Effect of Tie-break Options on DBC and Curtailment

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Contents

Executive Summary

This document has been prepared by EirGrid in fulfilment of a request by the Regulatory Authorities (RAs) to examine the impact of three of the tie-break options on Dispatch Balancing Costs (DBC) and on the curtailment of non-firm wind. The three options examined were Option 1 (Grandfathering), Option 2 (Pro Rata), and Option 4 (Pro Rata with no compensation for curtailment), as outlined in SEM-12-028.

The results show that Option 4 leads to the greatest DBC savings. The savings in Option 1 converge to those for Option 4 as the proportion of non firm wind increases. The savings under Option 2 are less pronounced.

DBC savings vary with the fuel forecast. As fossil fuel prices increase, the cost of compensating wind curtailment also increases, as do savings under each of the tiebreak options.

Taking our 2020 base scenario, savings of €13 million are seen under Option 4. Under Option 1 (Grandfathering), the savings in DBC depend on the proportion of wind that is non-firm. As this proportion increases, the savings converge to the €13 million figure seen under Option 4. Under Option 2 (Pro Rata), lower savings are seen compared to Options 1 & 4, with a maximum of €5 million. The €13 million savings observed in the base scenario are not overly significant in the context of the predicted DBC budget, and are expected to represent less than 10% of total DBC in 2020. DBC savings increase with fuel prices, as does the overall DBC.

Curtailment levels for non-firm wind can be sizeable under the Grandfathering option. In the base scenario, the figure can be up to 24% depending on the proportion of non-firm wind installed. This compares to 4% under the Pro Rata option.

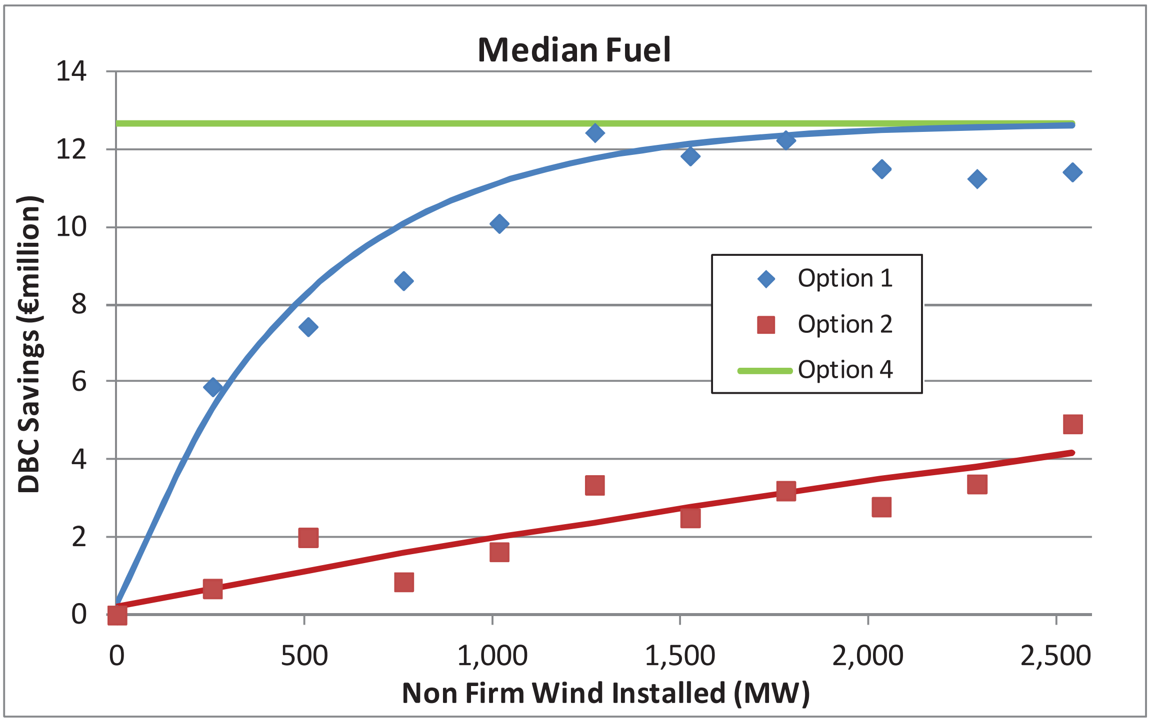
For the 2012/13 tariff year, no real DBC savings are observed by applying the tie-break options. The curtailment level for non-firm wind under the Grandfathering option is sizeable at 10%, compared to 2% under the Pro Rata option.

It should be noted that these studies are carried out to examine constraint costs and wind curtailment under a particular set of scenarios only. Any outturn which is different to the assumptions can, and most likely will, lead to a different set of results.

DBC Costs

EirGrid has carried out studies examining the impact of three of the tie-break options on DBC costs. The studies examine the longer term impacts using 2020 as the study year, and the short term impact by focussing on the next tariff year (2012/2013).

The 2020 study assumes that there is enough renewable generation on the all-island system to meet a 40% RES-E target. A fixed level of installed wind (2943 MW) is assumed to be always firm based on all pre-Gate 3 wind generation in Ireland and a proportional amount in Northern Ireland. For the remaining wind generation (2540 MW), the proportion of this considered non-firm was varied from 0% to 100% in 10% steps.



Savings in DBC achieved in 2020 under each of the tie-break options under the base scenario. Savings are as compared to a reference case where all wind curtailment is compensated. The total installed wind capacity is the same for each data point.

The results indicate that, in our base scenario in 2020, Option 4 saves €13 million when compared to a reference case where all wind curtailment is compensated. The savings in Option 2 depend on the proportion of non-firm wind. Since the total wind capacity is constant on our studies, so is the total amount of curtailment. As the capacity of non-firm wind increases, the volume of non-firm wind curtailment converges towards the total wind curtailment volume, and the DBC savings saturate towards €13 million. The savings due to Option 2 are less pronounced.

Currently, DBC is in the order of €140 million, and it is likely that this figure will increase by 2020. Against this, €13 million would not be considered overly significant.

