Integrated Single Electricity Market (I-SEM)

Energy Trading Arrangements Detailed Design

Markets Consultation Paper

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EXECUTIVE SUMMARY

The European Union (EU) is building an internal market for electricity and gas, to help deliver energy supplies that are affordable, secure and sustainable. This is underpinned by the implementation of the European Electricity Target Model (EU Target Model) arising from the EU's Third Energy Package. Specifically, the EU Target Model is a set of harmonised arrangements for the cross-border trading of wholesale energy and balancing services across Europe. In this context, the SEM Committee committed to implementing the Integrated Single Electricity Market (I-SEM) that will go-live in Q3 2017, replacing the current Single Electricity Market (SEM) arrangements.

Following extensive consultation over 2014, the SEM Committee published the Decision Paper on the High Level Design (HLD) for the I-SEM in keeping with its statutory objectives. Namely, the SEM Committee HLD Decision seeks to maximise benefits for consumers in the short-term and long-term, while ensuring security of supply and meeting environmental requirements.

Subsequently, the Detailed Design Phase of the I-SEM commenced and a number of workstreams were established including the Energy Trading Arrangements (ETA) workstream. As stipulated in the I-SEM Project Plan, the ETA workstream aimed to publish a Building Blocks and a Markets Consultation Paper in the first half of 2015 followed by a Decision on the proposals in Q3 2015. The Building Blocks Consultation Paper was published on 11 February 15 following three Rules Liaison Group (RLG) meetings with representatives from the industry. Another three RLG Meetings were also held to discuss proposals for the detailed market design and this process has culminated in this Markets Consultation Paper.

This document consults on the substantive issues around the design of the energy trading arrangements in the different market timeframes with a particular focus on the Balancing Market design. The proposals as set out aim to be in keeping with the EU Target Model, associated network codes and the HLD, while also being cognisant of current SEM arrangements.

System Operation in the I-SEM

At the outset, the paper discusses proposals to address the objectives of the European Target Model and Network Codes with regard to allowing the market to balance any energy shortfalls/surpluses to the extent possible while at the same time being cognisant of the Transmission System Operators' (TSOs) statutory obligations to maintain a safe and secure electricity system. To allow the TSOs to perform their statutory duties, the HLD stipulated that the Balancing Market (BM) will open shortly after the Day Ahead Market (DAM) results are published and thus run concurrently with the Intraday Market (IDM). However, to ensure that such early actions taken by the TSOs are kept to a minimum, the SEM Committee has set out three proposals based around three principles:

- the timing of early actions;
- monitoring of contingency reserve; and
- reporting requirements of early actions.

Ex-ante Markets

With regard to the DAM and IDM, the detailed design is largely decided at an EU level. The DAM is now operational across a number of European markets while the IDM is still under development. However, potentially the European cross-border IDM solution may not be in place for the I-SEM Go-Live in Q3 2017. Given that participants will be balance responsible in the I-SEM, the IDM is therefore an important mechanism to give participants the opportunity to trade into balance following publication of the DAM results and updated demand and wind forecasts. Hence, this paper sets out a number of options which could be implemented in the event that the IDM is not in place for the I-SEM. This also includes the possibility of implementing intraday auctions as part of the I-SEM design.

Physical Notifications

With regard to the BM, the first design issue arising relates to Physical Notifications (PNs). Once the DAM results are published, participants will have an ex-ante position, be it for the full, part or none of their available capacity depending on the outcome of the schedule in a particular hourly period. Following the receipt of these DAM results, participants are required to submit PNs to the TSOs. These PNs represent the MW profile that the participant intends to generate/consume in the absence of having any incremental offer or decremental bid accepted by the TSOs in the BM. However, there is an open question around whether wind generation or non-dispatchable demand should be required to submit PNs. This paper sets out three options in respect of how PNs from participants should be linked to their ex-ante trades namely:

- should PNs be linked to ex-ante trades at all times;
- should PNs be linked to ex-ante trades at gate closure only; or
- should PNs only need to reflect the best estimates of the intended generation or demand of the participant.

The paper also discusses the potential for the inclusion of an information imbalance charge.

Form of Offers and Bids

Participants will submit PNs throughout the day which may to some extent, depending on the preferred option as mentioned above, reflect trading in the IDM. These PNs will have associated incremental offers and decremental bids that will reflect the prices at which the participant is prepared to deviate away from their PN. The paper proposes three options under which participants could declare these prices:

a) simple MWh blocks, whereby the offers and bids are priced in Euro per MWh up to a certain MWh quantity in that period;

b) the Relative MW approach, whereby the prices have a fixed relationship relative to the PN level; and

c) the Absolute MW approach, whereby the prices have a fixed relationship with the unit's MW levels.

Further to incremental and decremental costs, participants need to reflect their fixed costs (i.e. start-up and no load costs) should the TSOs accept an incremental offer or decremental bid during the BM. This paper also sets out three options in this regard:

- the first option would see explicit start-up contracts being struck between the TSOs and participants outside the BM;
- the second option would see participants submitting a range of alternative block bids and offers to reflect their start costs over defined time periods instead of simple bids and offers in the BM; and
- the third option would see the participant declare their explicit start-up costs.

Once the TSOs accepts a bid or offer from a participant, a question arises as to whether participants should be able to rebid their prices to the TSOs for the quantities of energy that would be available for subsequent acceptance, up until the time that a further quantity was needed by the TSOs. Alternatively, it is discussed whether freezing all offer and bids prices should be the proposed solution. It is also for consideration whether undo prices should be included whereby the participant would receive payment should the TSOs ‘unwind’ a bid offer acceptance. Under the former approach, undo prices would not be required given that participants are free to update their offer and bid prices for the quantities not already accepted by the TSOs in the BM i.e. the updated incremental offer/decremental bid in the opposite direction to the acceptance would represent the undo price.

Interaction between the Balancing Market and the Intraday Market

As mentioned already, the first section of this paper discusses approaches to minimising early actions taken by the TSOs in the concurrent running of the IDM and BM while being cognisant of their statutory obligations to maintain system security. As was apparent in the RLG meetings with industry, this concurrent operation of the IDM and the BM raises concerns regarding the potential distortion that early BM actions may have on the IDM. In particular the opinion was expressed in the stakeholder workshops that it could remove liquidity from the IDM and potentially lead to inefficient transactions between participants.

Against this backdrop, there is a further question as to how a participant can subsequently trade once the TSOs have accepted an offer or bid from them and the IDM is still open. A number of options in this regard have been set out:

a) ‘Freeze’ PNs whereby a participant could not update their PNs further to any IDM trading and hence would be in breach of any obligation to match PNs to ex-ante trades (if such an obligation exists) if subsequent IDM trades were executed;
b) ‘Additive’ PNs whereby IDM trades could be executed as long as they were in addition to the bid or offer acceptance by the TSOs; and
c) ‘Substitutive’ PNs whereby any further IDM trades would replace the quantity of energy arising as a result of a bid or offer acceptance from the TSOs.

Within the ‘Substitutive’ PNs approach, there is also the possibility to either have it that the bid-offer acceptance locks in the bid price from the unit such that if the participant wishes to trade in the Intraday Market and substitute the bid-offer acceptance they will need to achieve a more advantageous price in the IDM than the bid-offer acceptance or have a methodology whereby the unit locks in the premium above or below the imbalance price through the bid-offer acceptance.

Lastly with regard to interactions between the IDM and the BM, this paper sets out a number of proposals to address the issue whereby, upon acceptance of a bid or offer from the TSOs, the participant knowingly trades in the opposite direction or manipulates its prices for any future TSO actions where they know the TSOs will likely need further balancing actions from that participant.

Treatment of System Services

In order to maintain system Operational Security, the TSOs pay market participants to provide system services such as frequency and voltage stability. The SEM Committee is not proposing any changes to the current operation. Instead, the paper takes some of the proposals from this paper and sets out examples for the deployment of reserves. Specifically, the example is based on the 'Substitutive' PN approach.

There are two options put forward for those, deemed to be rare, instances where the TSOs need to commit a unit prior to the opening of the BM. This could be done either through the ancillary services framework or through the use of bids and offers from the previous trading day.

Imbalance Pricing

The proposals outlined so far have discussed both energy and non-energy actions taken by the TSOs in the BM. As stipulated in the HLD, the non-energy actions shall be pay as bid and energy balancing actions shall be pay as cleared based on a single marginal price. Here, the SEM Committee has proposed three options for determining the single marginal price. The first approach would employ a flagging and tagging approach similar to that used in the BETTA market. The second approach would involve the development of an unconstrained imbalance price calculation that may or may not take into account plant dynamics. In the third approach, instead of constructing an unconstrained schedule, an imbalance pricing algorithm would calculate the marginal price of the unconstrained energy balancing actions from the actual dispatch stack.

Imbalance Settlement

Participants in the I-SEM potentially will have transactions in:

- the DAM depending on the results from the EUPHEMIA algorithm;
- the IDM depending on their trading activity in this timeframe; and
- the BM depending on the level to which the TSOs moves said participants from their ex-ante positions (with the imbalance price being paid for any remaining energy produced or consumed).

Imbalance settlement ensures that participants get paid or pay the correct amount for the electricity consumed or produced. The paper outlines a number of examples in this context, taking account of the proposals discussed in the paper and also the Building Blocks Consultation Paper. Other topics discussed here include curtailment, constrained renewable generation without a PN, uninstructed imbalances and ex-ante trading periods of different duration to the Imbalance Settlement Period (ISP).

Other Issues

Finally this paper highlights a number of issues that, while not directly related, have an impact on the market design (some of these areas will be addressed outside of this workstream). These are:

- **Global Aggregation** – three options are proposed. Two are based on either allocating the cost, or quantity, of the residual error to suppliers while the third is a mechanism for smoothing the uncertainty associated with the residual error by fixing an estimate of the residual error for any given period, with the TSO carrying the cost of the discrepancy (which will be recovered by them in the following period).
- **Local Market Power** – the I-SEM market power mitigation workstream will consider market power in the energy trading arrangements. However, this paper prompts some initial discussions on whether measures might be required in the balancing market systems.
- **Metering** – this section highlights that the SEM Committee is of the view that it is appropriate to deal with metering in the I-SEM with a similar process as was adopted for SEM, meaning that it is proposed that the four Meter Data Providers will work together under the governance of the RAs and develop the required approach.
- **Instruction Profiling** – this section seeks to elicit any suggestions for improvements that could be made to the Technical Offer Data (TOD) from dispatchable units such that profiling of a unit’s technical characteristics can be more precise.

CONTENTS

1 INTRODUCTION

1.1 THE ETA DETAILED DESIGN PHASE

The ETA Detailed Design Phase is the first stage of Phase 3, the ‘Detailed Design and Implementation Phase’, of the I-SEM project. The objective of the ETA Detailed Design Phase is to develop a set of detailed energy trading market rules that are consistent with the HLD of the I-SEM.

Within the ETA Detailed Design Phase there is a requirement first to establish the workings of the Energy Trading Arrangements at a high level to enable procurement of the participant systems, and TSO systems. Following on from this, the very detailed legal drafting of the market rules must be completed. These detailed legal rules in the current SEM take the form of the Trading and Settlement Code.

The overall I-SEM ETA Detailed Design Phase has been split into two distinct parts namely, the Building Blocks and Markets. The Building Blocks part looks at a number of key high level policy issues and how they can be accommodated in the I-SEM design. The SEM Committee published a Consultation Paper on the Building Blocks on 11 February 2015. Responses to this were received on 25 March 2015.

As stipulated in the I-SEM Project Plan, there is a separate Market Power workstream that has commenced in tandem with ETA workstream. This workstream will consider in detail any market power issues that are raised in this ETA Markets Consultation Paper.

1.2 I-SEM MARKETS PAPER

The Regulatory Authorities (RAs) facilitated five days of RLG Workshops in early 2015. Following these workshops the RAs sought comment from interested parties on their content. 12 non-confidential responses were received from interested parties and these were published on 23 April 2015.

The purpose of this Consultation Paper is to set out the key topics for consideration in the design of the detailed energy trading arrangements with a focus in particular on the design of the BM.

The key building topics for discussion in this paper are as follows:

- System Operation in the I-SEM
- Ex-Ante Markets
- Physical Notifications
- Form of Offers, Bids and Acceptances
- Interaction between the Balancing Market and Intraday Market
- Treatment of System Services
- Imbalance Pricing
- Imbalance Settlement
- Global Aggregation
- Local Market Power
- Metering
- Instruction Profiling

2 SYSTEM OPERATION IN THE I-SEM

2.1 INTRODUCTION

The characteristics of the electricity system in Ireland and Northern Ireland are such that local constraints and reserve requirements are proportionately greater than those in mainland Europe. This is mainly due to the island nature of the system (relatively high levels of DC interconnection compared to other EU zones), the increased penetration of variable generation, the system demand (generator capacities are typically large compared to peak demand) and the location of generation in relation to the demand. As a result the TSOs will likely need to take both energy and non-energy actions to maintain a secure electricity system during the IDM. Obviously these actions will be not limited to the IDM as these will also be taken in the last hour and in real time operation. There may also be rare occasions where actions are taken pre DAM.

Energy actions can be broadly considered as actions taken by the TSOs to address an overall imbalance between supply and demand across the settlement period. Non-energy actions can be considered as actions that are taken by the TSOs to address system issues that would still exist even if the market had perfectly balanced. These non-energy requirements include:

- Reserves
- Dynamics (Inertia, RoCoF, SNSP)
- Voltage support
- Thermal transmission constraints

The Electricity Balancing Network Code (EBNC) defines the BM as the market for balancing capacity and energy that is utilised post 'Balancing Energy Gate Closure Time' (one hour ahead of the delivery hour). Prior to the 'Balancing Energy Gate Closure Time' the TSOs will schedule and dispatch participants to manage system security. The TSOs will use the mechanisms of the I-SEM BM to achieve these security objectives.

However, these will be taken in a timeframe in advance of the BM as strictly defined in the Electricity Balancing Network Code. Consequently, and as set out in the I-SEM HLD, the IDM and BM will be open and will operate in parallel with each other in the I-SEM. The bids submitted to the TSOs in the BM will be used for resolving system constraints (non-energy actions) and also for energy balancing (energy actions).

However, a question arises as to what extent the TSOs shall take actions, in particular energy actions, prior to the BM gate closure. It is worth noting that throughout this paper the reference is to the TSOs' actions. However, the DSOs have a significant role in respect of energy and non-energy actions and therefore in this paper it has been assumed that the TSOs will coordinate with the DSOs as is currently the case in SEM.

The purpose of this section is to discuss the principles by which the TSOs are likely to take such actions prior to gate closure, the timing and effect of such actions and proposals for ensuring that the IDM solves the energy balancing to the extent possible while taking account of the TSOs' obligations to maintain a safe and secure electricity system.

Note that the proposals in this consultation are designed to address the concerns raised by market participants in relation to the effect that early actions taken by the TSOs could have on the outcome of the IDM. However, the RAs also mindful of the need for transparency in such early actions and therefore the proposals outlined aim to address this criterion where such actions are taken.

The RAs welcome comments in this regard, setting out specifically what the issues are and their likely impact such that they can inform a decision on the below proposals.

2.2 I-SEM PHILOSOPHY

The I-SEM HLD set out six principles in relation to the philosophy of how the I-SEM should operate. These are:

I. Preference for a competitive approach that is in the interests of consumers, in accordance with the statutory duties of the SEM Committee.
II. Access to all I-SEM market places for participants of all sizes and technologies.
III. Liquid trading of financial forward contracts for effective hedging of short term prices, which is particularly important for independent generators and suppliers.
IV. Liquid and transparent centralised short term physical markets that are coupled with European trading mechanisms, and are exclusive routes to physical scheduling.
V. Balance responsibility for all participants to ensure that their notifications of generation or demand best reflect their actual expectations.

VI. An explicit capacity remuneration mechanism to help deliver secure supplies for consumers in the all-island market, particularly with increasing variable generation.

Of these six principles, the two in relation to the route to physical scheduling and balancing responsibility are of particular relevance to this section. Both of these principles are discussed in turn below and form the basis for the discussions in relation to proposals aimed at reducing early energy actions taken by the TSOs.

2.2.1 PHILOSOPHY IV - ROUTE TO PHYSICAL SCHEDULING

Point 4 of the I-SEM HLD Decision in respect of the I-SEM philosophy states that ***'Liquid and transparent centralised short term physical markets that are coupled with European trading mechanisms, and are exclusive routes to physical scheduling.'***

In the current SEM arrangements, generators are centrally scheduled and dispatched and are not permitted to self-schedule (with the exception of priority dispatch). Specifically, the TSOs take the commercial offer data (COD) and the technical offer data (TOD) and produce an indicative operational schedule to take account of system constraints. SEMO takes this information and based on a stack of the most economic generation determines the 'unconstrained' market schedule and the System Marginal Price (SMP) for the period. Further, the form of the COD is subject to the licence condition on cost-reflective bidding and the Bidding Code of Practice which requires generation to bid cost reflectively.

In contrast, a physical schedule in the I-SEM will be achieved through the DAM and the IDM. This means that for generators (and demand) to achieve a firm physical schedule they will need to be contracted in the DAM and IDM. Typically, any energy not contracted in these markets will be settled at either:

- the incremental offer or decremental bid price if dispatched by the TSOs and not in merit, or
- the single imbalance price if otherwise.

However, the TSOs are under no obligation to facilitate the energy on the system that has, or has not, obtained an ex-ante position (subject to further consideration of Priority Dispatch and facilitation of the Balancing Market in the last hour in compliance with the Network Code on Electricity Balancing). Where the TSOs deem that it is not safe to dispatch a unit to its ex-ante position from a security of supply perspective, the TSOs will accept a decremental bid from this unit.

The IDM is a continuous trading platform. Therefore volumes traded will continuously change, such that the magnitude of generation sold in the DAM and the IDM, matches expected demand, and the mix of generation with net sales represents the least cost generation available to meet that demand. The TSOs will still need to take non-energy actions but for energy actions a question arises as to what point, given their statutory obligations, the TSOs intervene where they anticipate the market being either long or short compared to their forecast at that point, while also being cognisant of allowing the market maximum time to balance.

2.2.2 PHILOSOPHY V – BALANCE RESPONSIBILITY

Point 5 of the I-SEM HLD Decision in respect of the I-SEM philosophy states '***Balance responsibility for all participants to ensure that their notifications of generation or demand best reflect their actual expectations.'***

This means that all participants will be balance responsible and any differences between traded positions in the ex-ante markets, including activation of balancing energy by the TSOs, and actual metered generation/demand will be paid at, or will receive, the imbalance price.

The market information section of the I-SEM ETA Building Blocks Consultation Paper[1] discusses the possibility of the TSOs providing the market, during the IDM, with information on:

- the aggregate notifications,
- TSO wind generation forecasts,
- scheduled interconnector transfers, and
- TSO demand forecast (to give an indication of whether the system will be long or short).

The provision of this information should give a good indication to suppliers of their own expected positions and, given the continuous nature of the IDM, should allow

[1] http://www.allislandproject.org/en/wholesale_overview.aspx?article=a0314980-d66c-4281-8231-30e7a1999804

for participants to trade into balance as forecasts become more accurate closer to real time.

This balance responsibility obligation for participants and the provision of information during the IDM trading period may be sufficient to enable the system to balance with minimal TSO intervention being required prior to IDM gate closure. However, in the transition to the I-SEM from the current arrangements, the market may not balance to within a required tolerance to allow the TSOs to balance the system within the hour prior to real time. The remainder of this section discusses energy and non-energy actions in turn and discusses measures that might be taken to understand and minimise these actions.

2.3 ENERGY ACTIONS

As mentioned previously, energy actions are deemed to be those actions taken by the TSOs to match dispatched generation with demand where, absent of such actions, the system would have an excess or deficit of generation. Typically, this is carried out by moving generation, or flexible demand, in response to changes in demand forecast right up to real time operation at which point the balancing actions are taken in response to the system frequency changes. This section addresses those energy actions that are taken early, specifically in excess of one hour before real time. Hence, for the purposes of this section, an early energy action shall be those actions taken where at a particular time the TSOs, based on their forecast (demand and wind), anticipates that the quantity of energy contracted in the DAM and IDM will be significantly greater or less than the TSOs' forecast for the period. The resulting action taken by the TSOs during the IDM to balance forecasted demand and PNs is deemed to be an early energy action. Note that the TSOs do not necessarily have to balance if there is sufficient generation online or generation can be curtailed/de-committed within the last hour.

To illustrate, let's say the TSOs' forecast four hours from real time operation predicts that demand in that hour will be 4,300MW. Based on the DAM and IDM trades at that time, 3,900MW of energy has been contracted. The profile of PNs from the generators four hours from real time indicate that the TSOs need to call generation that currently does not have a market position (it may be the case that the scheduled generators at that time are scheduled at their maximum available output).

There are two types of energy actions; those that are taken as mentioned above where the market is long or short, and those that are taken as a result of arbitrage. It is expected that arbitrage actions should be minimal given that the DAM schedule is based on the least expensive units required to meet demand and therefore arbitrage based on the PNs received by the TSOs following the DAM results is unlikely. However, should an arbitrage opportunity arise during the IDM, a trade would likely be executed between the participants given its continuous nature.

2.3.1 MINIMISING EARLY TSO ENERGY ACTIONS

A significant number of generation plant in the SEM have start up and ramp times in excess of one hour. Hence, there will be scenarios where, for energy actions, the TSOs will need to call a plant before IDM gate closure. However, there will also be a decision in respect of the economics of calling a plant for an energy action i.e. typically a unit called during the IDM with longer start times is more economical than calling a fast response unit within the last hour before real time.

The RAs are cognisant of the concerns raised by the industry in relation to the potential impact that early energy actions taken by the TSOs during the IDM may have on market outcomes and participant behaviour. However for the reasons outlined above, the TSOs will need to take some early actions, given their statutory obligations and the technical characteristics of the generation plant on the island. Therefore, the following proposals for consideration aim to strike a balance between minimising such actions while also allowing the TSOs to perform the necessary functions to maintain system security and, where such actions are taken, that there is an adequate level of transparency around the decisions taken.

2.3.1.1 PROPOSAL 1 – DEFINED PRINCIPLES AND TIME PERIOD FOR EARLY TSO ENERGY ACTIONS

This proposal would see the TSOs publishing a document that sets out the principles for which it takes balancing actions. This would aid in increasing levels of transparency around such decisions. By way of comparison, the BETTA market in Great Britain (GB) adopts a late opening approach, whereby BM actions (bid-offer acceptances) cannot be taken until after gate closure, which is one hour before the start of the relevant settlement period. National Grid has a publically available

Balancing Principles Statement document[2] that defines the broad principles and criteria under which all balancing actions are taken, both during the BETTA BM, one hour ahead of real time, and actions that extend beyond the particular settlement period.

It is proposed that a similar document is published by the TSOs for the I-SEM. However, while noting the information provided in the National Grid document, a particular focus of this document would be on early actions taken by the TSOs during the concurrent running of the IDM and the BM.

Additionally, this balancing principles document could also include the following two principles in relation to energy actions:

1. The TSOs only take early energy actions within an agreed timeframe before real time operation.

The current generation fleet has diverse notification time requirements (unit notification and loading times) to synchronise and reach minimum load. Times range from 15 minutes to in excess of 15 hours depending on generator status (hot, warm, cold). The possible range of approaches that the TSOs could take in regard to the timing of energy actions fall between two extremes:

- The first approach would be where energy actions could start to be taken after the DAM results are published as needed based on the TSOs unit commitment schedule.
- The second approach would mean any energy actions are taken only after the IDM closes (one hour before real time).

There are a number of advantages and disadvantages associated with each approach. The first approach could lead to lower operational production costs and greater system security in the event where the system is deemed to be either long or short. Where the market is short, the TSOs will have sufficient time to schedule the

[2] http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/Balancing-framework/bpsr2013/

most economic plant whilst not taking the dispatch action until the start-up times of the previously-scheduled most economic plant is being met.

Where the market is long, the TSOs again should have sufficient time to schedule the de-committing of a plant with high costs while respecting the time taken to de-synchronise from the system. However, allowing such actions shortly after the DAM results could remove liquidity from the IDM and potentially lead to inefficient transactions in the IDM if suppliers were not aware that the TSOs had taken early energy actions on their behalf.

On the other hand, the second approach allows greater time for the market to reach energy balance and hence provides a stronger incentive for participants to balance, as it is likely to lead to higher cost generation being dispatched to meet demand. However, this scenario may regularly breach operational security limits (with insufficient time to synchronise sufficient generation). It would also lead to a higher reliance on quick start units (at the expense of long notice, potentially cheaper, actions) and an increase in wind curtailment (due to the inability to shut down plants with long shut-down periods), both of which, if realised, could lead to an increase in operational production costs and more volatile prices.

Hence, through a TSO led consultation, it is proposed that a time is agreed between market participants and the TSOs before which the TSOs would aim to avoid taking energy actions. (e.g. no early TSO actions prior to four to six hours before IDM gate closure). This proposal could provide a compromise between the contrasting approaches outlined above. However, it should be noted that this proposal would not prevent the TSOs from starting up or shutting down a new unit, whether less or more expensive, if deemed necessary for operational security reasons.

Furthermore, the RAs propose that the time period would be kept under review and updated, following a TSO led consultation process, which would take into account historic market experience to ensure that the appropriate trade-off between maintaining a secure electricity system and maximising the decision making of market participants (given their balance responsibility) is achieved. In other words, at I-SEM Go-Live, the RAs propose that the appropriate balance is achieved by setting this time quite early. After the market becomes established and market participants acquire knowledge on how the market responds to changes in system conditions, the timing for TSO intervention could be reviewed with the aim of reducing the time period for energy actions.

Such a periodic review would need to involve both market participant representation and the TSOs, and would need to have an agreed set of criteria by which the impact on the market could be assessed (e.g. production costs, wind curtailment, market distortion, frequency and reserve impacts). Again, the RAs would welcome comments on what the impacts of TSOs' early actions are on the IDM.

2. **The TSOs will only initiate early energy actions if the difference between the sum of scheduled wind and market demand (aggregate PNs), and the TSOs' forecast of wind and system demand, is outside of a pre-agreed tolerance.**

Another proposal would be that the TSOs will use the market demand in the unit commitment schedule once it is within a specified range of the TSOs' forecasted demand expectation. This means that, if the difference between the TSOs' demand forecast and the aggregate PNs is within an agreed tolerance, the TSOs would not take any energy actions. e.g. if the tolerance was 100MW and difference between the TSOs' forecast and the market demand was 50MW then the TSOs would not accept a bid-offer acceptance from a particular plant to meet the potential 50MW shortfall until within the last hour balancing timeframe. Again, similar to the first proposal, this range (X MW), which would be the difference between the TSOs demand forecast and the aggregate PNs would need to be agreed between market participants and the TSOs, through a TSO led consultation process. The range could also take into account the PNs from wind, if applicable, and the TSOs' own wind forecast such that it could be netted against the differences in the TSOs' forecast demand. Both the demand forecast tolerance and the wind forecast tolerance would be reviewed periodically.

2.3.1.2 PROPOSAL 2 – DEFINED PRINCIPLES AND CONTINGENCY RESERVE MONITORING

An alternative approach would be focused more on operational security whereby the TSOs maintain adequate ramping capability, rather than a time based approach. Under this approach, the TSOs would continually monitor the levels of contingency reserve and take action to increase the available reserve level where it sees that the difference between the aggregate PNs and the TSOs' demand forecast is greater than a defined tolerance. The tolerance could be designed in the same way as set out in the first proposal i.e. as a function of the difference between the TSOs' wind and demand forecast and the aggregate PNs from participants and as a function of time to real time. Where this differs from the first proposal is that under the first proposal the TSOs would take actions to close the 'gap' between aggregate PNs and demand forecast once outside an agreed tolerance and within the timeframe agreed; whereas this option would increase the level of contingency reserve to account for the increased risk to the TSOs of ensuring that the system is balanced during the period.

It is worth noting however that while the contingency reserves are being monitored under this approach, it may be the case that the TSOs take energy actions that required a plant to start such that ramping capability is provided. In this scenario, the plant will now be providing energy that would close the 'gap' between the difference of the TSOs' forecasts and aggregate PNs.

Notwithstanding that the requirement for contingency reserve may be higher closer to time depending on how long/short the market is expected to be, it is likely that the level of contingency reserve is such that it would be a gliding path that reduced as real time operation approaches. This is likely to be the case given the improvement of forecasting as real time approaches and the continuous trading in the IDM as participants trade with the aim of being in balance. This means that any energy actions to provide more contingency reserve as a result of the difference between aggregate PNs and the TSOs' demand forecast when the BM opens would likely only be taken outside a tolerance than is greater than it would be at, say two hours before real time.

As a simplistic example, let's say that the tolerance when the IDM and BM opens is 800MW and at two hours prior to real time it is reduced to 200MW with the tolerance reducing linearly between the two points in time. This means that the TSOs, upon receipt of the PNs from participants after the DAM results will only take an energy action to increase the level of contingency reserve if the difference between the aggregate PNs and the TSOs forecasts (wind and demand) is greater than 800MW. Let's say that the difference is within this tolerance at BM opening. The IDM trading continues and at two hours prior to real time, the TSOs, when comparing their forecast against the aggregate PNs at that time calculate a difference of 300MW which is now 100MW outside the tolerance. The TSOs then will increase the level of contingency reserve to account for the 100MW such that the TSOs have the capability to balance and hold sufficient reserves to cover both the loss of single largest in-feed and forecast error during the last hour/real time (e.g. commit a unit through acceptance of an incremental offer).

2.3.1.3 PROPOSAL 3 – REPORTING REQUIREMENTS OF EARLY TSO ENERGY ACTIONS

Another proposal would see the TSOs reporting annually on all early TSO actions to all market participants. Such a report would specify the circumstances within which the action was taken and the reasons for the actions. By setting out the circumstances under which an early action was taken, the TSOs would have an incentive to minimise such actions as any actions, that in hindsight may be deemed un-necessary, would be highlighted and potentially avoided in future circumstances, if of a similar nature. This report could build on the current publication of the Quarterly Imperfections Costs Report published by the TSOs[3] and would be a key part of the current incentivisation of all-island balancing costs.

It may be the case that this proposal should be implemented in conjunction with either proposal 1 or 2 whereby a detailed report of early energy actions is published in conjunction with the principles document discussed above to increase levels of transparency. It could also be that the report only discusses those actions that were taken outside of the agreed timeframe or contingency reserve level agreed between market participants and the TSOs.

2.4 NON-ENERGY ACTIONS

Non-energy actions on the other hand are those actions that are taken due to the constraints (thermal, voltage, frequency and dynamic stability) on the system. It seems to be accepted that the task of system balancing is more acute in the SEM, compared to other markets, given that it is a smaller and proportionately more constrained system. As a result, the I-SEM HLD requires the BM to open during the IDM to allow the TSOs sufficient time to redispatch generation as needed to account for these constraints.

In other markets, such as in the BETTA market, the system operators, instead of calling plants in the IDM will use out of market contracts to procure system services. These contracts mean that the TSO can instruct a contracted generator to submit a PN that will represent the energy required from that unit for a particular period as a result of the system constraint.

[3] http://www.eirgrid.com/operations/reports/

It was deemed that for the I-SEM opening the BM early would serve two advantages namely, transparency and competition, compared to out of market contracts. Specifically in the SEM, the number of generators available to address system constraints is quite limited and therefore procuring these generators through out of market contracts would likely not be the most cost effective approach nor would it place incentives on generation to be more flexible. Secondly, these contracts are agreed between the TSOs and the specific generators and hence the level of transparency is reduced in comparison to the TSOs taking early actions based on submitted PNs with associated incremental offers and decremental bids.

There may also be a cost efficiency dimension to non-energy actions especially when there are few alternatives to 'constrain on' generation within an import constraint zone. From a perspective of minimising costs it is often better to take early actions to resolve such constraints rather than wait to the last moment.

2.4.1 MINIMISING NON-ENERGY ACTIONS

Minimising non-energy actions is an issue that is more far reaching and has a wider context that those issues falling under the I-SEM Energy Trading Arrangements. Non-energy actions arise due to system constraints; minimising these constraints would obviously reduce non-energy actions taken by the TSOs. This section aims to discuss, at a high level, current policies and projects outside the scope of the I-SEM that are ongoing which should ultimately reduce system constraints to some extent. Lastly, the question is posed as to whether there are any other areas that need to be considering in reducing the non-energy actions taken by the TSOs.

Regarding the current incentives to minimise non-energy actions, the SEM Committee in 2012 published its Decision on Incentivisation of All-Island Balancing Costs[4]. Dispatch Balancing Costs (DBCs) are levied on suppliers through the Imperfections Charge. These charges are forecasted by the TSOs and consulted on by the RAs. Any differences between the charge and the actual costs are subsequently adjusted through the k-factor. An ex-post review of the costs is then carried out which includes consideration of any defined external factors that lead the DBC being in excess of 10% of the ex-ante baseline.

[4] http://www.allislandproject.org/en/transmission_decision_documents.aspx?article=40b93d75-e3f6-4eef-b997-3d9209a2b7d8

Based on this review and in consideration of the bands as outlined the table below, the TSOs will either be penalised or rewarded for difference between the forecasted DBCs and the actual DBCs. For the purposes of this consultation it not proposed to change this Decision and hence these incentives will remain for the I-SEM.

€m's	Lower Bound	Dead Band	Upper Bound	Below Target	Above Target
Dispatch Balancing Costs	7.5%-20% below baseline	7.5% below and above the baseline	7.5%-20% above baseline	TSOs retain 10% of every 2.5% below	TSOs penalised 5% of every 2.5% above

There are currently other significant projects that are on-going that will ultimately reduce system constraints. The TSOs for example are currently undertaking significant network upgrades which will upgrade the system as needed to maintain sustainable and reliable power supply into the future and account for the changing generation portfolio arising from the deployment of renewable generation. These developments include addressing the constraint groups identified in 2012 (Donegal, Cork/Kerry, Northern Ireland). On completion, this will reduce the number of constraint related non-energy actions that need to be taken by the TSOs. It is important to note that in general there is an economic balance to be struck between investing in transmission infrastructure and making constraint payments and that in some situations the cost of constraints and their associated non-energy actions will remain.

With regard to early actions defined by generator notification times, the DS3 programme will deliver solutions to the challenges associated with increasing levels of renewable generation. A significant piece to this programme is with regard to the incentives for quick start generation that will be key to facilitating increased levels of variable generation. Again, when delivered this should reduce the number of early non-energy actions taken by the TSOs. There may be other approaches that merit consideration and would fall under the ETA of the I-SEM project. For example, the approach under which the TSOs make decisions in relation to taking early non-energy actions in the current SEM may have scope for improvement when compared to approaches taken in other systems. The RAs would welcome comments from industry if there are areas that merit consideration in this regard.

2.5 SUMMARY

In the context of the philosophy outlined in the I-SEM HLD and the objectives of the European Target Model and Network Codes, it is important that the market is left to balance any energy shortfalls/surpluses to the greatest extent possible. However, there will be instances where the TSOs, in keeping with their statutory obligations to maintain a safe and secure electricity system, will need to take both energy and non-energy actions prior to the closure of the IDM. This section sets out a number of proposals aimed at minimising such actions and ensuring that where actions are taken, the reasoning is clear and transparent for market participants.

The RAs welcome comments on these proposals and any alternatives if any.

Specifically, comment is sought on:

1. **What are the impacts of early action by the TSOs on the Intraday Market?**

2. **What measures can be taken to minimise early actions by the TSOs?**

3 EX ANTE MARKETS

3.1 CONTEXT

The EU Guideline on Capacity and Congestion Management (CACM) sets out objectives and minimum conditions for achievement of efficient and competitive electricity trading across Europe including harmonised rules for Day Ahead and Intraday Markets. These rules will be based on an agreed approach to capacity calculation, congestion management and electricity trading. More detailed rules and methodologies for operation will be developed by the TSOs and Nominated Electricity Market Operators (NEMOs) and shall also apply to the I-SEM as appropriate.

The harmonised rules include development of common requirements for a price coupling algorithm and continuous trading matching algorithm. The price coupling algorithm will ensure that pricing will maximise the economic surplus for the Day Ahead Market through a single marginal clearing price applied to all accepted bids. This will be in accordance with agreed allocation constraints, cross-zonal capacity calculations and harmonised rules dealing with timescales and products etc. The continuous trading matching algorithm will determine the orders selected for matching in the Intraday Market in order to maximise the economic surplus of each trade. It will also respect allocation constraints and cross-zonal capacity calculations within the procedures and process set out in the CACM. The CACM Guideline sets certain parameters for operation of intraday coupling and allows for the development and implementation of complementary regional intraday auctions providing these comply with defined principles and conditions.

The SEM Committee HLD Decision of the I-SEM is that the European Day Ahead Market will be the ‘exclusive’ route to a physical nomination at the Day Ahead stage. As forward trading in the I-SEM will be financial only, bidding generation or demand into the European Day Ahead price coupling process will be the only route by which a market participant can take a forward position to offset their balancing responsibility.

In a similar fashion, making a matched trade in the European intraday price coupling mechanism will be the only route by which a market participant can update their physical contract nomination at the intraday stage. It is intended that this will support scheduling in the market of more efficient electricity flows between the all-island market and the GB market and deliver robust compliance with the EU Target Model. The RAs, in cooperation with the TSOs are currently trialling the functionality of the EUPHEMIA algorithm in order to determine the scope for the range of the I-SEM bidding formats that can be accommodated. The I-SEM HLD Decision paper also noted that "The Intraday Market in I-SEM will employ the products available through the EU central platform. In the medium term these are expected to be quite simple bidding structures but may develop more in the future to more sophisticated products as foreseen by the CACM Network Code."

The harmonised rules set out in CACM and decisions to make the European Day Ahead Market the 'exclusive' route to a day ahead physical notification, and European intraday price coupling mechanism the only route to update it, provide the fundamental design features of these market timeframes. The CACM also provides for the further elaboration of harmonised rules for these markets.

The CACM Guideline and its future development therefore has application not just to the market rules for I-SEM as it interfaces with the European markets but to the complete set of market arrangements within these timeframes. The scope for determining the rules for the ex-ante markets within I-SEM is therefore also restricted within this framework. The following sections set out the main features of the ex-ante markets, the thinking behind their design and the necessary steps to be taken for their implementation.

3.2 DAY AHEAD MARKET

The aim of this market timeframe is to allow a day ahead route to market for physical trade, this is will be the first option for physical trade in I-SEM. Supply and demand, including cross border flows, should be matched at the lowest possible cost. The clearing price will be based on matching order books of different parties in different markets, within physical limits of interconnection, through EUPHEMIA[5].

The Day Ahead Market will be auction-based. As a consequence:

- Calculated prices are market clearing prices which apply to every executed order.

[5] http://www.apxgroup.com/wp-content/uploads/Euphemia-public-description-Nov-20131.pdf

- Orders are sent into Order Books at limit prices without knowing the prices and quantities of the other orders.
- Trade execution is made simultaneously for all trades after gate closure.

EUPHEMIA is the matching algorithm that will deliver a common, cleared market price produced through the coupling process. This price can subsequently be used as a reference price for other purposes, e.g. CfDs, PPAs.

The prices and quantities determined by the price coupling algorithm will have hourly resolution. The TSOs will require physical nominations on a higher granularity than what is outputted by the algorithm. The process whereby this hourly quantities will be converted into a higher resolution nomination will be discussed in the Section 4.

The specifics of all-island fleet and system will be reflected in bids via the adoption of one or more of the bidding options supported by EUPHEMIA. Simple Bids/Linked Block Orders/Exclusive Block Orders/Complex Orders (with minimum income conditions) are currently under consideration by a joint task force involving the RAs/TSOs and Industry representatives. This initiative has been named as the EUPHEMIA trial.

The EUPHEMIA trial will be divided into different phases covering issues such as the conceptual analysis of the results produced by the algorithm, stress test and commercial phase with the input of the industry. The timeframe, terms of reference and the details of the trail have been published by EirGrid

3.3 INTRADAY MARKET

The aim of the IDM is to allow a within-day route to market for physical trade and adjustment of DAM positions (second option for physical trade). Parties will seek to trade in the IDM to cover positions not met in DAM (i.e. sell more or buy more) and to manage variations in positions as information improves (e.g. wind and demand forecasts) or situations changes (e.g. commodity price variations, forced outage). Variability around forecasts could be an important driver for trade and this suggests that demand and wind should participate in the market rather than seek to remove themselves from it.

The HLD of the I-SEM established that the IDM will be the exclusive conduit for physical trade within day. The underlining reason for that was to promote a sufficiently liquid IDM with depth to allow parties to fine tune positions and hedge risks as circumstances evolve.

Continuous trading is the modality of the market. As a consequence:

- Each execution price applies to one trade: no common clearing price is defined.
- Orders are sent into Order Books (OBKs) continuously; trades are executed even though all orders may not have been sent to OBKs.
- When determining offered quantity and limit prices and sending orders in OBKs, traders can see the quantity and price of orders which are already in OBKs.
- Orders are matched in a sequence governed by the First-Come First-Served rule: no welfare optimisation process is performed.

