# The impact of wind on pricing within the Single Electricity Market

February 2011

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***Version History***

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| Final V1 | 23rd February | Final report | Phil Grant<br>Edmund Phillips | Adrian Palmer |

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# Contents



### List of figures



### List of tables

# Executive summary

***A rapid and large scale deployment of wind capacity is required to meet national targets***

The Republic of Ireland and Northern Ireland are both committed to delivering 40% of electricity consumption from renewable sources by 2020. Wind generation is expected to supply the majority of the renewable electricity. Wind supplied approximately 10.5% of electricity demand in the All-Island market in 2009[1] and therefore a continued large scale deployment of wind capacity is required in order to meet the 40% targets.

There has been a desire amongst market participants to understand the impact that wind generation has on wholesale electricity prices in the All-Island Single Electricity Market (SEM), and therefore the impact on the costs to consumers. To help address this, Wind Skillnet commissioned Redpoint to prepare a training course and a supporting study examining the impact of differing levels of wind generation on electricity prices and renewable support costs. Using the power market simulation tool PLEXOS we have analysed three years (2011, 2015, and 2020) and a number of alternative sensitivities on wind penetration levels, commodity prices and the capacity mix.

The analysis conducted for Wind Skillnet focussed solely on the impact that wind generation has on two components of consumer bills; electricity prices and renewables support. It is not intended to provide a fully detailed Cost Benefit Analysis of wind generation in the SEM. The study aims to simulate the process of wholesale price formation in the SEM, and as such it does not consider the technical constraints of operating the electricity network.

***Wholesale power prices remain very closely linked to gas prices through to 2020***

Our analysis demonstrates that through to 2020, gas fired CCGT plant will set the wholesale electricity price, System Marginal Price (SMP), for the majority of the time through the year although as the marginal fuel, gas loses market share when output from wind plant increases.

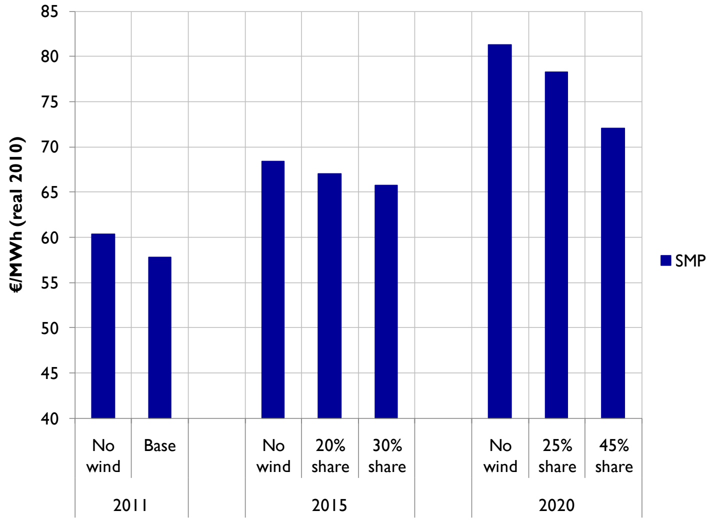
In 2011 and 2015 at times of high output from wind plant, the marginal CCGT is displaced by a slightly less expensive CCGT, although the difference in generation cost, and hence SMP, is relatively modest. With the recent fall in electricity demand, combined with the commissioning of 800 MW of new CCGT, the SMP is set very rarely by more expensive conventional gas plant and oil plant.

However, by 2020, at times of high wind output and relatively low demand, there are periods in which wind could supply all electricity demand. Wholesale prices in these periods fall to zero. In the scenario in which wind meets 45% of electricity required in 2020, there are over 500 hours in which wind fully meets demand. For approximately 200 of these hours, exports to Great Britain ensure that the price in SEM does not fall to zero.

The chart below shows the change in SMP through time and with differing levels of market share for wind.

[1] Source: SEAI Renewable Energy in Ireland 2010 Update

**Figure 1 SMP results summary**




***Generation costs fall more rapidly than wholesale prices***

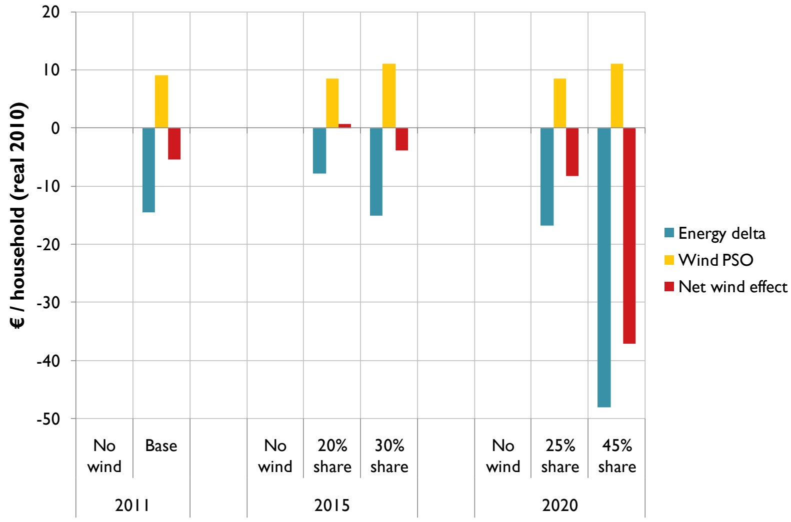
All generators scheduled to operate are paid the same price for their output in the SEM, irrespective of their cost of generating. As the market share of wind grows, displacing thermal generation, the average generation cost falls. The fall in generation costs is much greater than the reduction in price, due to CCGT plant remaining the marginal technology.

***The cost of supporting wind through the Public Service Obligation is lower than the savings in wholesale power costs***

Through the Public Service Obligation (PSO) levy, electricity consumers in RoI support national policy objectives, including renewable electricity generation. In the analysis we consider three separate incentive schemes for wind plant and compare the aggregate costs of providing support under these mechanisms to a counterfactual scenario in which there is no wind on the system.

Under the scenarios modelled, consumers are shown to pay less through the support mechanisms than the savings they make from lower wholesale power prices, as illustrated in the chart below. The modelling shows that in 2011, a typical domestic consumer saves approximately €5.40 per year, and this could rise to approximately €38 by 2020 if there is a high penetration of wind on the system. Our sensitivity analysis indicates that the consumer savings will vary depending on factors such as underlying commodity prices and the generation output mix. Nevertheless, the general trend observed in the modelling was of renewable support costs being more than offset by lower wholesale prices.

**Figure 2 Summary of net effect on domestic consumers**




***With higher commodity prices the net savings to consumers increase***

For 2020 we ran a series of sensitivities in which commodity prices were markedly higher than in the core scenarios. This analysis demonstrated that wind generation can help hedge consumers against high commodity prices as the net savings increased to €58 compared to the counterfactual without wind. Were commodity prices to outturn lower than in the core scenarios, the net savings to consumers from wind would fall.

# 1 Introduction

## 1.1 Context

In 2007 the European Union agreed a 20% target for the consumption of energy produced from renewable sources[2] and each member state has a legally binding commitment to deliver towards this overall goal. Within this directive the Republic of Ireland (RoI) has a target of 16% of energy from renewable sources and the United Kingdom a target of 15%. Each member state has flexibility to set targets across the heating, transportation and electricity sectors to meet the overall renewable energy targets[3]. Both RoI and Northern Ireland (NI) have set targets of 40% of electricity consumption to be met from renewables sources by 2020.

Whilst there has been a rapid growth in generation from renewable sources over the last five years (increasing 108% to 4.4 TWh from 2005 to 2009 in RoI), in order to meet the 40% target in both jurisdictions a further acceleration in renewable deployment rates is required. Delivering high levels of large scale, intermittent generation will bring challenges for planners, policy makers, regulators, investors and for those operating the system.

In this context it is important for market participants to understand the effect of increasing levels of wind generation on power prices, and how this interacts with the cost of support to wind power provided through the AER and REFIT schemes. To help address these questions Wind Skillnet commissioned Redpoint to undertake detailed modelling of the Single Electricity Market (SEM) in order to quantify the net effect of wind generation on the consumer.

## 1.2 Project objectives

This report and the supporting analysis is framed to provide a clear understanding of the links between wind generation and electricity prices and to quantify the potential size of identified effects on those prices. This must be compared to the cost of supporting wind generation through the AER and REFIT schemes to find the overall effect on consumer costs in RoI. As the SEM is an all-island market we have conducted the analysis for RoI and NI, except where specified.

We have modelled three years (2011, 2015, and 2020) and a number of alternative scenarios and sensitivities on wind penetration levels, commodity prices and the capacity mix to explore how wind is likely to impact wholesale prices in the SEM. These scenarios have been agreed with IWEA and reflect a range of potential outcomes in the market. In this analysis we make no judgement on the wider costs or benefits of wind generation on the system beyond the impact on wholesale prices and on the Public Service Obligation (PSO) levy. The scope of our analysis has focussed on the 'unconstrained system' and in particular does not reflect transmission constraints or system balancing costs. It is beyond the scope of this analysis therefore to assess what volume of wind that the system overall can absorb, taking into account the demands that intermittency may place on operating the system[4]. In this context it should also

[2] Directive 2009/28/EC.

[3] Subject to a minimum of 10% of energy use in transport being renewable sourced by 2020.

[4] For an analysis of this point, please refer to the 'All Island TSO Facilitation of Renewables Study', published by EirGrid and SONI.

be noted that the results presented are based on the market schedule rather than actual despatch, which may differ due to technical constraints.

