Recommended Values for I-SEM Scheduling and Dispatch Parameters

Report to the Regulatory Authorities

Version 1.0 10/05/2017

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1. SEM Committee Policy and Trading & Settlement Code Obligations

1.1 Overview of the SEM

With the introduction of I-SEM, Participants will have the opportunity to trade in multiple timeframes. Participants will have the option to buy and sell energy in the day-ahead market and the intraday market, with generators having bids or offers accepted in the balancing market based on commercial offers for deviations from their physical notifications as provided to the System Operators (SOs). Settlement for trading energy outlined in new draft of the Trading & Settlement Code covers both balancing actions taken by the SOs and an imbalance settlement requirement which intends to true up Participants' aggregate market positions based on activity in the day-ahead, intraday and balancing markets against their actual (or deemed, in the case of Assetless Units and DSUs) metered positions. In addition to these markets for trading energy, the I-SEM includes a Capacity Market (CM) based on Reliability Options.

The I-SEM decisions allow the TSOs to take actions for non-energy reasons (such as system requirements like voltage support, reserve provision etc.), and to take actions for energy reasons (i.e. maintaining the balancing between demand and supply), using the commercial data submitted for the balancing market. These actions and any differences between traded positions and metered output or consumption are settled through the imbalance settlement processes.

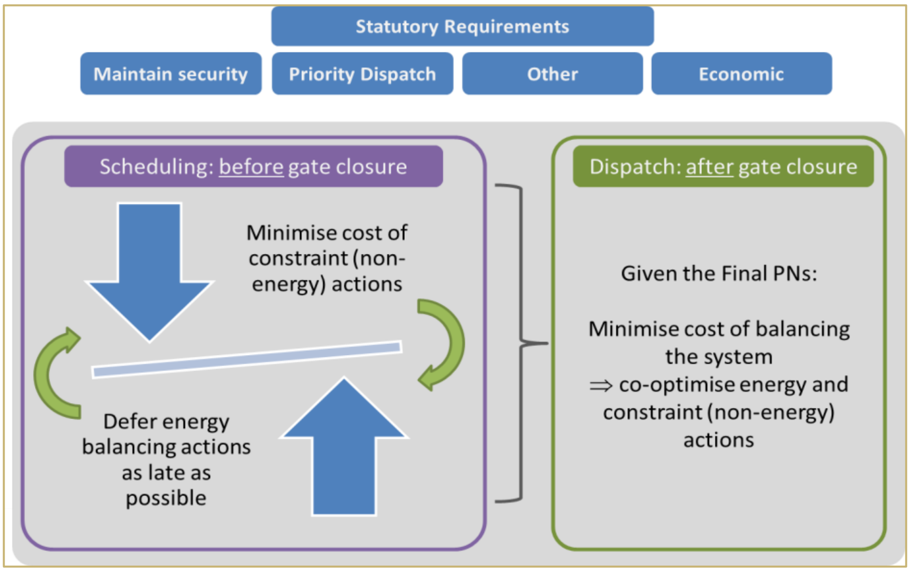
The High Level Design Decision Paper (SEM-14-085) requires that the balancing market opens after the completion of the day-ahead market. This is to allow the SOs to schedule and dispatch units to maintain a safe and secure system. This results in the balancing market and intraday market being open at the same time. This was considered in the I-SEM ETA Markets Decision Paper (SEM-15-065), which clarified the objectives of scheduling and dispatch with the balancing market in different timeframes as follows:

- Insofar as it is possible, energy balancing actions should be deferred as much as possible until after the Balancing Market Gate Closure, and the ex-ante markets should be left to resolve the energy supply/demand balance;
- The TSOs should not take any action prior to the Balancing Market Gate Closure unless it is for reasons of system security, e.g. for reserves, for priority dispatch, or for other statutory requirements;
- Costs for both constraint (non-energy) actions and energy actions should be minimised.

One of the I-SEM objectives is that the day-ahead and intraday markets should be the primary mechanisms by which the energy supply / demand balance is resolved. If the market finds a balanced energy position through the ex-ante markets, the need for SO energy actions will be minimised. However, if the market is not balanced, there is a risk that the proposed approach could result in "early" actions that could dilute the signals to market participants and appear to impact on the intraday market. For example, a large imbalance indicated by the initial PNs may suggest the need for the SO to start up additional generating plant and if generator units with long notice times appear to offer the lower cost options in scheduling the system, such decisions may be taken before final gate closure. However, this could pre-empt potential trading activity in the intraday market and / or lead to sub-optimal outcomes if the supply / demand balance subsequently changes prior to real time dispatch.

Actions to balance energy requirements are not fully distinguishable from constraint (non-energy) actions or vice versa. The scheduling and dispatch of balancing energy can cause or relieve constraints. Similarly, constraint (non-energy) actions, taken to maintain system security, can increase or decrease energy imbalances. In addition, priority dispatch actions can affect energy imbalances and/or system security.

The challenge in the scheduling and dispatch process is to simultaneously solve for these objectives while respecting the over-arching statutory requirements as illustrated in the figure below.



It has been proposed that the means of enacting the high level objectives of scheduling and dispatch, while recognising that the tools used in the process will be focussed on minimising the cost of all actions simultaneously, is to include in the process two factors, a Long Notice Adjustment Factor (LNAF) and a System Imbalance Flattening Factor (SIFF), that effectively apply a weighting to the costs of offline generators and thereby reduce the propensity for taking early commitment actions in the scheduling process. The LNAF and SIFF will apply to unit start-up costs (or, in the case of a Demand Side Unit, to shut down costs) in the scheduling process. This will tend to minimise the likelihood of early unit commitment decisions by the SOs to start up long notice plant over the use of shorter notice units. If the scheduler has no choice but to start a long notice unit to satisfy a security constraint then it will do so. However, given a choice of a number of resources with the same (or similar) cost, application of the LNAF and SIFF will tend to favour shorter notice resources in the scheduling process. The following sections describe the process for determining the LNAF and SIFF (and associated System Shortfall Imbalance Index – SSII) and their application in the scheduling tool.

1.2 Parameters for Scheduling and Dispatch

Under section 10A of the proposed EirGrid Transmission System Operator Licence, and section 22A of the proposed SONI Transmission System Operator Licence, the System Operator (SO) is required to report to the Regulatory Authorities proposing parameters to be applied in the scheduling and dispatch process. This document provides the methodologies to be used by the SOs to calculate the following parameters and the recommended values as considered under those licence conditions:

- Long Notice Adjustment Factor (LNAF);
- The System Imbalance Flattening Factor (SIFF); and
- Daily time for fixing the System Shortfall Imbalance Index (SSII) and SIFF.

1.3 Determining the Long Notice Adjustment Factor

The LNAF to be applied to the Start Up Costs of a Generator Unit, for all Warmth States, depending on the Unit's Notice Time will be determined as follows:

- An LNAF per Notification Time interval will be specified (a fixed set of values as illustrated in the step-wise graph in Figure 1). An LNAF value can be specified per 15 minute Notification Time interval; however, a value for all periods in the Trading Day will be used in order to reduce the complexity of the implementation of the factor;
- LNAF can equal zero where it is determined that no LNAF should apply to a unit;
- For each unit an LNAF corresponding to the associated Notification Time may apply. LNAFs will increase as Notification Time increases.

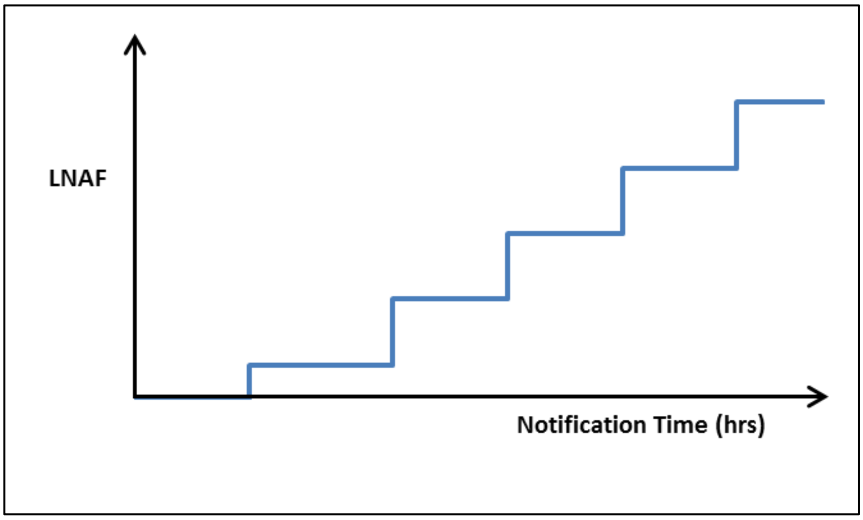


Figure 1: Illustration of LNAF vs Notice Time

Energy actions should only arise when there is an energy imbalance. If the imbalance is zero, all actions should be non-energy actions and the LNAF would not be required as the schedule should seek to resolve non-energy actions at least cost. It is therefore also proposed to implement a System Imbalance Flattening Factor (SIFF) based on a System Shortfall Imbalance Index (SSII). When the system imbalance is high, there will be a high SIFF; when system imbalance is low, there will be a smaller SIFF. This should help target the LNAF and SIFF at times when early energy actions are more likely and dampen or remove their effect when not required.

The following section sets out the process for determining the SSII and corresponding SIFF.

1.4 Determination of the System Shortfall Imbalance Index

The forecast imbalance for a Trading Day will be reflected in a System Shortfall Imbalance Index (SSII) which will be determined as follows:

- Once the PNs based on the day-ahead market results have been provided to the SOs (13:30 day-ahead), the shortfall (if any) between the forecast demand and the sum of PNs, Interconnector schedules and forecast renewable generation over the Trading Day will be calculated;
- The System Shortfall Imbalance Index (SSII) will be calculated as the ratio of the total of any energy shortfall over the Trading Day (the sum of energy shortfalls in each Imbalance Settlement Period) divided by the total energy demand forecast for the Trading Day;
- The SSII shall not take into account any surplus of PNs, Interconnector Schedules and forecast renewable generation in an Imbalance Settlement Period over the forecast demand in that Imbalance Settlement Period;
- The SSII shall take the form of a real number between 0 and 1. Zero will indicate no shortfall. A value of 0.01 would indicate a 1% energy shortfall during the Trading Day;
- This SSII will be considered indicative immediately post day-ahead market. Updates to PNs, reflecting intraday market trades, demand and renewables forecast update and interconnector schedule updates will be factored in to hourly updates of the indicative SSII. At a pre-defined time (to be determined) the SSII for the Trading Day will become fixed for the purposes of the scheduling process.

1.5 Determination of the System Imbalance Flattening Factor

Once the SSII has been fixed for a Trading Day, a corresponding System Imbalance Flattening Factor (SIFF) will be determined. The relationship between the SSII and the SIFF will be predetermined. This may be as a fixed table of SSIIs and SIFFs which may be defined, as illustrated by the stepwise curve below. The SIFF can be zero and will increase with ascending values of SSII. In reality is unlikely that the PNs will exactly match the forecast demand so this approach would allow some tolerance to be built into the application of the SIFF.

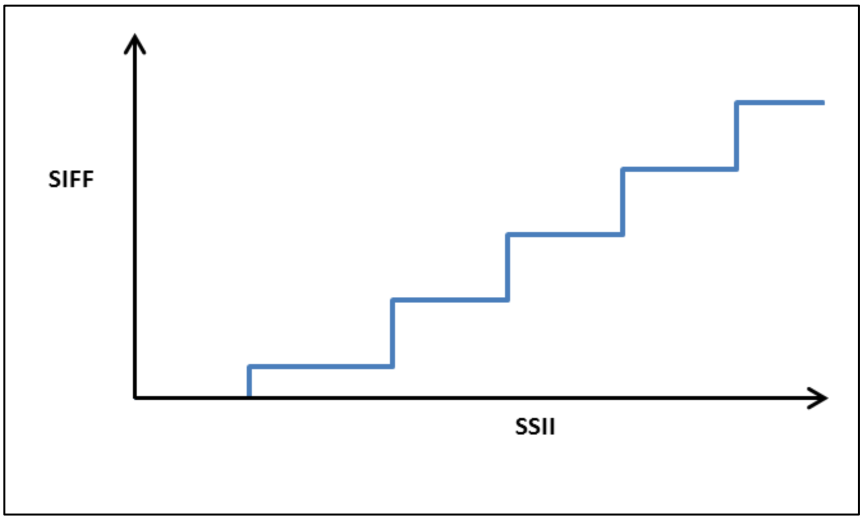


Figure 2: Illustration of SIFF v SSII

Alternatively, SIFF can be a binary value of 1 or 0 triggered by values of SSII to determine when the LNAF should be applied in the scheduling process.

Like the SSII, the SIFF will be indicative up until the time at which the SSII becomes fixed. Indicative and final SSII/SIFF values will be published by the SOs.

1.6 Determination of the Start-Up Cost Used in the Scheduling Tool

The application of the LNAF to the start-up cost for each warmth state of each generator unit in any scheduling run will be determined as:

Start-up cost in scheduling run = Submitted Start Up Cost * [1 + (LNAF * SIFF)]

Since the LNAF and SIFF will only affect the scheduling for offline units, those units with long notice requirements will have an additional incentive to trade in the intraday market rather than waiting to be scheduled by the SOs. They would also incentivise units to reduce their notice times where this is technically and economically feasible.

It is intended that the LNAF and SIFF would be used in the scheduling process only – no LNAF or SIFF adjustment would apply in real-time MW dispatch or in settlement.

Incorporating the LNAF and SIFF into the scheduling process should result in a reduction in actions taken on Generator Units with longer notice times in the balancing market. However it may apply in times where there are drivers for both energy balancing and non-energy balancing actions on the schedule, meaning all actions (both energy and non-energy) could be affected by the application of these factors. While the reduction in actions taken on longer notice units for energy balancing drivers would align with the I-SEM ETA Markets Decision Paper (SEM-15-065) on the objectives for energy balancing, it would potentially result in the reduction of actions being taken on these units for non-energy balancing drivers, which could lead to increased costs of non-energy actions. This is because in all cases the schedule will choose an action to resolve a constraint driving non-energy balancing, but which unit it takes can change due to the application of the LNAF, i.e. it may resolve the constraint with less economic units than if the LNAF had not been applied. This may also depend on which units trade in the intraday market for energy balancing purposes – some units responding in that market may result in implicit benefits to the balancing market in that it could reduce the need for non-energy actions; however, other units may result in implicit disbenefits to the balancing market by driving the need for additional non-energy actions.

Therefore it would be important in situations where non-energy drivers for balancing actions are greater than energy balancing drivers that the effect of the LNAF is reduced or removed. The extent of the trade-off between decreased actions on longer notice units for energy balancing drivers with increased costs of non-energy actions can be determined by the setting of the LNAF/Notification Time and SSII/SIFF tables of parameters.

1.7 Risks and uncertainties:

The following risks and uncertainties must also be taken into account in a qualitative fashion alongside assessment of scenarios with quantitative results:

- The level of constraints on the power system coupled with the requirement to implement priority dispatch policy already results in the operational scheduling and dispatch process being highly constrained at times. The application of the LNAF and SIFF parameters add further to the complexity of this process and further constrain the scheduling solution. While this methodology will consider some of the impacts of the application of the LNAF and SIFF this will be based on modelling tools with predetermined input assumptions. There is therefore a risk that the application of the parameters could have unintended consequences (on system security, priority dispatch and constraint costs) when applied in the operational scheduling tool with real market data and actual power system conditions as inputs;
- The cost of application of the LNAF/SIFF will be incurred in the balancing market with the benefit achieved in changes to ex-ante market behaviour (market participants balancing their position early) and / or improvements in technical capability (shortening of notification times). The analysis performed under this methodology will produce indicative costs for application of the parameters but any benefit is unlikely to be apparent until some time after operation of the new arrangements;
- The risk to system security associated with incentivising the scheduling tools to choose shorter notice units over longer notice units. There would be fewer fallback options if short notice units fail to synchronise, or fail to reach Minimum Stable Generation;
- Shorter notice units (e.g. open cycle gas turbines, OCGT) may have limited annual running hours imposed by jurisdictional environmental protection agencies. There is an inherent risk if these running hours are unduly consumed by balancing actions, rather than using these units for emergency actions;

- Many OCGT units in the generation fleet are operating beyond their normal lifespan and by implication less reliable;
- By placing a heavier duty on shorter notice units, this will increase their maintenance requirements and may, as a result, decrease their availability;
- Depending on the relative magnitudes of the costs and factors, there may be an incentive on fundamentally long notice units to offer shorter notice times but at a higher cost.

1.8 Analysis Overview

In the absence of operational data, a modelling approach was used to simulate the market outcomes arising from different scenarios of parameter values. The focus of this modelling approach was on qualitative outcomes and on understanding the dynamics of the market. Therefore, the assumptions and methodology used for the approach were not developed with the aim of forecasting exact values, but rather to indicate trends and the relative magnitude of differences in outcomes for different scenarios. An overview of the modelling assumptions and approaches taken is included as an appendix to this report.

2. Long Notice Adjustment Factor and Notice Time Group Curve

2.1 Background

The scheduling and dispatch process operates within an obligations framework that extends from European regulations through to TSO Licences, the Trading and Settlement Code and Grid Codes. These Obligations can be categorised under four main headings as illustrated below.

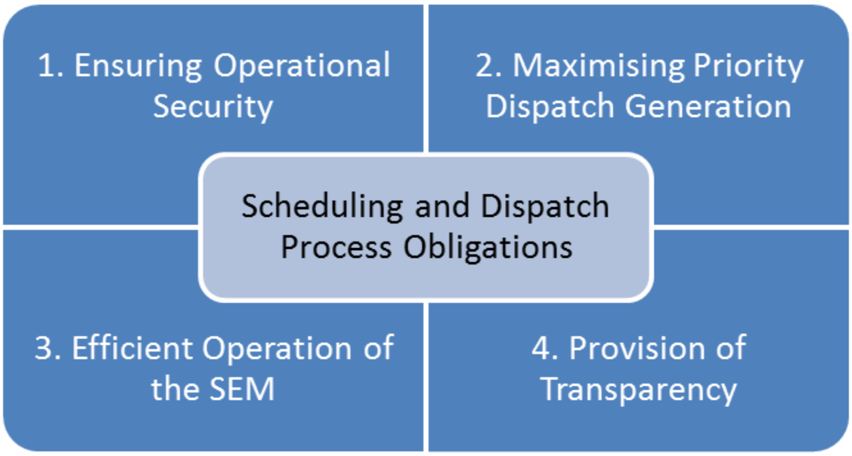


Figure 3: Scheduling and Dispatch Process Obligations

These obligations are described in the TSOs' Balancing Market Principles Statement[1] that is currently under consultation (from 7 April 2017 to 19 May 2017). The obligations reflect European and local (Ireland and Northern Ireland) legislation, TSO Licences, Regulatory decisions and Codes. This statement also sets out how these obligations are ranked and how they are implemented in the scheduling and dispatch optimisation process.

The intent of the Scheduling and Dispatch Policy Parameters presented in this paper is to support obligation 3, Efficient Operation of the SEM by weighting scheduling decisions towards shorter notice units. This allows the ex-ante markets to resolve

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[1] Balancing Market Principles Statement consultation version: http://www.sem-o.com/ISEM/General/EirGrid%20and%20SONI%20Balancing%20Market%20Principles%20Statement%20for%20Consultation%207%20April%202017.pdf

energy imbalances with a reduced requirement for the TSO to take actions during the ex-ante market timeframe. However, as these parameters are intended to adjust the schedule and resulting dispatch decisions, they have the potential to impact on the other objectives of 1, Ensuring Operational Security and 2, Maximising Priority Dispatch Generation. There are also aspects of the application of these parameters that require transparency considerations.

