Recommended Values for I-SEM Pricing 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 I-SEM arrangements place a large focus on "Balance Responsibility". A major component of this responsibility is for participants to be in balance with the energy which they have traded in the ex-ante markets to buy or sell. This is done through the signals in the Imbalance Settlement Price, and the fact that all Participants are financially responsible for the differences between their trade volumes (in terms of Trading and Settlement Code terminology, the Ex-Ante Quantity, QEX) and their actual consumption or generation (the Metered Quantity, QM) through the imbalance settlement arrangements (the Imbalance Component Charge or Payment, CIMB).

On the topic of the Imbalance Price, the I-SEM ETA Markets Decision Paper (SEM-15-065) decision included a summary of participant responses including that:

- Imbalance prices should be based on the actions taken by the TSO to balance the system;
- The approach should be capable of delivering prices shortly after the trading period;
- Any arrangements should not be overly influenced by any TSO subjectivity in determining which actions, or parts of actions, are classified as non-energy and thus excluded from the calculation of imbalance prices; and
- The basis of the price calculation should be transparent.

In response to participant views, the SEM Committee also decided that the implementation of Flagging and Tagging in the I-SEM should include the greatest level of objectivity that can be achieved. There are three key elements to this:

- First, the process for the classification of actions taken by the TSOs needs to be clearly documented, thus avoiding ambiguity;
- Second, the processes put in place by the TSOs to tag out non-energy actions from the calculation of imbalance prices must be published, and the TSO performance audited and reported on annually;
- Third, the SEMC considers that the implementation of Flagging and Tagging in TSO systems should focus on solutions that are automated to the greatest extent practical.

Therefore, the Imbalance Pricing solution needs to have the following characteristics:

- Efficient:
  - Marginal energy action taken to meet the NIV;
  - Based on actual dispatch / actions taken;
  - Mitigates imbalance price pollution by non-energy actions;
  - Mitigates spurious outcomes and/or excessive volatility; and
  - Can produce prices within one hour of real time.
- Robust & Adaptable:
  - Builds on GB experience;
  - Adapted for non-energy requirements of I-SEM;
  - Not susceptible to over-tagging; and
  - Capable of operating under changing market dynamics;
- Objective & Transparent:
  - Clearly documented process published;
  - Automated to the greatest extent practical; and
  - Not be overly influenced by any TSO subjectivity.

There are a number of aspects of the calculation of the Imbalance Price which help mitigate volatility, including the parameters considered in this report, calculating the half-hour Imbalance Settlement Price as the average of size five-minute Imbalance Prices (therefore if a high priced action was accepted for a short period of time, it does not set the price for the whole half-hour), and the use of Net Imbalance Volume Tagging (so that when there are insufficient SO-Flagged balancing actions to tag in order to meet the NIV, the most expensive remaining actions are then tagged until the NIV is met through untagged actions).

1.2 Parameters for Imbalance Price Calculation

Under section E.2.1 of Part B of the Trading and Settlement Code (the Code), the MO is required to report to the Regulatory Authorities proposing parameters to be used in the calculations of Imbalance Price as required from time to time if requested by the Regulatory Authorities. This document provides the methodologies to be used in determining the MO's proposals for the following parameters considered under section E.2.1 of the Code:

- De Minimis Acceptance Threshold; and
- Price Average Reference Quantity.

Under paragraph B.19.3.1 of Part B of the Code, the MO is required to report to the Regulatory Authorities proposing parameters to be used in determining the occurrence of recalculating the Imbalance Settlement Price as required from time to time. This document provides the methodologies to be used in determining the MO’s proposals for the Pricing Materiality Threshold considered under paragraph B.19.3.1 of the Code.

In all cases, any changes in context between the SEM and I-SEM arrangements, and where applicable between the I-SEM and BETTA arrangements, were considered in developing these recommendations. Where analysis and considerations has identified a potential need to change values from those currently used in the SEM, the rationale for these recommendations has been outlined. This was the case with the Price Materiality Threshold.

1.3 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. De Minimis Acceptance Threshold

2.1 Background

The application of the De Minimis Acceptance Threshold (DMAT) is intended to prevent very small volumes arising from the integration of dispatch instructions from influencing the price. Each Accepted Offer and Accepted Bid, with a quantity ($QAO_{uoi\varphi}$ or $QAB_{uoi\varphi}$) whose absolute value is less than the DMAT value is excluded from the ranked set which is used to set the Imbalance Price for an Imbalance Pricing Period at the start of the process.

2.2 Considerations

2.2.1 Criteria and Trade-offs

There are two primary reasons for applying the DMAT to the imbalance pricing process:

- Firstly, to prevent small inadvertent acceptances resulting from rounding errors in the systems from impacting on the Imbalance Price; and
- Secondly, to prevent small accepted quantities that are considered inappropriate to set or influence the price due to their size alone, or whose small size is representative of another aspect of the acceptance which is considered inappropriate such as the length of time the acceptance was open or if the quantity arose due to quirks in the data rather than a deliberate acceptance, from impacting on the Imbalance Price.

It would be important to set DMAT to a level which excludes actions which could have unintended consequences, while not excluding actions which are intended to set the price but which happen to have a small volume. Since it is a single value which is applied to all Accepted Offers and Accepted Bids, there may be situations where if the value is too high, acceptances which are considered appropriate to set the price are removed from the pricing, while if the value is too low, acceptances which are not considered appropriate to set the price can have an impact.

The impact of inappropriate acceptances setting the price is mitigated by the fact that the price would only be set for a five minute period. If the price would be considered inappropriate to apply across an entire half-hour, the five-minute pricing would reduce the impact through averaging the prices across all five minutes, so the signal from that five minute price is still retained but its effects are reduced if the actions in the remainder of the half hour are not reflective of this action. With this in mind, the value for DMAT must also be suitable for the length of the period to which it is applied, and the relative size of the market considering the level of consumer demand in the market, the size of the units within the market, the size of the imbalance volumes, and the size of the Accepted Offer and Accepted Bid Quantities.

As the value of this parameter will have an impact on the Imbalance Price, it is part of the suite of measures which impact on the volatility of the price. A sufficiently large value could remove from pricing the influence of acceptances which would be difficult to forecast and which could be very different to the other accepted prices. Quantities which could arise due to the function-of-time basis for the calculation of Accepted Offers and Accepted Bids may not be forecasted through typical block-time based modelling approaches. This is particularly the case where the average dispatch quantity over the period would not cross multiple price bands, while on a function of time basis it could do so.

Since quantities in adjacent bands can introduce step-change price differences, it could represent a substantial reduction in forecast uncertainty and volatility to remove this potential for step-change differences in the price. Also prices which arise due to unintended acceptances would tend to introduce step-change differences to those from intended acceptances. This is because intended acceptances would be based on a merit order, and therefore it is likely that they would represent gradually increasing/decreasing range of prices would be considered in the imbalance pricing process. However quantities which were not intended to be accepted may not have any relationship with the merit order or the prices of other Accepted Offers and Bids, as they only arise through quirks in the data.

However a value which is too large may reintroduce forecasting difficulty. It could have the effect of excluding the signal of an Accepted Offer or Bid which is easily forecasted, and therefore introduce uncertainty as to whether the resulting function-of-time quantity would be sufficiently large to determine that including the forecasted quantity would be accurate.

2.2.2 Assessment Approach and Drivers of De Minimis Acceptance Threshold

In the absence of operational data, a modelling based approach may not be adequate to accurately assess the value of this parameter. A modelling approach can be used for the other parameters with assumptions of the operational regime because they have a macro effect on the market in terms of price setting and settlement. However the DMAT would have a micro effect, removing small volumes of Bid Offer Acceptances from the price setting formulation. With the modelling approaches proposed, it would not be possible to accurately represent or assess this micro effect of removing small volumes from five minute pricing.

One reason for this is because it is likely that many of the small volumes would be caused by the ramping of instruction profiles between different periods, while the modelling approach is dependent on having block volumes (in this case half hour blocks). Even if five minute block volumes were to be assessed, it would still not be an accurate comparison for assessing based on the criteria outlined. It could be argued that a smaller volume which is present in all of a five minute period should have an influence on the price, while a smaller volume which is present only in the minority of the five minute period should not have this influence. It would not be possible to assess this kind of criterion with modelling data.

It may be suitable in the future, with operational data, to assess the frequency of smaller volumes of different magnitude and to investigate the influence on the price in each Imbalance Pricing Period and each Imbalance Settlement Period. For go-live of the I-SEM, a value for DMAT which reflects the theoretical needs of the functionality will be proposed.

The exclusion of small volumes from the Imbalance Price and the micro-impacts that has on the price is not likely to be as closely related to the macro aspects of the market such as the level of demand. It is more important to take into account the magnitudes of Accepted Offer and Bid Quantities, and here the differences between the BETTA and I-SEM approaches for calculating the quantities can be assessed while considering the value for the equivalent of DMAT in the BETTA market (1MWh).

Since the DMAT is applied on an Imbalance Pricing Period basis, it needs to consider the relative scale of the energy amounts in that period versus the energy amounts in the half-hour Imbalance Settlement Period considered in the BETTA market. If 1MWh is used over half an hour in the BETTA arrangements, to scale this to a five minute quantity this would need to be considered around a value of approximately 0.17MWh. This indicates that a suitable level of magnitude for the DMAT in the I-SEM may be less than 0.2MWh, rather than in the 1MWh range considered in BETTA, as it is likely that having the larger value apply to a five minute period would inadvertently exclude actions which were not intended to be excluded.

The BETTA market has closed instructions and matching closed acceptances for the calculation of Accepted Offer and Bid Quantities. I-SEM has open instructions, and settlement logic in order to create closed acceptances from those open instructions. The settlement logic involves accepting orders which reflect “the minimum quantity given the relevant technical offer data”. Therefore it is possible that volumes of orders accepted in the I-SEM will be naturally smaller than orders accepted in the GB arrangements. The settlement logic in the I-SEM may result in a larger number of orders with smaller volumes than the equivalent acceptance under the GB approach which may result in smaller numbers of orders with larger volumes, for the same overall energy amount being procured.

The appropriateness of the value for all situations would also need to be considered. For example, it may make sense that for a unit who overall has a large energy volume accepted on it, but it just so happens that the equivalent energy amount in a certain Band, in a certain Imbalance Pricing Period, which would be a desired Bid Offer Price to have impact on the Imbalance Price, has a small volume as a result of the drivers outlined previously. However it may also be the case that very small volumes being accepted on units not being driven by balancing reasons, but just by virtue of quirks in the data inputs for calculating Accepted Offer and Bid Quantities, should not be able to set the price.

One example would be due to small increases or decreases in a unit’s FPN which, when averaged to a half hour or five-minute basis, would not be present in the scheduling process. If the scheduling tools suggest a half hour or five minute quantity as a recommended dispatch quantity which can be achieved by statically maintaining output at that level, the SOs in issuing this dispatch instruction would be doing so with the intention of not procuring any balancing energy through running the unit at what the scheduling tool sees as its FPN. However due to the function-of-time differences between the static dispatch quantity curve and the ramping FPN curve, this could result in unintended acceptance of bids and offers.

There is potential for the Imbalance Price to be set based on prices submitted for Accepted Offer and Bid Quantities which were accepted not due to balancing requirements but due to data quirks. It would be a desirable outcome of the parameter setting exercise to determine a value for DMAT which is sufficiently large that it prevents these acceptances from unduly influencing the Imbalance Price, while not being so large that it prevents quantities driven by balancing requirements from being able to influence the Imbalance Price. In the RA public model, ramp rate up and down data can be used to determine the average typical ramp rate of a unit. The volumes which could arise in a five minute period between an FPN curve ramping at this rate, and a dispatch curve static at the average value of the FPN curve over the five minutes, can provide further indication of the magnitude required of the value for the DMAT parameter.

2.2.3 Calculation of Recommended De Minimis Acceptance Threshold

The ramp up rate data from the RA public model provides the following information:

- The mean ramp up rate is 5.92MW/min and a maximum capacity weighted average of 7.77MW/min, with a maximum of 50MW/min (which is an outlier considering the next largest is 20.6MW/min), a minimum of 0.03MW/min, and a median of 5MW/min;
- The mean ramp down rate is 7.6MW/min and a maximum capacity weighted average of 8.85MW/min, with a maximum of 50MW/min (which is an outlier considering the next largest is 26.8MW/min), a minimum of 0.04MW/min, and a median of 6MW/min.

With this information it would be possible to calculate MWh values for Accepted Offers and Bids which could arise in a five minute period through a ramping FPN curve while the constant dispatch quantity curve represents constant output at the average of the FPN curve over the five minute period. Under such an arrangement, the following values would result:

- Ramping at 5.92MW/min would result in Accepted Bid and Accepted Offer Quantities each of magnitude 0.296MWh in the five minute period; and
- Ramping at 8.85MW/min would result in Accepted Bid and Accepted Offer Quantities each of magnitude 0.4425MWh in the five minute period.

This suggests that a value for DMAT between 0.3MWh and 0.44MWh may be suitable for the purposes of excluding prices for such orders impacting on the Imbalance Price. Considering the calculation earlier which indicates the effect of a 1MWh DMAT over a half-hour period scaled to a five minute period being implemented through a value of 0.17MWh, this gives a total range of options for the value of the DMAT parameter of between 0.17MWh and 0.44MWh. These would represent a DMAT effective over the half hour in the range between 1MWh and 2.655MWh.

A value at the upper end of this range could have the same effect of removing from the price setting process quantities in a period where a unit's market position represents a constant output through their function of time FPN curve, and where the dispatch curve is ramping across it. The ramping dispatch curve for a static FPN curve indicates that there is an intention of accepting an offer or a bid through the dispatch, and it may be considered inappropriate to remove the prices of intended acceptances from being able to set the Imbalance Price just because they have a small value. However it may also be considered appropriate in both of these circumstances to conclude that the volumes in the five minute period where ramping FPN or dispatch curves overlap with the opposite curves of static output are not "accepted", as it is the five minute period in which the dispatch quantity is intended to be equal to the market position, and therefore these bids and offers should not affect the price in this half-hour.

This range of values does not take into account the potential for these quantities to be split between different bands or split between different orders arising from closed acceptance of open instructions, both of which would result in smaller values. Therefore a smaller value may still be appropriate for many scenarios, although it would not be possible to know for certain what proportion of appropriate scenarios would be covered until operational experienced is gained. Having a smaller value would reduce the possibility of inadvertently removing from the price setting process offers and bids with small volumes but which are appropriate to include, and would reduce the effective DMAT over the Imbalance Settlement Period as may be more appropriate considering the drivers for generally smaller volumes in the I-SEM versus the BETTA market.

However a smaller value of DMAT within this range may also make it more difficult to forecast whether or not an Accepted Offer or Bid would be excluded from pricing as it would depend on whether the Imbalance Pricing Period within which the FPN curve and dispatch quantity curve are overlapping is also coinciding with a Price Quantity Curve breakpoint or a closed acceptance of an open instruction. A larger value would means that in most situations the quantity would be removed from pricing, which should make it easier to forecast

Considering all of this, a value of 0.4MWh is recommended, which represents an effective DMAT over the Imbalance Settlement Period of 2.4MWh, and should exclude quantities calculated considering ramp rates less than 8MW/min in the curve-overlap scenarios previously considered (which would cover the ramp up rates of 51 units, and ramp down rates of 43 units, out of the total of 68 units with ramp rates in the RA public model). This may be interpreted as a slightly conservative value which should ensure that in most Imbalance Pricing Periods where the dispatch quantity curve and the FPN curve overlap that the resulting accepted quantities are removed from the pricing process, which should work to reduce volatility in the Imbalance Settlement Price and make forecasting this price easier. With operational experience of the I-SEM it can be investigated whether such a value is indeed conservative and should be reduced in order to stop preventing intended quantities from setting the price.

2.3 Recommendation

It is recommended that a value of 0.4MWh is used for the De Minimis Acceptance Threshold from go-live of the I-SEM, on the basis that it should remove the impact of unintended accepted offers and bids from the Imbalance Price, should work to reduce volatility in the Imbalance Settlement Price, and should help making forecasting this price easier.

3. Price Average Reference Quantity

3.1 Background

The Price Average Reference Quantity (QPAR) is a parameter which determines the volume of untagged actions in the ranked set of Bid Offer Acceptances over which the volume-weighted average price is calculated.

In the BETTA market, the original purpose of the PAR Tagging mechanism was to more closely align the main energy imbalance price with the price of the marginal energy balancing action (i.e. the most expensive action taken by the SO to balance total energy supply and demand). It is important to note that GB has moved progressively to average pricing over a smaller subset of quantities and intends to move to marginal pricing in 2018. The imbalance price is calculated based on the volume-weighted average of a defined volume of the most expensive remaining unflagged actions. In BETTA, as of 5th Nov 2015, this defined volume is 50MWh moving to 1MWh from 1st Nov 2018.

