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Wind for a Euro

Cost-benefit analysis of wind energy in Ireland 2000-2020

January 2019

Version History

Version	Date	Description	Prepared by	Approved by
V4_0	24/01/2019	Final version	Monne Depraetere Mark Turner	Oliver Rix

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Contents

Executive summary

From a starting point of near zero in 2000, wind farm capacity in the Republic of Ireland (ROI) has grown to reach over 3.4 GW in 2018. It is expected to exceed 4.1 GW by 2020. To put this into context, the total installed generation capacity in ROI today is around 11 GW. Wind will contribute 11 TWh of electricity generation each year by 2020 – this is equivalent to around 35% of total electricity consumption. Initial figures indicate that in 2018 wind power surpassed 30% of Ireland's electricity supply for the first time.

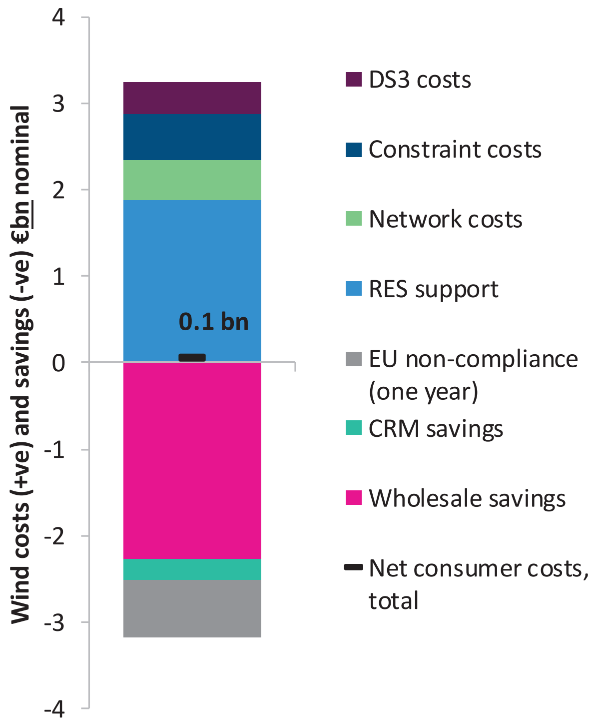
In this study, Baringa Partners LLP ("Baringa") has analysed the financial impact for end consumers of the deployment of wind generation in Ireland over the period 2000-2020. We have used our advanced in-house models of the Irish electricity market to calculate how the costs and benefits for end consumers would have differed if no wind farms had been built. We have also calculated the impact of wind farms on carbon emissions and fossil fuel consumption. The analysis is based on historical data for the years 2000-2017, while the years 2018, 2019 and 2020 are based on a projection, as the study was carried out during 2018.

Figure 1 presents a summary of our analysis of the total costs and benefits for end consumers of wind development in Ireland over the period 2000-2020. While wind farms have increased end consumer costs in some areas, they have also resulted in significant benefits and savings in others.

Our analysis indicates that the deployment of 4.1 GW of wind generation capacity in Ireland between 2000 and 2020 will result in a total net cost to consumers, over 20 years, of €0.1bn (€63 million to be exact), which equates to a cost of less than €1 per person per year[1].

[1] The total cumulative cost over 20 years of €63 million was divided by 20 and then divided by the population of Ireland in 2017 (4,792,500), which was obtained from the Central Statistics Office.

Figure 1 **Cumulative costs and benefits of wind farms for Irish consumers 2000-2020 (€bn)**



This total net cost is significantly lower than the gross cost of €3.3bn. This is due to wind-driven reductions in wholesale power prices, savings on capacity payments, and avoidance of EU non-compliance costs. These savings amount to a total of €3.2bn, which almost entirely offsets the additional cost of wind.

Aside from the financial costs and benefits, we calculate that the deployment of wind generation in Ireland avoids:

- 33 million tonnes of power sector CO_2 emissions. The total carbon emissions from electricity generation in 2017 was 11.7 Mt, so a saving of 33 Mt is equivalent to almost 3 years of total carbon emissions in the electricity sector today[2].
- 137 TWh of fossil fuel consumption at a saving of €2.7bn. In comparison, Ireland consumed 44 TWh (3814 ktoe) of fossil fuels for electricity generation in 2017[2], so a saving of 137 TWh is equivalent to 3 years of current fossil fuel consumption for electricity generation.

It is important to note that our analysis does not take account of the broader socio-economic benefits of wind. For example, we have not included the benefits of job creation, cleaner air, or the full societal benefit of lower carbon emissions as a result of using domestic wind energy instead of imported fossil fuels.

[2] https://www.seai.ie/resources/publications/Energy-in-Ireland-2018.pdf

The remainder of this report is structured as follows:

- **Section 1** lists and explains the costs and benefits of wind considered in this study
- **Section 2** discusses the key results of the cost-benefit analysis
- **Section 3** outlines other wind benefits: lower fuel costs and emissions savings
- **Section 4** presents our detailed methodology

All monetary values in this report are presented in nominal money, unless otherwise stated.

1 Overview of wind costs and benefits

1.1 Wind in Ireland

Over 20 years, Irish wind generation has grown from very low levels to become a major energy source. From a starting point of near zero in 2000, installed wind farm capacity in the Republic of Ireland (ROI) has grown to over 3.4 GW in 2018, and is expected to exceed 4.1 GW by 2020. To put this into context, the total installed generation capacity in ROI is around 11 GW today. Wind will contribute around 11 TWh of annual electricity generation by 2020 – this is equivalent to around 35% of total electricity consumption. This has transformed the Irish energy system, and has resulted in both additional costs and benefits to the Irish consumer, which this study seeks to quantify.