The impact of applying the Scheduling and Dispatch Policy Parameters on these obligations is presented in section 2.3 below.

2.2 Considerations

2.2.1 Intended Outcomes

The intention is to determine the factor which, by applying it to a generator’s start-up cost, would cause the scheduling system to favour (subject to fulfilling system security, priority dispatch and other statutory requirements) actions with high variable cost short notice time units (i.e. units which can be started closer to or after gate closure) over actions with low variable cost longer notice time units (i.e. units which cannot be started closer to or after gate closure). By selecting shorter notice units as a fallback option for energy balancing in the scheduling systems, participants in the ex-ante markets would have more time in which to identify and clear the most economically efficient energy action. This would then be reflected in the scheduling system through the chosen unit’s subsequent PN submission, which should in turn reduce the requirement for the short notice energy actions initially scheduled by the SOs.

The primary impact on system operations is the determination in the schedule of the marginal units that are actually going to be committed for energy balancing requirements, if any. It may result in the selection of a different unit (or number of units) than would be selected without the application of this factor. It may also have a secondary outcome of units which are already synchronised being scheduled to be kept on for longer than they otherwise would have been without the application of this factor. This is because the scheduling system would seek to optimise the overall production cost over time, and keeping the unit on would appear cheaper than desynchronising it and synchronising it again, as incurring the LNAF-adjusted Start Up Cost would be avoided.

It is assumed that the intended outcome is not to calculate LNAFs which accurately reflect the adjustment which would be required to make a long notice, cheap action equivalent to a short notice, expensive action. Instead a view is taken that the intended outcome is to calculate LNAFs which generally reduce the instances of the scheduling tools suggesting actions on longer notice units in scenarios where the drivers for energy balancing actions are greater than the drivers for non-energy balancing actions.

2.2.2 High Level Assessment Approach

The methodology for determining the LNAF values to be applied is split into two phases:

- A data analysis phase, where data is used to determine the relative scale of LNAF values and corresponding groupings of units by their notification times and costs, hereafter Notice Time Groupings, which would represent a base from which to analyse variations to further tweak the incentives; and
- A modelling phase, where different scenarios and sensitivities are layered onto the outputs of the data analysis phase, and production cost dispatch modelling is used to determine the relative impact of different LNAF values on market and system outcomes.

2.2.3 Data Analysis Phase of Assessment Approach

The Long Notice Adjustment Factor (LNAF) curve will consist of a LNAF value per Notice Time (NT) value. This means that the appropriate Notice Time Groupings for different values of LNAF need to be determined. The determination of these Notice Time Groupings needs to consider the interactions with the operation of scheduling tools, the timing of Balancing Market Gate Closure, and the cost of running units within a Notice Time Grouping relative to the cost of running units within other Notice Time Groupings (in particular, those with longer Notice Times relative to units with shorter Notice Times). Once these Notice Time Groupings have been determined, the LNAF required for each can be determined through the relationship between the average unit costs of the units in the groupings.

An "Equivalent Price" can be created for each unit, which is a price based on the same set of assumptions of the cost of starting and running that unit in a way which would typically reflect energy balancing actions which are equivalent across the different units. With the same set of assumptions, it can be established which units are cheaper or more expensive for the equivalent use in energy balancing. This can then be used to determine the Notice Time Groupings (i.e. groups of units with similar Equivalent Prices and Notice Times can be grouped together) and the factor which would be required to make the prices equal, which would be the minimum value for an LNAF which would mean that, on average, all units would be considered equally for use in energy balancing. This can then act as the start point for the values of LNAFs which favour shorter notice actions over longer notice actions.

This could be based on an analysis considering different Notice Time Groupings, calculating the Average Equivalent Price of the units in that group, and standard deviation of these prices from the average, within that grouping. The groupings should consider Average Equivalent Prices decreasing (i.e. requiring increasing LNAFs to bring the cost of running to being seen as equivalent in scheduling software), while having the lowest standard deviations possible (so that the units considered in the Notice Time Groupings are somewhat related to each other in price, so the LNAF is not disproportionately affecting some units over others).

2.2.3.1 Data Analysis Phase Assumptions for Initial LNAF Calculation

The Average Equivalent Price approach requires assumptions around:

- The running level,
- The heat state, and
- The running time

over which the costs are considered to calculate a price. The following discussion attempts to compare and contrast logic for the use of different assumptions.

The most likely use of units for energy balancing would be based on their Hot Warmth State – it is when Start Up Costs and Notice Times are the lowest. However, using the Hot Warmth State would not allow for data relating to a larger number of Notice Times to be used. For example, typically the maximum Notice Time for a unit in its Hot Warmth State would be ~ 6hrs. This means that information relating to cost equivalency up to the potential 18hrs of notice required for some units under their Cold Warmth State would not be used, making the determination of values for LNAF in that output range potentially arbitrary. A means around this is to calculate the LNAF with respect to Cold Warmth State conditions.

Logic is also required for whether the relative costs of units in the different Notice Time Groupings should be maintained, and whether the LNAF value should continuously increase with increasing Notice Time value. For example, if NT Groupings were set up such that a grouping of units with relatively lower NTs had a cost of running which was already lower than the cost of running a grouping of units with relatively higher NTs, this would indicate that the LNAF should be 1 (or less than 1, if following an approach of establishing equivalent costs). However, this would be contrary to the principle that the adjustment should be made to disincentivise the use of longer notice plant while allowing for their costs to be correctly considered if only being used for non-energy reasons). It also means that, if this logic was carried forward, that the LNAF could decrease from one Notice Time Grouping to the next highest Notice Time Grouping to reflect their costs. However, this would clearly create a perverse incentive for units, where they could benefit from increasing their notice times, while the intention is to incentivise the reduction of notice times.

Therefore, it is proposed that, in instances where the costs (represented by the Average Equivalent Price) of a Notice Time Grouping are lower than that of the previous Notice Time Groupings, the LNAF should not reduce to match. The LNAF should instead increase, in a way which is proportionate to the LNAF for other Notice Time Groupings, over the value for the previous NT grouping to reflect the desired outcomes of reducing instances of taking actions on longer notice units.

On the basis of this discussion, the following are proposed to be the base case assumptions for calculating the Equivalent Prices and LNAFs:

- Unit costs calculated based on starting in the Cold Warmth State;
- Max Capacity as MW base output over which the price is calculated;
- Minimum On Time (or 1 hour if Minimum On Time is less than 1 hour) as hr base time over which the price is calculated;
- LNAFs for Notice Time Groups whose prices are smaller than those of previous Notice Time Groups should represent an increased value which is a linear interpolation between the last Notice Time Group with a higher price, and the next Notice Time Group with a higher price than that.

2.2.3.2 Data Analysis Phase Initial LNAF Calculations

Initial LNAF values which give an indication of the magnitude of the factors required to implement the intention of favouring higher cost, shorter notice time units over lower cost, longer notice time units can be determined, using the inputs and assumptions described, as follows:

- Notice Time Groupings can be determined first by examining the relationships between the data available and calculated for units, including:
  - Cost data for starting and running the unit according to the assumptions discussed;
  - The Notice Time data for each unit;
  - The fuel type of each unit;
  - The operational timings, and optimisation horizons, for different aspects of the scheduling process (for example the Long Term Schedule and Real Time Commitment scheduling runs).
- Consider the total cost of running a shorter notice unit over a certain length of time, and calculate the factor which would be required to have the cost of the longer notice unit equal this cost over the same length of time:
  - Then compare the average cost of starting and running the short notice units with the average cost of starting and running units in each of the Notice Time Groupings considered to determine the factor element of the curve.

Comparing the costs can be done by comparing the Average Equivalent Price of the Notice Time Group in question, with the Average Equivalent Price for the Notice Time Group of units with notice times less than one hour (who can therefore always be synchronised after gate closure). The costs should be compared so that, if an LNAF was applied to the Start Up Costs of the units, it would lead to the Average Equivalent Price of the Notice Time Group being equal to that of the Average Equivalent Price of those with less than 1 hour notice. This means an equation for calculating the LNAF for each Notice Time Group which enacts this can be derived as follows, where n is the Notice Time Group and u is a generator unit:

$$[Average\ Equivalent\ Price]_{(n=1)} = [LNAF\ Adjusted\ Average\ Equivalent\ Price]_n$$

$$AEP_{(n=1)} = \frac{\sum_{u\in n}\left(\frac{(1+LNAF_n)\times CSU_u + CNL_u + [Variable\ Cost]_u}{[MW\ base\ \times hr\ base]_u}\right)}{[No.of\ units\ in\ NT\ Group]_n}$$

$$AEP_{(n=1)} = \frac{\sum_{u\in n}\left(\frac{(1+LNAF_n)\times CSU_u}{[MW\ base\ \times hr\ base]_u}\right) + \sum_{u\in n}\left(\frac{CNL_u + [Variable\ Cost]_u}{[MW\ base\ \times hr\ base]_u}\right)}{[No.of\ units\ in\ NT\ Group]_n}$$

$$\left(AEP_{(n=1)} \times [No. of\ units\ in\ NT\ Group]_n\right) = (1 + LNAF_n) \times \sum_{u \in n} \left(\frac{CSU_u}{[MW\ base\ \times hr\ base]_u}\right) + \sum_{u \in n} \left(\frac{CNL_u + [Variable\ Cost]_u}{[MW\ base\ \times hr\ base]_u}\right)$$

$$(1 + LNAF_n) \times \sum_{u \in n} \left(\frac{CSU_u}{[MW\ base\ \times hr\ base]_u}\right) = \left(AEP_{(n=1)} \times [No. of\ units\ in\ NT\ Group]_n\right) - \sum_{u \in n} \left(\frac{CNL_u + [Variable\ Cost]_u}{[MW\ base\ \times hr\ base]_u}\right)$$

$$LNAF_n = \frac{\left(AEP_{(n=1)} \times [No. of\ units\ in\ NT\ Group]_n\right) - \sum_{u \in n} \left(\frac{CNL_u + [Variable\ Cost]_u}{[MW\ base\ \times hr\ base]_u}\right)}{\sum_{u \in n} \left(\frac{CSU_u}{[MW\ base\ \times hr\ base]_u}\right)} - 1$$

Once Notice Time Groupings have been determined, the Average Equivalent Prices (and components thereof) for these groups can be calculated and, using the final equation derived above, the LNAF value for each NT Grouping can be calculated. This calculated LNAF value then may be adjusted for other outcomes intended to be represented by the LNAF curve, such as LNAF values only increasing with increasing Notice Times.

Under the average price approach, the average of the Start Up Costs of all units in the group are considered, meaning the influence of different units and fuel types is considered. While this may have the effect of dampening or enhancing the factor for different units in the group, it means that a single unit would not have a disproportionate effect on the remaining units in the group. Using an approach which relies on a single unit, such as a minimum price approach, is potentially more subject to large changes in LNAF if recalculating it to reflect small changes in unit Notice Times, and would potentially require more regular updating. This would result in a less stable variable than using the average approach, which is counter to the intention to create a parameter which has an overall general impact on scheduling. Therefore, it is proposed to use the average approach.

Another consideration is whether those units which have zero costs in the data (for example, hydro units) should be excluded in the formulation of the LNAF. While in their Commercial Offer Data (COD) they may provide Start Up Costs, these would tend to be much lower than those of thermal units, and would not appear in the data used as it is based on fuel costs rather than their submitted COD. Their value of zero decreases the average price, and may have a disproportionate effect on the Average Equivalent Price in the first Notice Time Grouping, on which the LNAF of all other groupings is based, as those units tend to have relatively short notice time requirements. It is proposed to filter out such units for use in this methodology – reflecting only those units which have non-zero variable costs.

2.2.4 Modelling Phase of Assessment Approach

Following the determination of initial LNAF curves, a number of scenarios where increases and decreases to these initial values can be modelled. The intention of this phase is to simulate the outcomes which would arise from the implementation of different LNAF values. This would also allow for sensitivities which were not reflected in the data analysis phase to be incorporated, such as allowing for potential changes in fuel prices.

A number of scenarios for LNAF values will be modelled to compare the outcomes of each, which can be used to determine which scenario most closely results in the desired outcomes while resulting in the least unintended outcomes. These scenarios can include:

- Increasing the Initial LNAF values determined in the data analysis phase by 10%, 20%, 30% etc.;
- Decreasing the Initial LNAF values determined in the data analysis phase by 10%, 20%, 30% etc.

This approach would involve an I-SEM model, utilising the Plexos modelling software, which represents the scheduling and dispatch of the I-SEM in three phases:

- An “ex-ante market” model, an unconstrained model which represents trading in the ex-ante markets using the data as would be available during those timeframes. The results of this model can be used as a proxy for the (Final) Physical Notifications participants would submit, such that any deviation from this in other model phases can be determined as an SO action. For the purposes of this methodology this will be referred to as the “Day-ahead Market” or “DAM” model, but for the avoidance of doubt, it will be based purely on the modelling tools utilised for this methodology (i.e. Plexos), and is intended to broadly represent the results of all ex-ante market trading to the extent possible with the assumptions made;
- A “scheduling” model, a constrained model which represents the operation of Security Constraint Unit Commitment tools using the data as would be available during those timeframes, to represent the adjustments to the schedule which may be entered into by the SOs in ensuring system security through the application of Operational Constraints. It is in this phase of the model that the LNAFs would be introduced. For the purposes of this methodology this will be referred to as the “Long Term Schedule” or “LTS” model, but for the avoidance of doubt, it will be based purely on the modelling tools utilised for this methodology (i.e. Plexos), and is intended to broadly represent the results of all scheduling software runs which commit units for use in real-time balancing to the extent possible with the assumptions made;
- A “dispatch” model, a constrained model which represents the final dispatch arising from the operation of Security Constrained Economic Dispatch tools using outturn data rather than the forecast data used in other model runs and including forced outages, to represent any adjustments to the schedule required for imbalances such as unit trips, forecast errors, etc. It will take the

output of the "scheduling" model as a start point, with the unit commitment of a number of units fixed based on those results (for example, if long-notice units are not committed for a period in the "scheduling" model then their commitment will be fixed as off in the "dispatch" model. For the purposes of this methodology this will be referred to as the "Real Time Dispatch" or "RTD" model, but for the avoidance of doubt, it will be based purely on the modelling tools utilised for this methodology (i.e. Plexos), and is intended to broadly represent the final dispatch of the system to the extent possible with the assumptions made.

The results of the "dispatch" model can be compared with the results of the "ex-ante market" model to calculate volumes, and prices, of SO actions for that scenario. Results representing the state of the system (such as binding or breaching operational constraints) can be found from the "dispatch" model for that scenario. All three phases of the model would be run for each scenario in order to gather the required results, and scenarios will be set up such that there is a base case where no LNAF is applied and a number of scenarios where different values of LNAF are applied. Comparing the results for each scenario can help determine the optimal set of values to propose.

The LNAF only needs to be applied to LTS and RTD models, as the DAM stage represents ex-ante market trading and PN submission, the outcome of which would not be directly influenced by LNAF. Although they would not be applied to the RTD stage of scheduling in the actual operation of the system, it is required in both models for this piece of work to ensure equivalence between the outcomes of the schedules in both models, such that the only differences between the resulting schedules would be due to imbalances being introduced in the RTD model.

The following scenarios were considered, and how they were implemented through the different model components, in the modelling phase of the assessment as outlined in the table below. 0 gives further details about the modelling approach and assumptions.

Scenario Name	DAM	LTS	RTD
Base	Base	Base	Base
ILNAF	Base	Base & Initial LNAF applied to Start Cost input data	Base & Initial LNAF applied to Start Cost input data
ILNAFx1p1	Base	Base & 10% increase on Initial LNAF applied to Start Cost input data	Base & 10% increase on Initial LNAF applied to Start Cost input data
ILNAFx1p2	Base	Base & 20% increase on Initial LNAF applied to Start Cost input data	Base & 20% increase on Initial LNAF applied to Start Cost input data

Scenario Name	DAM	LTS	RTD
ILNAFx1p5	Base	Base & 50% increase on Initial LNAF applied to Start Cost input data	Base & 50% increase on Initial LNAF applied to Start Cost input data
ILNAFx2	Base	Base & 100% increase on Initial LNAF applied to Start Cost input data	Base & 100% increase on Initial LNAF applied to Start Cost input data
ILNAFx3	Base	Base & 200% increase on Initial LNAF applied to Start Cost input data	Base & 200% increase on Initial LNAF applied to Start Cost input data
ILNAFx0p9	Base	Base & 10% decrease on Initial LNAF applied to Start Cost input data	Base & 10% decrease on Initial LNAF applied to Start Cost input data
ILNAFx0p8	Base	Base & 20% decrease on Initial LNAF applied to Start Cost input data	Base & 20% decrease on Initial LNAF applied to Start Cost input data
ILNAFx0p5	Base	Base & 50% decrease on Initial LNAF applied to Start Cost input data	Base & 50% decrease on Initial LNAF applied to Start Cost input data

2.2.5 Criteria and Trade-offs

It is important to understand that the modelling results will be on the basis of the incentive but not on the response to the incentive. As such, the model cannot represent how participants may or may not react in their market participation in response to the impact of the application of the LNAF. While it would be expected that some longer notice units are less likely to be committed in the balancing market by the System Operators under this regime, it could equally be expected that such a participant would seek to ensure that their longer notice units are scheduled in the ex-ante markets or take steps, where possible, to reduce their notification times; however, these responses cannot be catered for in the model.

Also, in carrying out this modelling, the LNAF is applied in all scenarios. It is unlikely that the LNAF will be applied for all trading days given the application of the SIFF to assess whether the LNAF should be applied on a given trading day or not on the basis of the size of the market shortfall. However, the purpose of this modelling was to assess the impact of the application of the LNAF and, therefore, does not take account of this in the results.

2.3 Results and Analysis

2.3.1 Initial LNAF Calculation

The approach described above was applied to data from generator units in the SEM. The graph below shows, grouped by fuel type, the number of generators that would fall into specific Notice Time Groupings based on the number of whole hours included in their cold notification times.

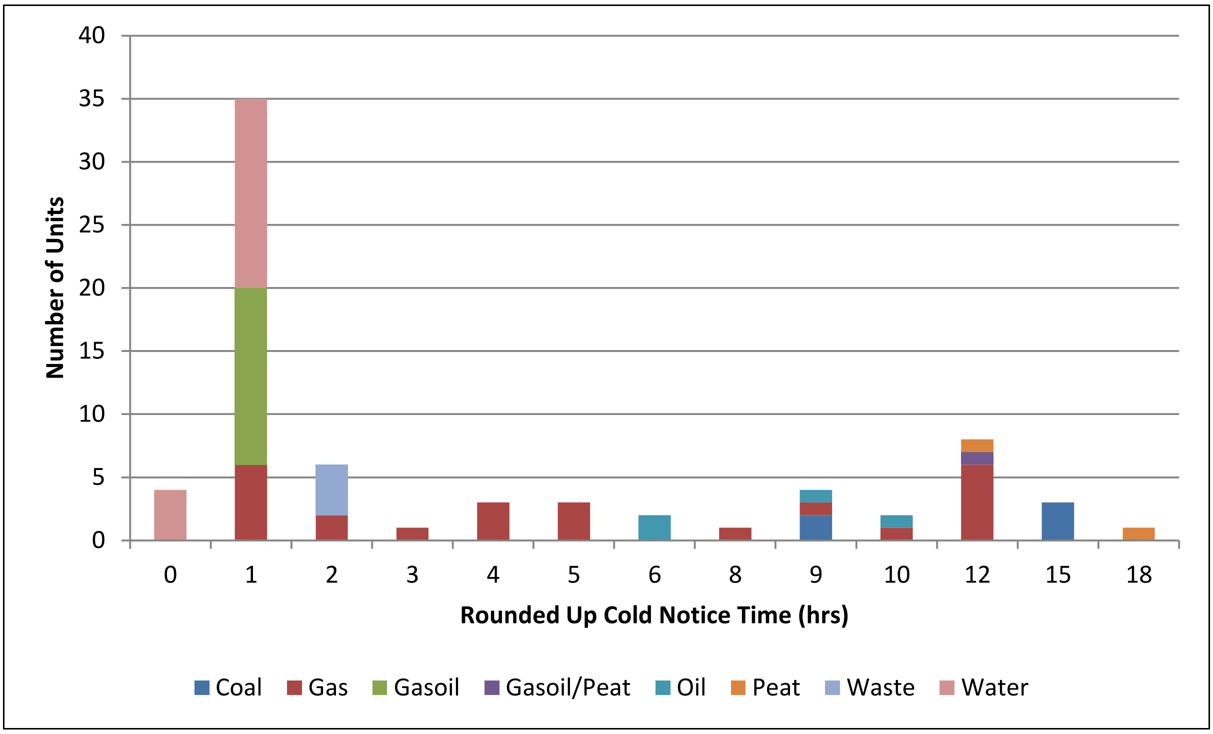

Figure 4: Cold Notice Time by Number of Units and Unit Type

This can also be represented as follows when considering the total MW of installed capacity for each of the generators in each of the Notice Time Groupings.