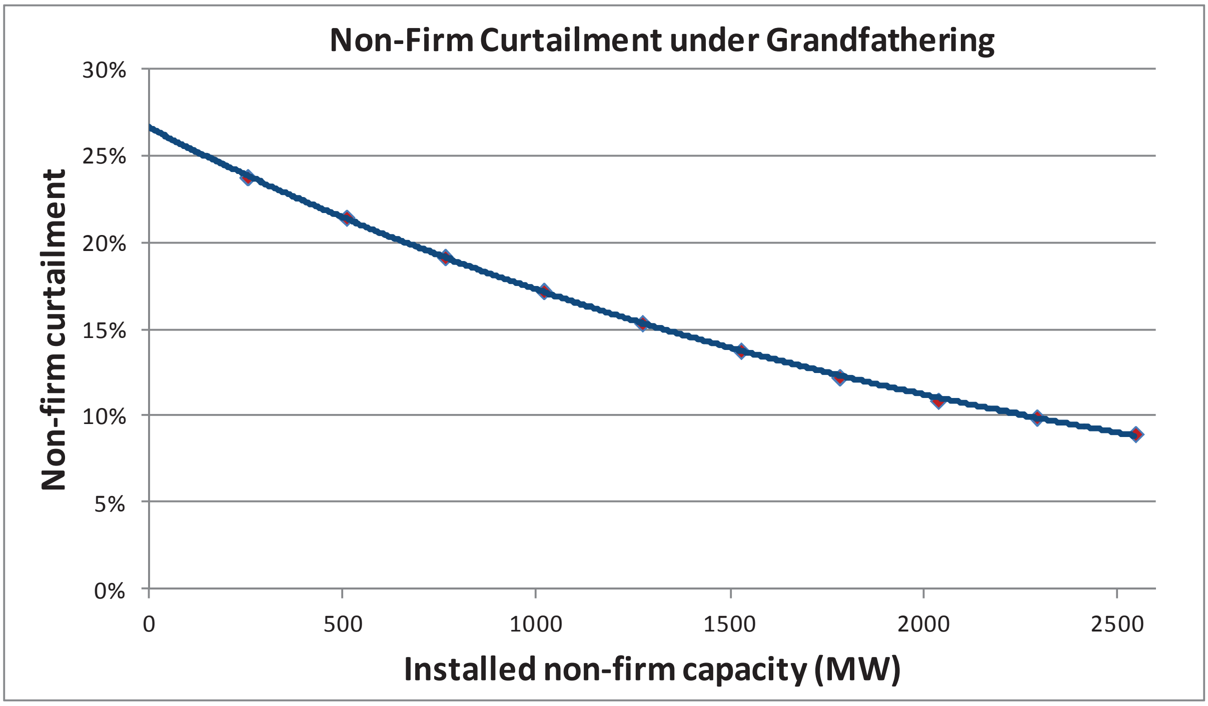
For the short term impact, the study period was Oct 2012 to Sept 2013. The level of wind assumed installed by the end of this period in Ireland (IE) was 1,966 MW, of which 172 MW is expected to be non-firm. In Northern Ireland (NI), 513 MW of installed wind was assumed, all of which was firm. Only Options 1 and 2 were examined.

Looking at the short term impact, the results show a difference in DBC of €1.8 million between these two tie-break options, with Grandfathering giving the lower figure. It should be noted that this is within the range of accuracy for these studies. It would therefore be reasonable to say that **no discernible DBC saving** should be expected if the Grandfathering option were to be applied in the next tariff year.

Curtailment of non-firm wind

The choice of tie-break option can have a considerable impact on curtailment levels for non-firm wind. If Option 1 (Grandfathering) were to be applied for the 2012/13 tariff year, non-firm wind farms would see **10%** curtailment, compared to 2% under Options 2 & 4 (i.e. Pro Rata).

For 2020, the forecast curtailment levels experienced by non-firm wind farms under Grandfathering are shown in the graph below. The rate of non-firm wind curtailment under Pro Rata is 4%, which is also the level of overall wind curtailment.



Percentage curtailment of non-firm wind under Option 1 (Grandfathering) in our base scenario in 2020.

With a higher proportion of non-firm wind on the system, the curtailment under Grandfathering is shared and the overall level is reduced. Conversely, the less non-firm wind on the system, the more curtailment that non-firm will see under Grandfathering. If there was less than 100 MW of non-firm wind in our base scenario, it would see curtailment levels of over 25% under Option 1.

Conclusion

In summary, savings are seen in DBC by applying each of the three tie-break options studied, with the greatest saving seen in Option 4. The savings in Option 1 converge to those for Option 4 with increasing proportions of non firm wind. The savings under Option 2 are less pronounced. Compared with the expected total DBC, the savings are not overly significant in our base case scenario. The savings increase with higher fuel prices.

The choice of tie-break option can have a considerable impact on curtailment levels for non-firm wind farms, with their curtailment levels highest under Option 1 (Grandfathering). The lower the proportion of non-firm wind, the higher the curtailment experienced by those non-firm wind farms under Grandfathering. The studies show curtailment levels of over 25% for non-firm wind in our base case in 2020, when only a small proportion of wind is non-firm.

1 Introduction

1.1 Tie-break Options

The treatment of priority dispatch generation in the SEM is a complex issue and has been discussed extensively. Three SEM papers (SEM-11-062, SEM-11-063, SEM-11-086, and SEM-11-105) were published in 2011 concerning the principles of dispatch of priority generation types, and their subsequent treatment in the event of tie-breaks arising within a generation type.

In the RA's decision paper SEM 11-062, a hierarchy is given defining the order of curtailment for priority dispatch generation. However, it will be necessary on occasion for the TSOs to make curtailment decisions within these generation categories, particularly in the case of wind. When there is more wind generation available than the system can handle, a decision needs to be made on which wind farms to turn down first. This is known as a tie-break situation.

On 26th April 2012, the SEM Committee published a consultation paper (SEM 12-028) which proposed four options for dealing with tie-break situations in the SEM. This report looks at three of those options, namely Option 1 (Grandfathering), Option 2 (Pro Rata), and Option 4 (Pro Rata with no compensation for curtailment). Specifically, the report examines their effect on Dispatch Balancing Costs (DBC)[1], and also on the levels of curtailment[1] experienced by wind generation. It assumes that differentiation between wind farms under Option 1 is carried out on the basis of their access rights – i.e. whether they are fully firm, partially firm or non-firm[1].