In the I-SEM ETA Markets Decision Paper (SEM-15-065), the SEM Committee considered the definition of the marginal price and whether imbalance prices should be less sharp than if price were to be set solely on the marginal increment required to provide energy balancing. The decision sets out the following in relation to PAR:

- Preference for marginal imbalance price;
- A suite of pricing parameters can be considered together to mitigate the concerns of participants (e.g. Continuous Acceptance Duration Limit or CADL, De Minimis Acceptance Threshold or DMAT, and QPAR);
- Some averaging may be permitted if evidence-based and time limited; and
- If any averaging measure is introduced, it should not unduly dampen the Imbalance Price or blunt incentives to balance.

During the Rules Working Group process which followed this decision, the approach of calculating the Imbalance Price on a five minute basis, and from this calculating the Imbalance Settlement Price as a simple average of the six Imbalance Prices within the Imbalance Settlement Period, was outlined. This approach removed the need for a Continuous Acceptance Duration Limit (CADL) parameter, and in itself introduced an additional mechanism for mitigating against volatility in the price. From the Rules Working Group process it was also clear that there is an appetite for a Price Average Reference at least on a transitional basis. In order to facilitate this, the functionality was included in the rules and systems for the calculation of the imbalance price.

3.2 Considerations

3.2.1 Participant Concerns

Participant concerns were noted in the I-SEM ETA Markets Decision Paper (SEM-15-065) in relation to Imbalance Pricing. There were a number of comments in relation to participants that would be exposed to the imbalance price and a desire for some form of risk mitigation function. Others expressed concerns with respect to the transition from SEM to I-SEM and wanted to see mechanisms to dampen potential volatility in the Imbalance Price as new systems and processes were bedded in and the industry adapted to the new regime. There was support for approaches similar to that adopted in GB of transitioning towards marginal pricing. Equally, there were comments that dampening volatility of the Imbalance Price would introduce distortions which affect the wider market and that the price should reflect the actual costs of balancing the systems.

It is in the context of these concerns and the SEM Committee decisions that the analysis for the PAR Quantity has been carried out noting that any approach other than basing the price on the marginal MWh should not unduly dampen the price and balancing signal. An approach which is more marginal would ensure the price reflects the cost of balancing, and in providing a strong signal for balance responsibility would drive the need for participants to use the ex-ante markets to ensure they are balanced.

However the greater volatility caused by such a purely marginal approach could create uncertainty which would have adverse impacts on ex-ante market trading, reducing liquidity as participants would be more conservative, i.e. they would be less likely to trade to a position which is reflective of what they actually expect and would instead sell less generation or buy more energy through the ex-ante markets than they expect to arise in physical reality, in order to reduce the possibility of having a negative imbalance at a potentially high price.

Therefore, those concerns focussed around dampening volatility in the price, and mitigating against unintended impacts during a period of uncertainty at the start of the new arrangements, could be investigated, rather than investigating a dampening in the general signal provided by the price. However, this would also need to be carefully considered against the possibility that implementing an average price approach could cause a lack of the situations about which participants would need to learn and to which they would need to develop responses. This would suggest that different potential values for QPAR should be investigated given the intended outcome of reducing the volatility in the price signal (for example as indicated through the maxima/minima and standard deviation in the price over a study period), while not dampening the overall price signal itself (for example as indicated through the average price over a study period, or the average price in each hour over the study period).

3.2.2 Potential Qualitative Impacts of Price Average Reference Quantity

It may become more difficult to forecast prices with a relatively large QPAR. Typically modelling tools would be useful to determine the prices of the marginal actions taken in balancing, and also more simplistic methods could be used by comparing an offer stack with an imbalance requirement to determine the marginal action which would be taken, and the price of that action. It may be more difficult to predict the other-than-marginal actions which would be taken in the balancing market, particularly given the constrained nature of the market so that it is not a given that an “in-merit” action would be taken in its entirety: it may in fact be only partially taken before a constraint prevents the remainder of that action from being taken. Considering that the marginal action should reflect the last MWh required, the volumes of those other-than-marginal actions are likely to be larger than the volume of the marginal action. This could mean that the price of the other-than-marginal actions would have a large influence on the Imbalance Price as it is a volume weighted average price over the PAR Quantity. As a result, the larger the PAR Quantity, and the less marginal the Imbalance Price calculation is, the more difficult is may be to forecast the price accurately.

If the Imbalance Settlement Price is reduced from the cost of the marginal energy action, the mismatch between money-in and money-out (i.e. imperfections) would change. It is not necessarily the case that a reduction in the price would always result in an increase in the imperfections. It would depend on the relationship between the Bid Offer Prices used in settlement and the Imbalance Price calculated, and the ratio of imbalance volumes to accepted offer and accepted bid volumes. This is because a decrease in the price would result in:

- A simultaneous decrease in imbalance payments to participants who are long and decrease in imbalance charges from participants who are short;
- A decrease in the inframarginal rent through Imbalance Payments for accepted offers whose offer price is less than both the marginal Imbalance Price and the QPAR averaged Imbalance Price;
- An increase in the premium payments for accepted offers whose offer price was less than the marginal Imbalance Price but is greater than the QPAR averaged Imbalance Price, or whose offer price was greater than both of these prices;
- An increase in the inframarginal rent through imbalance charges for accepted bids whose bid price is less than the marginal Imbalance Price but is greater than the QPAR averaged Imbalance Price, or whose bid price was greater than both prices; and
- A decrease in the discount payments for accepted bids whose bid price was less than the both the marginal Imbalance Price and the QPAR averaged Imbalance Price.

This complex interaction may need a modelling assessment of settlement outcomes under different scenarios to determine the likely outcome. If the result is that the imperfections increase through the reduction in the price, participants who were out of balance in a negative direction will have to pay a price which is lower than the price which must be paid to the marginal energy action used to keep the system in balance. This could create the macro effect that the cost of balancing the system becomes more socialised across all consumers (through recovering this mismatch in Supplier Imperfections Charges) rather than being based on a more “polluter pays” principle of those who were out-of-balance in that period paying for the balancing actions they caused, which would be more effective in incentivising balance responsibility. This would have to be considered in the trade-off between different outcomes of different levels of PAR Quantity.

One potential effect of increasing the value of QPAR would be the potential for the price to be switched from being positive in the baseline marginal price scenario to being negative in the larger QPAR scenario. For example, under a baseline of a small value for QPAR it is likely that the price would be set by a single Accepted Offer or Accepted Bid, or by a number of Accepted Offers/Bids which are close together in the merit order and therefore are likely to have prices of similar magnitude and sign. However as the number of Accepted Offers and Bids over which the average price is calculated increases with an increasing QPAR value, the more likely it is that prices which are of very different magnitude, and potentially of different signs, would be included in the average.

Having anything other than marginal pricing could also be a barrier for units which are not in the Capacity Mechanism, due to the interaction with the Market Power decision that if a unit is found to have non-energy actions from the point of view of the Flagging and Tagging process in Imbalance Pricing then their Bid Offer Price is changed to reflect a price to which Balancing Market Offer Principles apply. These units would rely on applying scarcity premia to their offers for those few run-hours in the year where they may be run in order to recover their costs. If these units also happen to contribute to non-energy actions from being NIV tagged, in settlement this unit would have their Bid Offer Price changed to reflect their Short Run Marginal Costs, which would not have this premium. However, since the unit is likely to be the marginal unit for energy balancing purposes in these cases due to its high price and the potential reasons for accepting such an action, it is also likely to set the price (i.e. it is not fully NIV tagged). If it sets the price, then regardless of whether the Market Power provisions apply in settlement, the unit will still receive its scarcity premia. However, if the price is no longer set based on the absolute marginal unit but rather based on the average of a number of prices, the price can reduce and alongside it the scarcity premium paid to these units in these scenarios.

All of this would suggest that only a relatively small value for QPAR should be considered, as larger values could result in these types of effects. Therefore, if the only scenarios which have the intended effect of reducing volatility in the price are larger QPAR values which also result in these other impacts on the price, this suggests that a marginal price approach should be used.

3.2.3 Investigation of Studies Undertaken for Price Average Reference in BETTA Market

In the BETTA market, a number of modifications, proposed and implemented, considered the exact value for the PAR parameter, including the following:

- P205 – increase PAR from 100MWh to 500MWh (implemented);

- P217 – change to other aspects of flagging and tagging, but adjusted proposal (which was to reduce PAR to 100MWh) so that PAR of 500Mwh is maintained (implemented) ;
- P304 – reduce PAR from 500MWh to 250MWh (rejected);
- P305 – Electricity Balancing Significant Code Review (includes reducing PAR from 500MWh to 50MWh in Nov 2015 then 1MWh in 2018) (implemented);
- P314 – reduce PAR from 500MWh to 350MWh (rejected);
- P316 – introduction of single marginal imbalance price (rejected, due to the implementation of P305).

As the modifications which were implemented to change the values of PAR firstly to be increased towards having more average-based pricing, and then to be decreased towards having marginal pricing, modifications P205 and P305 have interesting considerations for this study. Some of the findings from the analysis performed for these modifications, and the modelling approach and metrics used to perform this analysis, are outlined in the following sections.

3.2.3.1 P205

This modification, the information and analysis related to which can be found at the following link, followed from one to move from an approach of calculating a price based on the average of all actions to a more marginal approach by calculating a price based on the average of a subset of actions (P194).

The main reasons modification P205 was proposed included the following:

- Parties were already doing everything that they could to balance, and having a stronger balancing signal would not change behaviour;
- The proposal provided less incentive to take a long position;
- There would be fewer negative system sell prices (SSP) due to problems in the tagging mechanism;
- It would lessen the impact on smaller parties (particularly renewables); and
- A lack of market liquidity creates difficulties to balance, particularly for small parties.

In the Urgent Modification Request report (P205UMR), a number of potential issues raised by using a single or small volume balancing action to set the Imbalance Price were outlined, such as:

- Tagging mechanisms to remove balancing actions from the pricing calculation may be imperfect, and therefore if the price was based on a single action, it could be based entirely on a system action – whereas if it was based on an average of untagged actions, it would reduce the influence of that system action on the price. However, increasing PAR would also increase the proportion of settlement periods where the influence of system actions is present.
- Making the arrangements more open to manipulation and the exercise of market power. If the PAR Tagging is carried out over a relatively small volume, it may be possible for a single / small number of units, or a single / small number of corporate entities, to set the price. However the analysis

summarised in the report of market power issues suggested that the relationship with PAR was weak and therefore analysis of this metric is not likely to sufficiently justify different values of QPAR.

These can both be mitigated through use of a PAR Quantity which considers more than this single balancing action. However these are issues in their own right, and may be more appropriately dealt with through revisions of the mechanisms directly, rather than being mitigated indirectly through PAR Tagging. If it is considered important to have a value for QPAR which minimises the possibility of a single action, single unit or single corporate entity from setting the price, a means of determining an approximate value of PAR Quantity as a start point would be to assess the average Bid Offer Acceptance Quantity. The Average Bid Offer Acceptance Quantity plus two standard deviations would statistically suggest that more than one balancing action would be used to set the price approximately 95% of the time.

Most participant views shared through their consultation responses distilled down to differences in opinions about whether the price should be aligned with the marginal energy balancing action.

To help support the decision to implement modification P205, analysis was provided, primarily by EDF and Elexon.

In their analysis, Elexon provided the following analysis metrics which may provide an idea for which metrics to use in the analysis for the I-SEM QPAR parameter:

- The average price per settlement period calculated using past data over a period of time (a year from April to March in this case), given different values for PAR. The calculated System Buy Price and System Sell Price were displayed together against average demand and the average "Market Price". They also displayed a "tolerance" for sell and buy separately;
- The frequency distribution of percentage of periods in which PAR makes up a range of percentages of NIV, showing times when PAR makes up low percentage of NIV (e.g. in 2% of periods it represented 0-10% NIV) and when PAR makes up high percentage of NIV (e.g. in 80% of periods PAR represented 90-100% of NIV), for each option of PAR being considered;
- The price in each period on a given day with certain characteristics (for example with shortage on the system), for each option of PAR, displayed against the Net Imbalance Volume in each of these periods;
- The average price, the standard deviation of the price, and the extreme prices for different options of PAR in different years.

In their analysis, EDF provided the following analysis metrics which may provide an idea for which metrics to use in the analysis for the I-SEM QPAR parameter:

- System Sell Prices and System Buy Prices in all hours of a year (05/06 in their example), calculated using past data for different scenarios of PAR, and graphing these prices (£/MWh) against the System Margin (MW). Using this, the "sharpness" of the price signal can be compared with the need for it to be

sharp, i.e. if the price is high when the margin is low, this could be seen as the correct signal;
- The extent of the influence of system actions on the imbalance price could be illustrated through instances of negative bid prices and high positive offer prices influencing the Imbalance Price. By looking at the number of instances of outlier negative prices, it could be investigated whether at these times system actions have "polluted" the System Sell Price. This may not be as relevant for the I-SEM. In the Imbalance Pricing mechanism, all actions taken for system reasons are explicitly flagged before the Marginal Energy Price is determined. This price should then reflect energy actions only, to the extent that the System Operator Flags account for all non-energy actions. Following that, replacement prices are determined, and the Imbalance Price is calculated in a way that SO-Flagged units are "tagged out", so even if their price was not replaced, that price would not be able to influence the overall Imbalance Price. Therefore it is considered that this metric is not relevant for the analysis of the PAR Quantity in the I-SEM;
- Determining the number of units and corporate entities who directly influence the setting of the Imbalance Price in each period (or focussing on a typical day) for different options of PAR, would help in considering the potential for market power of different participants to set the price. PAR could be a tool which would potentially expand the price setting to additional corporate entities, reducing the scope for market power. However, in the I-SEM context, market power in the balancing market has already been explicitly considered by the Regulatory Authorities, with a decision not to implement controls for energy balancing – only introducing controls for non-energy balancing actions. Therefore it is considered that this metric is not relevant for the analysis for the PAR Quantity in the I-SEM.

3.2.3.2 P305

Modification P305, the information and analysis relating to which can be found at the following link, was proposed as it was thought that deriving a weighted average from a volume of 500MWh creates an imbalance price which does not reflect the marginal cost of balancing energy for a given Settlement Period. It was thought that this may lead to parties overlooking balancing opportunities available before Gate Closure which are cheaper than actions available to the SO, which would be especially material during very tight margins when differences between the costs of accepted balancing actions are greatest.

The following were primary reasons for the decision to implement the modification (in relation to the PAR element):

- The draft Electricity Balancing Network Code (now known as the Electricity Balancing Guideline) required a marginal pricing approach for energy balancing prices, and at a minimum a weighted average price approach for imbalance prices;
- It created a better incentive to improve balancing performance and increases the competitive advantage gained by parties that avoid worsening system

imbalances, and better signals the value of flexible capacity to the market supporting competition and liquidity through marginal price signals to balance;
- The analysis carried out suggested that the distributional effects of the proposal would not lead to detrimental impacts on competition.

The following were outcomes of the analysis carried out by Elexon to support the P305 modification which would be relevant to the I-SEM context:

- Prices calculated with a smaller PAR are more sensitive to individual large positive or negative actions (in terms of volume or price);
- Reducing PAR tended to increase the price;
- Reducing PAR could have a more detrimental effect on Parties who fail to manage their imbalance positions adequately;
- Moving to a single price approach had an impact of reducing all Party types' imbalance cash flows; however, reducing PAR diminished the beneficial reduction in imbalance cash flows introduced by the single price approach;
- From the wider theoretical analysis:
    - The entire set of packages (including moving from PAR of 500MWh to PAR of 1MWh) would likely lead to more efficient balancing behaviours, resulting in savings to consumers, due to industry facing imbalance charges that are reflective of the costs incurred in keeping the system balanced;
    - Having prices where these costs are not reflected will not accurately reflect the value of flexibility;
    - Sharper price signals in periods with tighter system margins should result, meaning the cost of capacity adequacy could be reduced, driving efficiency in security of supply. This may also help to address the missing money problem for those participants who had exited the Capacity Market;
    - Smaller participants, which historically have had larger relative imbalance volumes, could be expected to be disadvantaged by sharper price signals to a greater extent than other Participant Types, but similarly can benefit from this price signal when imbalance volumes result in a payment rather than a charge.

To develop output metrics which could be used to assess different options for PAR, an approach of recalculating imbalance prices based on historical data of accepted Bids and Offers with scenarios for different parameter inputs to the process in terms of values of PAR was taken. Using other inputs such as traded volumes and system margin / loss of load probability, a wide variety of output metrics were developed.