Figure 2 Irish wind installed capacity 2000-2020

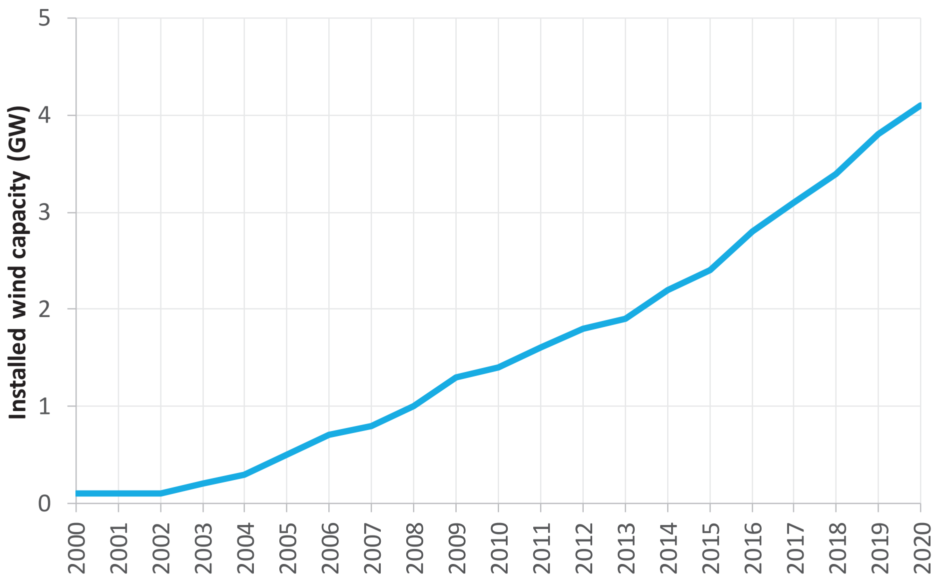
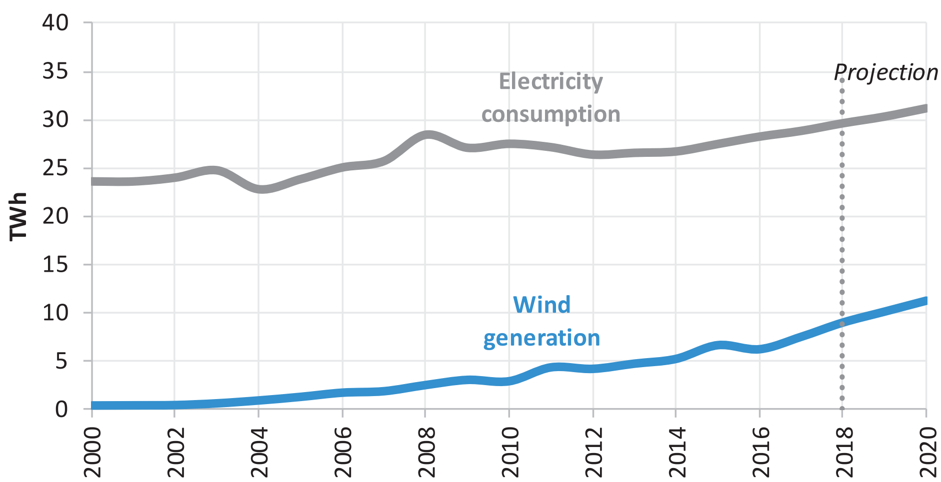


Figure 3 Irish electricity demand and wind generation, 2000-2020



Note: This section introduces the wind benefits and costs we considered in this study. For a detailed calculation methodology of these costs and benefits, please see Section 4.

1.2 Wind benefits

This section lists the key financial benefits of wind for end consumers considered in this study. These benefits are quantified in Section 2.

- **Wholesale energy cost savings:** Wind farms require no fuel to run and therefore, once built, generate electricity at very low cost. As a result, wind generation displaces more expensive electricity sources such as gas or coal-fired power stations or electricity imports, reducing power prices on the wholesale market.[3] Fuel costs are an important component of electricity bills, driving direct savings for consumers through lower electricity tariffs.[4]
- **Capacity payment savings**: All electricity generators, as well as being paid for the energy they produce, have historically also received a capacity payment for being available to produce electricity. This strengthens Ireland's security of supply. Irish wind contributes to security of supply without receiving net compensation for this under the Capacity Remuneration Mechanism (CRM)[5]. This means that wind generators do not benefit from capacity payments, but the amount of wind capacity available is used to calculate the payments that are made to fossil fuel generators. In essence, the greater Ireland's wind generation capacity, the smaller the capacity payments made to conventional generators. Therefore, the growth of wind generation in Ireland has resulted in a net capacity payment saving for Irish consumers.
- **Avoided non-compliance costs:** The EU has committed to achieving 16% of final energy consumption from renewable sources by 2020[6]. Ireland's contribution to meeting this target is set out in the Irish National Renewable Energy Action Plan (NREAP), which is legally binding. Ireland's expected failure to reach a 16% renewable energy consumption share will result in a progressive fine for each percentage point missed on the target. Given that wind generation helps to reach the target and avoid fines, this represents a saving to Irish taxpayers and consumers. We have conservatively included only one year of non-compliance costs in our analysis. However, if wind power had not previously been

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[3] In the wholesale electricity market, generators compete in daily auctions to deliver electricity. The bids made by generators reflect to a large extent their short-run marginal cost of electricity generation, which consists largely of fuel, carbon and variable operating costs. In these auctions, generators with lower marginal costs will clear first, and the power price is set by the *marginal generator*, which is the generator with the highest marginal costs that is still needed to meet electricity demand. Wind generation has a marginal cost of close to zero and virtually always clears the auction, reducing the remaining volumes for fossil fuel generators, which results in the most expensive fossil plants not clearing the auction. As a result, less expensive plants are required to clear the market, leading to lower power prices.

[4] Based on CRU's 2017 Electricity and Gas Retail Markets Annual Report, in 2017, fuel costs represented 43% of the total electricity bill for small commercial customers. (CRU does not publish the equivalent figure for retail customers).

[5] Historically under the Single Electricity Market (SEM), wind farms have received capacity payments – however, this capacity revenue has been netted off in the calculation of PSO support payments under REFIT, resulting in zero additional cost to consumers.

[6] Renewable Energy Directive 2009/28/EC

developed in Ireland, it would likely take much longer than a single year to make up the shortfall and therefore the fines could occur over multiple years.

1.3 Wind costs

This section lists the key costs of wind for end consumers considered in this study. These costs are quantified in Section 2.

- **Renewable support costs**: There have been two main support schemes for Irish wind generators since 2020 – the Alternative Energy Requirement (AER) and the Renewable Energy Feed-in Tariff (REFIT). Over the course of the AER and REFIT support schemes, Irish wind generators have typically received support payments for their output that reflect a premium above the prevailing price of wholesale electricity. This premium is paid by the Government and is recovered from end consumers through the Public Service Obligation (PSO) levy on energy bills and therefore represents a cost to end consumers.
- **Constraint costs**: For stability reasons, the All-Island power system has to operate within certain operating limits or 'constraints'. For example, one constraint sets a limit on the level of generation from wind, solar, or imports across interconnectors at any one time. These generation sources are 'non-synchronous' and this is known as the System Non-Synchronous Penetration (SNSP) limit. Other constraints set a minimum safe level of generation for specific groups of power plants. If these constraints are at risk of being violated, the system operator needs to intervene to turn up or turn down power plants, which comes at a cost. The growth of wind generation has driven an increased need for these redispatch interventions, adding to costs.
- **DS3 costs:** Another set of tools that the system operator uses to manage the power system is called 'ancillary services'. The current ancillary services scheme in the All-Island market is known as 'DS3'. Under DS3, electricity generators are paid to provide ancillary services[7] . The growth of wind generation is driving an increased need for DS3 services, the costs of which are recovered from end consumers.
- **Network costs**: Wind farms require access to the electricity grid to export their power. Given that wind farms are often built in regions that have limited grid capacity, and given the fluctuating nature of wind in-feed, wind generation has resulted in a need to upgrade the electricity grid, resulting in additional costs.