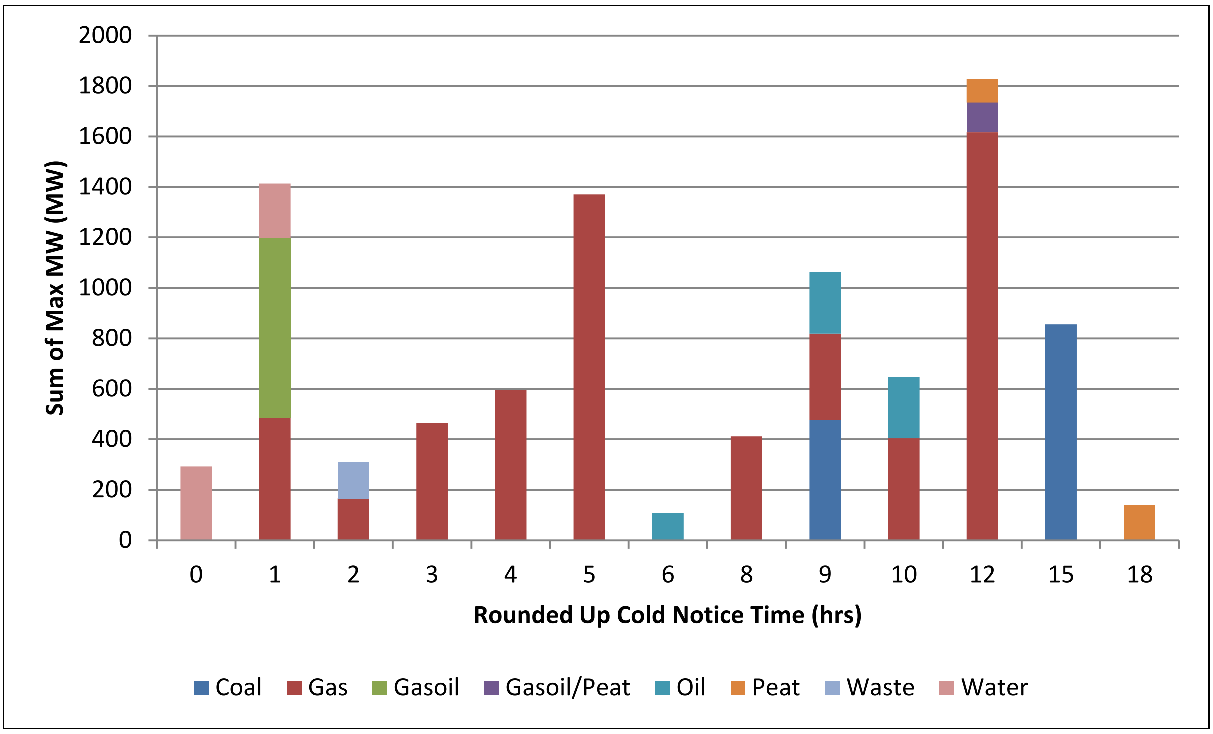

Figure 5: Cold Notice Time by Max MW and Unit Type

Applying the average cost as set out above, we determined the possibility of three approaches for Notice Time Groupings, shown in the following paragraphs.

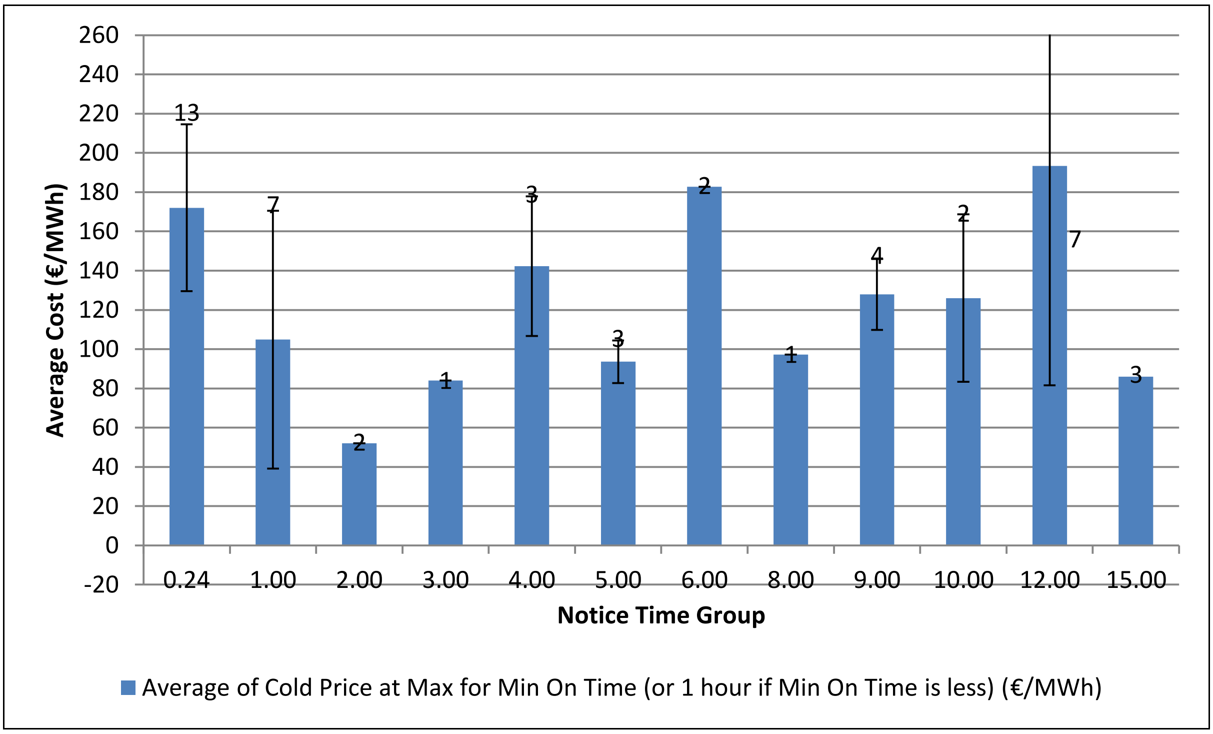

Figure 6: Average Cost and Standard Deviation per Notice Time Grouping 1 - Distribution by Notice Time, Unit Types and Grouping of Prices - Excluding Close-to-Zero Cost Units

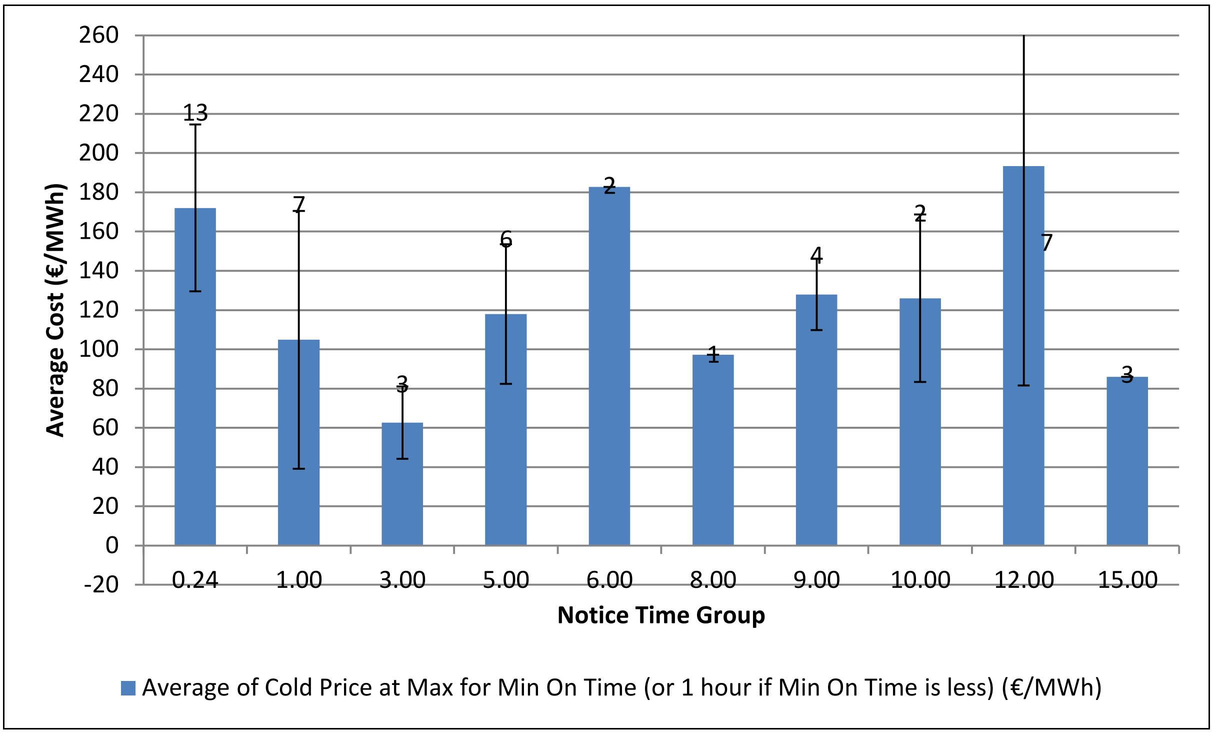

Figure 7: Average Cost per Notice Time Grouping 2 - Distribution by Notice Time, Unit Types and Grouping of Prices - Excluding Close-to-Zero Cost Units

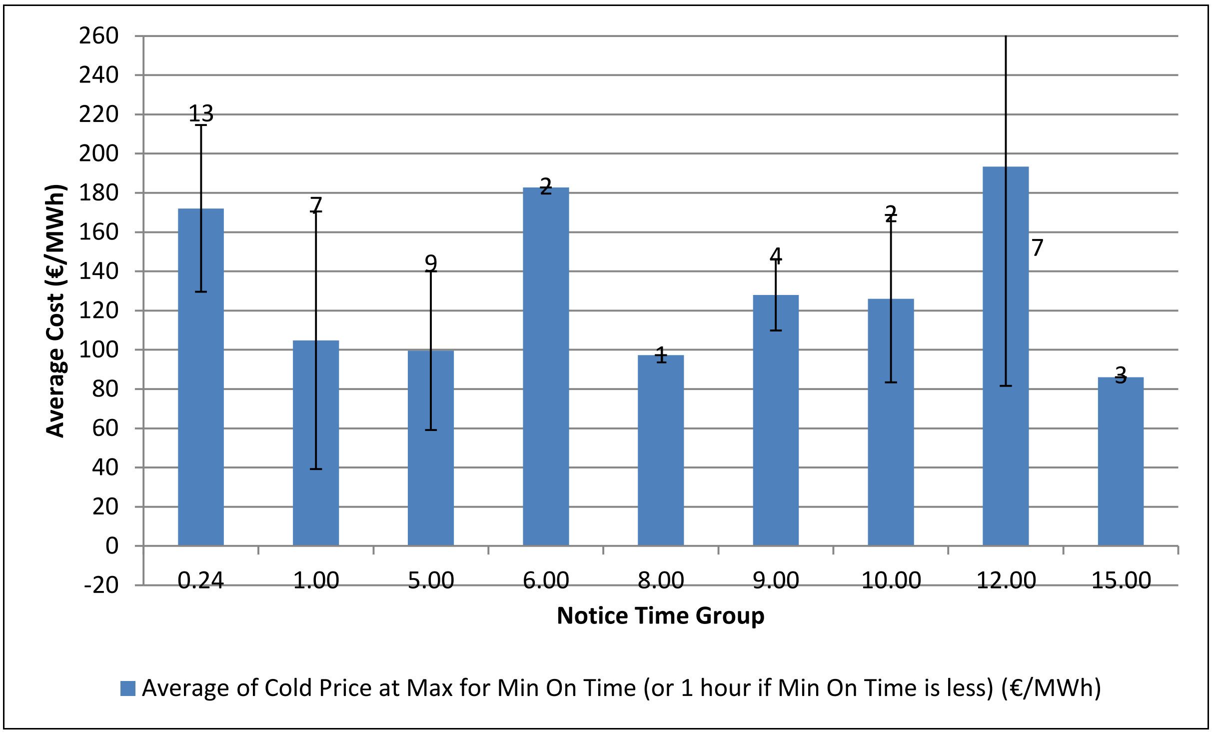

Figure 8: Average Cost per Notice Time Grouping 3 - Distribution by Notice Time, Unit Types and Grouping of Prices - Excluding Close-to-Zero Cost Units

In each of these potential groupings, the units with notice times of less than one hour were split between those with cold notice times of less than 0.24 hours and others.

This is because the types of units, and the relative magnitude of the costs of the units, were very widely spread when considering all of these units together, and splitting them out allowed for the higher cost of the units with less than 0.24 hours' notice to be explicitly considered in the calculation of the initial LNAF, rather than potentially dampening the cost against which others would be measured in order to calculate the initial LNAF.

Based on these potential groupings of units and their costs, the Initial Long Notice Adjustment Factors were calculated based on Notice Time Grouping 2 (Figure 7). The rationale behind this was that there were a smaller number of units considered in the 3 hours' Notice Time Group with relatively similar costs, while under the 2 hours' Notice Time Group under Notice Time Grouping 1 was based on a single participant whose units had the exact same cost, and the 5 hours' Notice Time Group under Notice Time Grouping 3 had a wide range of costs setting the average, as shown by the standard deviation bars. Also Notice Time Grouping 2 resulted in Initial LNAFs which were between those calculated for the other groupings, and since the approach for determining the LNAF includes a modelling phase where a range of increases and decreases from the Initial LNAF are considered, a range of potential scenarios for the LNAF could be modelled.

Table 1 outlines the factors calculated to apply to start costs of units in different notice time groupings based on this set of Average Equivalent Prices, and interpolating/extrapolating between values as required:

Notice Time Group	Start Cost Multiplier for Model	Initial LNAF
0	1	0
1	1	0
2	2.21	1.21
3	3.43	2.43
4	4.64	3.64
5	5.86	4.86
6	7.07	6.07
7	8.29	7.29
8	9.5	8.5
9	10.71	9.71
10	11.93	10.93
11	13.14	12.14
12	14.36	13.36
13	15.57	14.57
14	16.78	15.78
15	18	17
16	19.21	18.21
17	20.43	19.43
18	21.64	20.64
19	22.86	21.86
20	24.07	23.07

Notice Time Group	Start Cost Multiplier for Model	Initial LNAF
21	25.28	24.28
22	26.5	25.5
23	27.71	26.71
24	28.93	27.93
25	30.14	29.14
26	31.35	30.35
27	32.57	31.57
28	33.78	32.78
29	35	34
30	36.21	35.21

Table 1: Initial LNAF and Resulting Start Cost Multiplier to be Applied to the Modelling Phase of the Assessment

2.3.2 Modelling Phase Results

In reviewing the results of the modelling, it is important to remember that the focus of model is qualitative outcomes and the emphasis is on understanding the dynamics that follow from the application of the LNAF. The aim of model is not to predict future, but to determine relationships between the parameters and scheduling process. As such, the focus is clearly on whether the results represent the desired impacts of a reduction in the number of starts of longer notice units over shorter notice units in the balancing timeframe. However, the potential increase in costs and impacts on system security that appear to arise are of significance also.

The dynamics observed arise due to balance of the incentives between timeframes; however, ultimately some form of equilibrium will emerge based on behavioural changes that arise in response to the signal, e.g. in response day-ahead and balancing market prices, participants may develop more active trading strategies to manage their imbalances in the intraday market; in response to less running hours in the BM, participants may focus their trading strategies on the ex-ante markets. It is important to understand that this modelling does not represent the final equilibrium point. It represents the signal but not the response.

The first key observation from the modelling results is that with the application of the LNAF in the modelling, there is a significant shift of all units starts from longer to shorter notice plant with an observable reduction in the use of units with notice times longer than 2 hours. The table below shows an increase in starts across the study of over 2500 (from value of initial LNAF up) from the original base case with significant reductions in the number of starts in most other areas (with the exception of the outlier at 6 hours where additional starts appear to have been incurred due to the relatively lower cost of the units in this group).

Notice Time Group	Base	ILNAF x0p5	ILNAF x0p8	ILNAF x0p9	ILNAF	ILNAF x1p1	ILNAF x1p2	ILNAF x1p5	ILNAF x2	ILNAF x3
1	10193	12247	12549	12625	12768	12771	12761	12864	12949	12882
2	57	73	83	83	82	82	82	81	76	73
3	81	10	10	10	10	10	10	10	9	9
4	181	33	27	26	26	26	26	26	28	27
5	115	70	35	35	35	33	35	34	29	28
6	0	16	33	33	52	51	48	46	47	46
7	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
8	25	27	23	20	17	17	16	13	13	13
9	22	14	14	13	14	14	13	14	12	13
10	89	7	4	4	4	4	4	4	4	4
11	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
12	44	1	1	1	1	1	1	1	1	1
13	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
14	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
15	26	3	1	1	1	1	1	1	1	1
Interconnector	0	0	0	0	0	0	0	0	0	0
Total	**10833**	**12501**	**12780**	**12851**	**13010**	**13010**	**12997**	**13094**	**13169**	**13097**

Table 2: Total Unit Starts by Notice Time

Taking this back to the fuel type, the table below shows how these results affect the running of the different unit types. Of note here is the higher usage of Demand Side Units in the schedule as well as the significantly increased number of starts for distillate units. These artefacts need to be considered as this represents a different profile of operation for these type of units. Demand Side Units are called for provision of energy in a manner that is unlikely to have been considered in their original design. The increased level of starts for distillate units may see more two-shifting behaviour, similar to that observed at the start of the SEM for mid-merit units which led over time to an increase in their start costs. A similar outcome for distillate units as a result of the application of the LNAF may not be a desired result.