## 1.3 Report structure

This report contains the following sections:

- Section 2 presents the assumptions and modelling approach
- Section 3 presents the results of the analysis including the generation profile, emissions, and the impact on prices. The latter is compared with the cost of supporting renewable electricity generation, allowing assessment of the impact on the overall cost to the consumer of increasing levels of wind generation
- Appendix A provides detailed assumptions data
- The key numerical results data is provided in Appendix B

## 1.4 Conventions

Our analysis is presented in real 2010 terms.

Unless otherwise stated, the report refers to the All-Island electricity market (the SEM). Analysis on the Public Service Obligation (the PSO) is presented for RoI only. Different renewables support arrangements apply in NI, with wind projects currently receiving support under the Renewables Obligation Certificate (ROC) scheme. However, under its Electricity Market Reform programme, the UK government is considering replacing the Renewable Obligation with a feed-in tariff scheme before 2020, subject to consultation and policy development.

# 2 Modelling methodology and assumptions

## 2.1 Scenarios and sensitivities

We have modelled three discrete years in this analysis (2011, 2015 and 2020) and have developed scenarios for each year. Table 1 summarises the core scenarios modelled together with the wind market share of generation.

- For 2011 we compare a *Base* scenario with a theoretical *No wind* scenario to enable a comparison of the effects in the near term of wind on the system. The *Base* scenario is formed by combining sources of quoted market data and key sources include the Regulatory Authorities' (RAs') validated dataset, EirGrid's Generation Adequacy Report (GAR) and quoted commodity price forward curves.
- For 2015 and 2020, three core scenarios are analysed: *No wind*, a scenario in which wind grows at a steady rate (*20% wind market* share in 2015, and *25% wind market share* in 2020), and a scenario in which wind power is deployed at a more rapid rate (*30% wind market share* in 2015, and *45% wind market share* in 2020). These scenarios make a number of assumptions about the evolution of demand, the capacity mix and long term commodity prices. These assumptions are outlined in section 3.

**Table 1 Core scenario summary (wind market share)**

| Description | 2011 | 2015 | 2020 |
|---|---|---|---|
| 'Base' scenario | 16% | | |
| No wind | 0% | 0% | 0% |
| Steady growth | | 20% | 25% |
| Rapid deployment | | 30% | 45% |

In addition to the core scenarios we analysed a number of sensitivities for 2020. In these cases we tested the sensitivity of outcomes to changes in commodity prices, windier or calmer years and changes to the supply mix. Table 2 summaries the sensitivities modelled for 2020.

**Table 2 2020 sensitivities**

| Description | No wind | 25% share | 45% share |
|---|---|---|---|
| 150 $/bb oil | X | X | X |
| Calm year | | X | |
| Windy year | | | X |
| 45 €/t carbon | X | X | X |
| Existing capacity extension | X | X | X |

## 2.2 Modelling the SEM

The Single Electricity Market (SEM) is a mandatory gross pool that covers both RoI and NI. Given the prescriptive and algorithmic nature in which market participants submit bids to the market and wholesale prices are established, it is a market that can be well represented by simulation and modelling. Since the formation of the SEM, PLEXOS for Power Systems has been the market modelling software most commonly used by the RAs and market participants to analyse the market. PLEXOS has been a core component in our analysis in this project.

Each year, the RAs undertake a market model validation exercise, to assess the robustness of PLEXOS for modelling prices in the SEM. As part of the validation exercise, a validated SEM PLEXOS model dataset is published by the RAs, and this has formed the starting point for this analysis. We have added further detail for generators in the SEM model including non-fuel variable operating costs and starts costs: the latter being critical in determining the level of uplift in wholesale prices. We have also included forward-looking data to parameterise the scenarios.

PLEXOS simulates the hour to hour dispatch of plant to meet demand at least cost taking into account generators' costs and technical constraints together with any system-wide constraints such as emissions or energy-limited plant. The modelling includes interconnection to Great Britain with both Moyle and, in the 2015 and 2020 cases, the East-West interconnector. Much like the market itself, PLEXOS will calculate a single price for each period (the System Marginal Price (SMP)) and a generator output schedule (the Market Schedule). We have extracted some of the PLEXOS results to analyse the relative impact of wind on electricity prices, and compared this to the provisions made for wind plant in the Public Service Obligation (PSO) in RoI. Consistent with the market itself our modelling of the SEM does not take into account transmission constraints and reserve requirements in forming the SMP and Market Schedule.

Prior to dispatch, PLEXOS will calculate the availability of plant through the year, taking into account planned and unplanned maintenance. The former is optimised across the system, whilst the latter is modelled as a random effect. For each of the years modelled we have fixed the outage profile for each generator taking into account both planned and unplanned outages. These outage profiles are then applied in each of the runs in each of the modelled years.

In addition to the revenues from the wholesale market, generators also receive capacity payments for each trading period. These are paid to thermal generators based on availability and to wind plant based on output. We combine period-level outputs from PLEXOS, with a model which projects the annual capacity payment pot, to calculate a system average capacity payment per megawatt hour of available energy for each modelled year.

## 2.3 Key assumptions

In this section of the report we briefly present the key assumptions for the modelling.

### 2.3.1 Annual energy and peak demand

Demand for electricity in Ireland fell in 2009 due to the contraction in the economy. In the longer term, as economic growth returns, electricity demand is expected to resume its upward trend. Historically EirGrid and SONI have produced annually projections for demand in their respective jurisdictions.

For our modelling we apply two methods in order to project demand in the SEM through to 2020. For 2011 and 2015, we combine the demand projections published by EirGrid[5] for RoI and SONI[6] for NI to

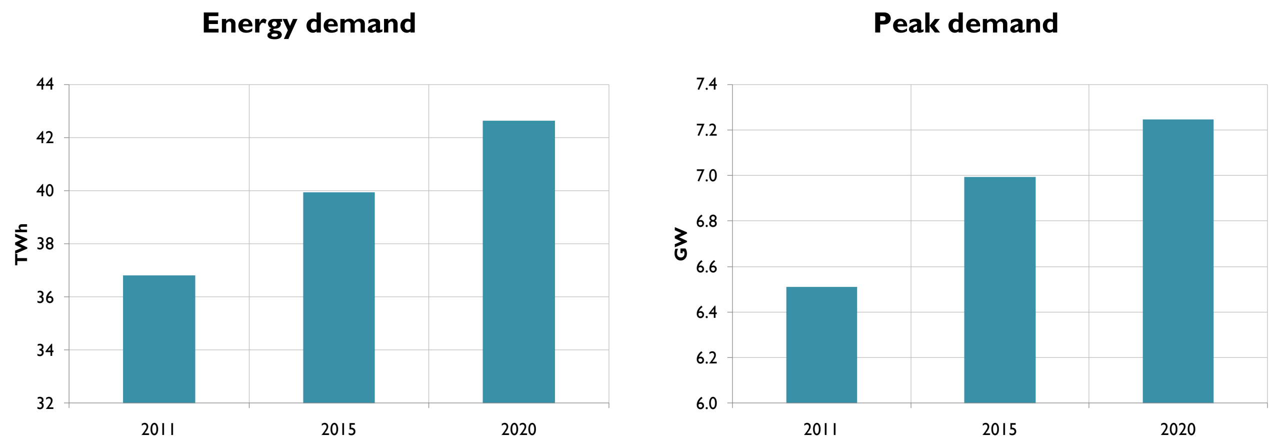
[5] The median values as defined in Eirgrid's 'Generation Adequacy Report 2010-2016'

produce an All-Island demand projection. Beyond the time horizon of the System Operators' (SOs) projections we calculate demand growth based on GDP growth assumptions and the relationship between GDP growth (assumed to be 2% per annum) and energy demand growth (the energy intensity ratio – assumed to be 0.5). The load curve is assumed to flatten slightly through time with peak demand growing less rapidly than annual energy demand.

The demand assumptions were formed prior to the publication of the Generation Capacity Statement 2011-2020 in December 2010 but the assumption is close to the published projection.

Figure 3 illustrates the energy demand and peak demand assumptions.

**Figure 3 Annual SEM energy demand and peak demand**




## 2.3.2 Commodity prices

Commodity prices are the key determinant of wholesale prices in the SEM since the market bidding principles oblige generators to submit bids reflecting the spot price of the underlying commodities (oil, coal, gas and carbon). We derive our commodity price projections by combining commodity forward curves for the near term and then through interpolation to the International Energy Agency's (IEA's) long term 'Current Policies' scenario.

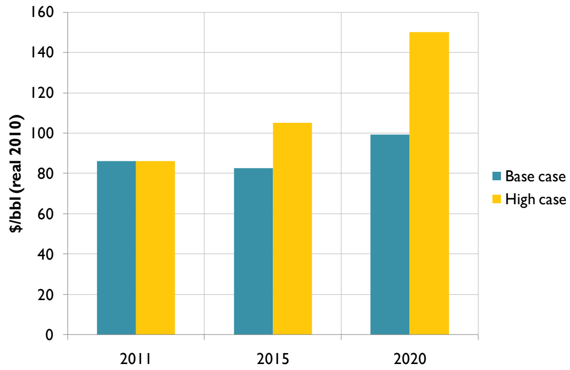
The assumptions for each commodity are outlined in more detail in Table 3 below.