[7] One of the uses of DS3 services is to help manage some of the constraints on the power system, such as the SNSP limit. In that sense, DS3 services contribute to reducing constraint costs.

2 Results and discussion

2.1 Overview

Our analysis indicates that the deployment of 4.1 GW of wind generation in Ireland between 2000 and 2020 will result in a total net cost to consumers of €0.1bn (€63 million to be exact). This cost is paid by all electricity consumers across the residential, commercial, agricultural and industrial consumers. To put this cost in context, it equates to less than €1 per person per year[8].

This total net cost breaks down as follows:

- €2.3bn wholesale energy cost **savings**
- €0.2bn CRM **savings**
- €0.7bn avoided EU non-compliance with 2020 target **savings**
- €1.9bn renewable support **costs**
- €0.4bn DS3 **costs**
- €0.5bn network upgrade **costs**
- €0.5bn constraint **costs**

Figure 4 Yearly costs and benefits of wind in SEM 2000-2020 (€m, nominal)

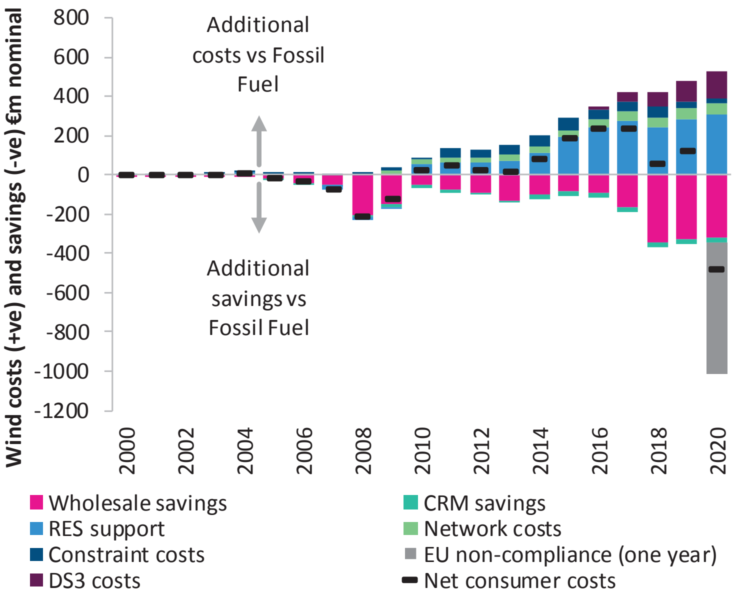
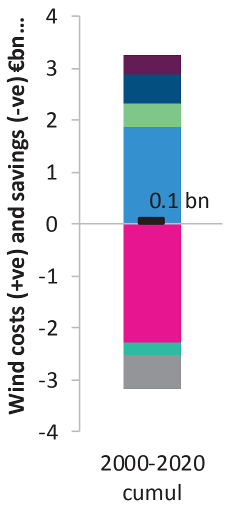


Figure 5 Cumulative, 2000-20 (€bn, nominal)



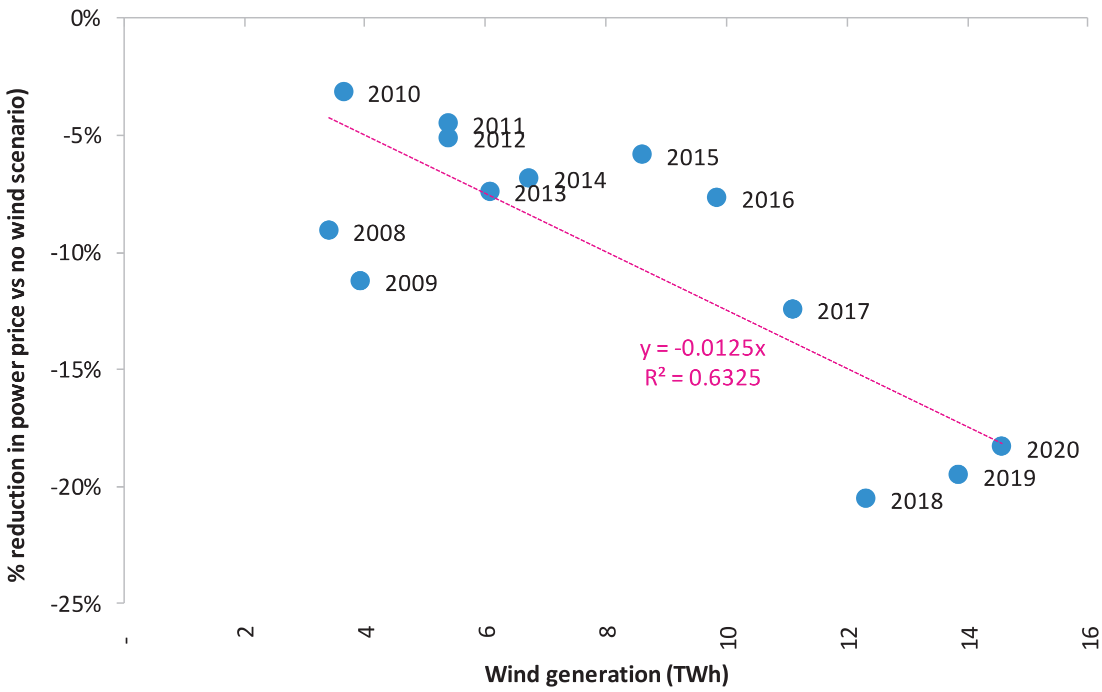
The net cost of wind has evolved over time (see Figure 4). The key trends and drivers over time are as follows:

[8] The total cumulative cost over 20 years of €63 million was divided by 20 and then divided by the population of Ireland in 2017 (4,792,500), which was obtained from the Central Statistics Office.

