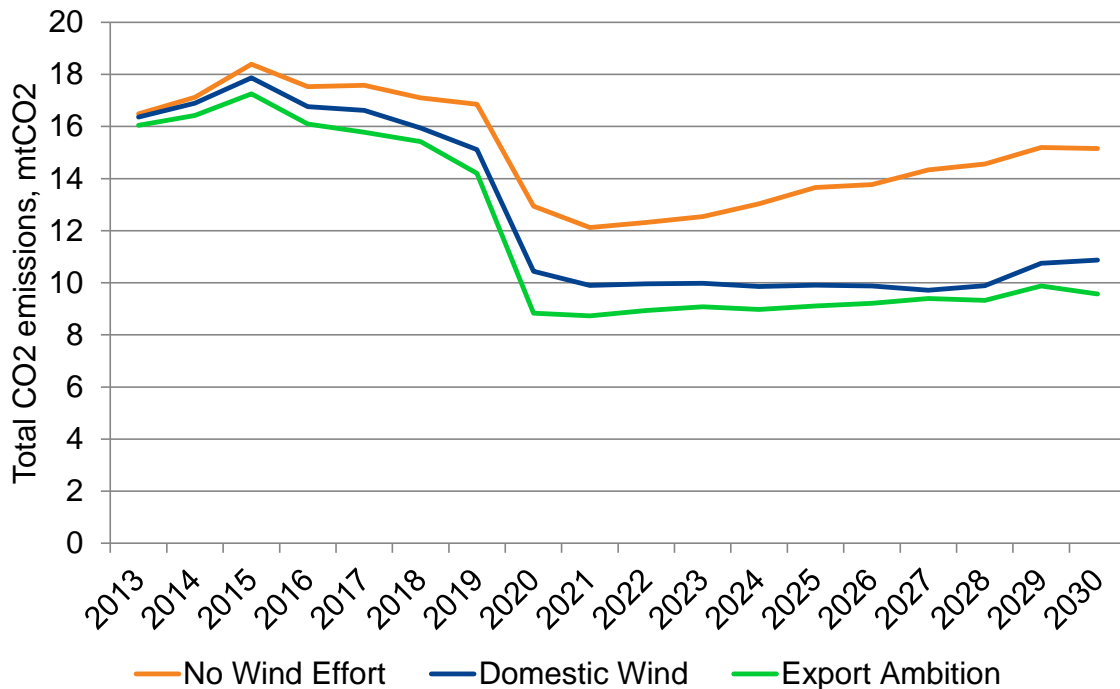
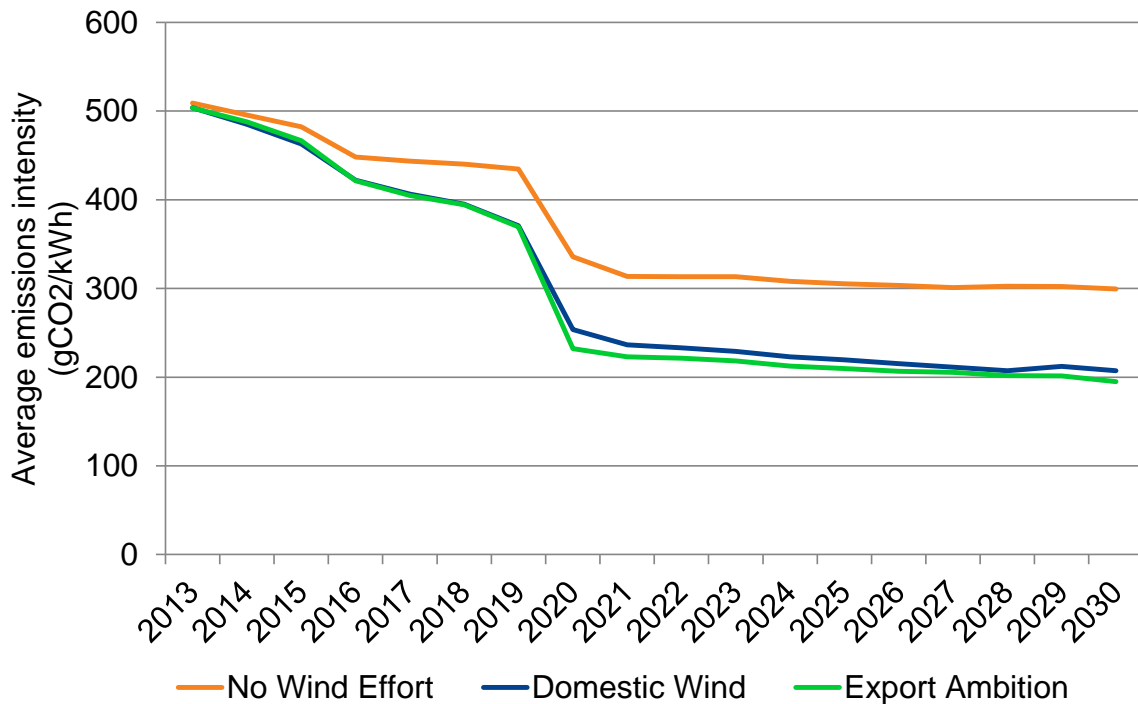


Figure 56 – Average SEM emissions intensity (gCO₂/kWh)