[6] The medium demand scenario from System Operator of Northern Ireland's (SONI) 'Seven Year Generation and Capacity Statement 2010-2016'

## Table 3 Commodity price projections

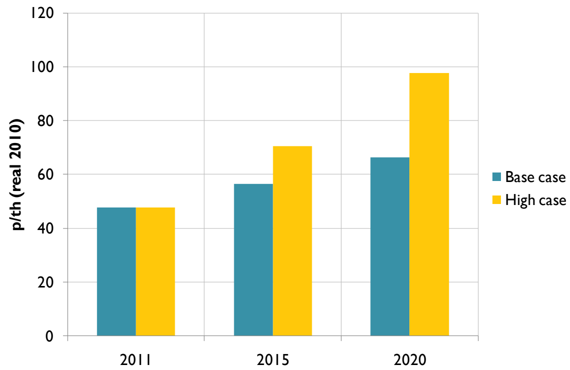
***Brent crude***

Brent oil prices are based on the traded forward curve in the period through to 2015. The projection is then based on the International Energy Agency's (IEA's) long term 'Current Policies' scenario with a trend towards 133 \$/bbl in 2030, reaching 99 \$/bbl by 2020. The Brent crude price directly determines the price of heavy fuel oil and gasoil, as well indirectly setting the long term gas price through oil-gas linkage. A high oil price sensitivity is also considered, where oil reaches 150 \$/bbl by 2020.



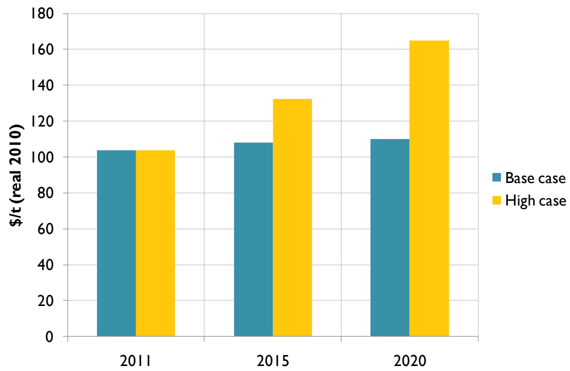

***Gas***

The gas price reflects the GB NBP forward curve in the near term and is then derived from indexation to the oil price. Transportation costs are added to the NBP gas price projection and we also apply seasonality to the annual prices shown. For reference, the current year ahead NBP gas price is 58 p/th[7] - above the level assumed in the modelling.




***Coal***

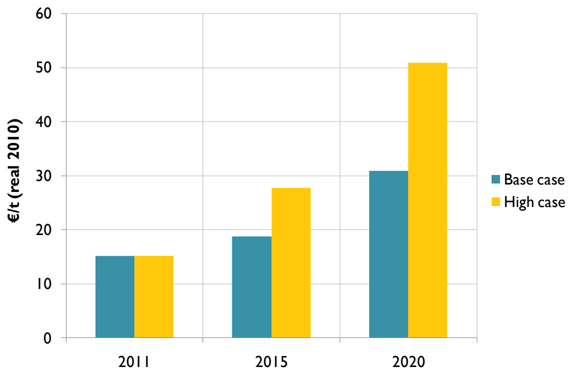
Coal prices are based on the API2 forward curve through to 2015. The projection then trends towards 115 \$/t in 2030 – again based on the IEA's projection. Transportation costs are added to the coal price projection.




[7] As-of 21 January 2011

***Carbon***

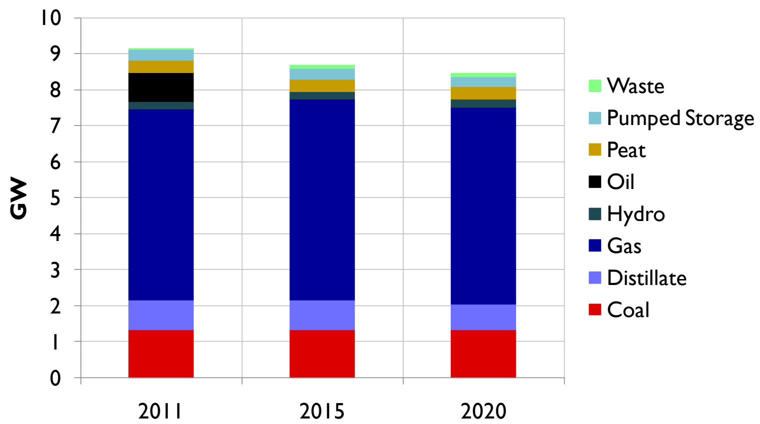
Generators' offer prices into the market include the costs of emitting carbon. The carbon price reflects a world in which carbon abatement in Europe is achieved largely in the power sector through coal to gas switching. This drives the EUA price steadily higher to 55 €/t in 2030. At this point, the generation cost of coal and gas are approximately equal. Year ahead carbon is currently trading at 14.4 €/t[7].




### 2.3.3 Evolution of thermal capacity

Gas-fired capacity remains the dominant fuel-type in SEM throughout the next decade as shown in Figure 4. Over the course of the next decade some existing conventional gas capacity is replaced by modern CCGT and OCGT plant. There is a small overall reduction in the installed capacity of thermal plant with the decommissioning of oil-fired generation being the single largest change. Finally, there is a small amount of waste to energy capacity commissioned in the period between 2011 and 2015.

**Figure 4 Non wind capacity mix**




The specific assumptions made with regards to the commissioning and decommissioning of plant are detailed in Appendix A.

### 2.3.4 Public Service Obligation

Through the Public Service Obligation (PSO) levy, electricity consumers in RoI support national policy objectives, including peat fired and renewable electricity generation. Three support mechanisms for wind plant in RoI are considered in the modelling. These are the Alternative Energy Requirement (AER), Renewable Energy Feed-In Tariff 1 (REFIT 1) and REFIT 2. Payments for renewable support in RoI are made to suppliers rather than directly to project developers, but for modelling purposes, we assume back-to-back arrangements exist between wind generators and off-taking suppliers.

Eligible renewable energy projects have been able to enter six rounds of competition for support under the AER programme. In 2011, we assume that support has expired under all rounds previous to AER 6, and by 2015 the AER programme will have expired fully with respect to wind projects. Under the scheme wind projects enter a Power Purchase Agreement whereby they receive the difference between the prevailing market power price and a reference price (or pay that difference should the market price be higher). Different reference prices apply to large and small scale (under 5 MW) wind projects.

The price that wind farms under the REFIT 1 regime receive for each unit of power generated has three components. Firstly, should the market price be below a reference price, projects receive the difference between the two values. Secondly, a balancing payment is made of 15% of the reference price. Lastly technologies other than large scale wind receive a technology premium, for which small scale wind is eligible. The reference price, balancing payment and technology premium are indexed to CPI. A ceiling of 1,450 MW has been set for wind projects receiving support under REFIT 1. Capacity built beyond that is assumed to receive support under REFIT 2. REFIT 2 is structured in the same way as its predecessor, but we assume that the balancing payment is not indexed[8]. In addition, no balancing payment will be paid under REFIT 2 when the market price exceeds the reference price plus the balancing payment. The figures in this report are presented in 2010 prices, when the REFIT reference price was 66.353 €/MWh, and the technology premium for small wind is 2.328 €/MWh.

Appendix A details the total capacity of wind plant receiving support under the schemes described for each year and scenario, and the assumptions used in deriving results for PSO payments. When evaluating market revenues of wind generation under each support scheme, we consider the average SMP received (ie weighted by wind output), and the expected receipts of wind generation under the capacity payment mechanism. We assume that the allocation of the PSO levy payment to domestic consumers remains constant through the years modelled. The results presented in this report do not take account of PSO related support to plant other than wind.

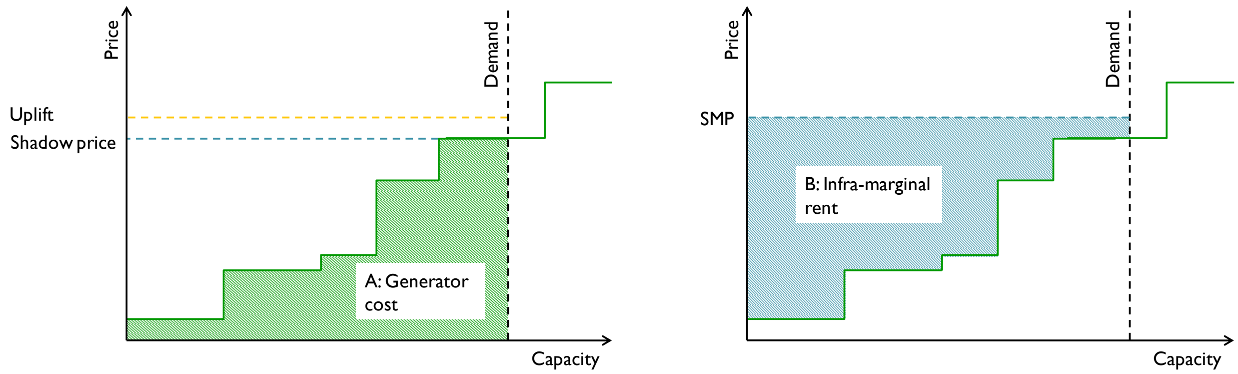
[8] Assumption taken from IWEA Members Policy Update, 12 July 2010

# 3 Market results

## 3.1 Introduction

In this chapter we present the key results of the analysis for each year and sensitivity. We begin by introducing some of the concepts underlying the results. Figure 5 represents the supply curve (with capacity on the horizontal axis and price on the vertical axis) and demand level in a particular trading period in the market, and illustrates the price setting mechanism.

**Figure 5 Price setting in SEM**




The terminology used is explained in Table 4.