- 2000-07: Low levels of wind generation result in limited costs and benefits. Overall, wholesale savings drive a small net benefit of €0.1bn.
- 2008-13: Power prices increase to an average 61 €/MWh, up from around 40 €/MWh in the previous years. This is driven by higher commodity prices and, up to 2010, strong electricity demand. Higher prices narrow the premium paid to wind farms under the REFIT and AER schemes, resulting in low wind support costs. In addition, amid high fuel and carbon prices, zero-marginal cost wind generation provide a downward force on power prices, significantly reducing wholesale costs. Including CRM savings and network and constraint costs, we calculate a total net wind benefit of €0.2bn.
- 2014 to 2017: Lower commodity prices drive down the power price to an average of 49 €/MWh. This has the effect of increasing the subsidy payments under the REFIT scheme and reducing the wholesale cost savings potential of wind generation. Increasing levels of wind generation also drive up constraint costs. Overall, the total net cost of wind during this period is €0.7bn.
- From 2018 to 2020: Amid strong power prices, wind support payments fall and wholesale savings from wind increase, reducing the net cost of wind. However, this is offset by increasing DS3 costs as higher penetrations of wind energy need to be accommodated on the power system. It is important to note that 2018-2020 is a projection as this study was carried out in 2018. If the analysis only included historical data, 2000-2017, then the net cost to the consumer would be even less than the final result as shown. There is some uncertainty within the results for the period 2018-2020 – like any projection, the exact degree of alignment with actual outturn is unknown.

Figure 6 shows the simulated impact of wind generation on the wholesale power price: actual power prices are significantly lower than power prices simulated under a ‘no wind’ scenario, The effect increases as wind generation grows – for example, we estimate that in 2018, wind helped to reduce power prices by over 20%.

Figure 6 Wind generation and wholesale price reduction vs 'no wind' scenario



3 Other wind benefits

3.1 Reduced exposure to volatile fuel prices

Wind generation results in less gas-fired generation. Over 2000-2020 we estimate that wind generation displaces a total of 10.3 mTOE (or 120 TWh) of natural gas burn. This is equivalent to about 16% of total estimated gas imports to Ireland over the same period. Wind farms, which produce electricity at a stable cost, reduce Irish customers' exposure to the price of gas, which can fluctuate by more than +/-100% over time[9]. Overall, we estimate that wind generation reduces gas buying costs in Ireland by about €2.5bn from 2000 to 2020.

The impact on coal burn is lower than that on gas, with wind displacing a total of 1.4 mTOE (or 17 TWh) between 2000 and 2020. Because of the lower cost of coal generation compared to gas, coal tends to be displaced by wind only once most gas plants have already stopped generating. We estimate that wind generation reduces combined coal and gas buying costs in Ireland by about €2.7bn from 2000 to 2020 (see Figure 7).

To put these figures in context, Ireland consumed 44 TWh (3814 ktoe) of fossil fuels for electricity generation[10] in 2017, so a total coal and gas energy saving of 137 TWh is equivalent to 3 years of current fossil fuel consumption for electricity generation.

3.2 Avoided carbon emissions

As wind has driven down gas and (to a lesser extent) coal burn, carbon emissions have dropped too. We estimate that between 2000 and 2020, wind generation has reduced CO_2 emissions in Ireland by a cumulative 33 million tonnes (see Figure 8). The total carbon emissions from electricity generation[10] in 2017 were 11.7 mtCO_2, so a saving of 33 mtCO_2 is equivalent to almost 3 years of total carbon emissions in the electricity sector today.

[9] https://www.erce.energy/graph/uk-natural-gas-nbp-spot-price

[10] https://www.seai.ie/resources/publications/Energy-in-Ireland-2018.pdf

Figure 7 **Ireland cumulative fuel cost savings by wind, 2000-20 (m € nominal)**

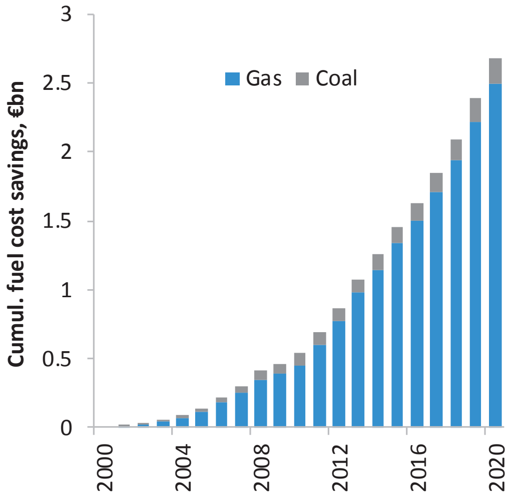
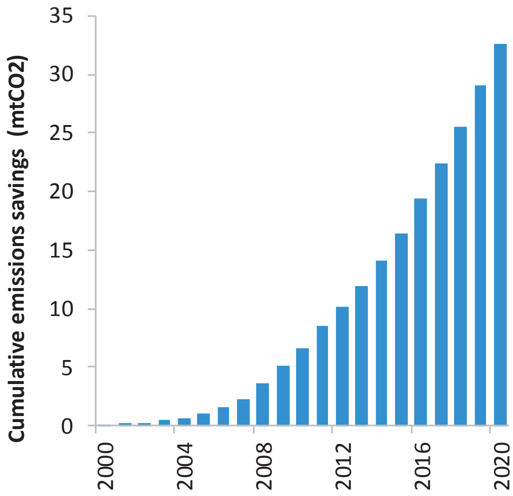


Figure 8 **Ireland cumulative emissions savings by wind, 2000-20 (mtCO2)**



4 Calculating the cost savings and additions due to wind power

This section describes each of the cost savings and additional costs in more detail than the overview provided in the previous section, particularly in relation to the methodology applied to quantify each one.

4.1 Cost savings due to wind power

The cost savings due to additional wind power in Ireland include:

- reduction in wholesale electricity costs
- reduction in capacity market costs due to the capacity contribution of wind, and
- avoided EU compliance costs (e.g. fines).

In this section we explain each of these cost savings, and our methodology for quantifying them.

4.1.1 Reduction in wholesale electricity costs

Wind farms, once constructed, are inexpensive to run as wind generation has a low marginal cost. Wind generation therefore displaces higher cost electricity sources such as gas plants or imports. This dynamic means wind reduces power prices across the entire electricity market, which also lowers end costs for all consumers (a detailed description of this dynamic is in Appendix A).

We have analysed the impact of wind generation on SEM and I-SEM wholesale power prices in detail using our powerful in-house pan-European modelling platform.[11] This incorporates a power plant-level representation of the All-Island market, and simulates their operation in the market at hourly granularity.

As a first step, we set up our model in 'back-cast' mode to simulate and reproduce historical power prices from 2008-2018 YTD. This involves using actual outturn values for key inputs to the model such as gas, coal and carbon prices, power demand, installed capacity and wind generation. Once set up and run in this mode, our model very closely replicates actual historical power prices (see Figure 9).