B.8 Carbon sensitivity

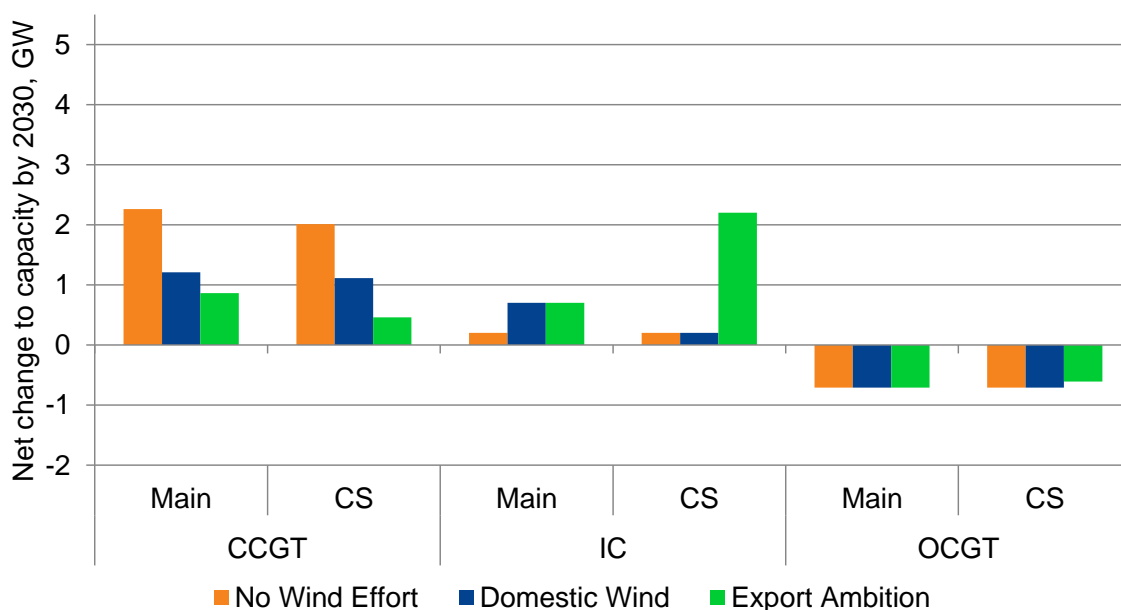
A carbon price differential between the SEM and GB market can have a significant impact on the direction of flow over the interconnectors due to its impact on domestic wholesale electricity prices and the resulting arbitrage opportunities. We completed a sensitivity analysis on the EU carbon price applied to the SEM to measure the impact on our scenarios. In our sensitivity we maintained the same UK carbon price underpinned by the carbon price floor trajectory and so reach €90/tCO₂ by 2030 in the GB market. But instead of applying IEA’s central view for the EU carbon market which only achieves a price of €30/tCO₂ by 2030, we assume that the EU carbon market pushes for a higher value of carbon more in line with the GB approach and delivers a €70/tCO₂ by 2030 (see Figure 38 for detail).

The narrower carbon price differential between the interconnected markets of SEM and GB will minimise this driver of wholesale price differences and interconnector flows.

B.8.1 Impact on physical flows

The tighter differential in carbon price between markets changes the projected capacity mix to deliver less CCGT new build in all scenarios, no new interconnection in *Domestic* and maximum potential interconnection in *Export* scenario⁴² as shown in Figure 57.

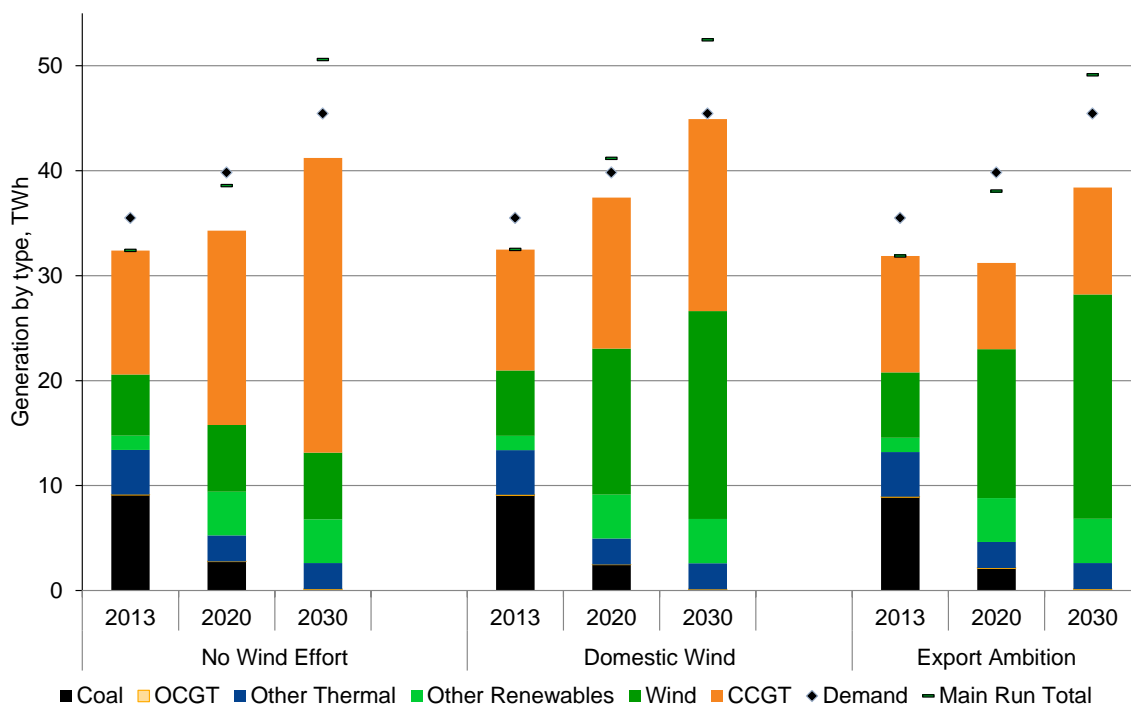
Figure 57 – Changes to capacity mix in carbon sensitivity (GW)



⁴² The opportunity to construct cheaper interconnection in the *Export* scenario is enabled by connecting into the export wind infrastructure on mainland Ireland. This potential is limited by the assumed number of available substations with corresponding 1GW links back to the UK grid. We assume that one 500MW HVDV interconnector tie-line can be constructed per 1GW export project GB connection.

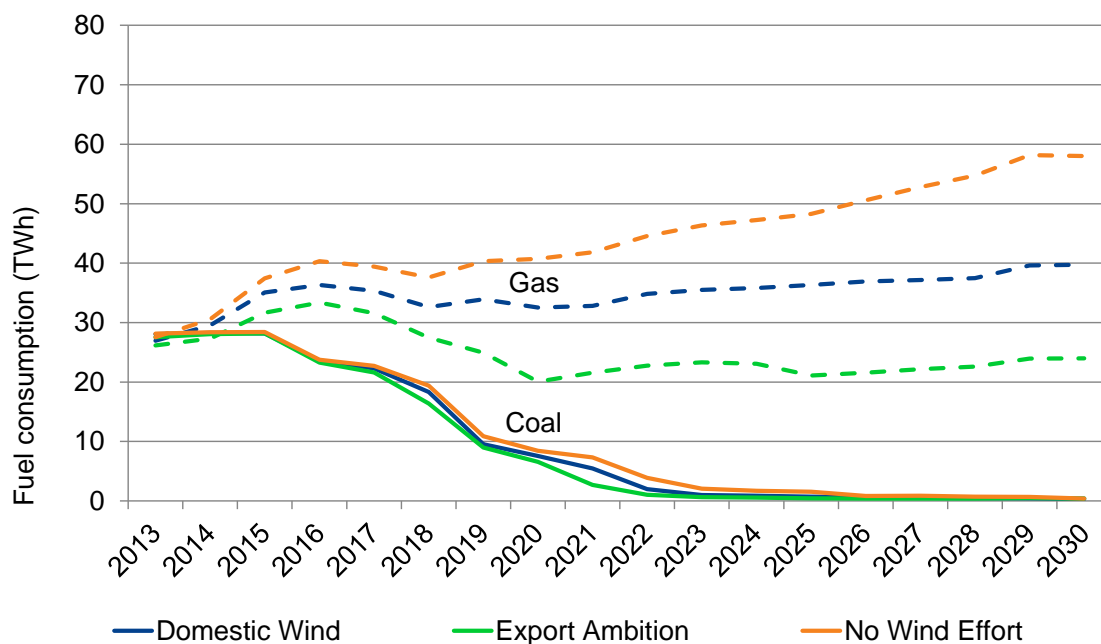
The greatest difference caused by the higher carbon price in SEM is the reduced running of domestic CCGT and the fact that SEM relies on electricity imports to meet demand, particularly in the export scenario. Figure 58 shows the output from generation in the SEM. The blue diamond in the chart represents SEM demand and the blue dash line indicates the level of generation output by SEM generators in the main scenarios.