To apply this to the I-SEM an approach of using modelled data, as opposed to historical data, would need to be used. This is because the current price is not based on offers and bids accepted by the SOs, it is based on the purely marginal price of an unconstrained market schedule. Incremental and decremental volume data is not readily available from current market data, and if it could be made available, using a baseline price of the SMP would not be representative of the baseline scenario for the Imbalance Settlement Price in the I-SEM.

The BETTA approach was a static one, i.e. it did not attempt to model the behaviour change which would result from the change in the signal provided by the Imbalance Settlement Price(s). Therefore this would not be entirely representative of market outcomes under each regime: normally Participants would respond to the signal provided by the price, changing the signal provided, which again changes the response until such a time as an equilibrium of signal and behaviour response may be attained. The approach used in BETTA, and which would need to be adopted for the I-SEM, would not represent this element to the QPAR parameter. This instead needs to be inferred from the theoretical outcomes of the potential responses to different price signals.

Under this modification, the following scenarios were considered:

- PAR of 1MWh;
- PAR of 50MWh;
- PAR of 100MWh;
- PAR of 250MWh;
- PAR of 350MWh;
- The base case scenario considered a PAR scenario of 500MWh based on the historically calculated prices.

The following output metrics were considered to assess impacts on the balancing signals through the imbalance price under each scenario:

- Maximum Imbalance Settlement Price over the study year, by scenario;
- Minimum Imbalance Settlement Price over the study year, by scenario;
- Average, maximum, minimum, and standard deviations of Imbalance Settlement Prices of each Trading Day / quarter over the study year, by scenario;
- Number of negative price events in the study year, by scenario;
- Frequency distribution of Imbalance Settlement Price in different ranges of price, by scenario;
- Average change in the price versus the base case, per Trading Day over the study period, by scenario;
- Maximum change in the price versus the base case, per Trading Day over the study period, by scenario;
- Frequency distribution of Imbalance Settlement Price Change into different ranges of price differences, by scenario;
- Scatter plot of Imbalance Settlement Price versus the System Margin, linear representation of the relationship between the two metrics, with separate graph per scenario.

Distributional effects, i.e. additional cost or benefit versus the base case, were also investigated through comparing values for different Participant Types.

3.2.4 Scale Considerations

There are a number of things which need to be considered in assessing the relative scale of the QPAR for the I-SEM, including:

- The duration of period to which it is applied relative to the duration of the interval used in the modelling methodology to determine the parameter, and relative to the duration of the period in the BETTA market to which the equivalent parameter is applied;
- The magnitude of the I-SEM balancing market and imbalance volumes to the magnitude of the BETTA market balancing market and imbalance volumes;
- The extent to which system actions are captured in the I-SEM flagging mechanism relative to the extent to which they are captured in the BETTA market mechanism; and
- The magnitude of the I-SEM electricity demand and installed generation capacity relative to the magnitude of these in the BETTA market.

Since the PAR is applied on an Imbalance Pricing Period basis, it needs to consider the relative scale of the energy amounts in that period versus the energy amounts in a half-hour period considered in the BETTA market. For example, if the PAR Quantity in the GB arrangements is 60MWh for a half-hour quantity, to scale this to a five minute quantity this would need to be considered around a value of 10MWh. Also, in order to accurately assess the impact of this value in the modelling approach used with its hourly interval duration, the values for QPAR used in the modelling scenarios considered should consider that the value used in the market would need to be scaled down by 1/12. For example, in order to assess a 10MWh QPAR value, a value of 120MWh should be used as a modelling scenario.

The total volume of actions available for price setting through PAR tagging is dependent on two main things: the Net Imbalance Volume (i.e. the total energy imbalance which needed to be corrected through system actions) and the level of System Operator Flags (i.e. whether actions are flagged as non-energy due to being taken for system reasons relating to operational constraints in the scheduling tools). These in turn are influenced by the size of the system, as the maximum practical net imbalance would arise if all demand was cleared through the imbalance arrangements rather than the ex-ante markets. This would be unlikely, but is useful to know as an extreme. If we take the Total Electricity Requirement (TER) peak demand for 2015 for Ireland and Northern Ireland at 6746MW (reference Generation Capacity Statement 2016 – 2025), and the Average Cold Spell (ACS) peak demand for the “Gone Green 2015” scenario, for the period 2015/16, of 55200MW (reference Electricity Security of Supply Report 2015), a rough estimate of the maximum scale of this difference is (6746/55200) x 100 = 12.22%, i.e. the I-SEM values should be considered at approximately 12% of those considered for the BETTA market.

Non-energy balancing market volumes would be driven by the operational constraints on the system, and the trading of generator units in the ex-ante markets which could cause a constraint to be relieved or bound. There would typically be a greater level of operational constraints for the I-SEM system than the BETTA system, which would result in a relatively larger volume of such actions, and, with more constraints considered as requiring SO Flags, it is less likely that System Operator actions will inadvertently influence the Imbalance Price. This does not mean that actions which were initially considered to be for system reasons would not have any influence on the price. However this influence would be an intentional part of the design. For example, it is possible for actions which were initially SO Flagged to be untagged in situations where there were more actions which were initially tagged than were required to meet the Net Imbalance Volume. If the price of such an untagged action was “in merit” in an Imbalance Pricing Period, the prices of these actions can be considered in an average price situation. However the price of an action which was not “in merit” has its price replaced with Price of the Marginal Energy Action prior to continuing towards calculating an average price, and therefore would not have its price considered even if it were to be untagged in a similar fashion.

The more constraints that are considered as requiring SO Flags, the smaller the remaining volume of untagged energy actions in the stack, used firstly in the NIV Tagging process and then to set the Imbalance Price, will be. The effect of calculating a price over a larger amount of the remaining untagged volume would be different between I-SEM and the BETTA market due to the different positions of actions tagged in the approaches of each market. The NIV Tagging approach in the BETTA market is the main means by which system actions are removed from the price, and it typically works in a single direction (from top to bottom). Therefore having a large PAR Quantity typically means that it is taking prices of the remaining volumes in that same direction, from the top down, with the most extreme prices (highest or lowest) all tagged prior to calculating this average. Taking actions in that direction would typically represent a gentle gradient in prices, as it would generally follow the merit order from top down, and depending on participant submissions, prices would not differ drastically from one action to the next. In the I-SEM, given that NIV tagging considers SO-Flagged actions first before then applying the top-down approach, it is more likely that a large PAR Quantity would be taking in very different prices from different parts of the merit order, e.g. it would be starting from the top of the remaining actions (e.g. higher priced actions), would then skip over tagged actions within the middle of the merit order, and then would take in prices from further down the merit order (e.g. lower priced actions). The gradient between the prices considered in the PAR Quantity is likely to be larger (i.e. the differences between the price from one order considered in the average to the next is likely to be larger) than what is considered for the BETTA market. This further suggests that a relatively smaller PAR Quantity may be more suitable for the I-SEM than that considered for the BETTA market.

It needs to be considered if these differences in scale are additive or overlapping, i.e. should the scale of the parameter be reduced first for the time period implications, and then further reduced due to the scale of the system. An incentive which relates to the system scaling is whether or not the QPAR should be set to a level which reflects the marginal cost of balancing, or which doesn’t. For example, if the decision was taken to not strictly reflect the marginal cost of balancing, as was previously implemented in the BETTA market, a value for QPAR which reflects this would need to be scaled by size of system, as those other incentives would depend on system size. A value of 500MWh was chosen in GB to largely maintain the status quo of calculating the average over all actions taken: the overall volume of actions taken depends on the size of the system, and therefore to accurately reflect this as an appropriate value for the I-SEM, it would need to be approximately 12% of 500MWh which is 60MWh. However if the incentive was intended to strictly reflect the marginal cost of balancing, a value of 1MWh may be decided (as is planned for the

BETTA Market). This value is related to the marginality of actions, rather than the size of the system, and would not need to be scaled to have the same meaning for the I-SEM system.

Therefore for each PAR Quantity scenario considered, only relatively small values of QPAR should be considered. As such scaling due to system size may not be necessary other than to indicate the absolute maximum QPAR value which can be considered, which based on the previous paragraph would be 60MWh for a half hour. Scaling related to timing is a core requirement, i.e. if a value is deemed appropriate over a half-hour (for example, a QPAR value of 60MWh over a half-hour for a wider average pricing approach or 1MWh over a half hour for a marginal pricing approach) then to accurately reflect its influence in a five minute period where the offer and bid quantities would be scaled down, that value would need to be scaled by time. In this case, if the appropriate value to reflect a wider average pricing approach is 60MWh, the value to do so in a five minute period must be 5MWh, and if the appropriate value to reflect a strictly the marginal cost of balancing in half an hour is 1MWh, the value to do so in five minutes must be approximately 0.17MWh.

3.2.5 Considerations for Proposed I-SEM Price Average Reference Quantity Determination Approach

The high level methodology consists of determining from modelling work what the value should be on an hourly modelling interval basis, and then mechanistically adjust the resulting value to the appropriate value for a five minute Imbalance Pricing Period (i.e. dividing the resulting hourly value by twelve, and rounding to an appropriate degree), with this value being the final parameter being recommended for use in the I-SEM.

One result for QPAR which could closely match the conflicting criteria in the trade-off would be a value which:

- Reduces the Standard Deviation of the Imbalance Settlement Price (and therefore reduces overall volatility;
- Reduces the magnitude of outlier maximum and minimum prices over the study year to being representative of the values in other periods;
- Does not have a significant impact on the average Imbalance Settlement Prices;
- Concentrates this effect in periods where the volume of imbalances is relatively small, while the higher prices and higher volatility is still present to an extent sufficient to be a signal for balance responsibility and learning (even if diluted to a certain extent) in those periods where the volume of imbalances is relatively large.

This could be thought of as a QPAR which effects a “step change”, where the price is not calculated as an average over multiple actions in general but where it is calculated as such in those periods where it is deemed desirable. This would depend on the relationship between the magnitude of the QPAR value and the characteristics of the ranked set of Accepted Offers and Bids on which the parameter is used, in those periods where its dampening effects are desired, and this relationship in those periods where its dampening effects are not desired / not needed.

The PAR Quantity values used in these scenarios need to be stated in light of the period to which they are relevant (five minute Imbalance Pricing Period, half an hour Imbalance Settlement Period for example in considering the equivalent parameter in the BETTA market, or an hour interval in the modelling tool). This is clarified through additional columns in the table below, which outlines the scenarios considered, and the differences between the different models. Appendix A gives further details about the modelling approach and assumptions.

Scenario Name	QPAR in IPP	QPAR in ISP	QPAR in model interval	DAM	LTS	RTD
HHQPAR1	0.17	1	2	Base	Base	Base, price with QPAR = 2MWh
HHQPAR20	3.33	20	40	Base	Base	Base, price with QPAR = 40MWh
HHQPAR40	6.67	40	80	Base	Base	Base, price with QPAR = 80MWh
HHQPAR50	10	60	120	Base	Base	Base, price with QPAR = 120MWh
HHQPAR60	16.67	100	200	Base	Base	Base, price with QPAR = 200MWh

Annual average prices and standard deviations, daily profiles of average, maximum and minimum prices, and standard deviations (represented as error bars on the average with one standard deviation in each direction) of prices in each modelling over the study year, with a separate graph per scenario, are considered the primary outputs used to determine the effects of QPAR on the Imbalance Price.

3.3 Results and Analysis

It is important to read these results in the context that the modelling work carried out to calculate them was not intended to be a forecast of future operating regime, but rather was intended to show the relative differences between two scenarios when different values are applied to the same calculation methodology.

Imbalance Prices for each model period were calculated for each scenario of QPAR considered, using the methodology and assumptions outlined in the appendices. Scenarios for QPAR ranging between 0.17MWh to 10MWh were investigated, as they represented the range of values considered in section 3.2.4. An additional scenario with a larger QPAR of 16.67MWh, equivalent to 100MWh for a half hour period, was also considered. The results for all of these scenarios are outlined in Appendix B. For the remainder of this section, the two core scenarios at the edge of the range of those considered, HHQPAR1 (with a QPAR value of 0.17MWh for the five minute Imbalance Pricing Period, equivalent to 1MWh for a half hour period) and HHQPAR60 (with a QPAR value of 10MWh for the five minute Imbalance Pricing

Period, equivalent to 60MWh for a half hour period) were considered, as the results between these two scenarios largely linearly interpolated between them.

Figure 1 outlines the results for the annual average and standard deviations of the price for the two scenarios. Figure 2 outlines the results for the daily profile of the average, maximum, minimum and standard deviation of the prices over the study year for HHQPAR1 scenario and Figure 3 outlines the same result for the HHQPAR60 scenario. Figure 4 and Figure 5 zoom in on the range of the price profiles previously shown in Figure 2 and Figure 3 respectively in order to show more clearly the differences in the average price profile and the standard deviations between the scenarios.

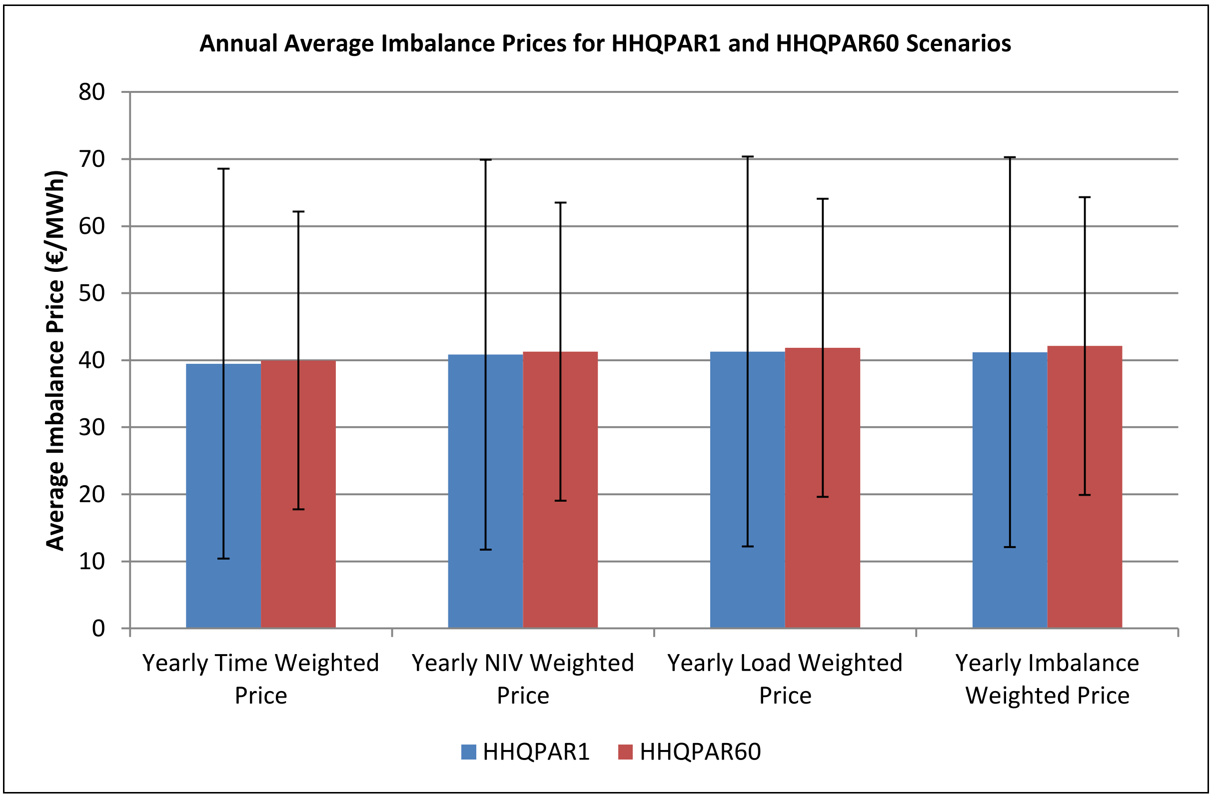


Figure 1: Annual Average Imbalance Prices for HHQPAR1 and HHQPAR60 Scenarios

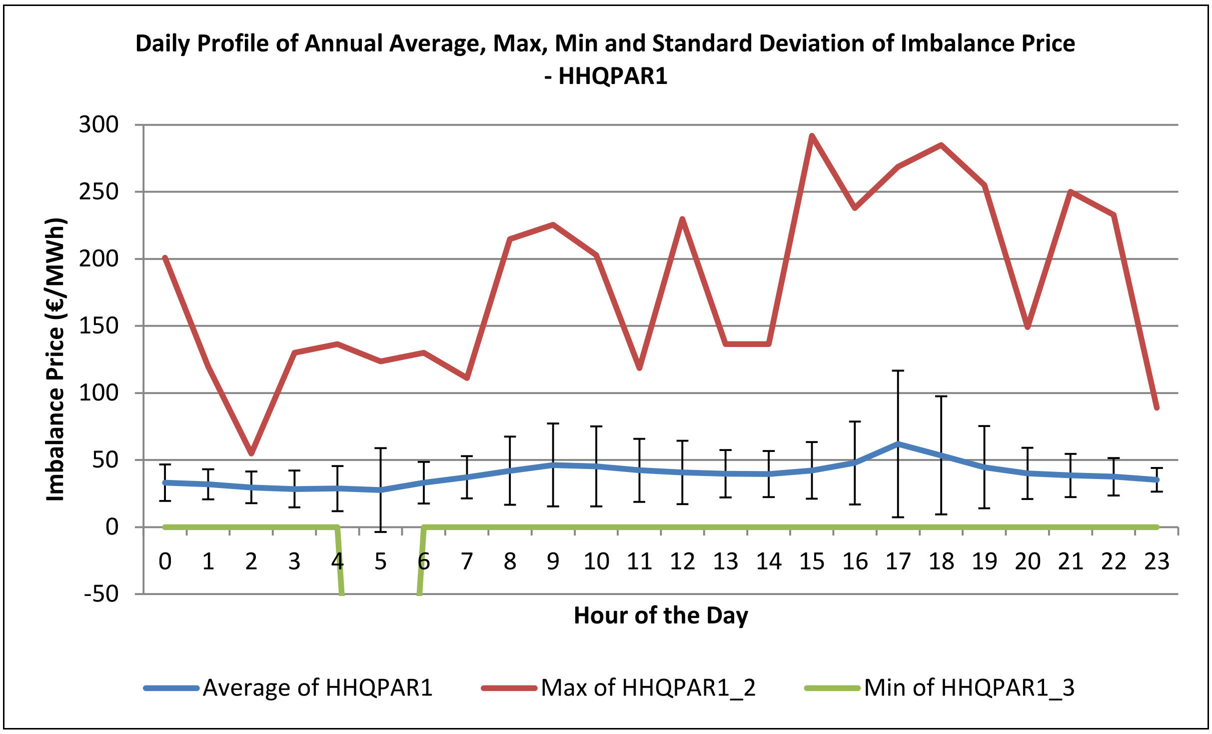


Figure 2: Daily Profile of Annual Average, Max, Min and Standard Deviation of Imbalance Price - HHQPAR1