As a second step, we assume wind generation to be zero and rerun the market model to simulate power prices in a 'no wind' counterfactual (see Figure 10). To maintain the same level of system security, we maintain a similar de-rated capacity margin by substituting wind for open cycle gas turbine (OCGT) plants. Under the I-SEM capacity market rules, wind receives a capacity credit of about 10% and OCGTs a capacity credit of about 92%. This means that 1 GW of wind is replaced by

[11] The SEM operated as an All-Island mandatory pool spot market for Northern Ireland and the Republic of Ireland from 1 November 2007 to 30 September 2018. A new market design, the Integrated Single Electricity Market (I-SEM), went live on Monday 1 October 2018, having been delayed from 23 May 2018. This more closely integrates the Irish electricity spot market with the GB and continental markets, as well as replacing the previous administered mechanism for capacity payments with a new auction-based capacity market.

109 MW (= 1 GW * (10% / 92%) of OCGTs. We calculate the savings as the difference in wholesale price (in €/MWh) between the two runs, multiplied by the overall GWh electricity demand in Ireland.

Figure 9 SEM historical and modelled SMP

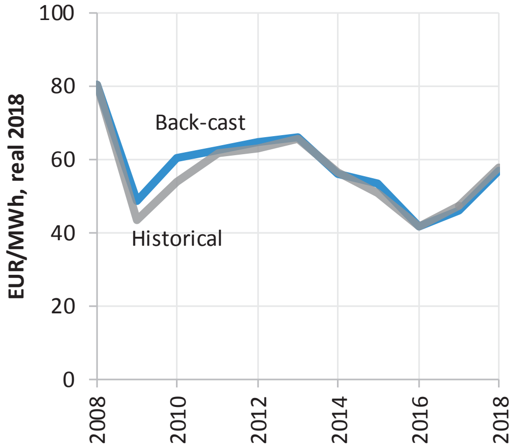
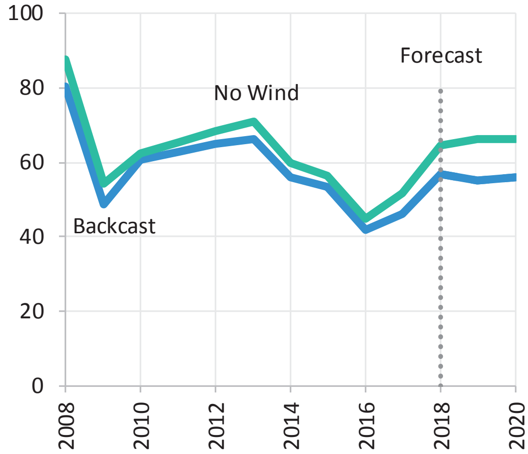


Figure 10 SEM back-cast and 'No Wind' SMP



For 2018 to 2020, we use our Baringa Reference Case assumptions[12] on capacity mix and the evolution of demand. For 2019 and 2020, we assume that commodity and carbon prices equal market forward prices for FY 2018. For the years 2000 to 2007, a lack of data availability prevents us from fundamentally modelling the wholesale price impact of wind. Instead, we have deduced a linear relationship between wind generation and power price impact from the 2008-17 back-cast and have used this to approximate the power price impact and wholesale savings of wind for the earlier period (see Figure 6).

Table 1 presents the installed wind capacity, wind generation and ROI electricity demand assumptions we have used in our modelling.

[12] The Baringa Reference Case represents Baringa's central view on the evolution of the SEM market. Under this scenario, Irish and EU Governments pursue a balanced energy policy, attempting to meet the sometimes competing demands of security of supply, competitive market structure, and environmental sustainability.

Table 1 Ireland wind capacity, generation and total electricity demand, 2000-20

Year	Wind capacity (GW)	Wind generation (TWh)	Electricity demand (TWh)
2000	0.1	0.3	23.5
2001	0.1	0.3	23.5
2002	0.1	0.3	23.9
2003	0.2	0.5	24.7
2004	0.3	0.8	22.7
2005	0.5	1.2	23.8
2006	0.7	1.6	25.0
2007	0.7	1.8	25.6
2008	0.9	2.4	28.4
2009	1.3	3.0	27.0
2010	1.4	2.8	27.4
2011	1.6	4.3	27.1
2012	1.7	4.1	26.3
2013	1.9	4.6	26.5
2014	2.3	5.1	26.6
2015	2.4	6.6	27.4
2016	2.8	6.1	28.2
2017	3.3	7.4	28.8
2018	3.6	8.9	29.6
2019	3.9	10.1	30.3
2020	4.1	11.2	31.2

4.1.2 Reduction in capacity market costs

Under both the historical SEM and current I-SEM electricity market arrangements, generators can receive payments for providing capacity to the system. These payments are in addition to the revenue that generators earn by selling the power they generate. Under both the historical SEM capacity mechanism and the current I-SEM capacity markets, ROI wind farms do not benefit from capacity payments.[13] However, the system operator still takes the capacity contribution of wind farms to meeting peak electricity demand into account while calculating the capacity requirement, which defines how much firm capacity needs to be contracted through the capacity mechanism. This results in a net benefit for customers: if there were no wind generators then the capacity requirement would be higher, resulting in higher capacity payments.

[13] Although wind generators receive capacity payments, these are subsequently netted off in the calculation of the PSO top-up payment under REFIT, meaning that on a net basis, wind receives no capacity payments

The rate at which wind capacity reduces the capacity requirement is defined by the wind capacity credit, which is around 11% of installed wind capacity.[14] To calculate the historical capacity market savings of wind under SEM, we consider the counterfactual without any wind capacity: this increases the Capacity Requirement and as a result the 'Annual Capacity Payment Sum (ACPS). We calculate an average Capacity Requirement cost per MW for each year by dividing the ACPS by the Capacity Requirement and multiply this figure by the total wind capacity credit to calculate the SEM Capacity payment savings from wind. As the Capacity Requirement is set for SEM which covers both ROI and NI, we then reduce the savings proportionally using the relative capacity share of wind in Ireland vs the overall SEM market to calculate the saving for Ireland specifically. Under I-SEM, we assume that without wind, there would be a need for new capacity build, meaning the capacity price for the calendar years 2019-2020 reflects the cost of new entry at 73 €/kW-year.[15]

More details on the modelling for capacity payments is available in Appendix A.

4.1.3 Avoided EU compliance costs

The EU has committed to achieving 20% of final energy consumption from renewable sources by 2020[16]. Ireland's contribution to meeting this target is set out in the Irish National Renewable Energy Action Plan (NREAP), which is legally binding. Ireland's failure to reach a 16% renewable energy consumption share will result in a progressive fine for each percentage point by which the target is missed. The investment in wind farms from 2000-2020 will help Ireland to avoid these non-compliance costs.