**Table 4 Key terminology**

| | |
|---|---|
| Generation cost | Each generator offers into the market at its short run marginal cost based on prevailing spot commodity prices. The last unit to be scheduled to meet demand is the marginal unit. The total system generation costs include the fuel, carbon and non-fuel operating costs of all plant that operate during the year. |
| Average generation cost | The sum of the cost of each unit of power generated divided by the total units of power generated. |
| System Marginal Price (SMP) | SMP is the calculated market price for power. It is comprised of the marginal plant's fuel and carbon costs (the Shadow Price), plus the revenue required so that generation plant recover start and no load costs over the period in which they are operating (the Uplift). |
| Infra-marginal rent | A plant operating with a generation cost below the SMP earns profit, termed Infra-marginal rent. The total system infra-marginal rent is shown as area B in Figure 5. |

Wind power has zero marginal cost, and so will be introduced at the bottom of the supply curve. When wind is generating, its output will tend to displace the output of the marginal unit, and if there is sufficient wind generation, mean that a lower cost plant can meet the last unit of demand. In this way wind generation will reduce the trading period's SMP, a phenomenon known as the 'Merit Order Effect'. The introduction of wind power to a system will therefore tend to reduce the average wholesale cost of power.

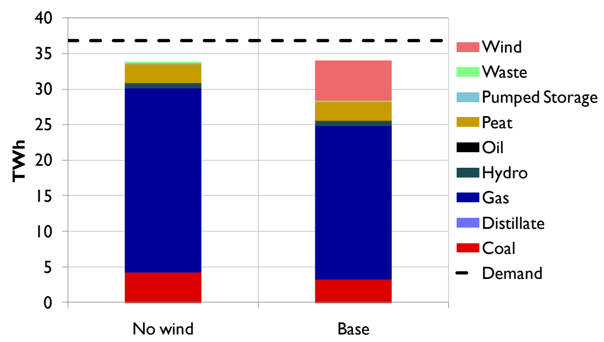
## 3.2 2011

For 2011 the *Base* scenario is compared to a counterfactual case in which there is zero output from wind plant. From this analysis we can compare the delta in costs and market prices with and without wind on the system.

### 3.2.1 Summary results

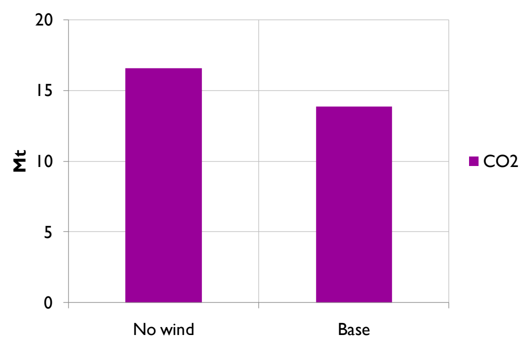
***Generation***

- In the *Base* scenario gas fired capacity dominates the generation mix with total output of 21.6 TWh which is 70.5% of total demand.
- With no wind generation, gas output increases to 25.9 TWh, and coal increases by 1 TWh demonstrating that gas is the swing fuel.
- Imports from GB make up the remainder of demand.



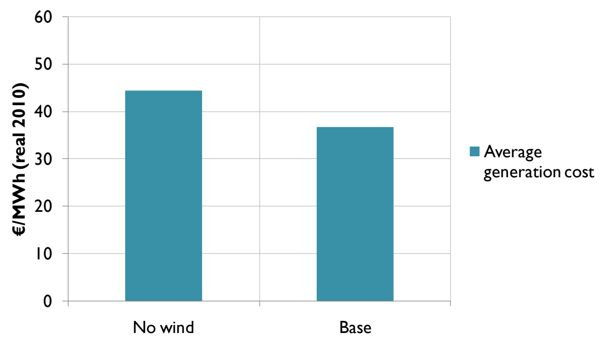

***Carbon emissions***

- By removing wind from the system, gas and coal generation increase and consequently $CO_2$ emissions rise by 19% from 13.9 Mt to 16.6 Mt.



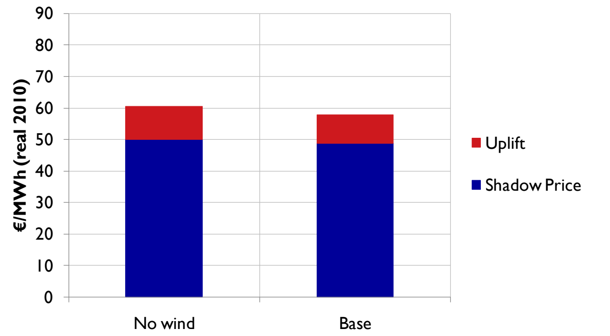

***Average generation cost***

- Removing wind from the system increases the average generation cost compared to the *Base* scenario by 21% (from 36.5 €/MWh to 44.3 €/MWh).
- The total cost of the incremental gas and coal burnt in power generation in the *No wind* scenario is €213 m.



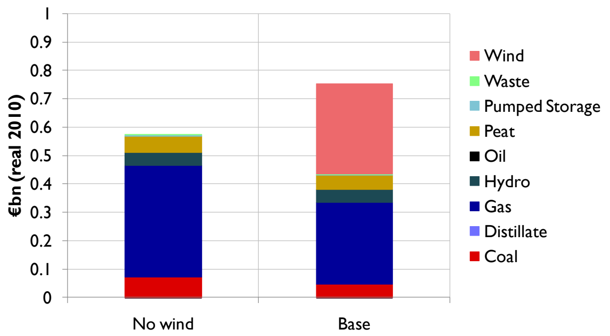
***Time-weighted average SMP***

- The 2011 SMP increases 4% from the *Base* scenario to the *No wind* scenario (57.8 €/MWh to 60.3 €/MWh)[9].



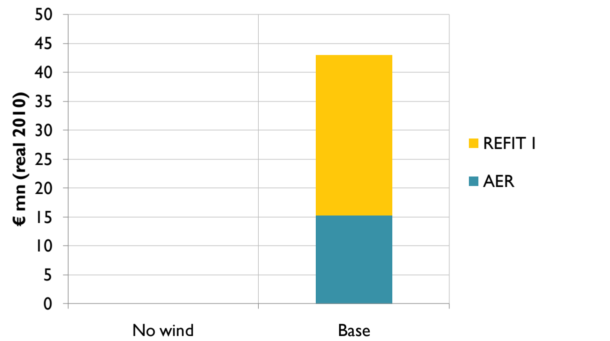

***Infra-marginal rent***

- The significant increase in the average generation cost of the system, coupled with the modest increase in SMP leads to significant reductions in infra-marginal rent for the system with a fall of 24% (€750 m in the *Base* scenario to €570 m in the *No wind* scenario).




***RoI wind support costs***

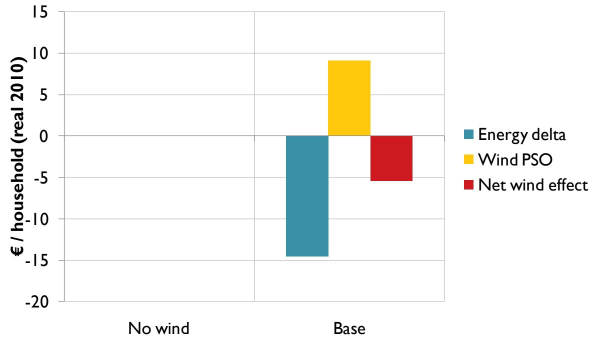
- The costs of supporting wind through the PSO are estimated at €43.0 m and in 2011 are split between AERs and REFIT 1. This compares to the total cost to consumers of wholesale electricity of €1.74 b.




[9] A sensitivity was also modelled where the maintenance schedule was optimised in the No wind scenario rather than being fixed to be the same as that in the Base scenario. In this instance, SMP was 59.51 €/MWh.

***Impact on RoI consumers***

- The average domestic consumer benefits by €5.40 in 2011 as a result of wind generation. This is the delta between the costs of support to wind through AERs and REFITs, and the lower wholesale electricity prices in the SEM (on a load weighted basis) as a result of wind generation.
- The total savings to all types of RoI consumer from addition of wind to the system is €36.6 m.



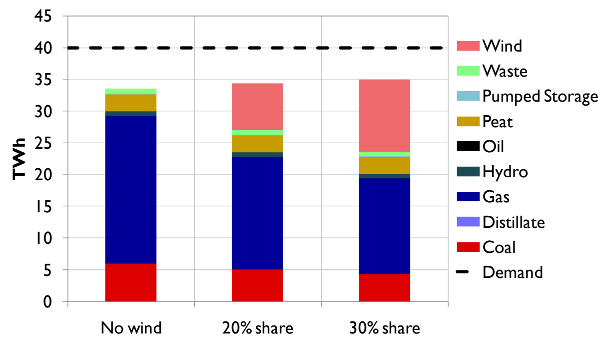

# 3.3 2015

For 2015, we have modelled three scenarios: *30% wind market share* (4 GW), *20% wind market share* (2.6 GW) and *No wind*. By 2015, the East-West interconnector has been commissioned, together with approximately 500 MW of thermal capacity. Conversely 1 GW of (mostly oil-fired) plant has retired. Gas prices have remained flat from 2011 whereas the other commodity prices have risen slightly.

## 3.3.1 Summary results

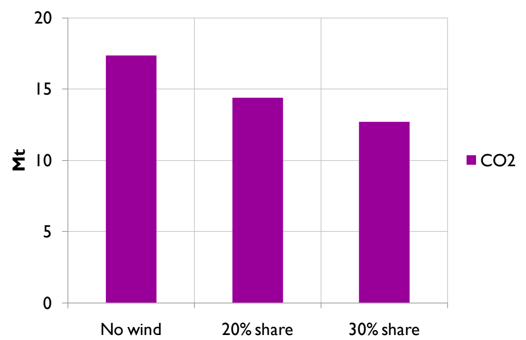
***Generation***

- Gas continues to dominate the generation mix with a market share of 64% in the *No wind* scenario, falling in the *30% wind market share* scenario to 44%.
- Total generation in SEM increases by 4 TWh between the *No wind* and *30% wind market share* scenario, reflecting higher exports to GB.



