Impact of Wind Generation on Wholesale Electricity Costs in 2011

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Sustainable Energy Authority of Ireland

The Sustainable Energy Authority of Ireland was established as Ireland's national energy authority under the Sustainable Energy Act 2002. SEAI's mission is to play a leading role in transforming Ireland into a society based on sustainable energy structures, technologies and practices. To fulfil this mission SEAI aims to provide well-timed and informed advice to Government, and deliver a range of programmes efficiently and effectively, while engaging and motivating a wide range of stakeholders and showing continuing flexibility and innovation in all activities. SEAI's actions will help advance Ireland to the vanguard of the global green technology movement, so that Ireland is recognised as a pioneer in the move to decarbonised energy systems.
SEAI's key strategic objectives are:

- Energy efficiency first – implementing strong energy efficiency actions that radically reduce energy intensity and usage;

- Low carbon energy sources – accelerating the development and adoption of technologies to exploit renewable energy sources;

- Innovation and integration – supporting evidence-based responses that engage all actors, supporting innovation and enterprise for our low-carbon future.

The Sustainable Energy Authority of Ireland is financed by Ireland's EU Structural Funds Programme co-funded by the Irish Government and the European Union.

EirGrid PLC

EirGrid plc is a leading energy company committed to delivering high quality services in Ireland and Northern Ireland. The Group includes the EirGrid Transmission System Operator (TSO) business in Ireland; System Operator Northern Ireland (SONI), the licenced TSO in Northern Ireland; and the Single Electricity Market Operator (SEMO) which operates the Single Electricity Market on the island of Ireland.

1. Overview

SEAI and EirGrid have conducted a joint modelling exercise to investigate the impact of increased wind generation on electricity generation costs in 2011[1] for Ireland (IE). In general, while capital costs of wind energy plants are higher than conventional generation, wind energy can act as a hedge against high fuel costs by depressing the wholesale cost of electricity. This exercise attempts to identify how much the wholesale cost is depressed and compares this to the additional costs faced by consumers, namely the Public Service Obligation (PSO) and the additional constraint costs. A scenario with the expected 2011 installed wind capacity is compared to a scenario that does not have any wind capacity [2]. The Single Electricity Market (SEM) operates on an all-island basis and both Ireland's and Northern Ireland's (NI) electricity systems are modelled.

This modelling exercise specifically quantifies the impact of wind generation on the Single Electricity Market (SEM) wholesale price of electricity. The differing operational constraint costs[3] are included for both scenarios. For the 2011 expected wind capacity scenario the cost of Ireland's PSO for wind generation is added.