3.4 DAY AHEAD AND INTRADAY MARKET IMPLEMENTATION

Day Ahead Market

The Day Ahead Market in I-SEM will utilise the DAM processes foreseen in the CACM Guideline. These processes are already operational across much of the EU since February 2014. This was made possible through the early implementation project set up which was called the North West Europe (NWE) project. The DAM in I-SEM will use the EUPHEMIA market processes already in place in many other markets and operated by other Power Exchanges in the EU including APX, Nord Pool Spot, EPEX Spot, OMIE and GME.

Given the above, the implementation of the DAM in I-SEM will largely be an implementation of processes similar to what operates elsewhere in Europe. Related to this is the recent SEM Committee Consultation Paper on Roles and Responsibilities in I-SEM[6]. This paper discusses the possible framework for the Market operator in I-SEM. At this stage it would appear appropriate to await the outcome of the process to designate a Market operator in I-SEM and into put in place a robust implementation plan as part of that. It is likely that this implementation process will consider the following issues:

[6] http://www.allislandproject.org/en/TS_Current_Consultations.aspx?article=5d172226-e065-4bba-9ff9-80512012c885&mode=author

- Registration
- Communication channels between the Market Operator and participants
- Any required pre-processing of bids and offers
- Clearing and Settlement
- Fall Back Procedures

Intraday Market

Similar to the Day Ahead Market, it is expected that the implementation of the Intraday Market in I-SEM will utilise much of the practices and process established through the intraday early implementation project XBID.

Interim Arrangements

The XBID project is currently under development by power exchanges and TSOs across Europe but is following a later implementation date than the DAM. Specifically, the XBID project has been delayed compared to what was originally expected. This poses a risk for I-SEM and in particular it will need to be established whether an interim arrangement might be required where XBID implementation happens later than I-SEM. There are three potential approaches for this:

- The I-SEM could commence with an IDM which covers the I-SEM zone only. With this approach, all capacity would be allocated to the market through the DAM; the IDM would allow no further allocation of cross zonal capacity. Any cross border trade after the DAM would be achieved through countertrading.
- An interim arrangement could be put in place to couple the I-SEM IDM with the GB IDM. This would require the Market Operator in I-SEM to cooperate with the relevant GB Market Operator to put coupling arrangements in place ahead of the EU wide solution.
- An interim arrangement could be put in place to implement regional intraday auctions between GB and I-SEM in advance of the XBID Go-Live. Regional auctions are discussed further below.

Options two and three above would require the GB Market Operator and TSOs to be available to cooperate in such interim arrangements.

Intraday Auctions

Another aspect of the intraday arrangements the SEM Committee wishes to consider is whether intraday auctions should be implemented in I-SEM. Intraday auctions would involve an auction solution being put in place during the intraday timeframes at certain times. Given the level and importance of interconnection, any auction would need to be coordinated with the GB market and in practice would likely see a solution, similar to the DAM, run again during the intraday timeframe. This would in all likelihood require that the I-SEM GB border be closed to continuous trading during the auction. This is allowed for in the CACM Guideline.

Implementing auctions could have a number of benefits in I-SEM. Specifically, they could assist smaller players and could act to increase and focus liquidity. They could also provide a more robust price setting mechanism (including capacity pricing) and provide a more efficient allocation of cross border capacity.

Participants have previously expressed an interest in having intraday auctions in I-SEM. Like the rest of the DAM and IDM implementation, the identification of a Market Operator is a key enabler in developing any proposals with existing GB Market Operators. As part of this Consultation Paper the SEM Committee is interested to hear views as to whether respondents believe that intraday auctions should form a part of the intraday solution and whether there are potential advantages of those auctions that are not set out here.

3.5 SUMMARY

The DAM and IDM will be key market timeframes in the I-SEM. Much of the detail around the implementation of the DAM and IDM will be decided through the EU implementation. The DAM is already in operation across a number of EU markets.

The IDM is still under development at EU level. There is a potential that I-SEM Go-Live will happen before IDM implementation at EU level. This chapter has put forward a number of options which could be implemented in the event that IDM is not in place for I-SEM.

This chapter also put forward the possibility of implementing intraday auctions as part of the I-SEM design. Comments are welcomed on this also.

Specifically, comment is sought on:

1. **Which of the three options put forward for interim IDM arrangements is most appropriate?**
2. **Should intraday auctions be implemented in I-SEM? Are there any advantages to those auctions not described in this paper?**

4 PHYSICAL NOTIFICATIONS

4.1 INTRODUCTION

This chapter outlines the details around physical notifications (PNs), for example their timings and granularity, and also introduces for consultation three options as to how PNs from participants should be linked to their ex-ante trades. These three options are given the names:

(1) PNs Linked to Ex-ante Trades at All Times;

(2) PNs Linked to Ex-ante Trades at Gate Closure Only; and

(3) PNs Reflecting the Best Estimate of Intended Generation or Demand[7].

4.2 PURPOSE OF PHYSICAL NOTIFICATIONS

The PN submitted by a participant to the TSOs in respect of a generator unit represents the MW profile that the participant intends to generate in the absence of having any incremental offer or decremental bid accepted by the TSOs in the BM. Similarly, the PN submitted by a participant to the TSOs in respect of dispatchable demand represents the MW profile that said participant intends to consume in the absence of having any incremental offer or decremental bid accepted by the TSOs in the BM.

The I-SEM HLD Decision notes that the notified profiles should reflect generator physical constraints and be sufficiently granular to support the TSOs in operating a secure and safe system.

PNs are important for the secure and safe operation of the system by the TSOs as they provide an indication of the expected running regime of each unit on the system. In aggregate, PNs provide the TSOs with the market's expectation of the supply demand balance and this allows the TSOs to take actions when required. PNs also, importantly, provide the TSOs with locational information on the expected

[7] At the RLG meetings these options were described as: "Linked Physical Notifications"; "Partially Delinked Physical Notifications" and "Fully Delinked Physical Notifications", respectively.

generation at different points on the transmission system. This allows the TSOs to forecast constraints on the transmission system and take non-energy actions to resolve these constraints where appropriate. Set out below are some examples of where the submission of PNs is important.

- If, following the submission of PNs after the DAM, it becomes evident that the total expected generation is significantly lower than expected demand the TSOs can take this into account in their planning of next day operations. The publication of this information would also make the wider market aware of a potential supply imbalance.
- PNs will also make the TSOs aware of the location of expected plant running. This allows the TSOs to carry out its constraint management and to identify any dispatch requirements needed to resolve constraints at an early stage.
- Related to the above, the PNs submitted allow the TSOs to plan for deployment of reserves across the generation fleet including instructing any plant starts needed to meet reserve requirements.

4.3 TIMINGS AND GRANULARITY OF PARTICIPANT PHYSICAL NOTIFICATIONS

Timings

The initial Day Ahead PN should be submitted at some reasonable period of time after participants have received their results from the Day Ahead Market. These results will be received by participants at approximately 12:00 and it is proposed that the final deadline for the submission of initial Day Ahead PNs will be 14:00. In the event that DAM fallback procedures were invoked then there could be scope to also push back this deadline.

Each participant's initial Day Ahead PN will cover at least the whole next 24 hour period trading day (i.e. 23:00 on the day in question to 23:00 the next day). These will be in addition to the PNs for the period from 14:00 to the start of the next trading day that will have been submitted first as initial PNs at 14:00 the day before, and may also have been subsequently updated as a result of intraday trading for that period.

The I-SEM BM is mandatory. Therefore the initial Day Ahead PNs from each participant must be accompanied by its incremental offers and decremental bids to the BM and also its availability profile for the time period in question. If a generator suffers a complete forced outage event, at any time following the initial submission of PNs, then it should immediately re-declare its availability to zero. This would negate the need to resubmit its PN immediately. If a generator suffers a partial forced outage then it should re-declare its availability to the appropriate level immediately.

To the extent that participants are making intraday trades, they will be submitting updated PNs to the TSOs throughout the intraday period. The resubmission of PNs could be required, for example:

a) within [x] minutes of an IDM trade being completed;
b) when there is a change of [y] MW from the previous PN submission; or
c) on each hour.

In practice, there may not be any reason to go with anything other than a continuous notification. The aim of the process should be to get the best information to the TSOs as early as possible, without putting requirements on participants that are too onerous.

These updated PNs, where they occur in hour x which is after the start of the trading day, should cover the time period from hour x+1 to at least the end of the trading day (23:00).

The last PN submitted by a participant at the time of gate closure (one hour ahead of real time) will becomes by definition its FPN. It will be for participants to manage their trading in the IDM to ensure that any trades executed are reflected in their FPNs.

It is for discussion as to whether there should be an exception here for plant with priority dispatch which may be permitted to continue submitting updated PNs closer to real time. This will depend on the ultimate treatment of priority dispatch plant.

With one hour gate closure the time period covered by FPNs will be either:

a) the BM settlement period(s) from 60 to 90 minutes ahead; or
b) the BM settlement periods from 60 to 120 minutes ahead for which ex-ante trading has closed.

Views are sought from respondents on the issues related to the timings of PNs discussed above. Views should be supported with rationale.

Granularity

The TSOs need to balance the generation and demand on the system instantaneously and at all times. Therefore the PNs submitted by participants in respect of generation and dispatchable demand should define the instantaneous MW levels they intend to generate at all times during the period in question.

However, the actual spot data points at which the MW level is defined in the PN submitted to the TSOs could be at a one minute resolution, or at a two minute resolution, or at a five minute resolution, and so on. The MW levels at intervening time periods between MW levels defined at the submitted spot data points would be calculated through a simple linear interpolation. Accuracy shall have to be weighed against costs of participant processes, data and IT requirements. It is likely that a requirement for spot MW levels at a resolution of anything less than one minute would be a requirement for spurious accuracy that would not be of any measurable benefit to the TSOs. It may therefore be that a one minute resolution is appropriate.

It may be prudent to ensure that TSO systems are procured that allow for a range of granularity with the most appropriate number decided upon in the detailed implementation phase.

Comment is sought from respondents as to the most appropriate resolution of PNs. Comments should be supported with rationale. Support for longer resolution should include comment on whether rule sets would be needed by the TSOs to break the notifications to smaller resolution.

4.4 REQUIREMENTS ON DEMAND AND WIND PARTICIPANTS TO SUBMIT PHYSICAL NOTIFICATIONS

PNs will be required from dispatchable generators and dispatchable demand, given that their expected running will be determined by their activity in the ex-ante markets. Whether non-dispatchable demand and/or wind generation should submit PNs is discussed below.

Non-Dispatchable Demand

Unlike dispatchable units, where the TSOs cannot forecast which units will have matched trades in the DAM and IDM and therefore needs information on PNs, PNs may not be required from non-dispatchable demand participants. There are several arguments as to why this would be the case, notably:

- The TSOs will be using their own forecasts of demand in determining the early energy actions, and non-energy actions, that it is appropriate for them to take to balance the system. As an important aside here, the TSOs' forecast of demand will increasingly need to reflect the price responsiveness of non-dispatchable demand.
- Non-energy actions by the TSOs will be location specific. PNs from non-dispatchable demand would not be location specific, and would just represent aggregate demand at the trading point, and would therefore not provide useful information to the TSOs in terms of resolving non-energy issues.
- Non-dispatchable demand participants cannot respond to instructions from the TSOs and therefore will not be submitting incremental offers and decremental bids to the BM.

Consequently, it is unclear to what use the TSOs would put information from non-dispatchable demand, and therefore, what would be gained from a requirement for non-dispatchable demand participants to submit a PN that would simply be a forecast of their individual consumption.

Subject to the discussion in the Building Blocks Consultation Paper, the TSOs will publish information to facilitate balance responsibility. This will likely include publishing their aggregate demand forecast throughout the day. This may aid suppliers in forecasting their own demand and help inform their purchases in the ex-ante markets. The TSOs may also publish the difference between their aggregate demand forecast and the combined PNs or aggregate contract positions, as appropriate. This should help inform all market participants as to whether the market is likely to be long or short.

Wind Generation

There is also an open question as to whether or not PNs should be required from wind generators. Wind has priority dispatch and in all likelihood the wind generator will produce as much as the weather permits.

As with non-dispatchable demand, the TSOs make forecasts of aggregate wind generation output. These forecasts are likely to be more accurate than the sum of individual participants' forecasts, as would be expressed through PNs.

If PNs are not required from wind generators then they should still have the choice as to whether to submit them or not subject to having required systems in place. This is linked to the discussion on priority dispatch in the Building Blocks Consultation Paper. A wind generator may be able to submit an FPN and any additional available output above that would not have priority dispatch.

If a participant chooses not to submit PNs in respect of wind generation and instead allows the TSOs to establish a FPN on their behalf, it needs to be established how the FPN is arrived at.

Given the potential for constraints, curtailment, etc. it is likely that the FPN should represent the availability of the windfarm, where the windfarm has an availability signal to the TSOs. In the absence of such a signal the TSOs would use the metered generation value. This is only an issue for settlement where it needs to be established whether the wind farm was turned down from its maximum availability.

4.5 PARTICIPANT PHYSICAL NOTIFICATIONS AND EX-ANTE TRADES

The I-SEM HLD envisages that the participants should trade their intended production and consumption in the ex-ante markets. The Forwards and Liquidity workstream will consider whether and what specific liquidity promotion measures should be placed on participants in the ex-ante markets. The HLD also envisages that the traded positions from the ex-ante markets should form the starting point for dispatch.

While it is anticipated that participants will want to trade in the Day Ahead and Intraday Markets, and thus avoid exposure to imbalance prices to the maximum extent possible, it is also possible that under some circumstances the commercial interests of some participants could be served by not trading all of their generation or demand ex-ante, and buying (selling) some of their demand (generation) in the Balancing Market if they expect the imbalance price to be lower (higher) than the prices in the ex-ante markets. Whether or not this pricing arbitrage between markets will be permitted or encouraged will depend on the behavioural measures placed on participants in the ex-ante markets.

Hence, by default, the I-SEM HLD could be given effect by requiring participants to submit PNs to the TSOs for each unit that represent a profile of generation (or demand) that correspond as closely as possible with the sales and/or purchases for that unit in the ex-ante markets.

Generators currently work under a Grid Code obligation requiring them to comply with TSO instructions. In I-SEM, generators will continue to be expected to comply with TSO instructions which will facilitate their PNs to the extent that these are consistent with safe and secure system operation.

There is a possibility that any given schedule of sales and/or purchases in contiguous trading periods may not be deliverable by a profile of generation (or demand) that is physically feasible, given the technical offer data for the relevant unit. It therefore seems likely that some tolerance may be required in respect of the equivalence of the PNs to the ex-ante trades.

However, it is also the case that, as to the intended profile of generation (or demand) for each unit, the PNs are an important source of information for the TSOs in determining how to dispatch and balance the system. Thus, to the extent that participants might under certain circumstances have an incentive to run an imbalance, then requiring PNs to correspond exactly (or to within some small defined tolerances) with the ex-ante traded positions could create an incentive to deviate from their PNs and to run uninstructed imbalances. This could have the undesirable effect of devaluing the usefulness of the PNs in providing the best possible information to the TSOs, which could have the knock-on effect of increasing the cost of balancing the system.

Thus, having considered the matter in more detail, this Consultation Paper sets out a number of options to give effect to the HLD in respect of the submission of PNs, and respondents' views are sought on these options:

(1) PNs Linked to Ex-ante Trades at All Times;

(2) PNs Linked to Ex-ante Trades at Gate Closure Only; and

(3) PNs Reflecting the Best Estimate of Intended Generation or Demand.

4.5.1 OPTION 1: PHYSICAL NOTIFICATIONS LINKED TO EX-ANTE TRADES AT ALL TIMES

Under this option, the PNs submitted in respect of a unit – generation or dispatchable demand – would be required to match the ex-ante trades in respect of that unit at all times. Thus the initial submission of PNs, made shortly after the closure of the Day Ahead Market and the receipt by participants of their Day Ahead Market results, would be equivalent to the Day Ahead Market position. The PNs would then have to be updated following trades in the Intraday Market.

The main drawback of this option is the potential for the TSOs to receive poorer quality data, which would be used as the basis for non-energy actions used to resolve system constraints. Accurate information on expected unit output is important for the TSOs to allow them plan and operate the system, in advance of real time dispatch, in as efficient a manner as possible.

The volume of transactions in the DAM may not reflect the full volume of generation and demand. If, for example, absent a mandatory DAM, 75% of demand cleared in the DAM, for whatever reason, under this option the PNs would give the TSOs a day ahead expectation of 75% of demand being met. Therefore, the usefulness of this information to the TSOs as a basis for early actions is unclear. It seems probable that the information of most relevance to the TSOs is the traded position the participant is intending to achieve at gate closure, and in this respect requiring the PNs to be equivalent to the traded positions at all times beforehand could be either misleading or not reliable enough on which to base decisions.

For instance, in the Intraday Market, some participants might pursue a strategy of trading early while others might prefer to trade late. If PNs have to be matched to the traded position at all times, the PNs of the different participants at intermediate times between Intraday Market opening and closing might be very different depending on their trading strategy, even though the FPNs might be the same.

Also, if the requirement for physical feasibility were to apply to all submissions of PNs, and not just those at gate closure, this could limit participants' flexibility in the Intraday Market, by limiting trades to only those that lead to physically feasible PNs at all times. Not only could this requirement be onerous for individual participants but, given that Intraday Market trades are between one participant and another (notwithstanding the fact that there might be a central counterparty for clearing), then in the case of, say, a sale from one generator to another, the trade would have to be physically feasible for *both* parties. This could limit the scope for Intraday Market trades even further. Limiting the flexibility for participants to make Intraday Market trades in this way, and hence limiting their ability to trade into balance through the ex-ante markets, would seem to be contrary to the aims of the HLD.

Views are sought from respondents on what information the TSOs would use to make early energy and non-energy action decisions if this option were adopted.

With this option, certain tolerances would have to be defined within which a unit's PN will be allowed to deviate from the ex-ante traded position. These tolerances would be designed so as to free units from having to, for example, exactly match their start profile with trades in the ex-ante markets.

This option may encourage participation in the Day Ahead Market. However it could also result in less flexibility for participants, particularly thermal generators, in how they participate in the DAM as all orders to this market would have to be fully technically feasible (within the to-be-defined tolerances).

4.5.2 OPTION 2: PHYSICAL NOTIFICATIONS LINKED TO EX-ANTE TRADES AT GATE CLOSURE ONLY

The second option is to impose the requirement that PNs match the ex-ante markets traded position at gate closure only, i.e. the requirement would apply to the FPN only. PN submissions prior to the FPNs would be required to be the participant's best estimate of their FPN, even though the participant might not, at any given time, have executed the trades it was intending to execute in order to achieve its intended final combined Day Ahead Market and Intraday Market position. Depending on participant behaviour, this would seem to offer the possibility of providing information that is more useful to the TSOs in planning the operation of the system.

This could be considered in many ways as an alternative of Option 1 with infinite tolerances on the differences between contracted position and PN up to the submission of the FPN.

The possibility should be recognised that a participant could fail to make the trades intended to achieve its desired ex-ante contracted position and hence have to change its PN substantially close to gate closure, requiring a corresponding intervention by the TSOs to balance supply and demand. However, it needs to be considered whether this is worse than the possibility, under the previous option, that the participant might succeed in making the desired trades close to gate closure and hence be making similar changes to its PN, albeit in the opposite direction[8].

This option would seem to allow the participant to provide more useful information to the TSOs than Option 1. If the TSOs were concerned as to the actual traded position of participants at any time then a relatively straightforward solution might be to provide a direct feed to the TSOs of the outputs of the Day Ahead Market and from the Intraday Market. Thus, this option could allow the TSOs to know *both* participants' current traded positions and their intended final traded positions, rather than just the current traded positions in the previous option.

Also, by breaking the correspondence between PNs and individual trades, this option may also seem to give more scope for participants to trade in the Intraday Market. This is because it would no longer be necessary for each individual trade to result in a physically feasible profile. Instead, participants could use a number of Intraday Market trades, potentially with a variety of different counterparties, to construct a physically feasible profile of generation, even if each individual trade wouldn't have produced a physically feasible profile on its own.

This would mean that, if there were a sufficiently strong incentive to deviate from the ex-ante contracted position then there would be a strong incentive also to deviate from the PNs, i.e. to run not just an imbalance but an *uninstructed* imbalance.

4.5.3 OPTION 3: PHYSICAL NOTIFICATIONS REFLECTING THE BEST ESTIMATE OF INTENDED GENERATION OR DEMAND

As discussed above, the I-SEM HLD envisages participants endeavouring as best they can to trade ex-ante to the maximum extent possible, and to avoid exposure to

[8] i.e. a generator failing to make an intended late sale might, under this option, have to re-declare its physical notification down very close to gate closure. However, under the previous option, the same generator would have to re-declare its physical notification up in the event that it succeeded.

imbalance prices. However, also as discussed above, to the extent that some participants could under some circumstances deviate from their ex-ante contracted position, the requirement to submit PNs which matched their traded positions would mean that deviating from the ex-ante traded position would involve also deviating from the PN.

It is not clear at this stage why a generator would seek to submit an FPN which didn't match its commercial ex-ante positions. Any volumes not traded ex-ante would be settled at the imbalance price, and in reality the IDM will be open very close to the real time BM in any case. In addition, the forwards and liquidity workstream will consider what liquidity promotion measures should be in the ex-ante markets while the market power workstream will consider whether specific measures are required for participants deemed to have the potential to exercise market power.

The rationale for this option is that it ensures that in the event that a participant deems it necessary to deviate from commercial positions that they still give the TSOs accurate information on expected running.

At the pre-consultation Rules Liaison Group meetings there was significant consideration of this option in particular. Some participants raised questions as to whether this was actually in line with the I-SEM HLD and also whether it results in the I-SEM being a self-scheduling market.

The SEM Committee has considered these opinions and is of the view that this option does not make the I-SEM a self-scheduling market in that a plant will not be able to force itself onto the system through its FPN and receive compensation for being dispatched down.

The SEM Committee accepts the point however, that this option could, in the absence of any specific DAM and IDM requirements, allow low cost generators to spill through the single price imbalance market to a supplier. However, the key question here is whether this would be any different to a generator bidding zero in the DAM to achieve a DAM trade to match their desired operating level, or indeed it could be argued that a low cost plant will be running under all scenarios so this won't make any significant difference. There may be a question as to whether this option 3 allows participants to avoid DAM and IDM fees but this is a separate issue that will be addressed through the charging structure in the market.

The main advantage of this option is that it provides useful information as early as possible to the TSOs to manage system constraints, and minimise incorrect early actions. It also means that incentives for participants to give the best information are highest; this means that there is less need for complex mechanisms to track the validity of information submitted which can be costly to implement.

Like Option 2, by breaking the correspondence between PNs and individual trades, this option would seem to give more scope for participants to trade in the Intraday Market. This is because it would no longer be necessary for each individual trade to result in a physically feasible profile. Instead, participants could use a number of Intraday Market trades, potentially with a variety of different counterparties, to construct a physically feasible profile of generation, even if each individual trade wouldn't have produced a physically feasible profile on its own.

4.5.4 SUMMARY OF PHYSICAL NOTIFICATIONS AND EX-TRADES

The SEM Committee has put forward three options for the treatment of the link between PNs and ex-ante trades:

1. PNs Linked to Ex-ante Trades at All Times;
2. PNs Linked to Ex-ante Trades at Gate Closure Only; and
3. PNs Reflecting the Best Estimate of Intended Generation or Demand.

At a high level the SEM Committee is of the view that there is merit in not requiring a rigid link between PNs and ex-ante trades, at least before the FPN stage, in order to facilitate the role of the TSO in balancing the transmission system. The SEM Committee is of the view that to require a rigid link would overly restrict participants' ability to operate in the ex-ante markets. Such an option would also have a strong potential to give less reliable information to the TSOs, which would have a corresponding impact on system security and the cost of non-energy actions to the customer.

Therefore the SEM Committee wishes to focus on the merits of Option 2 versus Option 3. In reality with both Option 2 and Option 3 (and indeed Option 1), there will be similar liquidity promotion measures in the ex-ante marketplaces. Perhaps the key difference between the two options would become more apparent if there were no ex-ante participation requirements. Absent these requirements, Option 3 would allow infra-marginal participants to spill through the BM, without setting the BM price, while Option 2 forces the participants into ex-ante trades. It is an open question as to whether this potential for lack of liquidity in the ex-ante markets is a sufficient enough concern to make this an unfavourable option.

The key advantage of Option 3 is that it ensures that even where a participant finds reasons not to generate (or consume) at its ex-ante position, be it a good or bad reason, the TSOs will still have accurate information to operate the system.

4.6 INFORMATION IMBALANCE CHARGE

Earlier, this section discusses the importance of the provision of accurate information to the TSOs. If inaccurate information is provided to the TSOs, then they may make less efficient decisions when determining the most appropriate way in which to operate the system.

It therefore may be considered appropriate to provide an incentive on participants to submit PNs which are as accurate as possible. One possible way to do this would be through the introduction of information imbalance charges. These could be levied on the difference between a unit's metered quantity and its Day Ahead PN and/or FPN, as modified by any bid-offer acceptances.

Recognising that early information could be of use to the TSOs in planning the operation of the system, (which is why the TSOs will require participants to submit PNs soon after the closing of the DAM), it might be considered appropriate that an incentive should apply also to the PNs submitted before gate closure. Different charges could apply, with perhaps lower rates applying to earlier submissions, with a higher rate applying to the FPN.

One disadvantage of levying an information imbalance charge on earlier PNs may be that it could discourage trading in the Intraday Market, as it will be Intraday Market trades that will be the most likely cause of participants changing their PNs. That said, if it was established that an information imbalance charge was reflecting the impact of poor information at different times on the costs incurred in balancing the system, then such a charge might still be appropriate.

Therefore the introduction of an information imbalance charge in the context of I-SEM needs significant consideration. In particular, I-SEM is not a self-dispatch market and therefore it might be suggested that an information imbalance charge would be a penalty against something over which the participant does not have control.

The BETTA market has provision for an information imbalance charge but the rate was set at zero initially and has remained at zero for the 15 years that BETTA has been in operation.

Accordingly, an information imbalance charge may not be necessary in I-SEM, although this may be dependent on whether or not there is an incentive to deviate from submitted PNs, which in turn may depend on which of the options in the previous Section 4.5 is adopted.

Any information imbalance charge likely needs to be considered in the context of uninstructed imbalances which are discussed in the imbalance settlement chapter. In particular, there may be a perceived overlap between uninstructed imbalances and an information imbalance charge on the differences between FPNs and metered generation. This may support the implementation of any imbalance charge on earlier PN submissions.

Finally, it may be that the issues around ensuring the most accurate information to the TSOs is best considered under generator performance incentives.

4.7 SUMMARY

The SEM Committee welcomes respondents' views on the issues raised in this chapter. **In particular, the SEM Committee welcomes respondents' views on:**

1. **The timing of PN submissions to the TSOs**
2. **The removal of the requirement on wind generation and non-dispatchable demand to submit PNs**

3. **How PNs from participants should be linked to their ex-ante trades and their opinions on which of the three options outlined in this chapter is optimal for I-SEM. The three options outlined are:**

    1) **PNs Linked to Ex-ante Trades at All Times;**
    2) **PNs Linked to Ex-ante Trades at Gate Closure Only; and**
    3) **PNs Reflecting the Best Estimate of Intended Generation or Demand.**

4. **The potential for the inclusion of an information imbalance charge. In addition, comment is sought as to whether this issue is best addressed under the generator performance incentives.**

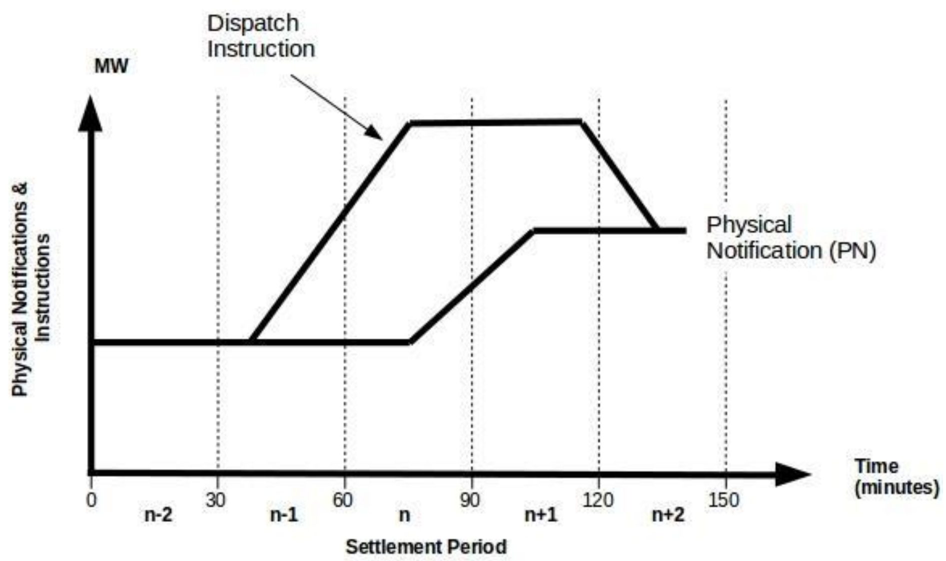
5 FORM OF OFFERS, BIDS AND ACCEPTANCES

5.1 INTRODUCTION

The requirement of the I-SEM HLD Decision is that detailed and feasible PNs will be submitted for all participants. The decision also notes that the notified profiles should reflect generator physical constraints and be sufficiently "granular" to support the TSOs in operating a secure and safe system.

As discussed in Section 4, PNs are a declaration of what the market participant, typically a generator or dispatchable demand, intends to generate or consume in the absence of the acceptance of any bids or offers by the TSOs. At gate closure, the PNs that have been submitted (FPN), in combination with the TSOs' own forecasts of supplier demand and wind generation, allow the TSOs to assess whether the system is likely to be in balance, taking account the various operational constraints that the TSOs must observe. As necessary, the TSOs may then instruct participants to deviate from their PNs in order to maintain stability of the system.

Earlier submissions of PNs, submitted ahead of gate closure, whilst subject to possible re-declaration by participants, give the TSOs advanced notice of likely imbalances and system constraints, thus allowing them to plan balancing actions beforehand and, as appropriate, take balancing actions in advance of gate closure. Such actions could include dispatching plant to provide reserve or resolve



transmission constraints.

As such, it is important that these PNs are physically feasible. If they are not then, in the absence of any balancing actions being taken, the participant will not be able to follow their PNs and hence the PNs will not represent the intended generation (or consumption) for the particular unit. Accordingly, again as discussed in Section 4, it is proposed that PNs will take the form of a sequence of spot MW-time values, which define the intended generation (or consumption) of the participant in respect of the particular unit.

It is proposed that, after instruction profiling[9], instructions from the TSOs will be of a similar form. Whilst in the ex-ante markets, participants may trade energy between themselves in hourly 'blocks', when the TSOs determine that the need to balance the system requires that a participant deviates from its PN then they will typically require that the participant achieves particular MW level of generation (or consumption) at specified times. This is because the balance of the system must be maintained more or less at every instant, and so it will not be adequate for participants to be instructed merely to generate (or consume) additional quantities of energy at any time of their choosing over an entire settlement period.

5.2 FORMAT OF OFFERS AND BIDS

Being instructed to deviate from its PNs by the TSOs is likely to change a participant's costs. For example, increasing the output of a fossil-fuelled generator increases fuel costs, whereas reducing the output will decrease them. In the case of generation with out-of-market support, increasing or reducing output may also affect any support payments to which the generator is entitled.

Accordingly, the HLD envisages that participants declare:

- offers to increase generation or reduce consumption and
- bids to decrease generation or increase demand.

Offers can be regarded as offers to sell energy to the system or to the TSOs acting on behalf of the system, while bids can be regarded as bids to buy additional energy from the system or from the TSOs acting on behalf of the system. In the case of a bid

[9] See Section 10.5

to reduce generation, the participant is, in effect, bidding to buy *back* from the system, energy it has sold to other market participants through the ex-ante markets. Similarly, an offer to reduce demand is an offer to sell *back* energy that the participant has bought.

When the TSOs instruct a participant to deviate from its PN, the TSOs are accepting the offers and/or bids submitted by the relevant participant. The issue thus arises as to how participants can most accurately express the change in their costs that will result in the event that the TSOs instruct them to deviate from their PNs.

The remainder of this section describes options whereby participants can declare their costs (and the level of compensation they require). First options are considered for declaring incremental and decremental (per MWh) costs. Second, options are considered whereby participants can reflect costs that do not vary with output, i.e. start-up costs and no-load costs.

5.2.1 INCREMENTAL AND DECREMENTAL (PER MWH) PRICES

Three potential options are considered below for the manner in which participants can express their [per MWh] costs, which are referred to as:

(1) Simple MWh;

(2) MW Relative; and

(3) MW Absolute.

5.2.1.1 SIMPLE MWH

In this option offers and bids are priced in Euro[10] per MWh in a given settlement period up to a certain MWh quantity in that period. In Figure 5.1 below, the hatched area in settlement period n represents additional energy bought by the TSOs as a result of the instruction, while in settlement period n+2 the hatched area represents energy sold back to the participant.

[10] For illustrative purposes all examples in this paper are priced in Euro. However, the Building Blocks Consultation Paper proposes that all participants in the I-SEM will be able to submit bids and offers in their own currency.

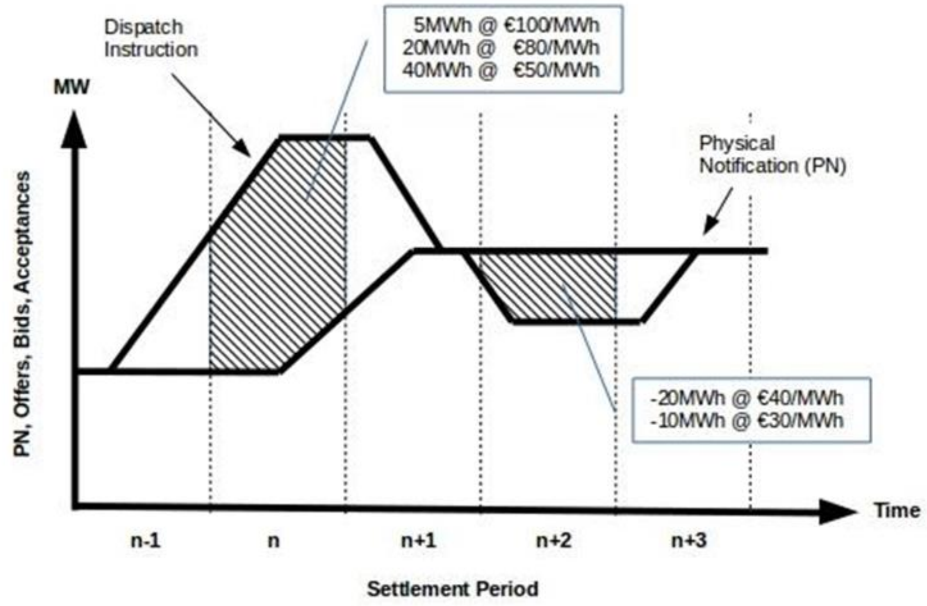


Figure 5.1 Showing Offer and Bid Acceptances

To illustrate, suppose, in settlement period n, the additional energy is +65MWh. Suppose also that the participant declares offers to the effect that:

- the first +40MWh are priced at €50/MWh;
- the next +20MWh are priced at €80/MWh; and
- another +20MWh are priced at €100/MWh.

The bid-offer acceptances implied by the instruction to deviate from the PN comprise:

(a) an acceptance of all +40MWh of the first offer at the first offer price of €50/MWh;

(b) an acceptance of all +20MWh of the second offer at the second offer price of €80/MWh; and

(c) an acceptance of a further +5MWh of the third offer at the third offer price of €100/MWh.

Similarly in settlement period n+2, suppose the energy sold back to the participant is 30MWh. Suppose also that the bids are:

- -20MWh at €40/MWh; and
- a further -20MWh at €30/MWh.

The bid-offer acceptances implied by the TSOs' instruction are:

(a) an acceptance of all -20MWh of the first bid at the first bid price of €40/MWh; and

(b) a bid acceptance of -10MWh of the second bid at the second bid price of €30/MWh[11].

It is important to note that the format of the offer does not imply any discretion for the participant as to when in the settlement period the accepted MWh are delivered; rather, the participant will be required under the auspices of the Grid Code to follow each individual spot MW dispatch of the instruction. The simple MWh bid-offer format affects only the calculation, for settlement, of the quantities that are accepted at each price.

It should be noted that the format works also for dispatchable demand registered in the BM. For dispatchable demand, the PN will be negative, representing a flow *from* the system rather than a flow *on to* the system. Moreover, an offer is now an offer to reduce demand rather than to increase generation, and a bid is now a bid to increase demand rather than being a bid to reduce generation.

One possible advantage of this approach is its simplicity. A possible disadvantage, though, is that it may provide a poor representation of the actual costs incurred by the participant. For example, consider the two acceptances shown in Figure 5.2.

These have equal accepted quantities in settlement period n, although Instruction A requires the participant operate at higher output than Instruction B and may thus, for generators with costs that increase with output, incur higher costs. It is unlikely that this would be an issue for zero incremental cost generation, such as wind or solar, but could be a significant issue for thermal generation. Thus, the SEM Committee thinks the disadvantages of this approach could outweigh the advantages.

[11] Under the proposed sign convention, energy delivered on to the system is positive and energy taken off the system is negative. Thus an accepted offer of +40MWh at price of €50/MWh represents a payment of €2000 to the participant. Bid quantities are negative, such that an accepted bid of -20MWh at €40/MWh represents a payment of -€800 to the participant, i.e. a payment of €800 from the participant to the TSO. In the event that a bid were negatively priced, an accepted bid of -20MWh at €40/MWh would represent a payment of €800 to the participant, which would imply in the case of a generator that the participant would have to be paid to reduce output.

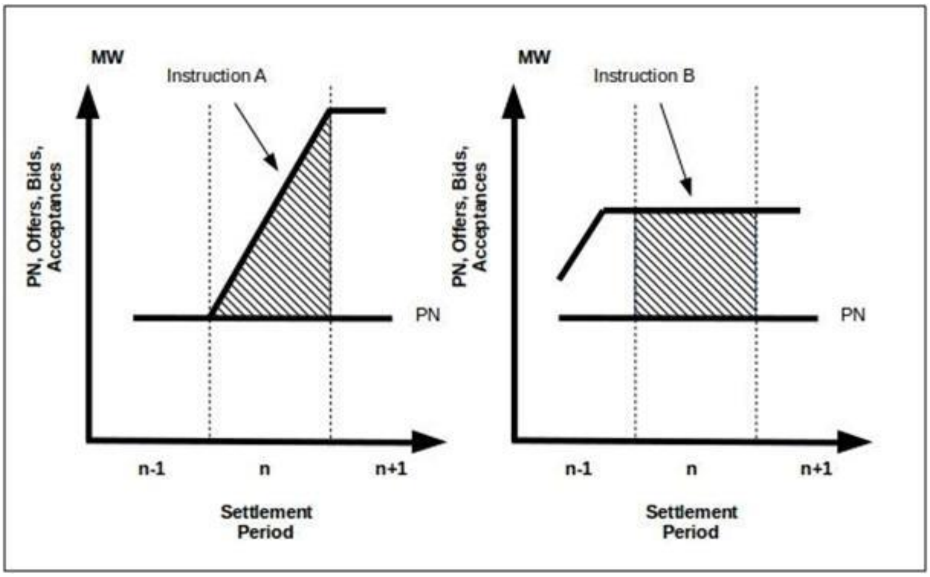


Figure 5.2: Two Offer Acceptances with equal MWh but different maximum output levels

5.2.1.2 MW RELATIVE AND MW ABSOLUTE

MW Relative

Under the "MW Relative" approach, the participant may declare different costs depending on how far, in MW terms, the unit is required to deviate from the PN. In essence, price "bands" may be defined relative to the PN. Figure 5.3 illustrates this, and the different hatched areas show the accepted quantities at each offer price implied by a dispatch instruction.