In a 2016 report[17], the Sustainable Energy Authority of Ireland (SEAI) estimates these compliance costs to be between €65m and €130m per percentage shortfall on the overall binding target. Based on SEAI analysis, Ireland is projected to reach a renewable energy consumption share of about 13% in 2020 (compared to its 16% target). Without wind generation, we estimate the share would be 6%, i.e. about 7 percentage points lower.[18] Taking a cost per percentage shortfall of €97.5m (the midpoint of SEAI's estimated cost range), this amounts to a total compliance cost of €664m in the 'no-wind' scenario. The exact methodology for calculating the non-compliance costs is still to be finalised. In our calculation, we have conservatively assumed that the compliance costs would be a one-off fine for 2020 only, rather than an annual payment until the target is met.

4.2 Additional costs due to wind power

The additional costs due to wind power in Ireland include:

- Renewable energy support

[14] The wind capacity credit changes slightly year-on-year, and for 2016 it was set at 11% of nominal wind capacity.
[15] See also AIP/SEM/15/059
[16] Renewable Energy Directive 2009/28/EC
[17] Sustainable Energy Authority of Ireland (SEAI), April 2016: 'Ireland's Energy Targets: Progress, Ambition and Impacts'
[18] This assumes total ROI energy consumption in 2020 of 164.5 TWh (based on the Irish National Renewable Energy Action Plan). We project total wind generation in 2020 to be 11TWh, or about 7% of overall energy consumption.

- Power plants accommodating the variability of wind power on the grid (i.e. constraint costs)
- Building additional electric grid (i.e. network costs)
- Adding more flexibility and controls to the grid (i.e. DS3 costs)

In this section we explain each of these costs, and our methodology for quantifying them.

4.2.1 Renewable support costs

We have calculated support costs for wind in Ireland under the AER and REFIT renewables support schemes.

Since AER launched in 1995, six AER competitions were held and currently AER is closed to new entrants. We have calculated the costs for AER support payments for wind based on PSO levy decision paper documents prepared by CRU, which state the estimated AER support cost for a year and an 'R-factor' which correct for over/under estimates of the support cost of past years[19]. The detail in these documents varies by year and for some years, the R factor is not broken down between AER and REFIT. In that case, we use the AER / REFIT wind capacity to define the R-factor split for that year. Prior to 2002 there is no AER cost data available and therefore we estimate costs for those years by assuming that 2000 & 2001 costs per MW of installed wind capacity are the same as in 2002.

We have calculated the cost of REFIT support for wind based on our modelled output. Up to 2016/17 (the last year where full cost data is available) this closely matches the costs as reported in the PSO levy. To calculate the REFIT costs, we first calculate the difference between the REFIT strike price and the generation-weighted average (GWA) price or 'captured price' received by Irish REFIT wind generators and multiply this by overall wind generation to calculate the total wind support payment for that year.

The costs of REFIT also include a 'balancing payment' paid to wind generators. The exact treatment of this balancing payment differs depending on when a wind farm was commissioned, however for simplicity we have assumed a payment level of 9.9 €/MWh for all REFIT wind farms.

The design of REFIT means that as wholesale electricity prices increase, the level of REFIT top-up payments decreases. If REFIT wind farms achieve revenues from the wholesale electricity market that exceed the REFIT floor price, then no top-up payments are made under REFIT. This situation arose for many wind farms over the period 2006-2008 when wholesale electricity prices rose to high levels. In 2008 in particular, the overall REFIT support cost was close to zero.

Table 2 presents the results of our calculations of wind support costs in Ireland over the period 2000-2020.

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[19] In order to calculate the historical AER and REFIT costs for wind, we have consulted the following CER / CRU publications: CER 02152, 03151, 04269, 05125, 06147, 07103, 08129, 09119, 10131, 11130, 12121, 13168, 14361, 15142, 16252, 17241, and CRU 1848.

Table 2 Wind support costs in Ireland 2000-2020 (€m)

Year	REFIT	AER	Total
2000	-	1	1
2001	-	2	2
2002	-	3	3
2003	-	7	7
2004	-	16	16
2005	-	5	5
2006	3	0	3
2007	5	-30	-25
2008	-	-16	-16
2009	55	-58	-4
2010	33	24	58
2011	47	14	60
2012	50	10	61
2013	62	8	71
2014	117	-6	112
2015	186	5	191
2016	236	7	243
2017	268	6	274
2018	232	7	239
2019	284	-	284
2020	306	-	306

4.2.2 Power plants accommodating the variability of wind power on the grid (constraint costs)

The representation of Ireland in our power market model closely replicates the way in which the market operates under the SEM and I-SEM structures. Generators are dispatched based on their short run marginal cost taking account of start fuel costs, ramp rate, availability, minimum up and down time, heat rate variation, output capacity variation and other technical attributes. Two runs take place in the model:

- In the initial unconstrained run, no system constraints are in place and plants are dispatched on a merit-order basis. This model run simulates the wholesale electricity market price, which is set on an unconstrained basis.
- In the constrained run, we simulate the actual physical operation of power plants on the system. We have modelled two main system constraints: a minimum generation constraint in Ireland and Northern Ireland respectively, and a System Non-Synchronous

Penetration (SNSP) constraint across the whole island[20]. The SNSP increases gradually from 50% in 2015 to 65% in 2018 and 75% by 2020.

We estimate the wind constraint costs (i.e. the costs resulting from the fact that the SEM power system is insufficiently flexible to absorb all wind generation) as follows: we run an unconstrained and constrained model for both the backcast and 'no wind' counterfactual scenario. In each case, we calculate the constraint cost by looking at the difference in generation costs between the unconstrained and constrained model runs. We then compare the 'backcast' and the 'no wind' scenarios in order to determine the change in constraint costs that can be attributed to wind. We have allocated the constraint costs between Ireland and Northern Ireland in line with the wind generation split.

4.2.3 Upgrading the electricity grid (network costs)

We have made a high-level estimate of the additional network costs incurred due to the deployment of wind capacity in Ireland since 2000. We studied the network capital expenditure by EirGrid between 2009 and 2018. We then assumed that this cost is entirely attributed to the 3560 MW of renewable capacity added during that period. This is a conservative assumption as, in reality, part of this capital expenditure would not be related to connecting the renewable capacity, such as ongoing upgrades and renewal of the network infrastructure. Using this assumption, we then estimated the network expenditure required per MW of renewable capacity added.

For each year from 2009 to 2020, we calculate the annual wind capacity additions and multiply this by the average network expenditure per MW. This annual grid upgrade cost is then spread across a 40-year period by calculating a 40-year annuity at a discount rate of 4.95% (based on allowed PR4 rate of return set by the Commission for Regulation of Utilities, CRU). This aligns the costs with the benefits, which will still be accrued in the future.

We have assumed that prior to 2009, there were no significant additional network costs as a result of wind capacity.