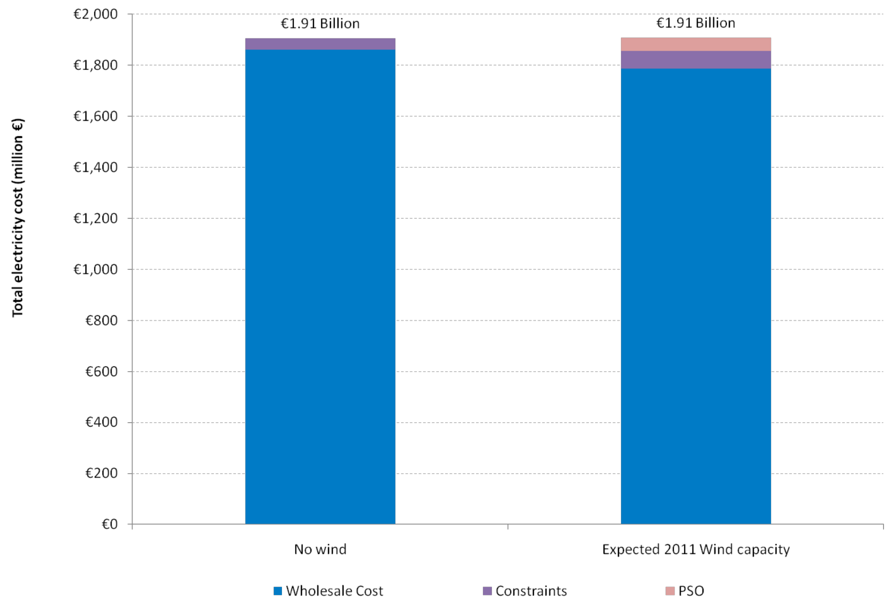
Key Messages

- The wind generation expected in 2011 will reduce Ireland's wholesale market cost of electricity by around €74 million.
- This reduction in the wholesale market cost of electricity is approximately equivalent to the sum of Public Service Obligation (PSO) costs, estimated as €50 million, and the increased constraint costs incurred, due to wind in 2011.
- The total cost of generation is the sum of the wholesale cost of electricity, the PSO cost of wind and the dispatch constraint costs. The total cost does not increase with the inclusion of the 2011 wind capacity.

Figure 1 shows graphically how the various costs compare across both scenarios for Ireland. The wholesale markets costs shown reflect the market payments to generators of electricity. This is the aggregate amount paid by suppliers for the electricity. Constraint costs are additional costs incurred in running a stable electricity system and apply to both the no-wind and the expected 2011 wind capacity scenarios. The PSO amount is the cost of the policy support mechanisms for wind. The sum of the three is the estimated total cost of producing electricity for the 2011 system.

1 The 2011 modelling in both scenarios includes the long term maintenance outage in Turlough Hill pumped storage station. This has the effect of increasing constraints as compared to a typical year in which this station is operational.
2 The non-wind generation capacity is identical in both scenarios. Details of the wind capacity and fuel price assumptions are contained in the appendix
3 Constraint costs as shown here differ from constraint payments as defined in the SEM. They reflect the total expected costs in deviating from the economic running of generation as defined by the market.

Figure 1: Projected Cost of Electricity Generation in 2011



Single Electricity Market (SEM) and the Public Service Obligation (PSO)

The rules of the all-Island Single Electricity Market (SEM) are detailed in the trading and settlement code. Under the code, electricity generators offer electricity into a central pool from where electricity suppliers purchase electricity to cover their consumer's demand for each half hour throughout the day. Price making generators bid into the pool a price for their production that is equal to the short term cost of producing that energy. The SEM pool price is set by the most expensive generator required to meet supplier demand in a half hour trading period. All generators who produce electricity in a trading period receive the SEM pool price for that period, which for most generators is greater than their short term cost of producing electricity. This System Marginal Price (SMP) is the energy component of the total cost of producing electricity. Other market payments are made to generators, to ensure that the system has adequate generation capacity into the future. These payments are called capacity payments. The capacity price and the market SMP price represent the average long term cost of producing electricity in the SEM.

The SEM market software produces a least cost schedule of generation for all the units on the system with the assumption that there is no network or operational constraints. In order to maintain a safe and secure power system, the Transmission System Operator (TSO) may have to deviate from the generation schedule created by the SEM. This creates additional costs to the system, called Dispatch Balancing Costs, commonly known as constraints costs.

Policy supports have been introduced by Government to encourage the development of renewable energy in order to capture some of the wider benefits associated with renewable energy – such as a reduction in the reliance of Ireland on imported fossil fuels. These supports are also required to comply with targets specified in EU legislation. Wind power generation is supported by two policy mechanisms that are paid through the PSO levy on all electricity consumers: the legacy Alternative Energy Requirement (AER) scheme and the current Renewable

Energy Feed in Tariff (REFIT). Under these schemes an electricity supplier buys the output of a wind farm at a fixed rate determined or influenced by the policy mechanism. The supplier then sells the electricity into the SEM pool. If the aggregate revenue a supplier receives from each trading period throughout the year is less than the policy tariff then the difference is paid through the PSO. Under REFIT, suppliers also receive a balancing payment – 15% of the large wind category tariff – to cover the cost of managing the short term variable production of wind energy.