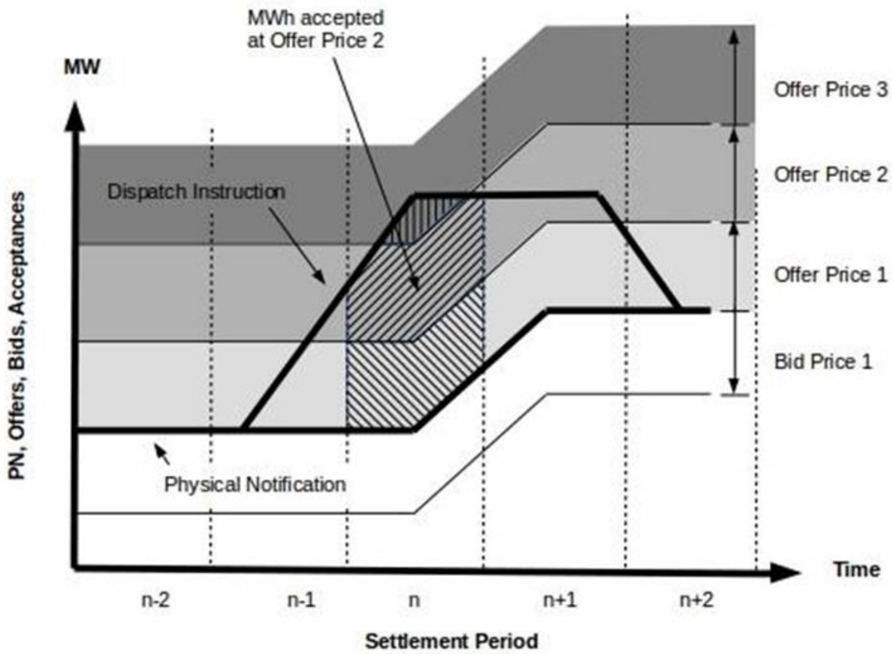


Figure 5.3 Offer and Bid Price Bands Relative to PN

This option is the convention adopted in the British Electricity Trading and Transmission Arrangements (BETTA). It improves on 'Simple MWh' to the extent that participants may now reflect MWh for producing additional energy that varies depending on how far a dispatch instruction requires the participant to deviate from the PN.

MW Absolute

The MW Absolute option is similar to MW Relative, with the difference being that the MW price bands that the participant may declare are measured relative to zero MW, rather than relative to the PN.

Under this option it is no longer possible to unambiguously label a price as being an offer price or a bid price. Whether the price is an offer price or a bid price depends on the level of the PN. This option may be regarded as being more similar to the commercial offer data (COD) format in the current SEM. This option is illustrated in Figure 5.4 below.

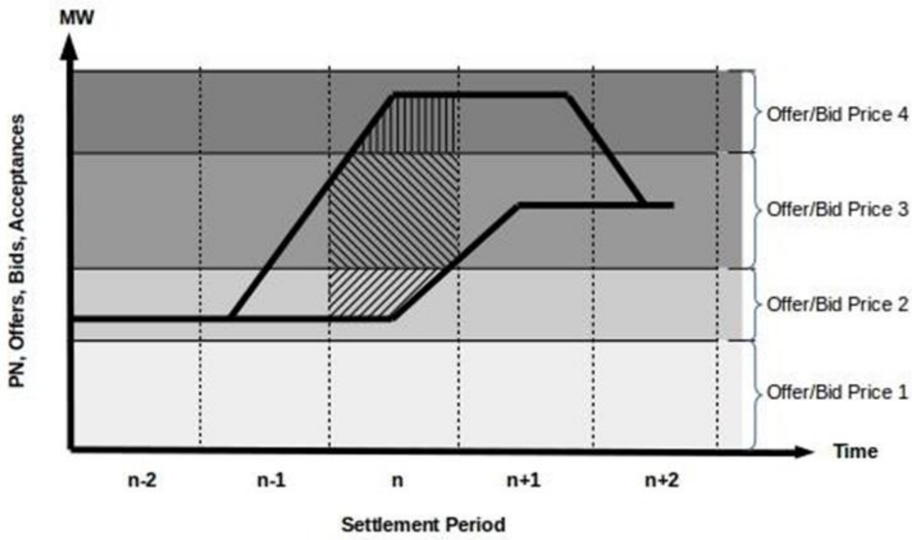


Figure 5.4 Offer and Bid Price Bands in Absolute MW

It is possible as part of this option that participants could be permitted to submit two separate cost curves - one for being instructed up and one for being instructed down.

5.2.2 COMPARISON OF MW RELATIVE AND MW ABSOLUTE

The MW Relative and MW Absolute options differ only by the datum relative to which the participant-declared MW price bands apply. The significance of this difference becomes clearer only when considering the ability for participants to update prices during the time the BM is open.

In BETTA, the BM opens only after gate closure, which occurs one hour before the start of the settlement period. Consequently, the TSOs can begin accepting offers and bids only after the time at which PNs (and offer and bid prices) are fixed. In contrast, in I-SEM, the BM will open shortly after the DAM, and will be open in parallel with the IDM. Hence, participants may execute trades in the IDM and wish to revise their PNs during the time that the BM is open. The issue is whether, as a result of changing its PN, a participant's offer and bid prices need to change to reflect changes in costs for deviating, if instructed to do so by the TSOs, from this new higher or lower level of output or consumption.

Figure 5.5 shows a notional cost curve for a generator. Not only does the cost per hour increase with increasing output but the cost per MWh, being the slope of the cost curve, increases also. To the extent that this is a reasonable representation of the participant's costs then, under the MW Relative option, a participant changing PN from PN_1 to PN_2 will need to re-declare its first bid price to be its previous first offer price and its second offer price to be its previous first offer price and so on. In contrast, under the Absolute MW option, the participant does not need re-declare its prices.

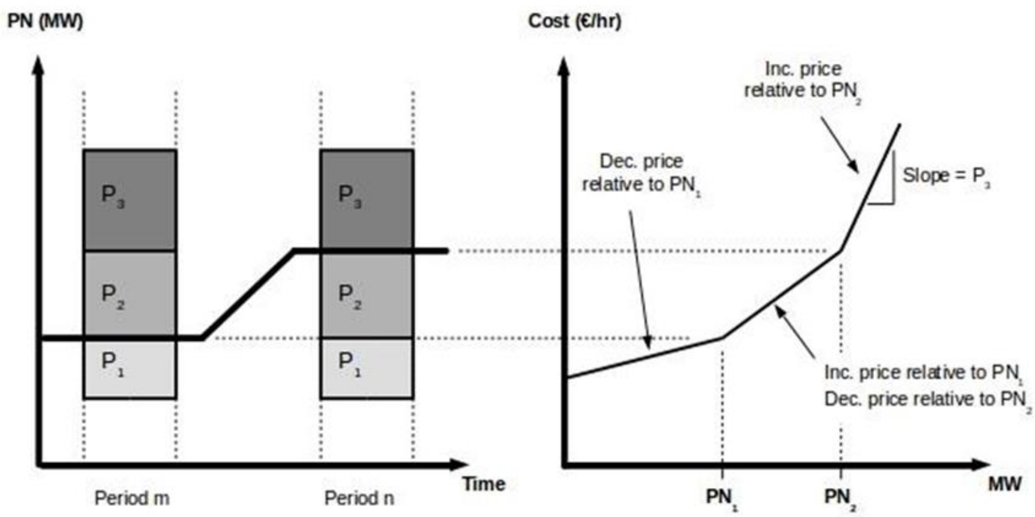


Figure 5.5 Offers and Bids with Changing PN

Were a participant's costs for incremental offers and decremental bids to maintain a fixed relationship relative to the PN, irrespective of changes in the PN, then, just as a participant can represent a fixed cost curve under the MW Relative option by rebidding its offer and bid prices every time it changes its PN, it could also represent this relative cost-MW relationship under the MW Absolute approach. Again, this would be achieved by re-declaring prices every time the PN changed.

The choice of option is thus not a point of principle (as outcomes should be economically equivalent) and the relative merits of either approach should be determined by which option best represents the cost characteristics of participants and which will allow them to represent their costs with the minimum need to resubmit information.

That said, it is recognised that many other factors may change, such as the delivered price of gas for a CCGT or the value of electricity consumption for dispatchable demand, any of which may cause a participant to wish to revise its prices. These changes in cost can be reflected under either option. Nevertheless, it will be more transparent and simpler if participants have to revise their offer and bid prices only to reflect changes in their underlying costs and not merely as a result of changing some other submission, i.e. their PN, even when the underlying costs have not changed.

5.3 TREATMENT OF START COSTS

Generators may have costs of generation that do not vary with output. In the current SEM these are represented as start-up and no load costs.

In I-SEM, for generators that have sold output in the ex-ante markets and declared a non-zero PN, these fixed costs are likely to have been factored into the prices at which the participant offered to sell, and therefore in the price received in the ex-ante market. Under such circumstances, it may be not important that the fixed costs can be reflected in the BM, and important only to reflect the incremental (or decremental) per MWh costs of deviating from the PN.

However, it is likely that there will be times when units will be required by the TSOs to run even though the participant has not secured sales for the output in the ex-ante markets and the relevant PNs have been declared as zero. The reasons for this will generally be related to non-energy actions such as deployment of reserves or addressing local constraints.

For such generators, the recovery of start-up and no-load costs may be an issue. To recover such costs through per MWh incremental prices requires the participant to estimate the quantity of energy that the TSOs are likely to dispatch. Too high an estimate and the participant risks under-recovering its fixed costs, whilst too low an estimate and the resulting price may be too high with the result that the participant is not dispatched, even when it would have been economic to do so.

BETTA does not provide for the explicit representation of fixed costs in the Balancing Market. However, the BETTA Balancing Market does not open until one hour before each settlement period. Consequently, the likelihood that plant with high start-up costs will be committed in the Balancing Market is low. Further, it is standard practice under BETTA to contract significant amounts of generation through out-of-BM contracts, such as STOR, pre gate closure balancing transactions and BM start-up contracts.

A number of options are set out in the following sections for the recovery of start-up costs in the I-SEM BM:

Option 1: Start Up Contracts;
Option 2: Block bids; and
Option 3: Explicit Start Costs.

5.3.1 START UP CONTRACTS

These would be contracts struck outside the BM in manner similar to BETTA. Transparency could be an issue with this approach as it would depend on the TSOs striking contracts with the relevant generators (and/or dispatchable demand) at efficient prices. However, this is not to say that such a process could not be transparent, the contracts could be struck on the basis of a tender and results could be published.

This approach could also lead to simplicity in the design of the BM. However, the approach could raise issues similar to those seen and not satisfactorily resolved in BETTA, as to how such the cost of such contracts should be reflected in imbalance prices if taken as a result of an energy action requirement.

5.3.2 BLOCK BIDS

Another approach might be to permit participants to specify block bids guaranteeing a minimum quantity of energy over which fixed costs could be recovered. Thus a participant could offer a price of, say, €100/MWh providing a guaranteed minimum dispatch of, say, 100MW for four hours.

However, this approach might limit the flexibility available to the TSOs for balancing the system. Specifically, there is the potential that a highly flexible plant, with a short minimum on time and fast run-up and run-down rates, might nevertheless make an offer that did not reflect this flexibility purely in order to ensure recovery of its fixed costs. Denying such flexibility would seem counter-intuitive when flexibility is becoming increasingly important to the operation of the system, and when the DS3 Programme is a major initiative to increase rather than reduce incentives for flexibility.

A possible enhancement might thus be to enable participants to submit alternative block bids. Thus, a generator might make an offer of:

- €100/MWh providing a guaranteed minimum dispatch of, say, 100MW for four hours or
- €120/MWh providing a guaranteed minimum dispatch of, say, 80MW for two hours or
- €90/MWh providing a guaranteed minimum dispatch of, say, 100MW for eight hours.

However, even with this approach a large number of such alternatives might be necessary in order to provide the TSOs with the maximum flexibility possible while also assuring that the participant is not exposed to significant risk.

Constructing and submitting a multiplicity of such offers could be complex and burdensome for the participant, while optimising a large number of such offers would likely be complex and burdensome for the TSOs. It is not clear that this approach could be readily adopted for real-time power system control or whether the benefits of doing so would outweigh the costs.

5.3.3 EXPLICIT START COSTS

This option would involve submitting an explicit start-up cost, in a similar manner as in SEM. Given that the problem being addressed is how to present start-up costs to the TSOs, it is likely that one such option should be to declare the costs itself explicitly. The plant would submit a start-up cost and then incremental offers and decremental bids away from its PN.

One of the key advantages of the explicit start cost is that it allows the generator to reflect its costs in a very straightforward fashion. In particular, it doesn't need to build in any assumptions about running hours etc., which it might have to do under other approaches. An explicit start-up cost will give the TSOs a clear view of the cost to start a plant which could help in making decisions on how to operate the system in the most efficient manner. Specifically, it is questionable whether the approach of multiple block offers, as in Option 2 above, conveys any more useful information than could be conveyed by submitting start-up costs[12].

If a participant were to submit a spectrum of multiple block bids, to the extent that the underlying structure of the participant's costs could be described by start-up and no-load costs, the TSOs would be able to infer what these underlying costs were. It is thus for consideration as to whether enabling participants to declare these costs explicitly would be a more efficient means of conveying the same information. It would not be constrained as to how it uses the plant in the same way that for example a block bid might.

There is a further question with this approach as to whether no-load costs might need to be reflected also. Specifically, it would need to be established whether no-load is of significant importance that it needs to be expressed explicitly. It is expressed as a standalone item in the current market but that is not to say it's definitely required in I-SEM.

5.3.4 COMPARISON OF START COST TREATMENT

In summary, this paper has put forward three options for the expression of start-up costs to the TSOs.

[12] Clearly this depends on start-up costs being a reasonable representation of participants' actual costs.

Option 2, Block Bids may give consistency with the bid types to be expected in the DAM and IDM.

Option 1 and Option 3 could have similar outcomes. For example, if Option 1 had a procurement timeframe of one day it would have the same effect as Option 3. An issue with either option is how start costs are reflected in the energy imbalance prices where the start relates to an energy action. This issue will be less important when actions are non-energy as such actions are pay as bid.

Given the potential complexities with Option 2 the SEM Committee sees greater merit in pursuing Option 1 or Option 3.

A key question with all the options would be how the start-up cost feeds through to pricing and imbalance settlement. Specifically, it is most important where a start-up is incurred for an energy action. There are likely to be a number of ways to approach this. For example the start cost could be spread across all the hours that the plant ran and be then fed into the price for each hour. Alternatively, the cost could be spread across the total MWh produced and divided across trading period where the plant ran on that basis. Another possible option would be to remunerate the impacted generator only, though a form of make whole payment. This issue is related to the decisions on pricing in Section 8.

5.4 REBIDDING OF OFFER AND BID PRICES

One aspect in which the current SEM design may not allow participants to reflect their underlying costs in their commercial offer data (COD) arises from the limited opportunity to reflect costs that change during the day. As mentioned earlier, CCGT generators may experience changing costs for gas and for gas capacity, and there is currently very limited opportunity to reflect this in their COD.

As the I-SEM Balancing Market will be mandatory following the Day Ahead Market, and the same offers and bids will be used by the TSOs for re-dispatching the system for non-energy reasons, it is necessary to consider how rebidding can be accommodated within the I-SEM design so that participants can reflect changing costs throughout the day.

Three approaches are considered below:

- fixing the price of only accepted offer and bids;
- “undo” prices; and
- fixing all offer and bid prices following an acceptance.

5.4.1 FIXING PRICE OF ACCEPTED BIDS AND OFFERS

Where the TSOs accept offers and bids submitted by participants, it seems obvious that the price of that offer or bid should be fixed once it has been accepted, notwithstanding that participants' costs may change. To allow otherwise would seem to create the potential for significant uncertainty for the TSOs, and the opportunity for perverse gaming behaviour by participants. Most obviously, if the prices of offers and bids are not fixed following acceptance by the TSOs, participants would be able to raise the price of an offer after it had been accepted in order to increase its revenue from the accepted offer, up to the point at which the TSOs would have to consider cancelling the instruction and instructing a balancing action from some other unit, assuming such an alternative balancing action existed. Similarly, participants would be able to lower the price of an accepted bid.

Thus, in this first approach, the price of offers and bid quantities that have been accepted by the TSOs are fixed at the last price that had been submitted, at the time of the acceptance. This approach is consistent with the IDM, wherein participants cannot change the price of accepted positions once they have cleared.

Participants would be able to revise the price of any remaining offer and bid quantities that are available for subsequent acceptance, up until the time that a further quantity is accepted.

However it is an open question as to whether participants would be permitted to revise the price of a bid that would reverse the effect of a previously accepted offer, and the price of an offer that would reverse the effect of a previously accepted bid. There may be merit in freezing these prices as participants should not be allowed to change offer/bid prices to levels that would completely preclude the possibility of reversing an acceptance.

5.4.2 UNDO PRICES

The BETTA market provides for the submission of “undo” prices. These prices apply in the event that an accepted offer or bid is “unwound”, i.e. in the event that a bid acceptance reverses the effect of a previously accepted offer or an offer acceptance reverses the effect of a previously accepted bid.

Arguably this approach is necessitated in GB by the fact that the BETTA BM does not afford the opportunity for prices to be updated. Thus, given that incremental offer and decremental bid prices apply to deviations in generation or consumption relative to PNs then, without undo prices, a participant would have no mechanism for indicating that the cost saving of reversing an action was different from the cost of taking the action in the first instance. Undo prices allow participants to reflect the fact that costs might be sunk once a balancing action has been instructed. These would be costs that cannot be recouped in the event that the balancing action is no longer required (e.g. gas transmission capacity). The approach was also intended to provide degrees of “firmness” for BM transactions, in that, like ex-ante market trades between participants, the TSOs could not necessarily cancel a balancing action without compensation.

The fact that the I-SEM BM is open for longer than the Balancing Market in BETTA suggests that undo prices would be more important in I-SEM as there is potentially a longer period during which an accepted offer and/or bid may need to be reversed.

However, provided that only the prices of accepted offers and bids are frozen at the price that had been submitted at the time of acceptance then undo prices are unnecessary in I-SEM to the extent that participants have the ability to revise their prices for bids and offers not yet accepted. Following the acceptance of an offer, participants may submit a price for the bid that would reverse the effect of the offer, or, following the acceptance of a bid, a price for an offer that would reverse the effect of the bid. This would require that the TSOs could only reverse the effect of an earlier bid or offer acceptance through a subsequent bid or offer, as opposed to merely cancelling the earlier bid or offer acceptance.

That said, this ability to revise prices will not apply after gate closure. While the extent to which balancing actions are likely to be undone over such short timescales i.e. following gate closure, is not clear, there is a possibility that it could happen.

The submission of undo prices could be included as a part of I-SEM. In principle, this would have the advantage of allowing the TSOs to distinguish before issuing any instruction between offer or bid acceptances that might be more expensive but cheaper to unwind than other offer or bid acceptances that might be cheaper but more expensive to unwind. However, it is unlikely that power system dispatch systems would be able to take such considerations into account.

It should be noted that undo prices won't of themselves completely remove risk for the bidding participant. The undo price will need to be based on a prediction of costs; if those costs move between acceptance and undo then the undo price may not fully cover such movements. If undo prices could be changed after acceptance of the corresponding "do" action then they may not give much additional certainty to the TSOs, as to the cost of unwinding any balancing action.

Undo prices can be submitted for any of the bid offer format options described in this section. Concerns were expressed in the RLG and subsequent feedback that undo prices would not be compatible with the Absolute MW but this is not the case. For example, an Absolute MW bid format could quote, say, a do price of €80/MWh and an undo price of €70/MWh between 250MW and 300MW. A undo price, as well as a "do" price, can be specified between any two MW levels, irrespective of whether the MW levels are defined relative to a PN or in absolute MW terms. Likewise, fixed costs, such as start up costs, could have separate do and undo prices. Thus one price could be declared for incurring a start, before the start is instructed, and a separate price declared for cancelling the start before the start has occurred[13].

If, under the Absolute MW format, units submitted two separate cost curves - one for being instructed up and one for being instructed down, then each could be the "undo" price for the other.

It is an open question as to whether "undo" quantity bands should have to be the same as the initial offer/bid quantity bands. There would be simplicity and symmetry in having the same quantity bands but participants may be better able to represent their actual costs through different quantity bands.

[13] More sophisticated treatment of start-up costs is possible. For instance, the England & Wales Electricity Pool had "cancelled start" payments, whereby a generator could be paid a proportion of its start-up cost, depending on how far through the notice to sync period the start instruction was cancelled.

5.4.3 FREEZING ALL PRICES

In the extreme, all prices for subsequent acceptances relating to a given unit could be fixed after the TSOs accepted any offer or bid quantity from that unit. The advantages of this approach would undoubtedly be simplicity of implementation in settlements and maximum certainty for the TSOs in system operation. However, it would be severe in limiting the flexibility of participants to re-declare prices to reflect changing costs, and might be regarded as being inconsistent with the requirements of the Electricity Balancing Network Code. Moreover, it could even create the opportunity for perverse behaviour by the TSOs, by which the TSOs could, in effect, freeze the prices of any unit at any time by instructing a minimal deviation, and hence making a minimal offer or bid acceptance.

5.5 OPEN AND CLOSED INSTRUCTIONS

Bid-offer acceptances are implied by instructions from the TSOs to a participant to deviate from the participant's PN. It is for consideration whether the form of TSO instructions to market participants should change for the implementation of I-SEM.

The SEM currently uses open instructions, except for cross-border actions with GB over the Moyle and East-West interconnectors. Open instructions take the form "go to X MW", with participants expected to maintain their last instructed position until further notice.

The GB Balancing Market, by contrast, uses a closed instruction protocol. Each instruction comprises a series of spot MW values which deviate from, and then return to, the participant's Final Physical Notification (FPN): for example, "go to X MW at time t, hold for y minutes, then return to Z MW at time u".

Figure 5.6 below illustrates the two instruction formats. The participant submits a FPN of 125 MW flat over the period. The TSO instructs the generator to increase output to 140 MW by 10:20. In the open format, the TSO issues a subsequent instruction to decrease output back to 125 MW. In the closed format, the same output profile is communicated as one or more deviations from the PN (shown in this illustrative example as an initial instruction for 10 minutes at 140 MW, followed by two subsequent instructions extending the duration by 10 minutes at a time). In both cases, the bid-offer acceptance volume can be inferred from the delta between the PN and instructed quantities (noting that instruction profiling will be required to interpolate between the spot MW values instructed by the TSO, see section 10.5).

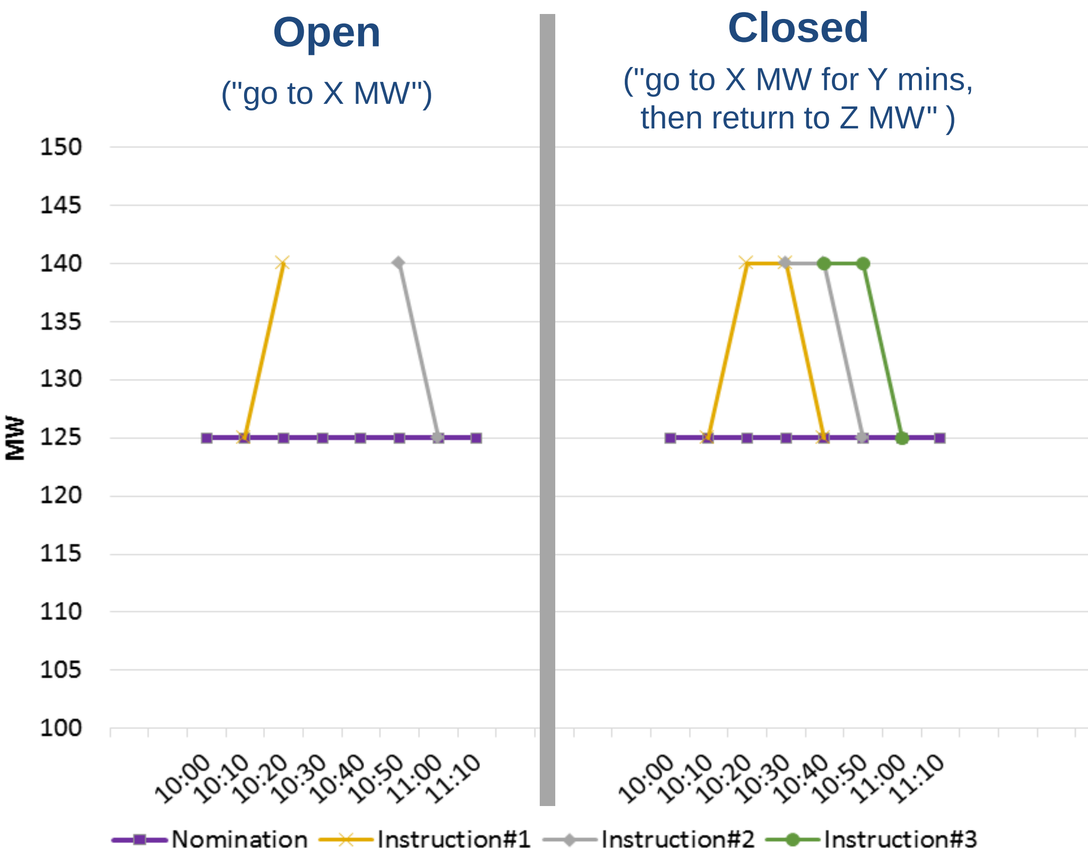


Figure 5.6: Schematic comparison of open and closed instructions

For short duration balancing actions issued at short notice after gate closure, there are unlikely to be significant differences in practice between open and closed instructions. For longer duration actions or early notice actions before gate closure, there may be some implications to consider in terms of information flows for participants and the TSOs.

A closed instruction arguably provides greater clarity to participants as to the intended duration of TSO actions, thereby informing the participant's trading position in the intraday electricity and fuel markets. The duration of an open instruction is, by definition, open-ended. However, a closed action could be extended or unwound by a subsequent TSO instruction (albeit at potentially different prices to the original action, as discussed in section 5.4) and if this occurred regularly then closed instructions may not provide much greater clarity in reality.

In all cases, the TSOs would be obliged to respect the technical operating parameters submitted by the participant, such as minimum on and off times. However if open instructions are retained for I-SEM then it may be the case that the TSOs should have the ability to curtail a participant's bid-offer acceptance volume to be less than that implied by its TOD if said participant was to vexatiously change its prices following an acceptance.

In that case the unit would be out of balance for the curtailed bid-offer acceptance volume and would forego any premium on it. In GB, for example, where balancing actions extend beyond the 1½ hour BM window due to plant dynamics National Grid is not obliged to extend a bid-offer acceptance if the participant changes prices. Alternatively, it may be necessary to fix the incremental offer price for the minimum volume implied by the unit's technical offer data. See the example in Figure 5.7 below and the discussion relating.

A closed instruction would generally be expected to lock in the price and volume for the TSO balancing action at the time of instruction, thereby providing greater certainty for the TSO and participants (subject to the discussions in this paper on substitute IDM trades and rebidding). Following an open instruction, a participant would be free to revise its bid-offer pricing before Gate Closure; the TSO would implicitly continue to accept incremental or decremental volumes at the revised prices, unless a subsequent open instruction were issued to return the participant to its PN position.

There is a question of how rebidding would be accommodated under open and closed instructions. Consider the example shown in Figure 5.6 of the TSOs committing a generator to start, with the generator's notice time requiring the instruction to be issued prior to Gate Closure. Section 5.4 discusses the concept of freezing the price of accepted bids and offers. For a closed instruction covering the unit's minimum run time at minimum generation level, this would imply fixing the incremental offer price for volume A, shaded dark blue in the diagram. Participants would still be free to revise their pricing for any subsequent volumes (as illustrated by the light shaded area B). For an open instruction, it may be necessary to fix the incremental offer price for the minimum volume implied by the unit's technical offer data, to mitigate the opportunity for perverse gaming behaviour by participants following an instruction.

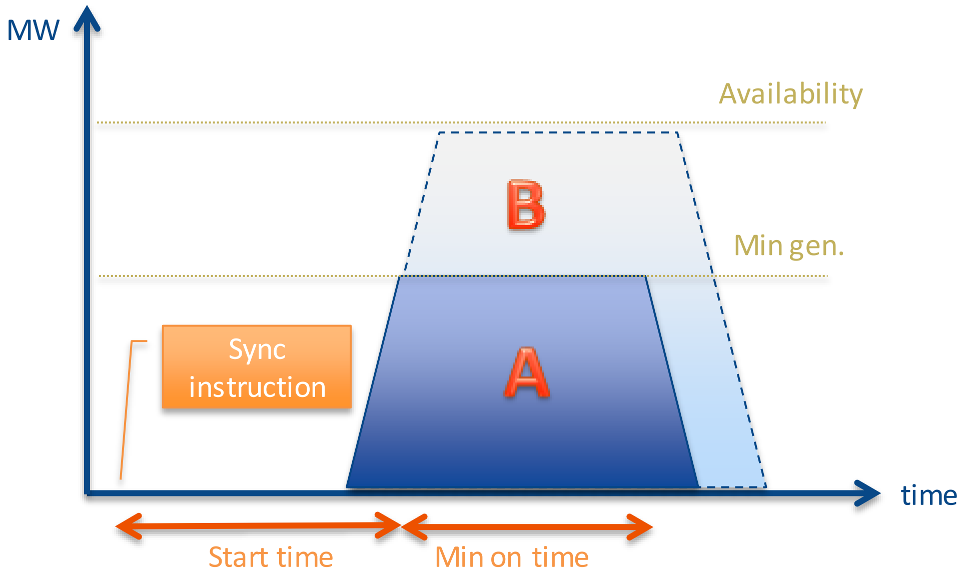


Figure 5.7: Schematic of a start instruction

One potential consequence of closed instructions is an increase in the frequency of TSO-participant communications. If the TSOs are uncertain of the required duration of a TSO action, it may issue an initial closed instruction for a short period and then extend the implied bid-offer acceptance, if required, with subsequent instructions. As illustrated in Figure 5.6, this may ultimately result in a greater number of instructions compared to the open format for the same requested output profile.

It is anticipated that, under the European Target Model, cross-border balancing actions will follow a closed instruction format. The systems and processes developed for I-SEM will therefore need to be capable of supporting closed instructions, even if open instructions are retained for internal balancing actions in the I-SEM.

5.6 SUMMARY

In I-SEM, offers and bids will be submitted by market participants to express the costs that they incur (and hence the compensation they require) for deviating away from their PNs. There are a range of options for declaring these costs.

Incremental and Decremental (per MWh) costs

For incremental and decremental costs, prices can be declared for simple MWh blocks, although there would seem to be significant downsides with this approach for thermal generation. Two other options allow the costs of deviations to depend on MW levels, defined either:

- relative to PNs ('Relative MW' approach) or
- in absolute terms ('Absolute MW' approach).

The Absolute MW approach may minimise the need to re-declare prices following PN changes where participants' costs are better represented as a fixed relationship to MW levels. Conversely, the Relative MW approach may be more appropriate where these costs are better represented as a fixed relationship relative to the PN level.

Fixed Costs

To allow participants to reflect fixed costs, options may be:

- to have explicit start-up contracts;
- to allow the submission of a range of alternative block bids; or
- to allow the declaration of explicit start-up and no-load costs.

Start-up contracts appear to simplify the BM design, although the TSOs have the same complexity in deciding how to deploy contracted plant, and it is not straightforward to incorporate these costs into imbalance prices.

While multiple blocks might appear straightforward, they could be complex for participants to prepare and submit and for the TSOs to evaluate.

Lastly, explicit fixed costs could be declared in a manner not dissimilar from the current SEM. As with incremental prices, which is the most appropriate approach is likely to be a matter of practicality rather than principle.

Rebidding and Undo Prices

There are also options for the rebidding of prices over the period the BM is open. Freezing all prices for a given unit in the event that any offer or bid is accepted for the unit could be straightforward but would likely be overly restrictive. The opposite extreme is to allow all prices, other than the prices for acceptances that have already been made, to be changed at any time up to gate closure. It is also for consideration as to whether there is any merit in submitting “undo” prices. If all prices, other than for accepted offers and bids, may be re-declared then undo prices are not necessary, and it is a matter of whether they would be a convenient format for data submission.

Open and Closed Instructions

Two options (open and closed) are put forward for the format of dispatch instructions from the TSOs to participants.

The SEM currently uses open instructions, except for cross-border actions with GB over the Moyle and East-West interconnectors. Open instructions take the form "go to X MW", with participants expected to maintain their last instructed position until further notice.

The GB Balancing Market, by contrast, uses a closed instruction protocol. Each instruction comprises a series of spot MW values which deviate from, and then return to, the participant's Final Physical Notification (FPN): for example, "go to X MW at time t, hold for y minutes, then return to Z MW at time u".

Comment is sought on:

1. **Which of the proposed formats should be used for bids and offers for deviating from PNs?**
   (a) Simple MWh
   (b) Relative MWh
   (c) Absolute MWh

2. **How should fixed costs be represented within bids and offers?**
   a. **Explicit start up contracts**
   b. **Block bids**
   c. **Explicit start-up (and no load) costs**

3. **Should it be possible to rebid offer and bid prices following an acceptance? Three options are proposed:**
   a. **Fixing prices of accepted bids and offers**
   b. **Undo prices**
   c. **Freezing all prices**

4. **Should open or closed instructions be used to move participants away from their PN?**

6 INTERACTIONS BETWEEN THE BALANCING MARKET AND INTRADAY MARKET

6.1 INTRODUCTION

As set out in the I-SEM HLD, the IDM and BM will be open and will operate in parallel to each other in I-SEM. This means that during the continuous running of the IDM, the TSOs will have the ability to take early actions to resolve system constraints (re-dispatch of plant) and also for energy actions.

Concurrent operation of the IDM and BM is not necessarily a feature of other EU wholesale electricity markets. The GB market, BETTA uses the same bids for re-dispatch and energy balancing but the BM opens at the end of the IDM. Other markets, such as Germany have separate markets for dispatch and balancing.

The purpose of this section is to:

- discuss further the reasons behind the SEM Committee decision to have concurrent operation of the BM and IDM,
- set out a number of proposals with regard to how a participant may operate in the IDM once the TSOs have instructed an early energy or non-energy action and thus accepted an incremental offer or decremental bid from that particular participant, and
- outline the possible effects of concurrent operation.

6.2 CONCURRENT OPERATION OF THE INTRADAY AND BALANCING MARKET

The I-SEM HLD stated that the TSOs would minimise the cost of deviations from the market schedule. The detailed design in respect of this issue has been the subject of discussion at the pre-consultation RLG meetings. In particular, concerns have been expressed that actions taken by the TSOs while the IDM is still open would affect the outcome of the IDM, either by removing liquidity and/or biasing prices in an upward or downward direction.

Distortion of the IDM by actions taken by the TSOs in the BM could potentially be eliminated if the BM opened only when the IDM has closed. With such arrangements, the ex-ante markets could trade independent of TSO actions, and in a clear way based on the bids and offers submitted by market participants.

Participants would then submit FPNs that reflect their ex-ante traded positions. Participants would declare offers and bids that accurately reflect their costs for being instructed by the TSOs to deviate from their FPNs.

While other EU markets may not have concurrent opening of the IDM and the BM, it appears that TSOs still need to take dispatch actions to maintain system security prior to IDM gate closure. For example, the BETTA market in GB adopts the late opening approach, whereby BM actions, i.e. bid offer acceptance, cannot be taken until after gate closure, which is one hour before the start of the relevant settlement period. However, National Grid enters into contracts with market participants covering very significant quantities of generation and demand reduction that oblige contracted participants to behave in the BM in accordance to instructions that may be given in advance of gate closure.

The costs of these contracts also have to be factored into imbalance prices, which seems to have proved difficult to do in anything other than a relatively unsophisticated manner. This suggests that with the late opening approach, the ability for the TSOs to balance the system entirely using actions that would be available at gate closure without pre-gate closure contracts is not clear. The SEM Committee and the TSOs concur that the task of system balancing is likely to be more acute in the SEM than in BETTA, being a smaller system with a higher level of transmission and generator operating constraints than the GB market. Rather than relying on out-of-market contracts, the I-SEM HLD thus requires the BM to open earlier, specifically, not long after the DAM has closed.

Another key difference between other markets and the I-SEM is the treatment of reserves. In I-SEM, it is proposed that the current SEM treatment of reserves be maintained where reserve deployment is achieved by moving a plant up or down from its unconstrained position. This of itself creates significant non-energy actions. In other markets it is often the case that the reserve contract between the TSOs and the participant would require the participant to position itself at the reserve deployment level and any forgone revenue from the reserve volume not participating in the energy market is covered in the reserve contract. Such an approach is generally seen in a self-dispatch market.

The above supports the SEM Committee HLD Decision to open the BM after the DAM and as a consequence the IDM and BM should be open in parallel.

The TSOs will have a scheduling tool which will consider:

- the technical characteristics of the entire system;
- the PNs from participants; and
- the incremental offers and decremental bids to move away from those PNs.

Based on the output of this scheduling tool the TSOs will take actions to ensure system security. As was discussed in Chapter 2, it is intended that the TSOs will seek to minimise early actions for energy balancing reasons and thus will endeavour to intervene early only for non-energy reasons.

6.3 INTERACTION BETWEEN BALANCING MARKET OFFER ACCEPTANCES AND INTRADAY MARKET TRADES

When the TSOs instruct a particular unit to take a balancing action, then, in addition to instructing the participant to operate the unit at particular outputs at particular times, the TSOs are also buying energy from or, in the case of a decremental bid acceptance, selling energy to, the participant[14].

However, trades with the TSOs and trades with other market participants differ in that trades with other market participants are made at a market wide price, i.e. irrespective of location. Trades with the TSOs, specifically those classified as "system" actions, may take place at prices that are higher or lower than the market price depending on, for example, a unit's location or dynamics.

Concerns were expressed at the RLGs that the parallel operation of the IDM and BM may present the opportunity for participants to arbitrage between IDM prices and the prices at which TSOs are willing to take balancing actions.

Specifically, with the parallel IDM and BM, a participant, having been sold energy by the TSOs in the BM (i.e. had a decremental bid accepted) in order to solve a constraint or create reserves, etc., could then sell that energy to another market participant through the IDM, leaving the participant to generate at the same level and leaving the TSOs again with the same problem of resolving the transmission constraint or creating the reserve, etc. This cycle of arbitrage could potentially repeat until gate closure.

[14] Whether the TSO is buying balancing actions on its own account, or whether it is buying such actions on behalf of the system, is not relevant at this juncture.

This problem can be avoided by maintaining a clear separation of the trades participants make with other market participants and the trades participants make with the TSOs as balancing actions. The former are made in the DAM and IDM and reflected in the PNs that the participants submit, whilst the latter take the form of accepted offers and bids which are measured relative to the PNs. When participants trade energy with the TSOs, these offers and bids should *not* affect the PN declarations. This separation has been assumed throughout in this Consultation Paper.

The TSOs taking a balancing action before gate closure implies issuing an instruction now for actions to be delivered more than one hour (and potentially as long as 31 hours[15]) later. Such instructions may be necessary only when lead times for delivery are long, typically due to long notices to synchronise or slow ramp rates, and then only when declarations of PNs indicate that the participants are failing to choose to commit plant as a result of ex-ante market trading.

In the event that the TSOs take such a balancing action, the issue arises as to the options that remain available to the participant in respect of the relevant unit. Three Options are put forward here for consideration.

Also, the assumption throughout this Consultation Paper is that PNs must be physically feasible at all times. The requirement that PNs are physically feasible could limit the ability of participants to make IDM trades. Hence, respondent views are sought on whether there are possible scenarios, especially where participants are permitted to continue trading in the IDM following early bid-offer acceptances by the TSO, where infeasible PN submissions could or should be permitted.

6.3.1 OPTION 1: FREEZE PNs

One option would be, on the acceptance of an offer or bid, to freeze the PNs of the relevant unit. This would allow the participant to continue to resubmit offer and bid prices and the TSOs to take further balancing actions against those prices. However, were the participant to continue to make IDM trades in respect of the relevant unit,

[15] Assuming the Balancing Market opens at the same time as the IDM, this is envisaged as being 14:00 for the trading day running from 23:00 to 23:00 the following day. In this case, at Balancing Market opening, gate closure for the final [half-hour] settlement period of the upcoming trading day will be at 21:30 on the following day, i.e. 31.5 hours later.

with no facility to update the PNs, the unit would be long or short, and in breach of any obligation to match PNs and ex-ante trades (if such an obligation exists).

This option would appear to be highly restrictive for the market participant as it would restrict a unit's ability to take any part in the IDM once a BM action is taken and would limit the unit to only being able to trade with the TSOs, thereby withholding capacity from the IDM. The SEM Committee does not see merit at this stage in taking this forward as an option.

6.3.2 OPTION 2 "ADDITIVE" PN CHANGES

A second option would be to allow the participant to continue to make IDM trades which were additional to the bid or offer acceptances. Thus, if a participant declared a PN of 100 MW following the DAM and the TSOs accepted an offer of 50MW in the BM, then the unit would be required to generate 150MW. If the participant then sold an additional 20MW in the IDM then the PN would be revised to 120MW, which with the additional bid-offer acceptance, would require the unit to generate 170MW. Figure 6.1 illustrates.