The three options essentially combine two methods for determining how wind farms are curtailed with two methods for determining how curtailment is compensated.

The two options determining how wind farms are curtailed as applied in this report are as follows:

1. Grandfathering
   Access right preference is applied so that non-firm wind farms are curtailed down ahead of partially firm wind farms, which in turn are curtailed down ahead of fully firm wind farms. This is applied in Option 1.

2. Pro Rata
   Curtailment is applied proportionately to the output of all wind farms regardless of their access rights. This is applied in Options 2 and 4.

The two options for determining how curtailment is compensated as applied in this report are as follows:

1. Compensation for firm wind only
   Wind farms with firm access rights are compensated for curtailment at the System Marginal Price. Non-firm wind farms receive no compensation. This is applied in Options 1 & 2.

2. No compensation for curtailed wind
   Wind farms do not receive compensation for any curtailment, irrespective of their access rights. This is applied in Option 4.

[1] See section 2 for a definition of these terms.

This is summarised in Table 1 below

	Curtailment method	Compensation for wind curtailment?
Option 1	Grandfathering	Firm wind compensated
Option 2	Pro Rata	Firm wind compensated
Option 4	Pro Rata	No Compensation

Table 1 *Summary of the three tie-break options examined in this report.*

1.2 Financial Impacts

Market rules have recently been modified[2] so that the ex-post market schedule quantity (MSQ) for a non-firm wind farm is equal to its real time dispatch. For a firm wind farm, their MSQ equals their real time availability. This has the effect that, currently, firm wind farms get compensated in the market for being curtailed, whereas non-firm wind farms do not. Under Option 4, the ex-post MSQ for a firm wind farm would be equal to its dispatch quantity excluding any reduction in generation due to network constraints.

Another perspective can be gained by examining the market Schedule Demand. The Schedule Demand is the demand that has to be met by price-making generation (effectively thermal generation) in the SEM. Currently, the Ex-ante Schedule Demand[3] is effectively equal to (System Load) – (availability of firm price-takers) – (dispatch of non-firm price-takers). A reduction in the dispatch of non-firm price-takers (i.e. non-firm curtailment) increases the market Schedule Demand by the same volume. This may lead to an increase in market production costs, in turn leading to lower DBC. This is illustrated in Figure 1.

Since Grandfathering will generally mean that non-firm wind experiences more curtailment than under Pro Rata, this may have financial implications on both the consumer and wind farm owners. This report focuses on one financial aspect in particular: Dispatch Balancing Costs (DBC). DBC is essentially the difference in cost between the generation dispatch as scheduled by the SEM, and the actual dispatch as performed by the TSOs via their respective control centres. This cost is ultimately borne by the consumer.

Note that if Option 4 were to be applied, it would be all curtailment, not just non-firm curtailment, which would impact on the Ex-ante Schedule Demand.

[2] http://www.sem-o.com/MarketDevelopment/ModificationDocuments/Mod_43_10_V3.docx

[3] The actual definition is different to that presented here, however this approximation is suitable for the sake of this illustration

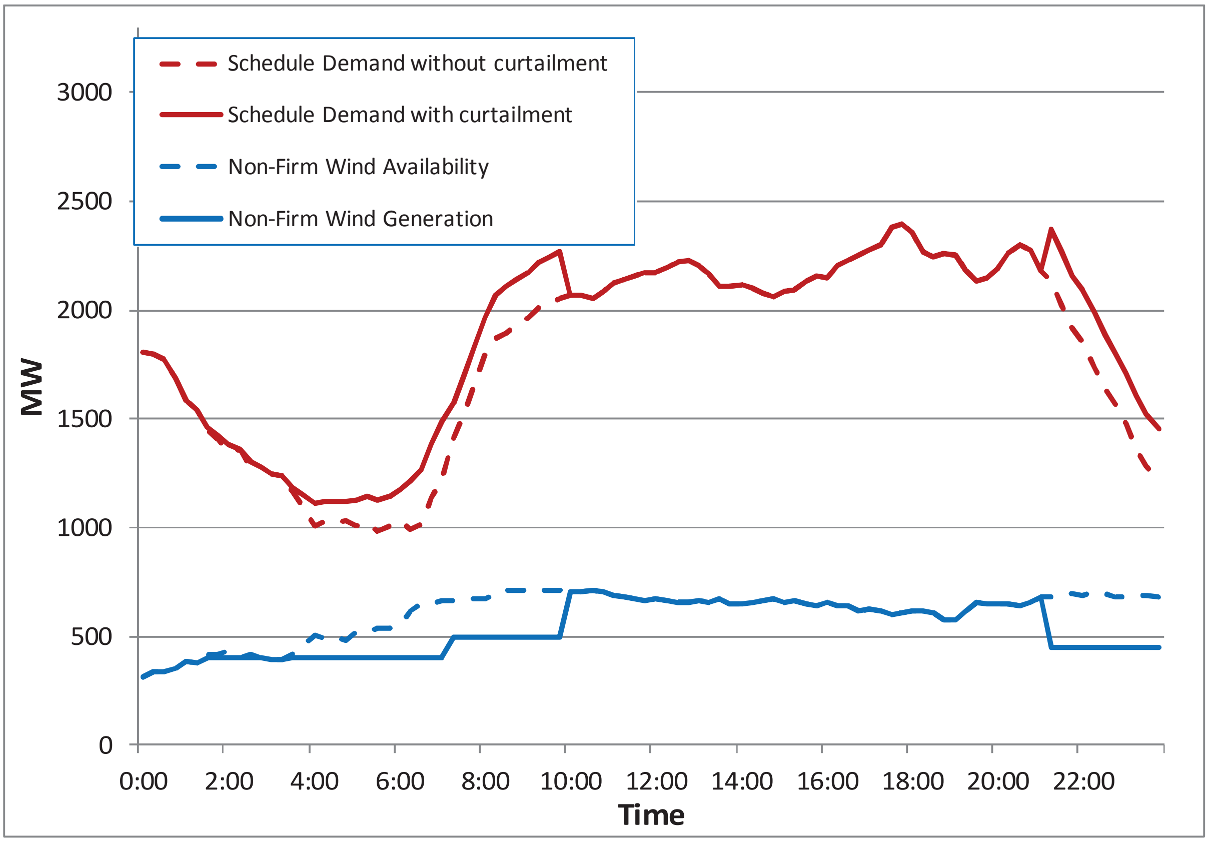


Figure 1 Schedule Demand shown with and without non-firm wind curtailment. The availability and output of non-firm wind is also shown. Any non-firm wind curtailment causes an increase of Schedule Demand by the same volume.