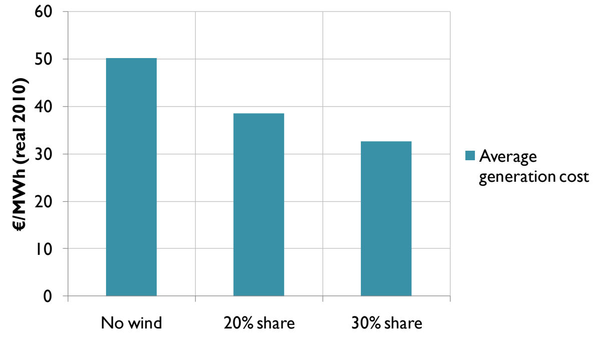

***Carbon emissions***

- Total system $CO_2$ emissions are 4.6 Mt lower in the *30% wind market share* scenario compared to *No wind*.
- At the projected 2015 EUA price this is a reduction in generation costs of €86 m.



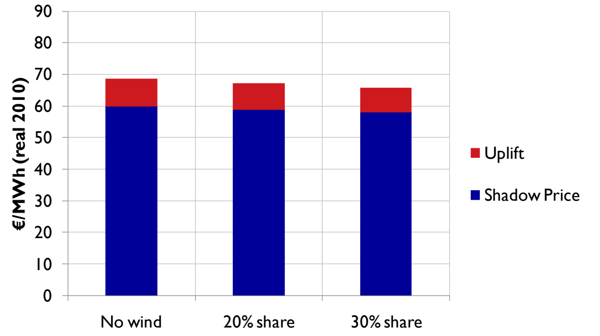
### ***Average generation cost***

- Removing wind from the system increases the average generation cost by 53% compared to the *30% wind* scenario (from 32.7 €/MWh to 50.3 €/MWh). The difference in 2015 is much greater than in 2011 due to the much higher market share of wind.
- The total cost of the incremental gas and coal burnt in power generation in the *No wind* scenario versus the *30% wind market share* scenario is €453 m.



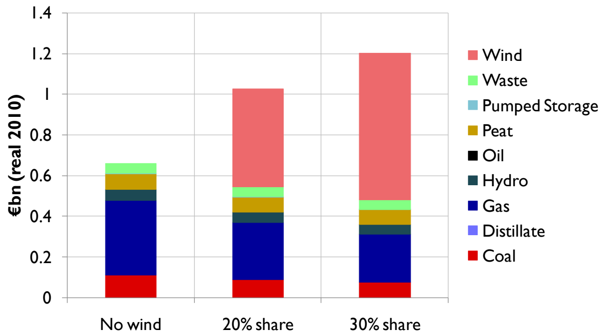

### ***Time-weighted average SMP***

- The difference in annual average SMP between the 2015 scenarios is similar to 2011, with a 4% change between *No wind* (68.4 €/MWh) and the *30% wind* scenario (65.7 €/MWh).
- This illustrates that despite the different generation mix across the three scenarios, the marginal technology remains gas. In particular it is the fleet of approximately 4 GW of relatively new CCGT plant, all with similar cost structures, that are setting prices for the majority of the periods.



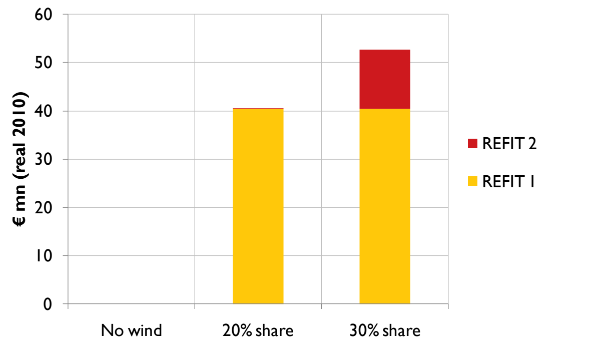

### ***Infra-marginal rent***

- Given the relatively small change in SMP between scenarios in 2011 and 2015, but the large delta in average generation costs changes, the difference in infra-marginal rent in the system in 2015 is greater than in 2011.
- Total infra-marginal rent in the *30% wind* scenario (€1.2 b) is almost double that in *No wind* scenario (€660 m).



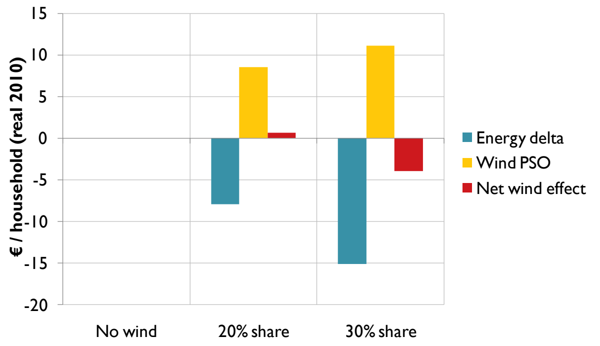

### ***RoI wind support costs***

- The costs of supporting wind through the PSO in RoI are estimated at €40 m in the *20% wind market share* scenario and €53 m in the *30% wind market share* scenario.



**_Impact on RoI consumers_**

- In the *20% wind market share* scenario, the cost of supporting wind to domestic consumers is slightly greater than the reduction in load weighted electricity prices relative to the *No wind* scenario.[10].
- Conversely there is a net saving for domestic consumers in the *30% wind* scenario with consumer costs falling by €3.95 /year. Taking all RoI consumers, there is a net saving of €37.7 m from the *No* to the *30% wind* scenario.




# 3.4 2020

For 2020 we have analysed five cases. In addition to the *No wind*, *45% wind market share* (6.6 GW) and *25% share* (3.6 GW) scenarios, we have analysed two extreme sensitivities:

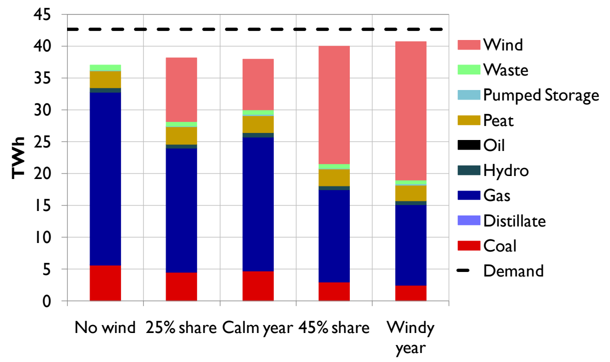
- *Windy year* in which the average load factor of wind is increased by 20%. This is modelled with the installed wind capacity of the *45% wind share* scenario
- *Calm year* in which the average load factor of wind is decreased by 20%. This is modelled with the installed wind capacity of the *25% wind share* scenario

By 2020 an additional 1.1 GW of existing thermal capacity has been decommissioned, which has been replaced with an additional 900 MW of new CCGT and OCGT. Hence, the overall system efficiency has improved from 2015.

## 3.4.1 Summary results

**_Generation_**

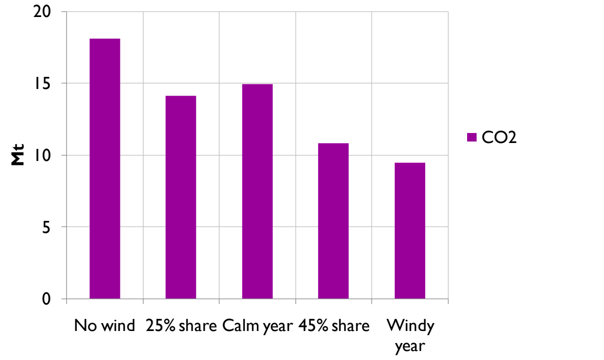
- The trend seen in 2015 is also reflected in 2020; gas market share falls as wind output increases. In the *Windy year sensitivity* the market share of gas falls to 31% with wind dominating the market with 53% market share.




[10] Considering all types of consumer there is an annual saving of €6.9 m. The allocation of the PSO levy between domestic, small and medium, and large profile users is based on their respective share of total aggregated maximum demand. Given domestic demand is more peaky than commercial or industrial demand, the domestic allocation of the PSO levy is higher than its share of total annual consumption. Therefore domestic consumers receive proportionally less of the net savings from wind power than commercial and industrial users.

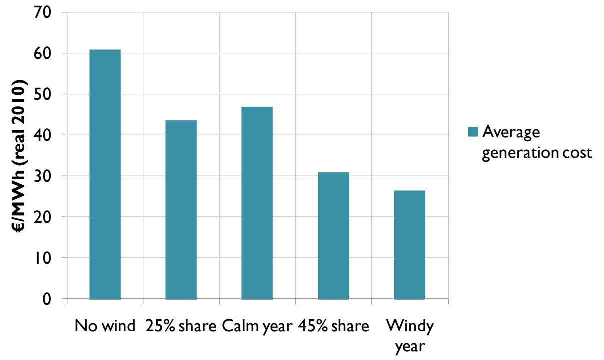
### *Carbon emissions*

- The total system $CO_2$ emissions reflect the generation output. In the *Windy year* (9.5 Mt), emissions are approximately half that of the emissions in *No wind* scenario.
- The impact of the *Windy year* is to decrease emissions by 1.3 Mt per year, and conversely emissions increase by 0.8 Mt per year in the *Calm year*.