The PSO cost arising from wind is calculated and levied to consumers as follows:

- The Commission for Energy Regulation (CER)[4] establishes the PSO cost a year in advance by estimating, among other things, the system wide annual average time weighted SMP, as well as estimates of the other market payments.
- During that year, the relevant PSO period, consumers are levied for this estimated PSO amount.
- Following this PSO period, when actual market revenues and electricity generation data are available, the CER calculate a correction to the PSO known as the R factor.
- At a high level, the R factor[5] for the REFIT and AER mechanisms are determined by firstly calculating the revenue of these participating suppliers across all trading periods in which they were supplying electricity to the grid. This is done for each generation unit contracted to a supplier by considering, among other things[6], their actual generation and the actual SMP in each trading period, as well as their actual capacity and constraint payments for these periods. Where this support amount for the output of a wind unit contracted to a supplier differs from the original ex-ante PSO estimation, consumers are retrospectively reimbursed or levied for the outstanding amount, through the R-factor.

As wind generators do not consume fuel they have no short term costs and hence can bid a zero price to the SEM. As price takers in the SEM, they receive the SMP set by the most expensive generator for their output in that half hour trading period. By displacing higher cost fossil fuel generation, wind generation tends to reduce the total cost of producing electricity and hence the SMP.

2. Modelling Assumptions and Methodology

The basis for the modelling exercise is the 2011 all-island electricity system. As such the scope of this study does not include an examination of the likely capital investment costs involved in expanding the generation portfolio / transmission network to support a secure future electricity system, or the fixed costs incurred by generators. These factors relate to future wind and no wind scenarios. Nor does it assess the impact that wind generation has on retail prices to customers since these prices are largely set in a competitive open market. The conclusions of this study only report on the impact of wind generation on wholesale market prices and how this compares to PSO costs in 2011. The 2011 PSO costs are calculated on an *ex-post* basis and assumes that the R factor correction has been applied.

4 The Commission for Energy Regulation's (CER) duties as calculator and certifier of the PSO are set out under S.I. No. 217 of 2002 (as amended).

5 For further information in respect of the R-factor calculation see the CER decision paper CER/08/236 Calculation of the R-factor in Determining the PSO levy http://www.cer.ie/en/renewables-decision-documents.aspx?article=39ce537a-1620-486d-b93e-bc70ab5934ca

6 Including interest rates, indexation, and auditing costs

The PSO levy for wind only applies to wind generation in Ireland. As a result, we have excluded the wholesale cost of electricity in Northern Ireland from our studies. Also, while contraint costs have been calculated on the basis of an all-island system, we have split these costs between Ireland and Northern Ireland on a pro-rata basis of demand. Only the constraint costs allocated to Ireland are considered in our calculations.

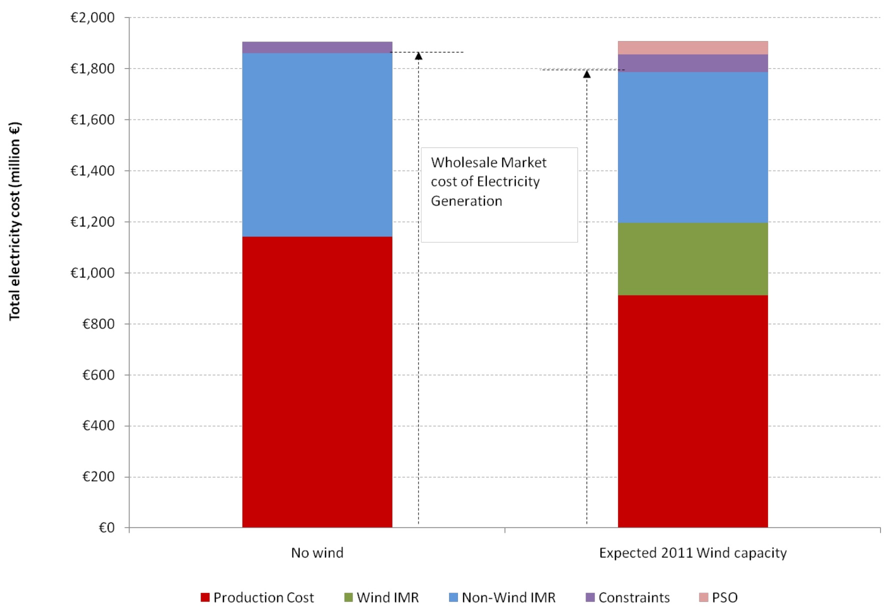
The latest validated model published by CER is used as the basis for modelling the Single Electricity Market (SEM). This model has been updated to take into account the most recent fuel prices from futures markets, and current CO_2 prices. EirGrid's projections of 2011 demand and details of the planned generator maintenance outages were also included in the model. The long term maintenance outage at Turlough Hill pumped storage is also accounted for. Wind profiles from 2008 for the various regions of the country were used as the input for 2011 wind generation[7] . Start-up generator costs are based on EirGrid's projections. The Moyle interconnector flows are assumed to adhere to a historical profile. Some further detail of the modelling input assumptions are shown in the appendix.