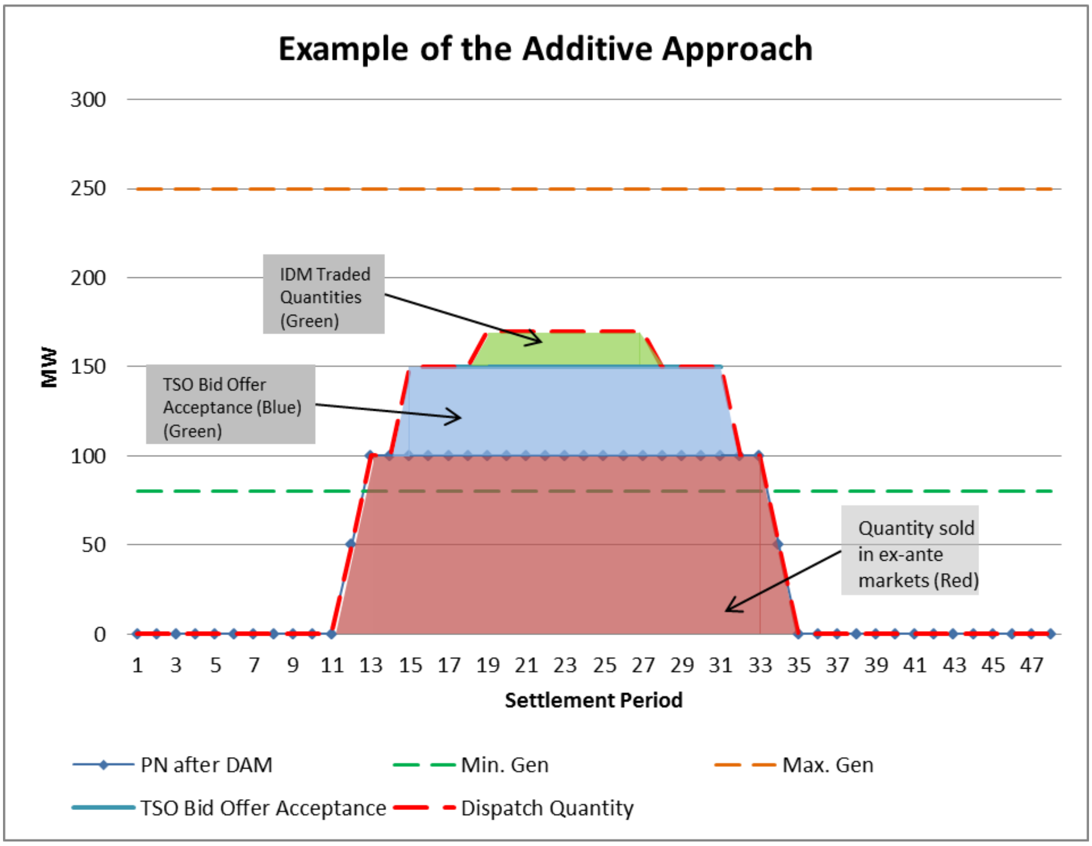


Figure 6.1: Example of the Additive Approach

This option would appear to be straightforward in that any trades (IDM and BM) use the PN as the datum point. The participant will have a clear view of their commercial position with the TSOs and could base their intraday trading on that knowledge.

However, there are a number of potential issues set out below for discussion.

Firstly, it may be argued that the additive approach could unnecessarily distort the IDM. If a slightly extra-marginal (not in merit) plant was called early in the BM to position themselves at 50% output, they would only have the remaining 50% of their output to sell in the IDM. If the expectation of demand subsequently increased and the plant's output was in-merit in the IDM (at a price higher than the bid-offer acceptance), then the plant would have forgone market revenues by trading early in the BM with the TSOs. However it could be argued that if IDM prices were higher than the price of the offer acceptance then the imbalance price would likely be higher also. Any early energy action would be paid the higher of the offer price and the imbalance price. It could also be the case that the plant could oversell in the IDM and buy back at the imbalance price if it felt that the imbalance price was going to be lower.

Secondly, there is a potential that early BM actions by the TSOs could subsidise a plant's entry to the IDM. If the TSOs instruct a plant with a zero PN to 50% output the TSOs will likely have to pay for the plants start costs. With this additive approach, the plant could trade 50% of its output in the IDM at its marginal cost and ignore start costs. This could allow an extra-marginal plant into the IDM ahead of a more efficient plant who didn't get its start costs paid by the TSOs through an early BM action. However it could be argued that this is the best economic outcome for the consumer given that the plant's start cost has been paid for by the consumer in any event.

Thirdly, with this approach it may be that the required output of the generating unit could be changing close to real-time, with the possibility that the TSOs would not be able to find alternative balancing actions. At the very least, the TSOs might be in the situation, where the unit was dispatched for reasons concerning system stability, of having to make equal but opposite bid-offer acceptances.

For instance, a unit selling in the DAM and declaring a PN of 100MW could have a decremental bid for 50MW accepted, say due to an import constraint; the participant might subsequently be able to buy, say, 20MW in the IDM and declare the PN down to 80MW, necessitating a further offer acceptance of 20MW. In the event that the offer price was higher than the IDM price, there would be a clear arbitrage opportunity giving the participant a strong incentive to do this. This issue is discussed later in this Chapter.

6.4 OPTION 3: "SUBSTITUTIVE" PN CHANGES

A third option would be to allow PN changes which would automatically "unwind" previously accepted offers or bids with the TSOs. For example, if a participant declared a PN of 100 MW after the DAM and the TSOs accepted an offer of 50MW, this would require the unit to generate 150MW. If the participant sold an additional 20MW in the IDM then, as with the Additive PN Change, the PN would be revised to 120MW. However, in this option, the offer acceptance would be deemed to have reduced by 20MW, such that the TSOs' instruction to operate at 150MW remained unchanged. Figure 6.2 illustrates.

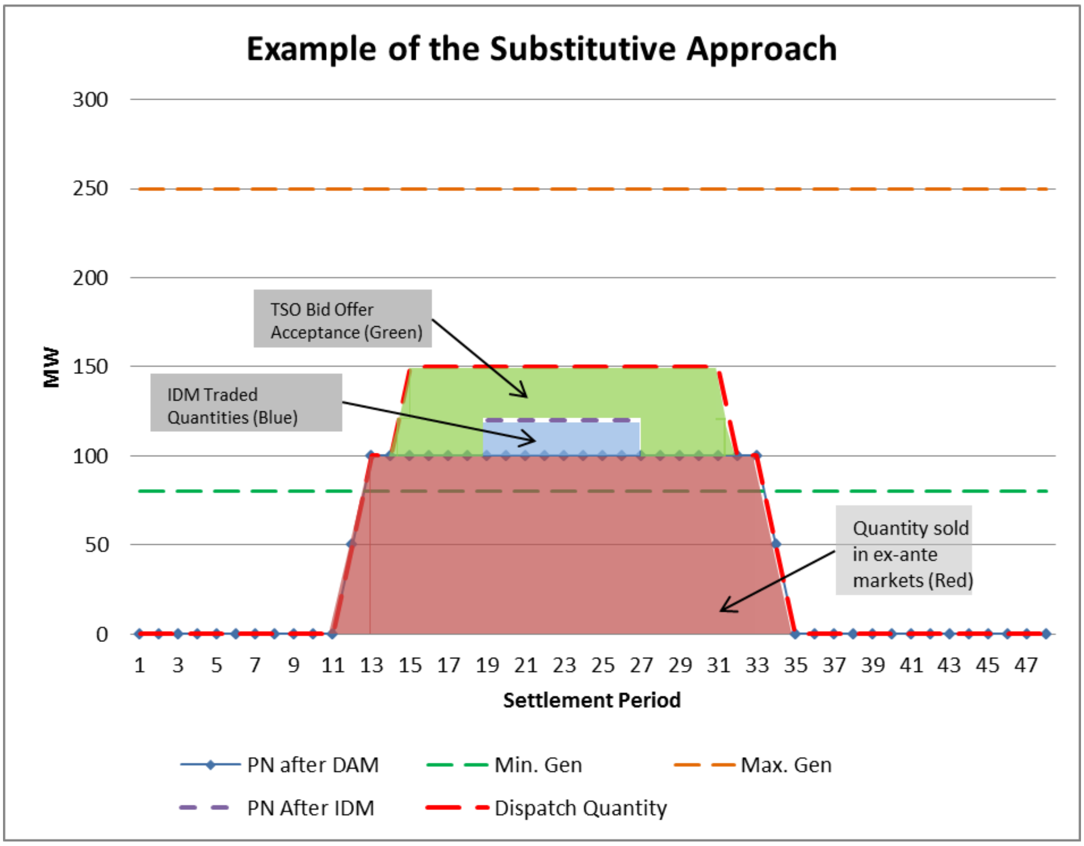


Figure 6.2: Example of the Substitutive Approach

- In the case of energy actions, it is possible that the TSOs instruct the sale of energy from a generator because they perceive it likely that the system will be short. If the participant subsequently succeeds in selling through the IDM then, all other things being equal, the system will be less short by this amount[16].

- In the case of system actions, it is likely to be important for system security that the unit operates at a given level. If the participant subsequently sells energy from the unit then the TSOs will require less additional energy from that unit.

Thus, both cases seem to fit well with the notion of "substitutive" PN changes[17].

This option would appear to have a number of merits. This option appears to minimise distortion between the BM and IDM and in particular should act to minimise the potential for any early BM actions to distort the IDM. For example, the TSO could instruct a plant to start early in the BM for reasons of provision of spinning reserve. However, demand may increase such that the plant which was called for reserve would be in merit in the IDM. With the "substitutive" approach, the plant would be free to trade its entire output in the IDM.

Under this option, participants can continue, unrestricted, to make IDM trades. Each IDM trade will, in effect, be swapping an imbalance price exposure for the IDM price or vice versa.

However, this option may be complex to implement as there may not be a precedent for this elsewhere. In addition, further potential complexity is introduced to this option in the next section.

6.4.1 SUBSTITUTION OPTIONS

Within the substitution option there are two potential methods for swapping out or netting IDM trades against bid-offer acceptances:

[16] It is recognised that the sale of energy in the IDM from a generator could be due not to the purchase by a supplier who is short but due to the purchase from another generator, say as a result of plant breakdown. However, in this situation, there are, in effect, two transactions: the first is the sale of energy by the first generator that makes the system less short and the second is the breakdown of the second generator making the system more short. It is coincidental that the two happen together, and the mechanism needs to cope with the each event happening on its own.

[17] Note also that until the imbalance prices are calculated, it may be unclear whether the action will be regarded as having been "energy" or "system". Thus it seems highly desirable that the mechanism works for both.

- It could be the case that the bid-offer acceptance locks in the bid price from the unit at the time of bid-offer acceptance. If the participant wishes to trade in the intraday and substitute the bid-offer acceptance they will need to achieve a more advantageous price in the IDM than the bid-offer acceptance price.

- Another approach would be to implement a methodology which sees the unit lock in the premium above or below the imbalance price through the bid-offer acceptance. If the participant traded nothing in the IDM they would receive the imbalance price and a premium between their bid/offer and the imbalance price. If they traded in the IDM, for the volume traded they would receive their IDM price and not the imbalance price but they would receive the premium. Therefore their decision to trade in the IDM would be based off an expectation of the imbalance price rather than their bid-offer price.

The first option is reasonably straightforward in that it will be clear to the unit what their bid-offer acceptance is and therefore it will be clear what price they must beat in order to make it appropriate to trade in the IDM.

The second option has merit also. A possible problem in balancing mechanisms generally is that when the TSO buys energy then there must be a party that is left short and who will be compelled to buy, at the imbalance price, the energy the TSO has bought. With the second approach above, participants that have had offer or bids accepted that are deemed to be energy actions will be paid (or pay) at the imbalance price. Hence they will have the same incentive as any other participant to trade in the IDM. Even participants that have, say, sold in the BM at an offer price that will be higher than the imbalance price will be able to trade in the IDM and swap the imbalance price for the IDM price, knowing that they will retain any premium of the offer over the imbalance price.

It is recognised that participants that have had offers or bids accepted that prove to be system actions, i.e. which are paid for at the relevant offer or bid price rather than the imbalance price, will, in effect, be hedged against uncertainty in the imbalance price. A participant should still have the incentive to sell in the IDM if the IDM price compares favourably with the expected imbalance price. Some participants however, may be less inclined to trade in the IDM to the extent that the bid or offer acceptance has underwritten the risk premium.

In particular, a party with an offer accepted at a high price may be prepared to sell in the IDM only at the risk-neutral expectation of imbalance price rather than a lower risk-adjusted expectation of imbalance price, on the basis that the 'offer acceptance premium' may hedge the imbalance price volatility. Similarly, a party with a bid accepted at a low price may be prepared to buy in the IDM only at the risk-neutral expectation of imbalance price rather than a higher risk-adjusted expectation of imbalance price, on the basis that the 'bid acceptance premium' hedges the imbalance price volatility.

Consideration needs to be given as to the extent of this issue with the second option above. The first option would appear to be an appropriate mitigating measure. If the market is balanced with an equal quantity of offers and bids then it is possible that the efficient trades will be possible between the parties hedged by having an offer acceptance premium and the parties hedged by having a bid acceptance premium. Where the market is long or short, it is inevitable that there will be an imbalance between buyers and sellers each exposed to the imbalance price, accounted for by the parties that have sold to (or bought from, in the case of a long system) the TSOs at a fixed offer (or bid) price. If there is, indeed, a distortion resulting from the underwriting of the risk premium by the TSOs' balancing action, it needs to be established how the same issue manifests itself in other market designs and how other market designs mitigate the problem.

6.5 TRADING IN THE OPPOSITE DIRECTION

With Option 2 (Additive) and Option 3 (Substitutive) above, there is a potential for unintended consequences where BM participants could make additional gains because of early actions of the TSOs. This issue could arise where a participant submits a non-zero level PN and where the TSOs need to move them from their PN level early in the BM. For instance:

- a unit selling in the DAM and declaring a PN of 200MW could have an decremental bid for 200MW accepted by the TSOs due to a constraint;
- the participant might subsequently be able to sell, say, an additional 200MW in the IDM and declare the PN up to 400MW, necessitating a further decremental bid acceptance of 200MW if the TSO wants them at 0MW.

In this scenario the unit could be given an early indication that the TSOs want them at 0MW and could sell the additional 200MW in the IDM to increase the size of the bid-offer acceptance with the TSOs.

A similar issue could arise where the TSO needs to constrain on a plant early in the BM. For instance:

- a unit selling in the DAM and declaring a PN of 200MW could have an incremental offer for 100MW accepted due to a local system issue;
- the participant might subsequently be able to buy, say, an additional 200MW in the IDM and declare its PN down to 0MW, necessitating a further offer acceptance of 200MW if the TSOs need them at 300MW.

In this scenario the unit could be given an early indication that the TSOs want them at 300MW and could buy an additional 200MW in the IDM to increase the size of the offer acceptance with the TSOs to 300MW.

The above two examples could be seen as merely reflecting the ongoing running of the IDM and the fact that the TSOs take action early and therefore no specific consideration is needed. However, in the above scenarios, the TSOs are giving the participant notice that the unit is needed at a certain level and the participant can take advantage of this by manipulating the quantity of the incremental offers and decremental bids the TSOs have to accept through its IDM behaviour and its incremental offers and decremental bids.

There are a number of potential solutions to dealing with this issue:

- Firstly, no specific consideration of this could be reflected in the market design. To the extent that it is found that a participant manipulates its incremental offers and decremental bids to take advantage of the TSOs as a distressed buyer/seller, this could be dealt with through local market power measures, should these be deemed to be required.
- A second option could be to implement a rule that would prohibit PN changes that increase the quantity of any offer or bid acceptance. This would have the effect of freezing PNs in one direction and would prevent the participant from increasing the constrained-down or constrained-up quantity.
- A third option would be to permit PN changes in either direction but, in the settlement of the offer or bid acceptances, to limit the quantity on which the premium (e.g. offer or bid price - imbalance price) is payable, such that a change

in PN cannot increase this quantity. For the second worked example above, this would mean that the bid price - imbalance price premium would be applied to 100MW, and the 200MW which was sold back in the IDM would get the imbalance price.

It would appear that the first approach is most in keeping with the concept of an unconstrained IDM. However, the potential to take an unfair advantage of the TSOs position cannot be discounted. Given that the consumer will ultimately pay for any additional costs it is prudent to include provision to address this matter.

The second option above would likely be difficult to implement and would likely involve difficult administrative processes for the TSOs.

The third option would appear to have greater merit than the second option as it doesn't restrict PNs but does limit the impact on potentially unwarranted costs. The third option could be implemented in the imbalance settlement algebra (see Section 9).

Therefore, it is proposed that the third option above be incorporated in the development of the imbalance settlement systems. The decision on whether or not the third option above will be used can be taken based on information to hand closer to I-SEM Go-Live or indeed experience in I-SEM.

6.6 SUMMARY

The I-SEM HLD envisages the BM opening shortly after the Day Ahead Market has closed and published its results, and opening in parallel with the Intraday Market. The issue thus arises as to how the ability of participants to trade in the IDM can continue in the event that the TSOs accept a BM offer or bid whilst the IDM is still open.

The SEM Committee welcomes comment from interested parties on the interaction between the IDM and BM and in particular how any potential distortions might manifest themselves.

This section has set out commentary on this interaction and has put three forward options for how to address the issue.

Comments are sought on the proposals and views described, and on any alternative proposals participants may have to address the issues being considered.

Specifically, comment is sought on:

1. **Which of the options put forward should apply to participation in the IDM in the event that the TSOs take a balancing action pre-gate closure:**
    a. **Freeze PNs**
    b. **Additive PN Changes**
    c. **Substitutive PN Changes**

2. **If the substitutive PN Changes option is taken, there are two further options for swapping out or netting IDM trades against bid-offer acceptances:**
    a. **If the participant wishes to trade in the IDM and substitute the bid-offer acceptance they will need to achieve a more advantageous price in the IDM than the bid-offer acceptance price**
    b. **Implement a methodology which sees the unit lock in the premium above or below the imbalance price through the bid-offer acceptance**

3. **Which of the three options put forward for dealing with "Trading in the Opposite Direction" should be implemented:**
    a. **No specific consideration of this would be reflected in the market design**
    b. **Implementing a rule that would prohibit PN changes that increase the quantity of any offer or bid acceptances**
    c. **Permit PN changes in either direction but, in the settlement of the offer or bid acceptances, to limit the quantity on which the premium is payable, such that a change in PN cannot increase this quantity**

7 TREATMENT OF SYSTEM SERVICES

7.1 INTRODUCTION

In order to ensure Operational Security, the TSOs manage limits related to frequency, voltage, thermal, short circuit and dynamic stability. As part of the processes to manage these limits, the TSOs pay market participants for the provision of system services.

This chapter examines the issues surrounding the interactions between participant trading in the I-SEM and the TSOs ensuring that adequate operational reserves are in place for real time operation. This chapter builds on the proposals described in section 6 (Interactions between the BM and IDM) and more specifically are based on *Option 3 'Substitutive' PN changes* and how this proposal would apply to operational reserves given that this type of system service is a significant part of Dispatch Balancing Costs.

To ensure the continued secure and stable operation of the electricity system, the TSOs require that operating reserve is carried by specific generation units. Operating reserve is required for:

a) Control, where there are forecast errors associated with demand or wind, and

b) System contingency, in the event where a unit trips or the single largest in-feed is lost (e.g. EWIC).

In readiness of such an event, generators carrying operating reserve have the capability to either ramp up or down to a specific MW output within a specific timeframe as required by the TSOs.

In addition to reserves, the TSOs have contracts in place for reactive power and black start. While this chapter sets out the proposal largely in the context of operational reserves, the same proposals also apply to these other system services.

7.2 SYSTEM SERVICES AND DS3

It is intended that, at least at a conceptual level, system services will operate as they do in the current market. As per the SEM Committee Decision on DS3 System Services, the SEM Committee stated:

"In most cases this will mean that a provider must be in the market (or constrained on by the TSO) to receive system service revenues. Therefore units must bid into the energy market in such a way so as to ensure they are in the market schedule".

This approach is in contrast to other markets, such as BETTA, where system services are procured as firm contracts where the generator must position themselves to provide the services. This is not an insignificant difference. In SEM generators earn infra-marginal rents in the energy markets and receive additional revenues for the provision of the system services through ancillary services payments. In BETTA, the generator will earn infra-marginal rents associated with the system service through the ancillary services contract. The approach adopted in BETTA is more suited to a self-dispatch as opposed to a more centralised market like I-SEM.

This is not to say that a market participant would ignore system services in how it bids into the market. If, for example, there is a price established for providing reserve, a generator might incorporate that price into their energy market bid to place them in a position to provide the service. As per the DS3 Decision Paper from December 2014, all payments will be made on the basis of whether the service is technically realisable from that provider by the TSOs in a given trading period. The activation of the service will be achieved through the BM.

7.3 OPERATIONAL RESERVES IN SEM

Reserve requirements tend to be proportionately greater and more dynamic in the SEM compared to other European synchronous areas. This is largely as a result of the characteristics of the electrical system (lower levels of interconnection to other synchronous areas, unit size compared to demand) and the proportion of the generation fleet that has a variable fuel source (wind). The following table sets out a comparison of the characteristics of the SEM system compared to the GB system.

	SEM	BETTA
System size (max Demand)	6,500	60,122
Number of Generators (excluding wind transmission connected)	75	391
Typical Unit Size (MW)	400	400
Typical Unit Size as a % of maximum demand (%)	6.15%	0.67%
System demand reduction with 0.2% frequency drop (MW)	26	240
System demand reduction with 0.5% frequency drop (MW)	65	601
Wind generation operational (MW)	2,013	6,580
Wind Generation (% max demand)	30.97%	10.94%
Wind Generation forecast error 10% (MW)	201	658
Wind Generation forecast error 10% as a percentage of maximum demand (%)	3.10%	1.09%
Largest single credible contingency (MW)	450	1,320
Largest single credible contingency (% max demand)	6.92%	2.20%
Interconnection (MW)	1,000	4,000
Interconnection (% of max demand)	15.38%	6.65%

Source: TSO Report on Dispatch Models SEM-12-105b

Operational reserves can be broken into three distinct areas or timeframes: capability, deployment and activation. Each is outlined below in the context of the arrangements in the current SEM and in the I-SEM.

7.3.1 CAPABILITY

As stipulated in the Grid Code[18], generators must have the capability to provide reserve. The TSOs will test the generators' capability to provide this service and contract for this service through an Ancillary Services Agreement. This agreement will detail the specific capabilities for that particular plant i.e. where reserve requirements are exceeded or if any derogation(s) may apply.

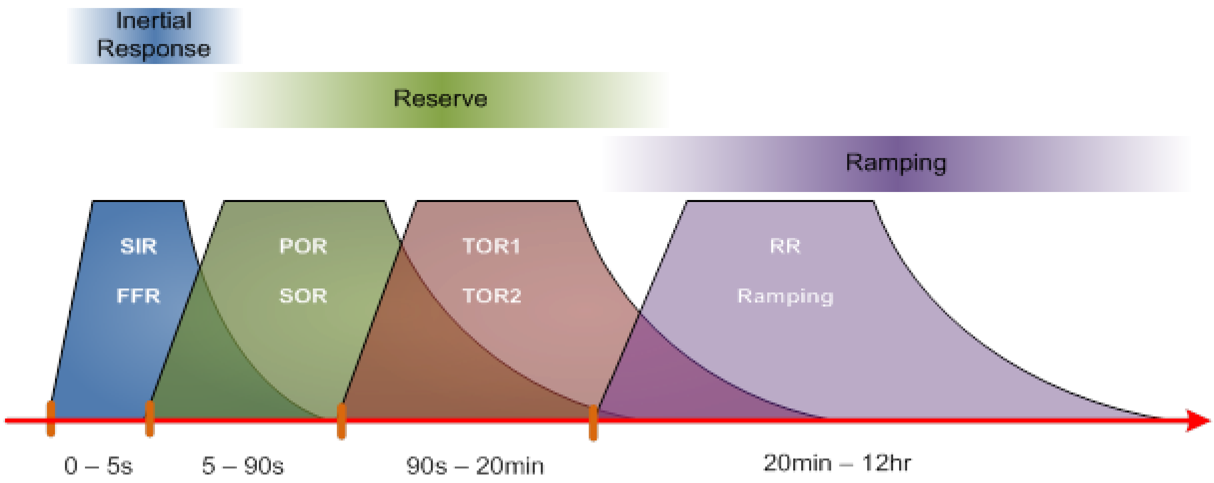
[18] http://www.eirgrid.com/operations/gridcode/

Currently, in SEM, reserve is broken in four categories:

- Primary Operating Reserve (POR),
- Secondary Operating Reserve (SOR) and
- Tertiary Operating Reserve (TOR1 and TOR2).

Each category is defined based on the response times that it takes for a generator to provide this service. The table below sets out the suite of system services that will be put in place as part of the implementation of the DS3 program.

New Services		**Existing Services**	
SIR	Synchronous Inertial Response	**SRP**	Steady-state reactive power
FFR	Fast Frequency Response	**POR**	Primary Operating Reserve
DRR	Dynamic Reactive Response	**SOR**	Secondary Operating Reserve
RM1	Ramping Margin 1 Hour	**TOR1**	Tertiary Operating Reserve 1
RM3	Ramping Margin 3 Hour	**TOR2**	Tertiary Operating Reserve 2
RM8	Ramping Margin 8 Hour	**RRD**	Replacement Reserve (De-Synchronised)
FPFAPR	Fast Post-Fault Active Power Recovery	**RRS**	Replacement Reserve (Synchronised)



7.4 DEPLOYMENT

Once the TSOs have tested the capability of generators to provide reserve, the TSOs can then deploy these contracted generators to provide this service in advance of real time operation.

Contracted generators require different deployment notice times depending on their technology. Furthermore, if a generator is not synchronised it will require longer notice times to account for start-up and synchronising.

Notwithstanding that generators are likely to be running and providing reserve from previous periods, the TSOs will deploy reserve, as needed, at various times in advance of real time operation. Generators will be positioned to provide this service by synchronising to the grid or dispatching down from maximum output to a specified level.

Similar to the treatment of constraints in SEM, a generator that has been deployed for reserve will receive compensation. Therefore, where a generator is in the Market Schedule to run at full output and is reduced down to provide reserve, then this generator will receive its infra-marginal rent for the constrained down quantity, i.e. its MSQ less its actual output (which includes any activation of the reserve by the TSOs).

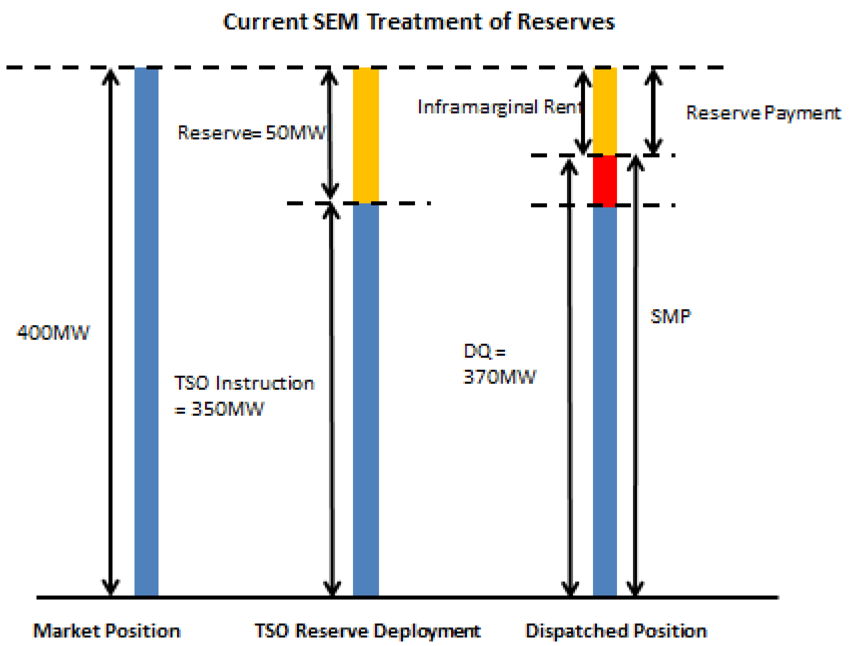
7.5 ACTIVATION

In real time operation, the TSOs will have all the reserve requirements deployed and positioned for activation, as required.

As stated previously, in a system event such as plant tripping off the system, or for control where the actual wind generation is lower than predicted, then the TSOs will activate reserves from the generators that have been deployed. Some of this reserve is provided automatically by certain generators in the first number of seconds during an event (e.g. activation of POR due to changes in demand or wind) while other types of reserves are activated manually (e.g. TOR may be activated in the minutes after a plant has tripped off the system).

Where a generator has been activated to increase its output in response to a system event then that generator shall also receive a balancing energy payment for the quantity of energy provided. This balancing energy payment rate is dependent on the type of reserve provided at the time of the event[19].

A high-level example of treatment of reserves in SEM is outlined in the diagram below. If a generator fails to activate its reserve upon instruction from the TSOs as per its capability in the Ancillary Services Agreement then that generator may be subject to re-testing.



[19]http://www.eirgrid.com/media/2014_2015_HarmonisedAncillaryServiceStatement%20_ofPayments_and_Charges.pdf

In this example, the generator has a position of 400MW based on the market schedule. The TSO requires the generator to carry 50MW of reserve and issues an instruction for the generator to position itself at 350MW. In dispatch, the TSO activates 20MW of reserve from the generator. As a result, assuming a settlement period of one hour, the generator will receive the SMP for 400MWh, will pay back its bid price for 30MWh and receive a reserve payment for 30MWh.

7.6 OPERATIONAL RESERVES IN I-SEM

In I-SEM the trading day will commence at 23:00. The Day Ahead Market (DAM) gate closure will be at 11:00 with results typically being published at 11:40. As stipulated in the HLD, the Balancing Market (BM) is mandatory and therefore it is expected that all market participants will be Balancing Services Providers and that the PNs will be received from all participants at a time likely to be around 14:00. These PNs will be submitted with associated incremental offer and decremental bid prices. The Intraday Market (IDM) will open after the publication of the DAM results and will close one hour before real time operation.

Given the reserve requirements in the current arrangements, the TSOs will need the ability to deploy reserves prior to IDM gate closure. Hence, and as per the HLD Decision Paper, the BM will open in parallel with the IDM and participants will update their PNs to reflect any IDM trading activity with their FPNs being notified at gate closure.

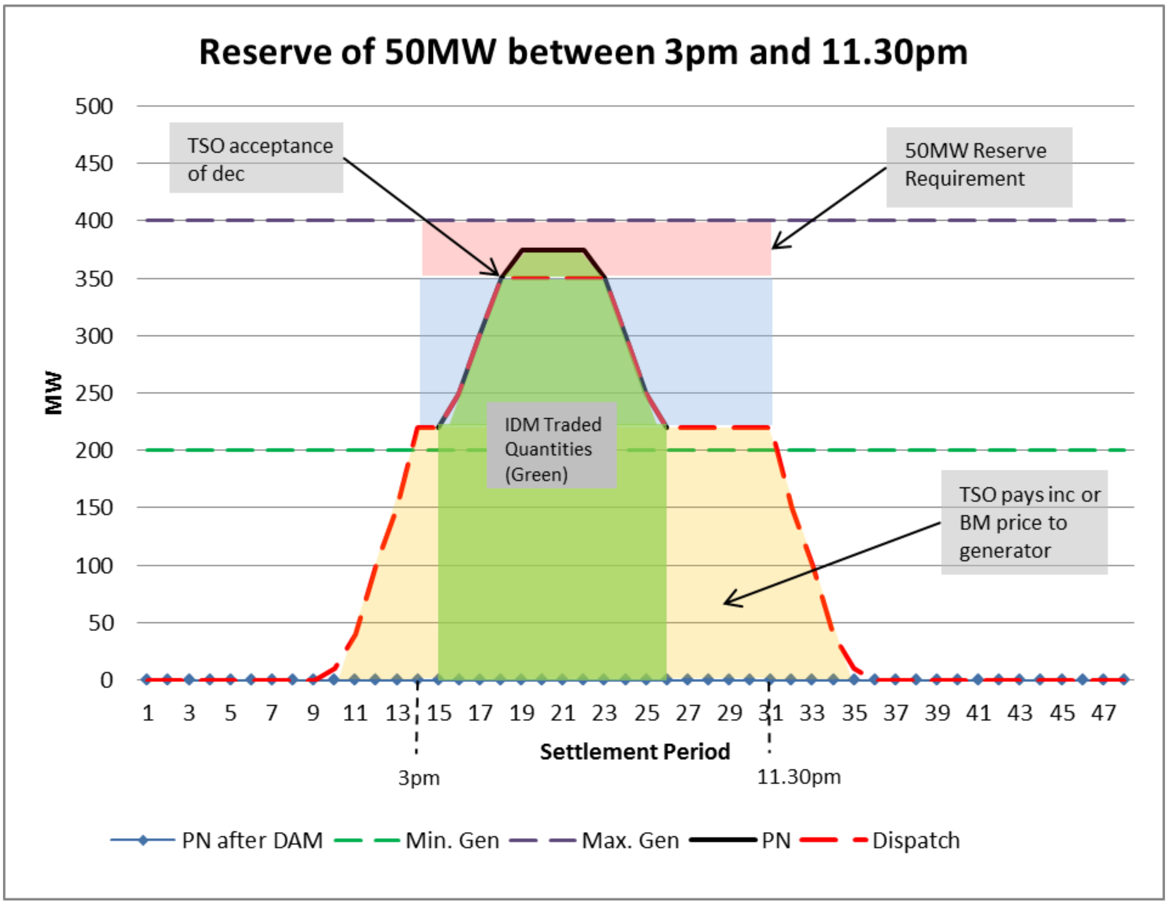
In this context, it is proposed that where a generator is deployed for reserves, it should be constrained in the IDM to the minimum extent possible. In other words, where the TSOs issue an instruction to dispatch down to a specific level from the submitted PN or where a generator is instructed to start up from a PN of zero, that generator should to the extent possible still be able to trade in the IDM normally. There are a numbers of issues however that merits consideration and these are addressed in section 6.3.

The following section sets out a number of examples for the purposes of illustrating the interactions between the TSOs' dispatch instructions for reserve deployment and the participants' trading activity. Again, as mentioned in the introduction, these examples build on the proposals set out earlier in this paper. However, given the various approaches discussed in earlier sections and the potential combinations of these approaches, the following examples focus specifically on the 'Substitutive PN' approach from Chapter 6. This does not pre-suppose any decision and comments are welcome in respect of all approaches outlined and their application to system services.

7.6.1 UNIT WITH NO EX-ANTE MARKET POSITION

In this example the generator has not received a contract nomination in the DAM and therefore is not scheduled to run. It therefore submits a PN of zero for the 24 hour period. However, based on the Security Constrained Unit Commitment scheduling, the TSOs in order to maintain system security require this particular generator to provide 50MW of reserve between 3pm and 11:30pm (settlement periods 14 – 31).

This particular generator requires a minimum of four hours' notice to allow time to start up and synchronise with the electricity system. Hence, the TSO must issue this instruction prior to the closure of the IDM.



Unit with no DAM Position Deployed for 50MW Reserve

It is proposed that the generator can still trade power in the IDM. In this example, after receipt of the TSOs' bid-offer acceptance for the unit to provide reserve, the generator decides to sell a quantity of energy in the IDM as defined by the green area under the curve in the above graph. This might occur for example where the generator sees a price in the IDM that is greater than its incremental offer price submitted to the TSOs. Note however that in this example the generator has already sold a portion of this energy that is within the TSOs' reserve requirement. This is discussed in Section 6.3 of this paper as part of the interactions between the BM and the IDM.

The TSOs will receive an updated PN reflecting the intraday trade(s) along with associated incremental offers and decremental bids. If the deployment of reserve from this generator is still required then the decremental bid will be accepted to dispatch down to 350MW. Alternatively, the TSOs may have the opportunity to call the reserve from an alternative source with a lower decremental bid price.

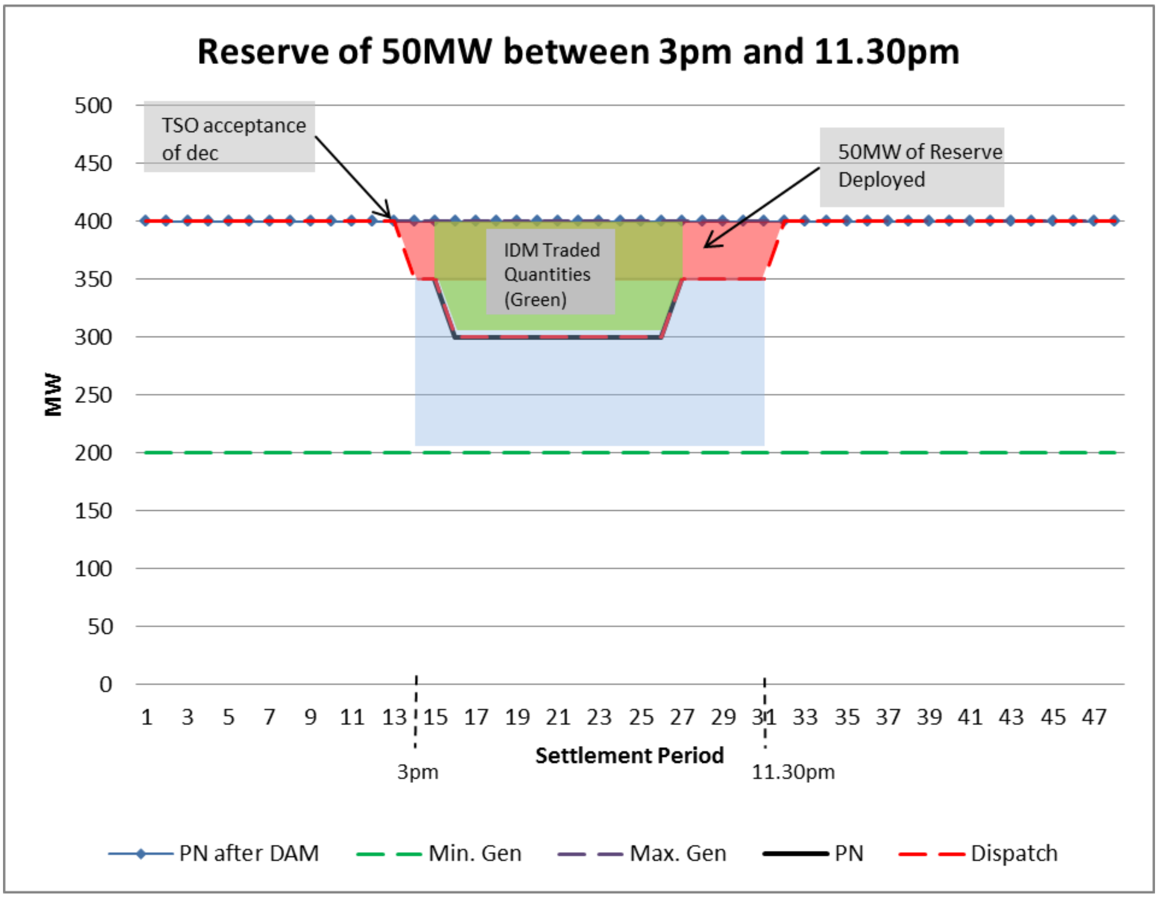
In terms of overall cashflow, the generator will receive/make the following payments:

1. It will receive the incremental offer price for the quantity of energy dispatched based on the TSOs' bid-offer acceptance less any quantities sold in the IDM that are within this area (i.e. the quantity within the yellow area of the above diagram will be paid at the incremental offer price).
2. It will receive the price achieved in the IDM for the quantities of energy sold (green area)
3. It will pay the decremental price for the quantity of energy sold in the IDM that is within the reserve requirement of the TSOs.
4. It will receive reserve payments for the provision of 50MW of reserve in settlement periods 14 to 31 inclusive.

7.6.2 UNIT WITH A DAY AHEAD MARKET AND INTRADAY MARKET POSITION

In this example the generator has received a contract nomination in the DAM for its full available output. Hence it submits a PN of 400MW for the entire trading day. The TSOs, in order to maintain system security require this particular generator to provide 50MW of reserve between 3pm and 11:30pm (settlement periods 14 – 31).

Again to allow sufficient notice times, the TSOs are likely to need to instruct the generator, prior to the closing of the IDM, to provide this reserve. The TSOs will instruct the generator to reduce its output to 350MW.



Unit with DAM Position deployed for 50MW of Reserve

As before, it is proposed that the generator can still trade in the IDM. In this example, after receipt of the TSOs' instruction, the generator decides to buy a quantity of energy in the IDM as defined by the green area under the curve in the diagram above. The TSOs will then receive an updated PN reflecting this intraday trade(s) along with associated incremental offers and decremental bids.

In settlement, the generator will receive/make the following payments:

1. It will receive the DAM price for the quantities nominated in the DAM market.
2. It will pay its decremental bid price for the quantity of energy dispatched based on the TSOs' bid-offer acceptance (i.e. the area above the TSO Dispatch profile in the above diagram) less any quantities sold in the IDM that are within this area.

3. It will receive the price achieved in the IDM for the quantities of energy sold (green area)
4. It will receive reserve payments for the provision of 50MW of reserve between 3pm and 11:30pm

There is a question with the above example as to what happens when a plant is in the DAM but buys all its output back in the IDM and intends not to run (i.e. it will now submit PN of zero similar to the example in section 7.6.1). Under the substitutive approach, the PNs submitted by the generator after a BM order has been accepted should not actually influence the physical running of the plant. Rather they will operate as per their BM instruction, with their updated PNs just affecting the quantities settled in IDM vs BM.