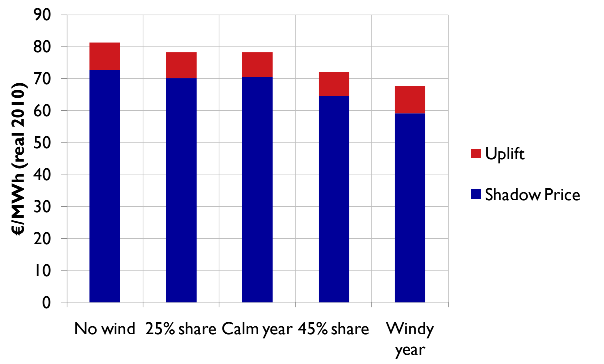

### *Average generation cost*

- The large difference in the generation mix between the scenarios results in an even greater reduction in the average generation cost in the system than in 2015. The spread between the *Calm year* and the *Windy year* is an average of 20.4 €/MWh.
- The total cost of gas and coal is €1.7 b in the *No wind* scenario, reducing to €0.9 b in the *45% wind* scenario and €0.8 b in *Windy year*.



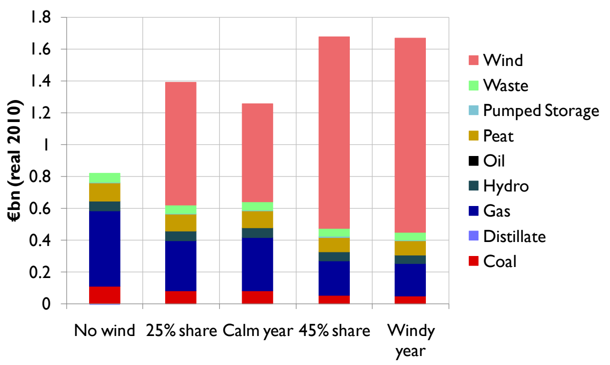

### *Time-weighted average SMP*

- The delta in SMP between the *No wind* (81.3 €/MWh) and *45% wind* (72.1 €/MWh) scenarios is 9.2 €/MWh which is larger than the equivalent delta in 2015. In *Windy year* the delta would increase to 13.6 €/MWh.
- The reduction in SMP as a result of wind on the system increases with higher levels of wind output. The relationship between the reduction in SMP and wind output is non-linear, with greater reductions per MWh of wind output with higher absolute wind output levels.



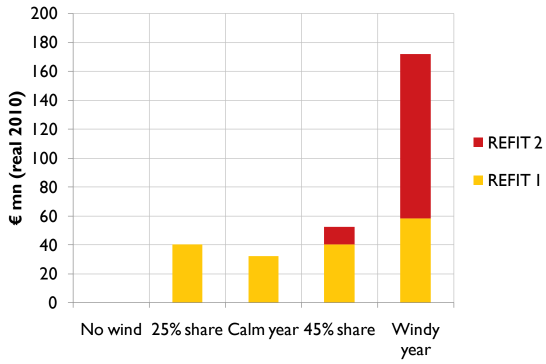

### *Infra-marginal rent*

- The message in terms of the impact on infra-marginal rent in 2020 is similar to 2015.



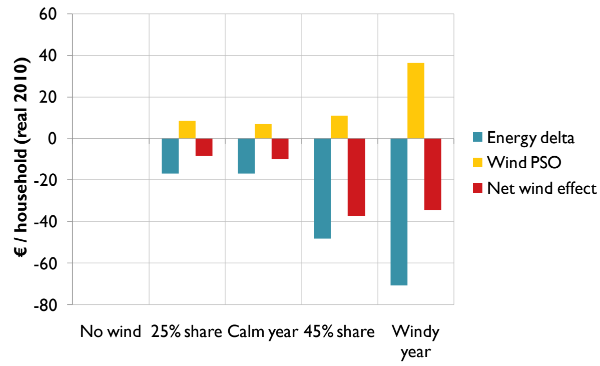
***RoI wind support costs***

- In the *25% wind market share* scenario and *Calm year* sensitivity, power prices are sufficiently high that no payouts are made under the REFIT 2 scheme.
- In the *45% wind* scenario, lower power prices trigger payouts under REFIT 2 of €12 m, increasing to €114 m in the *Windy year* sensitivity.
- The consistent level of REFIT 1 costs seen across the scenarios is due to the balancing component, which is not linked to power market prices under this scheme. By contrast, under REFIT 2, the balancing payment is also market linked, leading to a greater step change in payouts when the floor price is triggered.
- In the *45% wind* scenario the wind capacity supported under REFIT 2 is more than double that under REFIT 1. Support costs per unit of capacity are lower under REFIT 2 because even when balancing payments are made (as in *Windy year*), they are not CPI indexed.




***Impact on RoI consumers***

- In all of the 2020 scenarios there is a net reduction in the load weighted wholesale costs of power to the domestic consumer as a result of wind on the system. The delta is more material than in 2015 with domestic consumers paying up to €37.90 /year less in the *45% wind* scenario compared to the *No wind* scenario.
- The results show that if the large scale deployment of wind power continues, the increase in support due under the REFIT scheme is more than offset by the reduction in prices wind causes. The total savings across all types of RoI consumer versus the *No wind* scenario is €256 m in the *45% wind* scenario. This increases to €281 m in the *Windy year* sensitivity.



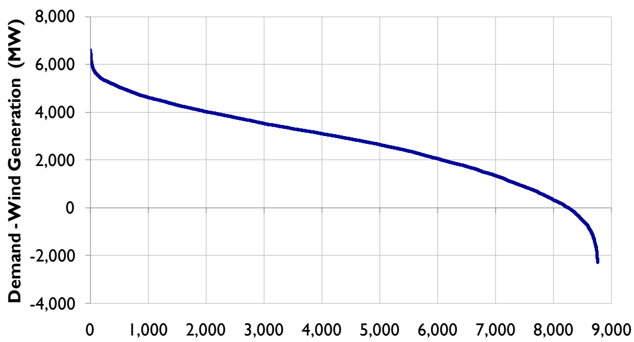

### 3.4.2 Market operation, 2020

The previous sections in this report have presented results averaged across the year in question. In this section we focus on specific hours of the year when we observe extremes in wind generation, in both the *45% wind market share* and *25% wind market share* scenarios. We first chart the net demand: this is the system demand less wind generation, or demand that must be met by non-wind plant. In periods when net demand is below zero, demand in the SEM is being met fully from wind plant.  Below the net demand duration curves we show the annual Price Duration Curves (PDCs): the SMP for each period of the year stacked from highest to lowest. This shows the extremes of high and low prices through the year. We then examine the merit order and system operation at the times of lowest and highest net demand.

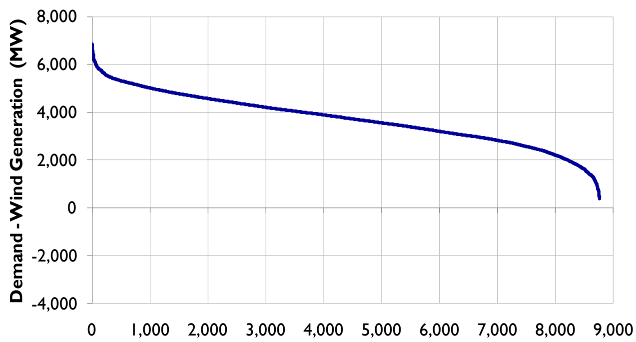
***Annual Net demand and price duration curves***

- The charts show PDCs for 2020 for the *45% wind market share* and *25% wind market share* scenarios.
- In the *45% wind* scenario there are approximately 500 hours of the year in which demand is being met by zero marginal cost plant. In the most extreme sensitivity, generation from wind plant exceeds total system demand by over 2 GW. This results in outturn SMP being zero for over 300 hours of the year. The periods in which the net demand is below zero, but prices are positive reflect exports to GB.
- By contrast in the *25% wind market share* scenario, there are no periods in which demand is fully met from wind plant and hence prices remain above zero for the whole year. Wind output would have to increase, or demand fall, by approximately 150 MW in the period of lowest net demand, for wind to be the sole generator.
- The presence of these zero SMP periods in the *45% wind* scenario contributes to the significant reduction in average SMP compared to *No wind* for this scenario (9.3 €/MWh). In the *25% wind market share* scenario, where no such periods occur, the reduction in SMP versus *No wind* is substantially less (3.0 €/MWh).