Fuel Type	Base	ILNAF x0p5	ILNAF x0p8	ILNAF x0p9	ILNAF	ILNAF x1p1	ILNAF x1p2	ILNAF x1p5	ILNAF x2	ILNAF x3
DSU	84	267	344	369	374	371	385	402	382	385
Oil	0	16	33	33	52	51	48	47	48	47
Distillate	864	2069	2551	2623	2668	2662	2705	2729	2737	2729
Coal	31	11	9	8	9	9	8	8	6	7
Gas OCGT	2235	2454	2229	2212	2227	2226	2202	2211	2247	2259
Gas CCGT	552	154	106	102	99	97	98	94	90	88
Storage	637	592	607	606	600	592	599	598	609	602
Peat	130	151	133	135	134	133	132	134	136	134
Biomass, Biogas, LFG, WtE	35	35	43	40	39	39	31	35	33	36
Hydro	6048	6495	6437	6430	6518	6545	6500	6553	6609	6538

Fuel Type	Base	ILNAF x0p5	ILNAF x0p8	ILNAF x0p9	ILNAF	ILNAF x1p1	ILNAF x1p2	ILNAF x1p5	ILNAF x2	ILNAF x3
CHP	95	130	162	169	162	161	166	162	149	146
Tidal	115	117	115	115	117	116	116	113	115	114
Other Renewables	7	10	11	9	11	8	7	8	8	12
Wind	0	0	0	0	0	0	0	0	0	0
Interconnector	0	0	0	0	0	0	0	0	0	0
Total	**10833**	**12501**	**12780**	**12851**	**13010**	**13010**	**12997**	**13094**	**13169**	**13097**

Table 3: Total Unit Starts by Fuel Type

The following tables consider the level of start-up as the variance between units starting in the ex-ante market and the balancing timeframe. This represents the delta between the decisions that are affected directly by the application of the LNAF. Again, we see the expected result of units with shorter notice times being started more frequently in the balancing timeframe and a reduction in the number of starts for longer notice plant (represented here as a negative number). The lack of change with respect to starts on group 9 relates to the model keeping units on rather than turning them off and re-starting again.

Notice Time Group	Base	ILNAF x0p5	ILNAF x0p8	ILNAF x0p9	ILNAF	ILNAF x1p1	ILNAF x1p2	ILNAF x1p5	ILNAF x2	ILNAF x3
1	2409	4463	4765	4841	4984	4987	4977	5080	5165	5098
2	16	32	42	42	41	41	41	40	35	32
3	-17	-88	-88	-88	-88	-88	-88	-88	-89	-89
4	-682	-830	-836	-837	-837	-837	-837	-837	-835	-836
5	-25	-70	-105	-105	-105	-107	-105	-106	-111	-112
6	0	16	33	33	52	51	48	46	47	46
7	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
8	-72	-70	-74	-77	-80	-80	-81	-84	-84	-84
9	8	0	0	-1	0	0	-1	0	-2	-1
10	-18	-100	-103	-103	-103	-103	-103	-103	-103	-103
11	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
12	-48	-91	-91	-91	-91	-91	-91	-91	-91	-91
13	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
14	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
15	-50	-73	-75	-75	-75	-75	-75	-75	-75	-75
Interconnector	0	0	0	0	0	0	0	0	0	0
Total	**1521**	**3189**	**3468**	**3539**	**3698**	**3698**	**3685**	**3782**	**3857**	**3785**

Table 4: Unit Starts, Real Time Dispatch vs DAM by Notice Time

The data when applied by fuel type continues to demonstrate that the application of the LNAF in the scheduling process will tend to select short notice units over long notice ones.

Fuel Type	Base	ILNAF x0p5	ILNAF x0p8	ILNAF x0p9	ILNAF	ILNAF x1p1	ILNAF x1p2	ILNAF x1p5	ILNAF x2	ILNAF x3
DSU	74	257	334	359	364	361	375	392	372	375
Oil	0	16	33	33	52	51	48	47	48	47
Distillate	441	1646	2128	2200	2245	2239	2282	2306	2314	2306
Coal	-45	-65	-67	-68	-67	-67	-68	-68	-70	-69
Gas OCGT	296	515	290	273	288	287	263	272	308	320
Gas CCGT	-859	-1257	-1305	-1309	-1312	-1314	-1313	-1317	-1321	-1323
Storage	19	-26	-11	-12	-18	-26	-19	-20	-9	-16
Peat	96	117	99	101	100	99	98	100	102	100
Biomass, Biogas, LFG, WtE	-1	-1	7	4	3	3	-5	-1	-3	0
Hydro	1400	1847	1789	1782	1870	1897	1852	1905	1961	1890
CHP	15	50	82	89	82	81	86	82	69	66
Tidal	98	100	98	98	100	99	99	96	98	97
Other Renewables	-13	-10	-9	-11	-9	-12	-13	-12	-12	-8
Wind	0	0	0	0	0	0	0	0	0	0
Interconnector	0	0	0	0	0	0	0	0	0	0
Total	**1521**	**3189**	**3468**	**3539**	**3698**	**3698**	**3685**	**3782**	**3857**	**3785**

Table 5: Unit Starts, Real Time Dispatch vs DAM by Fuel Type

In terms of average hours of operation, the results show increases in the running hours of units in the 3 – 5 notice time groups which is brought about by extending the running for these generators as this becomes more economic than de-committing and re-committing them (when considering the LNAF adjusted start cost of these units). Interestingly, while there is an increase in the number of starts for notice time groups 1 and 2 as noted above, this does not always translate into a significant increase in average running hours. This would again give rise to a concern that there may be more instances of two-shifting of shorter notice generators than in the base case.

Notice Time Group	Base	ILNAF x0p5	ILNAF x0p8	ILNAF x0p9	ILNAF	ILNAF x1p1	ILNAF x1p2	ILNAF x1p5	ILNAF x2	ILNAF x3
1	3203.31	3551.46	3690.73	3715.58	3747.56	3750.29	3769.17	3794.25	3813.58	3822.96
2	8129.25	8106.5	8085.25	8084.5	8080.25	8079.25	8078.5	8059	7983.5	7852
3	5336	8251	8219	8219	8219	8219	8219	8219	8163	8261
4	6814.33	7354.33	7362.67	7365.67	7382.67	7378.33	7382.67	7382.33	7356.33	7222.33
5	3258.33	6498.67	7634.67	7618	7619.33	7602.33	7628	7601	7536	7483.67
6	0	51	126	122.5	246	249.5	227	257	219	186
7	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
8	6491	3534	3032	2817	2241	2239	2153	1887	1876	2161
9	942.75	1428.5	1785.25	1787.5	1813	1843	2164.5	2171.75	2238.5	2236.25
10	1472.5	2500	700	700	699.5	699.5	699.5	699.5	699.5	699.5
11	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Notice Time Group	Base	ILNAF x0p5	ILNAF x0p8	ILNAF x0p9	ILNAF	ILNAF x1p1	ILNAF x1p2	ILNAF x1p5	ILNAF x2	ILNAF x3
12	6702	1857.5	1869.5	1869.5	1869.5	1869.5	1154.5	1154.5	1142.5	1142.5
13	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
14	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
15	7750	1718	430	430	430	430	430	430	430	430
Interconnector	4566.5	5493.25	5657.75	5686.25	5726.75	5758	5751.5	5764.5	5796	5789.5

Table 6: Average Hours of Operation by Notice Time

Considering the average hours of operation by fuel type, it can be seen that the bulk of the increase in running hours of the Notice Time Group 1 units is again met by increases in running hours of Demand Side Units.

Fuel Type	Base	ILNAF x0p5	ILNAF x0p8	ILNAF x0p9	ILNAF	ILNAF x1p1	ILNAF x1p2	ILNAF x1p5	ILNAF x2	ILNAF x3
DSU	67	354	523.5	553	608.5	603	661	709	722	735.5
Oil	0	25.5	63	61.25	123	124.75	113.5	135.75	119	102.5
Distillate	118.57	552.29	927	985.29	1041.21	1039.57	1076.5	1123.64	1150.71	1173
Coal	5136.4	1313.6	530.8	532.6	553	577	554.8	554.8	606.4	604.6
Gas OCGT	1300	2450.57	2702.71	2734	2782.86	2799.29	2825	2868.14	2898.43	2904
Gas CCGT	4977.75	5529.92	5596.58	5575.25	5531.75	5526.25	5523.83	5494.83	5464.5	5449.83
Storage	4621	4736	4546	4548	4560	4566	4554	4566	4578	4599
Peat	3857	4578	4462	4477	4525	4515	4543	4585	4652	4656
Biomass, Biogas, LFG, WtE	8588	8584.6	8577.8	8581.4	8584.4	8585.2	8587.8	8586.8	8586.6	8584.8
Hydro	4637.88	4718.69	4705.38	4708.5	4721.69	4724.06	4728.38	4733.36	4746.38	4751.25
CHP	8159.67	8100	8035.67	8035.67	8032.33	8034	8030	8008	7918.33	7737.33
Tidal	7726	7725	7729	7731	7732	7737	7734	7738	7733	7733
Other Renewables	8769	8757	8749	8758	8763	8761	8768	8765	8766	8761
Wind	8784	8784	8784	8784	8784	8784	8784	8784	8784	8784
Interconnector	4566.5	5493.25	5657.75	5686.25	5726.75	5758	5751.5	5764.5	5796	5789.5

Table 7: Average Hours of Operation by Fuel Type

We also consider the changes to Production Cost observed across the different study runs. In this model, total SEM production costs represents units located in Ireland and Northern Ireland while GB Production costs relate to the costs of imports. The combined value represents the total production costs of the modelling runs. Looking across the results, this shows significant increases in production costs as a result of the application of the LNAF. This should be expected as the decision to require the TSO to operate the system on a “last time to order” basis does mean that the TSO should forego cheaper longer notice units in favour of more expensive fast acting units that can be activated after Balancing Market Gate Closure.

However, we should also restate that this modelling work is based on assessing the impact of the application of the LNAF and not predicting how the market will respond to its application (such as revised trading strategies in the ex-ante markets for longer notice plant, etc). Also, the values here do not consider the System Shortfall Imbalance Index and thus, apply the LNAF in all cases. Again, the model does not attempt to consider whether participants would react to the LNAF application (or other operations or pricing parameters) by trading into long positions in the ex-ante markets thereby setting the SIFF in a manner so as not to trigger its application.

These numbers as such do not attempt to predict the change in production cost that could arise as a result of the application of the LNAF but does provide observations on modelling outcomes in scenarios where there is no response from the market to the signal. Note that the fixed cost element of the production costs were calculated using the non-LNAF adjusted start-up cost information, rather than the LNAF-adjusted costs. The GB element of the production costs is calculated as a consideration of the dummy generators and BETTA price profile used to model interconnection with the BETTA market.

	Base	ILNAF x0p5	ILNAF x0p8	ILNAF x0p9	ILNAF	ILNAF x1p1	ILNAF x1p2	ILNAF x1p5	ILNAF x2	ILNAF x3
Total SEM Production Costs (€bn)	€1.148	€1.135	€1.157	€1.160	€1.162	€1.161	€1.163	€1.166	€1.166	€1.168
Total SEM Difference vs Base (€bn)	**€ -**	**- €0.013**	**€0.009**	**€0.012**	**€0.014**	**€0.013**	**€0.015**	**€0.018**	**€0.018**	**€0.020**
Total SEM+GB Production Costs (€bn)	€1.375	€1.454	€1.493	€1.497	€1.503	€1.503	€1.506	€1.510	€1.513	€1.515
Total SEM+GB Difference vs Base (€bn)	**€ -**	**€0.079**	**€0.118**	**€0.122**	**€0.128**	**€0.128**	**€0.131**	**€0.135**	**€0.138**	**€0.140**

Table 8: Production Costs (€bn)

The following tables include results of some critical operational security indicators. The results indicate a trend towards more frequently binding security constraints and deterioration of some of these indicators, albeit in a small number of periods.

Element	Base	ILNAF x0p5	ILNAF x0p8	ILNAF x0p9	ILNAF	ILNAF x1p1	ILNAF x1p2	ILNAF x1p5	ILNAF x2	ILNAF x3
SEM POR Spinning (hrs)	3	22	34	38	40	41	40	41	51	62
SEM POR Total (hrs)	3	31	48	51	63	72	62	76	84	89
SEM SOR (hrs)	3	28	43	47	53	55	55	61	69	77
SEM TOR1 (hrs)	4	46	71	77	88	94	99	109	116	123
SEM TOR2 (hrs)	4	46	71	77	88	94	99	109	116	123

Table 9: Hours of Reserve Shortage

Element	Base	ILNAF x0p5	ILNAF x0p8	ILNAF x0p9	ILNAF	ILNAF x1p1	ILNAF x1p2	ILNAF x1p5	ILNAF x2	ILNAF x3
SNSP Limit (hrs)	1182	1142	1122	1118	1128	1125	1124	1124	1127	1116
NI Min Units (hrs)	1091	1512	1546	1544	1703	1681	1702	1702	1680	1653
ROI Min Units (hrs)	343	872	1359	1371	1385	1385	1385	1385	1385	1434
SEM Inertia (hrs)	6029	6992	7040	7049	7099	7069	7148	7170	7207	7182
SEM POR Spinning (hrs)	3120	3203	2906	2861	2805	2802	2789	2749	2790	2798
SEM POR Total (hrs)	433	1449	1849	1878	1932	1923	1939	1983	1977	1978
SEM SOR (hrs)	7	37	55	56	66	67	71	75	83	91
SEM TOR1 (hrs)	2899	2405	2140	2160	2204	2227	2281	2300	2326	2329
SEM TOR2 (hrs)	144	95	150	164	173	169	154	163	164	171

Table 10: Hours of Constraints Binding

Scenario	Hours of Unserved Energy
Base	2
ILNAFx0p5	11
ILNAFx0p8	18
ILNAFx0p9	19
ILNAF	19
ILNAFx1p1	18
ILNAFx1p2	20
ILNAFx1p5	22
ILNAFx2	26
ILNAFx3	32

Table 11: Hours of Unserved Energy

The following figures show the percentage of energy provided by different unit types for both the base case and the ILNAF case. They indicate that the introduction of an LNAF reduces the provision of energy from coal plant, largely being replaced by Gas CCGT plant. It also results in a reduction cross border flows from a net export position of 4% of generation to almost zero net position.

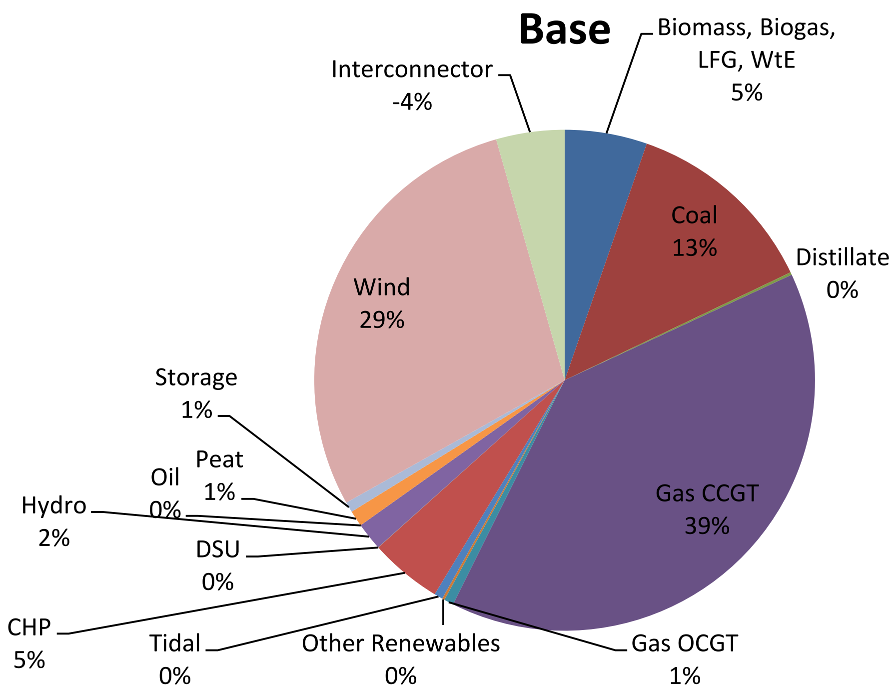

Figure 9: Annual Energy Provision by Unit Type for Base Case

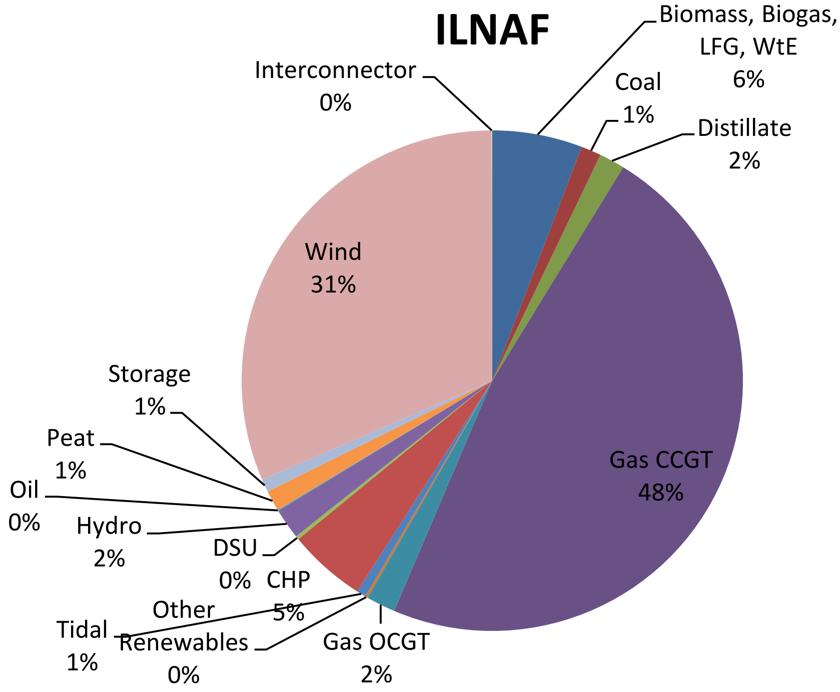

Figure 10: Annual Energy Provision by Unit Type for ILNAF Case

The following sections set out the views of the TSOs with respect to the obligations framework discussed in section 2.1 and in the Balancing Market Principles Statement and the impact of the results as presented above.

2.3.3 Ensuring Operational Security

Binding Constraints

LNAFs generally lead to increases in the number of periods in which system constraints are binding. This is particularly the case for jurisdictional minimum number of unit constraints where larger units (which are also longer notice units) are required to maintain system stability. There are also some decreases in the number of periods in which reserve constraints are binding – this could be due to the replacement of larger units with smaller units and a reduction in the 'Largest System Infeed' leading to reduced reserve requirements. However, there is also an increase in the number of periods of reserve shortfall (i.e. insufficient reserve to meet the requirement) and unserved energy (i.e. load shedding).

Reserve Scarcity & Unserved Energy

The scheduling and dispatch optimisation process prioritises operational security. While the schedule should only allow the LNAF adjusted utilisation of short notice units over long notice units when security can be maintained (and should also only allow this provided Priority Dispatch is maintained as discussed in the next section) the modelling results demonstrate that this is not always the case.

While the scheduling optimisation is designed to develop schedules that are balanced (i.e. matching supply and demand) and secure for normal contingency events (e.g. tripping of the Largest Single Infeed) with and without LNAFs applied, it may at times not be possible to satisfy all constraints. This can be due to unavailability of the required units or for abnormal events, e.g. tripping of multiple units or larger than expected changes to wind output. In such events, reserve requirements may not be met and/or load shedding may be required as there is insufficient spare capacity available.

This impact is more pronounced as LNAFs are applied as the level of spare available short notice capacity is reduced. Short notice units can be used to generate energy, provide reserve (on-line or off-line) or they can be off-line and surplus to energy and reserve requirements (although still available to provide energy and reserve if required). The application of LNAFs will tend to utilise more short notice units to provide energy and reserve (replacing the energy and reserve provided by the longer notice units which are not scheduled to run) and so will tend to reduce the availability of spare short notice units. This effect is illustrated in the Figure below. Note that longer notice units cannot be counted for short notice reserve if they are not on-line.