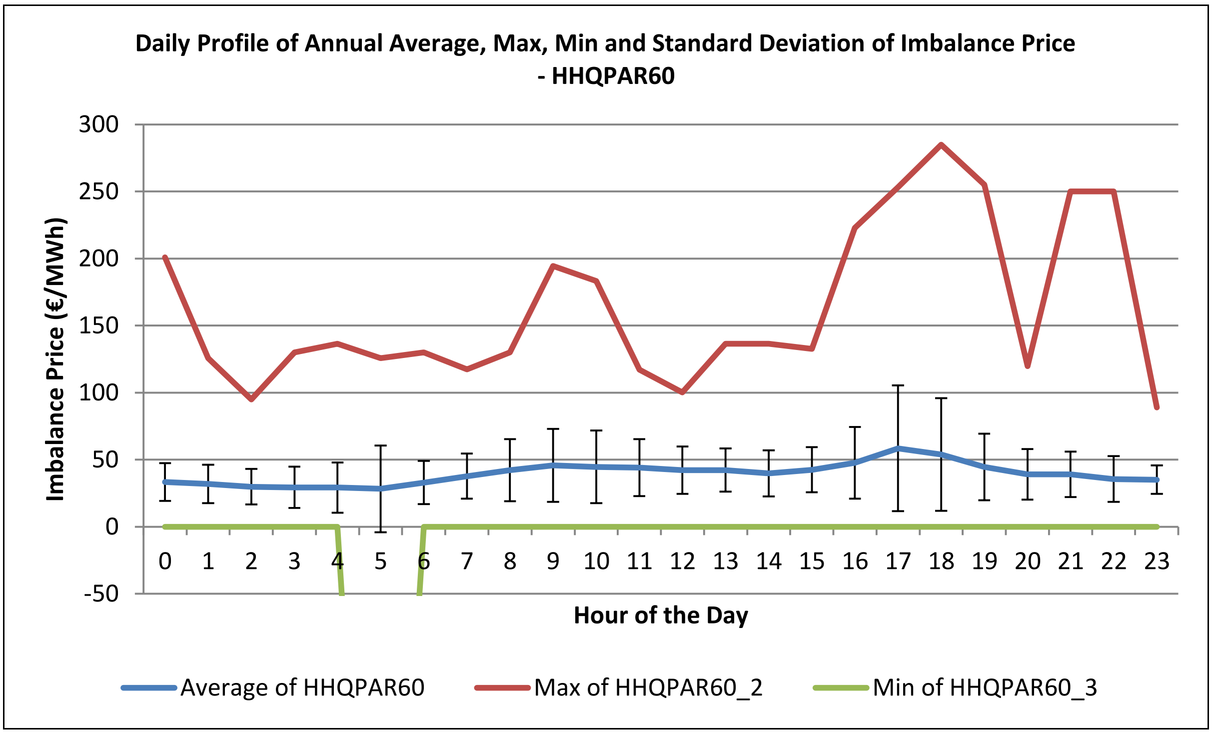


Figure 3: Daily Profile of Annual Average, Max, Min and Standard Deviation of Imbalance Price - HHQPAR60

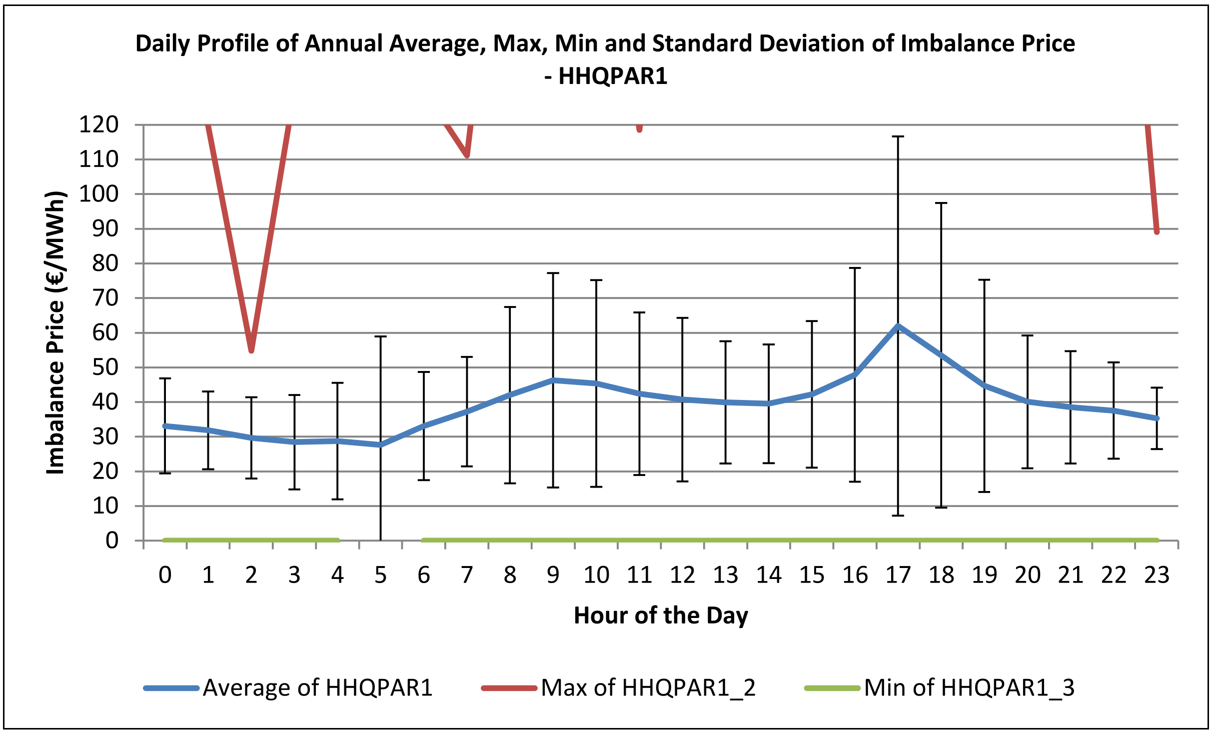


Figure 4: Daily Profile of Annual Average, Max, Min and Standard Deviation of Imbalance Price - HHQPAR1, Zoomed in on Price Profile Range

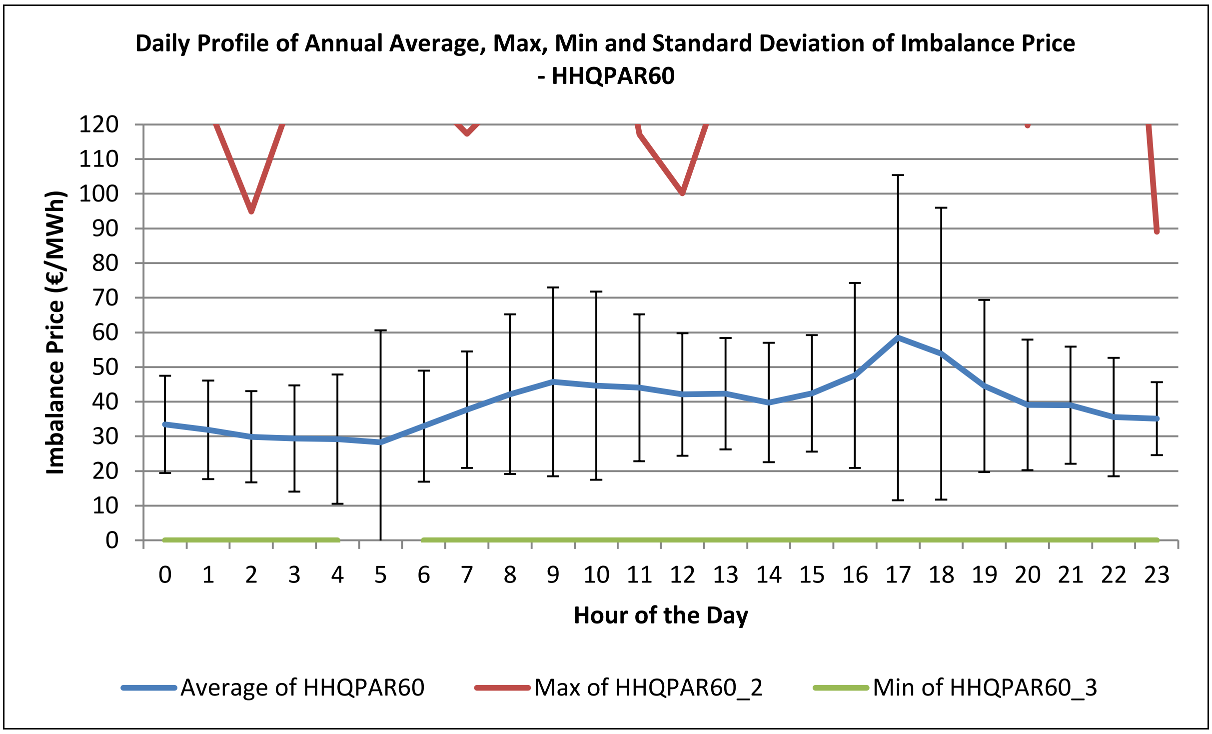


Figure 5: Daily Profile of Annual Average, Max, Min and Standard Deviation of Imbalance Price - HHQPAR60, Zoomed in on Price Profile Range

One outcome shown by these results is that the standard deviation in the price is relatively low in both scenarios, both on an annual and a daily profile basis. Also, while there is a slight reduction in the average price in the peak period of hour 17 resulting through increasing the QPAR, there is a slight increase in the price in other periods, and the overall effect on the annual average is to slightly increase the average price.

From investigating the data, it occurs in particular in periods where the Net Imbalance Volume Quantity is negative. In this situation, according to the Imbalance Pricing rules, the Marginal Energy Action Price (PMEA) is set to be the minimum price of unflagged actions, while the Replaced Bid Offer Price (PRBO) of all actions is set to be the maximum of PMEA and the Bid Offer Price. Therefore when there are situations where the number of actions considered increases from those which have PRBO equal to PMEA to including actions with replacement prices greater than PMEA which are unflagged and are able to be included in setting the average price, an Imbalance Price which is greater than PMEA results. A higher value for QPAR means those higher priced actions would be setting a greater portion of the average price, therefore increasing the price with increasing QPAR value.

This effect is more clearly shown in Figure 6, where the Imbalance Prices after application of QPAR are compared with PMEA. These profiles show that implementing larger levels of QPAR may have a larger impact on the signal from the price, as it decreases the average price versus the marginal price over peak periods and increases the average price versus the marginal price over non-peak periods. Rather than reducing the price in every instance, it seems to reduce the incentive of the price, making a flatter curve where the lowest averages in the profile are increased and the highest averages in the profile are reduced.

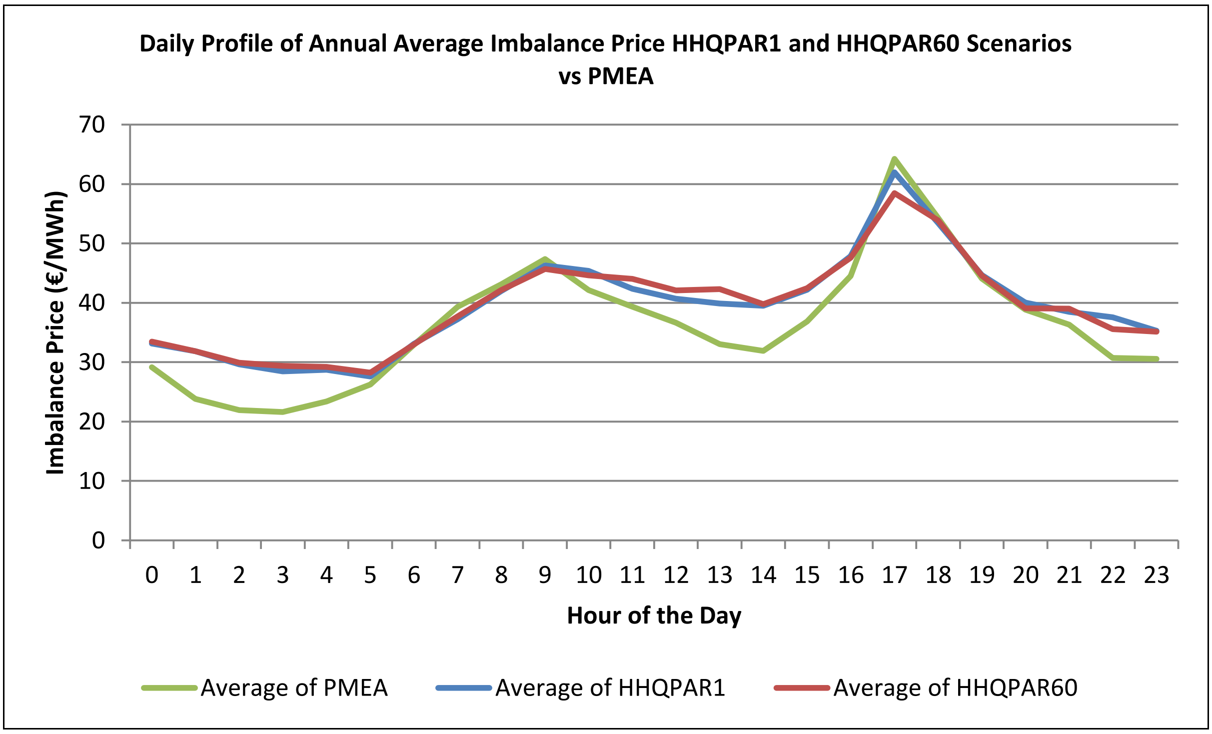


Figure 6: Daily Profile of Annual Average Imbalance Price HHQPAR1 and HHQPAR60 Scenarios vs PMEA

Despite these being the two scenarios at the opposite edges of the range of QPAR scenarios considered, there is not a large difference in standard deviation and average prices in these two scenarios either on an annual average basis of a daily average price profile basis. This appears to be partially due to the scale of QPAR relative to the actions in the stack it is using to set the price. In most instances, despite the QPAR value increasing, the price was being set by the same action in both scenarios. This scale consideration limits the effectiveness of the QPAR; however, as considered in section 3.2.4, it is necessary to scale to this level of QPAR to account for other factors such as the overall size of the ranked set of Bid Offer Acceptances.

In summary, the impact of increasing QPAR on decreasing standard deviation of the Imbalance Price appears to be small. There appears to be a small impact on the average imbalance price also, one which appears to be opposite to the signal intended by PMEA.

3.4 Recommendation

Based on the assessment criteria outlined, the analysis of modelling outcomes undertaken, a value of 0.17MWh (the five-minute period equivalent to 1MWh being applied to a half hour period) is recommended for the Price Average Reference Quantity from go-live of the I-SEM.