4.2.4 Adding more flexibility and controls to the grid (DS3 costs)

The DS3 (Delivering a Secure Sustainable Electricity System) programme was established by EirGrid and SONI to 'meet the challenges of operating the electricity system in a safe, secure and efficient manner while facilitating higher levels of renewable energy'. A key aim is to ensure that the SEM system can operate at higher System Non-Synchronous Penetration (SNSP) levels of up to 75%. With wind being the major factor behind an increase in non-synchronous generation, a large portion of the costs of this programme can be attributed to the growth of wind generation (the predominant renewable electricity source in Ireland).

[20] For stability reasons, the All-Island power system has to operate within certain operating limits or 'constraints'. For example, one constraint sets a limit on the level of generation from wind, solar, or imports across interconnectors at any one time. These generation sources are 'non-synchronous' and this is known as the Systen Non-Synchronous Penetration (SNSP) limit. Other constraints set a minimum safe level of generation for specific groups of power plants. If these constraints are at risk of being violated, the system operator needs to intervene to turn up or turn down power plants, which comes at a cost. The growth of wind generation has driven an increased need for these redispatch interventions, adding to costs.

We have used the budget for DS3 services from 2015-2020 as set out by EirGrid and SONI, as shown in Table 3.[21] We have assumed that the budget for 2015 (€54m) reflects the cost of ancillary services excluding wind. This is because 2015 precedes the start of the effort to increase the SNSP level. We then assume that the increase in budget from €54m to €235m in 2020 is driven by the effort to increase the SNSP limit to 75% and therefore by wind. We have allocated the DS3 costs between Ireland and Northern Ireland by using the wind generation split.

Table 3 DS3 budget, 2015-2020

	Units	2015	2016	2017	2018	2019	2020
DS3 budget	€m	54	75	115	155	195	235

[21] EirGrid and SONI, July 2017: 'Consultation on DS3 System Services Enduring Tariffs', DS3 System Services Implementation Project

Appendix A Modelling methodology

Overview

Baringa has developed an in-house a Pan-EU power market model covering Ireland, Great Britain and most countries in Europe for the purpose of power market studies. The model sits within PLEXOS, a third-party commercial software product that is widely used in the power and utilities industry for market price projections, asset dispatch modelling, network analysis and other purposes. PLEXOS is also used by the SEM Regulatory Authorities, including the CRU.

The Baringa Pan-EU model takes key inputs and scenario assumptions such as hourly demand profile, commodity prices, plant build and retirement and hourly wind and solar profiles, and has detailed representations of generator technical parameters and interconnection between countries. The model engine carries out least cost optimisation to produce hourly dispatch for the generators and hourly prices for the markets taking full consideration of the operational constraints (ramp rates, start time, availability etc.).

The representation of Ireland in the model closely replicates the way in which the market operates under the I-SEM structure. Generators are dispatched based on their short run marginal cost, taking start fuel offtake, ramp rate, availability, minimum up and down time, heat rate variation, output capacity variation and other technical attributes into account. Two runs take place in the model. In the unconstrained run, no system constraints are in place and plants are dispatched on a merit-order basis. In the constrained run, two system constraints are modelled: a minimum generation constraint in Ireland and Northern Ireland respectively and a System Non-Synchronous Penetration (SNSP) constraint across the whole island.

PLEXOS

PLEXOS introduction

PLEXOS is a highly advanced market modelling tool, incorporating a number of approaches to the modelling of interconnected markets, and a number of advanced pricing algorithms ranging from marginal cost pricing through to game-theory approaches. It is deployed worldwide by energy companies, investors and system operators. It has been used in the All-Island Modelling Project to support the development of the SEM, and by the Regulatory Authorities to estimate market power and determine the pricing of Directed Contracts[22] which ESB, with the largest generation portfolio, is required to sell.

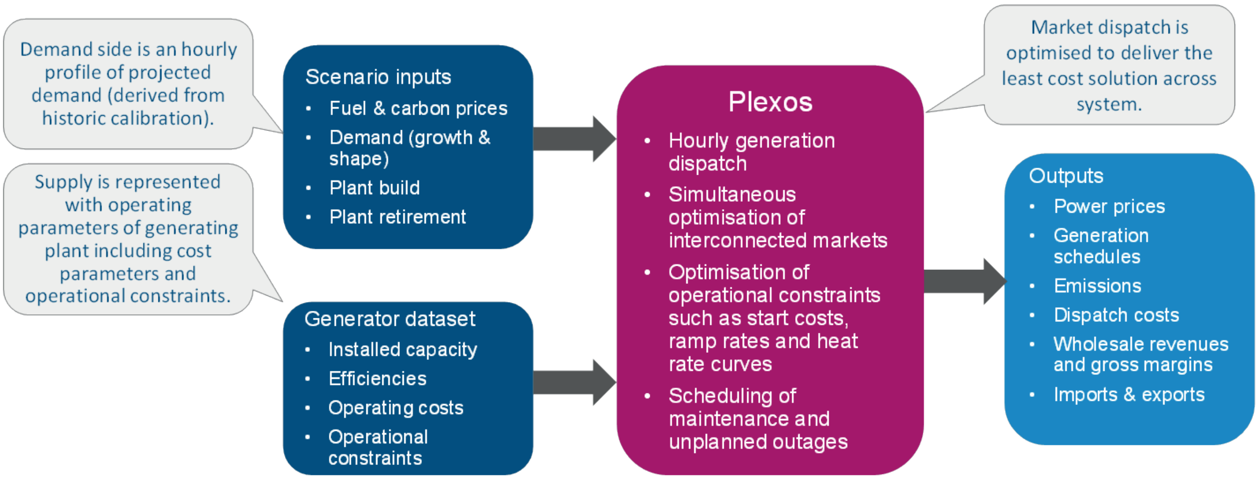
PLEXOS simulations are based on a mathematical programming formulation of power market dynamics. PLEXOS applies linear and mixed integer programming solution techniques to determine the dispatch and pricing outcomes, taking full account of short term dynamic constraints including ramp rates and min on/off times. This approach provides results that fully capture the complexity of power markets and allows the user to analyse fundamental issues such as nodal pricing, hydro

[22] Directed Contracts are financial contracts-for-difference (CfDs) which allow suppliers and generators to hedge against future power prices.

modelling, profit targeting and strategic behaviour. It is also conceptually similar to the way in which the market dispatch software works.

An overview of the model is shown in Figure 11.

Figure 11 PLEXOS Overview



All-Island configuration

Baringa has configured a model of the All-Island market from 2017 through to 2040 based on the RAs' validated dataset[23]. Some of the key modelling features are described below.

Demand

Demand is represented at hourly granularity. Hence, there are 8,760 settlement periods per year, with demand projected from actual historical hourly data to 2040, using both peak and energy demand growth forecasts. Demand is modelled on a station gate (sent out) basis.