Figure 58 – SEM output (TWh)



A follow on from reduced CCGT running is a reduced import dependency for gas. Figure 59 indicates that the demand for gas falls under our carbon sensitivity as gas generation is displaced in the merit order by cheaper import flows from GB. When compared with our main scenario results we find that the drop in SEM gas consumption is of the order of 10TWh.

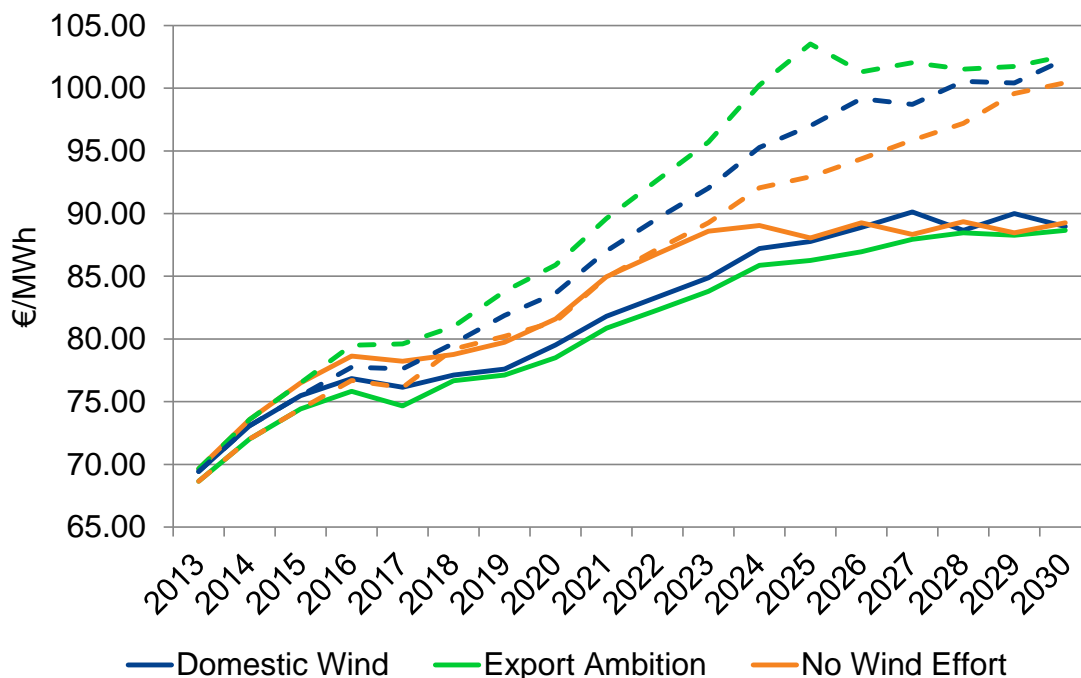
Figure 59 – SEM fuel demand by power generation



B.8.2 Impact on wholesale prices

The higher EU carbon price drives the SEM wholesale price upward across all three of our scenarios although with a greater proportional impact on our *No Wind* scenario as shown in Figure 60. The merit order effect of wind in this scenario is increased lowering the wholesale price in the *Domestic* scenario. We find that the *Export* scenario delivers a noticeably lower wholesale price than the *Domestic* scenario due to the much greater level of interconnection with GB and net imports from GB. In this scenario GB power flows to SEM to take advantage of the price arbitrage opportunity pushing the SEM price downward.

Figure 60 – Wholesale prices (€/MWh)