7.7 FURTHER CONSIDERATIONS

There are a number of considerations that merit discussion and to which respondents are invited to address in their consultation responses.

7.7.1 MARKET POWER

As discussed in the first example, it is proposed that where a generator trades energy required for reserve, the TSOs will either accept the decremental bid from the generator (who will pay back the lower of its decremental bid or the BM clearing price) or, select an alternative unit to provide reserve where it is economic to do so (assuming that it is technically feasible and there is still a requirement for this reserve).

However, there may be instances where a particular unit that is deployed for reserve is the only unit that can provide it (e.g. for local system security reasons). It is likely that such a unit would be aware of this and therefore consideration needs to be given to what the decremental price should be given that the unit knows that the TSOs have to accept the decremental bid price. A specific example of this could be where the TSOs deploy reserves from the only thermal plants synchronised on the system. If there is a requirement to activate reserves, the incremental offers and decremental bids from the BM would be used. The TSOs would have no alternative but to accept the incremental offers and decremental bids it has no matter what their level.

It may be that units deployed for reserves, through the reserve contract may have to bid cost-reflectively. Ultimately, it is proposed that this issue will be addressed in the Market Power Workstream. However, from an energy trading point of view, the issue does need to be addressed.

7.7.2 PRE BALANCING MARKET ACTIONS

The TSOs have previously highlighted to the SEM Committee, the potential need to take actions to instruct a plant before the opening of the Balancing Market. As discussed previously, it is expected that PNs will be delivered to the TSOs by participants at around 14:00 with the trading day commencing at 23:00. This leaves a time lag of nine hours between the first submission of PNs and the start of the trading day.

There may be situations where the TSOs need to instruct a plant to be on the system where the notice time of the plant is longer than the nine hours mentioned above. It should only be an exceptional situation where this might occur given that the trading day starts at a time where starts should be less common. However, there are a number of plants on the system that have a cold start-up time of more than nine hours plus their loading rates to get to synchronisation. The table below sets out the start-up times of a number of plants on the system as per the Technical Offer Data (TOD) submitted to SEM. The below excludes the time to get to minimum load and ramp up which can add further hours to the start-up.

Unit	Type	Notification Times (time to Sync.) Hrs		
		Hot	Warm	Cold
MP1	Coal	5	8	15
TB4	Oil	3	7	10
DB1	CCGT	2	3.5	5
HNC	CCGT	3	5	9
WG1	CCGT	3	5	12
TYC	CCGT	3	5	10
LR4	Peat	6	12	12
AT1	OCGT	0.33	0.33	0.33
TP1	OCGT	0.17	0.17	0.17

As above, the TSOs have suggested that they will need a facility to avail of plant before the opening of the Balancing Market. In addition, the SEM Committee stated that this issue would be examined in the detailed design phase. There appear to be two approaches to address this issue:

The first would see the use of the system services framework to contract with those generators that need to be scheduled prior to the BM opening. With this approach there would be no systemised mechanism in the BM to pay for actions taken before the BM opens so it would need to be through bilateral arrangements between the TSOs and the participant. Note that currently this is not covered under the existing scope of the system service project.

The action itself could take a number of forms including a warming contract to bring the plant to a hot start state, or a start-up contract. It would still be the case that any energy payment related to when the plant is on in the Balancing Market would be recovered through the BM. For example, a 12 hour notice plant could be told to warm up to hot state for 00:00 at 11:00. In this example, the start-up would be incurred in the BM but the cost of the warming contract would be a bilateral payment. The recovery of that payment by the TSOs would likely be through the ancillary services budget or through the or through the dispatch balancing costs.

The second approach would see the TSOs use incremental offers and decremental bids from previous trading day to call a plant pre-BM. For example, the TSOs might require a plant with a notice time of 14 hours to be synchronised shortly after midnight. In this approach, the TSOs would schedule this plant by accepting the incremental offer that was submitted with a PN in the last period. Notwithstanding that such actions should be minimal, generator costs are unlikely to significantly change over a short number of periods and therefore the use of previous incremental offers by the TSOs should likely not disadvantage these participants to any great extent. i.e. the costs for synchronising at 23:00 should not be significantly different to costs for synchronising at 03:00.

7.8 SUMMARY

In summary, the SEM Committee is of the view that:

- The treatment of system services in the energy market should remain the same in I-SEM as it is in SEM insofar as possible.
- Market power will need to be considered in the context of the activation of all system services and other system services.

Any instruction of plants before the start of the BM could be considered part of the ancillary services framework or through the use of incremental offers and decremental bids from the previous period. The SEM Committee welcomes comments from respondents as to their preferred option.

Specific comments are sought on:

1. **The proposal whereby a unit that is deployed for reserves should be constrained to the minimum extent possible in the IDM**

2. **Are there any market power issues that need to be specifically addressed in relation to System Services?**

3. **Which of the two approaches should be utilised where the TSOs have to schedule a plant before the opening of the Balancing Market:**
   - **A. A system services framework would be used to contract with those generators that need to be scheduled prior to the BM opening.**
   - **B. The TSOs would use incremental offers and decremental bids from previous trading day to call a plant pre-BM.**

8 IMBALANCE PRICING

8.1 INTRODUCTION

A key aspect of the detailed design of the imbalance pricing arrangements is the methodology for setting the imbalance price. The I-SEM HLD stated that the I-SEM will employ a single marginal energy imbalance price, such that market participants with a long position in imbalance settlement (i.e. contracted position is more than allocated volumes, as modified for any accepted offers and bids) will receive the same imbalance price as is paid by market participants with a short position (contracted position less than allocated quantities, again as modified by any accepted offers and bids) in the same imbalance settlement period.

A key consideration within the pricing methodology will be the treatment of non-energy actions. Unconstrained energy balancing actions will be subject to marginal pricing, while non-energy actions will be pay as bid.

This section sets out three broad approaches to setting the imbalance price:

- The first approach is a cause based approach referred to as flagging and tagging in this paper. Under this approach all the incremental offers/decremental bids accepted by the TSOs are identified (or "flagged"), and the TSOs identify those actions that are deemed to have been taken for non-energy reasons and excludes them from the imbalance price calculation ("tagged"). This is the pricing approach taken in the BETTA market in GB.

- The second approach is a price based one and considers all the bids and offers that were available to the TSOs in the BM (but not necessarily taken/dispatched) and calculates an appropriate imbalance price, given the net energy imbalance volume to be met. In this approach, a generator who was not actually called in the BM could set the price in the BM.

- The third approach is a price based approach but shares characteristics of the first two options. This option seeks to calculate the marginal price of the unconstrained energy balancing action from the actual dispatch stack.

8.2 THE NET IMBALANCE VOLUME

As per the I-SEM HLD, The I-SEM will employ a marginal pricing mechanism for energy balancing actions taken through the BM and that the marginal price reflects the cost for generating one more or one fewer MWh of electricity within the BM timeframe.

In order to calculate the imbalance price under the first two pricing options in this paper, it will need to be established how much increased or reduced demand must be met in the BM by the TSOs. This volume must be corrected for non-energy actions. The volume of energy actions to be met by the TSOs in the BM can referred to as the net imbalance volume and can be considered as a measure of how long or short the market is. There are different methodologies which might be used to calculate the net imbalance volume and the applicability of each might ultimately depend on the pricing methodology employed.

- One approach is to consider all actions taken by the TSOs in real time dispatch and to identify non-energy actions to leave a volume of actions which were taken to address the energy imbalance. As discussed later in this chapter, this approach relies on the ability to accurately distinguish between energy and non-energy actions.
- A second approach would be where the total FPNs from generators and dispatchable demand is compared to the demand to be met by the TSOs in real-time with the difference between the two being the amount of energy actions to be taken by the TSOs. This approach relies on the FPNs being a reflection of the participant’s commercial position and intended running level only. Therefore, the FPNs would not be reflective of any early TSO actions.

The choice between the options above largely comes down to the pricing methodology chosen. Therefore, the above does not seek to consult on a more appropriate methodology for calculating the net imbalance volume but rather sets out the different potential approaches.

8.3 ENERGY AND NON-ENERGY ACTIONS

As set out above, a key aspect of the imbalance arrangements is the differentiation between energy and non-energy TSO actions. Energy actions can be broadly considered as actions taken by the TSOs to address an overall imbalance between supply and demand across the settlement period. Non-energy actions can be considered as actions that are taken by the TSOs to address system issues that would still exist even if the market had perfectly balanced. These non-energy requirements include:

- Reserves
- Dynamics (Inertia, RoCoF, SNSP)
- Voltage support
- Thermal transmission constraints

Satisfying these requirements will likely require the TSOs to reposition resources away from their market positions by accepting incremental offers and decremental bids in the Balancing Market.

Details of the current enduring operational constraints for the all-island system are published on the TSOs' websites[20]. Operational limits for a given day may vary from time to time due to changing system conditions and network outages. In addition to today's operational considerations, the I-SEM and Network Codes will introduce new requirements for the TSOs to take non-energy actions, such as redispatching to maintain interconnector transfer capacity as set out in CACM.

8.4 APPROACHES TO CLASSIFYING ENERGY AND NON-ENERGY ACTIONS

Given their different treatment in pricing, the classification of energy and non-energy actions is important. Table 8.1 below sets out three different approaches; these are referred to as the cause, price and timing of a balancing action and provide three potential mechanisms to distinguish energy and non-energy actions.

[20] http://www.eirgrid.com/operations/dispatchbalancingcosts/operationalconstraints/
http://www.soni.ltd.uk/InformationCentre/Publications/

Table 8.1 – Approaches to identifying energy and non-energy actions

Attribute	Approach	Examples
Cause	• Attempt to identify the primary driver for each balancing action	• GB applies mechanistic rules to identify actions related to constraints or of short duration (<15 minutes) that are removed (tagged) or re-priced (flagged but not tagged) in the pricing calculation • Nordic regulation market flags actions taken out of price order or of short duration (<10 minutes)
Price	• Determine an unconstrained marginal price via optimisation • Actions more expensive than the marginal price are deemed non-energy	• US ISO markets typically calculate a real time marginal price (e.g. every five minutes) which is then averaged over the (e.g. hourly) settlement period • US markets settle pay-as-bid for units instructed over market price, and apply off-market dispatch and settlement for reliability must-run units • In GB, NIV tagging removes the most expensive actions from price-setting (if above net imbalance)
Timing	• TSO primarily conducts energy balancing only after Intraday Gate Closure • Actions before Gate Closure therefore deemed to be non-energy	• TSOs in markets such as Germany typically do not change the net system imbalance while the Intraday Market is still open, offsetting non-energy actions with equal and opposite actions

The first approach (Cause) takes all the incremental offers and decremental bids accepted by the TSO and assesses each action in turn to determine whether the primary driver for the TSO action was energy or non-energy, resulting in a subset of actions for consideration in imbalance price formation.

The second approach (Price) essentially turns the problem around, first determining an unconstrained price and then using this to distinguish energy and non-energy actions.

The third approach (Timing) simply uses the time the action was taken as a proxy to guide classification, on the assumption that the TSO is primarily focused on non-energy balancing to secure the system prior to Gate Closure, before increasingly focusing on energy balancing after Gate Closure.

The GB balancing mechanism, like the I-SEM, is used for both energy and non-energy balancing. As described in Section 8.5 below, the GB flagging and tagging methodology has evolved over a number of years in an attempt to improve the separation of energy and non-energy actions. In many other jurisdictions, non-energy balancing requirements are largely resolved outside of the Balancing Market.

- For example, Spain and Italy feature separate markets for adjustments or ancillary services that operate after the DAM.
- In some cases (e.g. Italy, Sweden, Norway), the major transmission constraint boundaries are reflected directly in the energy market via zonal pricing, thereby reducing the scope of TSO non-energy actions.

The classification of energy and non-energy actions may ultimately involve a combination of cause, price and timing. For example, the GB flagging methodology first considers the cause of the balancing action, identifying actions related to constraints or of short-duration as non-energy. However, these actions will subsequently be reclassified as energy-related if less expensive than an unflagged action. Timing is another consideration: actions that are initially identified as non-energy may be treated as energy actions in ex-post settlement, or vice versa.

Consider a scenario in which the TSO needs to commit a generating unit to address a local voltage constraint. Reflecting the generator's notice times, the TSO issues the commitment instruction a number of hours prior to Gate Closure. At the time the action is taken, it is regarded as a non-energy action. Subsequent changes in demand and generation lead to the system being short after Gate Closure, and it may transpire that the early balancing action was "in merit" for resolving the energy imbalance. Conversely, an action taken for energy balancing reasons may ultimately be treated as non-energy if the net direction of the system imbalance changes during the settlement period.

It is only at the end of the settlement period that the net imbalance volume over the half-hour is known, and the balancing actions which have contributed to the resolution of the energy imbalance can be identified.

Table 8.2 sets out some of the potential advantages and disadvantages with the three approaches to identifying energy and non-energy actions.

Table 8.2 – Appraisal of approaches to identifying energy and non-energy actions

Method	Pros	Cons
Cause	• Builds on methodologies developed and refined for GB	• Risk that the majority, or all, balancing actions for a trading period are non-energy tagged • Challenge of distinguishing different actions on the same generating unit • Risk to timely publication of prices if adopting a more comprehensive flagging approach
Price	• Allows consideration of the full stack of available actions, rather than only the actions taken • Delivers a price even if the majority of actions taken in practice have a non-energy component	• Requires appropriate treatment of technical constraints (e.g. plant dynamics), such that the price is not set by an action which could not have been taken in practice • Risk of dampening the price by assuming perfect foresight on the part of the TSOs (depending on the formulation of the pricing algorithm)
Timing	• Simplistic approach	• Ignores the potential for non-energy actions after Gate Closure • Effectively requires the TSOs to offset non-energy actions prior to Gate Closure with equal and opposite actions, which may be overly restrictive in the all-island system

The first approach (Cause) is considered in more detail in the next section as part of the description of the flagging and tagging arrangements in GB.

The second approach (Price) is considered in detailed in the subsequent section on the unconstrained price formation methodologies.

The third, timing-based approach could be considered as over-simplistic, given that it would ignore the possibility of non-energy actions being taken after Gate Closure, or energy actions before Gate Closure. For this approach to be effective, the TSOs could be required to offset non-energy actions prior to Gate Closure with equal and opposite actions, so as not to impact the net system position. This may prove overly restrictive in the all-island system, and preclude more economic courses of action nearer the delivery period.

For example, consider the scenario in which the TSOs need to commit a generating unit prior to Gate Closure to address a local voltage constraint. The timing of this non-energy action is dictated by the generator's declared notice times. However, in the reverse direction, it may be more efficient to defer taking offsetting actions until "the last time to order" for the delivery period, at which point the TSOs will have greater certainty on the state of the system. It is proposed that this approach is not taken forward as an option for imbalance pricing in I-SEM.

8.5 CAUSE BASED METHOD - FLAGGING AND TAGGING

This section provides an introduction to cause based methodology for distinguishing between energy and non-energy actions in order to inform the development of a potential approach to non-energy classification in the I-SEM. Specifically, this section describes the arrangements in the GB market which are referred to as flagging and tagging arrangements. A detailed description of the arrangements is published by Elexon[21], the GB imbalance settlement body.

The imbalance pricing arrangements have undergone numerous modifications since the NETA bilateral trading arrangements were implemented in March 2001, replacing the England and Wales Pool. The changes made or proposed to the GB imbalance arrangements have largely been driven by the desire to improve price signals and remove the potential "pollution" of imbalance pricing by non-energy actions.

[21] Elexon Imbalance Pricing Guidance
https://www.elexon.co.uk/wp-content/uploads/2014/11/imbalance_pricing_guidance_v8.0.pdf

Further modifications to the arrangements are under consideration following Ofgem's Electricity Balancing Significant Code Review. These include moving to a single marginal imbalance price (currently, a dual-pricing method is applied), and the introduction of scarcity pricing for reserve utilisation and demand control.

However, this section describes the key steps in the GB flagging and tagging process as it currently operates. Initially, in GB, the imbalance price was set based on actions taken by the TSO with no attempt to identify energy and non-energy actions.

SO flagging (transmission constraints)

SO constraint flagging was introduced in November 2009 following BSC Modification P217A. It represented the most significant development to date in the evolution of the GB arrangements for removing non-energy actions from imbalance pricing. The objective of SO flagging is to identify balancing actions related to the management of transmission constraints, including those arising from thermal ratings, voltage and transient stability.

National Grid's processes for SO flagging are set out in a System Management Action Flagging Methodology Statement, as required under its Transmission Licence (however, it not currently possible for Ofgem to audit this process). For actions taken in the Balancing Mechanism (acceptances of bid and offers), the process broadly operates as follows:

- Control room analysis identifies the active constraints on the system;
- Generation (or demand-side) units that could be used to manage the constraint are SO-flagged;
- Any Balancing Mechanism (BM) actions on these units are automatically flagged by the control room in real time;
- Once the constraint is no longer active the units are de-flagged.

All BM actions taken on flagged generation units are automatically flagged as being constraint-related at this first stage (a later step in the flagging and tagging process reclassifies actions as energy if they are less expensive than the last unflagged action).

In addition to accepting BM bids and offers, National Grid may also take actions outside the Balancing Mechanism, such as pre-gate closure transactions or SO-SO trades over interconnectors. These actions will be individually SO-flagged at the inception of the transaction if taken for system management reasons according to the principles set out in National Grid's methodology statement.

Emergency actions will also be SO flagged if they are issued for system balancing reasons (e.g. due to a fire or breakdown of transmission equipment).

CADL flagging (short duration actions)

Accepted bids and offers with short duration are flagged in the price calculation to remove the impact of sub half-hourly balancing actions from cash-out prices. The CADL flagging rules were introduced under Modification P18A in September 2001.

The Continuous Acceptance Duration Limit (CADL) parameter defines the short duration threshold and is currently set to 15 minutes: balancing actions less than 15 minutes in duration are flagged as non-energy. The rationale for CADL flagging relates to the granularity of settlement metering and the challenge of targeting cost-reflective prices at the participants causing the need for balancing actions.

If the TSO takes an expensive balancing action for 5 minutes to deal with a sudden increase or decrease in generation or demand, it may not be appropriate to target the costs of this action at participants who were out of balance over the half-hour settlement period, given that it is not possible for settlement metering to identify the participant imbalances that led to the need for the short duration action.

Other markets have analogous rules: for example, in the Danish regulating (balancing) market, a regulation bid must have been effective for at least 10 consecutive minutes in the delivery hour for the bid to be price-setting, otherwise it is paid-as-bid.

De Minimis Tagging

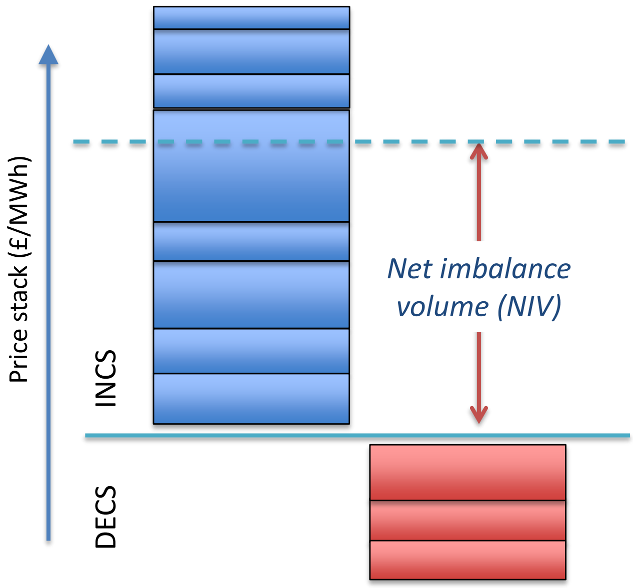
De minimis tagging excludes from imbalance pricing all balancing actions with a volume less than the De Minimis Acceptance Threshold, currently 1MWh. De minimis tagging was introduced by Modification P10 in May 2001, following concerns that imbalance prices could be set by "spurious" actions created by the finite accuracy of the systems used to calculate bid and offer volumes (e.g. during the half-hourly integration of spot dispatch instructions).

Arbitrage Tagging

Arbitrage tagging excludes from price setting equal and opposite volumes of buy and sell actions if these overlap in price (e.g. where a buy action is at a lower price than a sell action). In the current GB arrangements, arbitrage tagging prevents arbitrage trades executed by the TSO from dampening the volume-weighted imbalance price. The benefit of arbitrage trades therefore accrues to all system users (via lower balancing costs) rather than to those participants who were out of imbalance.

NIV Tagging

The TSO may be taking actions in both directions in a given settlement period, for example, to resolve transmission constraints or re-position resources for reserve. The Net Imbalance Volume (NIV) is calculated by subtracting the smaller stack of actions from the larger stack of actions to leave the residual volume of energy imbalance. This is illustrated schematically in the figure below:



The NIV Tagging rules in GB imbalance pricing assume that only the least expensive actions required to resolve the NIV are energy related. Having stacked all the buy and sell actions in price order, actions that exceed the NIV are deemed to be system related and tagged out from the price calculation. The remaining actions in the direction of the net imbalance are then considered in imbalance price formation.

NIV Tagging was introduced in 2003, prior to the SO Flagging of constraints. Concerns over the pollution of imbalance prices by non-energy actions were one of the key drivers for the introduction of NIV Tagging. The current combination of NIV Tagging and SO Flagging in GB results in the most expensive balancing actions being netted off and excluded from price-setting, irrespective of whether those actions were identified as non-energy via CADL or SO constraint flagging earlier in the classification process.

PAR Tagging

PAR Tagging was introduced by modifications P194 and P205 in November 2006. This changed the imbalance price calculation from a pure volume-weighted average to a "chunky marginal" basis. The Price Average Reference (PAR) volume is currently set to 500 MWh. The GB imbalance price is calculated as the volume weighted average of the most expensive 500MWh of balancing actions remaining in the price stack after NIV Tagging. PAR Tagging forms the final step in the flagging and tagging process. There are proposals under consideration in GB to move to full marginal pricing, PAR will be reset to 1MWh.

8.5.1 FLAGGING AND TAGGING IN I-SEM

In considering the appropriate arrangements for imbalance pricing it is useful to look at the closest market operating a similar process. In this case, GB has been operating flagging and tagging for a number of years. It has worked there but there has been constant consideration of potential changes. Arguably then, potential drawbacks to this arrangement would be in relation to its complexity and transparency in implementation.

Further, the key potential drawback of a flagging and tagging methodology for I-SEM, is the risk that the majority of incremental offer and decremental bid acceptances in a settlement period are associated with non-energy actions, leaving a narrow subset of actions for imbalance price formation.

Specifically, the SEM is a more constrained system than GB, with the majority of operational plant required for reserve scheduling and / or associated with active transmission constraint groups. In GB, analysis published by Ofgem[22] as part of its Electricity Balancing Significant Code Review showed that, over a two year period,

[22] Ofgem, Electricity Balancing Significant Code Review: P217A Preliminary Analysis, August 2012 https://www.ofgem.gov.uk/ofgem-publications/40803/p217a-preliminary-analysis.pdf

28% of the volume of all balancing actions taken by the SO was flagged in the first stage of the methodology, the majority of this (27%), for transmission constraints. Of the actions flagged as non-energy, around half were subsequently identified as being “out of merit” (60% of flagged actions on the sell-side, 40% on the buy-side).

The proportion of actions flagged would be expected to be higher in the I-SEM than GB, given the greater prevalence of constraints on the all-island system and the potential requirement to flag more action types (e.g. reserve, inertia, SNSP) than are covered by the GB methodology.

In light of the above, there is the potential that a flagging and tagging approach could have insufficient energy actions taken to set an imbalance price. There are solutions to this; for example the next section puts forward an option which might be used as a back-up in the event that flagging and tagging didn’t achieve a price. However, were the back-up to be used on a regular basis it may call into question the suitability of the primary mechanism.

8.6 PRICE BASED METHOD - UNCONSTRAINED IMBALANCE PRICE STACK

Under the unconstrained imbalance price stack approach there are two key inputs to setting the imbalance price: the net imbalance volume and the stack of bids and offers available.

The net imbalance volume in this option would be determined as the difference between the total aggregate position of the market, expressed through FPNs, and the demand to be met by the TSOs in real time.

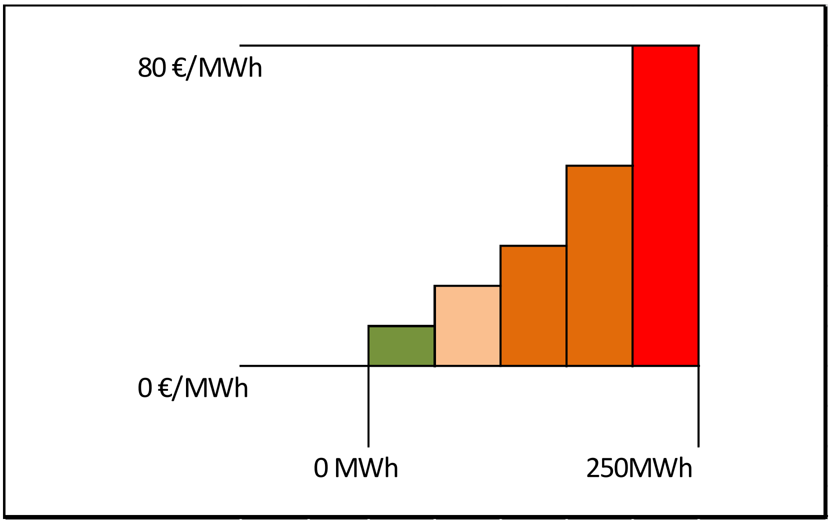
For example, if the total aggregate FPNs of the market were 4,000MWh for a settlement period and the demand across that settlement period was 4,200MWh, the net imbalance volume would be 200MWh and the market would be 200MWh short. The imbalance price would then be set by stacking up bids and offers in a merit order and selecting the bids and offers that provide 200MWh of energy at least cost.

This Consultation Paper sets out two potential options for how the price is set based on the simple stacks of bids and offers. The first option would simply stack up the bids and offers in ascending price order and set the imbalance price based on where supply meets demand without any consideration of whether the bids and offers are achievable in real time – a pure unconstrained stack approach.

The second option takes the same stack of bids and offers and but also considers the dynamics and technical offer data of the plant and whether it could actually have provided energy in real-time.

8.6.1 SIMPLE STACK

With this approach there would be a simple stack of the available bids and offers and the price would be set based on the net imbalance volume (NIV). The bids used would be the ones submitted at BM Gate Closure accompanying the FPNs. A simple illustration of this simple stack is set out below.



In the above example, a net imbalance volume of 250MWh would see an imbalance price of €80/MWh.

The simple stack option would not take into account the technical offer data of the plant in the BM. Consequently, plant in the stack might, in practice, not be able to meet actual imbalances. For example, if a unit was to have a very slow ramp rate then it might not be able to meet a rapidly changing imbalance. As a consequence, prices set using a stack of offers and bids not actually taken and ignoring the impact of dynamics could, as with PAR, and other parameters in tagging an flagging, say, dampen prices.

This option has many similarities to a Modification Proposal which was raised in the Balancing Market in GB in 2007. This was Modification Proposal P211 “Main imbalance price based on ex-post unconstrained schedule” which was submitted by

EDF Energy in 2007. P211 was raised by EDF as a way of establishing an energy imbalance price which would not take into account system actions.

Ofgem gave significant consideration to Modification Proposal but ultimately rejected it with a preference given to the alternative approach of incremental changes to the existing flagging and tagging process (notably the inclusion of SO constraint flagging) that was developed – Mod 217. Nevertheless, from the documentation published it would appear that Ofgem saw considerable merit in the proposal. There is significant background material on Mod P211 available on the Ofgem and Elexon websites and readers of this Consultation Paper are encouraged to consider this background material.

It would appear that one of the main reasons that Ofgem rejected the proposal was in relation to the cost reflectivity of the prices that would be established as a result of its implementation. The rationale for this is set out in the rejection decision[23]. In particular the concerns seemed to have focused on the following features of the proposed approach, notably that it:

- ignored plant dynamics in the price calculation; and
- ignored reserve creation bid-offer acceptances.

The lack of plant dynamics in the price calculation is discussed above. The references to reserve creation actions appear to be in relation to actions taken by the TSO before Gate Closure to ensure a balanced energy market which would not be taken into account by P211. In particular these referred to BM Start-up, Short Term Operating Reserve (STOR) and reserve creation BOAs. Given that these actions would likely be taken by the TSO before the energy price calculation took place (i.e. before the trading period in question) they would not be referenced in the price calculation. Finally, it would appear that a principle in the GB Balancing Market is to use actual actions taken to set cash-out prices. Otherwise there still remain concerns around manipulation and the ability of the arrangements to be able to send messages to the market that participants can respond to. This approach of pricing on the basis of actual actions taken is not one that is a feature of the current SEM which employs a full ex-post unconstrained schedule. Consequently, the principle that only actions actually taken can set the price is not necessarily enshrined in the all-island market.

[23] https://www.ofgem.gov.uk/ofgem-publications/40591/p217-revised-tagging-process-and-calculation-cash-out-prices.pdf

This option is not a full ex-post unconstrained schedule. It solely involves an ex-post calculation to calculate the price. It does not attribute unconstrained quantities to plant that don't run. It could therefore be the case that the plant setting the price may not have any physical position.

The SEM Committee is of the view that there is potential merit in this option. In particular allowing the balancing energy price to be determined on the basis of bids and offers that could have been used to achieve energy balancing would eliminate the need to carry out detailed identification of the reasons for each action taken by the TSOs – which is a characteristic of the flagging and tagging approach.

However, some of the issues identified in GB with the similar proposal, P211, would also apply in I-SEM. In particular, not taking account of plant dynamics in the simple stack could result in unintended consequences such as bids setting the price that could not have delivered balancing energy as a result of its technical characteristics. In addition, the simple stack on its own would not reflect or take into account any energy actions taken by the TSOs before Balancing Market gate closure i.e. one hour ahead.

Although the principle of the I-SEM HLD is that participants should trade into energy balance there may in practice, especially in the early days of I-SEM, be a requirement for the TSOs to take actions before gate closure. This could conceivably happen in the latter stages of the IDM where, say, four parties are short but the next available action is greater than the amount any one of them needs as it results in a plant with a high minimum stable generation starting. In such cases the TSOs may need to intervene to start the plant. More sophisticated products in the IDM, more flexible generation sets or intraday auctions could address this but it is prudent to allow for this in the design of the balancing arrangements.

While this option is not considered to be suitable as a first choice option for Balancing Market pricing it has potential to be used as a back-up to some of the other options under consideration. Specifically, if a flagging and tagging approach was adopted, then there could be instances in which there were no BM actions in a settlement period as all actions were tagged as non-energy. Under such circumstances, a fallback pricing approach should be required, and the simple unconstrained stack could be an appropriate approach.

8.6.2 UNCONSTRAINED STACK WITH PLANT DYNAMICS INCLUDED

This option is a refinement of the simple stack. In particular, this option would seek to address some of the perceived shortcomings of the simple stack. There are two key inclusions that this option would have over the simple stack:

- Plant dynamics
- An optimisation time horizon

The inclusion of plant dynamics in the pricing calculation would mean that the Technical Offer Data (TOD) of the plant submitted to the TSOs in the BM feeds into the price setting calculation. This happens in the current SEM today where both Commercial Offer Data (COD) and TOD are considered in the pricing engine. The precise nature of the TOD to be included would need to be determined.

The time horizon would allow for the price to be set taking into account more than the last trading period. For example, the previous option would look at each trading period in isolation and set the price based on the bids, offers and net imbalance volume. Using an optimisation time horizon would allow more than one trading periods to be considered.

The length of the time horizon would be a key consideration. It could be anywhere from one trading period out to the entire 24 hour trading day.

The addition of plant dynamics and an optimisation time horizon should see this option becoming a much more robust option than the previous option. As with the simple stack it would eliminate the need to carry out detailed identification of the reasons for each action taken by the TSOs. It would build on the simple stack through also addressing a number of the concerns Ofgem when rejecting P211, the simple stack approach. In particular, the plant dynamics would ensure that only actions that could actually respond would be considered in pricing and the optimisation time horizon would ensure that where energy actions are taken before the balancing energy gate closure, they are taken into account in pricing.

The complexity of the pricing stack algorithm would depend on the dynamics taken into account and the length of the time horizon. It is likely that it would include at least the following:

- Net Imbalance Volume for each trading period
- FPN from each unit for each trading period

- Incremental and decremental bid for each trading period (including start-costs as appropriate)
- Availability for each unit for each trading period
- Ramp Rate, Minimum Stable Level, Minimum On Time, etc.

There would be a number of material issues to consider with this option as part of the implementation phase, including the optimisation time horizon.

The SEM Committee sees merit in this option, and in particular believes it to be a more robust solution than the simple stack approach. The SEM Committee believes that it addresses the limitations of the simple stack approach, specifically the disconnect between the price set, and ability of units in the price stack to be dispatched up or down to meet energy imbalances in an unconstrained system. As with the simple stack, any algorithm that would be used to set the energy imbalance price would not give volumes and revenue streams to plant that are not running in the trading period.

This option has the significant attribute of not requiring a detailed process for the identification of energy and non-energy actions in each trading period. In a system with high levels of constraints like SEM, this is a material practical consideration. There would, however, be a requirement to develop the required algorithm.

8.7 PRICE BASED METHOD - UNCONSTRAINED UNIT FROM THE ACTUAL DISPATCH

This is a price based methodology for distinguishing between energy and non-energy actions but shares a number of characteristics with the cause based flagging and tagging method. With this approach and in comparison with the previous unconstrained stack approaches, the imbalance pricing algorithm would calculate the marginal price of the unconstrained energy balancing action from the actual dispatch stack.

This approach would take as inputs:

- unit offers;
- unit physical characteristics e.g. minimum stable generation;
- unit final physical notification and bid-offer acceptances;
- unit and load real-time MW from state estimator / SCADA; and,
- operational requirements e.g. operating reserve, SNSP, etc.

The imbalance pricing algorithm would then use a standard linear programming approach to calculate the marginal price of the unconstrained energy balancing action for a period. The standard period for this price calculation in other markets (e.g. PJM, MISO, ISO-NE in US and NEM in Australia) is anything from 5 minutes to 30 minutes with the resulting imbalance price being an average of these prices across the imbalance settlement period.

Units in the actual dispatch that are bound by a non-energy system constraint (e.g. primary operating reserve) cannot set the price in this schedule as their output is not available to be changed in the optimisation to meet the marginal unit of balancing energy required, or they are not the next economic unit to meet this requirement. This essentially removes binding non-energy actions from the pricing calculation.

Units in the actual dispatch that are contributing to a non-binding non-energy requirement (e.g. primary operating reserve) are still available to set the imbalance price. If a non-energy requirement such as operating reserve is not binding i.e. there is more reserve on the system than required, then units providing this reserve are still capable of providing the unconstrained balancing action and are therefore available to set the marginal price.

This essentially includes plant dynamics in the pricing calculation without the need for multiple hour optimisation horizons. The reason for this is that the actual dispatch already takes plant dynamics and the only additional dynamics that need to be captured are those which are applicable over the pricing period e.g. five minutes. This greatly reduces the complexity of pricing calculation.

This approach has a number of potential advantages:

- This process should be straightforward to implement as it is based on well-established market pricing methodologies that are used throughout the world for calculating imbalance prices and leverages systems that are required anyway for the purposes of system operations.

- This option does not require a detailed process for the identification of non-energy actions in each trading period without explicitly excluding them. In a system with high levels of constraints like SEM, this is a material practical consideration. It successfully prevents units which are meeting binding non-energy requirements from setting the price, while allowing those which are meeting non-energy requirements but are not bound by them to set the price, avoiding the issue of over-tagging of units such that there are no units available to set the imbalance price.

- With this approach, the price can potentially be published closer to real time if required, which may facilitate greater demand side participation and innovation in the retail market.

However, there are potential disadvantages.

- Calculating the marginal price of the unconstrained energy balancing action from the actual dispatch may be regarded as including system constraints in the pricing methodology. However, the outcome here would not be dissimilar to a flagging and tagging approach where non-energy actions are removed from the pricing stack

- While the price calculation methodology would be transparent, prices calculated based on optimisations can be non-intuitive and this may lead to the pricing engine being viewed as a "black box".

8.8 THE MARGINAL IMBALANCE PRICE

As per the I-SEM HLD Decision, the market will employ a single marginal imbalance price. In any given settlement period, market participants with a long position in imbalance settlement will receive the same imbalance price as is paid by market participants who are short.

In the response paper that accompanied the HLD Decision the SEM Committee stated that further consideration would be given to the setting of the imbalance price in the detailed design. In particular, the SEM Committee stated:

"The detailed definition of the marginal bid and offer used to set the imbalance price in each settlement period will be an important issue to be addressed in the detailed design phase. The issues to be considered include, but are not limited to:

- *the duration of bid and offer acceptance required to be the marginal bid or offer – i.e. the treatment of energy balancing actions shorter than the imbalance settlement period.*
- *the volume of bids and offers defined as being the marginal amount;*

- *the granularity of metering; and*
- *the process for separating energy balancing bids from system balancing bids (as discussed in more detail above)".*

A number of attendees at the pre-consultation RLG meetings suggested that the I-SEM HLD Decision had left some room for interpretation for how the marginal price would be calculated. In particular, some attendees suggested that an averaging across the last number of MWhs to calculate the price should be considered. In GB, for example, the imbalance price is calculated as the average price of the last 500MWhs, in a process known as Price Average Referencing (PAR).

The SEM Committee remains of the view that a marginal imbalance price is the most appropriate framework I-SEM and set out the following in the HLD Decision Response Paper:

"The use of a clearing price for energy balancing gives incentives for participants to bid at their own marginal cost. It improves access for small market participants who under alternative arrangements would be at a disadvantage, and provides a single reference price for energy balancing actions."

However, the SEM Committee wishes to understand this issue further. In particular, the SEM Committee is seeking to understand whether the key concern is of the potential for transitional issues when moving between SEM and I-SEM or whether there is a more fundamental belief that a PAR is needed, and if so why?

In practice all the pricing options put forward in this paper would incorporate some level of averaging of the marginal price. For example the flagging and tagging would likely eliminate very short duration actions and/or actions below a de-minimis volume from the price setting calculation. Similarly, with the unconstrained stack options some short actions taken by the TSOs for a proportion of the trading period could be excluded from the price calculation unless the net imbalance volume suggests it needed that action from the pricing stack to set the price.

As set out above and in the I-SEM HLD Decision, the SEM Committee believes that there could be the potential for unintended consequences and a distortion of signals across the markets if any significant averaging (above what’s inherent in the pricing) were to take place. It is likely that such averaging could dampen imbalance prices. If the imbalance price were overly dampened there could be a knock on impact for the DAM and IDM by reducing liquidity in these ex-ante markets, which is very important. For example, it could be that a participant that is expecting to be short would not act in the IDM in the expectation that the price will be lower in the BM due to averaging.

Further comment is sought on this issue from respondents on whether the concerns expressed by participants regarding sharper marginal prices for imbalance pricing relate primarily to the transition between the SEM and I-SEM, or whether there are other, broader concerns.

8.9 IMBALANCE PRICING AND THE ELECTRICITY BALANCING NETWORK CODE

Another issue that needs to be considered is the interaction of the pricing in the I-SEM BM and what will emerge as part of the implementation of the EU Network Code on Electricity Balancing. The Network Code is still under development by ENTSOE and ACER but at a high level it is expected that there will be a TSO-TSO model in place for sharing of balancing bids and offers after balancing gate closure.

The precise format of how the interactions between BMs will work is not yet established with the EBNC allowing some time before the TSOs are required to make proposals on issues such as the key principles of imbalance pricing.

At this stage, it would appear that the I-SEM BM design will be compatible with the emerging EBNC, noting that the EBNC references marginal pricing which is a proposed feature of the I-SEM BM. In addition, there a number of early implementation projects that will be established as part of the EBNC process. The Project TERRE, which will share energy from replacement reserves, will be of interest to I-SEM and National Grid in GB is involved in it. This project is already being established and should be in place before I-SEM Go-Live. Feedback from this implementation project will assist in developing I-SEM arrangements which will be robust to further changes down the line.

8.10 SUMMARY

The SEM Committee has put forward a number of options for setting the imbalance price and described a number of potential advantages and disadvantages of each approach.

Comments are sought from respondents on the merits of the approaches put forward and a view on the most appropriate methodology. **Specifically, comments are sought on each of the following options:**

1. **The Tagging and Flagging Approach. A "cause" based method for identifying energy and non-energy actions with the imbalance price being set only on energy actions.**

2. **Simple Stack. With this approach there would be a simple stack of the available bids and offers and the price would be set based on the net imbalance volume.**

3. **Unconstrained Stack with Plant Dynamics Included. There are two key additions that this option would have over the simple stack:**
    - **Plant Dynamics**
    - **An Optimisation Time Horizon.**

4. **Price Based Method - Unconstrained Unit from the actual dispatch. A price based methodology for distinguishing between energy and non-energy actions but shares a number of characteristics with the cause based flagging and tagging method.**

The SEM Committee is also seeking comment on whether the key concern is of the potential for transitional issues when moving between SEM and I-SEM or whether there is a more fundamental belief that a PAR is needed, and if so why?