1.3 Study Limitations

It should be noted that these studies are carried out to examine changes in DBC and curtailment levels under a particular set of scenarios only. Any outturn which is different to the assumptions can, and most likely will, lead to a different set of results. In particular, results will be sensitive to changes in the fuel forecast, interconnection capacity, the SEM market structure, the GB model, and security and operational rules on the Irish power system.

In addition, since the report only examines one aspect of DBC, all results are relative only. The results centre on the change in DBC caused by application of the different tie-break options, rather than determining the total DBC. The forecasting of the absolute value of DBC requires a far more complex process beyond the scope of this study.

Due to the nature of the modelling software, the models used have perfect foresight of wind generation, demand, and generator outages. In reality this will not be the case for the system operator, and actual dispatch will be less optimal. A less optimal dispatch would be expected to cause higher levels of curtailment.

The focus here is on DBC and curtailment only. Important aspects such as the impact of each tie-break option on SMP, wind farm connection rates, REFIT costs, meeting 2020 targets etc. have not been examined.

2 Definitions

It is worthwhile clarifying some key concepts at this point. **Dispatch Balancing Costs (DBC)** are the difference in cost between the generation dispatch as scheduled by the SEM, and the actual dispatch as performed by the TSOs via their respective control centres. The SEM will try to schedule generation to meet load in the most economical way possible. However to maintain system security, the TSOs need to account for operational reserve, voltage support, transmission congestion, forecasting uncertainty etc. This leads to a dispatch which is more expensive than that calculated by the SEM. This extra cost is called DBC and is ultimately borne by the consumer. It should be noted that modelling of certain aspects of DBC, such as uninstructed imbalances, is not appropriate for these studies.

For the purposes of this document, the term **curtailment** is assigned to any reduction of generator output for system integrity purposes. This includes but is not limited to maintaining a secure power system through providing for reserve or inertia, and ensuring that the maximum non-synchronous penetration limitation is not breached. Other contributing factors include maintaining mandatory priority dispatch plant such as qualifying hybrid units, high efficiency CHP, indigenous fuels, and renewables as “Must-run” generation. Excessive generation events in the market, whereby wind availability exceeds system demand are also considered to be curtailment events. Curtailment does **not** include generator output reduction as a direct consequence of alleviating transmission congestion.

Priority dispatch generation is generation which must be run before all other generation types, and typically consists of generation from renewable or partly-renewable sources – the exception being peat generation. In the SEM Committee’s decision paper SEM 11-062, a hierarchy is given defining the order of curtailment for priority dispatch generation. However, it will be necessary on occasion for the TSOs to make curtailment decisions within these generation categories, particularly in the case of wind. This is a **tie-break** situation.

Under current transmission connection rules, generators are given a Firm Access Quantity (FAQ) based on the interplay between their installed capacity, the capacity of the transmission network at their connection point, and the amount of generation either connected or attempting to connect in the region. **Firm** refers to generators whose FAQ is equal to or greater than their installed capacity. **Non-firm** refers to generators whose FAQ equals zero – this situation arises where generators connect on the presumption that network reinforcements, which will increase their FAQ, are forthcoming. **Partially-firm** refers to generators with some FAQ lower than their installed capacity. For the studies presented here, partial firmness has been ignored.

Simultaneous Non-Synchronous Penetration (SNSP) is defined as the ratio of wind generation plus imports to system load plus exports at any given instant. An SNSP limit effectively puts a cap on the amount of wind that can generate at a particular time.

3 Studies

Three studies were carried out.

1. <u>2020 DBC Study</u>

This study looked at the effect of the three tie-break options on DBC for different proportions of non-firm wind in 2020. The level of overall wind curtailment was constant.

2. <u>2013 DBC Study</u>
This study applied tie-break Options 1 & 2 to the latest DBC forecast model, covering the 2012/13 tariff year. This gives an indication of the immediate impact of applying these two different tie-break options on DBC.

4 Methodology

All modelling was carried out using Plexos 6.201 R31. This outputs an annual chronological unit commitment and dispatch schedule on an hourly basis for each scenario. The dispatch is obtained on an economic basis with provisions for any operational constraints (e.g. reserve) that are required.

DBC are determined by comparing production costs between unconstrained (market) and constrained (actual) dispatches. For thermal generators, the production cost is simply the cost of fuel burned by each generator. The cost of flows across the interconnector must also be accounted for. This is done by multiplying the volume of interconnector flows by the SMP for each trading period.

4.1 2020 DBC study

This study was based on an existing 2020 all-island model. The overall level of installed wind was set to 5,490 MW, which should be more than sufficient to achieve a 40% RES-E target for the island. All pre-Gate 3 wind in IE, and existing wind in NI, was considered firm. The proportion of firmness for the remaining wind was varied from 0% to 100%, in increments of 10%.

The Grandfathering tie-break option (Option 1) was simulated by giving non-firm wind a small but non-zero price, and firm wind a zero price. Since the model curtails wind in the most economic manner, non-firm wind generation was reduced first. To simulate the Pro Rata tie-break option, both non-firm and firm wind was given a zero price.

To determine the levels of non-firm curtailment, a set of 'Reserve Constrained' runs were initially carried out. These modelled reserve, inertia, and an SNSP limit of 70%. Different proportions of non-firm Gate 3 wind were assumed, though the overall level of installed wind was the same in each run.

A set of market runs were then carried out, with different proportions of non-firm Gate 3 wind assumed. These excluded reserve and other operational constraints. The availability of non-firm wind was reduced by the amount curtailed in the Reserve Constrained runs. For example, if a non-firm windfarm was curtailed by 10 MW for a period in the Reserve Constrained run, its availability for the same period was reduced by 10 MW in the market run.

DBC were determined by comparing the production costs of the market runs with those of the Reserve Constrained runs. The production costs due to interconnector flows were calculated by multiplying the volume of interconnector flows by the market price for each trading period.