3. Results

The results indicate that the impact of wind generation in 2011 is to reduce overall wholesale electricity prices. Comparing this reduction to the wind component of the PSO levy, we can see that this reduction is approximately equivalent to the additional payments incurred by wind generation through the PSO levy and the extra constraint costs incurred by having higher levels of wind generation on the system.

The overall costs of electricity in both scenarios, as shown in figure 2, are composed of the production costs due to the generators, the revenue received by generators in excess of their production costs, the constraint payments from the market to allow for the stable operation of the system and the PSO costs arising from the policy support mechanisms. Capacity payments are not shown in figure 2 as they apply equally across both scenarios. The capacity pool is calculated and published by the Commission for Energy Regulation (CER) and Northern Ireland's regulatory authority as €545 million[8] for 2011.

Figure 2: Cost of Electricity Generation in SEM 2011



7 The capacity factor across all wind regions for 2008 was approximately 30%

8 See decision paper SEM-10-053 at http://www.allislandproject.org/en/project_office_sem_publications.aspx?year=2010&section=2

When wind is added to the system the production costs of electricity in Ireland reduce by €74 million. Wind generation has no short term production costs. In the expected 2011 wind scenario, wind generation replaces fossil fuel generators with short term fuel and operating costs. Hence the wholesale cost of electricity production is reduced.

A section of the bar in figure 2 shows the revenue received by generators in the SEM that is in excess of their production costs. These revenues are termed 'Infra-Marginal rent' and allow generators to recover some of their long term costs. Infra marginal rent reduces for thermal generators in the 2011 wind scenario but increases overall. This is explained by the fact that wind generators can capture more rent than thermal generators as a result of their zero short term operating costs. The policy supports for wind account for the situation where this rent is not adequate to support the long term cost of generating electricity from wind, by paying the difference between the long term cost and market price. Conversely, these policy supports also recognise that if these rents do cover the long term cost of generation, only the balancing payments are made to wind suppliers.

The wind component of the PSO levy is made up of the cost of the REFIT scheme plus costs associated with Alternative Energy Requirement (AER) schemes and are approximately €50 million for 2011.