4. Price Materiality Threshold

4.1 Background

To date in the SEM, the Settlement Recalculation Threshold was used as a parameter for determining whether both recalculation of the SMP and a Settlement Rerun should occur. The I-SEM arrangements split these functions into two separate parameters, with the Price Materiality Threshold being introduced as a new parameter. The Price Materiality Threshold is now used to determine if a recalculation of the Imbalance Settlement Price should occur, while the Settlement Recalculation Threshold is now used only to determine if the queried data items should be included in the next Settlement Rerun.

The Price Materiality Threshold is a parameter which determines whether the MO will include a corrected data input value (following a Pricing Dispute) in recalculating the Imbalance Settlement Price and Settlement Rerun. The threshold is used to test when a change in input data to the pricing process resulting from an upheld dispute causes a change in the price greater than a certain amount. When the threshold is exceeded, the price will be recalculated and the changes will be included in a Settlement Rerun, otherwise the price is not recalculated.

4.2 Considerations

4.2.1 Sources for Relevant Changes in Prices

The following inputs to the calculation of the Imbalance Settlement Price would, if changed following a Pricing Dispute, likely result in a change to the price calculated:

- Application of System Operator Flags (SO Flags) and Net Imbalance Volume Tags (NIV Tags). Changes for these reasons would likely result in a relatively large change in the price because they have the effect of either including or removing entirely a bid or offer from the Imbalance Price. The removal of a SO Flag from an offer may have the indirect effect of resulting in additional NIV Tagging of different accepted bids and offers to when the original price was calculated, which can similarly result in a relatively large change in the price. These would only impact a single Imbalance Settlement Period, unless a number of separate incidents of incorrect application were found in the same Trading Day;
- Changes in Accepted Offers and Accepted Bids. This could arise for a number of reasons, which are likely to result in small volume changes (such as changing the incorrect timing around instruction issue or instruction effective times, or incorrect MW output level, being used in the original pricing calculation). How this volume change would translate into a price change would depend on how close to marginal the unit had been in the merit order originally, on the interaction with Price Average Reference, and indirect impacts this volume change may have on the application of SO Flags and NIV Tags, and on the prices of other units which were close to being marginal.

Therefore it is possible for large volume changes to have either a large effect, or little / no effect, on the price. In terms of the number of periods affected, this would depend on the nature of the error: it is possible that an error in instruction profiling could affect a number of periods depending on ramp rates, etc., but it is not likely to affect a large amount of periods in the Trading Day;

- Price information for an accepted offer and bid could change, also based on updated information such as the timing of COD submissions or the timing of the issuance and effectiveness of dispatch instructions. These changes may not result in a change in the Imbalance Settlement Price, depending on reasons outlined in the previous point, and similarly may affect one or more Imbalance Settlement Periods;
- Incorrect application of Administered Scarcity Pricing functionality. If this was incorrectly applied (for example through incorrectly stating that load shedding occurred, or through different incorrect inputs to the application of the Reserve Scarcity Price Curve application) it would likely result in large changes to the price, as this can change the level of a scarcity price, or remove / add scarcity signals in the price, and the magnitude of prices considered for administered scarcity are very large. This would be likely to only have an impact on the price in an individual Imbalance Settlement Period.

4.2.2 Scale Considerations

In the past, a value of 3% was selected for this value in an attempt to achieve a balance between the resettlement of a material data error and the operational overhead. In the current market, the 3% Settlement Recalculation Threshold was based on an approximate value of €250,000 change in settlement amounts across the whole market for a Trading Day, with the percentage being based on this value and the total settlement sum in a Trading Day. However, the settlement amounts considered in the I-SEM are not likely to be this large, the reasons for which and suggestions of alternative values are explored in the following paragraphs.

The process for the use of the Price Materiality Threshold in the I-SEM arrangements will be based on assessment of the Imbalance Settlement Price which would be likely to have an effect on settlement across all Participants rather than being focussed on only the Participant who raised the query, and if the threshold is exceeded it will trigger a Settlement Rerun which would have an administrative impact on all other Participants with similar costs for each of them. Therefore, the value for this parameter needs to be based on an assessment of changes in settlement amounts across the whole market and for individual Participants.

This parameter would also have an interaction with the materiality threshold for whether an ad-hoc Settlement Rerun should be facilitated. Because a change in the price would trigger an ad-hoc Settlement Rerun, it is important that the change in settlement amounts for an individual Participant would tend to be in excess of the Settlement Recalculation Threshold, or the High Materiality Threshold to have consistency in the approach for instigating ad-hoc Settlement Reruns.

However, it is unlikely that a change in participants' settlement amounts of the magnitude similar to that of these thresholds would arise from price changes in the magnitude previously considered (e.g. 3% for the current equivalent of the parameter). In the SEM, a change in the System Marginal Price (SMP) would have an effect on the revenue of every Participant which has a position in the market, because it is the single price which is used for all payments and charges. In the I-SEM, a change in the Imbalance Settlement Price would only have a large effect on the overall revenue of a unit which has a large position in the balancing market – if the unit has a market position but it only relates to the ex-ante markets and not the balancing market, a change in the price would have a small or no effect. Also even a relatively large change in the Imbalance Settlement Price may not have an impact on the settlement of a Generator Unit's balancing actions, depending on whether it changes from being out-of-merit pay-as-bid to being in-merit and therefore making inframarginal rent, or if they remain pay-as-bid and therefore no impact. Therefore, it is far less likely that a change of the same monetary magnitude for a given percentage level of price change would result, with changes to settlement amounts likely to be typically smaller in the I-SEM than in the SEM.

Depending on the Participant type raising the Pricing Dispute, and the size of the imbalance position of the units of that Participant, a Pricing Dispute may be raised with the aim of increasing or decreasing the Imbalance Settlement Price. A possible result is that for a Participant which has multiple units, changes to the price resulting in a gain in revenues for one unit may be offset by losses in revenue for another unit. Therefore scenarios for both should be considered to assess the increases and decreases, for particular participant types and across the whole market, which result from them. Since a Settlement Rerun is at a Participant level, it would be important to assess changes in settlement amounts across all of a Participant's units.

While the change in settlement amounts across the market may be large, it may be made up of a number of small changes in settlement amounts for each individual participant. Similarly a change in settlement amounts which appears small across the whole market may be made up of a number of large, but opposite, changes in settlement amounts for each individual participant. Also it is far less likely that the price would be different across as many periods in the Trading Day in the I-SEM as can occur in the SEM. In the SEM, recalculating the price requires a rerun of the Market Scheduling and Pricing (MSP) software, where a relatively small change in the inputs can create a very different outcome from the optimisation, and where intertemporal aspects of the software can result in different prices and Market Schedule Quantities for every period. However, in the I-SEM, this intertemporal aspect for pricing calculation does not exist and the quantities against which generators are settled is fixed (i.e., recalculation of the Imbalance Price does not involve re-optimisation of the market schedule as in the SEM): it is a simple merit order of accepted bids and offers, and while there may be some input changes which affect multiple periods, such a multi-period change in the I-SEM is much less likely to be as large as than the optimisation-based changes across all periods in the Trading Day in the SEM.

4.2.3 Criteria and Trade-offs

The main drivers for determining the Pricing Recalculation Threshold include:

- The value to each Participant of the change in settlement amounts, especially considering the relative impact on smaller participants;
- The value of changes being large enough to warrant an ad-hoc Settlement Rerun which outweigh the overheads of undertaking the rerun (i.e. the monetary value resulting from the price change should be generally greater than the Settlement Recalculation Threshold and should consider the High Materiality threshold);
- The value of changes being large enough and distributed enough throughout the market to warrant disruption to processes which typically depend on a firm price, such as settlement of contracts based on the Imbalance Settlement Price; and
- The likelihood of a change in price of X% due to a change in the inputs, so that it is not overly disruptive of regular processes which are dependent on the Imbalance Settlement Price (e.g. in assessing the potential regularity of changes in the price in excess of this amount arising, considering that parameters which would have greater regularity would be less optimal. This regularity should be assessed as the number of periods overall where the threshold is exceeded, versus what would be considered excessive).

With operational data it would be possible to assess the typical percentage change in the price recalculated for Pricing Disputes relating to pricing inputs, and use this to fine-tune the value of this parameter such that it should not occur so regularly that it would be overly burdensome. However, in the absence of such data, an initial value for this parameter can be found through modelling prices and settlement amounts representative of the I-SEM, and by focussing on the monetary impact for Participants of different levels of price changes. Depending on the level of this result, a conservative approach of increasing the resulting value if it is thought too low and potentially disruptive could then be taken.

4.2.4 Modelling Approach

The least complex means of modelling the effect would be to simply increase the price in every Imbalance Settlement Period by the value for the parameter considered in each scenario. However, this would more likely result in changes to settlement amounts which are in excess of the Settlement Recalculation Threshold than if that percentage change were to be implemented in a single Imbalance Settlement Period, and it would not reflect the lower likelihood of multiple Imbalance Settlement Periods being affected from recalculating the price in the I-SEM than currently is the case in the SEM. Therefore, the modelling approach could instead be to make a change in the price in the same smaller number of periods in each Trading Day, to reflect a slightly more realistic possibility. As a result, assumptions need to be made about the periods in which to make the change. The impact of a percentage change in the price would be different if periods where prices would tend to be low (e.g. at night) or periods where prices would tend to be high (e.g. at peak demand).

As this parameter is required to work across all scenarios, an approach which considers the average rather than the extreme may be more appropriate. Therefore, an approach of choosing the Imbalance Settlement Period whose average price is closest to the Trading Day average price is proposed. This period may in different circumstances reflect either a high, medium or low prices, such that the range of results may include samples periods of low, average, and high prices. Considering the results from the Price Average Reference Quantity studies in section 3 for the HHQPAR1 scenario, this meant changing the price in period 21:00 for every day in the study year, and then considering the effects on daily settlement amounts over the study year.

The metrics which can be used to assess each scenario against the criteria include: Total changes in settlement amounts across the market in each Trading Day; and Average, maximum and minimum changes in settlement amounts for each Participant in each Trading Day. The following scenarios were considered in the study, with the differences between the different models 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, settle with PIMB = result from HHQPAR1
PIMB+1	Base	Base	Base, settle with PIMB + 1%
PIMB+2	Base	Base	Base, settle with PIMB + 2%
PIMB+3	Base	Base	Base, settle with PIMB + 3%
PIMB+4	Base	Base	Base, settle with PIMB + 4%
PIMB+5	Base	Base	Base, settle with PIMB + 5%
PIMB+6	Base	Base	Base, settle with PIMB + 6%
PIMB+10	Base	Base	Base, settle with PIMB + 10%
PIMB+15	Base	Base	Base, settle with PIMB + 15%
PIMB+20	Base	Base	Base, settle with PIMB + 20%
PIMB+25	Base	Base	Base, settle with PIMB + 25%

4.3 Results and Analysis

Table 1 shows the average change in daily settlement amounts versus the base case (excluding those days where the change was zero) for each company (taken as a sum of the settlement amounts for each of the units assigned to that company) for each scenario considered. Table 2 and Table 3 show the maximum and minimum, respectively, changes in daily settlement amounts versus the base case for each company for each scenario considered. Note that the companies considered have been made anonymous for publishing purposes.

Company	PIMB+1	PIMB+2	PIMB+3	PIMB+4	PIMB+5	PIMB+6	PIMB+10	PIMB+15	PIMB+20	PIMB+25
Other Company	-€0.32	-€0.64	-€0.96	-€1.29	-€1.61	-€1.93	-€3.21	-€4.82	-€6.43	-€8.03
Company 1	€92.15	€186.10	€281.56	€373.30	€460.61	€556.20	€825.97	€1,272.86	€1,788.22	€2,293.41
Company 2	-€2.58	€1.68	€13.79	€30.82	€52.00	€74.68	€185.09	€344.06	€526.84	€724.53
Company 3	€4.00	€8.00	€12.00	€16.00	€20.00	€24.00	€40.00	€60.00	€80.00	€100.00
Company 4	-€34.43	-€68.87	-€103.30	-€137.74	-€172.17	-€206.61	-€344.34	-€516.51	-€688.69	-€860.86
Company 5	-€41.60	-€82.30	-€121.01	-€159.57	-€198.13	-€236.15	-€379.39	-€517.67	-€611.63	-€691.94
Company 6	-€2.53	-€4.64	-€6.36	-€7.83	-€9.15	-€10.47	-€14.67	-€19.24	-€23.80	-€27.82
Company 7	€53.29	€108.52	€166.77	€226.54	€289.69	€354.37	€616.38	€941.87	€1,276.39	€1,611.51
Company 8	-€68.76	-€136.06	-€193.58	-€253.95	-€314.12	-€374.11	-€614.08	-€892.96	-€1,176.15	-€1,459.34
Company 9	€77.46	€154.90	€227.42	€304.96	€375.97	€449.84	€730.60	€1,100.06	€1,466.71	€1,861.86
Company 10	€1.56	€3.12	€4.68	€6.24	€7.81	€9.37	€15.61	€23.42	€31.22	€39.03

Table 1: Average Change in Daily Settlement Amounts vs Base Case (Excluding Days of Zero Change) Over Study Year

Company	PIMB+1	PIMB +2	PIMB +3	PIMB +4	PIMB +5	PIMB +6	PIMB +10	PIMB +15	PIMB +20	PIMB +25
Other Company	€101.23	€202.45	€303.68	€404.91	€506.13	€607.36	€1,012.27	€1,518.40	€2,024.54	€2,530.67
Company 1	€980.00	€1,960.00	€2,940.00	€3,920.00	€4,900.00	€5,880.00	€9,800.00	€14,700.00	€19,600.00	€24,500.00
Company 2	€365.61	€740.53	€1,115.46	€1,490.38	€1,865.30	€2,240.22	€3,973.17	€6,285.75	€8,598.33	€10,910.91
Company 3	€7.19	€14.38	€21.57	€28.76	€35.95	€43.13	€71.89	€107.84	€143.78	€179.73
Company 4	€ -	€ -	€-	€ -	€-	€ -	€ -	€-	€ -	€-
Company 5	€ -	€ -	€-	€ -	€-	€ -	€ -	€-	€ -	€-
Company 6	€203.35	€406.69	€610.04	€813.38	€1,016.73	€1,220.07	€2,033.46	€3,050.19	€4,066.91	€5,083.64
Company 7	€475.99	€951.99	€1,427.98	€1,903.98	€2,379.97	€2,855.97	€4,759.94	€7,139.91	€9,519.88	€11,899.86
Company 8	€165.03	€330.06	€495.10	€660.13	€825.16	€990.19	€1,650.32	€2,475.49	€3,300.65	€4,125.81
Company 9	€237.04	€474.09	€711.13	€948.17	€1,185.22	€1,422.26	€2,370.44	€3,555.66	€4,740.87	€5,926.09
Company 10	€138.17	€276.33	€414.50	€552.66	€690.83	€828.99	€1,381.66	€2,072.48	€2,763.31	€3,454.14

Table 2: Maximum Change in Daily Settlement Amounts vs Base Case Over Study Year

Company	PIMB+1	PIMB +2	PIMB +3	PIMB +4	PIMB +5	PIMB +6	PIMB +10	PIMB +15	PIMB +20	PIMB +25
Other Company	-€88.52	-€177.03	-€265.55	-€354.07	-€442.59	-€531.10	-€885.17	-€1,327.76	-€1,770.35	-€2,212.93
Company 1	-€255.21	-€510.42	-€765.64	-€1,020.85	-€1,276.06	-€1,531.27	-€2,552.12	-€3,828.19	-€5,104.25	-€6,380.31
Company 2	-€874.23	-€1,748.45	-€2,622.68	-€3,496.91	-€4,371.13	-€5,245.36	-€8,742.27	-€13,113.40	-€17,484.54	-€21,855.67
Company 3	€ -	€ -	€-	€ -	€-	€ -	€ -	€ -	€ -	€ -
Company 4	-€71.77	-€143.55	-€215.32	-€287.09	-€358.87	-€430.64	-€717.74	-€1,076.60	-€1,435.47	-€1,794.34
Company 5	-€111.14	-€222.28	-€333.42	-€444.56	-€555.70	-€666.85	-€1,111.41	-€1,667.11	-€2,222.82	-€2,778.52
Company 6	-€391.39	-€782.79	-€1,174.18	-€1,565.57	-€1,956.97	-€2,348.36	-€3,913.93	-€5,870.90	-€7,827.87	-€9,784.83
Company 7	-€179.46	-€358.91	-€538.37	-€717.82	-€897.28	-€1,076.74	-€1,794.56	-€2,691.84	-€3,589.12	-€4,486.40
Company 8	-€270.86	-€541.71	-€812.57	-€1,083.42	-€1,354.28	-€1,625.13	-€2,708.56	-€4,062.84	-€5,417.12	-€6,771.40
Company 9	-€203.20	-€406.40	-€609.60	-€812.80	-€1,016.00	-€1,219.20	-€2,032.00	-€3,048.01	-€4,064.01	-€5,080.01
Company 10	-€120.82	-€241.64	-€362.45	-€483.27	-€604.09	-€724.91	-€1,208.18	-€1,812.27	-€2,416.36	-€3,020.46

Table 3: Minimum Change in Daily Settlement Amounts vs Base Case Over Study Year

The text highlighted in red shows the scenarios between which the value of the settlement amount change first crosses over the Settlement Recalculation Threshold previously recommended of €15,000 for an individual company. This did not occur for the average – a sensitivity study was carried out where a 50% increase in the price was introduced and the change in settlement amounts calculated, but this still did not result in an average which exceeded the threshold. Therefore the analysis should focus on the maximum and minimum change events. In both the maximum and minimum change, the €15,000 threshold was crossed between the cases when PIMB was increased by 15% and when it was increased by 20%. In particular for the maximum change scenario, the maximum change in the 15% scenario was quite close to the €15,000 threshold considered.