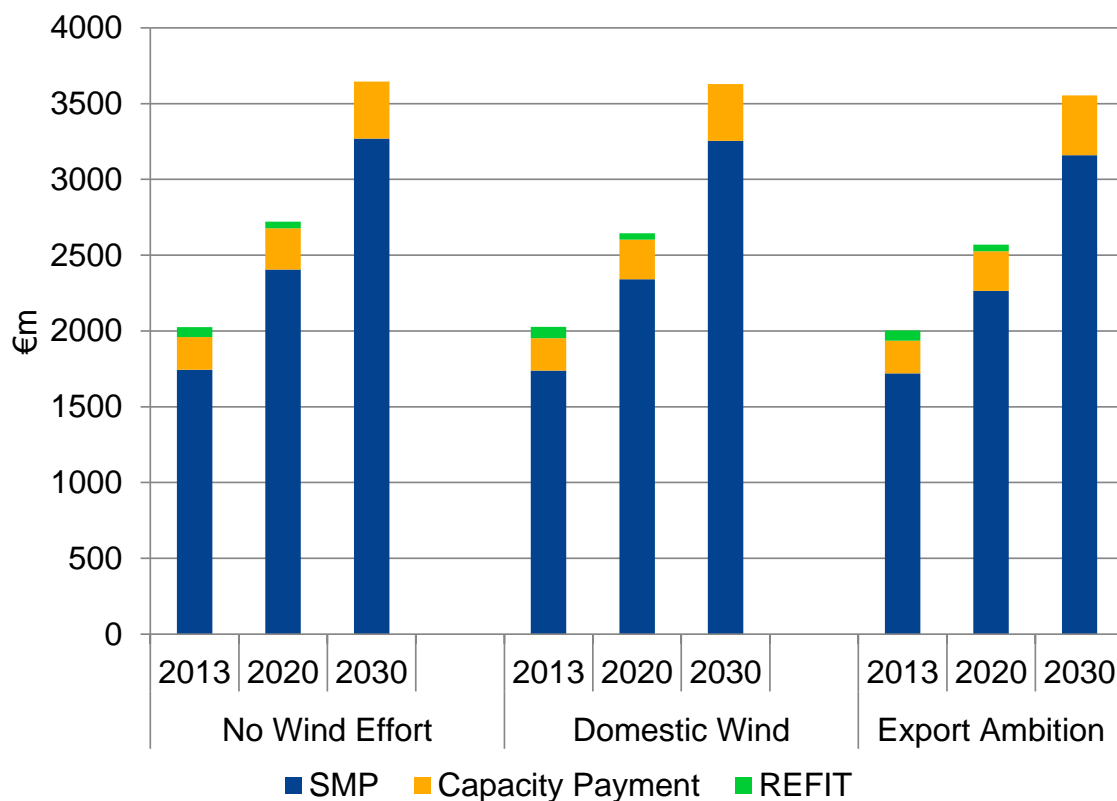


Note: Dashed line shows carbon sensitivity results. Main results charted with solid lines

B.8.3 Impact on production costs

The carbon sensitivity increases the generation system costs due to higher wholesale prices. This is driven by higher SMP revenues due to marginal sources of generation, usually gas fired CCGTs passing through the SRMC of carbon in their bids into the market schedule. The support costs of wind do not change in our carbon sensitivity as even at the lower carbon price assumption taken for our main scenarios the wholesale price rises above the REFIT 2 payment floor.

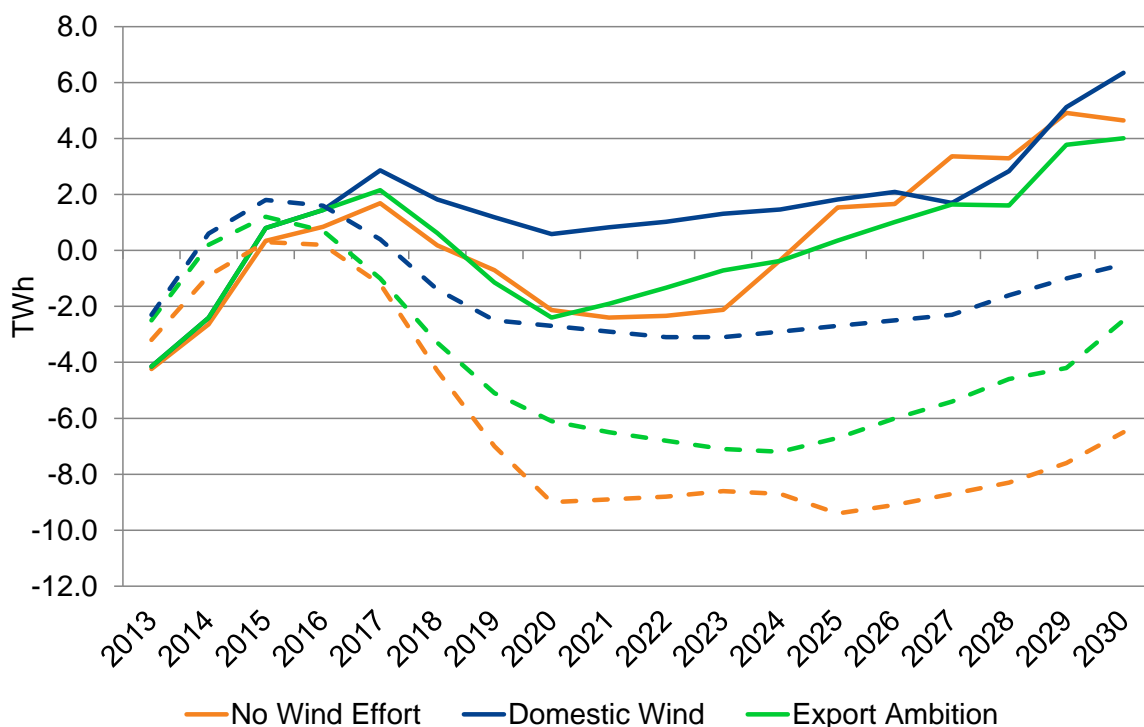
Figure 61 – Total cost of generation in ROI for carbon sensitivity



B.8.4 Impact on interconnector flows

The higher carbon price in SEM changes the net direction of flows and net payments out of Ireland in all scenarios. The higher renewable deployment in GB coupled with higher carbon price in SEM drives *Export* scenario payments downwards relative to *Domestic* as shown in Figure 62.

Figure 62 – IAI interconnector payments (€m)



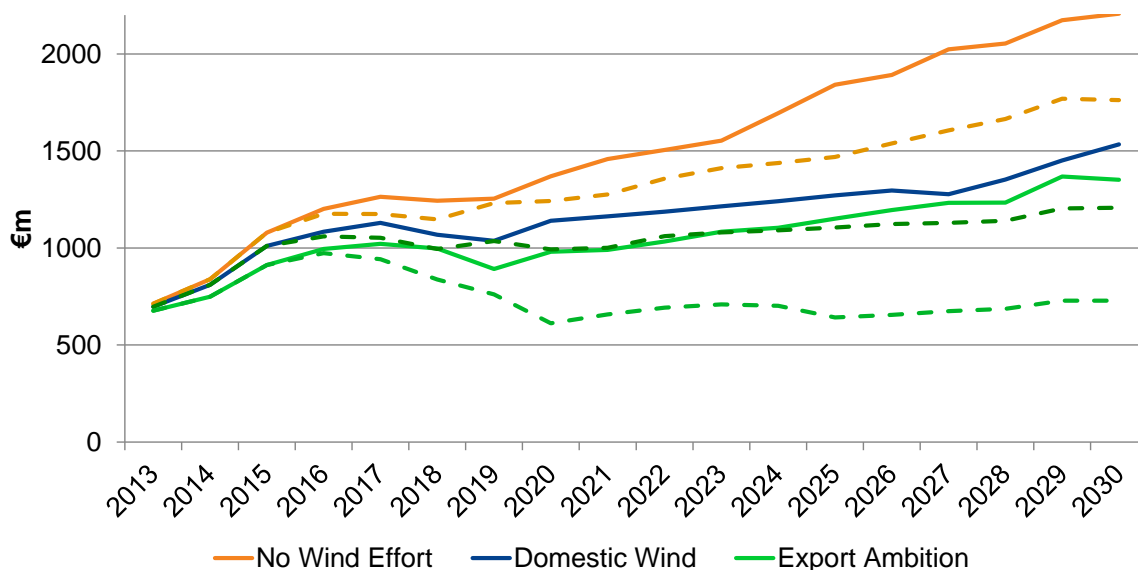
Note: Dashed line shows carbon sensitivity results. Main results charted with solid lines

B.8.5 Impact on security of supply

The same security standards are maintained in the carbon sensitivity as our main scenarios. Further description of the security standard in SEM and our approach to meeting that standard is described in Section B.6.1.