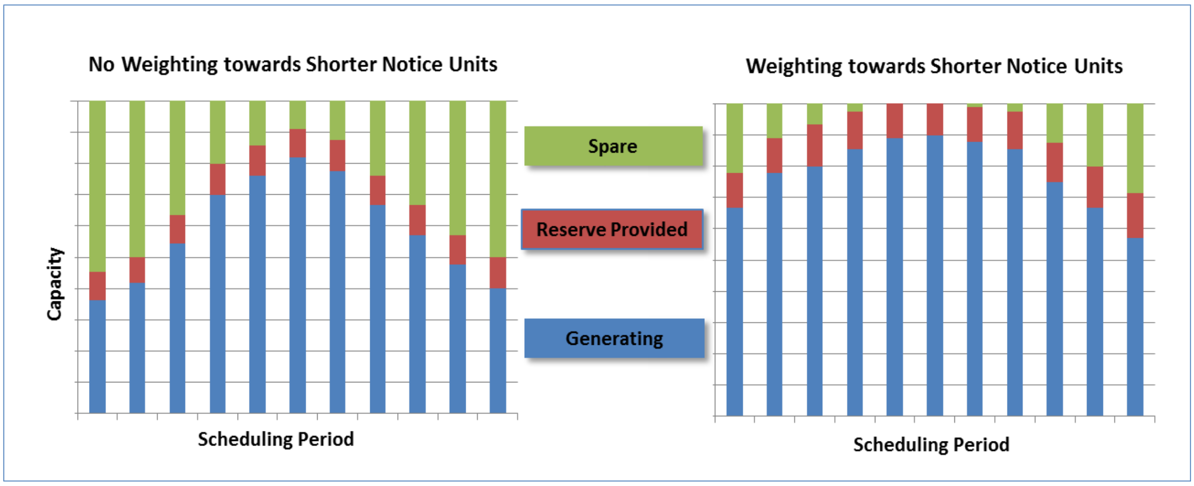

Figure 11: Illustration of Impact of LNAFs on Short Notice Units

The result is that during abnormal events it may not be possible to meet reserve requirements (reserve scarcity) and it may not be possible to meet all demand requirements (unserved energy).

Note that in reality, additional reserves may need to be scheduled to address increased risks to operational security. However, this would counteract the impact of the LNAFs and would add to balancing costs. The impact of scheduling additional reserves was not modelled.

Other Operational Impacts

The results indicate that application of LNAFs lead to significant changes in the utilisation of certain unit types. The main impacts are:

- Energy from long notice coal units is largely replaced with energy from shorter notice CCGT units; and
- Utilisation of short notice units such as DSUs, Peakers and OCGTs increases significantly although their energy contribution remains low given their installed capacity.

Such significant changes are likely to have impacts on the operating model of these units. Such impacts have been shown previously in SEM when increased 'two-shifting' of units led to changes in operating costs. DSU costs and availability reflect their relative infrequent running achieved today but a significant increase in capacity factor could fundamentally change this model. Peakers and OCGTs have emissions limits that are more likely to bind with increased capacity factor. These knock-on impacts have not been considered in the analysis.

In summary, the modelling results indicate that the application of LNAFs will tend to increase the binding nature of constraints and increase the probability of reserve scarcity and load shedding events under abnormal system conditions. There are also potential issues arising for specific unit types resulting from fundamental changes to their utilisation.

2.3.4 Maximising Priority Dispatch Generation

The results indicate that LNAFs have no material impact on priority dispatch generation, i.e. do not increase curtailment of priority dispatch generation.

As with the requirement to maintain operational security, the maintenance of priority dispatch generation is given priority over the application of LNAFs. The results indicate that even with the changes to the scheduling of other non-priority dispatch units, there is no adverse impact on priority dispatch generation although there are other negative impacts on operational security. These outcomes are discussed below.

Any unforeseen increase in wind levels should be matched with a decrease in non-priority dispatch unit output (subject to system security being maintained). In a scenario with LNAFs applied, leading to less long notice and more short notice units, the flexibility of shorter notice units to respond in such a scenario would not exacerbate any potential wind curtailment.

Any unforeseen decrease in wind levels should be matched with an increase in non-priority dispatch unit output. In a scenario with LNAFs applied, leading to less long notice and more short notice units, there would be greater potential for a reserve scarcity event or load shedding as discussed under obligation 1. In reality, additional reserves may need to be scheduled to address these risks. This would add to costs and potentially lead to additional curtailment of wind to 'make room' for the reserves.

In summary, the modelling results indicate that LNAFs have no material impact on Priority Dispatch generation.

2.3.5 Efficient Operation of the SEM

The analysis demonstrates the intended outcome of applying the LNAFs, i.e. that the factors effectively weight the schedule towards shorter notice units. However this is achieved at the expense of potentially significant increases in costs that will ultimately be borne by the market.

The TSOs Licence Objectives

The following section discusses the impact of LNAFs with respect to the following market related objectives set out in the TSOs Licences published on the 10th of March 2017:

(a) minimising the cost of diverging from physical notifications;

(b) as far as practical, enabling the Ex-Ante Market to resolve energy imbalances ; and

(c) as far as practical, minimising the cost of non-energy actions by the Licensee

The purpose of the LNAFs is to address objective (b) above by weighting the scheduling and dispatch process towards shorter notice units thus enabling Participants (rather than the TSOs) to resolve energy imbalances in the ex-ante markets. The results indicate that this objective is achieved through increased utilisation of short notice units over long notice units. Such an outcome should incentivise units with longer notification times to decrease these times so that they can reduce the impact of the LNAFs on their units and maintain their availability in the balancing market for longer. Balanced ex-ante markets and decreases in unit notification times will reduce the necessity for the TSOs to take actions during the intraday timeframe and lead to more efficient operation of the market.

While the analysis did not specifically identify the outcome with respect to objectives (a) and (c), the results provide a proxy for this by identifying significant increases in production costs with the application of LNAFs. So application of LNAFs will counter objectives (a) and (c).

This is an expected result of the application of LNAFs as the model essentially adjusts the merit order so that expensive short notice units appear more economic to run than cheaper long notice units. When actual costs are applied to the resulting schedule, higher overall production costs are observed.

SEM and GB Production Costs

It is important to consider the SEM and GB changes to production costs as a significant proportion of the costs result from increased imports from GB to SEM. This change to interconnector schedules reflects the utilisation of short notice capacity in GB which, in the model, appears more economic than some short notice capacity in SEM. These changes to the interconnector schedules would in reality be achieved by cross-zonal TSO initiated trades (post cross-zonal intraday market activity) and would rely on the availability of trades from a GB party (possibly the GB

TSO). However, the availability of such trades cannot be guaranteed nor is the mechanisms to trade agreed at this time. If cross-zonal trading was not possible then additional, more expensive, short term SEM capacity would be utilised if available. The resulting GB production cost would decrease but the SEM production cost would increase by more.

In summary, the modelling results indicate that LNAFs effectively weight the schedule towards shorter notice units but result in potentially significant increases in production costs.

2.3.6 Provision of Transparency

The optimisation process that produces schedules is extremely complex with many inputs, multiple objectives and continuously updated outputs. The addition of LNAFs will add to the complexity of this process and the potential difficulty in predicting and explaining its output.

However, to aid transparency, the policy parameters will be published and their application in the scheduling and dispatch process described in the Balancing Market Principles Statement. This will allow interested Participants to model their impact.

The TSOs will also prepare an annual report into the performance of the policy parameters and the scheduling and dispatch process will be audited to ensure compliance with policy objectives (subject to RA determination of Terms of Reference for this audit).

In summary, while transparency considerations have not been a part of this modelling process, the complexity and impact of these parameters is likely to reduce transparency of the scheduling and dispatch process.

2.4 Recommendation

The modelling work carried out thus far has demonstrated that the curve of LNAF values as applied will result in operational scheduling outcomes that favour short notice units over long notice ones and thus provide for a systemised implementation of the decision to operate the power system on a “last time to order” basis. However, the results include many risk indicators such as:

- increased hours of reserve shortage;
- increased hours of un-served energy;
- increased instances of starts/two shifting on short notice units;
- increased running of demand side units for energy production;
- decreased running hours for longer notice generators; and
- increased production costs (and thereby consumer costs) as the TSO foregoes cheaper generators in favour of expensive short notice units.

While every effort has been taken in the modelling work carried out, this cannot be a substitute to the actual market and system operation experience that will be gained after go-live. The transition from SEM to I-SEM is the most significant change in market and power system operation in Ireland and Northern Ireland in over ten years and its success is dependent on externalities such as the success of the ex-ante trading arrangements, particularly the liquidity of the intraday market. Given the large number of unknowns, we believe the application of the LNAF needs to be considered in this light.

As such, the TSOs propose that the value of LNAF is set to zero at market start and for a period of one year thereafter.

During the first year of actual operation of the I-SEM, SEMO and the TSOs can carry out further sensitivity analysis around the LNAF curve developed for these studies to assess if a lower gradient can deliver the intent with less risk. After a period of live operation, SEMO and the TSOs will carry out analysis on the results of actual market activity and system operation to consider ex-ante participation, and particularly, intraday market liquidity, the level to which TSO actions are impacting on the intraday market and the impacts of setting a non-zero value of LNAF. SEMO and the TSOs will provide a report to the Regulatory Authorities at that point making a further recommendation with respect to the application of the LNAF in the System Operator's scheduling systems to systemise the implementation of a "last time to order" policy.

3. System Imbalance Flattening Factor and System Shortfall Imbalance Index Curve

3.1 Background

The System Imbalance Flattening Factor (SIFF) curve will consist of a SIFF value per System Shortfall Imbalance Index (SSII) range of values. The SSII value is based on a calculation of the overall level of shortfall over the Trading Day as a proportion of total demand energy in that Trading Day. The overall level of shortfall over the Trading Day is determined by comparing the aggregate PN curve, including any forecasts for generator units which do not submit PNs such as wind units which are not dispatchable, with the forecast demand curve, and summing the energy amounts which arise from when the demand curve is in excess of the aggregate PN curve. Therefore the SIFF value is the extent to which the LNAF has effect in a Trading Day given the level of SSII in that Trading Day.

A simple idea of how this would work would be as follows:

- To increase SIFF with increasing SSII (i.e. increasing imbalance, all other things held equal) such that the LNAF would prevent the scheduling of longer notice units to resolve the imbalance in situations where the drivers for energy balancing actions are greater than the drivers for non-energy actions; and
- To decrease SIFF with decreasing SSII such that the LNAF does not prevent the scheduling of longer notice units if they are the most economically efficient solution to resolve a constraint in situations where the drivers for non-energy balancing actions are greater than the drivers for energy actions.

Alternatively, it could be considered that the SIFF is a binary flag and, rather than further scaling participant’s costs, it simply sets whether the LNAF is applied on a given trading day or not. This approach could have benefits of transparency and simplicity for participants who intend forecasting the impact of the LNAF and SIFF on their trading strategies.

There will be many situations where there are overlapping drivers for energy and non-energy actions, and it is not likely that there would be a single set of values which would adequately meet both of these objectives. Therefore, in the analysis of different scenarios put forward for potential values, an assessment of the trade-offs between these objectives needs to be considered.

3.2 Considerations

3.2.1 System Imbalance Flattening Factor Approach

The requirements for the development of initial values to be used as modelling scenarios for SIFF and SSII can be thought of separately:

- For SSII, analysis is required of the typical level of system shortfall which would result in energy actions being taken with longer notice, cheaper, plant, and a relationship established between the increase in system shortfall with the increase in taking longer notice, cheaper, actions; and
- For SIFF, analysis would be required of the extent to which it is desired to have LNAF influencing the schedule at the level of SSII, in terms of the relationship between the level of LNAF influence, the resulting desired outcomes.

As the SIFF relates to the level to which the LNAF curve will be active or inactive, its values should be determined taking into account the values of the LNAF curve as an input. For example, LNAF values could be calculated in such a way that they perfectly equalize the relative cost of longer notice and shorter notice units, such that by having a SIFF value equal to 1 that the LNAF value would apply and therefore the intended outcomes of having LNAF at that value could arise in those situations. It would follow then that by having a SIFF value less than 1 then the LNAF would be partially active and therefore the value of SIFF would need to be justified based on the intended outcomes being achieved by this partial value of LNAF. Similarly having a SIFF value greater than 1 would mean that the signal provided by the LNAF is strengthened; therefore, the value of SIFF would need to be justified based on the intended outcomes being achieved by this increased value of LNAF.

Because the basis of the SSII is the level of demand in the Trading Day in question, it in itself is not a strong indicator of the level of imbalance and the potential for that imbalance to result in the scheduling of cheaper, longer notice plant in the absence of an LNAF being applied. The same value of SSII can result from large imbalances at times of high demand, and from lower imbalances at times of low demand. The likelihood of requiring the application of an LNAF at a given SSII level in order to result in the desired outcomes depends on the level of demand feeding into the SSII calculation.

At low levels of demand, it is more likely that there would be multiple units, either through their market schedule or through the previous dispatch schedule, which would be part-loaded, and therefore able to respond to imbalance in the last hour without the need to start another unit. This would reduce one of the potential needs for the application of an LNAF. Also it would mean a lower level of imbalance versus the same value of SSII at a higher level of demand, and with lower levels of imbalance there would be lower possible requirements to start a unit. However, in this scenario there would be less units cleared in the ex-ante markets (due to lower demand), and therefore it would be more likely that cheap longer notice units do not already have a Physical Notification (PN) position. This would mean that these units would be available for scheduling in the absence of a PN being present for them.

At high levels of demand, it is more likely that there would be multiple units, either through their market schedule or through the previous dispatch schedule, which would be scheduled at their maximum output possible (keeping constraints such as reserve provision into account). Therefore these units would not be able to respond to imbalances in the last hour, resulting in the potential need to start a unit which, depending on its notice time, could result in an action earlier than the last hour. Also it would mean a higher level of imbalance versus the same value of SSII at a lower level of demand. With higher levels of imbalance comes greater chance of needing to start a unit to meet the shortfall. However, in this scenario there would be more units cleared in the ex-ante markets (due to higher demand), and therefore it would be more likely that the cheap longer notice units already have a Physical Notification position, meaning that the options for turning on units to meet imbalances may be restricted to those more expensive, faster acting units.

On this basis, it appears that for the same level of SSII, there are drivers which could mean the number of balancing market actions from cheaper long notice units in situations of energy balancing requirement could be higher or lower in high demand periods versus low demand periods. It is not known which drivers would be stronger to assess whether investigating periods with high demand or low demand would be more important from the point of view of assessing an SSII value for the application of LNAF through SIFF. Therefore for the initial analysis it is assumed that all situations, in terms of high versus low demand, are assessed equally. If a relationship between the need for the application of LNAF and the level of demand is found through further studies, this could help inform future analysis.

There are a number of high level approaches which can be chosen for the development of values, and the choice between them can be made on a theoretical basis in order to reduce the number of scenarios included in the modelling analysis. The areas to be considered include the following:

- Range of SIFF values:
    - 1. Between 0 and 1 only. This considers the application of the full LNAF, as calculated, at a certain value of SSII, with the potential to partially apply LNAF at different values of SSII leading up to the point where the full LNAF is applied;
    - 2. Between 0 and any number. This considers the application of the partial and full LNAF at different values of SSII as previous, but also allows for the LNAF signal to be strengthened by multiplying the LNAF by a value greater than one as the SSII increases.
- Under option 1, two potential sub-options apply in terms of the approach of application of LNAF:
    - 1a. Binary application. The value of SIFF can be either 0 or 1 only, with one value of SSII indicating the point of change. This means that the LNAF is not applied to scheduling up until a certain SSII value, and after that point LNAF is fully applied for all further SSII values;
    - 1b. Graduated application. The value of SIFF can vary between 0 and 1, with multiple values of SSII indicating the points at which the SIFF value increases. This gradually changes the influence of the LNAF on the schedule as the SSII values increase until the full application of the LNAF. By definition option 2 in the Range of SIFF values approach considers a graduated application.

Any LNAF applied would have values which have been developed to balance the trade-off between being at a level where the intended effect should occur (i.e. that shorter notice, more expensive units would be scheduled first over longer notice, cheaper units in situations where energy balancing drivers are greater than non-energy balancing drivers) and the operational and cost risks associated with this. As part of that methodology there is an element of basing this on the actual costs of the units, and then fine-tuning the value based on modelling analysis. There would not appear to be a similarly strong basis on which one could base the strengthening the signal of this value for increasing levels of SSII, and it is not likely that the enhancement of the value would result in any difference over the application of the full LNAF value itself. One potential benefit of strengthening the signal could be guaranteeing that the LNAF application has the desired effect in periods where SSII is high, indicating a strong energy balancing driver. However, this could be achieved through the assessment of values for the LNAF itself.

There would also not appear to be a strong basis for determining the level of partial application of LNAF which is sufficient at different values of SSII. Because LNAF is designed to create the intended effect of changing which units are considered first based on their actual costs, applying a fraction of this factor may not have the desired change to scheduling – the scheduling outcome could be the same as if no LNAF was implemented. Based on this it may also not be possible to determine a relationship between a fractional application of LNAF which results in the intended effects at different levels of SSII, if a partial LNAF does not result in the changes to the schedule. The partial application of LNAF could instead be seen as an arbitrary distortion to the schedule, which does not result in the desired outcomes and could instead have unintended outcomes.

It may also be easier for participants to model potential outcomes, and reduce uncertainty in scheduling results, with the understanding that LNAFs are created to result in the desired outcome of reducing energy balancing actions being accepted on cheaper long notice units, and it is known in advance of the Trading Day whether it is applied or not. This may also have the effect of reducing uncertainty in the operation of the system.

However, a disbenefit of this approach would be that the trade-off between allowing cheaper long notice units to be used when there is a non-energy balancing requirement, and not when there is an energy balancing requirement, relies on a single value of SSII, which represents all potential situations of the level of demand and level of forecast energy imbalance on the system. This would have a larger scope for the desired outcome on the energy balancing side not being implemented correctly in all situations if this SSII value is set too large so that it applies in less situations, and would have larger scope for the desired outcome on the non-energy balancing side not being implemented correctly in all situations if this SSII value is set too small so that it applies in more situations. However as outlined previously, it may be possible that having a graduating scale of applying LNAF may not actually result in the energy balancing desired outcome in any case.

Based on this rationale, it is proposed that the option 1a, of choosing a SSII value at which to change the value of the SIFF from zero to one to result in binary application of LNAF, should be used for determining the value of this parameter.

3.2.2 System Shortfall Imbalance Index Magnitude

It would be possible, through theory, to determine a magnitude of shortfall percentage at which it may be suitable to apply the LNAF in terms of the energy balancing drivers being very prominent. This can help restrict the range of scenarios of SSII to test in the modelling approach.

Based on the input data to this exercise, if those units which have a notice time of less than or equal to one hour are excluded, the Maximum Capacity of those units remaining ranges from 17MW to 512MW, with an average of 229.22MW and a median of 240.5MW. The Minimum Stable Generation level of those units remaining ranges from 1MW to 260MW, with an average of 97.17MW and a median of 92MW. This gives a wide range of potential levels of instantaneous imbalance which could result in different units being dispatched, from off, to Maximum Capacity or Minimum Stable Generation.

Considering the scenario which could result in an SSII at which LNAF may be appropriate, if the energy imbalance in a single Imbalance Settlement Period amounted to a shortfall which was the size of the largest Maximum Capacity of those units remaining, it may result in an action being taken on that unit to resolve the imbalance if other units were not available. If this occurred at the same time as the smallest value of demand over a Trading Day possible, this would indicate a level where, if all shorter notice units were more expensive or were no longer available, the highest capacity unit with longer notice times could likely be called to meet the imbalance, and would be a good indication of this potential magnitude. From the input data to this exercise, the minimum value for daily demand throughout the study year was 77170MWh.