The models assumed an asynchronous penetration limit of 70% by 2020. EirGrid plan to increase the SNSP limit to 75% by 2020. A number of measures are required in order to achieve this, as outlined in EirGrid's Facilitation of Renewables report[4]. However, as the modelling software used has perfect foresight of wind generation, demand, generator forced outages etc, it will give a more optimal solution than is possible from NCC dispatch. As a possible counterbalance, we have used a slightly lower SNSP limit.

4.2 2013 DBC study

This study was based on an all-island model used for the latest DBC forecast. This model therefore contains EirGrid's most up-to-date assumptions regarding operational rules, installed wind, demand, generation portfolio and any other issues which may impact on system production costs and generation dispatch.

The study period is Oct 2012 to Sept 2013. The level of wind assumed installed by the end of this period in IE was 1,966 MW, of which 172 MW was expected to be non-firm. In NI, 513 MW of installed wind was assumed, all of which was considered firm.

A constrained run was carried out for each tie-break option, to determine the amount of non-firm wind curtailment. This constrained run simulated all constraints which apply to generation dispatch, apart from network flow limitations. The Grandfathering tie-break option (Option 1) was simulated by giving non-firm wind a small but non-zero price, and firm wind a zero price. Since the model curtailed wind in the most economic manner, non-firm wind generation was reduced first. To simulate the Pro Rata tie-break option, both non-firm and firm wind was given a zero price.

A market run was then carried out for each tie-break option. These excluded reserve and other operational constraints. The profile of **available firm** wind energy and **generated non-firm** wind energy, as determined in the constrained run, were deducted from system demand to give the Market Schedule Demand used in the market run. A higher level of non-firm wind curtailment will therefore lead to a higher Market Schedule Demand.

The DBC were determined by comparing the production costs of the market runs with those of the constrained runs.

5 Assumptions

5.1 2020 DBC study

5.1.1 Demand

An all-island Total Electricity Requirement of 41.1 TWh was assumed. This figure comes from the Median demand forecast in the most recent All-Island Generation Capacity Statement 2012-21.

5.1.2 Wind Capacity

For IE, it was assumed that all pre-Gate 3 wind, totalling 2,543MW, was connected and firm. A further 1,600 MW of Gate 3 wind was assumed (equivalent to 40% of the Gate 3 wind connection offers). In the 2020 DBC study, the ratio of firm/non-firm for this Gate 3 wind varied between scenarios. Installed wind capacity was split into 13 regions to capture the geographical variation in wind generation profiles.

[4] See http://www.eirgrid.com/operations/ds3/ and http://www.eirgrid.com/media/FacilitationRenewablesFinalStudyReport.pdf for more details

For NI, it was assumed that 1,340 MW of wind was installed by 2020. Of this, 400 MW was always assumed to be firm (as per pre-Gate 3 in IE) in the 2020 DBC study, with the firmness of the remaining 942 MW varying between scenarios (as per Gate 3 in IE). As the 2020 curtailment study only looks at Option 4, the ratio of firm/non-firm wind is irrelevant.

Wind generation profiles are based on regional 2008 historical data. The total level of wind installed should be more than sufficient to meet the 40% RES-E target.

5.1.3 Interconnection

Moyle and EWIC were the only interconnectors modelled. A combined maximum export capacity of 830 MW, and import capacity of 950 MW, was assumed. A model of GB's BETTA market was used, with assumptions on the GB generation portfolio taken from UK National Grid's most recent 7-year statement[5].

5.1.4 Operational constraints

In determining the amount of wind curtailment, Primary, Secondary, Tertiary I and Tertiary II reserve categories were modelled as per current system requirements. A minimum system inertia requirement of 23,000 MWs was also modelled.

A penetration limit of 70% for asynchronous generation was modelled in the 2020 DBC study. EirGrid are targeting a 75% SNSP limit by 2020. However, as the modelling software used has perfect foresight of wind generation, demand, generator forced outages etc, it will give a more optimal solution than is possible from NCC dispatch. As a possible counterbalance, we have used a slightly lower SNSP limit.

Reserve, inertia, and the asynchronous generation limit were not modelled in the market runs.

5.1.5 Fuel forecast

Fuel forecasts were provided by the CER's Market Modelling team so as to line up with previous studies carried out by the RAs. The median forecast roughly corresponds to 2011 prices. High and low fuel forecast were also examined so as to identify trends in the results.

Fuel	Units	Low	Median	High
Coal	\$/t	60	120	240
DO	\$/t	475	951	1435
Gas	p/th	29	57	97
HFO	\$/t	306	612	1223
CO2	€/t	8	16	31

Table 2 *Fuel prices used in the 2020 DBC studies.*

The median forecast was used as the base case for these studies. The high and low forecasts are not expected to be realised in 2020, and are used for illustrative purposes and sensitivity analysis only.

5.1.6 Transmission Network

The transmission network was not modelled, as we are not examining network constraints.

[5] http://www.nationalgrid.com/uk/Electricity/SYS/current/

5.2 2013 DBC study

All assumptions for the 2013 study were as per the model used in calculating the Dispatch Balancing Costs forecast covering Oct 2012 – Sept 2013. A report on this model has been provided to the RAs. A total of 172 MW of wind was deemed non-firm, all of which was located in IE.

6 Results

In calculating DBC, the production cost of a market run is subtracted from the production cost of a constrained run. This represents the difference in costs between the market schedule and the actual generation dispatch. Increasing the production cost of a market run will therefore decrease constraint costs.

For thermal generators, the production cost is simply the cost of fuel burned by each generator. The cost of flows across the interconnector must also be accounted for. This is done by multiplying the volume of interconnector flows by the market price for each trading period.

Note that production costs in the constrained run are not affected by the proportion of non-firm generation, and will be the same for each tie-break option. Therefore the change in DBC across scenarios can be calculated by comparing the market runs for those scenarios.

6.1 2020 DBC study

Figure 2 shows the savings in DBC observed under the three tiebreak options for different proportions of non-firm wind. The median fuel forecast has been assumed, and an SNSP limit of 70% was used. The savings are against a reference scenario, where all wind curtailment is fully compensated. The level of precision of the software used leads to a range of accuracy of €2 - €3 million in these calculations.