Therefore in order to have a Price Materiality Threshold which is not too low with the potential negative impacts explained previously, but sufficiently low that it allows for changes in revenue approximately in excess of the cost of administering repricing and resettlement, a value of 15% for the Price Materiality Threshold would appear suitable.

4.4 Recommendation

On the basis of analysis carried out, a value of 15% is recommended for the Price Materiality Threshold from go-live of the I-SEM.

5. Conclusions

The recommended values for the Pricing Parameters are proposed in the table below, taking into changes in context through the introduction of the I-SEM arrangements, differences between the I-SEM and BETTA arrangements, the analysis undertaken, and the criteria for the signals from the new parameters introduced in the I-SEM arrangements.

Parameter	2017 Approved Value (or Equivalent)	I-SEM Go-Live Recommended Value
De Minimis Acceptance Threshold	N/A	0.4MWh
Price Average Reference Quantity (QPAR)	N/A	0.17MWh
Price Materiality Threshold	3%	15%

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 7 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 4 outlines in more detail the structure of the model in terms of inputs, settings and the processing of outputs.

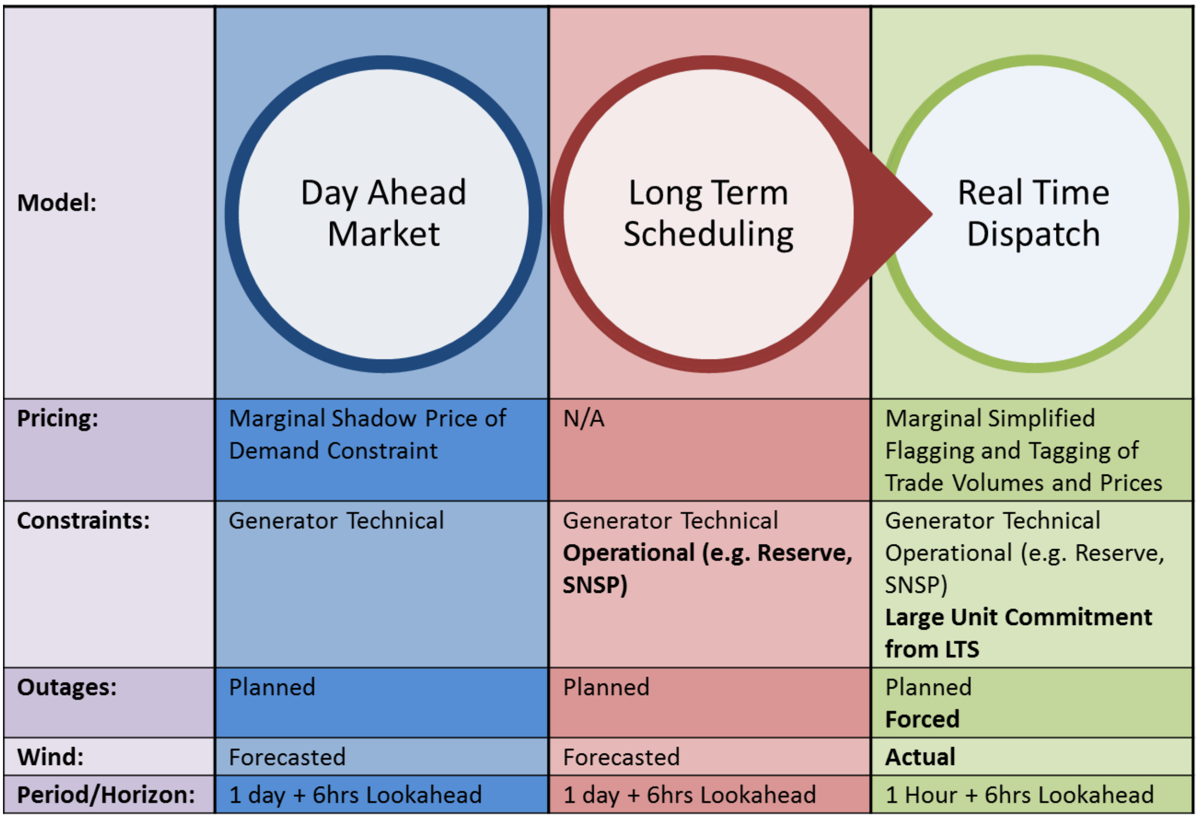


Figure 7 High Level Structure of the Model

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 4: 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 5 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 5: 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

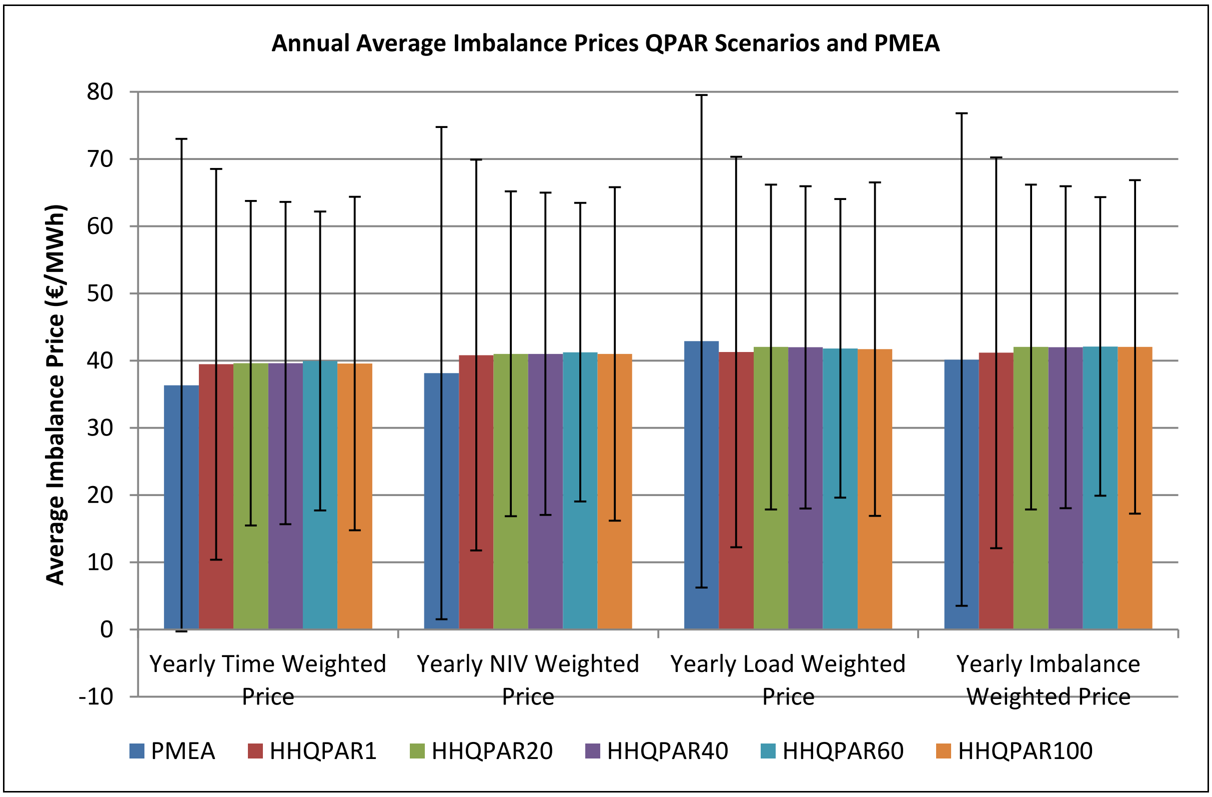
Settings Item	Settings used
Horizon	Planning Horizon: 371 Days Starting 31 December 2019

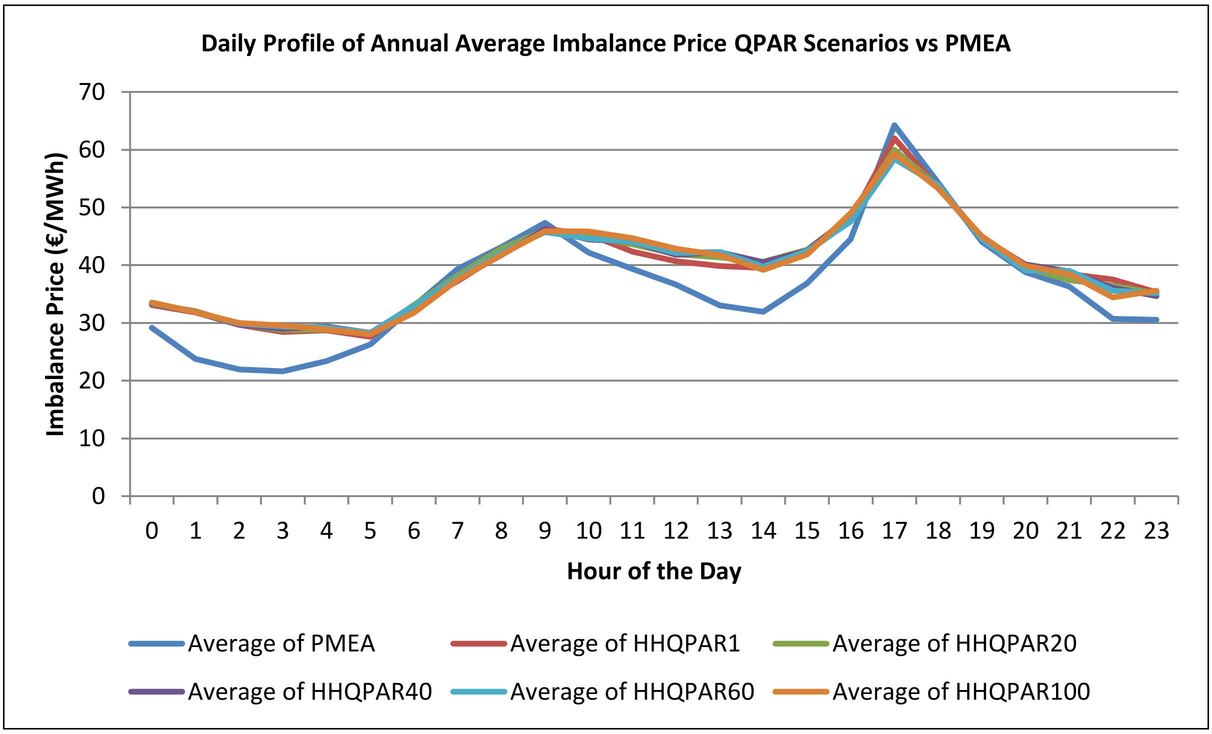
Settings Item	Settings used
	Interval Length: 1 Hour Day Begins: 11:00PM Chronological Phase: Full Chronology Begin at interval 1 on 31 December 2019 Schedule [for 24hr horizon] 367 steps of 1 day Schedule [for 1hr horizon] 8808 steps of 1 hour Additional Lookahead: 6 hours in some cases, 0 in others.
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

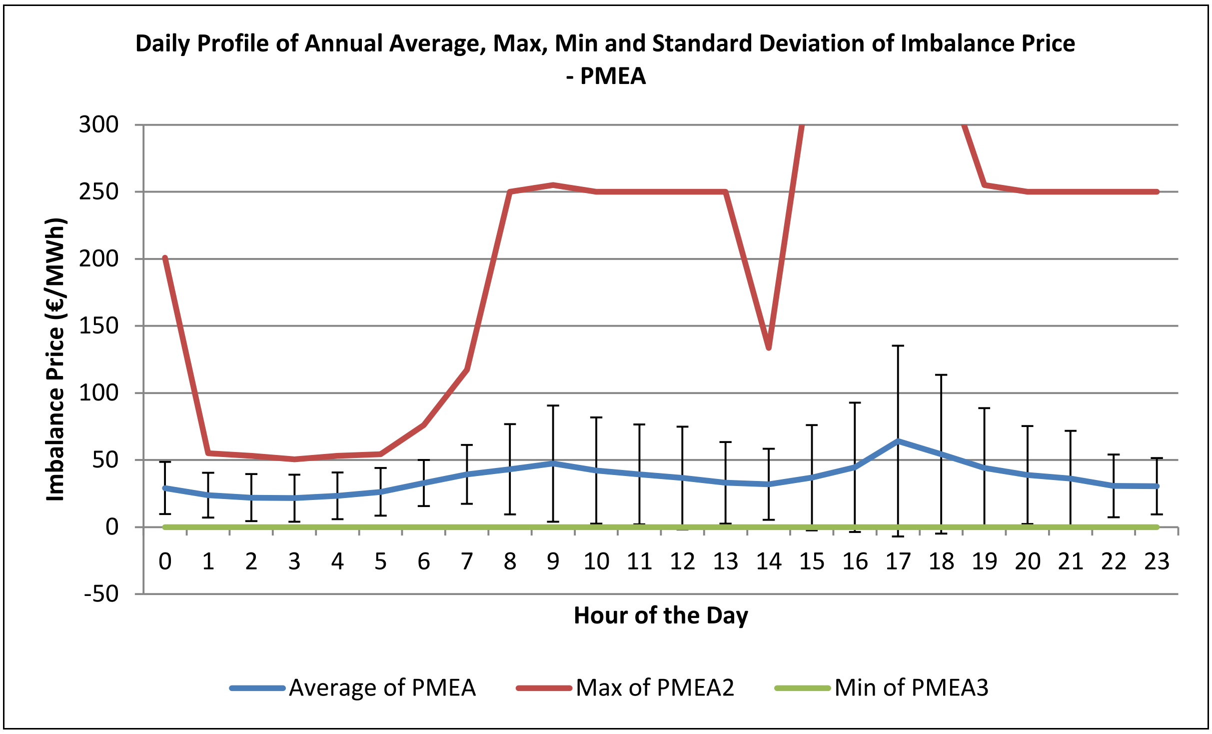
Settings Item	Settings used
	Do not select Network Reduction Single Slack Bus Reactance cutoff: 0 Flow PTDF Threshold: 1E-06 Wheeling PTDF Threshold: 0.05 Enforce line and transformer limits (enforced from 0kV), and interface limits, and bounds on Phase Angles (max absolute angle: 2 radians) Do not enforce 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

Appendix B Results for QPAR Scenarios



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Imbalance Price (€/MWh)
300
250
200
150
100
50
0
-50
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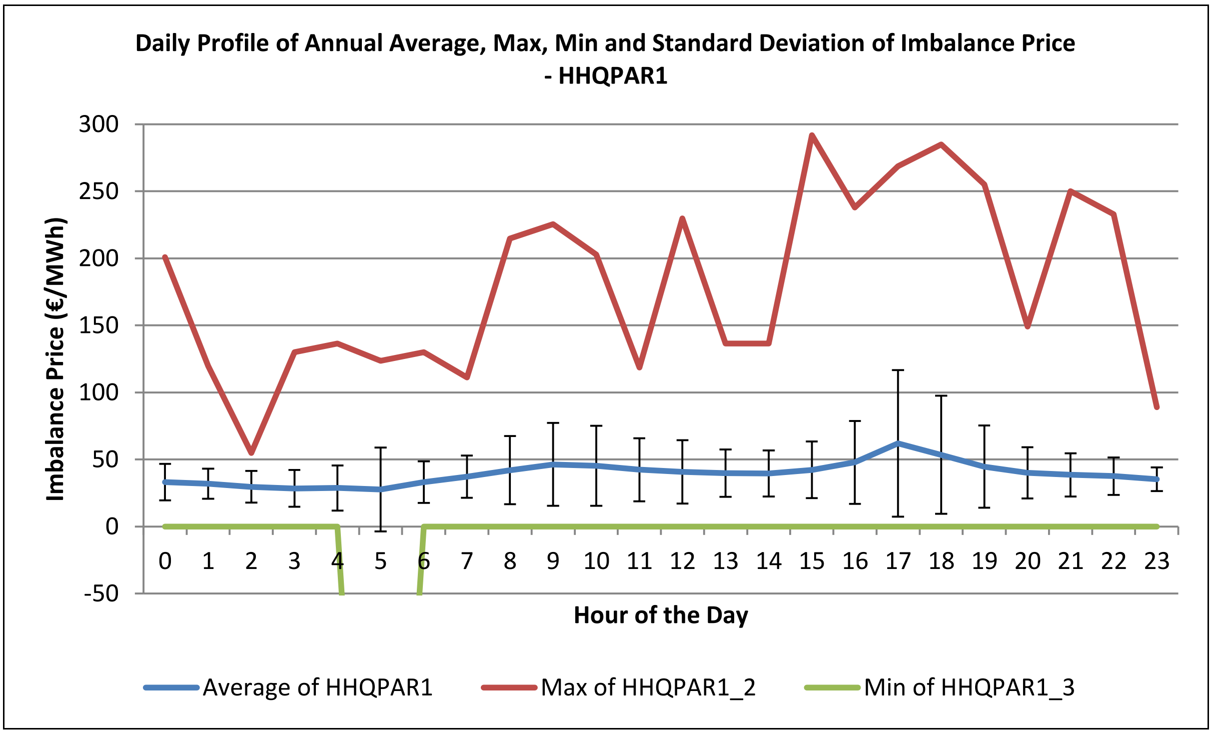
Hour of the Day
Average of PMEA
Max of PMEA2
Min of PMEA3