With an energy imbalance being met by that largest maximum capacity unit in a single Imbalance Settlement Period, this would result in an SSII of (512 x 0.5) / 77170 = 0.00332 (i.e. a shortfall imbalance volume over the Trading Day equal to approximately 0.3% of the daily demand). This would be quite a low level of SSII and may not reflect the likelihood of a unit of 512MW capacity being committed onto the system to resolve an imbalance in a single Imbalance Settlement Period. In that particular instance, the unit's minimum on time was 4 hours. Therefore, not taking into account the energy provided by ramping, loading and deloading, extrapolating this to the unit being committed for the more likely scenario of 4 hours of imbalance would result in an SSII of (512 * 4) / 77170 = 0.02654 (i.e. a shortfall imbalance volume over the Trading Day equal to approximately 2.7% of the daily demand).

While a relatively simplified calculation, this would indicate that values of SSII where the application of LNAF may become relevant, to be considered in modelling scenarios, may be in the range of 0% – 10% rather than larger potential values for SSII. This is especially true when it is considered that 2.7% was the value in the Trading Day with the lowest demand. This percentage is also within the margin for error in demand forecasting (typically less than 5%), so considering options which are larger than this but of the same order of magnitude would be a good starting point. If the Trading Day with the highest demand was chosen (giving 125569MWh), the level of daily shortfall imbalance volumes would need to be 3332.6MWh to equal an SSII of 2.7%, which would be equivalent to approximately 6.5 hours of imbalance being met by the unit of 512MW maximum capacity. The increased amount of time of imbalance would make such a decision to start a unit to meet the imbalance more likely, and it is likely that units other than the one with the largest maximum capacity could be chosen to meet this larger imbalance volume.

3.2.3 Energy Balancing and Non-Energy Balancing Drivers

Drivers for taking actions for energy reasons include:

- Imbalances caused by forecasting error in wind and demand where the actual amount in real-time is different to that considered in market trading and previous scheduling iterations;
- Imbalances caused by forced outages of plants;
- Market clearing at levels of demand and wind which are different to forecast (and actual) values;
- Uninstructed imbalances from generators not delivering power at the level to which they have been dispatched.

Drivers for taking actions for non-energy reasons include:

- Constraints of units required in certain areas of the network for voltage support;
- System services requirements, including reserve and inertia;
- Position of units in the market versus the system minimum requirements from these constraints;
- SNSP limits;
- Thermal limits on the transmission network;
- Actions taken to facilitate maximisation of Priority Dispatch generation;
- Actions taken to manage and maintain cross-zonal interconnector capacity.

In this modelling, the drivers which can be represented are those imbalances caused by forecasting error and forced outages. However, the drivers which would most likely lead to the need for LNAF to be applied to result in the desired outcome is around the market clearing at demand and wind levels other than that which is forecasted. It is this which could cause a shortfall to be calculated between the accumulated PNs, forecast wind, and the forecast demand. As this is the measure of the SSII, in order to determine the value of the SIFF and SSII parameters this element of energy balancing action drivers is introduced in the modelling approach.

In this modelling, the drivers which can be represented are the system services requirements, SNSP limits, and the minimum number of units in different jurisdictions. The level to which the LNAF has an impact on non-energy actions would largely depend on the market position of units versus the minimum requirements from these constraints. If the market position is such that these constraints have been resolved without the need to take further action in dispatch, then this is an indicator that there should be minimal drivers for non-energy actions and therefore any drivers for energy balancing actions should have priority (i.e. the LNAF could be applied in a way which can incentivise the desired outcomes from an energy balancing perspective while not being expected to have an adverse effect on non-energy balancing outcomes).

3.2.4 SSII Modelling Approach

The modelling approach developed to determine the SSII at which the SIFF should become 1 is to assess for different levels of SSII when the LNAF is applied or not, and determine which value best results the desired outcomes. This approach consists of:

- A baseline scenario where every model iteration is run on the basis of actual demand, representing a situation where the SSII is zero;
- Number of scenarios for different levels of SSII, where the demand used in the DAM model is reduced by the SSII proportion desired, while the LTS and RTD models are based on actual demand. This works on the basis of changing one of the elements of the SSII calculation, the net total of PN values submitted, by having the DAM model clear at a lower level of demand than actual demand. Considering that in the base case there is no demand forecast error such that the “forecast demand” is the actual demand, and there is a forecast wind, and therefore the proportional difference between the two should represent the SSII;
- For each scenario, a run of the model with and without LNAF applied.

This means that we would have a set of results for each scenario of SSII considered. Based on this, it would be possible to determine an SSII (or a number of SSIIs) where the influence of the LNAF would be needed in order to best result in the desired outcomes from both an energy and non-energy balancing perspective (based on assessment of trade-offs of each scenario). This can be done by assessing, for each SIFF scenario, the level of change for desired outcomes which was achieved by introducing the LNAF at those levels of SSII. If the basis of the curve is a binary one (i.e. SIFF is zero or one), a single SSII where this transition occurs could be identified through considering the results of these scenarios.

Reducing demand in the DAM models by the amount required for the SSII scenario depends on the intended approach for modelling this change. In scheduling systems, for the same level of SSII, the impact of having LNAFs apply could be different depending on whether the shortfall is a smaller amount relatively evenly spread through the Trading Day, or is a larger amount focussed on a particular subset of periods in the Trading Day. In the absence of operational data which could be used to determine in which periods a focussed shortfall would likely drive energy balancing actions, or where focussed shortfalls are likely to occur based on PN submissions, it is proposed to use the approach where the percentage shortfall is spread evenly into every Imbalance Settlement Period in the Trading Day. Under the spread approach, adjusting the demand which is to feed into the DAM model run is simply a case of reducing the demand in each period by the SSII percentage of the demand in that period.

The scenarios considered in the assessment of the SSII are outlined in the table below. Appendix A gives further details about the modelling approach and assumptions.

Scenario Name	DAM	LTS	RTD
Base	Base	Base	Base
Base&LNAF	Base	Base & LNAF applied to Start Cost input data	Base & LNAF applied to Start Cost input data
1%SSII	Base & 1% reduction in Demand	Base	Base
1%SSII&LNAF	Base & 1% reduction in Demand	Base & LNAF applied to Start Cost input data	Base & LNAF applied to Start Cost input data
2%SSII	Base & 2% reduction in Demand	Base	Base
2%SSII&LNAF	Base & 2% reduction in Demand	Base & LNAF applied to Start Cost input data	Base & LNAF applied to Start Cost input data
3%SSII	Base & 3% reduction in Demand	Base	Base
3%SSII&LNAF	Base & 3% reduction in Demand	Base & LNAF applied to Start Cost input data	Base & LNAF applied to Start Cost input data
4%SSII	Base & 4% reduction in Demand	Base	Base
4%SSII&LNAF	Base & 4% reduction in Demand	Base & LNAF applied to Start Cost input data	Base & LNAF applied to Start Cost input data
5%SSII	Base & 5% reduction in Demand	Base	Base
5%SSII&LNAF	Base & 5% reduction in Demand	Base & LNAF applied to Start Cost input data	Base & LNAF applied to Start Cost input data
6%SSII	Base & 6% reduction in Demand	Base	Base
6%SSII&LNAF	Base & 6% reduction in Demand	Base & LNAF applied to Start Cost input data	Base & LNAF applied to Start Cost input data
7%SSII	Base & 7% reduction in Demand	Base	Base
7%SSII&LNAF	Base & 7% reduction in Demand	Base & LNAF applied to Start Cost input data	Base & LNAF applied to Start Cost input data
8%SSII	Base & 8% reduction in Demand	Base	Base
8%SSII&LNAF	Base & 8% reduction in Demand	Base & LNAF applied to Start Cost input data	Base & LNAF applied to Start Cost input data
9%SSII	Base & 9% reduction in Demand	Base	Base
9%SSII&LNAF	Base & 9% reduction in Demand	Base & LNAF applied to Start Cost input data	Base & LNAF applied to Start Cost input data
10%SSII	Base & 10% reduction in Demand	Base	Base
10%SSII&LNAF	Base & 10% reduction in Demand	Base & LNAF applied to Start Cost input data	Base & LNAF applied to Start Cost input data

To simulate the System Shortfall Imbalance Index (SSII), a percentage level of shortfall imbalance was applied to the DAM model starting from an initial range of 1% to 10% which were considered as potential values of shortfall which could result in an additional unit being started and kept on for its minimum on time, taking account of a typical demand forecast error of approximately 5%, and not being so large that the LNAF would not likely apply in situations where it would be appropriate.

As the analysis for the LNAF focussed on trade-offs between the intended outcomes and the unintended outcomes, for the SSII, the intention is to investigate whether there is a level of shortfall imbalance at which the application of the LNAF has the greatest impact, and therefore focuses on the proportion of the desired outcomes (i.e. the increase in starts scheduled on shorter notice units and decrease in starts scheduled on longer notice units). The difference in assumptions between the DAM model to the RTD model would introduce a number of changes to unit starts in itself, and the introduction of a shortfall imbalance in the DAM model would also introduce a number of changes to unit starts. Therefore the focus in the results is to try and identify the extent to which the LNAF itself was the influence on the change in the number of starts, independent of the other drivers for changes.

3.3 Results and Analysis

This imbalance alone would result in changes to starts. Therefore, the intention of this modelling was to investigate how much influence applying the LNAF had on starts at that level of imbalance and If there are particular levels of imbalance where the LNAF had a larger impact relative to the imbalance alone, this would be a suitable candidate for a proposed value.

A comparison of the starts from the DAM model and from the Real Time Dispatch model indicates the number of starts in the balancing market while changes between the LNAF and non-LNAF cases show the extra level of starts in the balancing market which were caused by LNAF. The changes to the model were in the DAM component with the RTD component results being the same, therefore the results need to consider the differences between RTD and DAM, and if the introduction of an LNAF at a particular SSII creates larger or smaller differences in RTD relative to DAM.

Table 12 and Table 13 show results for the change in the number of starts between the RTD model and the DAM model, which is indicative of changes in starts due to balancing. The value is shown for each scenario of SSII introduced into the DAM model, and is shown when this DAM model is compared against the RTD model without an LNAF applied, and with the Initial LNAF shown in section 2.3.1 applied, respectively.

Notice Time Group	Base	1%SSII	2%SSII	3%SSII	4%SSII	5%SSII	6%SSII	7%SSII	8%SSII	9%SSII	10%SSII
1	2409	2388	2406	2420	2458	2448	2480	2446	2467	2442	2485
2	16	14	12	8	7	6	6	1	2	-1	-3
3	-17	-12	-15	-17	-19	-19	-22	-20	-23	-19	-19

Notice Time Group	Base	1%SSII	2%SSII	3%SSII	4%SSII	5%SSII	6%SSII	7%SSII	8%SSII	9%SSII	10%SSII
4	-682	-672	-665	-662	-667	-665	-667	-658	-659	-654	-658
5	-25	-15	-12	-5	0	5	15	21	22	27	29
6	0	0	0	0	0	0	0	0	0	0	0
7	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
8	-72	-73	-74	-76	-74	-79	-80	-79	-88	-88	-89
9	8	12	15	16	15	17	19	18	19	19	21
10	-18	-10	-13	-7	-6	-5	-4	0	-1	2	8
11	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
12	-48	-49	-46	-39	-46	-51	-45	-50	-48	-47	-44
13	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
14	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
15	-50	-54	-54	-57	-61	-65	-70	-72	-72	-81	-81
Total	1521	1529	1554	1581	1607	1592	1632	1607	1619	1600	1649

Table 12: RTD vs DAM Unit Starts by Notice Time Group for each SSII Scenario Without LNAF Applied

Notice Time Group	Base	1%SSII	2%SSII	3%SSII	4%SSII	5%SSII	6%SSII	7%SSII	8%SSII	9%SSII	10%SSII
1	4984	4963	4981	4995	5033	5023	5055	5021	5042	5017	5060
2	41	39	37	33	32	31	31	26	27	24	22
3	-88	-83	-86	-88	-90	-90	-93	-91	-94	-90	-90
4	-837	-827	-820	-817	-822	-820	-822	-813	-814	-809	-813
5	-105	-95	-92	-85	-80	-75	-65	-59	-58	-53	-51
6	52	52	52	52	52	52	52	52	52	52	52
7	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
8	-80	-81	-82	-84	-82	-87	-88	-87	-96	-96	-97
9	0	4	7	8	7	9	11	10	11	11	13
10	-103	-95	-98	-92	-91	-90	-89	-85	-86	-83	-77
11	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
12	-91	-92	-89	-82	-89	-94	-88	-93	-91	-90	-87
13	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
14	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
15	-75	-79	-79	-82	-86	-90	-95	-97	-97	-106	-106
Total	3698	3706	3731	3758	3784	3769	3809	3784	3796	3777	3826

Table 13: RTD vs DAM Unit Starts by Notice Time Group for each SSII Scenario With LNAF Applied

Table 14 shows the percentage difference in RTD vs DAM unit starts between the LNAF applied case and the non-LNAF applied case. This value is indicative of the level of influence the LNAF has on changing RTD vs DAM unit starts, independent of the other drivers for these changes. The higher the value of this percentage, the greater impact the LNAF is having an impact on the change in RTD vs DAM starts. The text in red is intended to highlight the two SSII scenarios where this percentage is at its highest for positive changes, or at its lowest for negative changes. The highlights are only included for those scenarios above 5%SSII

Notice Time Group	Base	1%SSII	2%SSII	3%SSII	4%SSII	5%SSII	6%SSII	7%SSII	8%SSII	9%SSII	10%SSII
1	33.08%	32.99%	33.07%	33.13%	33.29%	33.25%	33.39%	33.24%	33.33%	33.22%	33.41%
2	60.98%	58.14%	55.56%	51.02%	50.00%	49.02%	49.02%	44.64%	45.45%	43.10%	41.67%

Notice Time Group	Base	1%SSII	2%SSII	3%SSII	4%SSII	5%SSII	6%SSII	7%SSII	8%SSII	9%SSII	10%SSII
3	-72.45%	-76.34%	-73.96%	-72.45%	-71.00%	-71.00%	-68.93%	-70.30%	-68.27%	-71.00%	-71.00%
4	-17.96%	-18.17%	-18.32%	-18.39%	-18.28%	-18.32%	-18.28%	-18.47%	-18.45%	-18.56%	-18.47%
5	-57.14%	-61.54%	-62.99%	-66.67%	-69.57%	-72.73%	-80.00%	-85.11%	-86.02%	-90.91%	-93.02%
6	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
7	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
8	-8.25%	-8.16%	-8.08%	-7.92%	-8.08%	-7.69%	-7.62%	-7.69%	-7.08%	-7.08%	-7.02%
9	-57.14%	-80.00%	-114.29%	-133.33%	-114.29%	-160.00%	-266.67%	-200.00%	-266.67%	-266.67%	-800.00%
10	-79.44%	-85.86%	-83.33%	-88.54%	-89.47%	-90.43%	-91.40%	-95.51%	-94.44%	-97.70%	-104.94%
11	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
12	-46.74%	-46.24%	-47.78%	-51.81%	-47.78%	-45.26%	-48.31%	-45.74%	-46.74%	-47.25%	-48.86%
13	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
14	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
15	-32.89%	-31.25%	-31.25%	-30.12%	-28.74%	-27.47%	-26.04%	-25.51%	-25.51%	-23.36%	-23.36%
Total	**23.38%**	**23.40%**	**23.46%**	**23.53%**	**23.60%**	**23.56%**	**23.66%**	**23.60%**	**23.63%**	**23.58%**	**23.70%**

Table 14: Percentage Difference in RTD vs DAM Units Starts Between LNAF Applied Case and Non-LNAF Applied Case by Notice Time Group for each SSII Scenario

The results of the modelling work were not conclusive, showing a wide range in the scenarios with the maximum increase in shorter notice unit starts and maximum decrease in longer notice unit starts. From the modelling approach applied, there does not appear to be an obvious optimal SSII where the effects of the LNAF are most greatly felt. It may be possible with operational experience to attain better analysis of the correlation of imbalance levels with instances of starting longer notice units. Therefore, other more qualitative aspects must also be considered.

The value for SSII should be above the typical level of demand forecast error which is around the 5% level of magnitude. The value should also consider the impacts which cannot yet be modelled due to the lack of operational experience of the I-SEM, such as the number of days this would result in an LNAF being applied, with the potential impacts on production cost which could result. Setting it to a lower value would mean that it could apply to the scheduling process more often, but setting it too high would mean that it would not apply in times where it would be effective in preventing longer notice actions in the scheduling process.

On the basis of the results shown and the qualitative aspects considered, should a non-zero value for LNAF be considered, a proposed value for the SSII at which the SIFF would change from zero to one is 9% (this would be a value of 0.09 in the correct parameter format). This is toward the higher end of the range considered, coinciding with some of the results showing peak impacts of the LNAF, is above the typical level of demand forecast error. However, consistent with our proposal that the LNAF be set to zero at market start, we propose that the SSII is also set to zero at market start.

3.4 Recommendation

Having considered the concept of a range of values for the System Imbalance Flattening Factor, we believe that it is not clear that applying a scale of additional factors to the LNAF will have the desired affect and may conversely serve to hamper the correct application of the LNAF (by either scaling the value too low if the SIFF is less than 1 or too high if greater than 1). On this basis, we propose that the values for the SIFF are set at 1 and 0 only. As such, the SIFF is a binary flag that, when set to 0, will not apply the LNAF in the scheduling process and when set to 1 at a certain level of SSII, will apply the LNAF.

The modelling work did not provide an obvious optimal value of SSII whereby it would be appropriate to apply the LNAF in the scheduling process. This could be due to the modelling approach applied, where it may not be possible to clearly ascertain which level of the additional starts incurred was due to the imbalance introduced to the model and which were due to the application of the LNAF. As we noted above in the discussion on the value of the LNAF, there are a large number of uncertainties with regard to market participant behaviour and system operation in the I-SEM and it is more likely that, after a period of live operations, additional studies can be carried out based on real-time data and actual system shortfalls to measure actual behaviours.

As such and consistent with our proposal for the LNAF, the TSOs propose that the value of SSII is set to zero at market start and for a period of one year thereafter.

After a period of live operation, SEMO and the TSOs will carry out analysis on the results of actual market activity and system operation to consider ex-ante participation, the system shortfalls that occur, the level to which TSO actions are impacting on the intraday market relative to the size of the system shortfall and the impacts of the application of a non-zero value of LNAF. SEMO and TSOs will provide a report to the Regulatory Authorities at that point making a further recommendation with respect to the application of the SSII in the System Operator’s scheduling systems to systemise the implementation of a “last time to order” policy.

4. Daily Time for Fixing the SSII and SIFF for a Trading Day

4.1 Background

The design approach for the scheduling and dispatch parameters is to calculate the SSII based on the most up to date information, but to fix the SSII for the Trading Day at a point in time before the start of the Trading Day so that it applies in all subsequent scheduling runs until the SSII is set for the next Trading Day. This SSII then represents a snap-shot of any shortfall over the day. Therefore, a cut-off time for the data relating to the calculation of the final SSII, and therefore the SIFF, for a Trading Day needs to be decided.

While the SSII needs to be calculated for use in the scheduling process, it is not necessary to fix it at the value used in the very first scheduling run relevant to the Trading Day. For scheduling runs which span multiple Trading Days, the SSII for the first Trading Day would be used as an indicative value for the whole period until the SSII is updated for the later Trading Days. There are trade-offs between fixing the SSII later or earlier.