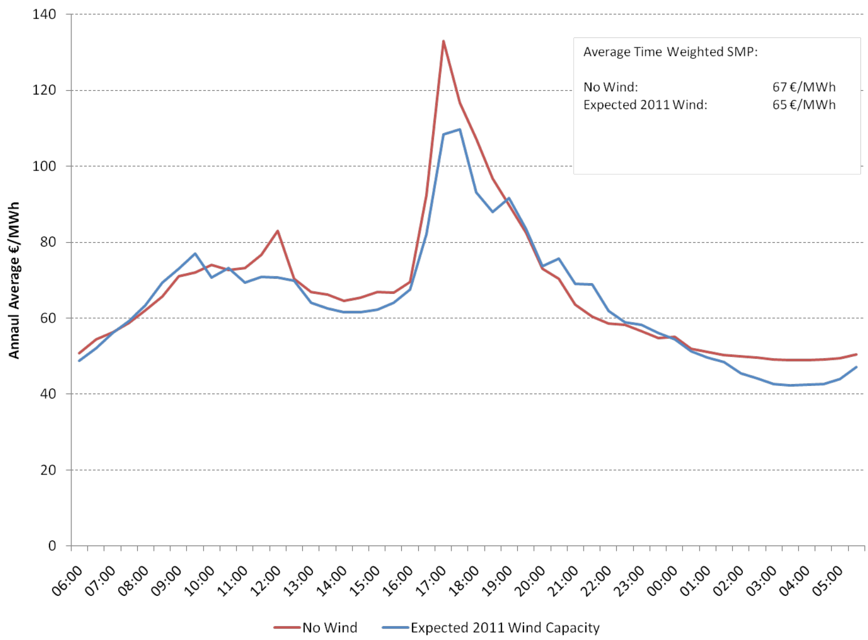
The AER component is based on a series of contracts issued to wind generators giving them a fixed price for each MWh of wind energy generated. The AER contracts act as contracts for difference; they are paid the difference if the SMP is less than the agreed price and they return money to the PSO if the SMP is greater than the agreed price. The AER VI scheme – the last and largest of the AER schemes – front loads the tariff so that the wind generators in this scheme receive 135% of their tariff for the first seven years. They receive 65% of the tariff for the remainder of the AER contract. As this study deals with 2011 and the AER VI schemes are less than seven years in existence, the front loaded tariff applies when calculating the PSO.

The amount of support paid though REFIT to a wind supplier depends on the revenue a supplier receives from the SEM for their output. The total annual supplier revenue for 2011, as calculated using this model, is in excess of the support level for the large wind REFIT category. As such, the balancing payment element of the REFIT accounts for the entire REFIT cost arising from wind in 2011. While this exercise does not attempt to quantify a direct impact on prices to consumers, it is noted that the balancing payment is paid to suppliers competing in a 100% de-regulated market. To the extent the balancing payment is greater than the cost of implementing their REFIT contracts, suppliers can choose to treat this as a reduction in their wholesale cost in determining prices offered to their customers.

The constraint costs in the with-wind scenario are greater than in the no-wind scenario. In order to maintain a safe and secure power system, there are minimum amounts of conventional generators that must be kept running to provide essential system services such as reserve and voltage support. The remaining demand that needs to be met can be quite small, especially during night hours. This means that sometimes a percentage of wind generation, which has a zero production cost, will go unused, and also more expensive conventional generation is required to run. This exercise focuses on the 2011 system and as such accounts for the current long term maintenance outage at Turlough Hill pumped storage station. Excluding this station tends to increase the constraints on the system.

The effect of wind generation on System Marginal Price (SMP) can be seen further in Figure 3. This graph shows the SMP by time of day, averaged over the full year. We can see that wind generation in 2011 causes the SMP to reduce for most of the hours of the day, and the affect is particularly noticeable during hours of peak and trough demand. The results from the model also show that the wind generation in 2011 will cause a small reduction in the variability of the SMP. It should be noted that the all-island wind capacity acts to reduce SMP but only the wind capacity in Ireland's support schemes receive payment from the PSO.

Figure 3: Average Time Weighted SMP 2011



4. Conclusions

The objective of this exercise was to quantify the likely impact of the wind generation that will be on the system in 2011 on the wholesale cost of electricity. The analysis showed that wind generation lowers wholesale prices by €74 million, which almost exactly offsets the costs of the Public Service Obligation (PSO) levy and other costs assosiated with the generation of wind energy. The study clearly demonstrates that wind energy is not contributing to higher wholesale electricty prices on the Irish electricity system.