Comment is also sought on whether the concerns expressed by participants regarding sharper marginal prices for imbalance pricing relate primarily to the transition between the SEM and I-SEM, or whether there are other, broader concerns.

9 IMBALANCE SETTLEMENT

9.1 INTRODUCTION

Imbalance Settlement is the process which settles, for each Imbalance Settlement Period (ISP):

- The differences between:
    - the quantity of electricity that a participant has contracted to produce or consume in the ex-ante markets (adjusted for any incremental offers and/or decremental bids accepted by the TSOs in the Balancing Market); and
    - the quantity of electricity that the participant actually produced or consumed.

- The incremental offers and decremental bids accepted by the TSOs in the Balancing Market.

Imbalance Settlement must ensure that participants get paid the correct amounts for electricity quantities that they produce and pay the correct amounts for electricity quantities that they consume.

The I-SEM HLD states that all market participants in I-SEM shall be balance responsible and that imbalance settlement will be at the unit level for generation, with possible exemptions for certain renewables, and for dispatchable demand.

Incremental offers and decremental bids that are accepted by the TSOs in the Balancing Market can be considered as contracts with the TSOs to produce and consume electricity respectively. Therefore, in the simplest terms, it can be said that Imbalance Settlement must ensure that a unit's un-contracted electricity quantity, being its total metered electricity production or consumption minus its total contracted electricity production or consumption, must be sold or bought at the imbalance price.

Participants may produce more or less energy than they have sold in the ex-ante markets, and may consume more or less energy than they have purchased, in any given settlement period. In such circumstances, these units are regarded as having 'an imbalance' and the quantities of energy produced or consumed and not covered by contracts (the 'energy imbalances') can be regarded as having been sold or bought to or from the Transmission System.

The imbalance price shall be calculated for each settlement period and used to settle or 'cash-out' these un-contracted quantities. The I-SEM HLD states that there shall be a single imbalance price in I-SEM, meaning that long and short energy imbalances will be settled at the same price for an Imbalance Settlement Period. The I-SEM HLD also states that the imbalance price shall be a marginal price based on unconstrained energy balancing actions. Imbalance pricing is discussed in Section 8.

The ETA Building Blocks Consultation Paper introduced a proposal for the settlement of non-energy actions. This proposal is as follows:

- A unit that is 'constrained down' due to a dispatch instruction from the TSOs pays back the lower of its decremental bid price or the imbalance price; and
- A unit that is 'constrained up' due to a dispatch instruction from the TSOs receives the higher of its incremental offer price or the imbalance price.

This proposal will mean that a unit is not financially worse off for having followed a dispatch instruction from the TSOs and having solved a constraint.

The remainder of this chapter is separated into the following sections:

- Settlement of Imbalances and Accepted Offers/Bids
- Settlement of Imbalances and Accepted Offers/Bids Taking Account of PNs and Firm Access
- Settlement of Curtailment
- Settlement of Priority Dispatch Units When Constrained Down
- Treatment of Uninstructed Imbalances
- Interaction Between the Balancing Market and the Intraday Market
- Settlement of Multiple Acceptances
- Quarter-Hourly vs Half-Hourly vs Hourly Settlement

9.2 SETTLEMENT OF IMBALANCES AND ACCEPTED OFFERS/BIDS

Participants' total cashflows for energy in the I-SEM Energy Trading Arrangements (ETA) will comprise three main elements:

1) cashflows arising from sales and purchases in the ex-ante markets (the Day Ahead Market and the Intraday Market);
2) cashflows arising from the energy imbalances, i.e. the differences between their metered quantities and their ex-ante sales and purchases; and
3) cashflows arising from the acceptance by the TSOs of incremental offers and/or decremental bids.

As the I-SEM HLD requires that participants are settled on a unit-basis the participant cashflows are of the form:

$$\begin{aligned} C_{ij} = \; & PEX_{ij}.QEX_{ij} \\ & + PIMB_j.(QM_{ij} - QBOA_{ij} - QEX_{ij}) \\ & + PBO_{ij}.QBOA_{ij} \end{aligned} \qquad (9.1)$$

where C_{ij} is the cashflow in respect of unit i in a period j;

PEX_{ij} is the price of ex-ante trades in respect of unit I in period j;

QEX_{ij} is the quantity of ex-ante trades in respect of unit I in period j;

$PIMB_j$ is the imbalance price in period j;

QM_{ij} is the metered quantities in respect of unit i in period j;

$QBOA_{ij}$ is the quantity of incremental offers and decremental bids accepted from unit i in period j; and

PBO_{ij} is the price associated with the accepted offers and bids for unit i in period j,

The three terms of equation 9.1 correspond with the three elements (1), (2), and (3) described above.

As the I-SEM HLD further requires that marginal pricing is used for unconstrained energy balancing actions and pay-as-bid is used for non-energy actions it is proposed, as discussed in the ETA Building Blocks Consultation Paper, that for all balancing actions:

- in the case of incremental offers participants are paid at the maximum of the offer price and the imbalance price; and,

- in the case of decremental bids participants pay back at the minimum of the imbalance price and the bid price.

The rationale for this approach is that any incremental offer with a price lower than the imbalance price and any decremental bid with a price higher than the imbalance price are "in merit" and would have been called by the TSOs to resolve any energy imbalance, notwithstanding the fact that they may have also resolved "non-energy" issues. This approach will mean that a participant is not financially worse off for having followed a dispatch instruction from the TSOs and having solved a "non-energy" issue.

The cashflow for the acceptance of an incremental offer thus becomes $max(P_{BO_{ij}}, P_{IMB_{ij}}).Q_{BOA_{ij}}$ and the cashflow for the acceptance of a decremental bid thus becomes $min(P_{BO_{ij}}, P_{IMB_j}).Q_{BOA_{ij}}$. The equation for the total cashflow can then be rearranged to become:

$$
\begin{aligned}
C_{ij} = \; & P_{EX_{ij}}.Q_{EX_{ij}} \\
& + P_{IMB_j}.(Q_{M_{ij}} - Q_{EX_{ij}}) \\
& + max(P_{BO_{ij}} - P_{IMB_j}, 0).max(Q_{BOA_{ij}}, 0) + min(P_{BO_{ij}} - P_{IMB_j}, 0).min(Q_{BOA_{ij}}, 0)
\end{aligned}
\tag{9.2}
$$

where:

(1) $P_{EX_{ij}}.Q_{EX_{ij}}$ is, as in (9.1), the cashflow in respect of the sales/purchases in the ex-ante markets, i.e. the Day Ahead Market and Intraday Market;

(2) $P_{IMB_j}.(Q_{M_{ij}} - Q_{EX_{ij}})$ is the imbalance price multiplied by the entire difference between the metered quantity and the ex-ante sales/purchases, now including any accepted incremental offers and decremental bids.

As $max(Q_{BOA_{ij}}, 0)$ is non-zero (and, specifically, positive) only for accepted incremental offers and $min(Q_{BOA_{ij}}, 0)$ is non-zero (and, specifically, negative) only for accepted decremental bids it therefore follows that:

(3a) $max(P_{BO_{ij}} - P_{IMB_j}, 0).max(Q_{BOA_{ij}}, 0)$ is a *premium* paid over and above the imbalance price on any incremental offer that is a "non-energy" action, i.e. any incremental offer acceptance for which the offer price is higher than the imbalance price; and

(3b) $min(P_{BO_{ij}} - P_{IMB_j}, 0).min(Q_{BOA_{ij}}, 0)$ is a *discount* on the amount paid back by the participant in respect of any decremental bid that is a "non-energy" action, i.e. any bid acceptance for which the bid price is lower than the imbalance price. Note that, given $QBOA_{ij}$ for a bid will be negative, this term, like the premium in (3a) above, will be a payment to the participant, being a refund of the discount on the bid acceptance quantity.

For “energy” actions, i.e. incremental offer acceptances for which the offer price is lower than the imbalance price or decremental bid acceptances for which the bid price is higher than the imbalance price, the bid-offer acceptance is paid at the imbalance price. Thus, for these energy actions, the premium or discount, as the case may be, is zero and the bid-offer acceptance is paid for in full through the imbalance term, $PIMB_j.(QM_{ij} – QEX_{ij})$.

Note that the imbalance is split into:

a) a “notified imbalance”, being the difference between the FPN and the ex-ante contracted quantities; and
b) an “un-notified imbalance” or “uninstructed imbalance”, being the difference between the metered quantity and the FPN (adjusted for any accepted offers and bids).

Notwithstanding this, the imbalance price, PIMB, is paid on the full difference between the metered quantity, QM, and the ex-ante market quantity, QEX, i.e. including not only the imbalance quantities but also the offer and bid acceptance quantities, with the offer premium payable on only the difference between the bid-offer acceptance and the FPN (this is discussed in more detail in the next section).

9.3 SETTLEMENT OF IMBALANCES AND ACCEPTED OFFERS/BIDS TAKING ACCOUNT OF PHYSICAL NOTIFICATIONS AND FIRM ACCESS

In addition to the metered quantity, QM, the ex-ante contracted quantity, QEX, and the bid-offer acceptance quantity, QBOA, settlement needs to take account of:

$QFPN_{ij}$ being the MWh quantity corresponding to the FPN in respect of unit i for the settlement period j;

QFA_{ij} being the MWh quantity corresponding to the Firm Access Quantity in respect of unit i for the settlement period j; and

QD_{ij} being the MWh quantity corresponding to the dispatch instruction issued by the TSO in respect of unit i for the settlement period j.

The ETA Building Blocks Consultation Paper discussed the treatment of Firm Access and responses to said consultation will influence the details of the settlement of these quantities. Nevertheless, these quantities will affect the quantity on which the bid-offer premium/discount is payable.

In particular, for incremental offers:

(G1) if the metered quantity, Q_M, is less than the dispatch quantity, Q_D, implying that the offer acceptance has not been fully delivered, then the premium is not paid on the full dispatch quantity. In the general, the premium is paid on the *minimum* of Q_M and Q_D;

(G2) the participant should not be able to increase the quantity on which the premium is paid by biasing its FPN to be *below* its ex-ante traded quantity, Q_{EX}. In the general case, the premium should be paid on the basis of the *maximum* of Q_{FPN} and Q_{EX}. Where Q_{FPN} is greater than Q_{EX} and an incremental offer is accepted then the difference between Q_{FPN} and Q_{EX} is settled at the imbalance price; and

(G3) the Firm Access Quantity, Q_{FA}, is irrelevant, as if a unit is dispatched above its FAQ into its non-firm region then its FAQ is not binding.

And for decremental bids:

(G4) if the metered quantity, Q_M, is more than the dispatch quantity, Q_D, implying that the bid acceptance has not been fully delivered, then the discount is not paid on the full dispatch quantity. In the general case, the discount is paid on the *maximum* of Q_M and Q_D;

(G5) the participant should not be able to increase the quantity on which the discount is paid by biasing its FPN to be *above* its ex-ante traded quantity, Q_{EX}. In the general case, the discount should be paid on the *minimum* of Q_{FPN} and Q_{EX}. Where Q_{FPN} is less than Q_{EX} and a decremental bid is accepted then the difference between Q_{FPN} and Q_{EX} is settled at the imbalance price; and

(G6) the discount should not be earned on quantities above the Firm Access Quantity, Q_{FA}. In the general case, the discount should be paid on the *minimum* of Q_{FA}, Q_{FPN} and Q_{EX}.

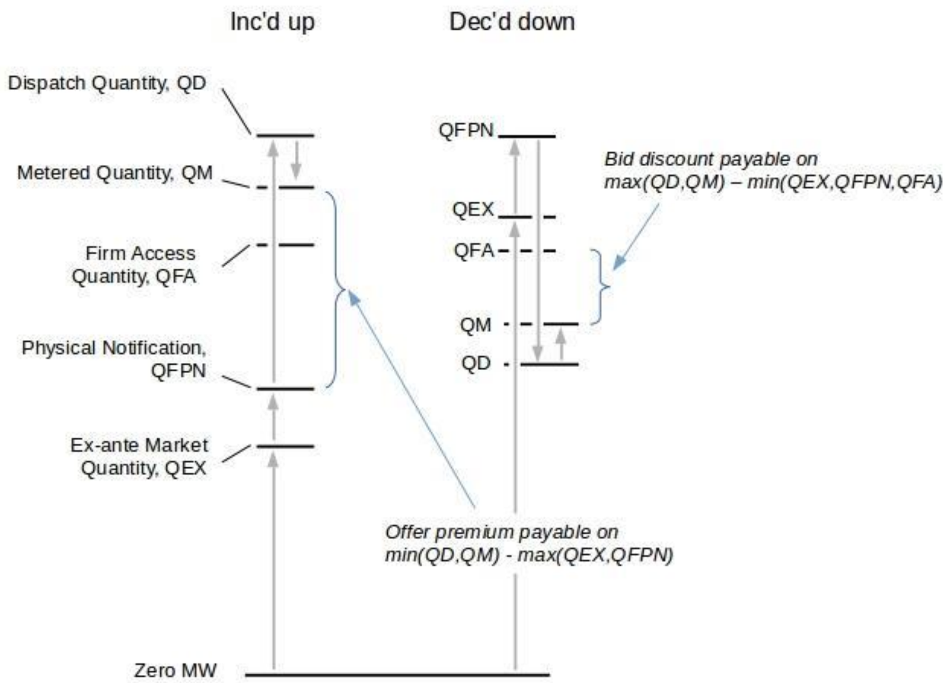


Figure 9.1 Premiums and discounts payable to generators

Thus, for incremental offers, the total cashflow is given by:

$$\begin{aligned} C_{ij} \;=\; & PEX_{ij}.QEX_{ij} \\ & + PIMB_{j}.(QM_{ij} - QEX_{ij}) \\ & + \mathit{max}(PBO_{ij} - PIMB_{j}, 0).\mathit{max}(\mathit{min}(QM_{ij}, QD_{ij}) - \mathit{max}(QFPN_{ij}, QEX_{ij}), 0) \end{aligned} \tag{9.3a}$$

And for decremental bids the total cashflow is given by:

$$\begin{aligned} C_{ij} \;=\; & PEX_{ij}.QEX_{ij} \\ & + PIMB_{j}.(QM_{ij} - QEX_{ij}) \\ & + \mathit{min}(PBO_{ij} - PIMB_{j}, 0).\mathit{min}(\mathit{max}(QM_{ij}, QD_{ij}) - \mathit{min}(QFPN_{ij}, QFA_{ij}, QEX_{ij}), 0) \end{aligned} \tag{9.3b}$$

On the demand-side, participants with dispatchable demand can purchase electricity in the ex-ante markets and may be able to sell it back to the TSOs (i.e. reduce demand) in the form of an accepted incremental offer in the Balancing Market. Demand-side participants may also buy additional electricity (i.e. increase demand) in the form of an accepted decremental bid in the Balancing Market.

Thus, for incremental offers on the demand-side:

(D1) As for generation incremental offers, an offer acceptance will not have been fully delivered if the metered quantity, Q_M (a negative quantity for demand), is less (i.e. more negative) than the dispatch quantity, Q_D (which will also be a negative quantity). Thus, as with generation incremental offers, the quantity that the premium is paid on should be based on the minimum of the Q_M and Q_D;

(D2) As for generation incremental offers, the participant should not be able to increase the quantity on which the premium is paid by biasing its FPN to be more negative than the ex-ante traded quantity, Q_{EX}. In the general case, the premium should be paid on the basis of the maximum of Q_{FPN} and Q_{EX}; and

(D3) In principle, Firm Access Quantities could be defined for the demand-side, as they are for generation. Q_{FA} would be a negative quantity representing the most negative Q_M that would be guaranteed[24], such that the premium on an accepted offer would be limited to the maximum of Q_{FA} and Q_{FPN}.

24 For a generation unit, FAQ is the maximum, i.e. most positive, metered value that is guaranteed, inasmuch as compensation is paid (through constrained-off payments in the current SEM or, in I-SEM, by accepting a decremental bid). However, for a demand-side unit, FAQ, were it defined, would be the most negative, i.e. minimum, metered value that were so guaranteed.

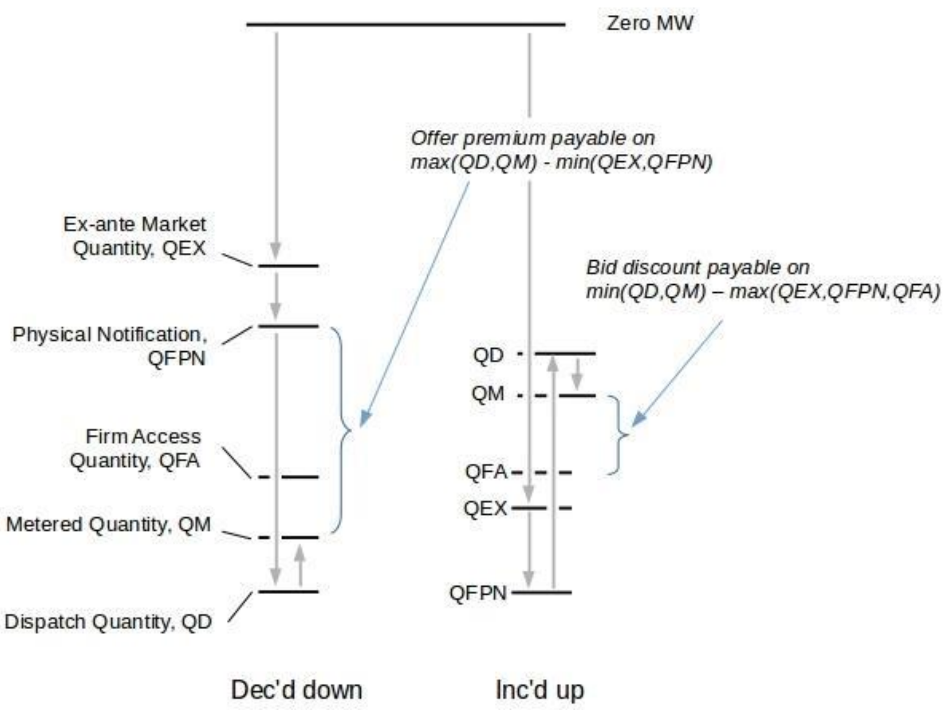


Figure 9.2 Premiums and discounts payable to dispatchable demand

And for decremental bids from demand-side:

(D4) As for generation decremental bids, a bid acceptance will not have been fully delivered by a demand-side participant if the metered quantity, Q_M, is more positive than the dispatch quantity, Q_D. Thus, the discount should be paid on the *maximum* of the two; and

(D5) As for generation decremental bids, the demand-side participants should not be able to increase the quantity on which the discount is paid by biasing its FPN to be more positive than the ex-ante contracted quantity. In the general case, the discount should be paid on the *minimum* of Q_{FPN} and Q_{EX}.

Thus, for the demand-side, the equations are the same, except in respect of Firm Access Quantity, Q_{FA}, i.e. for demand-side incremental offers:

$$C_{ij} = P_{EX_{ij}}.Q_{EX_{ij}}$$
$$+ P_{IMB_j}.(Q_{M_{ij}} - Q_{EX_{ij}})$$
$$+ max(P_{BO_{ij}} - P_{IMB_j}, 0).max(min(Q_{M_{ij}}, Q_{D_{ij}}) - max(Q_{FPN_{ij}}, Q_{FA_{ij}}, Q_{EX_{ij}}), 0) \quad (9.4a)$$

And for demand-side decremental bids:

$$C_{ij} = PEX_{ij}.QEX_{ij} + PIMB_j.(QM_{ij} - QEX_{ij}) + min(PBO_{ij} - PIMB_j, 0).min(max(QM_{ij}, QD_{ij}) - min(QFPN_{ij}, QEX_{ij}), 0) \quad (9.4b)$$

However, currently there is no proposal to introduce the concept of firm access for demand-side participants, and hence the same equations, (9.3a) and (9.3b), will work for both generation and demand-side, albeit with QFA undefined for the demand-side.

9.4 SETTLEMENT OF CURTAILMENT

Curtailment occurs when there is more wind generation available, in total, than can be accommodated on the system due to, for example, the System Non-Synchronous Penetration (SNSP) limit. In these situations the TSO dispatches down a proportion of all wind generation in order to maintain total system security.

There is currently no distinction between actions taken to relieve constraints and those taken for curtailment, in terms of settlement in SEM, with all curtailment actions being settled in the same manner as constraint actions. However, the SEM Committee provided clarity on curtailment policy in the Decision Paper SEM-13-010:

- curtailment will be applied pro-rata on all wind generation in the market;
- the TSOs will apply a rule set for distinguishing between constraints and curtailment; and
- from 2018 onwards, wind generation will not be compensated when it is curtailed.

The I-SEM ETA Building Blocks Consultation Paper discussed options for how this decision on curtailment compensation could be implemented in I-SEM from 1 January 2018. Three options were outlined and they are discussed again below in the context of their possible consequences for settlement.

1) Mandated Bidding Behaviour

Under this option wind generators would be required to submit a decremental bid price into the Balancing Market based on their revenues from the ex-ante markets. All curtailment would be treated as an out-of-merit dispatch instruction by the TSOs, and hence settled at the decremental price submitted.

This option would probably be dealt with through the introduction of a “deemed decremental bid” for curtailed wind in the central settlement systems, as it would be burdensome for the generator to have processes to calculate the appropriate decremental bid price, and for the relevant authorities to monitor.

A “deemed decremental bid” in respect of unit i in period j would have the same price as the price of ex-ante trades in respect of unit i in period j, $PEX_{ij.}$ The bid would not be price-setting in the Balancing Market and would not affect the TSOs’ dispatch of wind. The curtailed wind generator would be paying back this price for its curtailed volume regardless of whether this was higher or lower than the imbalance price, $PIMB_{ij}$.

2) Cash Out and Post Processing

Under this option deviations from DAM and IDM trades of wind generation in the imbalance market during a curtailment event would be settled in the same way as any other generation deviation is settled. Any decremental bid submitted by a wind generator that was curtailed would be ignored in the setting of the imbalance price.

Generators without ex-ante market transactions would be paid the imbalance price for their metered generation output, which by definition is net of curtailment. Hence, they would not receive any compensation for the amount of output that was curtailed, and no further settlement rules would be required.

A process for post processing of generator revenues would then take place. This would take into account the net revenues earned on curtailed volumes by wind generators who did have ex-ante trades.

In the event that the price of ex-ante trades in respect of unit i in period j, PEX_{ij}, was higher than the imbalance price in period j, $PIMB_j$, when unit i was curtailed then this extra revenue would be “clawed back”.

In the event that the price of ex-ante trades in respect of unit i in period j, PEX_{ij}, was lower than the imbalance price in period j, $PIMB_j$, when unit i was curtailed then the unit would be “made whole” for the difference.

3) Settled with no special rules for curtailment

Under this option deviations from DAM and IDM trades of wind generation in the imbalance market during a curtailment event would be settled in the same way as any other generation deviation is settled. Any decremental bid submitted by a wind generator that was curtailed would be ignored in the setting of the imbalance price.

Generators without ex-ante market transactions would be paid the imbalance price for their metered generation output, which by definition is net of curtailment. Hence, they would not receive any compensation for the amount of output that was curtailed, and no further settlement rules would be required.

9.5 SETTLEMENT OF PRIORITY DISPATCH UNITS WHEN CONSTRAINED DOWN

The I-SEM ETA Building Blocks Consultation Paper proposed that a unit with priority dispatch could become ‘price making’ for part of its output if it so wished and could:

- submit a PN, based on its expected output, to the TSOs. This PN would have Priority Dispatch status; and
- submit incremental offers and decremental bids to the Balancing Market reflecting the prices at which it is willing to deviate from its PN.

As the PNs submitted by Priority Dispatch units under this proposal would have Priority Dispatch status, there is an argument that the discount of the decremental bid price on the imbalance price should be paid on the FPN rather than on the minimum of the FPN and the ex-ante traded quantity.

However consideration must be given to the range of decremental bid prices that would be allowed if this were to be implemented. It is unlikely, for example, that Variable RES units with Priority Dispatch would be permitted to submit negative decremental bid prices. A “deemed decremental bid” with a price of zero could be used in this case.

Settlement of Variable RES when Constrained Down Without a Physical Notification

As set out in Section 4 there appears to be merit in allowing variable RES generators to choose not to submit PNs if they so wish.

Under this proposal a variable RES generator that wishes not to submit PNs would be dispatched to its availability (forecast of wind output) as far as possible by the TSOs, and would be out of balance for any un-contracted quantities (i.e. quantities that were not covered by ex-ante trades).

The question then arises as to whether a variable RES generator that is not submitting PNs should be able to submit decremental bids to the Balancing Market (incremental offers would be redundant as the TSOs will be dispatching the unit to its availability as far as possible). It is likely that such units would not be submitting decremental bids and that a “deemed decremental bid” with a price of zero would be used instead.

In their response to the I-SEM ETA Building Blocks Consultation Paper, EirGrid provided a useful explanation of how variable RES generators are controlled by the TSOs as part of systems operations. The main characteristics of the process are as follows:

- Normally wind units generate to their available level without being issued a dispatch instruction but may be required to “dispatch-down” for reasons of curtailment and constraint;

- Dispatch-down of windfarms is achieved by remote control initiated from the control centres when the TSO sends a maximum MW setpoint to (automated) wind farm control units as most windfarms are not staffed to accept dispatch instructions and control output accordingly; and

- In curtailment events setpoints are issued (simultaneously) to all controllable windfarms, and in constraint events to relevant subsets of windfarms. The TSOs only currently deal with a small number of groups of windfarms based on specific categories, rather than each of the numerous windfarms individually.

Price is not currently taken into account in the dispatch of wind. Therefore a whole new economic dispatch tool for dispatching-down wind would be required by the TSOs if wind units were to submit FPNs and decremental bid prices. The wind farms themselves would also need staff and systems at each unit in order to hold each unit at its FPN and respond to dispatch instructions from the TSOs when decremental bids were accepted.

In light of this it is considered very likely that a solely price-taker option will be required for I-SEM.

This could be achieved by the TSOs dispatching the unit up to its availability where possible. As the unit would not be submitting any decremental bid prices then in the event where it was constrained down it would pay back:

a) a “deemed decremental bid” price of zero when constrained down within its firm access quantity; and
b) the imbalance price when constrained down within its non-firm access region.

Where the unit’s actual dispatch was greater than its ex-ante traded quantity it would be settled at the imbalance price for the difference.

9.6 TREATMENT OF UNINSTRUCTED IMBALANCES

This section discusses whether additional consideration is needed for units that have uninstructed imbalances, on top of being out-of-balance.

Firstly, it needs to be understood whether there is an additional cost to the TSOs of participants not following their dispatch instructions. For example, there is likely a cost of a generator generating at full output having been instructed to operate at their minimum generation. In such an instance, the TSOs would need to reconfigure the system in real time to address the additional energy.

The current SEM addresses this through the Discount for Over Generation (DOG) and Premium for Under Generation (PUG) parameters. These are proposed to the RAs annually and then consulted upon and set.

One key consideration is whether the need for Uninstructed Imbalance specific treatment in pricing is as much a feature of I-SEM as it is in SEM and therefore whether it is necessary to ensure that the I-SEM systems can accommodate this. As with the current SEM, DOG and PUG can be considered specifically, as part of any parameters to be set before I-SEM Go-Live. If analysis was to find that no specific treatment was required then the parameters could reflect this.

For example (using similar parameters as SEM):

- units with metered quantity, QM_{ij}, greater than dispatch quantity, QD_{ij}, could pay back 20% of the price they receive for the quantity ($QM_{ij} - QD_{ij}$); and
- units with metered quantity, QM_{ij}, less than dispatch quantity, QD_{ij}, could pay 120% of the imbalance price for the quantity ($QD_{ij} - QM_{ij}$).

Such treatment of uninstructed imbalances in I-SEM would provide a clear distinction between notified and un-notified imbalances, and discourage any possible portfolio rebalancing after gate closure.

9.7 INTERACTION BETWEEN THE BALANCING MARKET AND THE INTRADAY MARKET

Section 6 discusses the fact that the Intraday and Balancing Markets are open simultaneously. It considers options whereby a participant could continue to trade in respect of a unit in the intraday market, even after the TSOs had accepted an offer or a bid from that unit. It proposes three options:

(1) 'Freeze PNs', in which the PNs, offers and bids cannot be changed, following any offer or bid acceptance;

(2) 'Additive PN changes', in which further intraday trades are additional to any offers and bids that have been accepted; and

(3) 'Substitutive PN changes', in which participants can change PNs to reflect intraday trades even after an offer or bid has been accepted. Increases in PNs will reduce the quantity of any offer acceptance and increase the quantity of any bid acceptance, and decreases in PNs will reduce the quantity of any bid acceptance and increase the quantity of any offer acceptance.

Under Options (1) and (2), the settlement of multiple acceptances is straightforward. Each offer or bid acceptance will be settled on the basis of the quantity of the acceptance and the price applicable to the acceptance.

Under Option (2), it should be noted that where an action is deemed to be an energy (rather than a system) action, the imbalance price that will apply will be the imbalance price that is calculated ex-post. Hence, whilst offer and bid prices may be re-declared at any time up until gate closure, such that successive acceptances will be settled at the price that applied at the time of the acceptance, this is not the case with the imbalance price.

Under Option (3), many aspects are the same as under Option (2). Offers and bids are, again, settled on the basis of the offer or bid price that applies at the time of the acceptance and the imbalance price that is calculated ex-post. The difference lies in the effect of a PN change that occurs after any offer or bid acceptance. Here there are a number of variants that could be implemented:

(a) The quantity on which a premium is paid for an accepted offer may be based on the maximum of the PN at the time that the offer is accepted and the PN at gate closure, such that trading "in the opposite direction" to an acceptance does not increase the quantity on which the premium is paid. An equivalent rule for bids, would base the discount for an accepted bid on the minimum of the PN at the time that the bid is accepted and the PN at gate closure.

Under this variant, if the participant trades "towards" the acceptance, and thus sells output of the unit to another market participant after having already sold it to the TSOs through a TSO acceptance, then the volume of the TSO acceptance is "replaced" by the intraday trade volume such as it is. The principle of this option is that if the participant finds another buyer for the unit output then it is no longer necessary for the TSOs to buy it. However, in the case of an action that is ultimately deemed to be a system action then there is possibly little incentive, under this option, for the participant to make the IDM trade as it is unlikely in the IDM to be able to better the price accepted by the TSOs.

(b) The quantity on which a premium is paid for an accepted offer may be based solely on the PN at the time that the offer is accepted. Likewise, the discount for accepted bids would be based on the PN at the time that the bid is accepted.

Under this variant, the participant can trade and change its PN, in either direction. However, this does not affect the original acceptance. If the participant trades 'against' the acceptance, the quantity on which the premium (or discount) is paid is not increased, but neither is it decreased if the participant trades 'towards' the acceptance. This may improve incentives to trade intraday.

(c) The quantity on which a premium is paid for an accepted offer may be based solely on the PN at gate closure. Likewise the discount for accepted bids would be based on the PN at gate closure.

The rationale for this variant is that the premium or discount is based on the conditions that apply at real-time and are not limited by the conditions that applied intraday at the time at which an earlier acceptance has been made. The concern is, however, that it may be more open to gaming, in that a participant can increase the quantity of a bid or offer acceptance after the TSOs have revealed the need for a system action and hence revealed that the unit may possibly be in a position of local market power.

It is also possible that a PN change will occur after more than one acceptance has been made (see the next Section 9.8, “Settlement of Multiple Acceptances”). In the options that imply a change in the quantity on which the premium or discount is paid, this raises the question as to which offer or bid acceptance has the premium or discount increased or reduced. As with the non-delivery rule, whereby it is proposed that the highest-priced offer or lowest-priced bid is deemed to have not been delivered, it is proposed that it would be the quantities associated with lowest-priced offers and the highest-priced bids that were deemed to be increased and/or, conversely, the quantities associated with highest-priced offers and the lowest-priced bids that were deemed to be reduced.

9.8 SETTLEMENT OF MULTIPLE ACCEPTANCES

This section considers how multiple acceptances of both incremental offers and decremental bids should be settled. This also covers how “undo” actions should be settled, given that an "undo" action can be thought of as an further acceptance that "undoes" a previous acceptance.

Particularly with a Balancing Market that is open some considerable time before gate closure, it is possible that the TSOs may wish to revise any instruction given to a participant in respect of any given unit. If the TSOs issue an instruction to a participant say to increase output of a generation unit relative to its PN then a subsequent instruction might request a further increase in output or, conversely, might request that the increase be not as large as originally instructed. Thus the offer acceptance implied by the first instruction might be followed either by a further offer acceptance or by a bid acceptance.

It is also quite likely, particularly where there is a significant period of time between issuing an instruction to increase output and the unit being able to deliver the increase, that the TSOs may still require the increase in output from the unit but require the increase to be delayed. Here, following the initial offer acceptance, the second instruction could imply both the acceptance of a bid, for the settlement periods where the original increase is reduced, and the acceptance of an offer, for the later periods when the increased output is required instead.

Thus, it is necessary that the I-SEM ETA Detailed Design provides for the settlement of a sequence of acceptances.

Were it to be the case that offer and bid prices do not change, as, say, under the option described in Section 5.4.1 that requires PNs and offer and bid prices to be fixed following any acceptance, then the settlement of multiple acceptances would be trivial. It would be necessary simply to take the final instruction and calculate the net offer and bid acceptance quantities implied by that final instruction. However, in any other option, either which allows prices to be re-declared even after the TSOs have made an initial acceptance, or which provides for "undo" prices that are different from the prices of initial acceptances, the quantity of each acceptance implied by each instruction needs to be determined and a cashflow calculated using the relevant offer and bid prices.

The I-SEM ETA Building Blocks Consultation Paper proposed that a unit which had an incremental offer accepted in the Balancing Market would receive the maximum of its offer price and the imbalance price, and that a unit which had a decremental bid accepted in the Balancing Market would pay back the minimum of its bid price and the imbalance price.

A refinement of this proposal is now proposed here. Under this refined proposal:

- A unit which had an incremental offer accepted would receive the maximum of its offer price and the imbalance price for any incremental volumes above its PN, and would receive its offer price for any incremental volumes below its PN; and

- A unit which had a decremental bid accepted would pay back the minimum of its bid price and the imbalance price for any decremental volumes below its PN, and would pay back its bid price for any decremental volumes above its PN.

This refined proposal would allow the TSOs to revise its instructions at less cost, and indeed perhaps costlessly, if so facilitated through the re-declared bid-offer prices, or “undo” prices, submitted by participants.

Respondents are asked for their views on two options:

Option 1: the initial proposal whereby the payment rule applies to all bid-offer acceptances; and

Option 2: the refined proposal whereby the payment rule applies only to incremental offer acceptance volumes above the PN and to decremental bid acceptance volumes below the PN.

The difference between the two options is illustrated in the two worked examples which follow.

Worked Example for Option 1: The payment rule applies to all bid-offer acceptances

A generation unit has a PN of 250MW.
The generation unit’s offer and bid prices are in the Absolute MW format and are declared as being:

- Offer/Bid Price 1: €30/MWh from 0MW to 200MW;

- Offer/Bid Price 2: €60/MWh from 200MW to 300MW; and
- Offer/Bid Price 3: €80/MWh from 300MW to 400MW.

The imbalance price is €50/MWh.

The TSO instructs this generation unit to 330MW in a given half hour settlement period, implying acceptances of:

- +25MWh, being 300MW less 250MW over the half hour settlement period, at the maximum of the Offer/Bid Price 2 of €60/MWh and the imbalance price of €50/MWh, giving a cashflow of +€1,500; and

- +15MWh, being 330MW less 300MW over the half hour settlement period, at the maximum of the Offer/Bid Price 3 of €80/MWh and the imbalance price of €50/MWh, giving a cashflow of +€1,200.

The participant then re-declares the offer/bid prices to be:

- Offer/Bid Price 1: €25/MWh from 0MW to 240MW;
- Offer/Bid Price 2: €55/MWh from 240MW to 320MW; and
- Offer/Bid Price 3: €75/MWh from 320MW to 400MW.

The TSO then instructs the generator unit to 300MW during the settlement period, rather than the previously-instructed 330MW, which implies further acceptances of:

- -5MWh, being 320MW less 330MW over the half hour settlement period, at the minimum of the revised Offer/Bid Price 3 of €75/MWh and the imbalance price of €50/MWh, giving a cashflow of -€250; and

- -10MWh, being 300MW less 320MW over the half hour settlement period, at the minimum of the revised Offer/Bid Price 2 of €55/MWh and the imbalance price of €50/MWh, giving a cashflow of -€500.

The total cashflow would thus be the sum of +€1500, +€1200, -€250 and -€500, i.e. €1950 for the net acceptance of +25MWh.

Worked Example for Option 2: The payment rule applies only to incremental offer acceptance volumes above the PN and to decremental bid acceptance volumes below the PN

A generation unit has a PN of 250MW.

The generation unit's offer and bid prices are in the Absolute MW format and are declared as being:

- Offer/Bid Price 1: €30/MWh from 0MW to 200MW;
- Offer/Bid Price 2: €60/MWh from 200MW to 300MW; and
- Offer/Bid Price 3: €80/MWh from 300MW to 400MW.

The imbalance price is €50/MWh.

The TSO instructs this generation unit to 330MW in a given half hour settlement period, implying acceptances of:

- +25MWh, being 300MW less 250MW over the half hour settlement period, at the maximum of the Offer/Bid Price 2 of €60/MWh and the imbalance price of €50/MWh, giving a cashflow of +€1500; and

- +15MWh, being 330MW less 300MW over the half hour settlement period, at the maximum of the Offer/Bid Price 3 of €80/MWh and the imbalance price of €50/MWh, giving a cashflow of +€1200.

The participant then re-declares the offer/bid prices to be:

- Offer/Bid Price 1: €25/MWh from 0MW to 240MW;
- Offer/Bid Price 2: €55/MWh from 240MW to 320MW; and
- Offer/Bid Price 3: €75/MWh from 320MW to 400MW.

The TSO then instructs the generator unit to 300MW during the settlement period, rather than the previously-instructed 330MW, which implies further acceptances of:

- -5MWh, being 320MW less 330MW over the half hour settlement period, at the revised Offer/Bid Price 3 of €75/MWh (ignoring the imbalance price as the decremental bid acceptance is above the PN), giving a cashflow of -€375; and

- -10MWh, being 300MW less 320MW over the half hour settlement period, at the revised Offer/Bid Price 2 of €55/MWh (ignoring the imbalance price as the decremental bid acceptance is above the PN), giving a cashflow of -€550.

The total cashflow would thus be the sum of +€1500, +€1200, -€375 and -€550, i.e. €1775 for the net acceptance of +25MWh.

In the event that the output of the unit is not as instructed then this could be treated simply as an imbalance to be settled at the imbalance price (together with any uninstructed imbalance charge). However, this could give rise to a participant being paid for an undelivered offer at a price equal to the difference between the offer and imbalance prices (or in the case of an undelivered bid, at a price equal to the difference between the imbalance and bid prices).

Accordingly, it may be appropriate to have a non-delivery rule such that, in the event that the unit output is not as instructed, the most expensive offers (or most expensive bids, as the case may be) are assumed to be undelivered, and any premiums or discounts for these actions relative to the imbalance price clawed back, in addition to the imbalance price and any uninstructed imbalance charge.

With intraday trading, PNs also may change between acceptances and these PN changes will need to be reflected in the calculated bid-offer acceptances. Depending on the approach taken to 'trading in the opposite direction', as discussed in Section 6, each offer acceptance quantity will be calculated on the basis of the PN at the time of the acceptance or the maximum of the FPN and the PN at the time of the acceptance (and each bid acceptance on the basis of the PN at the time of the acceptance or the minimum of the FPN and the PN at the time of the acceptance).

9.9 QUARTER-HOURLY vs HALF-HOURLY vs HOURLY SETTLEMENT

This section considers the potential consequences of ex-ante trades based on trading period durations that are different to the Imbalance Settlement Period (ISP) duration.

The trading period duration for the Day Ahead Market will be one hour at I-SEM Go-Live, although it is possible that a shorter trading period duration could be introduced in the future.

In terms of the Intraday Market, 15 minute products will be available on the borders where these are currently implemented. For the borders where these are currently not implemented, including the I-SEM – GB border, it is up to the involved Local Implementation Projects (LIPs) to decide on of implementation of 15 minute products (i.e. to decide whether 15 minute products are available at XBID Go-Live, at a later point in time, or at all).

The initial ISP duration will be 30 minutes although it is possible that this will move to 15 minutes in future as the European Network Code on Electricity Balancing progresses. This may create an issue for SEM where most of the systems are based on 30 minutes intervals. It may also be an issue for interval metering in Northern Ireland, which is also half-hourly.