Daily Profile of Annual Average, Max, Min and Standard Deviation of Imbalance Price - HHQPAR1
Imbalance Price (€/MWh)
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250
200
150
100
50
0
-50
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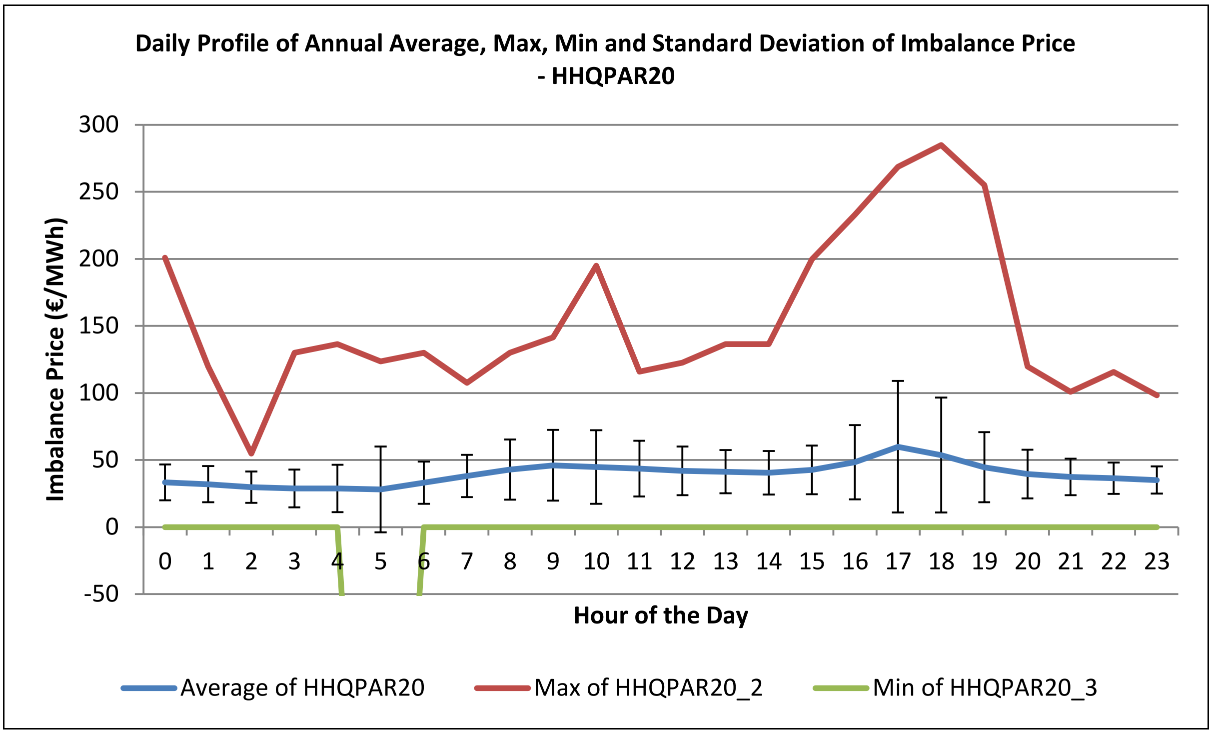
Hour of the Day
Average of HHQPAR1
Max of HHQPAR1_2
Min of HHQPAR1_3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Imbalance Price (€/MWh)
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250
200
150
100
50
0
-50
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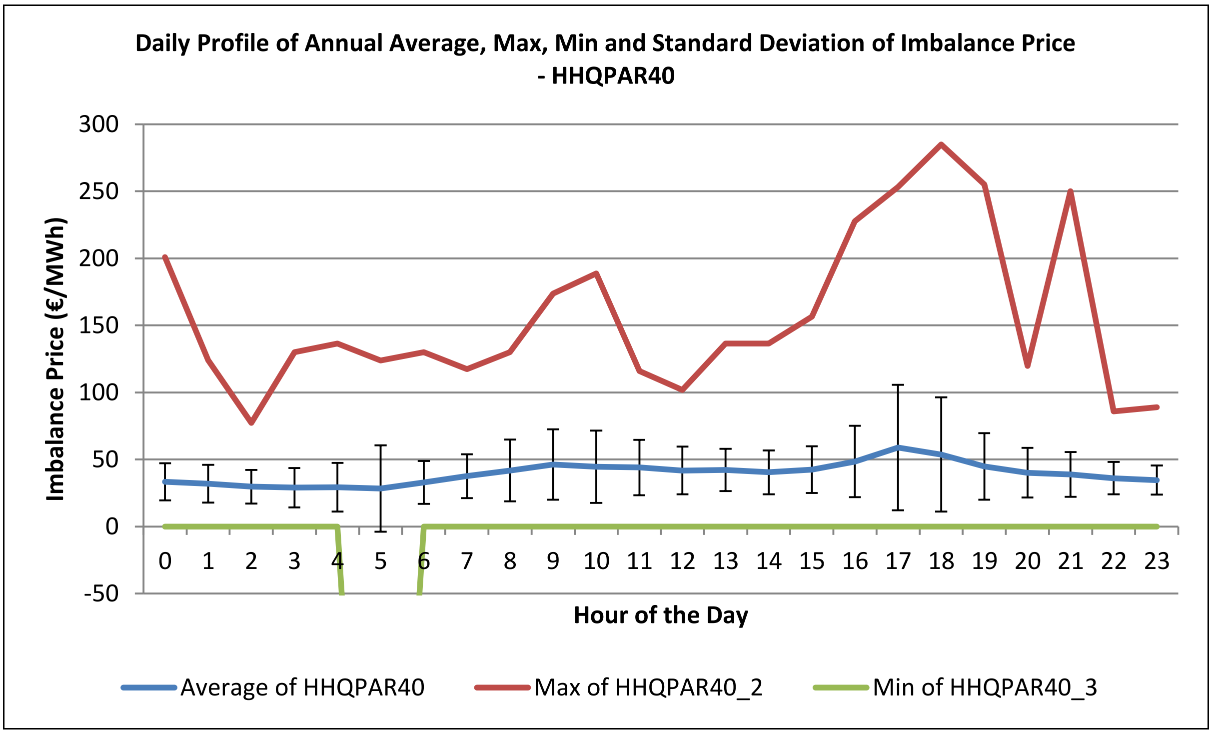
Hour of the Day
Average of HHQPAR20
Max of HHQPAR20_2
Min of HHQPAR20_3


Daily Profile of Annual Average, Max, Min and Standard Deviation of Imbalance Price - HHQPAR40
Imbalance Price (€/MWh)
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250
200
150
100
50
0
-50
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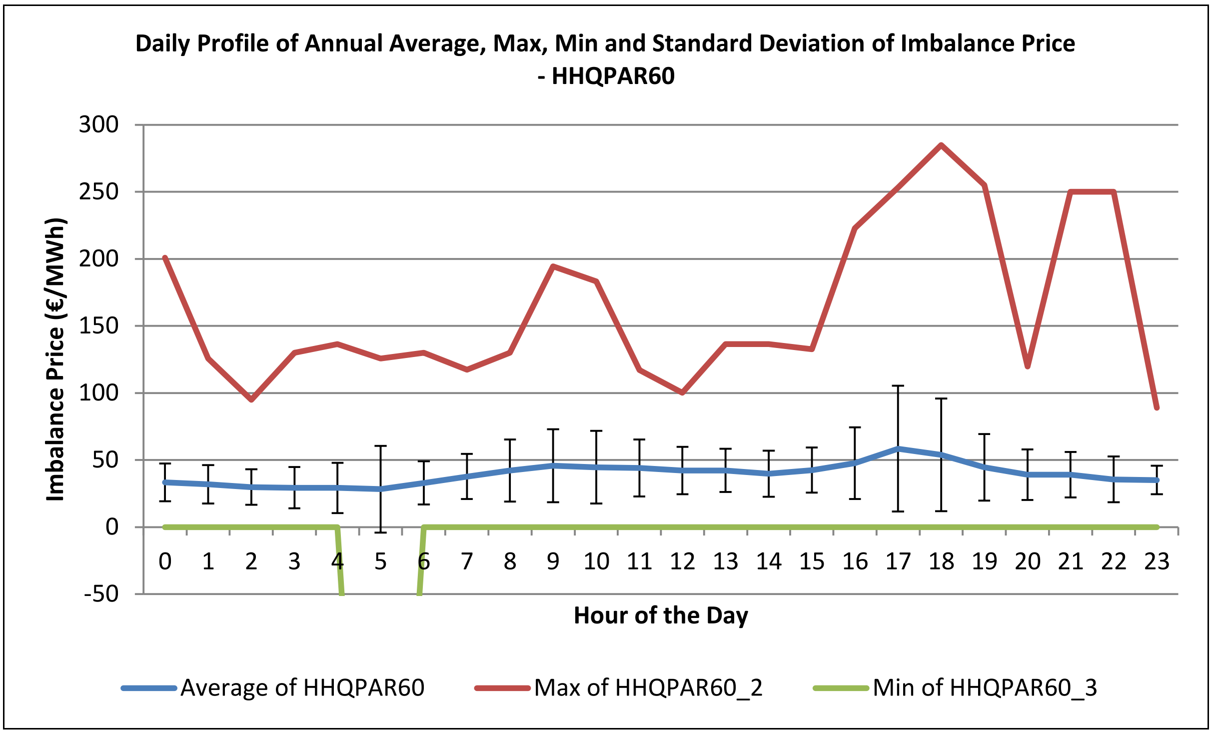
Hour of the Day
Average of HHQPAR40
Max of HHQPAR40_2
Min of HHQPAR40_3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Imbalance Price (€/MWh)
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200
150
100
50
0
-50
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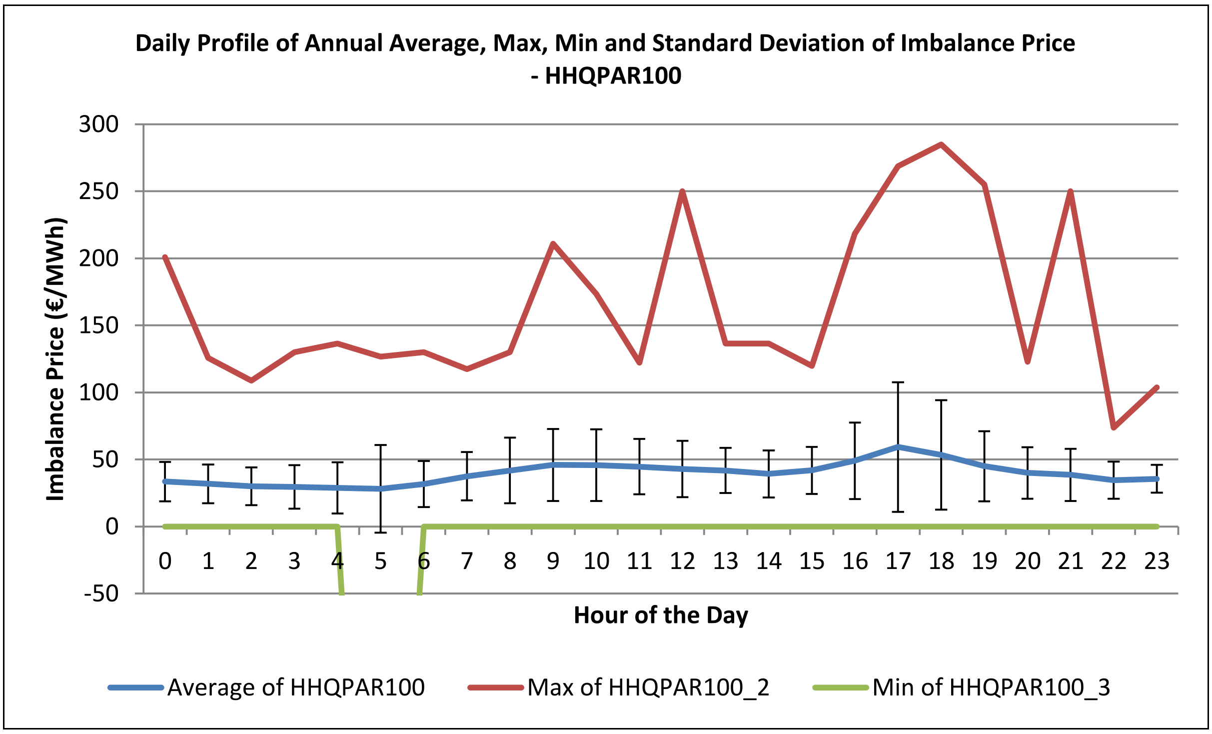
Hour of the Day
Average of HHQPAR60
Max of HHQPAR60_2
Min of HHQPAR60_3


Daily Profile of Annual Average, Max, Min and Standard Deviation of Imbalance Price - HHQPAR100
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200
150
100
50
0
-50
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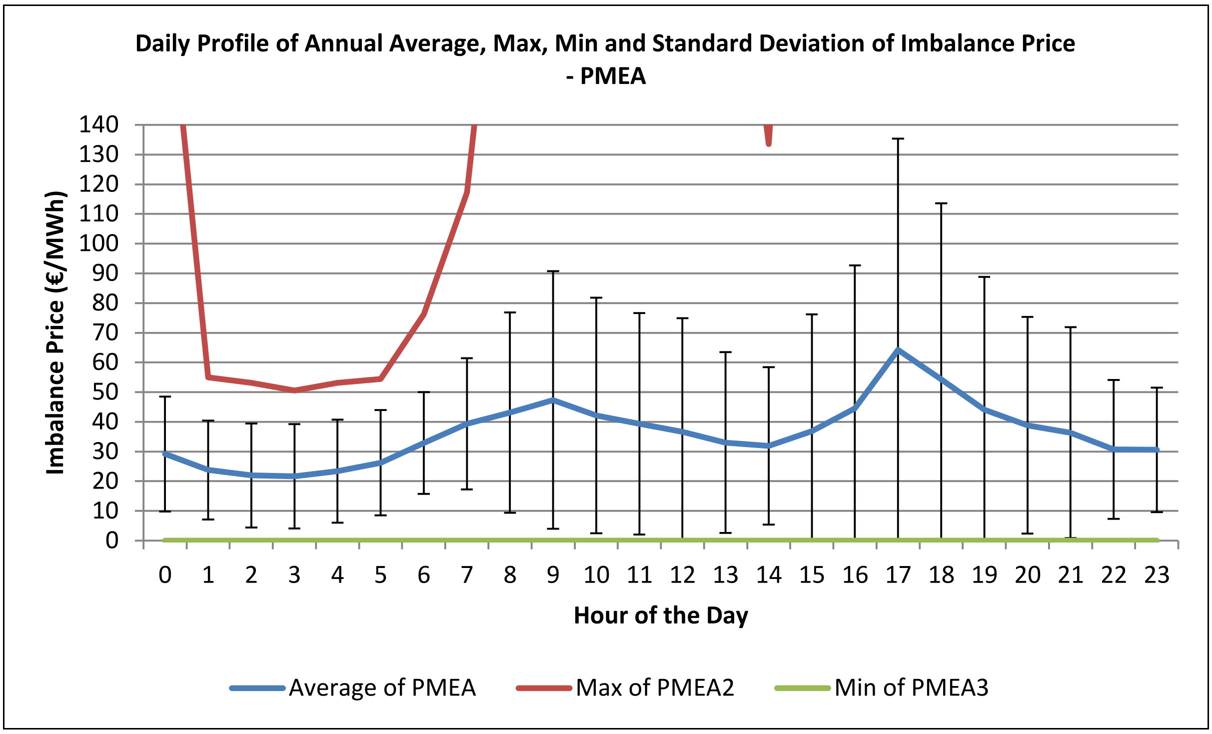
Hour of the Day
Average of HHQPAR100
Max of HHQPAR100_2
Min of HHQPAR100_3