Figure 63 shows the gas imports costs for power generation. The carbon sensitivity decreases the gas import dependency due to lower levels of domestic thermal generation. In this sensitivity demand is met through a greater reliance on net imports over the electricity interconnector. Figure 64 shows the balance of payments for energy. We can see that revenue accruing the Ireland over the interconnector is largely lost with the higher carbon price but this is balanced by a reduced gas import bill. As in the main scenarios, the export project offers a significant benefit to Ireland’s balance of payments.

Figure 63 – SEM power generation gas costs (€m)



Note: Dashed line shows carbon sensitivity results. Main results charted with solid lines

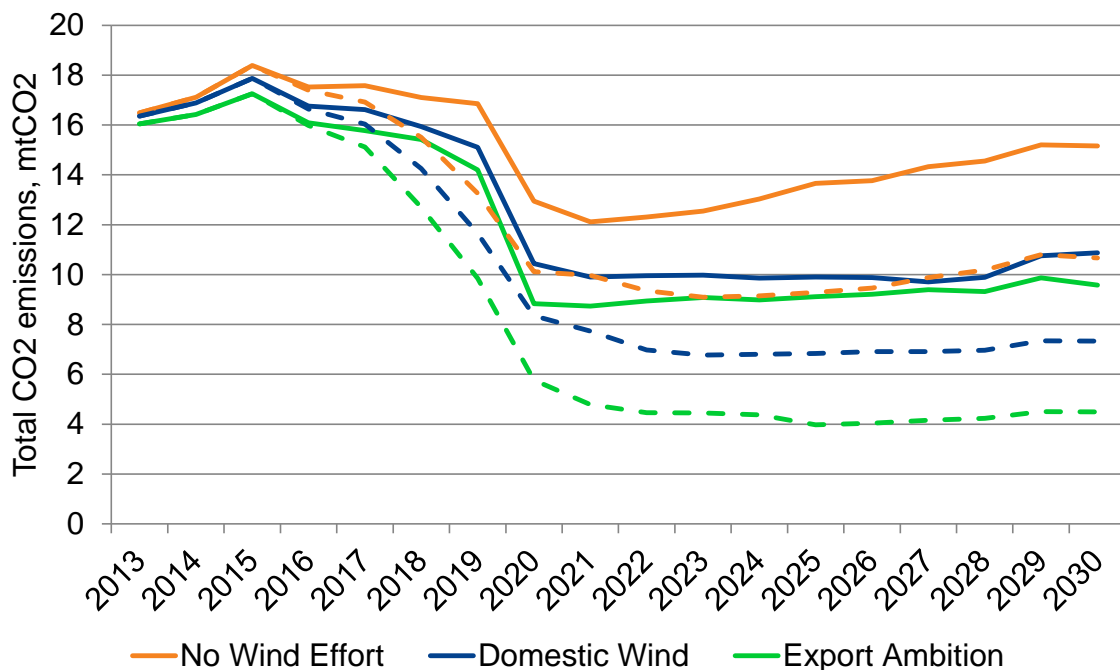
Figure 64 – Balance of payments for carbon sensitivity



B.8.6 Impact on environment

Figure 65 shows the CO₂ emissions by power generation in our carbon sensitivity. The level of emissions falls in all scenarios due to the replacement of domestic gas generation with electricity imports from GB.

Figure 65 – Total SEM emissions (tCO₂)



Note: Dashed line shows carbon sensitivity results. Main results charted with solid lines

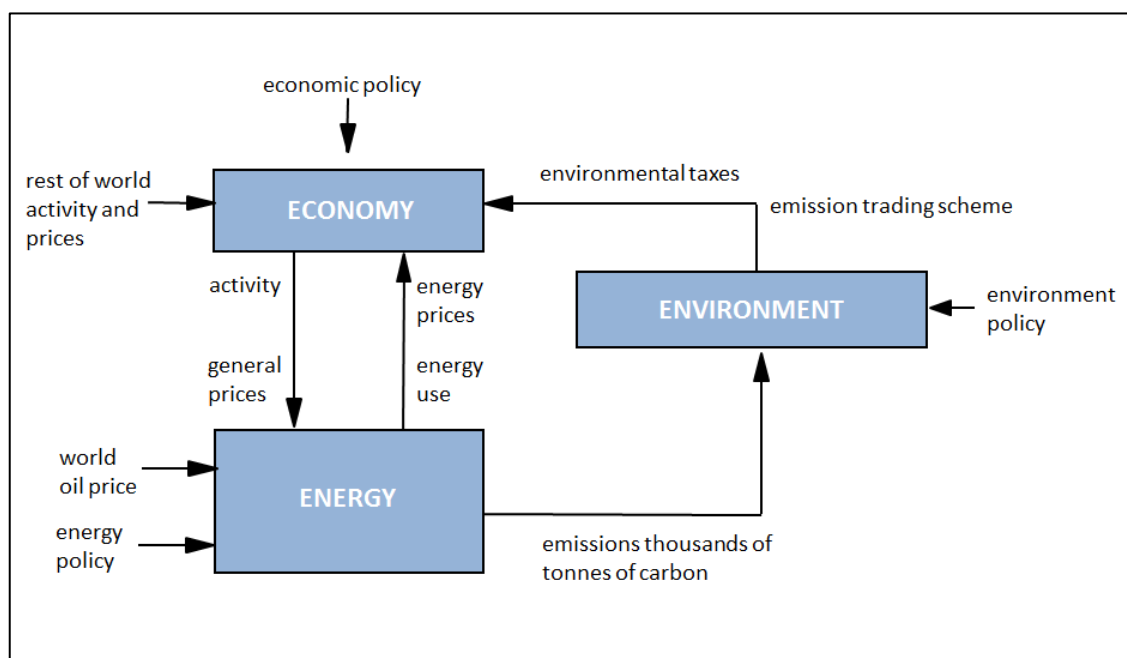
ANNEX C – CAMBRIDGE ECONOMETRICS’ MODELLING APPROACH

C.1 E3ME description

E3ME is a computer-based model of Europe’s economies, energy systems, and the environment (hence the three Es); more recently it has been expanded to also include demand for physical materials. E3ME was originally developed through the European Commission’s research framework programmes and is now widely used in Europe for policy assessment, forecasting and research purposes.