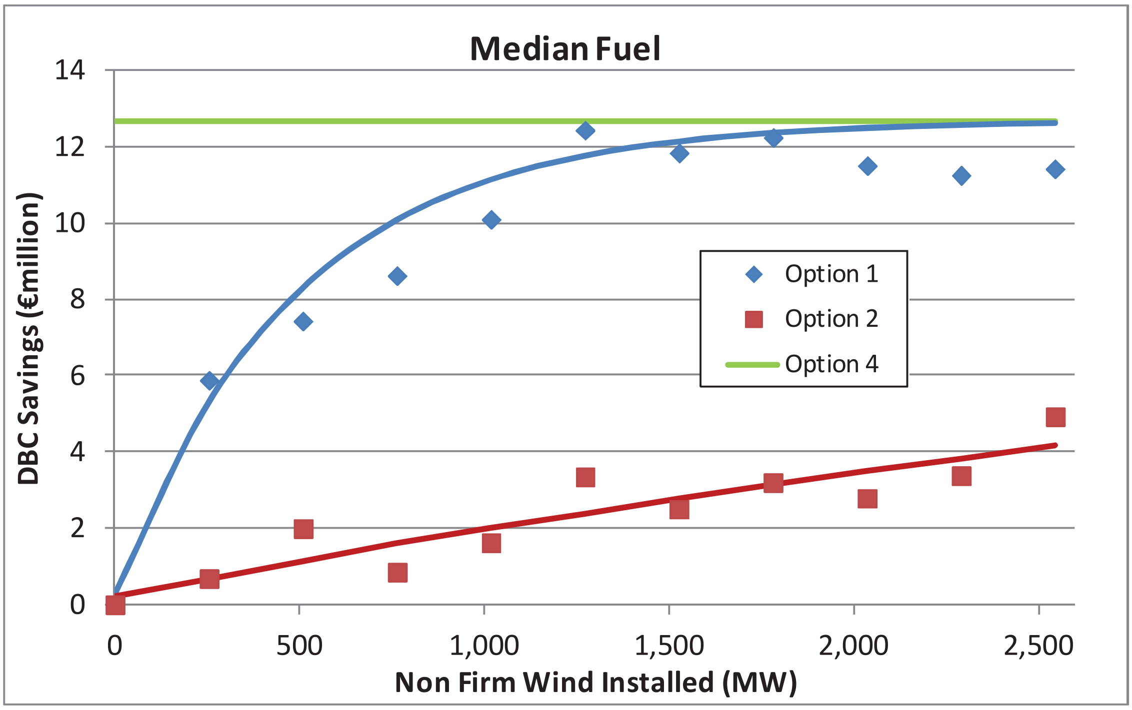


Figure 2 Savings in DBC achieved by using the different tiebreak options under the median fuel forecast, as compared to a reference scenario where all curtailment is fully compensated.

Under Option 1, non-firm wind is curtailed before firm wind. As the capacity of non-firm wind increases, the total amount of wind curtailment (which is fixed) is taken up by non-firm wind. The amount of non-firm curtailment therefore saturates, as do the DBC savings. Under Option 2 the savings are less pronounced, as curtailment is shared equally with firm wind farms, which are compensated for curtailment. In Option 4 there is no differentiation between firm and non-firm wind farms, and the savings are constant.

Figure 3 compares the level of curtailment of non-firm wind under the Grandfathering and Pro Rata curtailment options. The amount of non-firm curtailment converges towards the total wind curtailment amount as the proportion of non-firm wind increases.

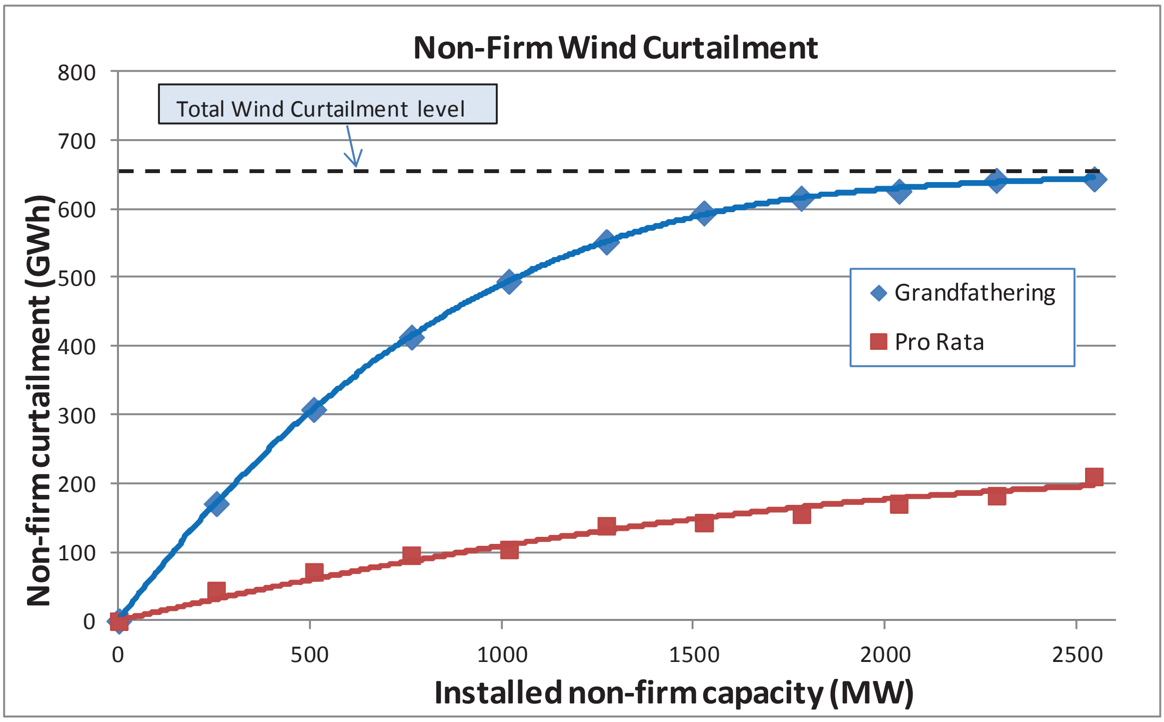


Figure 3 Curtailment of non-firm wind under the two tie-break options. The total level of wind curtailment for both firm and non-firm wind farms is shown.