Daily Profile of Annual Average, Max, Min and Standard Deviation of Imbalance Price - PMEA
Imbalance Price (€/MWh)
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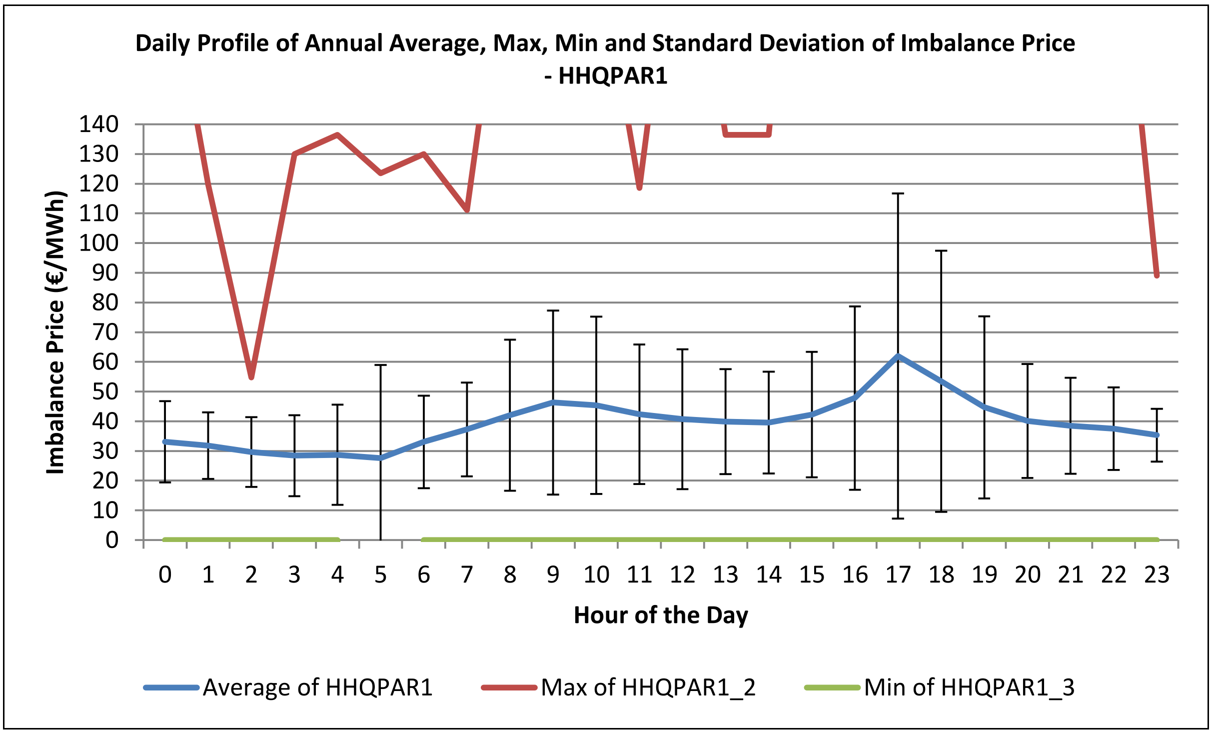
10
20
30
40
50
60
70
80
90
100
110
120
130
140
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23
Hour of the Day
Average of PMEA
Max of PMEA2
Min of PMEA3


Daily Profile of Annual Average, Max, Min and Standard Deviation of Imbalance Price - HHQPAR1
Imbalance Price (€/MWh)
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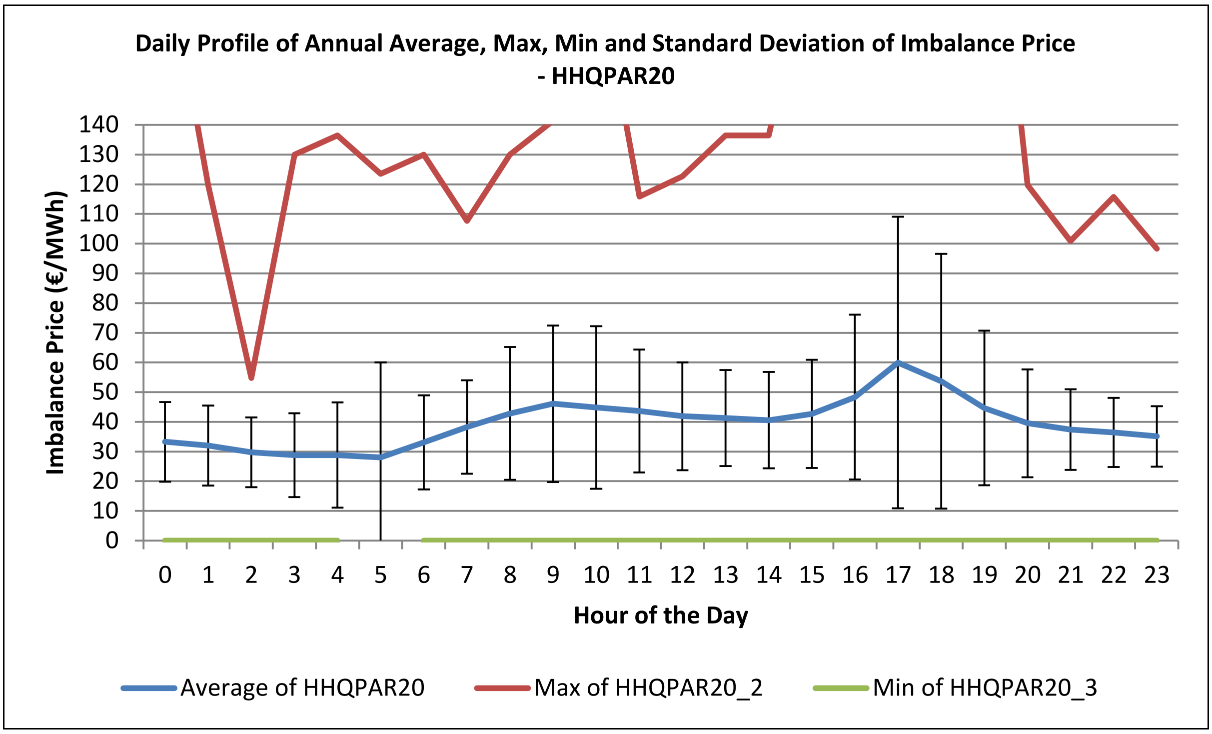
30
40
50
60
70
80
90
100
110
120
130
140
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23
Hour of the Day
Average of HHQPAR1
Max of HHQPAR1_2
Min of HHQPAR1_3


Daily Profile of Annual Average, Max, Min and Standard Deviation of Imbalance Price - HHQPAR20
Imbalance Price (€/MWh)
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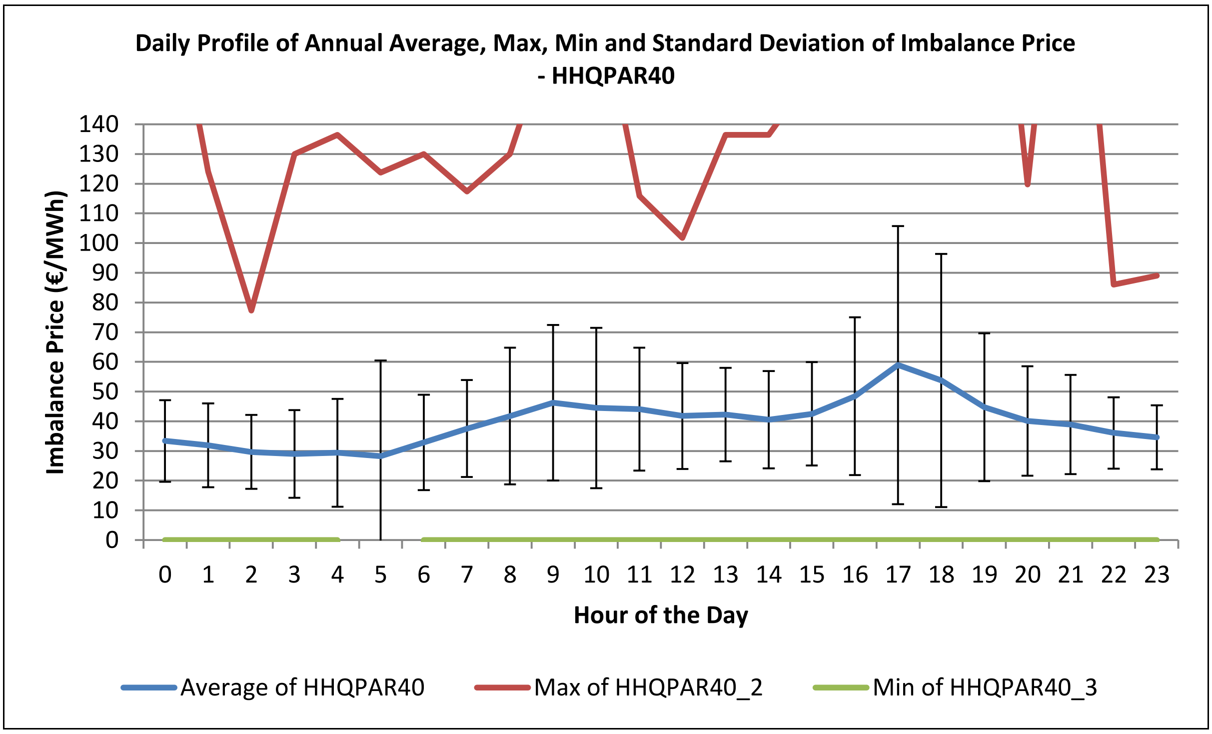
130
120
110
100
90
80
70
60
50
40
30
20
10
0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23
Hour of the Day
Average of HHQPAR20
Max of HHQPAR20_2
Min of HHQPAR20_3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Imbalance Price (€/MWh)
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30
20
10
0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23
Hour of the Day
Average of HHQPAR40
Max of HHQPAR40_2
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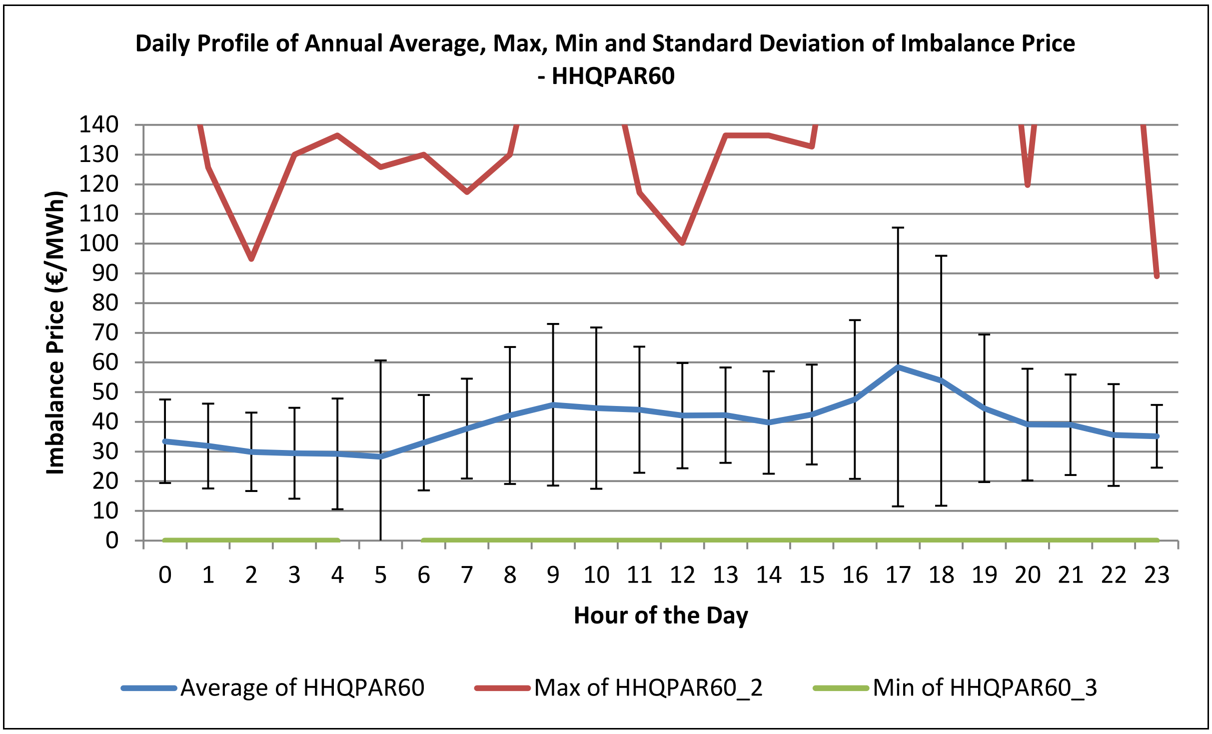
Daily Profile of Annual Average, Max, Min and Standard Deviation of Imbalance Price - HHQPAR60
Imbalance Price (€/MWh)
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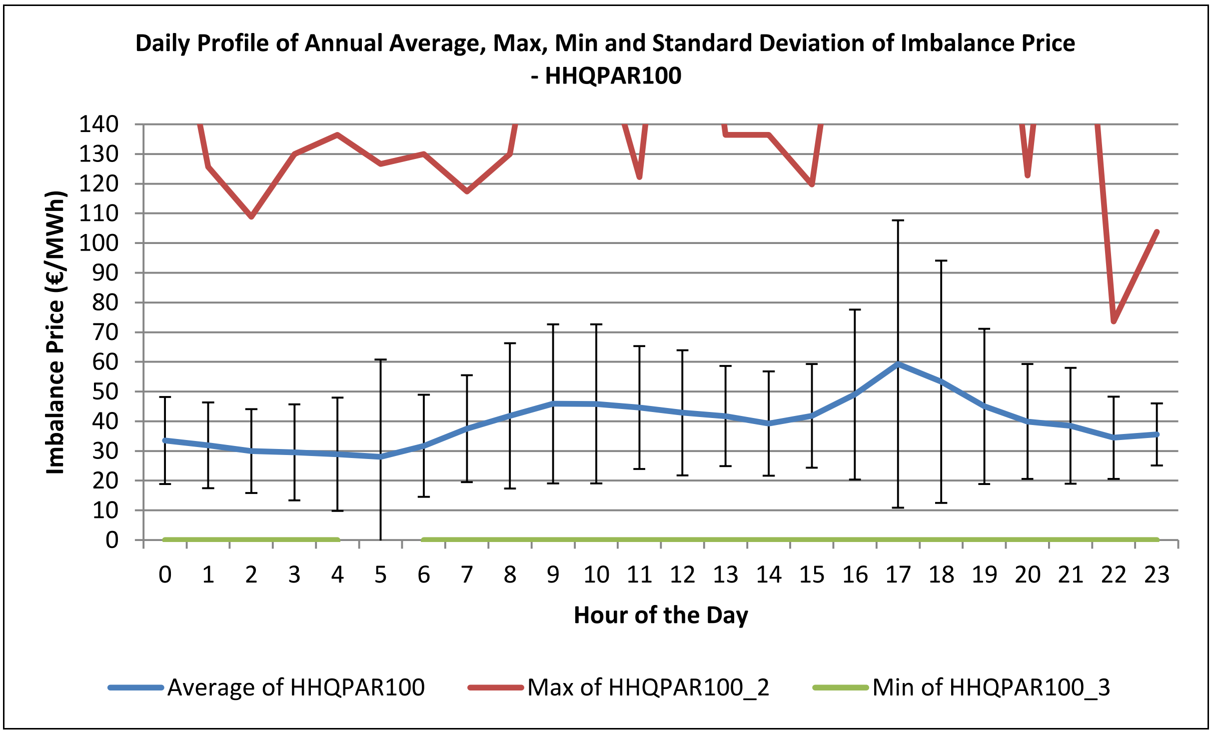
130
120
110
100
90
80
70
60
50
40
30
20
10
0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23
Hour of the Day
Average of HHQPAR60
Max of HHQPAR60_2
Min of HHQPAR60_3


Daily Profile of Annual Average, Max, Min and Standard Deviation of Imbalance Price - HHQPAR100
Imbalance Price (€/MWh)
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130
120
110
100
90
80
70
60
50
40
30
20
10
0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23
Hour of the Day
Average of HHQPAR100
Max of HHQPAR100_2
Min of HHQPAR100_3