In order to investigate the consequences of ex-ante trades based on trading period durations that are different to the ISP, consider the stylised example illustrated in figure 9.3 where the ex-ante trading period duration is 1 hour and the ISP duration is 15 minutes.

A generator unit is starting up and submits the PN to the TSOs represented by the MW generation profile in blue. It takes 50 minutes to reach its Minimum Stable Generation of 260MW and then sits at this level for the rest of the hour.

By selling 147MWh in the Day Ahead Market for this hourly trading period it ensures that it is in balance when its MW generation profile is summed over the hour. However if the Imbalance Settlement Period (ISP) duration is 15 minutes then there will be four ISPs covered by this DAM trade, labelled ISP A, ISP B, ISP C and ISP D in figure 9.3.

Therefore in imbalance settlement this 147MWh will be divided by four to give QEX_{ij} in each ISP. Assuming that ex-ante contract quantities are split evenly over the settlement periods that correspond to each hourly block then QEX_{ij} will be the same value for each ISP from A to D (147MWh/4 = 36.75MWh).

In the course of starting up to its Minimum Stable Generation the unit will have a different metered quantity, QM_{ij}, in each of the four ISPs, A; B ; C; and D. Therefore the unit will be out of balance in each of the four individual ISPs.

The sum of these four imbalances should be zero, i.e.:

$(QM_{iA} - QEX_{iA}) + (QM_{iB} - QEX_{iB}) + (QM_{iC} - QEX_{iC}) + (QM_{iD} - QEX_{iD}) = 0$

However, if the imbalance price, $PIMB_j$, is different in each (or any) ISP (A to D) the total cashflow for imbalance (CIMB) summed over the four individual ISPs will be non-zero, i.e.:

$CIMB_{iA} + CIMB_{iB} + CIMB_{iC} + CIMB_{iD} = PIMB_A.(QM_{iA} - QEX_{iA}) + PIMB_B.(QM_{iB} - QEX_{iB}) + PIMB_C.(QM_{iC} - QEX_{iC}) + PIMB_D.(QM_{iD} - QEX_{iD})$

Therefore the unit in question will have positive or negative cashflows in imbalance settlement despite the fact that its ex-ante trade is equal to the outturn volume from its PN for the hourly ex-ante trading period in question.

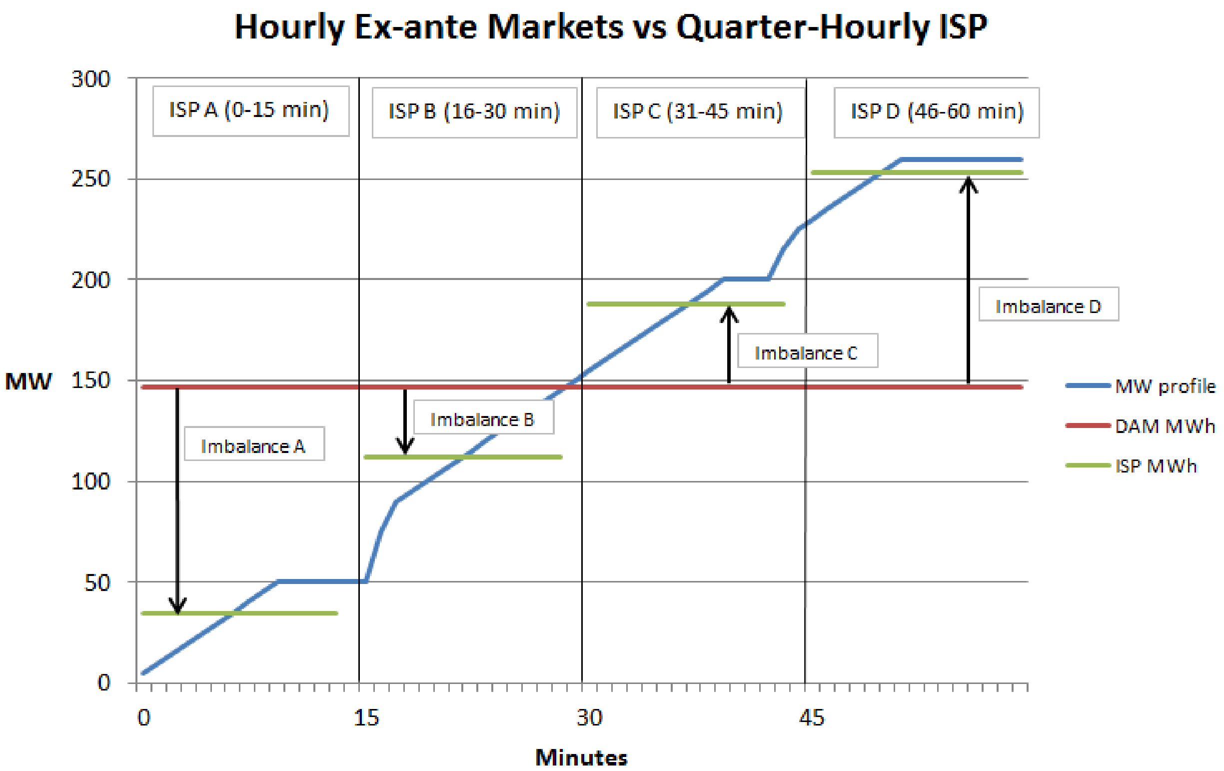


Figure 9.3 Hourly Ex-ante Markets vs Quarter-Hourly ISP

The same issue could arise for demand even though it might predict its hourly demand perfectly and purchase the correct hourly volume in the ex-ante markets.

As part of the Markets RLG discussions the idea of tolerances around ex-ante traded volumes and the submitted PNs was considered.

It also needs to be considered whether there should be tolerances around the differences in imbalance settlement cashflows caused by the difference between ex-ante trading period durations and the imbalance settlement period duration.

Options may thus include:

(i) Assume that hourly ex-ante contract quantities are split equally into the two/four ISPs. This will mean that participants could be balanced over the hour but have imbalance exposure in individual quarter or half hours.

(ii) Allow participants to allocate the ex-ante contract quantities between ISPs as they wish. A consequence of this approach would be that there would be a revenue shortfall, with short imbalances being charged a lower price than long imbalances pay.

(iii) Calculate imbalances on an hourly basis, with some sort of average (whether or not weighted by the quantity of imbalances in each settlement period) of the two (or four) imbalance prices across the hourly period.

In Options (ii) and (iii), the price paid to balancing actions would continue to be calculated as the marginal price in the individual half-hour (quarter-hour). This would mean that balancing actions would be priced differently to imbalances.

Note that a refinement of Option (ii) would be to allow the allocation of only the *notified* imbalances in the manner described. Thus the notified imbalance would attract the lowest (or highest) imbalance price, depending on whether the participant was short (or long). Un-notified, i.e. uninstructed, imbalances would be cashed-out at the individual period imbalance price (i.e. equal to the price paid for 'energy' balancing actions).

Note also that this will be much less of an issue if 15 minute products are available in the Intraday Market and that options (ii) and (iii) would likely not be needed if this is the case.

9.10 SUMMARY

The first sections of this chapter introduce and explain the proposed high level stylised algebra for imbalance settlement in I-SEM.

The next section, Settlement of Curtailment, discusses three options for the implementation of the SEM Committee decision on curtailment and their consequences for settlement. It introduces the concept of a "deemed decremental bid" to be used in settlement that would have the same price as a curtailed unit's ex-ante trades.

The next section discusses the settlement of priority dispatch units when they are constrained down, including the case where Variable RES units, having chosen not to submit a PN, are constrained down. It introduces the concept of a "deemed decremental bid" to be used in settlement that would have a price of zero.

The next section, Treatment of Uninstructed Imbalances, discusses how uninstructed imbalances should be settled and proposes maintaining the concepts of the Discount for Over Generation (DOG) and the Premium for Under Generation (PUG) in the I-SEM systems.

The next sections discuss the interaction between the Balancing Market and the Intraday Market and the settlement of multiple acceptances. A refinement of the proposal on pricing in the Building Blocks Consultation Paper is introduced and goes as follows:

- A unit which had an incremental offer accepted would receive the maximum of its offer price and the imbalance price for any incremental volumes above its PN, and would receive its offer price for any incremental volumes below its PN; and

- A unit which had a decremental bid accepted would pay back the minimum of its bid price and the imbalance price for any decremental volumes below its PN, and would pay back its bid price for any decremental volumes above its PN.

The final section discusses the possible consequences of ex-ante trades based on trading periods of different duration to the Imbalance Settlement Period (ISP). Three options were introduced, two of which would reduce participant risk if this were the case but would mean that balancing actions were priced differently to imbalances.

Views are sought form respondents on all the issues discussed in this chapter. All views should be supported with rationale.

10 OTHER ISSUES

10.1 INTRODUCTION

This section sets out a number of issues related to the detailed design of the energy trading arrangements. These are issues that have been covered at the RLG meetings and are introduced here.

10.2 GLOBAL AGGREGATION

The Building Blocks Consultation Paper discussed how current policy concerning the recovery of transmission losses, specifically involving the application of Transmission Loss Adjustment Factors (TLAFs) to generating units, can be applied in I-SEM. The application of a TLAF to each generating unit, in effect, allocates a quantity of losses to each generating unit in each settlement period, depending on the metered quantity of that generating unit and the value of the TLAF. Thus, a TLAF of 0.98 applied to a metered quantity of 100MWh in a given settlement period credits the generator with only 98MWh at the trading boundary and hence allocates losses of 2MWh to that generator.

However, TLAFs are forecast ex-ante and the TLAFs allocated to each generating unit are, in aggregate, unlikely to equal the actual transmission losses in that period. Moreover, a similar problem arises with the Distribution Loss Adjustment Factors (DLAFs), and with the demand profiles that are used to estimate the half-hourly consumption of non half-hourly metered customers. A further discrepancy arises due to unmetered supplies, unmetered generation and theft. The combined effect of all of these factors is that sum of loss-adjusted generation does not equal the sum of loss-adjusted demand, leaving a residual error in each jurisdiction. This residual error in each jurisdiction is named the Loss-Adjusted Net Demand and is explained visually in Figure 10.1 below.

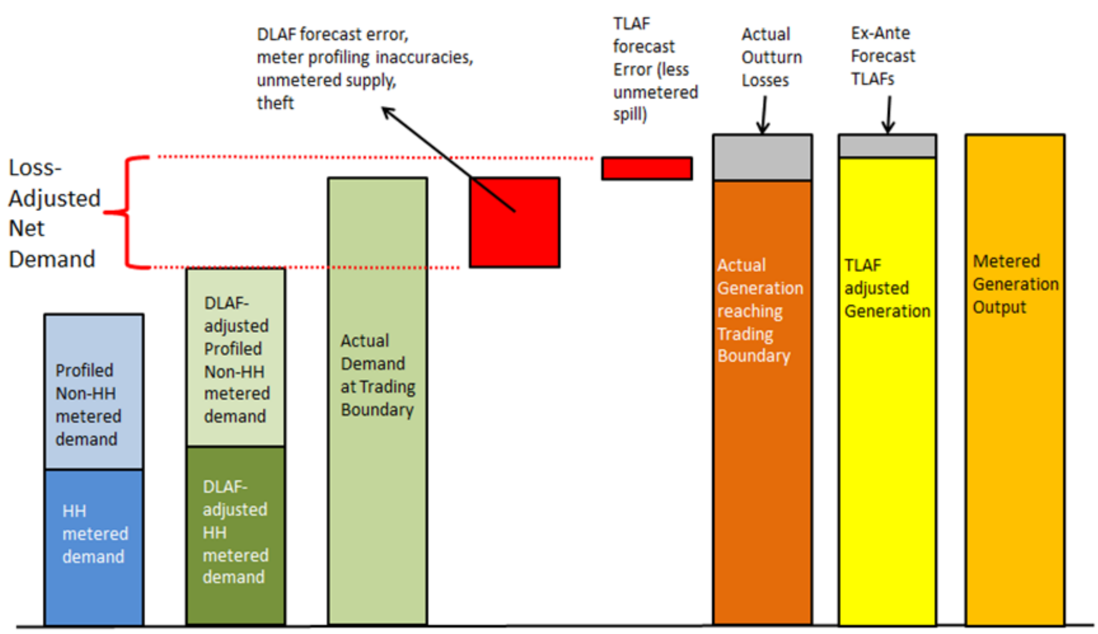


Figure 10.1 Loss-Adjusted Net Demand

This section discusses how the current policy for addressing this problem, which involves calculating the cost of the unaccounted energy, and allocating this cost to suppliers of non half-hourly metered demand, can be implemented in I-SEM. An alternative is suggested for consultation that involves allocating the quantity, rather than the cost, of the unaccounted energy, and which may have certain benefits. Further options are discussed that could provide mechanisms for managing the inevitable uncertainty in the quantity of unaccounted energy that needs to be allocated.

10.2.1 CURRENT POLICY

In the current Trading and Settlement Code, the residual error is called the Loss-Adjusted Net Demand and is calculated for each settlement period, h, and jurisdiction, e, as follows:

$$\begin{aligned} NDLF_{eh} = \; & \{\textstyle\sum_{u \text{ in } e} MG_{uh} - \sum_{v \text{ in } e} MD_{vh}\ NIJI_{eh}\} \\ & - \{\textstyle\sum_{u}(MG_{uh} - MGLF_{uh}) - \sum_{v}(MD_{vh} - MDLF_{vh})\} \\ & * \{(\textstyle\sum_{u \text{ in } e} MG_{uh} + NIJI_{eh}) / \sum_{e}\sum_{u \text{ in } e} MG_{uh}\} \end{aligned} \quad (10.1)$$

which is equal to the losses in the jurisdiction less the losses recovered through the application of TLAFs and DLAFs, apportioned to each jurisdiction on the basis of the jurisdiction's proportion of all-island generation plus north-south interconnector flow. This shortfall, i.e. the residual error, is recovered from Supplier Units by calculating the Energy Charge, ENC, for Supplier Unit, v, to be:

$$ENC_{vh} = (ND_{vh} + NDLF_{vh}.NDAF_{vh}).SMP_h \quad (10.2)$$

where ND is the Net Demand (broadly speaking the metered demand) whilst NDLF is the residual error, above, and NDAF is the share of the residual losses to be charged to the particular Supplier Unit. This share of the residual error is added to the Net Demand and is priced at SMP.

10.2.2 OPTION 1: ALLOCATING THE COST OF THE RESIDUAL ERROR TO SUPPLIERS

In I-SEM, one option would be to calculate the residual error in exactly the same manner as currently, using the imbalance price in place of SMP. This charge would then be levied on each supplier.

In I-SEM, there could be a number of consequences of this approach. In particular, if the loss-adjusted generation and loss-adjusted demand do not balance, with the cost of the discrepancy being levied as a charge on suppliers, then it will be impossible for all parties to be balanced. Whilst it is unlikely that, in any case, all parties would ever be in balance, this would still mean that the imbalances of some or all parties would be exacerbated by this effect.

Assuming that the loss-adjusted generation was greater than the loss-adjusted demand, then two extreme cases could arise:

Case 1 - Suppliers Neutral:

Suppliers could purchase in the ex-ante markets amounts equal to their loss-adjusted demand. This would leave suppliers balanced such that they were not exposed to an imbalance charge. Generators, in seeking to maintain balanced positions, would declare PNs that, in aggregate, would equal to total loss-adjusted demand. This would leave the TSO needing to accept offers in order to make good the residual error. The cost of these offers would be largely, if not completely, covered by the residual error charge levied on suppliers. However, in the event that any participant had an imbalance, the energy balancing actions required and hence the imbalance price charged on these imbalances, would be distorted by the additional balancing actions that had been necessitated by the residual error.

Case 2 - Suppliers Go Long:

Suppliers could go long in the ex-ante markets by an amount equal to the residual error (presuming in this extreme case that they forecast the residual error correctly). In this case, generators would declare PNs that, in aggregate, would cover both the loss-adjusted demand of suppliers *plus* the residual error. No balancing actions would be required, and hence no distortion of imbalance prices would occur. Suppliers, having gone long, would be exposed to imbalance price, in this case being in receipt of the imbalance price on a quantity, in aggregate, equal to the residual error. This should then be equal to the residual error charge, leaving suppliers financially whole.

Hence, at best, suppliers could, by deliberately going long[25] by an amount exactly equal to the residual error, leave themselves financially neutral. However, if they do not, and instead seek to buy ex-ante their loss-adjusted demand, then they will be exposed to a residual losses charge which is equivalent to an imbalance exposure, in addition to which, imbalance prices could be distorted.

10.2.3 OPTION 2: ALLOCATING THE VOLUME OF THE RESIDUAL ERROR TO SUPPLIERS

Another option would be to allocate the residual error to suppliers by volume. Under this option a supplier's imbalances would be calculated on the basis, not of their loss-adjusted metered quantities, but on the basis of their loss-adjusted metered quantities plus their MWh share of the residual error. Suppliers could then seek to procure this total amount in the ex-ante markets.

It is recognised that the residual error is subject to uncertainty. Thus it would be possible for suppliers to procure only their estimate of their share of the residual error in the ex-ante markets, and they would be exposed to imbalance to the extent that their estimate is wrong. However, this uncertainty is no different to the uncertainty in the residual error charge to which they would be exposed, were the cost (rather than the quantity) of the residual error allocated, as in Option 1. Also this is similar, in principle, to the uncertainty in the residual error charge under the current SEM.

[25] Or short, in the event that the residual error turns out to be negative.

In the event that a supplier did not seek to procure any of its MWh share of the residual error in the ex-ante markets then it would pay for it at the imbalance price and this option would have the same result as Option 1. Therefore this option could be said to offer more flexibility to suppliers than Option 1.

Managing Residual Error Risk

Either of the two options above would implement current policy concerning the recovery of the residual error. However, the question then arises as to whether there is any aspect of the I-SEM HLD that warrants a change or addition to the current policy.

A view expressed at the RLGs was that, to the extent that imbalance prices in I-SEM prove to be more volatile than SMP prices in SEM, there may be a case for providing a mechanism that can mitigate the exposure of each participant to imbalance prices on their share of the uncertain residual error. Thus, instead of being exposed to the uncertain NDLF in equation 10.2 (or the equivalent equation that will be used in I-SEM), participants would be exposed to a known quantity[26], which they could thus procure ex-ante, without being then still exposed to the imbalance price on the outturn quantity.

10.2.4 OPTION 3: FIXING AN ESTIMATED VOLUME OR COST OF THE RESIDUAL ERROR FOR A GIVEN PERIOD

Under this option there would be a centrally determined estimate of the residual error. Of course, to the extent that TLAFs, and DLAFs and profiles are unbiased, it might be expected the residual error to be zero[27]. To the extent that this is not the case, then an explicit value for NDLF could be estimated ex-ante and allocated to suppliers, whether as:

[26] Note that the quantity could vary from settlement period to settlement period. It is important only that it is known in advance, such that parties could procure the quantity ex-ante.

[27] If TLAFs are unbiased estimates of transmission losses, DLAFs unbiased estimates of distribution losses and demand profiles unbiased estimates of profiled consumers' demands, then the residual error might be expected to equal unmetered supplies, unmetered generation and theft. An allowance for unmetered supplies and theft could be made in, say, DLAFs, or an explicit mechanism for allocating these 'losses' provided, in which case the residual error would then be expected to be zero.

a) a cost (tariff); or
b) a volume

Cost (Tariff)

In order to allocate the estimated value for NDLF to suppliers as a cost, the estimated volume could be multiplied by a forecast of the imbalance price for the timeframe in question. This could be paid by suppliers through an explicit tariff. Any difference between the forecast and actual would be carried by a central body and recovered as a correction factor. The tariff could be set annually or it could be set with a smaller granularity. The length of tariff could depend on the level of exposure being carried by a central body (e.g. the TSOs).

Volume

If the explicit estimated value for NDLF was allocated to suppliers as a volume then they could procure this volume ex-ante, without still being exposed to the imbalance price on the outturn volume.

The estimate could be fixed for any defined timeframe, and could comprise a single (percentage) value for the timeframe or have different defined values for different settlement periods. To the extent outturn values of the residual error subsequently differ from the estimate in individual settlement periods this discrepancy would be allocated possibly to the TSO[28], with the cost of this discrepancy (which could be negative) over one forecasting timeframe being recovered by the TSOs through an adjustment to the NDLF estimate in the following forecasting timeframe. However, a consequence of this approach is that the TSOs will have to call offers and bids with the possibility of distorting imbalance prices, as in Option 1 above.

TLAFs, DLAFs and demand profiles are estimated some considerable time in advance of their application. Whilst they may be unbiased estimates at the time they are calculated, biases may emerge as time passes. Whatever the reason, estimates of NDLF could be updated at any stage. The closer to real-time NDLF is estimated, the less the need should be to call offers and bids to make good the discrepancy

[28] The TSO does not have to be the actual counter-party to this discrepancy. Rather, the cost could be carried by Trading & Settlement Code parties as a whole, with the TSO only being required to provide the necessary estimates.

between the estimate and out-turn NDLF. On the other hand the later the estimate of NDLF is determined, the less the opportunity for participants to act on it. Possible options might be:

(a) estimate NDLF year ahead to allow suppliers to incorporate the estimate into the pricing of annual retail contracts, but risking significant discrepancies leading to distortion of imbalance prices; or

(b) estimate NDLF days ahead to allow suppliers to reduce imbalance price distortion and take account of the estimate in ex-ante wholesale market trading but not longer-term retail contract pricing.

10.2.5 SMART METERING

A significant driver of the residual errors is understood to be errors in demand profiles. It is on that basis that the residual error is currently allocated to suppliers on the basis of their non half-hourly metered demand and not on half-hourly metered demand (some metering is actually quarter-hourly but this resolution of data is not currently used here).

If smart metering is installed and an increasing proportion of demand is interval metered rather than on profiles, then the component of residual error that is demand profile error will become actual metered customer demand. Hence the uncertainty that is seen now as being a problem caused by the demand profile calculation would become an inherent uncertainty of customer demand.

Thus, any measure that is taken to manage demand profile risk could be transitory if smart metering is rolled out. On the other hand, measures that mitigate demand profile risk may lessen the incentives for the adoption of smart metering.

10.2.6 SUMMARY

The residual error due to the discrepancies between actual transmission and distribution losses and the losses recovered through TLAFs and DLAFs, between actual and profiled demand, and due to unmetered supplies, unmetered generation and theft, is recovered in the current SEM by a charge on suppliers on the basis of non half-hourly metered demand. This policy can be replicated in I-SEM, although allocating the quantity (Option 2) rather than the cost (Option 1) of the residual error is an option that could minimise distortions in the market.

The potential for more volatile imbalance prices in I-SEM may warrant a mechanism for smoothing the uncertainty associated with the residual error by fixing an estimate of the residual error for any given period, with the TSO carrying the cost of the discrepancy which is recovered in the following period. This is presented for consultation as Option 3. Within Option 3 there are two approaches to how it might be implemented.

Specific comment is sought on the current policy and the three alternative options for dealing with Global Aggregation. The three alternative options are:

Option 1:	**Allocating the Cost of the Residual Error to Suppliers**
Option 2:	**Allocating the Volume of the Residual Error to Suppliers**
Option 3:	**Fixing an estimated volume or cost of the residual error for a given period**

10.3 LOCAL MARKET POWER

Transmission constraints arise where the network is unable to transmit the power that would have been supplied, e.g. resulting from the economic schedule of generation, to the location of demand. Such limitations can arise due to either thermal or voltage limits. Constraints can also arise on the distribution network. Where constraints arise, the TSOs need to take dispatch actions to increase or decrease the amount of electricity being generated (or, in the case of demand side response, consumption) at different locations on the network. The TSOs may also have to dispatch plant to ensure the security of the system, e.g. to carry reserve to cover the possibility of a generator or interconnector trip.

In the SEM, a unit whose dispatch quantity output is adjusted either up or down from its Market Schedule Quantity (MSQ) is compensated. Specifically, units that are constrained up receive their offer price for the portion of their dispatch quantity that is above their MSQ. Units that are constrained down receive the difference between the system marginal price (SMP) and their offer price, i.e. they retain their infra-marginal rent for the portion of their MSQ that is above their dispatch quantity.

Where constraints exist, generators may be able to benefit from local market power: a generating unit that is constrained up could benefit by raising its offer price (as it is paid the offer price); whereas a generating unit is that constrained down, could benefit by reducing its offer price (as it retains the difference between SMP and the offer price).

10.3.1 LOCAL MARKET POWER MITIGATION IN SEM

The SEM has a suite of measures to prevent participants benefiting from the exercise of market power in the setting of the wholesale price. Some of these measures also prevent market participants benefiting from local market power. Specifically:

- The bidding principles contained in the generation licences and the Bidding Code of Practice (BCoP) set out principles under which generators are required to submit cost-reflective bids. This obligation to bid in a cost-reflective manner ensures that participants cannot change a generating unit's bids to exploit local market power, i.e. they cannot increase the offer price knowing that the TSO will need to run them regardless of price, or decrease it below cost where they know the generating unit will dispatched below the MSQ level;
- Ex-post market monitoring ensures compliance with the licence and BCoP; and,
- The Grid Code prevents the with-holding of capacity.

10.3.2 LOCAL MARKET POWER IN I-SEM

The RAs are cognisant that the I-SEM design, and the reliance on certain generation assets to support the system in a market with increased levels of variable generation, presents significant challenges in ensuring that participants cannot exploit the opportunities across market timeframes either on a portfolio basis, or in the specific context of market local power on a unit/station basis. The RAs also note the concerns expressed at RLG 2.3, and in subsequent comments from participants, regarding the ability of portfolio participants to exercise market power in the spot market, and the impact that may have on prices in forwards timeframes.

Under the I-SEM project plan, there is a specific workstream that will consider market power. This will be closely aligned with the workstreams considering forward market liquidity and on the design of the capacity remuneration mechanism, both of which the HLD identified as areas which would form part of the measures to mitigate market power in the I-SEM as well as the ongoing development of the Energy Trading Arrangements.

Local market power considerations will apply to the provision of ancillary services and management of system constraints, and to the bids and offers submitted by units to the Balancing Market. Local market power issues are linked to limited competition for provision of system services with location specific requirements, for example voltage support and constraint management. If a participant has capacity either side of a constraint or capacity that has limited competition in the provision of local system services then it has the potential to exert local market power.

Local market power can be exerted in a number of possible ways (individually or in combination) in BM timescales:

- Price: changing pricing behaviour resulting in higher priced offers in periods where the unit is needed to resolve a constraint or provide system services.
- Capacity withholding: a participant with multiple units that could be used to resolve a constraint or provide system services could, in principle, withhold capacity at one (or more) unit so as to ensure a more profitable unit must be called, although the Grid Code prevents this.
- Technical characteristics: parties can set technical characteristics to affect TSO dispatch decisions.

It is the intention of the HLD, as reflected in this paper, that non-energy actions, i.e. trades where local market power may be capable of being exerted, are separated from the calculation of imbalance prices. Consequently, any potential exercise of local market power would not be expected to impact spot prices, but would affect the level of constraint payments and/or the cost of using system services.

At this stage the RAs do not wish to rule out any specific market power measures that may be required to ensure the efficient functioning of the ETA. With respect to the balancing market it is expected that measures could be considered that apply to units that are able to (or are potentially seeking to) exercise local market power, and/or broader measures applying to all BM bids. This will include consideration of whether particular participants/generating units that are able to exercise local market power in the balancing market can be identified ex-ante, such that more targeted controls may be feasible, or whether the level of non-energy actions is such that any controls required would need to apply to all units.

There are several ways in which a method of bid mitigation could be introduced whereby a generator’s offer/bid into the BM could be replaced by a regulated offer/bid. There are two timeframes where this could happen:

1) Where local market power is intermittent and transitory depending on system conditions. Generators are free to submit offers/bids each day but when local market occurs any offer or bid submitted by the generator is replaced with a regulated offer/bid; and
2) Where local market power is identified on a long-term basis. Generators with such local market power enter into some form of contract for energy and system services and the offers/bids they submit to the BM are always at the prices determined in the contract.

In terms of the market systems there are a number of ways in which bid mitigation could be facilitated:

- The provision of price and cost curve capabilities in the market systems. There are variants of this available that could include provision for an RA approved cost data methodology to be in place for generators with the potential for market power. This cost curve could then be used in instances where a generator is identified to have market power or where a generators offers/bids move outside a tolerance based around the RAs' approved methodology.

- A variant of the above option might be to have a price and cost curve for all generators in the BM. The price curve would allow a generator to express its desire to run in the BM with this price curve being used to make dispatch decisions. The cost curve would then be used in settlement of non-energy actions and could be used to address costs of generators which the TSO has no choice but to call.

- A further variant might be to ensure that market systems have the capability to change bids after gate closure. For example, if a generator is found to have exercised local market power they could have their bid replaced in settlement. The price curve would be used in the settlement of energy actions.

- There may be instances where a unit deployed for reserve purposes is the only unit that can provide the service due to, for example, local system security reasons. The unit has market power and may exploit this through the bid price submitted to the TSOs. Direct regulation is an option (e.g. requiring bidding in line with short run marginal cost in such cases). Ex-post monitoring, with enforcement options, may be another alternative.

- The provision of the capability in the market systems to take account of long term contractual arrangements that may be in place to deliver ancillary services and manage system constraints.

The RAs will examine issues in relation to market power and this section does not prejudge this work. However, comments are welcomed on whether the balancing market systems procurement should include an option for local market power measures.

10.3.3 SUMMARY

In summary, market power in the energy trading arrangements will be addressed as part of a dedicated workstream. However, in the context of developing detailed market rules and systems it is useful to consider whether any initial observations should be noted or whether any provisions should be made in systems procurement to accommodate different approaches that might be taken in the market power mitigation workstream.

Comment is sought on whether there are any specific issues in relation to Market Power which need to be considered at this stage.

10.4 METERING

The I-SEM will require a robust framework to ensure that meter data for generation and demand is delivered to the imbalance settlement process. The metering framework in place for the current SEM market was put in place by the meter data providers under governance structures put in place with the RAs. This was called the SIMDRACS program.

Metering in I-SEM will involve the four Meter Data Providers (MDPs). At the RLG 2.3 meeting, SEMO presented an approach to metering in the I-SEM which had been agreed across the MDPs. Specifically, this approach mentioned the following:

- Workshops with the SEM meter data providers
- Requirements of each meter data provider to be considered and discussed
- Detailed requirements to be documented and communicated
- Work will be under the governance of the RAs
- Most issues relate only to meter data providers and not the wider industry
- High impact issues (e.g. timelines of data provision) subject to full consultation

The SEM Committee is of the view that it is appropriate to deal with metering in the I-SEM with a similar process as was adopted for SEM. In particular the four MDPs will work together under the governance of the RAs and develop the required approach. This required approach will involve any interactions with the retail markets in Ireland and Northern Ireland. As per the SEMO presentation at the RLG, any market facing issues will be subject to consultation. The governance structure for the metering project will include a strategy for communicating the project to the wider stakeholder group.

10.5 INSTRUCTION PROFILING

10.5.1 INTRODUCTION

The TSOs operate the power system by issuing dispatch instructions to generator units during real time. These instructions represent a spot instruction for the generator to behave in a certain manner at a given time. For example, it could be an instruction to a generator (or demand side unit) to increase (decrease) output to 200MW at 3:00PM, whilst respecting the technical characteristics of the unit as submitted through their Technical Offer Data (TOD). The generator (or demand side unit) responds immediately to this instruction by adjusting their position to ensure they meet this level of output as soon as their technical characteristics permit. Instructions cover start up, shut down, increase and decrease in output as well as specific instructions to cover the operation of pumped storage generators.

For purposes of settlement, it is necessary to assess actual delivery, measured as metered output, against these instructions. As metered output is measured in average MWh over a trading period, it is therefore necessary to express these dispatch instructions at this granularity also. Instruction Profiling is the process whereby these spot instructions are converted to a time-weighted average MW value that represents the output that should be produced by a generating (or demand-side unit) unit given their TOD.

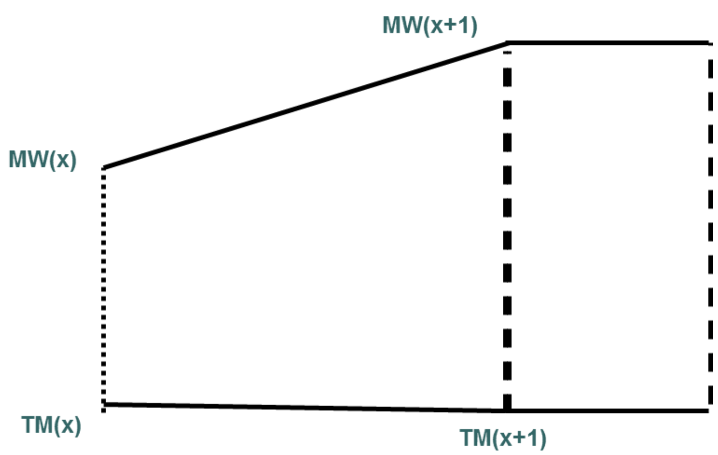
While the I-SEM has discussed the concept of "open" and "closed" instructions, either approach results in a series of spot instructions that must be expressed in this form.

10.5.2 INSTRUCTION PROFILING PROCESS

Instruction profiling first calculates the MW quantity during each trading period that a generating unit has been instructed to produce. When a TSO issues a dispatch instruction to a generator (or demand-side unit) to operate at a certain level, the unit will take a finite amount of time to ramp up or ramp down to the requested level.

In general the process will perform the following steps:

- Using the operating characteristics of each generator unit (or demand-side unit), together with its dispatch instructions, generate a piecewise linear curve of its instructed level (in MW) against time (in minutes).
- The curve follows both MW target points and time target points. In this way, the process will select a set level of output (e.g. a ramp rate breakpoint) and determine using the applicable ramp rate the amount of time to get to this point.



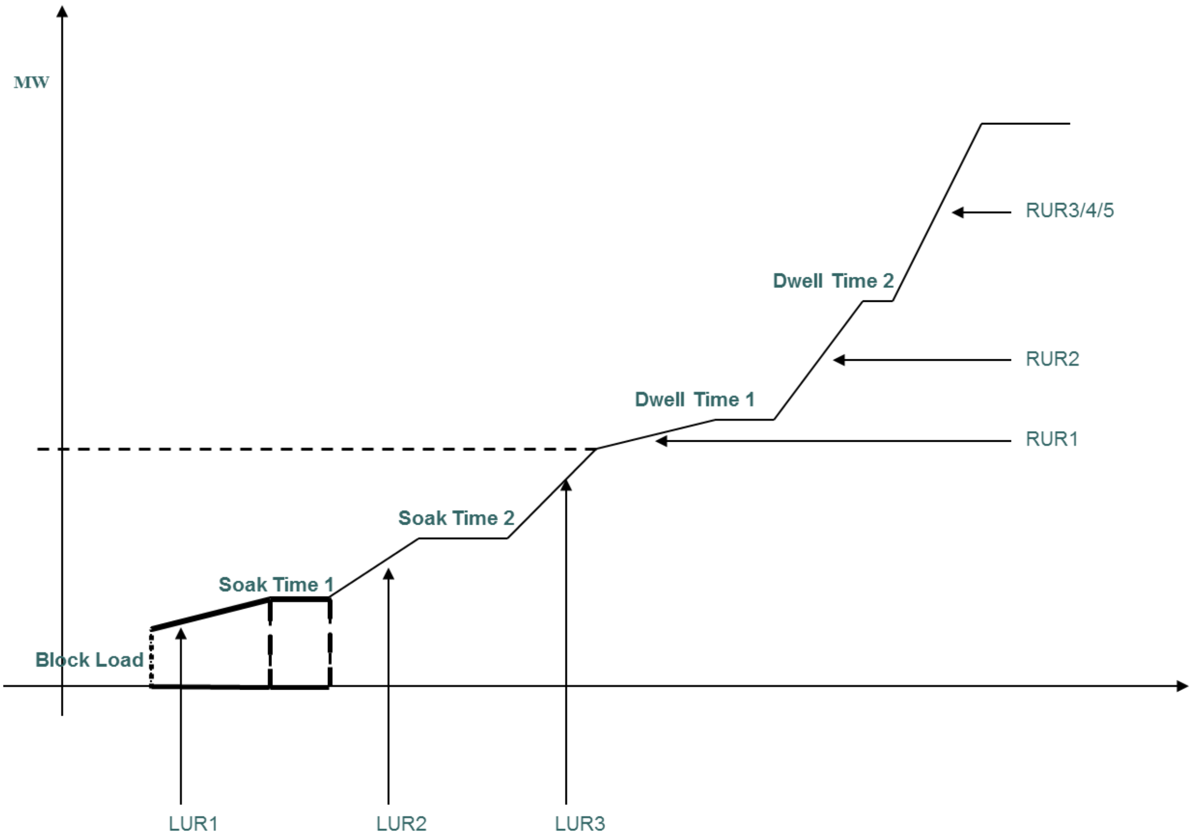
- The area under each time / MW set is then calculated as 0.5 * [MW(x) + MW(x+1)] * [TM(x+1) – TM(x)]
- Time points are also used to determine the start and end of a trading period and to note the associated MW of output at each.
- Each segment of the piecewise linear load up/down trajectory for the Generator Unit is identified by start MW, end MW, rate in MW/min and the time from start MW to end MW.
- The process is to calculate the time-weighted average MW value for each Trading Period by summing over all areas in each Trading Period, and then dividing by 30.
- This curve is then used to calculate the instructed quantity (multiply by 0.5 to get the integrated MWh energy value) for each Trading Period in the Trading Day.

10.5.3 DETERMINATION OF THE INSTRUCTION PROFILE

There are two determinants of the MW level of electricity that a unit should produce at a given time:

- A unit can receive an instruction to start producing electricity at a certain MW level. The unit will then try to produce at this MW level. Note that the instruction can be to produce a negative MW level for a pumped storage unit in pumping mode.

- The MW level that a unit can produce at a point in time is constrained by the registered technical characteristics of the unit represented through its technical offer data. These limits mean that a unit cannot normally instantly move to a given MW level. Instead, a unit can only increase the MW level at a certain rate (the relevant ramp rate or load up rate submitted as part of the Technical Offer Data for each Trading Day), and may have to remain at the same MW level for a given period of time (dwell or soak times) before continuing to increase output.



It is the combination of these two factors, (1) desired MW level and (2) unit operational constraints that determine the MW level that a unit should be producing at any time. Once the MW level that a generating unit should be producing is known, the total energy that should be produced in that period can be calculated by integrating the area under the MW/Time graph for each Trading Period as described in the earlier section.

The SEM contains special instruction profiling rules for some special units such as variable price takers, and variable price makers.

The final result of the instruction profiling process is the Dispatch Quantity. In the I-SEM, Dispatch Quantities will be used to determine a participants' uninstructed imbalance volume, envisaged in a similar way to the SEM today (i.e. comparison of Dispatch Quantity against Metered Output for each Trading Period).

This may also be used in the determination of notified imbalances (i.e. where a participant's FPN does not correspond to its aggregate contracted volumes (plus/minus any actions taken by the TSOs in the BM through bid-offer acceptances)). As such, the Dispatch Quantity may be of more important significance in the I-SEM when determining balance responsibility than in the current SEM.

The current process considers the following in determining the load up trajectory:

1) Heat state of the unit
2) Block Load Cold, Block Load Warm and Block Load Hot;
3) Loading Rate Hot 1, 2 & 3;
4) Loading Rate Warm 1, 2 & 3;
5) Loading Rate Cold 1, 2 & 3;
6) Load Up Break Point Hot 1 & 2;
7) Load Up Break Point Warm 1 & 2;
8) Load Up Break Point Cold 1 & 2;
9) Soak Time Hot 1 & 2;
10) Soak Time Warm 1 & 2;
11) Soak Time Cold 1 & 2;
12) Soak Time Trigger Point Hot 1 & 2;
13) Soak Time Trigger Point Warm 1 & 2; and
14) Soak Time Trigger Point Cold 1 & 2.

The following items are considered in the ramp up trajectory:

1) Maximum Generation
2) Minimum Generation
3) Ramp Up Rates 1, 2, 3, 4 & 5
4) Ramp Up Break Point 1, 2, 3 & 4
5) Dwell Time 1, 2 & 3
6) Dwell Time Trigger Point 1, 2 & 3

The ramp down trajectory takes account of -

1) Maximum Generation
2) Minimum Generation
3) Ramp Down Rate 1, 2, 3, 4 & 5
4) Ramp Down Break Point 1, 2, 3 & 4
5) Dwell Time 1, 2 & 3
6) Dwell Time Trigger Point 1, 2 & 3

The deloading trajectory takes account of

1) Minimum Generation
2) Minimum output
3) Deloading Rate 1 & 2
4) Deload Break Point

10.6 INSTRUCTION PROFILING IN THE SEM

Accurate instruction profiling is contingent on units being able to accurately reflect the technical characteristics of their plant in their technical offer data. Otherwise, units run the risk of being exposed to uninstructed imbalance charges in the cases where the unit's characteristics do not match the instruction profile.