The percentage of curtailment seen by non-firm wind farms can be considerable under Grandfathering, as shown in Figure 4. As a higher proportion of non-firm wind is installed, the curtailment is shared between more wind farms, and the percentage drops. For example, if at a particular time 10 MW of curtailment is required, and there is 10 MW of non-firm wind, this non-firm wind would experience 100% curtailment. If there is 20 MW of non-firm wind, the non-firm wind would only experience 50% curtailment.

The percentage of curtailment seen by non-firm wind farms under Pro Rata is 4% (equating to the overall wind curtailment in these studies). This does not change with the proportion of non-firm wind installed.

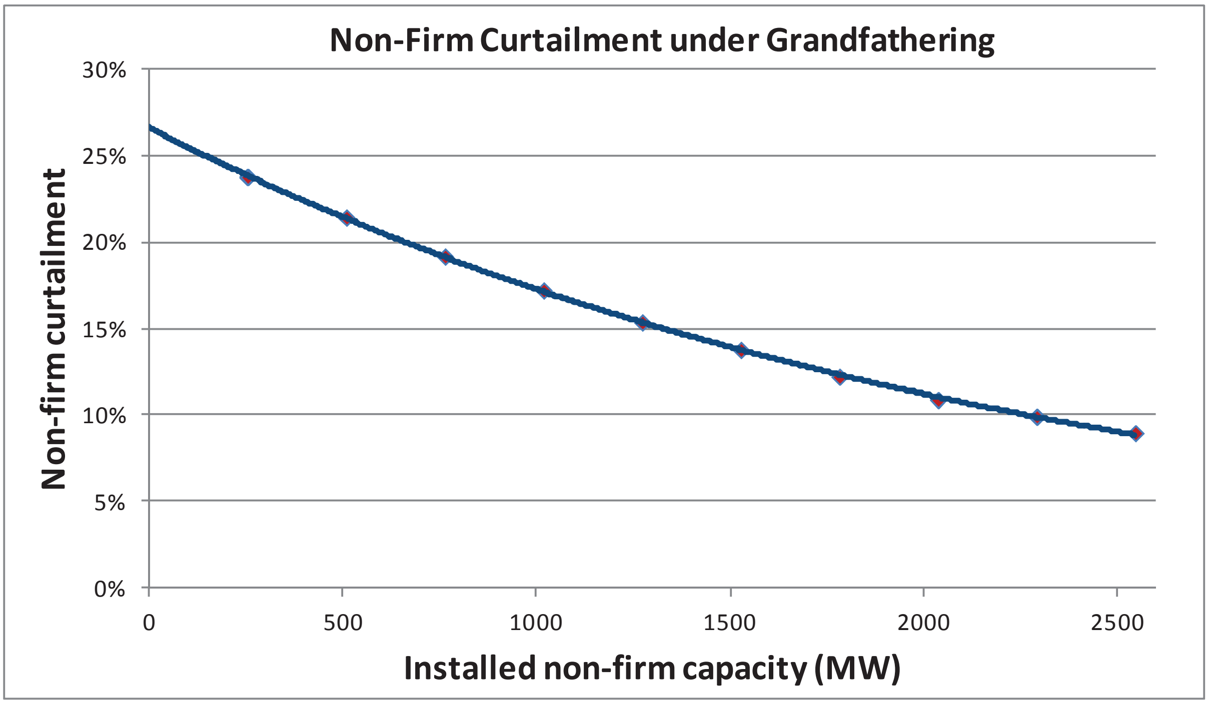


Figure 4 Percentage curtailment of non-firm wind under the Grandfathering tie-break option. As more non-firm wind generation is installed, curtailment is shared and the percentage reduces.

Different fuel scenarios were also examined. The fuel prices were provided by the RAs and are used for illustrative purposes and sensitivity analysis only. The results, shown in Figure 5 and Figure *6*, indicate that DBC savings increase with fuel prices, as would be expected. The savings are against a reference scenario, where all wind curtailment is compensated.

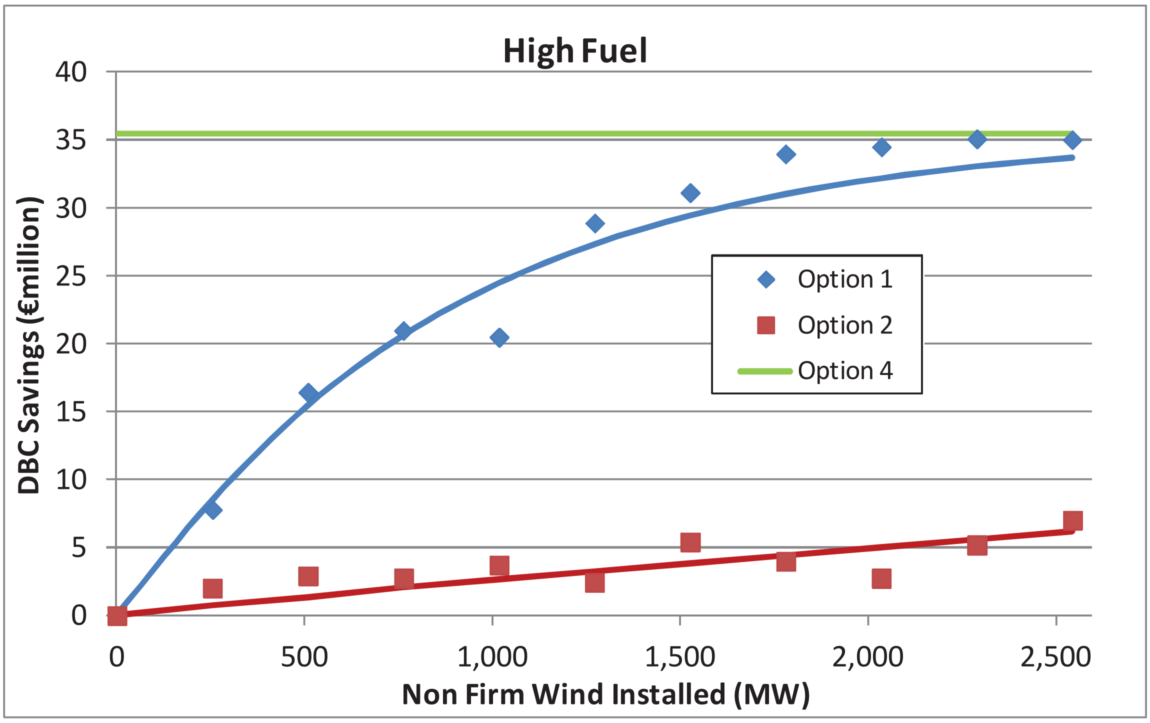


Figure 5 Savings in DBC achieved by using the different tiebreak options under the high fuel forecast, as compared to a reference scenario where all wind curtailment is compensated.