Figure 66 provides an overview of the model structure.

Figure 66 – The E3ME model



The economic structure of E3ME is based on the system of national accounts, as defined by ESA95 (European Commission 1996), with further linkages to energy demand and environmental emissions. The economic model includes a full set of macroeconomic feedbacks at the sectorial level that capture supply chain impacts and multiplier effects. The model contains a total of 33 sets of econometrically estimated equations, covering the individual components of GDP (consumption, investment, and international trade), prices, the labour market, energy demand and materials demand. Each equation set is disaggregated by country and by sector.

C.1.1 Determination of output

Output, measured in gross terms, is determined through the macroeconomic identity as the sum of intermediate and final demands. Intermediate demand is the demand from other economic sectors and is determined by input-output relationships (including

domestic and import supplies). Final demand consists of household and government demand, investment and exports. GDP and GVA are derived from these.

C.1.2 International trade

E3ME includes export and import equations for the trade of commodities within and outside of Europe. The basic assumption is that, for most commodities, there is a 'pool' into which a country supplies part of its production and from which the country satisfies part of its demand. The demand for a country's exports of a commodity is related to three factors:

- domestic demand for the commodity in all the other countries, weighted by their economic distance (determined by OECD bilateral trade data);
- the quality of national produce, determined by the technical progress indicators; and
- relative prices, including the effects of exchange rate changes.

Econometric equations are estimated to determine the magnitude of these effects.

C.1.3 Investment

Forecast changes in output are important determinants of investment in the model. Other determinants of investment are the relative price of capital, real interest rates and position in the economic cycle.

Sectorial investment is transformed by a converter matrix to go from the sector making the investment, to the one that receives the payment (e.g. construction or engineering). The resulting vector is a component of output (see above), providing the feedback loop between output and investment.

Gross fixed investment, enhanced by R&D expenditure in constant prices, is accumulated to provide a measure of the technological capital stock. Investment is central to the determination of long-term growth and the E3ME model embodies endogenous technical change and a theory of endogenous growth which underlies the long-term behaviour of the trade and employment equations.

C.1.4 Incomes and household expenditure

As described below, increases in economic output generate employment which, when multiplied by average wage rates, provides incomes to households. These are some of the largest payments to the personal sector, but not the only ones. There are also payments of interest and dividends, transfers from government in the form of state pensions, unemployment benefits and other social security benefits.

Employment and wages

E3ME includes equation sets for headcount employment, average wages, working hours and labour market participation. Increased economic output is expected to lead to higher levels of employment, greater wage demands and more incentive to work. Higher wage rates, however, are a deterrent to job creation.

Unemployment is calculated as the difference between employment and labour supply. It is an important determinant in wage bargaining.

Household expenditure

Totals of consumer spending are derived from consumption functions estimated from time-series data. These equations relate consumption to real personal disposable income, a measure of wealth for the personal sector, inflation and interest rates.

Consumption and output

Household consumption by product is converted to demand by sector using a transition matrix. This also subtracts consumption taxes, such as VAT. The resulting vector is used in the calculation of sectorial output. Sectors that typically benefit from higher rates of consumption include retail, hotels and catering and other personal services.

Prices

Each real economic variable has an associated price variable that goes with it. The relationships between prices and quantities are often complex and are estimated using behavioural relationships. It is also important to note the interaction between prices and wages. While inflation pushes up wage rates, higher unit wage costs for sectors lead to price increases which, when aggregated, lead to higher rates of inflation. There is thus a strong feedback loop in price effects.

C.1.5 Energy-Environment links

E3ME is intended to be an integrated top-down, bottom-up model of E3 interaction. In particular, the model includes a detailed engineering-based treatment of the electricity supply industry (ESI). Demand for energy by the other fuel-user groups is top-down, but it is important to be aware of the comparative strengths and weaknesses of the two approaches. Top-down economic analyses and bottom-up engineering analyses of changes in the pattern of energy consumption possess distinct intellectual origins and distinct strengths and weaknesses (see Barker, Ekins and Johnstone, 1995).

C.1.6 Parameter estimation

The econometric model has a complete specification of the long-term solution in the form of an estimated equation that has long-term restrictions imposed on its parameters. Economic theory, for example the recent theories of endogenous growth, informs the specification of the long-term equations and hence properties of the model; dynamic equations that embody these long-term properties are estimated by econometric methods to allow the model to provide forecasts. The method utilises developments in time-series econometrics, in which dynamic relationships are specified in terms of error correction models (ECM) that allow dynamic convergence to a long-term outcome. The specific functional form of the equations is based on the econometric techniques of co-integration and error-correction, particularly as promoted by Engle and Granger (1987) and Hendry et al (1984).

C.1.7 Model dimensions

The main dimensions of the version of the model used for this analysis are:

- 33 countries (EU-28 member states, Norway, Switzerland and three candidate countries);

- 69 economic sectors (2-digit NACE rev2 level), including a disaggregation of the energy sectors and 38 service sectors;
- 43 categories of household expenditure;
- 21 different users of 12 fuel types;
- 14 types of air-borne emissions including the six greenhouse gases monitored under the Kyoto protocol; and
- 13 types of household, including income quintiles and specific socio-economic groups.

Although our analysis focuses on the results for Ireland, all 28 countries in the EU were modelled in order to capture the expected trade flows for Ireland.

C.1.8 Comparison to CGE approaches

E3ME is similar in many ways to a Computable General Equilibrium (CGE) model and produces a similar set of outputs. However, E3ME does not impose the assumptions about the nature of the economy that are typically incorporated in CGE models. Instead, E3ME follows a more empirical approach, with behavioural parameters estimated using historical data sets rather than imposed or calibrated to conform to neoclassical economic theory. Consequently, the model's empirical validity does not depend on the validity of the assumptions common to CGE models, such as perfect competition or rational expectations, but it does mean that the model's validity depends on the quality of the data that are used to estimate the parameters.

C.1.9 Key characteristics

The key characteristics of E3ME for this exercise are thus:

- its coverage of the Irish economy;
- its two-way linkages between the economy and energy systems; and
- its econometric specification, allowing for analysis of both short and long-term impacts.