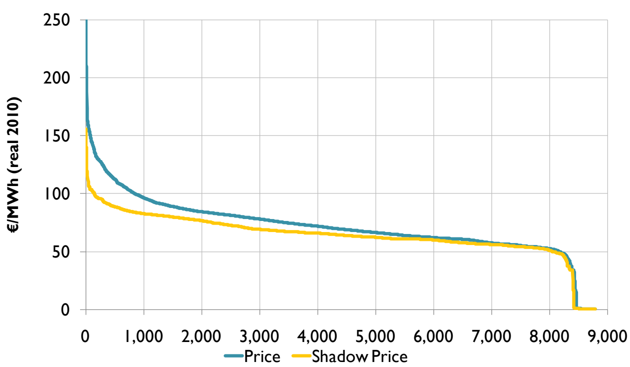
***45% wind scenario (net demand)***



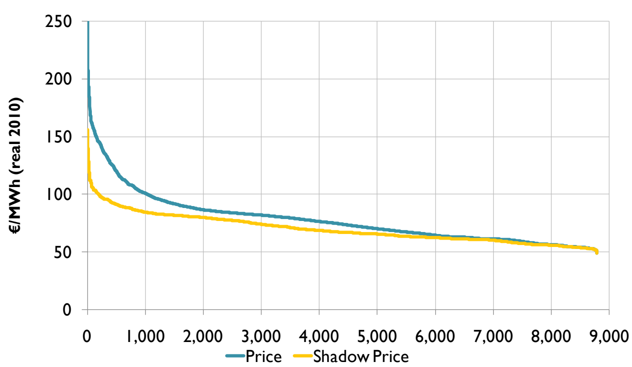

***25% wind scenario (net demand)***



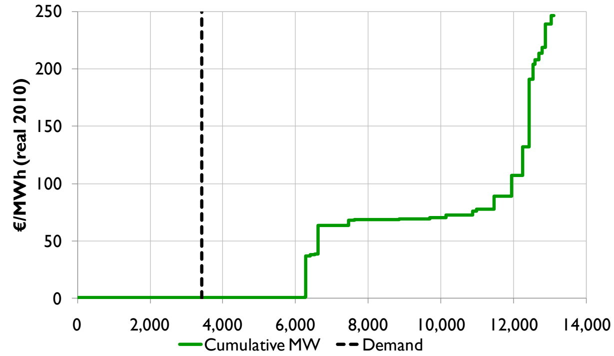
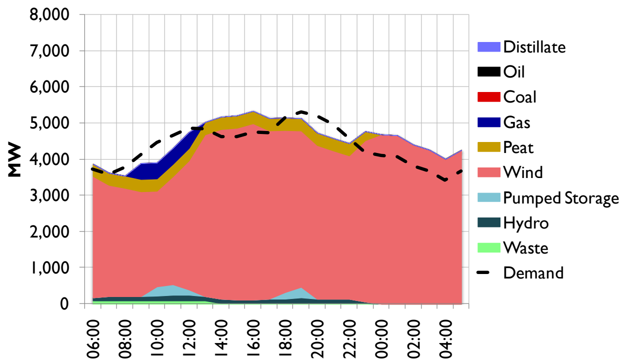
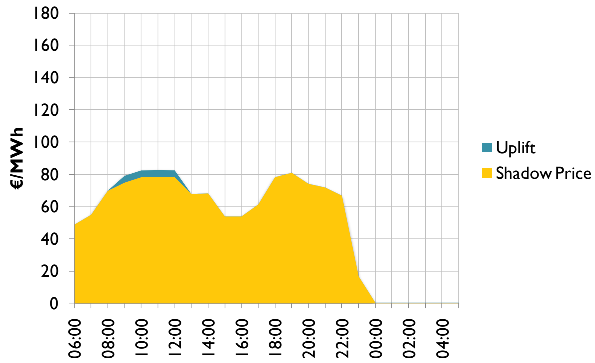

***45% wind scenario (PDC)***




***25% wind scenario (PDC)***




The following graphs focus on the specific day and hour when net demand is lowest. This occurs at 4.00 am on an Autumn morning, when demand is naturally low, on a day characterised by high wind.

| | |
|---|---|
| ***Merit order*** <br>• The merit order shows the available plant and the system demand (approx 3.4 GW) for the 4.00 am hour. Total available low cost generation is over 6 GW in this period. |  |
| ***Generation mix*** <br>• The chart plots the Market Schedule generation mix[11] across the day, with the hour of lowest demand on the right hand side of the graph. The whole day is dominated by wind generation, which accounts for 89% of total output for the day. There is very little output from gas, peat and hydro plant. <br>• The delta between generation output and the demand (shown as the dotted line) reflects net imports. <br>• At 4.00 am, wind generation exceeds demand plus available export capacity, and therefore wind output is curtailed. |  |
| ***Hourly SMP*** <br>• The chart shows the variation of SMP (and its constituent components) across the day. <br>• Despite wind dominating the market, prices are set by thermal plant from 6.00 am through to midnight. However, prices collapse to zero when the net demand is negative, and this introduces significant volatility into the market. |  |







[11] As noted in Chapter 2, for this study we have modelled the Market Schedule used to set SEM wholesale prices. The outturn generation mix, including the contribution from wind, may differ from the Market Schedule due to transmission constraints and system balancing requirements.

## 3.5 Sensitivities for 2020

### 3.5.1 Higher commodity prices

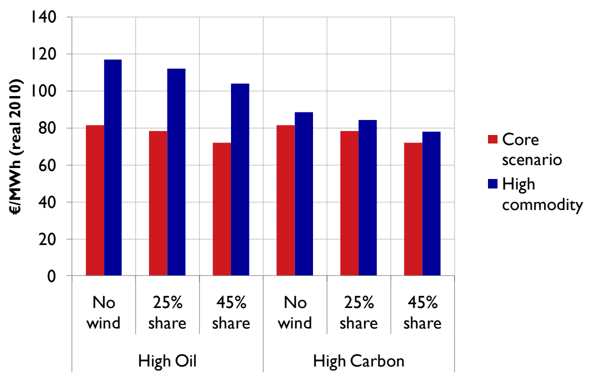
We ran several sensitivities for 2020 in which coal and then carbon prices were higher than in the core scenarios. The two sensitivities were:

- Higher carbon prices (45 €/t compared to 31 €/t in the core scenario)
- Higher oil prices (150 $/bbl versus 99 $/bbl in the core scenario)

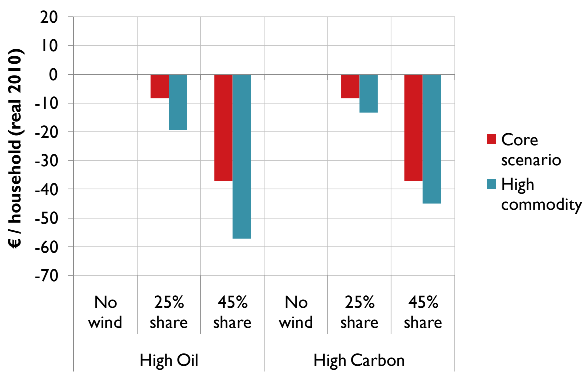
In both cases the relative value of wind on the system increased relative to the core scenarios as the higher commodity prices increased the cost of generation for fossil fired generators.

**Figure 6 High commodity price results**

**Time weighted average SMP**




**Impact on RoI consumers**

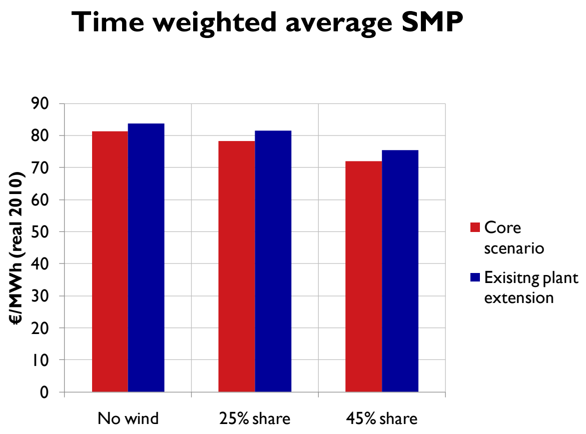


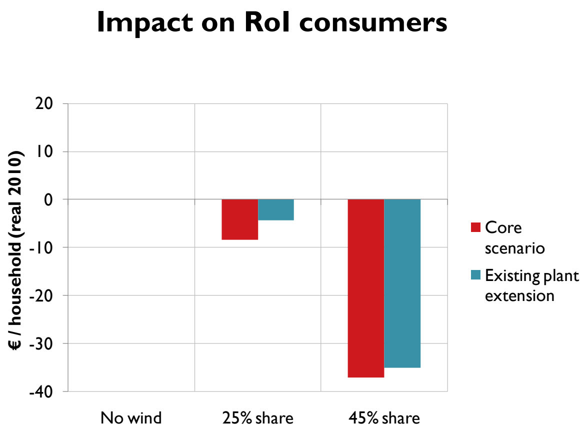

Against the *No wind* scenario, the *45% wind market share* scenario produces a reduction of 12.96 €/MWh in SMP in the *High oil* sensitivity and 10.58 €/MWh in the *High carbon* sensitivity, versus 9.27 €/MWh in the core scenario. The corresponding figures in respect of domestic energy bills are €57.24 /year, €45.11 /year and €37.09 /year. This analysis demonstrates the relatively higher savings to the consumer in cases where commodity prices are high. This highlights why wind generation is often referred to as a 'hedge' against high commodity prices. The full results are presented in Appendix B.

### 3.5.2 Extended lifetimes for existing plant

Finally, we examined a sensitivity in which there was no new entry of plant post 2015; the core scenarios assume 800 MW of CCGT and 100 MW of OCGT by 2020, and these plants would be very dependent on the Capacity Payments in order to be viable investments. In this sensitivity we assume the new entry does not manifest but existing plant remain open to retain approximately the same overall capacity on the system. Full results are presented in Appendix B.

**Figure 7 Capacity mix sensitivity**




The pattern of results does not vary significantly from the core scenario. SMPs in this sensitivity are around 3% to 5% higher than in the core scenarios due to the less efficient plant mix. The *45% wind share* scenario produces a reduction in SMP of 10% versus the *No wind* scenario, slightly less than the equivalent 11.4% reduction in the core scenario.