Fixing the value later could ensure that more accurate data (i.e. probably better representing the final market position) is used the calculation of the SSII for the subsequent scheduling runs, and these subsequent runs are the ones which are more likely to impact on balancing actions (e.g. based on more up to date wind and demand forecasts, and additional PN submissions following intraday trading to address imbalance identified after day-ahead market trading). Fixing the value earlier would ensure that the values for the SIFF and LNAF parameters included in the earlier scheduling runs for the Trading Day are those calculated for the Trading Day rather than the indicative values of the SIFF and LNAFs for the previous Trading Day. Including these updated parameters in earlier scheduling runs could help increase stability between all scheduling runs for that Trading Day, and therefore stability in the schedule information which is published to the market while the intraday market trading is still open. This could help better ensure the outcome intended of the market design that balancing actions for energy reasons are taken following the balancing market gate closure to the extent possible.

4.2 Considerations

4.2.1 Timing of Related Events

Updating the calculated SSII from its indicative value to its fixed value very close to the start of the Trading Day may introduce uncertainty and instability to the scheduling process. Therefore, the earlier it is fixed, the more certainty there will be on the influence of the SIFF on the scheduling outcomes. However, if it is fixed too early in the day, it may not reflect trading in the intraday market, and therefore may represent either too pessimistic (if calculating a larger level of system shortness than actually arises following all intraday market trading) or optimistic (if calculating a smaller level of system shortness than actually arises following all intraday market trading) view of system shortness, which would result in the intended outcomes being reduced.

As this approach is more dependent on the timing of market activity, scheduling activity, the quality of forecast information feeding into those activities (which is based on the timing of the publication of this information), it is considered that this parameter can be determined without the need for detailed modelling analysis. The trade-offs for this parameter can be more easily considered with basic information than the other parameters, where the influence of the value on outcomes is more dependent on exact values and are not intuitive, requiring modelling to take the complexity of the interactions into account. Also, in the absence of a modelling approach which can accurately represent the intraday and continuous auctions, and in the absence of operational knowledge about the behaviour in different trading mechanisms and timeframes, it would not be possible to create models with meaningful results to help inform the considerations.

The following is a list of the timing of events which would most likely influence the time of day for fixing the SSII (acknowledging that some elements of these activities can be carried out continuously):

- Publication of wind forecasts:
    - Updated every six hours for all hours of the day ahead of the time of update, published at these times: 00:00, 06:00, 12:00, 18:00.
- Publication of demand forecasts;
- Intraday Auctions;
- Gate closure time for the first Imbalance Settlement Period in the Trading Day:
    - For the period 23:00 – 23:30, the gate closure time would be 22:00 TD-1, 1 hour ahead of the start of the Trading Day;
- Gate closure time for the initial receipt of information for the Trading Day following Day-ahead Market completion:
    - Initial PNs, COD and TOD need to be submitted by 13:30 TD-1.
- Scheduling runs:
    - Long Term Schedule scheduling runs will be run every 240 minutes with an optimisation horizon from 4 hours after the time of the run until 34 hours after the time of the run;
    - Real Time Commitment scheduling runs will be run every 15 minutes with an optimisation horizon from 30 minutes ahead of the time of the run until 4 hours ahead of the time of the run;
    - Real Time Dispatch scheduling runs will be run every 5 minutes looking over the period from 10 minutes ahead of the time of the run until 1 hour and 10 minutes ahead of the time of the run.
- Notice times of units which could be feasibly scheduled and dispatched in advance of the start of the Trading Day:
    - The main influence this could have on the parameter is the possibility for balancing actions being taken on the basis of different values for SSII, and therefore on the basis of different applications of LNAF, at

different times in the Trading Day. The earlier the SSII is fixed for the day the less likely it is that this situation could arise; however, it would not need to be set multiple hours earlier than the notice time of units which would feasibly be dispatched in the absence of LNAF. For example there would be diminished benefits in this regard between fixing the parameter 8 hours in advance versus 6 hours in advance of the Trading Day if the notice time of units which would feasibly be dispatched (on whom the LNAF is intended to exert influence) is 3 hours. However, fixing the SSII at 3 or 2 hours ahead of the Trading Day would increase the chances of dispatch actions based on different SSII values for the Trading Day.

- Operational processes around the calculation of the SSII:
    - The calculation of this variable is automated in systems based on data feeds, with the possibility of an operator being able to review the result.
- Operational processes in participants using the result of the SSII:
    - Participants are likely to want to use the value of the fixed SSII to assist in modelling activities to inform the formulation of intraday bids and offers. While it is possible that the activity of submitting bids and offers could occur outside of business hours, it is also possible that the teams carrying out analysis work are separate to those carrying out submissions, and therefore it may be desired that the analysis work would be carried out within business hours. Therefore in order to be useful for those processes, the fixed SSII would need to be published sufficiently in advance of close-of-business to allow this analysis work to be completed.

4.2.2 Assessment of Timing

Based on the above, the final Long Term Schedule run in advance of a Trading Day could indicate, depending on the timing of its being run, that a dispatch action should be taken on a unit with a notice time of up to 4 hours for the first Imbalance Settlement Period in the Trading Day. However, it is much more likely, given the time of day, to be used to indicate actions required to start up long notice plants in time for the morning load rise (starting around 06:00), which would indicate that the latest time for fixing the value for the SSII would not necessarily need to be very far in advance of the start of the Trading Day in order to minimise impacts of different SSIIs driving different dispatch instructions to start units for the same Trading Day.

A further consideration is whether this should be some time after the latest update to the wind forecast at approximately 18:00 in advance of the Trading Day. This is on the basis that the updated forecast would give the most up to date data to participants to inform their continuous trading in the intraday market. This is one of the last common publications of information which could drive major changes in trading behaviour and therefore the PNs which result from this trading behaviour, such that waiting until after PNs have been submitted reflecting trades based on this updated information probably result in an SSII which best represents the market position in advance of the Trading Day. It would also mean that the wind forecast used in the calculation of the fixed SSII would be the most up to date. Sufficient time after the publication of updated wind forecasts would be needed to allow participants to use this information to determine updated bids and offers, submit them, have them cleared on the shared order book, and process the cleared data to formulate updated PNs, and submit this PN data so that it is present in the SO systems sufficiently in advance of the process for calculating the SSII being run.

It is likely that most of the large changes in market position (and therefore PN) are likely to arise from day-ahead market and intraday auctions, given the potential for pooled liquidity. The change in wind forecast information may also not be so large as to drastically change the position of dispatchable generator units. Based on this it is more likely that continuous intraday trades following 18:00 would be for smaller adjustments than the auction mechanisms, and given this a smaller amount of time between receipt of trade results and submission of PNs than that for the auction timeframes should be sufficient.

There is a trade-off between having the fixed SSII calculated for use in processes within office hours, and having the fixed SSII calculated based on the most up to date wind forecast and PN information after 18:00. As the primary intention of these scheduling and process parameters is to implement the decision on the objectives of accepting energy and non-energy balancing actions, it may be reasonably argued that the option which allows for the most accurate information to be used in implementing that decision should be the priority (i.e. after 18:00). Following this, there becomes a trade-off between how soon after 18:00 the value is fixed in order to give participants sufficient time to update PNs, versus how late after 18:00 the value is fixed in order to give certainty about the value to be used for all scheduling runs and by which all dispatch actions have been influenced.

Given that the updated SSII would be used for all subsequent Long Term Schedule scheduling runs, it would be important to ensure the update is calculated following the daily peak in demand so that the change in SSII, intended for a Trading Day TD, does not interfere with scheduling for the demand peak of the previous day, TD-1. This would indicate that around 19:00 would be the earliest time acceptable for such an update. An important consideration in determining the timing is that it should be sufficient to feed the updated SSII (and therefore updated LNAF) into the final Long Term Schedule scheduling run for the first Imbalance Settlement Period in the Trading Day. This schedule is run every four hours, and the final run in advance of the Trading Day would be important in determining the start up of long notice plants in time for the morning load rise, such that the SSII should be set within at least one hour of the start of this scheduling run. The timing of the Long Term Schedule runs has not yet been determined and it is unlikely to be finalised until following testing of systems, and potentially market trial. Therefore, an exact time for fixing the SSII would not be possible to determine until after the timing of this run has been finalised.

4.3 Recommendation

The recommended daily time for fixing the SSII for a Trading Day is between 19:00 TD-1 and 22:00 TD-1, and at least one hour prior to the start of the final LTS scheduling run, with the exact timing to be advised following the decision on the timing of this LTS run.

5. Conclusions

The transition to the I-SEM arrangements represents the most significant change in market and system operations in Ireland and Northern Ireland in ten years since the start of the SEM. While a number of steps have been taken in the design stages to ensure participants have freedom to trade into and out of positions with minimal impact from TSO actions, these remain dependent on a number of other assumptions and factors of which intraday liquidity is a significant item. A number of participants have previously raised concerns in their responses to earlier market design consultations with respect to this, suggesting that a cautious approach should be taken with setting some parameters at the start of the new arrangements. Given that I-SEM will not be joining the XBID initiative until sometime after go-live, we believe it is prudent to consider these concerns also when proposing the operational parameters.

The transition to a cascading market design was also noted as a design risk in the Stocktake Report. While it was suggested that other measures could be taken to manage this risk at market go-live, setting the LNAF to a value of 0 and using a binary SIFF would be an approach within the market design that would mitigate these risks.

While every effort has been taken in the modelling work carried out to date, this cannot be a substitute for the actual market and system operation experience that will be gained after go-live. EirGrid believes it is important that, after a period of market operation, these operational parameters are revisited taking account of how the initial values have met their goals should the current recommendations be accepted. This will allow us to consider whether sufficient liquidity has emerged in the interim intraday markets being implemented and whether setting the LNAF value to 0 at market start has resulted in early energy actions being taken by the TSOs. This operational experience will allow us propose revised values as required which may have less risk or unintended impacts on the I-SEM.

Appendix A Modelling Assumptions

A.1 Disclaimer

This document has been prepared by EirGrid Group (EirGrid plc and affiliated companies including without limitation its subsidiary SONI Limited). EirGrid plc is the licensed electricity Transmission System Operator (TSO) and Market Operator (MO) in the wholesale electricity trading system in Ireland and is the owner of SONI Limited, the licensed TSO and MO in Northern Ireland. The Single Electricity Market Operator (SEMO) is part of EirGrid Group, and currently operates the Single Electricity Market on the island of Ireland.

The purpose of this document is to provide an outline of the assumptions and methodologies developed to date by EirGrid Group to model a representation of the Integrated-Single Electricity Market (I-SEM). The assumptions and methodologies set out herein are provided for information purposes only and do not indicate any preference by EirGrid Group for any particular market design. Whilst every effort is made to provide information that is useful, and care is taken in the preparation of the information, EirGrid Group gives no warranties or representations, expressed or implied, of any kind with respect to the contents of this document, including, without limitation, its quality, accuracy and completeness. EirGrid Group hereby excludes, to the fullest extent permitted by law, all and any liability for any loss or damage howsoever arising from the use of this document or any reliance on the information it contains. Use of this document and the information it contains is at the user's sole risk.

A.2 Purpose of Document

In preparation for the future I-SEM, EirGrid have developed a model to help better understand how the new market might work. This is not intended to be a model of the I-SEM, but is intended to reflect some of the effects of the I-SEM which can be used to highlight and compare characteristics of different market timeframes and design options. The model is based around a set of methodologies and assumptions, which are subjective in their nature and involve representations of market rules that are still under development. The purpose of this document is to share the methodologies and assumptions which have been developed to date.

A.3 General Outline

A.3.1 Introduction

The current SEM is a relatively static market, with a single ex-post mandatory pool, Bidding Code of Practice (BCOP), a pay-as-bid approach for balancing actions and relatively more certainty of information but with less flexibility to respond to that information. The structure of the I-SEM on the other hand allows for orders to be placed in a series of dynamic ex-ante markets with different pricing approaches being introduced for different types of balancing actions and imbalances. This makes the I-SEM a market with less certainty of information but with more flexibility to respond.

We believe that the main goal of the model should be to capture the dynamic aspects of the I-SEM, with a sufficiently accurate representation of the general future state of the system, to provide the ability to analyse the impacts of these dynamics on the workings of the market. As such, the model is not intended to be used to forecast exact quantities of metrics likely to arise in the operation of the I-SEM. Similarly, this model is not suitable for use in purposes outside of the qualitative analysis of the dynamic aspects of the I-SEM, and results from this model cannot be compared with results of other models.

A.3.2 Software and Model Source

The model is developed using Energy Exemplar's Plexos software, version 6.302 R02 x64. The Plexos software is widely employed in the electricity industry, and is used by many of the world's largest utilities and system operators, as well as the Regulatory Authorities in Ireland and Northern Ireland.

The model of the I-SEM builds on the publically available RA validated model. This model was then adapted to include data from the Generation Capacity Statement (GCS) 2014-2023, and to include aspects of the market as described in the Integrated – Single Electricity Market (I-SEM) high level design (HLD) final decision and Energy Trading Arrangements (ETA) – Markets detailed design final decision.

A.4 Model Structure

I-SEM has four market timeframe components – the Forwards Market (FM), the Day Ahead Market (DAM), the Intraday Market (IDM), and the Balancing Market (BM). This model focuses on the DAM and BM components of the I-SEM. The model does not explicitly include the FM and IDM components, nor does it include aspects of the future market and operation of the system related to the Delivering a Secure Sustainable Electricity System (DS3) programme.

The model has three components to represent two primary aspects of the I-SEM structure: the DAM and the BM. The DAM is represented in one model, and conceptually can be thought of as representing the net trades from the ex-ante markets, and physical notifications from participants to the TSO. The BM is split into two models to represent the scheduling and dispatch process which drives the acceptance of bids and offers in that market, with the scheduling and unit commitment simulated through a Long Term Scheduling (LTS) component of the model and with the dispatch and reaction to imbalances in real-time simulated through a Real Time Dispatch (RTD) component of the model. This is done in order to separate the volumes of trade resulting from each component and apply the different pricing approaches of each component.

Figure 12 shows the elements of the high level structure of the model which are intended to reflect the change of information and physical capability over time which would be present in the operation of the I-SEM. Table 15 outlines in more detail the structure of the model in terms of inputs, settings and the processing of outputs.

Model:	Day Ahead Market	Long Term Scheduling	Real Time Dispatch
Pricing:	Marginal Shadow Price of Demand Constraint	N/A	Marginal Simplified Flagging and Tagging of Trade Volumes and Prices
Constraints:	Generator Technical	Generator Technical **Operational (e.g. Reserve, SNSP)**	Generator Technical Operational (e.g. Reserve, SNSP) **Large Unit Commitment from LTS**
Outages:	Planned	Planned	Planned **Forced**
Wind:	Forecasted	Forecasted	**Actual**
Period/Horizon:	1 day + 6hrs Lookahead	1 day + 6hrs Lookahead	1 Hour + 6hrs Lookahead

Figure 12 High Level Structure of the Model

Model	DAM	LTS	RTD
Name	Day-ahead Market	Long Term Schedule	Real Time Dispatch
Wind	DAM Forecast	DAM Forecast	Actual
Demand	Actual	Actual	Actual
Period	Hour	Hour	Hour
Horizon	1 Day + 6hrs LA	1 Day + 6hrs LA	Hour + 6hrs LA
Constraints	None	Operating Reserve, TCGs, SNSP	Operating Reserve, TCGs, SNSP
Outages	Scheduled Maintenance	Scheduled Maintenance	Scheduled Maintenance and Forced Outages
Technical Offer Data	Complex	Complex	Complex
Commercial Offer Data	Short Notice Units: Complex, DSU VOM. Longer Notice Units: Complex.	Short Notice Units: Complex, DSU VOM. Longer Notice Units: Complex.	Short Notice Units: Complex, DSU through Variable Operating and Maintenance

Model	DAM	LTS	RTD
			component. Longer Notice Units: Complex.
Market Price	Shadow Price of Demand Constraint	N/A	Simplified Flag and Tag rules for Trade Volumes and Trade Prices
Trade Volume	Generation	N/A	Generation, RTD - DAM
Trade Price	N/A	N/A	SRMC of unit
SO-SO Trade Volume	N/A	N/A	Interconnector Flow, RTD - DAM
SO-SO Trade Price	N/A	N/A	GB Regional Price
Interconnector Flow	Unrestricted	Unrestricted	Unrestricted
BETTA Representation	Dummy Generators	Dummy Generators	Dummy Generators
Fuel Price	Actual	Actual	Actual
Interleave model	N/A	RTD	N/A
Interleave Data: From Previous	N/A	N/A	From LTS: Units Generating (for commitment of Large Units)
Interleave Data: To Next	N/A	To RTD: Units Generating (for commitment of Large Units)	N/A
LNAF Applied	No	No	No
Settlement	Trade Volume x Market Price	N/A	Imbalance Volumes x Market Price, Trade Volume x Max or Min of Market Price and Trade Price, Curtailment Volumes x DAM Market Price

Table 15: Detailed Structure of the Model

Unit technical characteristics (Minimum Stable Generation level, Minimum Up/Down Time, Ramp Rate Up/Down) were included in all models including the DAM model. They are required by the LTS model to accurately represent the operational schedule, and it is intended that the only differences between the DAM and LTS models would be the inclusion of operational constraints for which NEB actions would be taken.

The LTS and RTD models represent scheduling and dispatch in the same hours taking into account the constrained aspects of scheduling and dispatch as opposed to the unconstrained market approach of the DAM model. To represent this, the BM models are interleaved with each other, with the information on the commitment of large generation units from the LTS model being passed to the RTD model. This reflects the more constrained nature of balancing for energy reasons close to real-time.

All generators are assumed to bid on a perfect competition Short Run Marginal Cost (SRMC) basis. This is done for a number of reasons, for example:

- There is insufficient data from the SEM to be able to calibrate parameters required for other competition models such as Nash-Cournot or Bertrand;
- It decreases the complexity in the results so that the impacts of the dynamics of different aspects of the market can be more clearly determined; and
- It also allows for easier understanding of the outcomes and results from the model as it is on the same basis as the current SEM models, around which a large degree of understanding has been developed.

Incremental and decremental (inc and dec) commercial offer data are not explicitly represented in the model. Instead, market schedules are determined in Plexos for each generator in each hour based on an optimisation which minimises production cost, using participants' fixed costs (e.g. start costs) and variable costs (e.g. heat rate curves and fuel prices). The volumes of balancing market bids and offers are determined afterwards by the differences in unit positions between the final constrained schedule and the initial unconstrained schedule (i.e. BM Accepted Bids and Offers = RTD Positions – DAM Positions). With the SRMC bidding assumption, the outcome of an optimised schedule with an objective function to minimise production cost, should be similar to the outcome of an optimised trading of incs and decs.

The commercial offer data is represented as static heat rate curves for all days in the study period, and changes with changing fuel prices. Separate start costs for three heat states are modelled where applicable to thermal units. It is assumed that incremental and decremental Price Quantity Pairs are the same in terms of prices and quantities.

A market price cap of €3000 and floor of -€500 are assumed in each market timeframe based on public information on the European multi-regional coupling (e.g.: http://www.apxgroup.com/wp-content/uploads/20140121-Member-Update-APX-Power-NL-NWE-Price-Coupling.pdf).

A.4.1 Market Volumes

The volumes dispatched by the DAM model represent the trades cleared in the ex-ante markets. The difference in MW quantity position for a unit between the DAM model and RTD model represents the volume of bids or offers accepted on that unit in the balancing market due to both non-energy and energy balancing actions.

It is assumed that the only differences between the DAM model and the LTS model are the addition of components related to system technical characteristics to the LTS model (e.g. reserve procurement, constraints, etc.). Therefore, the LTS model should result in the same unit dispatch results as the DAM model, except for changes due to system constraints which would drive balancing actions. Similarly, it is assumed that the only differences between the LTS model and the RTD model are the addition of components related to energy imbalances to the RTD model (e.g. unit forced outages, wind forecast errors). Therefore, in theory, the RTD model should result in the same unit dispatch results as the LTS model, except for changes due to imbalances which would drive balancing actions.