C.1.10 Modelling baseline

C.1.10.1 Overview of the baseline

A forward-looking, *ex ante*, assessment requires a baseline forecast with which to compare the different policy scenarios. This is not necessarily presented as a forecast of future developments, but rather as a neutral viewpoint for the purposes of comparison, since many of the model-based results are presented as (percentage) difference from baseline. Nevertheless, the values in the baseline are important in themselves, since they provide, for example, an indication of prices and energy requirements over the next decade. It is therefore important that a robust and credible baseline should be established.

The baseline that was chosen for this study is the 'PRIMES' 2009 reference case from the 'EU Energy Trends to 2030' publication⁴³, which has been updated with the most recent

⁴³ European Commission (2010), 'EU Energy Trends to 2030', available online http://ec.europa.eu/clima/policies/package/docs/trends_to_2030_update_2009_en.pdf

economic forecast from ‘The 2012 Ageing Report’, published by the European Commission (DG Ecfm)⁴⁴. The baseline assumes that there is no shale gas production in the EU in the period up to 2050.

Figure 67 summarises the baseline economic and energy projections.

Figure 67 – Summary of Modelling Baseline for Ireland

	2010	2020	2030	% pa growth (2010-2030)	% pa growth (2030-2050)
Population (000s)	4,450	4,767	5,225	0.7%	0.9%
GDP (€bn)	177.2	199.9	273.7	1.2%	3.2%
Employment (000s)	1,848	1,975	2,178	0.6%	1.0%
Greenhouse gas emissions (mtCO ₂ -eq)	12,428	12,132	12,727	-0.2%	0.4%

Sources: Cambridge Econometrics, based on PRIMES model outputs and economic projections from ‘The 2012 Ageing Report’, published by the European Commission.

C.1.10.2 Additional processing

Outputs from the PRIMES simulations and ‘The 2012 Ageing Report’ are incorporated into the E3ME solution. This includes the sectorial economic projections, energy and ETS prices, projections of energy demand by sector and by fuel, and sectorial CO₂ emissions. E3ME’s Energy Technology sub-model of electricity capacity and generation also makes use of some of the more detailed outputs.

However, in order to meet E3ME’s data requirements, it was necessary to carry out some additional expansion and processing.

- Classifications were converted – as E3ME and PRIMES use similar data sources, the classifications also tend to be quite similar. There are, however, some differences. For example, E3ME has more disaggregation of service sectors.
- Point estimates for occasional years were converted to annual time series – a simple interpolation method is used; short-term forecasts from the AMECO database are also used to take into account more recent data from the recession.
- Additional social and economic variables were estimated – only a small set of economic variables (GDP and the ones that are direct drivers of energy demand) are given in ‘The 2012 Ageing Report’ and PRIMES outputs. E3ME requires a complete specification of the national accounts so other variables must be estimated. The

⁴⁴ European Commission (2011), ‘The 2012 Ageing Report: Underlying Assumptions and Projection Methodologies’, available online http://ec.europa.eu/economy_finance/publications/european_economy/2011/pdf/ee-2011-4_en.pdf

procedure followed to achieve this is described below (proxies for other economic indicators).

These additional steps were carried out using software algorithms based in the Ox programming language (Doornik, 2007). The result of this exercise is a set of baseline projections that is both consistent with the published figures and the integrated economy-energy-environment structure of E3ME.

C.2 Modelling approach

The technical analysis undertaken by Pöyry established, for each scenario, a series of E3ME model inputs in the form of annual projections for the years 2013-2030. This included the following:

- power sector structure and demand for coal, oil and gas;
- wholesale electricity prices;
- wind subsidy costs;
- DS3 investment costs;
- grid investment costs;
- additional wind investment costs;
- electricity imports and exports; and
- electricity demand.

These were processed using the Ox software package and read into the E3ME model as exogenous inputs.

ANNEX D – MACROECONOMIC RESULTS

This annex provides a summary of the model inputs and a more detailed breakdown of the impact on the Irish⁴⁵ economy, as summarized in Section 5.

Section D.1 gives a brief outline description of the E3ME macroeconomic model and Section D.2 specifies the inputs that were fed into the model for the present exercise. Section D.3 presents the breakdown of the GDP impact into its component parts (consumption, investment, exports and imports) and Section D.4 presents the results of the sensitivity analysis.

D.1 The E3ME model

The E3ME⁴⁶ model was used to assess the effects on the Irish economy of the three scenarios for levels of wind generation of electricity. The model is organised as a series of accounting identities and empirically estimated econometric equations. Using these identities and equations, it draws on historical data to estimate the future relationships between key variables in the interactions between energy, the environment and the economy. Its input-output structure allows us to model the economic effects of different levels of wind energy investment on individual industries at the NACE 2-digit sectorial level of detail, taking account of down-stream, supply-chain effects and the distinct features of individual industries, including their cost structure, labour intensity and contribution to gross value added. More information on the model and the baseline assumptions, are provided in Annex D.

D.2 Energy market inputs

The macroeconomic analysis presented in Section 5 and this annex builds on the energy market modelling⁴⁷ undertaken (as outlined in the main report and Annex B). The following results of the energy market analysis were fed directly as inputs to the three scenarios used in the E3ME model:

- power sector structure and demand for coal, oil and gas;
- wholesale electricity prices;
- wind subsidy costs;
- DS3 investment costs;
- grid investment costs;
- additional wind investment costs;
- electricity imports and exports; and

⁴⁵ Although the energy market analysis focused on the whole SEM in the Island of Ireland, there are not enough national accounts to allow us to draw up a suitable economic baseline for the Island of Ireland. Consequently, the scenario results in this chapter should be interpreted as the macroeconomic results for Ireland only.

⁴⁶ More information on the E3ME model is available at www.e3me.com

⁴⁷ The energy market results were divided between Ireland and Northern Ireland in order to make it possible to model the macroeconomic results for Ireland only.

- electricity demand.

The assumptions about fossil fuel prices and carbon prices used in E3ME were also aligned to be consistent with the values used in Pöyry's BID3 Model (please refer to Annex A for more details).

D.3 Macroeconomic results

GDP is defined as the sum of consumption, investment, government expenditure, and net exports. The results for each of these components of aggregate demand are shown in Table 9 and Table 10 below.