Price formation

The model aims to dispatch plant in such a way that generation costs are minimised over each optimisation horizon (24 hours plus a 6 hour look-ahead; identical to SEM market dispatch software). In the Validated Dataset each generator has a multi-part heat rate curve. This is comprised of a no-load cost, and a number of incremental heat rates which apply over different tranches of the generator's capacity. The shadow price is calculated based on short-run marginal costs (SRMCs), and is set by the incremental heat rate of the marginal generator including the full pass through of the prevailing spot fuel and spot EUA (carbon) prices. This is consistent with the approach in the SEM Trading and Settlement Code (T&SC).

The calculation of the outturn prices for SEM includes a calculation of uplift, using an implementation of the algorithm as published in the T&SC. An uplift component is added in each period to ensure

[23] The RAs make available a public version of their SEM PLEXOS forecast model. This is independently updated and validated by independent consultants on a regular basis. The validated model is used by the RAs to fulfil several regulatory requirements, including the calculation of Directed Contract prices.

that each generator recovers its start-up and no-load costs (i.e. is 'made whole') over the period in which it operates. Hence, in each hour the model derives a marginal cost, an uplift payment and system marginal price (SMP).

Modelling of I-SEM

The new Integrated Single Electricity Market (I-SEM) arrangements began on 1 October 2018, and so for the final two years of our analysis, we have changed some aspects of our wholesale electricity market modelling approach in order to reflect the market design.

In accordance with the principle that the market will continue to be based on transparent centralised trading arrangements, least-cost dispatch of total system load and centralised unit commitment, we have assumed that the I-SEM energy market functions as a 'deregulated pool' with firm day-ahead pricing.

Under the simple or block-bidding formats in the I-SEM day-ahead market, generators bid either a simple price-quantity bid or potentially bid for variable levels of output over different periods. These bidding regimes differ from the previous SEM regime in that generators internalise technical uplift (start-up and running costs) in their bids at levels they themselves choose, as opposed to the previous ex-post algorithm calculation.

Recovery of generator start and no-load costs in the SEM was ensured via an uplift mechanism. In the SEM this uplift component often formed a significant portion of the power price, especially in certain hours. In I-SEM, generators have to internalise their start costs into bids into the EUPHEMIA day-ahead market coupling algorithm.

In line with the lack of bidding restrictions in the ex-ante markets under I-SEM, we assume that participant bids and offers in the day-ahead market are no longer restricted by a Bidding Code of Practice. This means that, under I-SEM, generators can bid above the price required to remunerate both their short run marginal cost and technical uplift during periods of system tightness. This additional uplift above generators short run marginal costs and technical uplift we describe as 'scarcity rent'. We have modelled 'scarcity rent' as a function of the capacity margin in each hour.

Plant constraints

All thermal plant on the system are modelled with annual maintenance rates and forced outage rates. The scheduling of maintenance is through a Monte Carlo approach to determine an optimal scheduling, whilst outage patterns are applied randomly. These parameters also feed through to the capacity payment modelling.

Plant dynamic constraints are also fully taken into account in the model. These are parameters that affect the dispatch of the plant and include minimum stable levels, minimum up and minimum down times, and maximum ramp rates.

Peat plant are assumed to be constrained to meet annual minimum fuel burn commitments, equivalent to an 80% load factor, with optimal economic dispatch where appropriate above this level. The wind plant are modelled by allocating installed capacity to one of twelve geographic regions in RoI, and one NI Wind region, each of which are assigned separate load factor profiles derived from historical data. These represent independent but correlated wind patterns at an hourly granularity. The resulting volatility can affect the dispatch of thermal plant.

Hydro modelling

The reservoir hydro units have a limited monthly energy profile, and the model will dispatch this energy according to prices within the month. The profile is kept constant for each river system over the scenario period.

Pumped storage plant will operate based on the day-night price differential and subject to the technical constraints of the plant (pumped load, pumping efficiency and head and tail storage capacity).

Gas capacity charges

Gas-fired generators in the Republic of Ireland have the option of buying annual, monthly, or daily gas capacity. We assign assumptions on this for each gas-fired plant in the market, based on the RAs' validated PLEXOS model, and based on the load factors of plant in our modelling. We assume that plant buying annual gas capacity would reflect this as a fixed cost in formulating their offers to the I-SEM capacity auction for Reliability Options. Plant buying daily gas capacity are assumed to seek to recover their variable gas capacity costs in the energy market.

Interconnection

The SEM PLEXOS model released by the RAs contains a simplified representation of the GB market. We have used this as a starting point for modelling the SEM and then added a full representation of the GB market including fuel prices and assumptions on the evolution of the GB plant mix. The model simultaneously optimises across both markets in a single step. This ensures that the operation of each market is consistent and that the flows through the two interconnectors represent the most economically efficient solution.

Capacity payment modelling

SEM capacity payment mechanism

The SEM design included a separate Capacity Payment Mechanism (CPM). This was a price-based mechanism, designed to incentivise a level of capacity surplus sufficient to meet the security standards in ROI and NI. It provided generators with an additional revenue stream related to their levels of availability. The costs of the capacity mechanism were recovered from end consumers. We have used actual historical data on capacity payment levels to calculate the end consumer costs of the CPM both with and without wind generation.

I-SEM capacity market

Under the new I-SEM, from 1 October 2018, the CPM has been replaced with a new capacity market. This allocates a limited volume of Reliability Option (RO) contracts by competitive auctions. Capacity providers which are successful in the auction are paid the auction clearing price which is an annual €/kW payment for the contracted capacity. The costs of the I-SEM capacity market are recovered from end consumers.

We have modelled the I-SEM capacity market using our in-house capacity auction model, using the following assumptions:

- A de-rated peak capacity margin of 4% is assumed for security of supply.
- All generators in principle can offer capacity into the market:
    - existing generators estimate their earnings from the energy and ancillary services markets and then compute the differential between this and their fixed costs required to remain operational, and
    - new-build generators similarly estimate their earnings from energy and ancillary services and compute the differential between this and the sum of their fixed costs plus their annualised cost of capital.
- The clearing price for each year is set at the level at which the required 4% de-rated peak capacity margin is achieved.
- New-build generators receive the clearing price over a period of 10 years, to ensure stability for those making capital investment decisions.

Appendix B List of Acronyms

SEMO	Single Electricity Market Operator
SEM	Single Electricity Market
OCGT	Open cycle gas turbine
CCGT	Combined Cycle Gas Turbine
CRM	Capacity Remuneration Mechanism
TWh	Terawatt hour
GW,MW	Gigawatt, Megawatt
DS3	Delivering a Secure Sustainable Electricity System
NREAP	National Renewable Energy Action Plan
CER / CRU	Commission for Energy Regulation / Commission for Regulation of Utilities
SRMC	Short-Run Marginal Costs
T&SC	Trading and Settlement Code
SMP	System Marginal Price