# Appendix A: Assumptions data

**Table 5 Demand assumptions**

| | 2011 | 2015 | 2020 |
|---|---|---|---|
| Peak (MW) | 6,510 | 6,994 | 7,247 |
| Energy (GWh) | 36,798 | 39,942 | 42,626 |

**Table 6 Commodity price assumptions**

| (real 2010) | 2011 | 2015 | 2020 |
|---|---|---|---|
| Base oil ($/bbl) | 86.06 | 82.69 | 99.32 |
| High oil ($/bbl) | 86.06 | 105.21 | 150.00 |
| Gas (p/th) | 47.78 | 56.48 | 66.27 |
| Coal ($/t) | 103.83 | 107.92 | 110.20 |
| Base carbon (€/t) | 15.11 | 18.78 | 30.86 |
| High carbon (€/t) | 15.11 | 25.07 | 45.00 |

**Table 7 Foreign exchange assumptions**

| | 2011 | 2015 | 2020 |
|---|---|---|---|
| $/€ | 1.37 | 1.37 | 1.37 |
| €/£ | 1.17 | 1.17 | 1.17 |

**Table 8 Thermal plant retirements**

| Plant | MW | Retirement |
|---|---|---|
| Poolbeg | 229 | Pre 2015 |
| Great Island | 212 | Pre 2015 |
| Tarbert | 588 | Pre 2015 |
| Ballylumford 4, 5 & 6 | 510 | Post 2015 |
| Aghada AD1 | 258 | Post 2015 |
| Marina CC | 85 | Post 2015 |
| Northwall CC, ST & CT | 267 | Post 2015 |

**Table 9 Thermal plant commissioning**

| Plant | MW | Commissioning |
|---|---|---|
| Aghada CCGT | 432 | Pre 2015 |
| Whitegate | 445 | Pre 2015 |
| Edenderry OCGT | 111 | Pre 2015 |
| Meath waste-to-energy | 17 | Pre 2015 |
| Dublin waste-to-energy | 72 | Pre 2015 |
| Cuilleen OCGT | 98 | Pre 2015 |
| Nore Power OCGT | 98 | Pre 2015 |
| Suir OCGT | 98 | Pre 2015 |
| New CCGT 1 | 400 | Post 2015 |
| New CCGT 2 | 400 | Post 2015 |
| New OCGT 1 | 100 | Post 2015 |

**Figure 8 Wind regions**

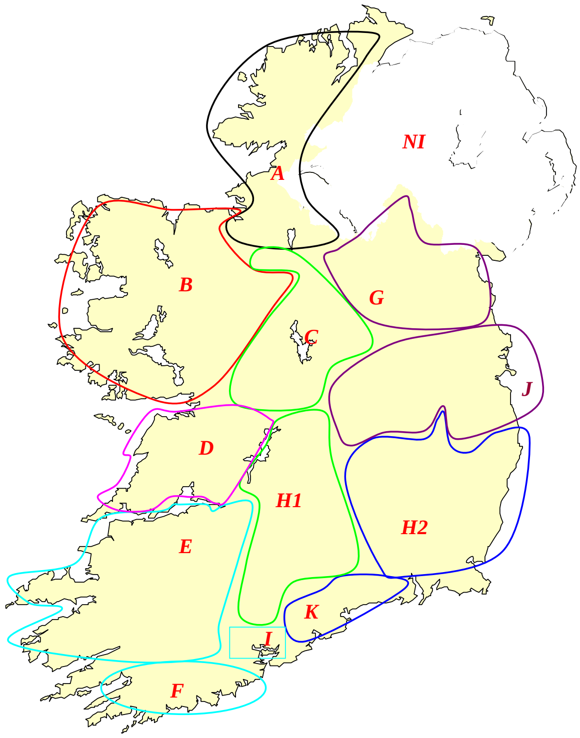



**Table 10 Wind region characteristics**

| Plant | Capacity Factor | Share of Capacity |
|---|---|---|
| Wind NI | 33% | 18% |
| Wind Region A | 33% | 22% |
| Wind Region B | 30% | 6% |
| Wind Region C | 28% | 1% |
| Wind Region D | 28% | 6% |
| Wind Region E | 33% | 26% |
| Wind Region F | 33% | 3% |
| Wind Region G | 31% | 6% |
| Wind Region H1 | 28% | 4% |
| Wind Region H2 | 31% | 8% |

**Table 11 Supported wind capacity**

| Wind capacity (MW) | | AER 6 | | REFIT 1 | | REFIT 2 | |
|---|---|---|---|---|---|---|---|
| | | Large | Small | Large | Small | Large | Small |
| 2011 | No wind | 0 | 0 | 0 | 0 | 0 | 0 |
| | Base | 116 | 166 | 821 | 34 | 0 | 0 |
| 2015 | No wind | 0 | 0 | 0 | 0 | 0 | 0 |
| | 20% share | 0 | 0 | 1,402 | 48 | 43 | 2 |
| | 30% share | 0 | 0 | 1,402 | 48 | 1,159 | 51 |
| 2020 | No wind | 0 | 0 | 0 | 0 | 0 | 0 |
| | 25% share | 0 | 0 | 1,402 | 48 | 788 | 35 |
| | 45% share | 0 | 0 | 1,402 | 48 | 3,172 | 139 |

**Table 12 PSO domestic assumptions**

| Assumption | Value | Source |
|---|---|---|
| Average Irish household annual consumption | 5,067 kWh | SEAI 2010 Energy in Ireland |
| Domestic allocation | 43% | CER |

# Appendix B: Results data

**Table 13 Core scenarios SMP results**

| | Scenario | SMP (€/MWh) |
|---|---|---|
| **2011** | No wind | 60.33 |
| | Base | 57.79 |
| **2015** | No wind | 68.43 |
| | 20% wind share | 67.09 |
| | 30% wind share | 65.74 |
| **2020** | No wind | 81.32 |
| | 25% wind share | 78.28 |
| | Calm wind | 78.19 |
| | 45% wind share | 72.05 |
| | Windy year | 67.66 |

**Table 14 2020 sensitivity SMP results**

| | Scenario | SMP (€/MWh) |
|---|---|---|
| **High oil** | No wind | 117.06 |
| | 25% wind share | 112.06 |
| | 45% wind share | 106.79 |
| **High carbon** | No wind | 88.51 |
| | 25% wind share | 84.35 |
| | 45% wind share | 77.94 |
| **Existing capacity extension** | No wind | 83.85 |
| | 25% wind share | 81.49 |
| | 45% wind share | 75.49 |

**Table 15 Core scenarios average cost of generation results**

| | Scenario | Average cost of generation (€/MWh) |
|---|---|---|
| **2011** | No wind | 44.31 |
| | Base | 36.53 |
| **2015** | No wind | 50.25 |
| | 20% wind share | 38.63 |
| | 30% wind share | 32.72 |
| **2020** | No wind | 60.78 |
| | 25% wind share | 43.41 |
| | Calm wind | 46.77 |
| | 45% wind share | 30.67 |
| | Windy year | 26.36 |

**Table 16 2020 sensitivities average cost of generation results**

| | Scenario | Average cost of generation (€/MWh) |
|---|---|---|
| **High oil** | No wind | 89.27 |
| | 25% wind share | 62.73 |
| | 45% wind share | 30.67 |
| **High carbon** | No wind | 66.14 |
| | 25% wind share | 47.02 |
| | 45% wind share | 32.99 |
| **Existing capacity extension** | No wind | 61.33 |
| | 25% wind share | 43.55 |
| | 45% wind share | 30.53 |

**Table 17 Core scenarios $CO_2$ emissions results**

| | Scenario | $CO_2$ emissions (Mt) |
|---|---|---|
| **2011** | No wind | 16,576,830 |
| | Base | 13,886,063 |
| **2015** | No wind | 17,333,486 |
| | 20% wind share | 14,372,572 |
| | 30% wind share | 12,715,845 |
| **2020** | No wind | 18,099,903 |
| | 25% wind share | 14,140,030 |
| | Calm wind | 14,944,323 |
| | 45% wind share | 10,820,021 |
| | Windy year | 9,475,744 |

**Table 18 2020 sensitivities $CO_2$ emissions results**

| | Scenario | $CO_2$ emissions (Mt) |
|---|---|---|
| **High oil** | No wind | 17,211,981 |
| | 25% wind share | 13,013,951 |
| | 45% wind share | 10,820,021 |
| **High carbon** | No wind | 16,179,910 |
| | 25% wind share | 11,854,460 |
| | 45% wind share | 9,059,570 |
| **Existing capacity extension** | No wind | 18,511,603 |
| | 25% wind share | 14,533,768 |
| | 45% wind share | 11,135,146 |

**Table 19 Core scenarios PSO cost results**

| (€ m) | Scenario | AER | REFIT 1 | REFIT 2 |
|---|---|---|---|---|
| 2011 | No wind | | | |
| | Base | 15.24 | 27.78 | |
| 2015 | No wind | | | |
| | 20% wind share | | 40.43 | 0.11 |
| | 30% wind share | | 40.43 | 12.32 |
| 2020 | No wind | | | |
| | 25% wind share | | 40.43 | |
| | Calm wind | | 32.35 | |
| | 45% wind share | | 40.43 | 11.99 |
| | Windy year | | 58.33 | 113.66 |

**Table 20 2020 sensitivities PSO cost results**

| (€ m) | Scenario | REFIT 1 | REFIT 2 |
|---|---|---|---|
| High oil | No wind | | |
| | 25% wind share | 40.43 | |
| | 45% wind share | 40.43 | |
| High carbon | No wind | | |
| | 25% wind share | 40.43 | |
| | 45% wind share | 40.43 | |
| Existing capacity extension | No wind | | |
| | 25% wind share | 40.43 | |
| | 45% wind share | 40.43 | 0.53 |