Table 9 – Summary of macroeconomic modelling results for Ireland, 2013-2020

	<i>No Wind</i>	<i>Domestic Scenario</i> (difference from <i>No Wind</i>)	<i>Export Scenario</i> (difference from <i>No Wind</i>)
GDP (€ m)	192,533	352 (0.18%)	2,517 (1.31%)
Consumption (€ m)	70,564	15 (0.02%)	248 (0.35%)
Investment (€ m)	33,566	359 (1.07%)	2,926 (8.72%)
Exports (€ m)	185,778	28 (0.02%)	891 (0.48%)
Imports (€ m)	144,560	50 (0.04%)	1,548 (1.07%)
Jobs (000s)	1,931	1.15 (0.06%)	7.45 (0.39%)

Table 10 – Summary of macroeconomic modelling results for Ireland, 2021-2030

	<i>No Wind</i>	<i>Domestic Scenario</i> (difference from <i>No Wind</i>)	<i>Export Scenario</i> (difference from <i>No Wind</i>)
GDP (€ m)	238,564	646 (0.27%)	5,015 (2.1%)
Consumption (€ m)	74,459	13 (0.02%)	381 (0.51%)
Investment (€ m)	41,570	398 (0.96%)	2,290 (5.51%)
Exports (€ m)	238,241	288 (0.12%)	3,694 (1.55%)
Imports (€ m)	185,281	53 (0.03%)	1,351 (0.73%)
Jobs (000s)	2,079	1.62 (0.08%)	11.84 (0.57%)

- **Consumer expenditure** remains largely unchanged in the Domestic scenario compared with the *No Wind* baseline. The negative impact on real disposable income brought about by higher retail electricity prices is entirely offset by a positive impact on average incomes due to a net increase in employment. In the *Export* scenario, however, the substantial increase in employment is sufficient to result in a modest increase in average incomes (an annual average increase of €370 per household over the period 2021-2030) and this leads to a small increase in consumer expenditure of around 0.5% per annum in the period to 2030.
- **Investment** in the economy is higher principally due to the direct investment in wind energy (although in the *Domestic* scenario, part of this investment is displaced). The increase in demand in the whole economy also drives further increases in investment due to higher profit expectations.
- **Exports** are higher due to the additional electricity exports to GB. This effect on exports is slightly offset by a reduction in industry competitiveness due to higher retail electricity prices and therefore higher industry costs.
- **Imports** are slightly higher in the *Domestic* and *Export* scenarios. The reduction in gas-fired power generation in the *Domestic* and *Export* scenario drives a reduction in imports of gas. However, this is offset by an increase in imports of wind turbines and an increase in final demand for goods.
- **Government expenditure** is assumed to remain fixed between scenarios. Section 5 provides details of the additional government tax revenues in the *Domestic* and *Export* scenarios.

D.4 Sensitivity analysis

Sensitivity analysis was carried out for the *Domestic* scenario out to test the impact of:

- growth in the domestic wind supply chain;
- a higher carbon price; and
- external financing for the wind investment costs.

D.4.1.1 Growth in the domestic wind supply chain to reach 50% domestic content

In this sensitivity we modelled the economic impact of an expansion of domestic turbine production capabilities. If Ireland were able to attract turbine blade manufacturers, the domestic content of the wind investment could increase from 36% to 50%. By increasing domestic production in place of imports, the increase in GDP in the *Domestic* scenario could be around €381m higher per annum compared with the *No Wind* baseline over the period 2013-2020 and €678m per annum higher, on average, over 2021-2030.

D.4.1.2 Higher carbon price

The carbon price assumption used in our central scenarios is consistent with UK DECC (2013) projections in the short term and in the long term it is consistent with the IEA Current Policies projections. Due to the merit order effect, a higher carbon price would lead to a greater difference between the wholesale electricity price in the *Domestic* and *No Wind* scenario. The increase in this wholesale price differential would drive a relative increase in net electricity exports. Under this assumption, the economic impact of the *Domestic* scenario compared with the *No Wind* baseline is slightly more positive, leading to an increase in GDP of €769m on average per annum over the period 2021-2030.

D.4.1.3 External financing of wind investment costs

The external financing sensitivity was used to assess the impact on the results if Ireland were able to secure financing of the wind and grid investment costs from an external source. In our central scenarios (ref) we assume that the wind investment costs are paid for by the domestic electricity sector. This leads to a reduction in electricity profits which then results in a reduction in investment that partially offsets the initial investment in wind. If the costs were paid for externally, electricity sector profits would not be affected, and the implications for investment and GDP would be more positive.

D.4.1.4 Results from the sensitivity analysis

Table 11 – Summary of results for key sensitivities in the Domestic scenario, 2013-2020

	<i>No Wind</i>	<i>Domestic Scenario – central scenario (diff. from No Wind)</i>	<i>Domestic Scenario – 50% domestic content (diff. from No Wind)</i>	<i>Domestic Scenario – External financing (diff. from No Wind)</i>
GDP (€ m)	192,533	352 (0.18%)	381 (0.20%)	493 (0.26%)
Jobs (000s)	1,931	1.15 (0.06%)	1.25 (0.06%)	1.79 (0.09%)

Table 13, Table 14 and Table 15 show the GDP and jobs impact of the key sensitivities tested.

Table 12 – Summary of results for key sensitivities in the Domestic scenario, 2013-2020

	<i>No Wind</i>	<i>Domestic Scenario – central scenario (diff. from No Wind)</i>	<i>Domestic Scenario – 50% domestic content (diff. from No Wind)</i>	<i>Domestic Scenario – External financing (diff. from No Wind)</i>
GDP (€ m)	192,533	352 (0.18%)	381 (0.20%)	493 (0.26%)
Jobs (000s)	1,931	1.15 (0.06%)	1.25 (0.06%)	1.79 (0.09%)

Table 13 – Summary of results for key sensitivities in the Domestic scenario, 2013-2020

	<i>No Wind – high carbon price</i>	<i>Domestic Scenario – high carbon price (difference from No Wind)</i>
GDP (€ m)	+192,356	+360 (0.19%)
Jobs (000s)	+1,931	+ 1.15 (0.06%)

Table 14 – Summary of results for key sensitivities in the Domestic scenario, 2021-2030

<i>No Wind</i>	<i>Domestic Scenario –</i>	<i>Domestic Scenario –</i>	<i>Domestic Scenario –</i>
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		central scenario <i>(diff. from No Wind)</i>	50% domestic content <i>(diff. from No Wind)</i>	External financing <i>(diff. from No Wind)</i>
GDP (€ m)	238,564	646 (0.27%)	678 (0.28%)	769 (0.32%)
Jobs (000s)	2,079	1.62 (0.08%)	1.71 (0.08%)	2.33 (0.11%)

Table 15 – Summary of results for key sensitivities in the *Domestic* scenario, 2021-2030

	<i>No Wind – high carbon price</i>	<i>Domestic Scenario – high carbon price (difference from No Wind)</i>
GDP (€ m)	237,478	+672 (0.28%)
Jobs (000s)	2,078	+1.67 (0.08%)

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