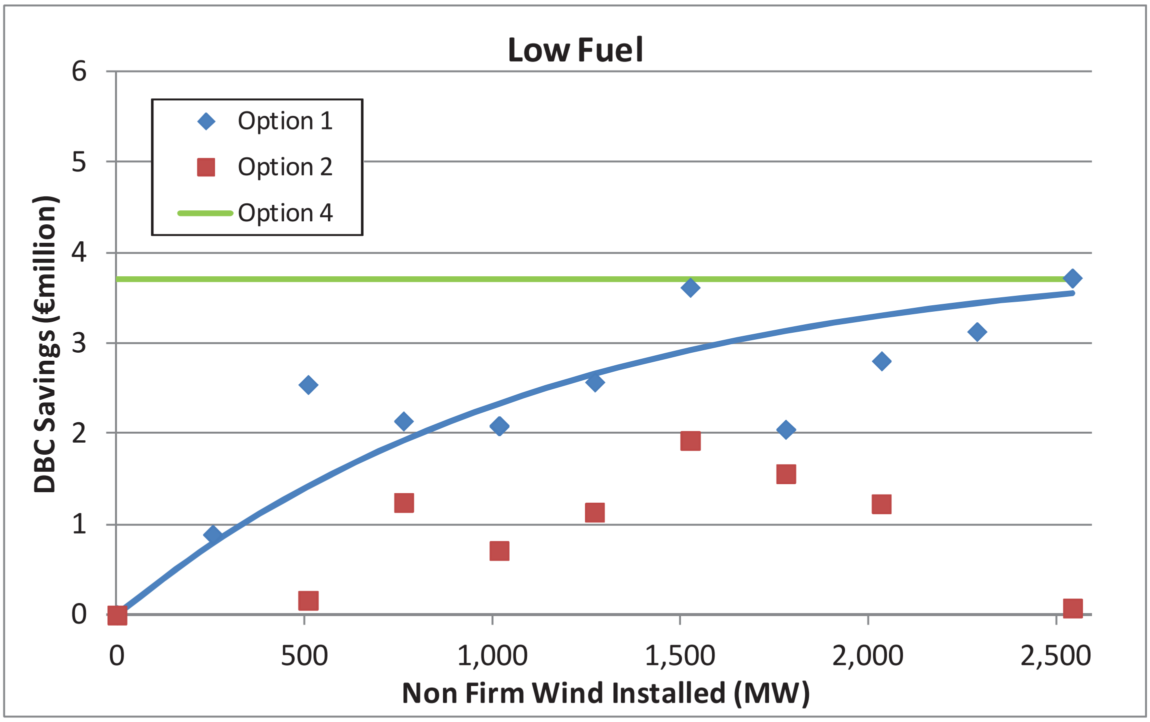


Figure 6 Savings in DBC achieved by using the different tiebreak options under the low fuel forecast, as compared to a reference scenario where all wind curtailment is compensated.

6.2 2013 DBC study

This study examined the savings in DBC for the 2012/13 tariff year gained by applying Option 1, as compared to Option 2.

In the 2013 study, the market production costs for SEM generation do not change significantly between applying the Grandfathering and Pro Rata tie-break options. The Grandfathering option leads to slightly higher market production costs, resulting in a saving in DBC of **€1.8 million.** This figure can be considered to be within the range of accuracy of the study, as the results compare production costs of the order of €1 - €2 billion.

Under the Grandfathering option, the non-firm units experience **10%** curtailment, compared to **2%** when the Pro Rata option was applied. This is a curtailment of 52 GWh against a potential generation capability of 542 GWh for non-firm wind. The overall wind curtailment rate is roughly[6] the same as that experienced by non-firm wind under the Pro Rata tie-break option (2%).

7 Conclusion

These studies compared DBC savings under three different tie-break options in 2020. The results show that Option 4 leads to the greatest DBC savings. The savings in Option 1 converge to those for Option 4 as the proportion of non firm wind increases. The savings under Option 2 are less pronounced.

The DBC savings vary with the fuel forecast. As fossil fuel prices increase, the cost of compensating wind also increases, and DBC savings under each of the tiebreak options increase. Taking the median

[6] Regional differences in wind profile cause a small amount of variation

fuel forecast, savings of €13 million are seen under Option 4, where neither firm nor non-firm wind is compensated for curtailment.

Under Option 1 (Grandfathering), non-firm wind is curtailed before firm wind, and only firm wind is compensated for curtailment. The savings in DBC under Option 1 depend on the proportion of wind that is non-firm, and as this proportion increases, the savings converge to €13 million seen in Option 4. Under Option 2 (Pro Rata), firm and non-firm wind farms are curtailed at the same rate, and only firm wind is compensated for curtailment. As a result, lower savings are seen compared to Options 1 & 4, with a maximum of €5 million.

The €13 million savings observed in this scenario are not overly significant in the context of the predicted DBC budget, and are expected to represent less than 10% of total DBC in 2020. DBC savings increase with fuel prices, as does the overall DBC.

These studies also compared curtailment levels for wind farms in 2020 under Grandfathering (Option 1) and Pro Rata (Options 2 & 4). Curtailment levels for non-firm wind can be sizeable under the Grandfathering option. This figure can be more than 25% depending on the proportion of non-firm wind installed. This compares to 4% under the Pro Rata option.

This study also looked at how Options 1 & 2 would affect DBC and curtailment in the next tariff year. For the 2012/13 tariff year, no real DBC savings are observed. The increase in curtailment levels for non-firm wind under the Grandfathering option is sizeable at 10%, compared to 2% under the Pro Rata option.

It should be noted that these studies are carried out to examine constraint costs and curtailment under a particular set of scenarios only. Any outturn which is different to the assumptions can, and most likely will, lead to a different set of results.