In light of recent debates on the cost of wind, it is useful to have this information modelled using the best objective assumptions available today and the appropriate assessment tools. Further benefits would arise from performing an expanded exercise to look at the cost impact of wind and other renewable technologies in the 2020 time frame.

Appendix

Fuel Price Assumptions - Note Oil Prices Adjusted for Actual Market Bids

FUEL PRICE	Q1 2011	Q2 2011	Q3 2011	Q4 2011
Gas (£p/therm)	56.75	54.75	51.75	61.75
Coal ($/tonne)	125.25	120.5	120.09	119.69
HFO ($/tonne)	569.18	596.03	612.56	634.98
Gasoil ($/tonne)	790.73	789.10	797.22	810.63

	Q1 - Q2 2011	Q3 - Q4 2011
CO_2 Price (€/tCO_2)	14.35	14.55

Installed Wind Capacity Assumptions For 2011

Wind Region	Expected Total Capacity (MW)
A	417.9
B	125.4
C	16.9
D	114.5
E	524.2
F	71.3
G	105.8
H1	107.2
H2	197.4
I	1.7
J	0.3
K	2.2
NI	478

Support Scheme Detail (REFIT Commenced in 2006 and Replaced AER Support Mechanism. AER Scheme are Closed to New Entrants)

Support Scheme (in order of implementation)	Capacity (MW)
Valoren	6
AER III	18
AER IV	3
AER VI	273
REFIT	1384

Details of Models Employed

The model used for the market modelling part of this study is based on the validated model published by the Commission for Energy Regulation (CER) in April 2010. The CER model is designed to model electricity prices in the Single Electricity Market (SEM) over a horizon of 1-2 years. The model optimises the generator dispatch for each half-hour in the day to produce the least-cost arrangement of plant to meet demand over the year. This optimisation is subject to constraints such as plant availability, system operating rules and wind profiles.

The constraint modelling part of this exercise was conducted using a PLEXOS model developed by EirGrid. This model is constructed so as to characterise the full detail of the entire electricity system and the rules that ensure its secure operation. As such it contains all of the detail of the market model along with a representation of the transmission network and a definition of the operational rules. This model optimises the system costs, taking into account these constraints, for each period of the day across the entire year.

PSO calcualtion

The PSO amount arising out of the wind support mechanisms is:

$$PSO_{Wind} = AER_{Total} + REFIT_{Total}$$

Where for the AER scheme:

$$AER_{Total} = (TARIFF_{AER}\ x\ ANNUAL\ AER\ Gen) - \sum_{t=1}^{17,520} ((SMP_t\ x\ AER\ Gen_t) + Capacity_t + Constraint_t)$$

And for REFIT if the annual revenue for a wind power supplier is less than the revenue implied by the REFIT tariff then:

$$REFIT_{Total} = Tariff_{REFIT}\ x\ Annual\ REFIT\ Gen - \sum_{t=1}^{17,520} [(SMP_t\ x\ REFIT\ Gen_t) + Capacity_t + Costraint_t] + (0.15\ x\ Tariff_{REFIT}\ x\ Annual\ REFIT\ Gen)$$

Otherwise if the annual revenue is equal to or greater than the revenue implied by the REFIT tariff then the support reduces to the balancing payment to suppliers

$$REFIT_{Total} = (0.15\ x\ Tariff_{REFIT}\ x\ Annual\ REFIT\ Gen)$$

Where:

AER_{total}: The total monies paid to/from the PSO arising out of the Alternative Energy Requirement wind support policy mechanism
$REFIT_{total}$: The total monies paid from the PSO arising out of the Renewable Energy Feed in Tariff wind support policy mechanism
Tariff: The price level at which the policy support tariff is set
Annual Gen: The annual output of all the wind generators
SMP_t: The System Marginal Price in the Single Electricity Market in trading period t
GEN_t: The total output from wind generators in trading period t
$Capacity_t$: The capacity payment from the market to wind generators in trading period t
$Constraint_t$: The constraint payments to wind generators in trading period t