Based on this, the volume for all Balancing Market Bid Offer Acceptances is taken to be the difference between the RTD position and the DAM position (the LTS position is not used for these calculations, instead only being used as an input into the RTD model). If the reason for this difference is due to an imbalance, for example for a forced outage in the RTD model, or because of forecast error resulting in a difference between the position of wind in the DAM and RTD models, then these are instead calculated to be imbalance volumes rather than BOA volumes. Table 16 illustrates how the volume in each market component is calculated.

Hour	Position DAM	Position RTD	Forced Outage RTD	DAM Trade Volume	BM Trade Volume	Imbalance Volume
1	100	50	0	+100	-50	0
2	100	110	0	+100	+10	0
3	100	100	0	+100	0	0
4	100	0	200	+100	0	-100

Table 16: Illustration of Volume Calculation Methodology

There will only be one BOA per unit per period, and it will only be an Offer or a Bid – therefore there will be no need to represent different Accepted Offers and Accepted Bids on the same unit in the same period having different prices, there is no need to calculate or settle Accepted Bid Above Physical Notification or Accepted Offer Below Physical Notification (“Undo”) quantities, and there will be no need to represent the complexity of Instruction Profiling to calculate the quantities: the simplification allows the outputs of the model to be used to calculate accepted quantities.

Changes in wind position due to forecast error and curtailment are separately calculated as volumes and are settled differently according to the market rules. The volumes were calculated on the basis of the wind’s ex-ante market position, their actual availability in the RTD model, and their generation position in the RTD model. The calculations take into account that curtailment quantities only apply in respect of volumes which are traded; therefore, if wind’s availability is greater in the RTD model than in the DAM model and the unit is curtailed, the volume between the availability in the RTD model and the availability in the DAM model is ignored.

A.4.2 Flagging and Tagging

The following elements of the methodology for determining System Operator and Non-Marginal Flags (linked here) have been incorporated into the modelling approach:

- Total Operating and Replacement Reserves Tests:
  - Primary Operating Reserve (separately for Spinning and Total);
  - Secondary Operating Reserve;
  - Tertiary Operating Reserve I; and
  - Tertiary Operating Reserve II.
- Inertia Tests;
- Dynamic and Voltage Stability Tests:
  - Northern Ireland System Stability;
  - Ireland System Stability.
- Generator Unit Limit Tests:
  - Turlough Hill Generation.

Data on a reserve constraint's shadow price is used to determine whether or not that constraint was binding in a period, and for other constraints Plexos directly outputs whether or not the constraint is binding in a period. Information on a unit's RTD Generation, Ramping Flexibility Up, Ramping Flexibility Down, Installed Capacity and Minimum Stable Generation were used to determine the results for the tests in the methodology for determining System Operator and Non-Marginal Flags.

A.4.3 Market Prices and Settlement

The day-ahead market has hourly prices for trades at the marginal price of energy. In the DAM model the marginal price is taken as a direct output from Plexos (price for the SEM region), and is assumed to be the price of the next incremental MW.

The mechanism for determining the Imbalance Settlement Price for the settlement of balancing market actions and imbalances is based on a Flagging and Tagging approach of the balancing market actions calculated. The balancing market actions with a volume less than the De Minimis Acceptance Threshold (DMAT) as scaled to the model interval level are excluded from the stack of actions which are included in the calculation of the net imbalance volume and for use in the remainder of the price calculation steps. Units which are assumed to have caused imbalances (i.e. units forced out and wind) are also excluded from this stack. The price of each Bid Offer Acceptance is taken as the Short Run Marginal Cost (SRMC) (€/MWh) of the unit. The series of steps outlined in Chapter E and Appendix N of Part B of the Trading and Settlement Code are then followed in order to determine the Imbalance Settlement Price, with the exception of those steps associated with the Administered Scarcity Price.

The Net Imbalance Volume (NIV) is calculated as the sum of the balancing market volumes (including curtailment volumes). The forced outage volume is taken as the negative of the DAM model cleared volume for the unit which is forced out in the RTD run. The wind imbalance volumes are taken as calculated in the methodology outlined in Section A.4.1.

All balancing market trades are settled with an imbalance component, and a premium / discount component, to reflect the design principle that participants will be settled at the better of their order price or the imbalance price for balancing market volumes. Where the individual participant's price (i.e. SRMC) is less than the imbalance price for an inc trade, or is greater than the imbalance price for a dec trade, the premium / discount component of their balancing market cash flow is zero and all cash flow is through the imbalance component. Where the opposite is true (i.e. SRMC is greater than imbalance price for inc or less than imbalance price for a dec), the premium or discount is calculated from the volume of trade and the difference between the SRMC and imbalance price.

It is assumed that Final Physical Notification Quantities are equal to the position of the unit in the DAM model, and therefore there is no need to calculate or settle Biased quantities. Since the LTS and RTD models take this Final Physical Notification as the point from which incs and decs are calculated, it assumes there has not been a dispatch instruction at a time where the value of the Physical Notification Quantity is different, and therefore there is no need to calculate or settle Trade Opposite TSO quantities. It is assumed that all units in the model are fully firm, and therefore there is no need to calculate or settle Non-Firm quantities. It is also assumed that all SO instructions have been met. Therefore, the unit position from the RTD model can be used as both the Dispatch Quantity (QD) and as the Metered Quantity (QM), and there is no need to calculate or settle Undelivered Quantities or Uninstructed Imbalances.

A.5 Study Years

A study year of 2020 has been chosen for all scenarios. 2020 is considered suitable for the purposes of this model as it is far enough out to be representative of the future state of the system, but close enough to give some certainty regarding assumptions. However, the model does not aim to give an exact snapshot of how the system will operate in this year, but rather examines the dynamics and impacts of the elements of the market with an appropriate representation of the future system.

A.6 Fuel and Carbon

Quarterly fuel price figures are used for coal, oil, peat, distillate, and gas, derived separately for IE and NI. A single annual price for peat is also used. Annual and monthly prices for fuels are similarly derived for GB, with the addition of an annual uranium price. The prices used are based on those used for the forecast imperfections revenue requirement analysis.

European Carbon ETS prices and exchange rates are based on the International Energy Agency's World Energy Outlook 2013 report based on the New Policies scenario. Carbon prices in GB are set to the Carbon price floor, which is assumed to be frozen at 2015-16 levels (£18.08 /tonne in nominal terms). The Carbon price floor is not applied in NI.

CO_2 production rates are sourced from "COMMISSION DECISION of 29 January 2004 establishing guidelines for the monitoring and reporting of greenhouse gas emissions pursuant to Directive 2003/87/EC of the European Parliament and of the Council" (2004/156/EC) Pg 22, Table 4".

A.7 BETTA Representation

A price profile for the BETTA market is used based on simulation results of a model that has a representation of generation units in BETTA. This representation has generalised data by portfolio unit type as opposed to representation of each actual individual unit in BETTA, based on data received from National Grid UK for their current portfolio. This BETTA portfolio is then extended to 2020 based on data from DECC and also from the 'Gone Green' scenario in National Grid's Electricity Ten Year Statement (NGUK's ETYS) published in 2012.

BETTA demand is based on the 'Gone Green' scenario in NGUK's ETYS published in 2013, for scenarios involving dispatching units in the BETTA region to attain a price profile.

BETTA generators are assumed to price their orders on a SRMC basis.

A Mixed Integer Programming (MIP) precision simulation using this scenario is used to output an accurate BETTA market hourly price profile time series. This time series of the price is used in all subsequent studies. Given that GB to Ireland and Northern Ireland interconnection capacity is small compared to GB peak demand (approx. 60 GW) it is assumed that interconnectors act as price takers to the GB market – i.e. GB to SEM interconnector flows will not move the wholesale price in the GB market.

The interconnector flows on Moyle and EWIC for all subsequent studies are represented by dummy generators and loads using the above time series rather than the full BETTA portfolio representation in order to reduce complexity in the model.

A.8 Transmission Network and Interconnection

Apart from interconnection, the transmission network and transmission constraints are not represented in the base case. Transmission Loss Adjustment Factors (TLAFs) are also not included in the model.

The existing interconnectors (Moyle and EWIC) are the only lines included in the study. Market flows on Moyle and EWIC are based on the modelled price differential between SEM and BETTA. Interconnector flows are calculated within the model. Plexos calculates prices in SEM, compares these with the BETTA price profile, and determines flows based on the price differential.

Moyle is assumed to have import and export capacities of 250MW at all points of the year. EWIC is assumed to have import and export capacities of 500MW at all points of the year. Losses are modelled explicitly on each interconnector. All losses are apportioned to the BETTA market node – generation in that market is dispatched to generate enough to cover these losses.

Ramp up and Down rates of 5MW/min are included for each interconnector. No wheeling charges are included. Maintenance on each interconnector is assumed at fixed times of the year lasting one week. Forced outage rates and mean times to repair were also added to each interconnector.

It is assumed that the interconnectors can provide reserve capability, which is modelled through the characteristics of the GB dummy generators at each node. Any reserve provided by interconnectors is achieved through the same approach as is applied to generators.

A.9 Generation Portfolio

A.9.1 Conventional Generation Portfolio

The generation portfolio is taken from the 2014-2023 GCS.

Units have been assigned typical forced outage and maintenance rates, and mean times to repair, based on historical data. Forced outage rates, maintenance rates and durations are based on those used for the generation adequacy studies in the 2014-2023 GCS.

To prevent differences in maintenance schedules between the models the schedule is determined from one model. The outage pattern for each unit resulting from the MIP precision run used to derive the BETTA price profile is taken and applied as an input to all subsequent model runs.

The frequency and duration of the forced outages are determined by Plexos based on the Forced Outage Rate of the unit and the Mean Time to Repair. Forced outage patterns are determined using a method known as Convergent Monte Carlo. The Convergent Monte Carlo method works by pre-filtering patterns of outages to eliminate statistically unlikely outcomes. In those models where they are included, the timing of scheduled outages is also performed by Plexos, with units being scheduled according to an analysis of system margins in a way which ensures security of supply over the year. To ensure that the same pattern of outages is used for each model run, the same base seed number is set for the Monte Carlo Outage simulation in each model.

A.9.2 RES and DSU Generation Portfolio

Installed RES capacity matches the assumptions outlined in the 2014-2023 GCS, with Ireland meeting the EU 2020 targets of 40% RES-E and Northern Ireland meeting the Strategic Energy Policy of 40% renewables in electricity.

It is assumed that wind forecast error would have a larger impact on the dynamics between the market timeframes than the regional variation of the resource, therefore the approach to model wind focuses on representing realistic wind forecast error.

This approach represents all SEM (IE and NI) wind generators in one “All-Island Wind” unit, with the total capacity reflecting installed capacity required to meet IE and NI RES-E targets of 40% renewables as per the 2014-2023 GCS. Two capacity factor hourly profiles, one representing the forecasted available generation at DAM and one representing actual available generation at real-time, are provided for this unit to represent variation in its output over time. These are based on hourly forecast data.

For hydro, a daily energy limit constrains how much generation hydro units can produce based on historical average data. Similar limits are placed on pumped storage units to ensure their reservoir does not exceed maximum capacity and is filled to target levels at the end of each trading day, assuming that these units would be trading in a way to achieve this. A constraint is placed on pumped storage to prevent it from generating during night hours (from 00:00 to 08:00) and a condition placed on the unit to prevent it from pumping at the same time as generating (i.e. when the unit is generating, pump load is set to 0MW). Rating factors are used to represent the energy limited nature of some other unit types, with values based on those used for 2014-2023 GCS studies.

Priority Dispatch RES units are priced to reflect their price-taker status, and were assumed to price themselves based on whether they have out-of-market supports. Units under support schemes (wind, biomass, landfill gas, tidal) have offer prices at price floor of -500€/MWh, as it is assumed that they would offer as low a price as possible to achieve a cleared volume in the market, and that their supports protect them from exposure to negative prices. Other priority dispatch units (Hydro, Waste-To-Energy and CHP) have offer prices at 0€/MWh, as it is assumed that they would also offer at as low a price as possible, but that they are not protected from exposure to negative prices like those with supports, and therefore they would not offer negative prices. Prices also consider the priority dispatch order of different RES units, with a small price adjustment used to give priority to units in the following order: wind; CHP; biomass, biogas, waste-to-energy and land-fill gas; and hydro.

DSUs' offers were priced at a constant level representative of their SEM bids.

In order to model scenarios where cash flow amounts per participant / company are considered, companies representing those who participate in the SEM were created, with generation portfolios assigned to them. The largest companies with thermal generation portfolios are explicitly modelled, while other smaller and non-thermal generators are combined into a single separate company. The all-island wind unit has its ownership shared between the largest wind-owning companies explicitly modelled and the separate company for combining other generators, with the sharing proportions calculated from current ownership share derived from REFIT Wind Power Purchase Agreement data.

A.10 Demand

Demand assumptions are taken from the median forecast of the 2014-2023 GCS. The load profile used is that from the studies carried out for the 2014-2023 GCS adequacy analysis. While the model structure is set up in such a way that a demand forecast error can be included, no values for demand forecast error are currently implemented in the model. It is assumed in the model that demand does not actively participate in the market, i.e.: the volume of demand in each hour is assumed to be inflexible and demand participants bid into the market as price takers.

GB demand is based on the 'Gone Green' scenario in NGUK's ETYS published in 2013, for scenarios involving dispatching units in the BETTA region to attain a price profile. In all other scenarios, a constant load is applied to the region in order to allow dummy generators, priced as per the BETTA price profile determined in the MIP precision run, to simulate the interconnector flows.

A.11 Operational Constraints

The following indicative operational constraints, based on the current operational constraints published on the EirGrid website, are included in the BM components of the model. It should be emphasised that these operational constraints are included to understand the potential impact on the dynamics of the I-SEM of the presence of system constraints in the balancing market, and should not be taken to be a forecast of operational constraints on the system.

Operational reserve, system non-synchronous penetration (SNSP), Min Sets Transmission Constraint Groups (TCGs) and a minimum inertia requirement are included in the LTS and RTD models. No constraints are included in the DAM model.

SNSP is assumed to be 75%, and is modelled through the following constraint rule in the model:

$$\text{SNSP Limit} \geq \frac{\text{All Island Wind Generation} + \text{Interconnector Imports}}{\text{All Island Demand} + \text{Interconnector Exports}}$$

The following reserve items are modelled, with the following assumptions:

- Primary Operating Reserve Spinning (Min Provision 160MW day, 125MW night)
- Primary Operating Reserve Total. Total requirement 75% of Largest Single Infeed (LSI). It is assumed that the Short Term Active Response (STAR) scheme provides 43MW of reserve.
- Secondary Operating Reserve. Total requirement 75% of Largest Single Infeed (LSI)
- Tertiary Operating Reserve 1. Total requirement 100% of Largest Single Infeed (LSI)
- Tertiary Operating Reserve 2. Total requirement 100% of Largest Single Infeed (LSI)
- An inertia requirement of 20GWs on the SEM system

The Minimum Number of Units TCGs were modelled under the following rules:

- IE: 5 Min Sets, from CCGT and Coal plants
- NI: 3 Min Sets, from CCGT and Coal plants

A.12 Model Settings

Plexos version used: 6.302 R02 x64

Settings Item	Settings used
Horizon	Planning Horizon: 371 Days Starting 31 December 2019

Settings Item	Settings used
	Interval Length: 1 Hour Day Begins: 11:00PM Chronological Phase: Full Chronology Begin at interval 1 on 31 December 2019 Schedule [for 24hr horizon] 367 steps of 1 day Schedule [for 1hr horizon] 8808 steps of 1 hour Additional Lookahead: 6 hours in some cases, 0 in others.
Projected Assessment of System Adequacy (PASA)	Resolution: Day Transmission Detail: Regional Line and Transformer and Interface Limits: Enforced Stochastic Method: Deterministic Load and Supply: Demand Side Participation Reliability: Don’t compute indices, don’t compute multi-area reliability indices, outage increment 10MW Output Maintenance Sculpting: 50, write outages to text files
Medium Term (MT) Schedule	[Only included in DAM model for GB price and EB model – these are the only models which have scheduling requirements (maintenance and forced outages)] Simulation Steps: Year (value 2) Chronology: Partial duration curves One duration curve each Week 12 blocks in each duration curve 0 blocks in last curve in Horizon Slicing Method: Weighted least-squares fit Weight a, b, c, d: 0, 1, 0, 0 Pin Top, Pin Bottom: -1, -1 Discount Rate: 0% End Effects Method: Perpetuity Discount Period: Week New Entry Driver and Capacity Mechanism: None Time lag for Entrepreneurial Entry: 12 months Capacity Mechanism: None Generation Pricing Method: Average Cost Start cost amortisation: 0hrs Reliability: untick Use Effective Load Approach, Outage Increment: 10MW Stochastic Method: Scenario-Wise Decomposition Heat Rate: Simple Transmission Detail: Regional
Short Term (ST) Schedule	Transmission Detail: Regional Heat Rate: Detailed Stochastic Method: Scenario-Wise Decomposition Discount Rate: 0% End Effects Method: Perpetuity Discount Period: Week
Transmission	MVA Base: 100 Variable Shift Factor

Settings Item	Settings used
	Do not select Network Reduction Single Slack Bus Reactance cutoff: 0 Flow PTDF Threshold: 1E-06 Wheeling PTDF Threshold: 0.05 Enforce line and transformer limits (enforced from 0kV), and interface limits, and bounds on Phase Angles (max absolute angle: 2 radians) Do not enforce limits on all lines in interface, or contingencies, or formulate all constraints upfront Model Losses, Loss Method: Automatic Do not detect (and correct) non-physical losses Loss Function Precision: 0% Max Loss Tranches: 10 Allow Unserved Energy and Dump Energy Internal VoLL 100000 Do not allow interruption sharing Report Transmission Solution (Reporting from 0kV), report all interzonal flows Convergence Report level: Normal Transmission Rental Method: Point-To-Point
Production	[Integer Optimal used to attain BETTA Regional Price, Rounded Relaxation used otherwise] Rounding up threshold: 0.5, Self Tune Start: 0.1, End: 0.9, Increment: 0.2. Dynamic program capacity factor (and error) threshold 20% Integers in Lookahead: Auto Group Generators by Power Station Capacity Factor refers to: Installed Capacity Start Cost Method: Optimise Formulate additional unit commitment constraints upfront Formulate ramp constraints upfront Piecewise Linear Approximation – Precision: 0%, Max Tranches: 10 Heat Rates non-convexities: Warn Adjust Report Adjusted.
Competition	Equilibrium Model: None Bertrand Competition: Off Detect Active Ramp Constraints Allow Out-of-merit-order dispatch No Residual Supply Index Do not add no-load cost markup, or mark up all generation including min stable level Contract consideration: No Contract Hand-off point: Purchaser's price
Stochastic	Stochastic Samples : 1 Reduced Samples: 0 Reduction Relative Accuracy: 1 Outage Patterns: 1 Automatically Schedule: All

Settings Item	Settings used
	Outage Method: Convergent Weibull Shape Parameter: 3 Convergence Period Type: Year Untick Forced Outages in Lookahead, and EFOR Maintenance Adjust.
Performance	Solver: Xpress-MP 27.01.08 Linear Optimizer: For small problems use Dual Simplex (Less than 250000 non-zeros) For Large Problems on cold start use Interior Point, on hot start use Free Simplex Maximum Threads: 4 Mixed Integer Optimiser: At root node use Interior Point, at B&B nodes use Free Simplex For both small and large problems: Relative gap: 0.01% Improve Gap: 0% Max Time: 60 Small problems have less than 1000 integers Maximum Threads: 4