Experience of the SEM has shown that in certain circumstances, a generator may be started a few hours into their hot cooling boundary. While technically still in a hot state, it may closer in time to its warm cooling boundary which may result in the actual output of the generator not precisely aligning with the exact technical characteristics of a "hot" generator. In these circumstances, the generators actual load up can be slower than the profiled Dispatch Quantity. This will result in uninstructed imbalances charges.

More generally, other experience from the SEM has shown that some generators are unable to model their complete technical characteristics with the available variables in the technical offer data. This has happened where a generator needs an equivalent of a soak or dwell as it switches between load up and ramp up states. In some circumstances, this has led to generators using very slow ramp up rates to model this characteristic which has had impacts on other data calculations in the SEM[29].

10.7 SUMMARY

The SEM Committee welcomes comments to this section. In particular, if it is feasible to more accurately model the precise loading of units and whether more technical characteristics need to be accommodated in the technical offer data.

[29] http://www.sem-o.com/Publications/General/Market%20Incident%20Report%20-%20Increased%20Use%20of%20MIP%20as%20the%20Market%20Solver%20Sept%202010.pdf

10.8 UNITS UNDER TEST

10.8.1 INTRODUCTION

During commissioning and during a generator's lifetime there is a requirement for a unit to undergo tests to confirm its technical capability. While the output to the system during testing is considered a non-market volume, it still needs to be accounted in the market systems and in particular settlement to ensure appropriate payment. The testing of units can impact the market schedule, market prices, system constraints, dispatch balancing costs and all users connected to the system (including priority dispatch). There are currently processes in place for test requests, approvals, market treatment and operational procedures to manage these impacts. These processes should remain in the I-SEM where possible. However it will need to be considered how units under test will be treated in I-SEM, especially across the day-ahead and intraday timeframes.

10.8.2 UNITS UNDER TEST IN SEM

Testing arrangements facilitate both market participant and TSO needs for testing generators and as such these needs for testing are divided into the following categories:

1) Generator Initiated Test – Full Day Test
    b. Commissioning
    c. Return from overhaul

2) Generator Initiated Test – Within Day Test
    d. Holding output for emissions testing
    e. AVR / Governor testing

3) TSO Initiated Test
    f. Secondary Fuel
    g. Ancillary Services Capability
    h. Availability
    i. Black Start

The following processes currently exist for each of these three testing categories (Testing Tariffs are prepared annually by the TSOs to reflect additional system costs associated with testing such as carrying more reserve while SEM-O calculates and settle the actual charges):

	1. Generator Initiated Full-Day Test	2. Generator Initiated Within-Day Test	3. TSO Initiated Test
Notice Period	In line with Grid Code / T&SC Typically 5 Working Days	In line with Grid Code/T&SC Typically Within Day	In line with Grid Code
SEM Treatment	Generator set to a Price Taker with associated nomination. Under Test in SEM for full day(s)	Not visible in SEM	Not visible in SEM
TSO Dispatch	Generator run in line with agreed testing profile / nomination Additional reserve may be carried.	Test Flag on dispatch instructions. Uninstructed imbalances incurred.	Generator dispatched as required. Constraint payments apply. Additional reserve may be carried.
Testing Tariffs Applicable	Yes - Tariff A or Tariff B	Not applicable	Not applicable
Capacity Payments	Based on min {MG, DQ}	Based on Availability	Based on Availability
Liable for Trip / SND Charges	No	Yes	Yes

10.8.3 PROPOSALS FOR UNITS UNDER TEST IN I-SEM

There are two options with regard to how units under test are treated in I-SEM. Both approaches largely maintain the current SEM treatment of units under test in I-SEM. The difference between the options relates to the treatment of the unit in the BM under a generator initiated test.

- Under the first approach, the unit has priority dispatch status when under generator initiated testing and hence is cashed out for any differences between ex-ante trades and the agreed testing profile.
- Under the second approach the unit remains as price maker under generator initiated tests and hence submits FPNs to reflect the agreed testing profile. However the incremental offers and decremental bids shall be set to PCAP and PFLOOR to ensure that the unit is not price setting.

The following tables summarise the two options. The RAs welcome comments from industry to which option is preferred in this regard or whether any alternatives should be considered.

	Generator Initiated tests (Full-Day or Within-Day)	TSO Initiated Test
Notice Period	In line with Grid Code Requirements, no later than X hours before day-ahead TSO security constrained run.	In line with Grid Code.
I-SEM Treatment	DAM and IDM: Unit can trade to reflect agreed testing profile to hedge against the imbalance price. BM: Set as price maker (FPN taken from agreed testing profile, no inc or dec submission) – settled at imbalance price for residual volume not captured in ex-ante trades.	DAM and IDM: Unit can trade as normal. BM: Submit PNs and inc / dec orders as normal, constraint payments apply.
TSO Dispatch	Test Flag on dispatch instructions. Generator run in line with agreed testing profile. Additional Reserve may be carried. Uninstructed imbalances incurred.	Generator dispatched (Inc / Dec from PN) as required.
Testing Tariffs	Yes as appropriate	Not Applicable
Capacity Payments	TBC	TBC
Liable for Trip/SND charges	No	Yes

Table 1 - Option 1 – Price Taker Status in BM under Generator Initiated Tests

	Generator Initiated tests (Full-Day or Within-Day)	TSO Initiated Test
Notice Period	In Line with Grid Code Requirements, no later than X hours before day-ahead TSO security constrained run.	In line with Grid Code.
I-SEM Treatment	DAM and IDM: Unit can trade to reflect agreed testing profile to hedge against the imbalance price. BM: Submit FPNs to reflect agreed testing profile, and inc / dec orders at price floor / cap respectively to be treated as price taker – settled at imbalance price for residual volume not captured in ex-ante trades.	DAM and IDM: Unit can trade as normal. BM: Submit PNs and inc / dec orders as normal, constraint payments apply.
TSO Dispatch	Test Flag on dispatch instructions. Generator run in line with agreed testing profile. Additional Reserve may be carried. Uninstructed imbalances incurred.	Generator dispatched (Inc / Dec from PN) as required.
Testing Tariffs	Yes as appropriate	Not Applicable
Capacity Payments	TBC	TBC
Liable for Trip/SND charges	No	Yes

Table 2 - Option 2 – Price Taker Status in BM under Generator Initiated Tests

11 NEXT STEPS

The SEM Committee invites interested parties to respond to this consultation presenting their view on the proposals and discussion in this paper.

The SEM Committee intends to make a decision in August 2015 on the detailed design of the Energy Trading Arrangements but will be carrying out a review of timelines in conjunction with the publication of this consultation. This decision will incorporate the comments to this paper and to the comments received on the Building Blocks Consultation Paper.

A public workshop will be held on 13 May 2015 in Dundalk and interested parties are asked to confirm their attendance to Kenny Dane (kenny.dane@uregni.gov.uk) and Kevin Hagan (khagan@cer.ie).

Responses to this Consultation Paper should be should be sent to Kenny Dane (kenny.dane@uregni.gov.uk) and Kevin Hagan (khagan@cer.ie) by 17:00 on 5 June 2015. Please note that the SEM Committee intends to publish all responses unless marked confidential[30].

[30] While the SEM Committee does not intend to publish responses marked confidential please note that both Regulatory Authorities are subject to Freedom of Information legislation.

12 APPENDIX A IMBALANCE SETTLEMENT WORKED EXAMPLES

This appendix outlines a number of worked examples to illustrate the concepts discussed in the Imbalance Settlement chapter. Note that the metered quantity, Q_M, is always assumed to be equal to the dispatch quantity, Q_D, in these examples for simplicity.

Example 1

- A generator unit sells 250MWh in the ex-ante markets at a price of 50 €/MWh.
- This generator unit submits a FPN which gives a volume of 270MWh and submits an incremental offer to the Balancing Market representing a volume of 50MWh at a price of 60 €/MWh.
- The TSO activates this incremental offer by dispatching the generator unit at a volume of 320MWh for a non-energy action.
- The imbalance price for this settlement period clears at 45 €/MWh.

$$
\begin{aligned}
C &= P_{EX} \,.\, Q_{EX} \\
&+ P_{IMB} \,.\, (Q_D - Q_{EX}) \\
&+ \mathit{max}(P_{BO} - P_{IMB}, 0) \,.\, \mathit{max}(Q_D - \mathit{max}(Q_{FPN}, Q_{EX}), 0) \\
&+ \mathit{min}(P_{BO} - P_{IMB}, 0) \,.\, \mathit{min}(Q_D - \mathit{min}(Q_{FA}, Q_{FPN}, Q_{EX}), 0)
\end{aligned}
$$

We can calculate the cashflow directly from the settlement algebra as follows:

Cashflow = (50 €/MWh) * (250MWh)
+ (45 €/MWh) * (320 MWh – 250MWh)
+ *max*(60 €/MWh – 45 €/MWh, 0) * *max*(320MWh – *max*(270MWh, 250MWh) ,0)
+ *min*(60 €/MWh – 45 €/MWh, 0) * ……..

= (50 €/MWh) * (250MWh)
+ (45 €/MWh) * (70MWh)
+ *max*(15 €/MWh, 0) * *max*(320MWh – 270MWh ,0)
+ *min*(15 €/MWh, 0) * ……..

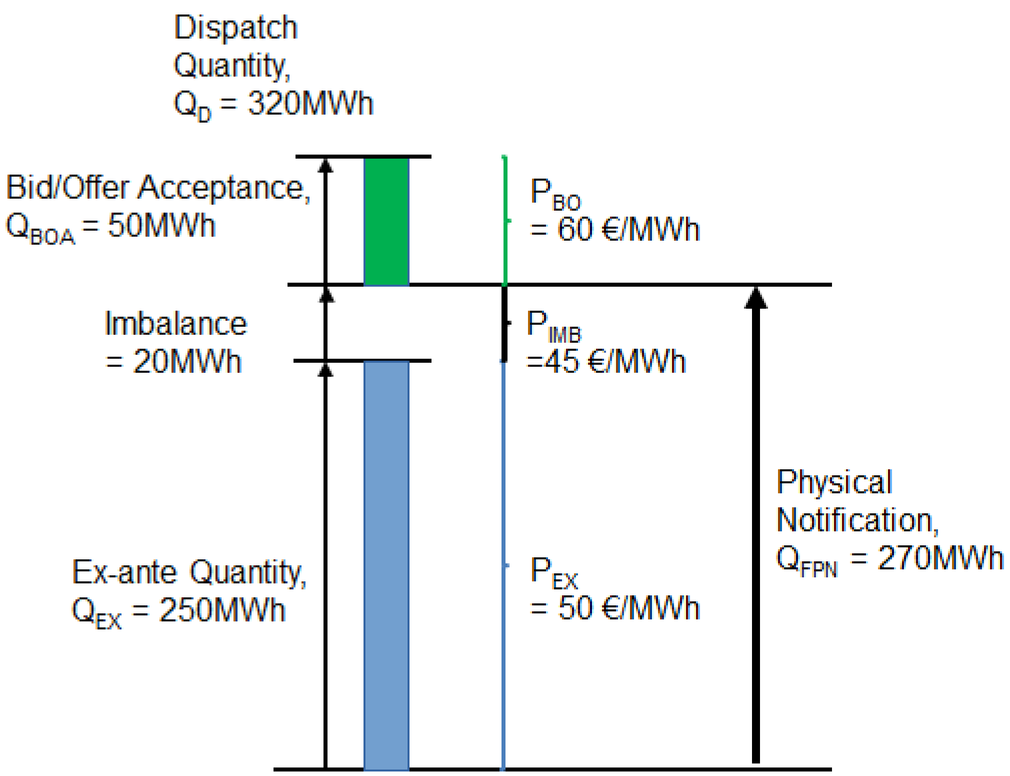
= (50 €/MWh) * (250MWh)
+ (45 €/MWh) * (70MWh)
+ (15 €/MWh) * (50MWh)

+ (0) * ....

= €12,500 + €3,150 + €750 +€0

= €16,400

An alternative way to examine settlement is to break it down into individual discrete trades, as shown in the diagram below.



In this example cashflow for the generator unit, in terms of individual trades, is comprised of:

1) Ex-ante trades of 250MWh at a price of 50 €/MWh;
2) An imbalance of 20MWh at a price of 45 €/MWh; and
3) An incremental offer acceptance of 50MWh at a price of 60 €/MWh.

The total cashflow is therefore equal to the sum of:

1) €12,500;
2) €900; and
3) €3,000.

This is equal to €16,400, which is the same cashflow as was calculated directly from the imbalance settlement algebra.

Example 2

- A generator unit sells 250MWh in the ex-ante markets at a price of 50 €/MWh.
- This generator unit submits a FPN which gives a volume of 230MWh and submits an incremental offer to the Balancing Market representing a volume of 50MWh at a price of 80 €/MWh.
- The TSO activates this incremental offer by dispatching the generator unit at a volume of 280MWh for a non-energy action.
- The imbalance price for this settlement period clears at 45 €/MWh.

$$
\begin{aligned}
C &= P_{EX} \,.\, Q_{EX} \\
&+ P_{IMB} \,.\, (Q_D - Q_{EX}) \\
&+ \mathit{max}(P_{BO} - P_{IMB}, 0) \,.\, \mathit{max}(Q_D - \mathit{max}(Q_{FPN}, Q_{EX}), 0) \\
&+ \mathit{min}(P_{BO} - P_{IMB}, 0) \,.\, \mathit{min}(Q_D - \mathit{min}(Q_{FA}, Q_{FPN}, Q_{EX}), 0)
\end{aligned}
$$

We can calculate the cashflow directly from the settlement algebra as follows:

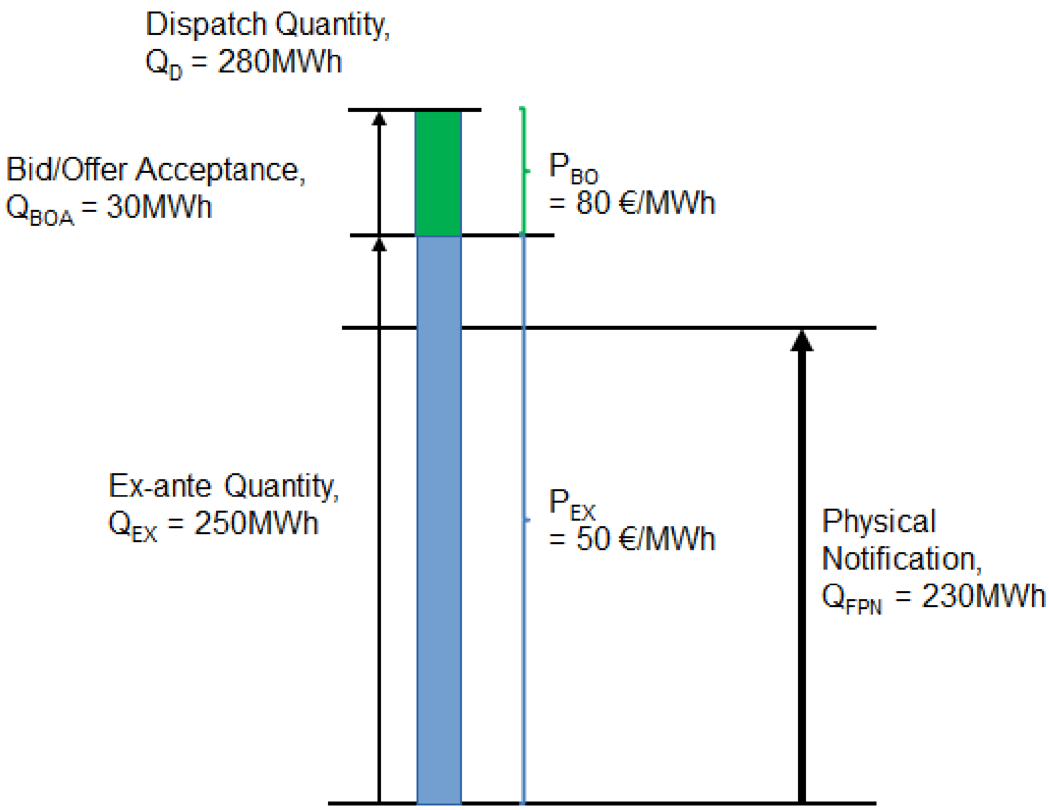
Cashflow = (50 €/MWh) * (250MWh)
+ (45 €/MWh) * (280 MWh – 250MWh)
+ *max*(80 €/MWh – 45 €/MWh, 0) * *max*(280MWh – *max*(230MWh, 250MWh) ,0)
+ *min*(80 €/MWh – 45 €/MWh, 0) * ……..

= (50 €/MWh) * (250MWh)
+ (45 €/MWh) * (30MWh)
+ *max*(35 €/MWh, 0) * *max*(280MWh – 250MWh ,0)
+ *min*(35 €/MWh, 0) * ……..

= (50 €/MWh) * (250MWh)
+ (45 €/MWh) * (30MWh)
+ (35 €/MWh) * (30MWh)
+ (0) * ……..

= €12,500 + €1,350 + €1,050 +€0
= €14,900

An alternative way to examine settlement is to break it down into individual discrete trades, as shown in the diagram below.



In this example cashflow for the generator unit, in terms of individual trades, is comprised of:

1) Ex-ante trades of 250MWh at a price of 50 €/MWh; and
2) An incremental offer acceptance of 30MWh at a price of 80 €/MWh.

The total cashflow is therefore equal to the sum of:

1) €12,500; and
2) €2,400.

This is equal to €14,900, which is the same cashflow as was calculated directly from the imbalance settlement algebra.

Example 3

- A generator unit (with FAQ of 300MWh) sells 250MWh in the ex-ante markets at a price of 50 €/MWh.
- This generator unit submits a FPN which gives a volume of 270MWh and submits a decremental bid to the Balancing Market representing a volume of 100MWh at a price of 45 €/MWh.
- The TSO activates this decremental bid by dispatching the generator unit at a volume of 170MWh for a non-energy action.
- The imbalance price for this settlement period clears at 70 €/MWh.

$C = P_{EX} \,.\, Q_{EX}$
$+ P_{IMB} \,.\, (Q_D - Q_{EX})$
$+ \mathit{max}(P_{BO} - P_{IMB}, 0) \,.\, \mathit{max}(Q_D - \mathit{max}(Q_{FPN}, Q_{EX}), 0)$
$+ \mathit{min}(P_{BO} - P_{IMB}, 0) \,.\, \mathit{min}(Q_D - \mathit{min}(Q_{FA}, Q_{FPN}, Q_{EX}), 0)$

We can calculate the cashflow directly from the settlement algebra as follows:

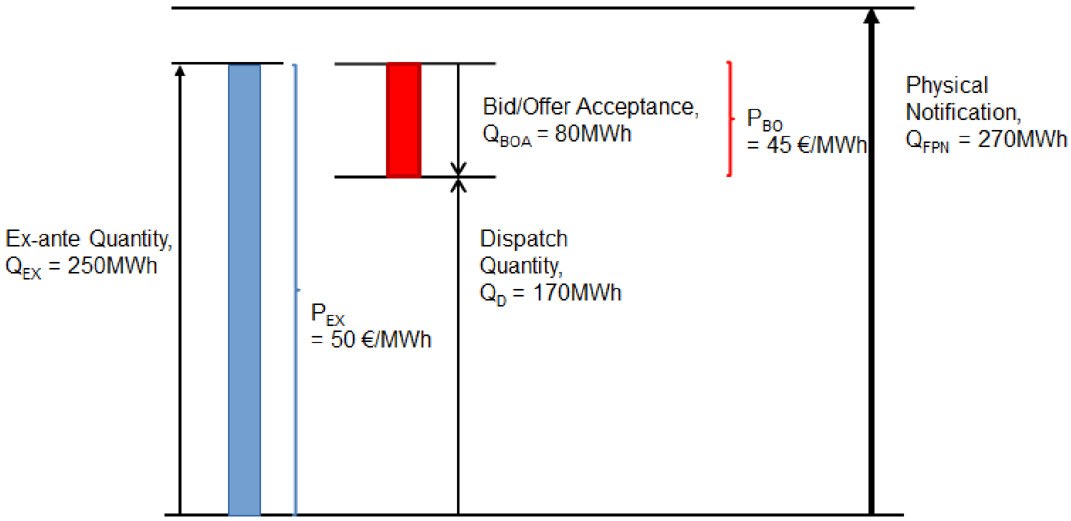
Cashflow = (50 €/MWh) * (250MWh)
+ (70 €/MWh) * (170 MWh – 250MWh)
+ *max*(45 €/MWh – 70 €/MWh, 0) * …….
+ *min*(45 €/MWh – 70 €/MWh, 0) * *min*(170MWh – *min*(300MWh, 270MWh, 250MWh), 0)

= (50 €/MWh) * (250MWh)
+ (70 €/MWh) * (- 80MWh)
+ *max*(- 25 €/MWh, 0) * …….
+ *min*(- 25 €/MWh, 0) * *min*(170MWh – 250MWh, 0)

= (50 €/MWh) * (250MWh)
+ (70 €/MWh) * (- 80MWh)
+ (0) * ……
+ (- 25 €/MWh) * (- 80MWh)

= €12,500 - €5,600 + €0 + €2,000
= €8,900

An alternative way to examine settlement is to break it down into individual discrete trades, as shown in the diagram below.



In this example cashflow for the generator unit, in terms of individual trades, is comprised of:

1) Ex-ante trades of 250MWh at a price of 50 €/MWh; and
2) A decremental bid acceptance of - 80MWh at a price of 45 €/MWh.

The total cashflow is therefore equal to the sum of:

1) €12,500; and
2) - €3,600.

This is equal to €8,900, which is the same cashflow as was calculated directly from the imbalance settlement algebra.

Example 4

- A generator unit (with FAQ of 300MWh) sells 250MWh in the ex-ante markets at a price of 50 €/MWh.
- This generator unit submits a FPN which gives a volume of 230MWh and submits a decremental bid to the Balancing Market representing a volume of 100MWh at a price of 30 €/MWh.
- The TSO activates this decremental bid by dispatching the generator unit at a volume of 130MWh for a non-energy action.
- The imbalance price for this settlement period clears at 40 €/MWh.

C = PEX . QEX
+ PIMB . (QD - QEX)
+ *max*(PBO - PIMB, 0) . *max*(QD – *max*(QFPN, QEX), 0)
+ *min*(PBO - PIMB, 0) . *min*(QD - *min*(QFA, QFPN, QEX), 0)

We can calculate the cashflow directly from the settlement algebra as follows:

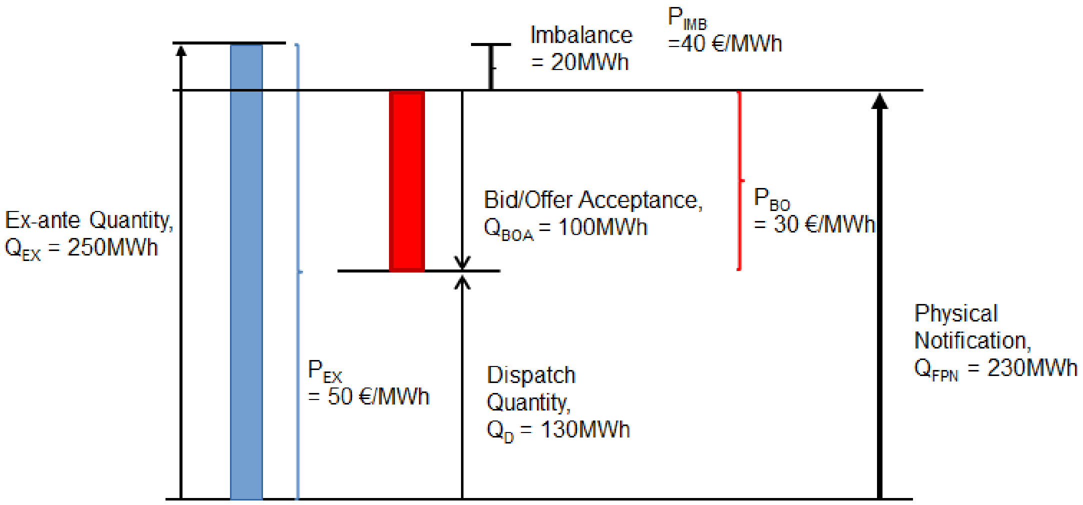
Cashflow = (50 €/MWh) * (250MWh)
+ (40 €/MWh) * (130 MWh – 250MWh)
+ *max*(30 €/MWh – 40 €/MWh, 0) * …….
+ *min*(30 €/MWh – 40 €/MWh, 0) * *min*(130MWh – *min*(300MWh, 230MWh, 250MWh), 0)

= (50 €/MWh) * (250MWh)
+ (40 €/MWh) * (- 120MWh)
+ *max*(- 10 €/MWh, 0) * …….
+ *min*(- 10 €/MWh, 0) * *min*(130MWh – 230MWh, 0)

= (50 €/MWh) * (250MWh)
+ (40 €/MWh) * (- 120MWh)
+ (0) * ……
+ (- 10 €/MWh) * (- 100MWh)

= €12,500 - €4,800 + €0 + €1,000
= €8,700

An alternative way to examine settlement is to break it down into individual discrete trades, as shown in the diagram below.



In this example cashflow for the generator unit, in terms of individual trades, is comprised of:

1) Ex-ante trades of 250MWh at a price of 50 €/MWh;
2) An imbalance of - 20MWh at a price of 40 €/MWh; and
3) A decremental bid acceptance of - 100MWh at a price of 30 €/MWh.

The total cashflow is therefore equal to the sum of:

1) €12,500;
2) - €800; and
3) - €3,000.

This is equal to €8,700, which is the same cashflow as was calculated directly from the imbalance settlement algebra.

Example 5

- A generator unit (with FAQ of 210MWh) sells 250MWh in the ex-ante markets at a price of 50 €/MWh.
- This generator unit submits a FPN which gives a volume of 230MWh and submits a decremental bid to the Balancing Market representing a volume of 100MWh at a price of 30 €/MWh.
- The TSO activates this decremental bid by dispatching the generator unit at a volume of 130MWh for a non-energy action.
- The imbalance price for this settlement period clears at 40 €/MWh.

$C = P_{EX} . Q_{EX}$
$+ P_{IMB} . (Q_D - Q_{EX})$
$+ \mathit{max}(P_{BO} - P_{IMB}, 0) . \mathit{max}(Q_D – \mathit{max}(Q_{FPN}, Q_{EX}), 0)$
$+ \mathit{min}(P_{BO} - P_{IMB}, 0) . \mathit{min}(Q_D - \mathit{min}(Q_{FA}, Q_{FPN}, Q_{EX}), 0)$

We can calculate the cashflow directly from the settlement algebra as follows:

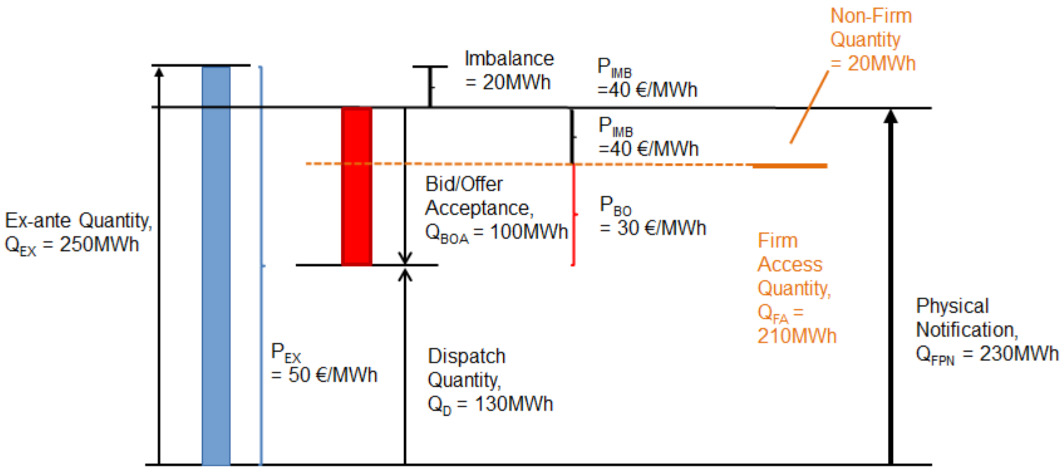
Cashflow = (50 €/MWh) * (250MWh)
+ (40 €/MWh) * (130 MWh – 250MWh)
+ *max*(30 €/MWh – 40 €/MWh, 0) * …….
+ *min*(30 €/MWh – 40 €/MWh, 0) * *min*(130MWh – *min*(210MWh, 230MWh, 250MWh), 0)

= (50 €/MWh) * (250MWh)
+ (40 €/MWh) * (- 120MWh)
+ *max*(- 10 €/MWh, 0) * …….
+ *min*(- 10 €/MWh, 0) * *min*(130MWh – 210MWh, 0)

= (50 €/MWh) * (250MWh)
+ (40 €/MWh) * (- 120MWh)
+ (0) * ……
+ (- 10 €/MWh) * (- 80MWh)

= €12,500 - €4,800 + €0 + €800
= €8,500

An alternative way to examine settlement is to break it down into individual discrete trades, as shown in the diagram below.



In this example cashflow for the generator unit, in terms of individual trades, is comprised of:

1) Ex-ante trades of 250MWh at a price of 50 €/MWh;
2) An imbalance of - 20MWh at a price of 40 €/MWh;
3) A decremental bid acceptance above FAQ of - 20MWh at the imbalance price of 40 €/MWh; and
4) A decremental bid acceptance within FAQ of - 80MWh at a price of 30 €/MWh.

The total cashflow is therefore equal to the sum of:

1) €12,500;
2) - €800;
3) - €800; and
4) - €2,400

This is equal to €8,500, which is the same cashflow as was calculated directly from the imbalance settlement algebra.

Example 6

- A dispatchable demand unit purchases 100MWh in the ex-ante markets at a price of 50 €/MWh.
- This dispatchable demand unit submits a FPN which gives a volume of - 100MWh and submits a decremental bid to the Balancing Market representing a volume of - 10MWh at a price of - 100 €/MWh.
- The TSO activates this decremental bid by changing the dispatchable demand to a volume of - 110MWh.
- The imbalance price for this settlement period clears at 60 €/MWh.

$$C = P_{EX} \, . \, Q_{EX}$$
$$+ P_{IMB} \, . \, (Q_D - Q_{EX})$$
$$+ \mathit{max}(P_{BO} - P_{IMB}, 0) \, . \, \mathit{max}(Q_D - \mathit{max}(Q_{FPN}, Q_{EX}), 0)$$
$$+ \mathit{min}(P_{BO} - P_{IMB}, 0) \, . \, \mathit{min}(Q_D - \mathit{min}(Q_{FPN}, Q_{EX}), 0)$$

We can calculate the cashflow directly from the settlement algebra as follows:

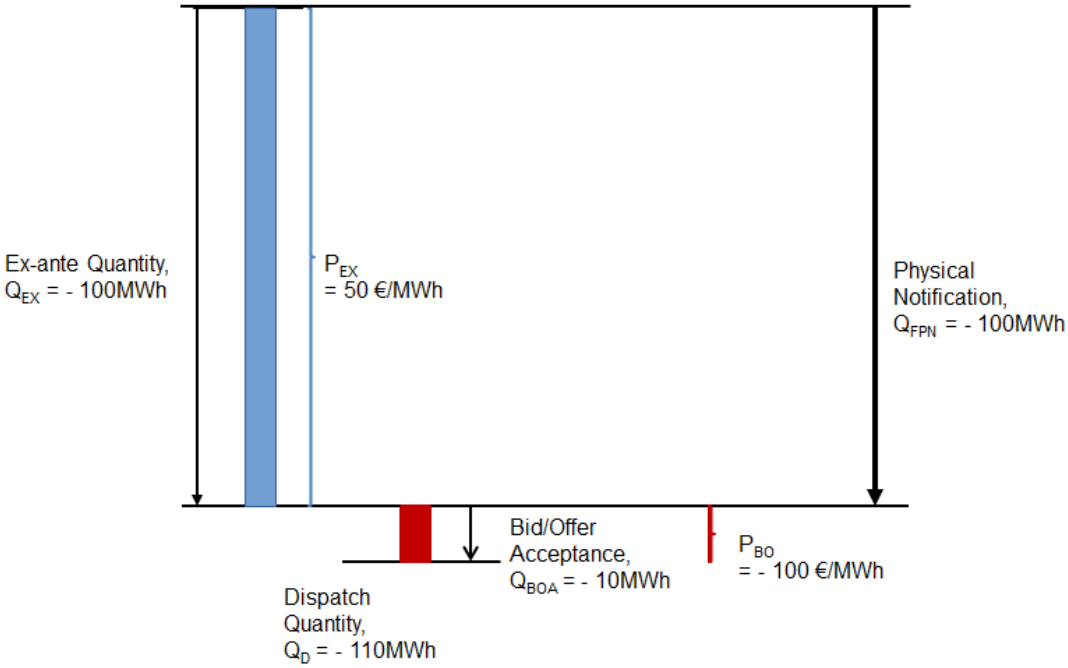
Cashflow = (50 €/MWh) * (- 100MWh)
+ (60 €/MWh) * (- 110MWh – (- 100MWh))
+ *max*(- 100 €/MWh – 60 €/MWh, 0) * …….
+ *min*(- 100 €/MWh – 60 €/MWh, 0) * *min*(- 110MWh – *min*(- 100MWh, - 100MWh), 0)

= (50 €/MWh) * (- 100MWh)
+ (60 €/MWh) * (- 110MWh + 100MWh)
+ *max*(- 160 €/MWh, 0) * …….
+ *min*(- 160 €/MWh, 0) * *min*(- 110MWh + 100MWh, 0)

= (50 €/MWh) * (- 100MWh)
+ (60 €/MWh) * (- 10MWh)
+ (0) * ……
+ (- 160 €/MWh) * (- 10MWh)

= - €5,000 - €600 + €0 + €1,600
= - €4,000

An alternative way to examine settlement is to break it down into individual discrete trades, as shown in the diagram below.



In this example cashflow for the dispatchable demand unit, in terms of individual trades, is comprised of:

1) Ex-ante trades of - 100MWh at a price of 50 €/MWh; and
2) A decremental bid acceptance of - 10MWh at a price of -100 €/MWh.

The total cashflow is therefore equal to the sum of:

1) - €5,000;
2) + €1,000;

This is equal to - €4,000, which is the same cashflow as was calculated directly from the imbalance settlement algebra.

Example 7

- A dispatchable demand unit purchases 100MWh in the ex-ante markets at a price of 50 €/MWh.
- This dispatchable demand unit submits a FPN which gives a volume of - 100MWh and submits a incremental offer to the Balancing Market representing a volume of + 10MWh at a price of 200 €/MWh.
- The TSO activates this incremental offer by changing the dispatchable demand to a volume of - 90MWh.
- The imbalance price for this settlement period clears at 60 €/MWh.

$C = P_{EX} . Q_{EX}$
$+ P_{IMB} . (Q_{D} - Q_{EX})$
$+ \mathit{max}(P_{BO} - P_{IMB}, 0) . \mathit{max}(Q_{D} – \mathit{max}(Q_{FPN}, Q_{EX}), 0)$
$+ \mathit{min}(P_{BO} - P_{IMB}, 0) . \mathit{min}(Q_{D} – \mathit{min}(Q_{FPN}, Q_{EX}), 0)$

We can calculate the cashflow directly from the settlement algebra as follows:

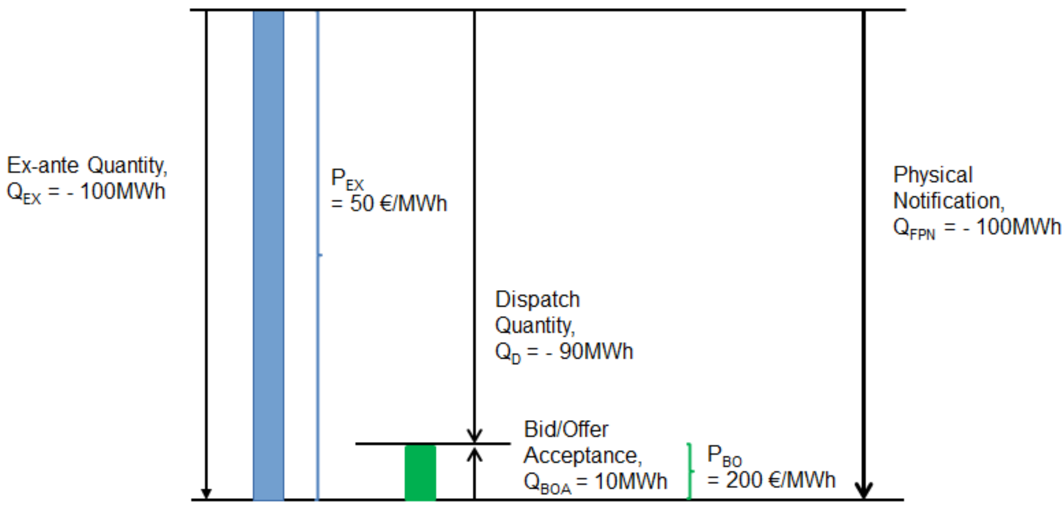
Cashflow = (50 €/MWh) * (- 100MWh)
+ (60 €/MWh) * (- 90MWh - (- 100MWh))
+ *max*(200 €/MWh - 60 €/MWh, 0) * *max*(- 90MWh – *max*(- 100MWh, - 100MWh), 0)
+ *min*(200 €/MWh - 60 €/MWh, 0) * ……

= (50 €/MWh) * (- 100MWh)
+ (60 €/MWh) * (- 90MWh + 100MWh)
+ *max*(140 €/MWh, 0) * *max*(- 90MWh – (- 100MWh), 0)
+ *min*(140 €/MWh, 0) * …..

= (50 €/MWh) * (- 100MWh)
+ (60 €/MWh) * (10MWh)
+ (140 €/MWh) * (10MWh)
+ (0) * ……

= - €5,000 + €600 + €1,400 + €0
= - €3,000

An alternative way to examine settlement is to break it down into individual discrete trades, as shown in the diagram below.



In this example cashflow for the dispatchable demand unit, in terms of individual trades, is comprised of:

1) Ex-ante trades of - 100MWh at a price of 50 €/MWh; and
2) An incremental offer acceptance of + 10MWh at a price of 200 €/MWh.

The total cashflow is therefore equal to the sum of:

1) - €5,000;
2) + €2,000;

This is equal to - €3,000, which is the same cashflow as was calculated directly from the imbalance settlement algebra.

Example 8

- A supplier purchases 250MWh in the ex-ante markets at a price of 50 €/MWh.
- The supplier's Metered Quantity is equal to -280MWh.
- The imbalance price for this settlement period clears at 60 €/MWh.

C = P_{EX} . Q_{EX} + P_{IMB} . (Q_M - Q_{EX})

We can calculate the cashflow directly from the settlement algebra as follows:

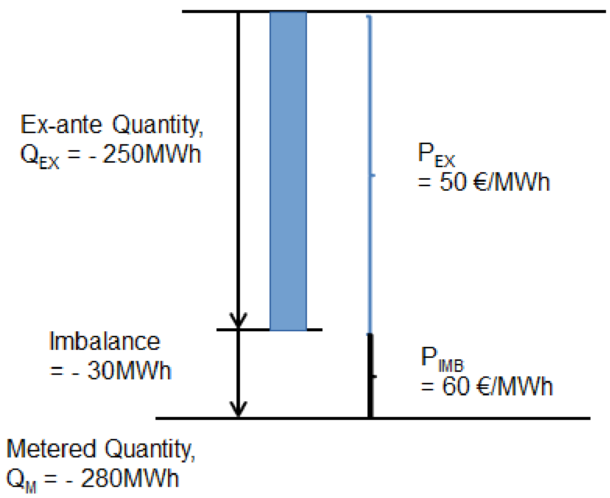
Cashflow = (50 €/MWh) * (- 250MWh)
+ (60 €/MWh) * (- 280MWh - (- 250MWh))

= (50 €/MWh) * (- 250MWh)
+ (60 €/MWh) * (- 280MWh + 250MWh)

= (50 €/MWh) * (- 250MWh)
+ (60 €/MWh) * (- 30MWh)

= - €12,500 - €1,800
= - €14,300

An alternative way to examine settlement is to break it down into individual discrete trades, as shown in the diagram below.



In this example cashflow for the supplier, in terms of individual trades, is comprised of:

3) Ex-ante trades of - 250MWh at a price of 50 €/MWh; and
4) An imbalance of - 30MWh at a price of 60 €/MWh.

The total cashflow is therefore equal to the sum of:

3) - €12,500;
4) - €1,800;

This is equal to - €14,300, which is the same cashflow as was calculated directly from the imbalance settlement algebra.

Example 9

- A supplier purchases 250MWh in the ex-ante markets at a price of 50 €/MWh.
- The supplier’s Metered Quantity is equal to -220MWh.
- The imbalance price for this settlement period clears at 40 €/MWh.

$C = P_{EX} . Q_{EX}$ $+ P_{IMB} . (Q_M - Q_{EX})$

We can calculate the cashflow directly from the settlement algebra as follows:

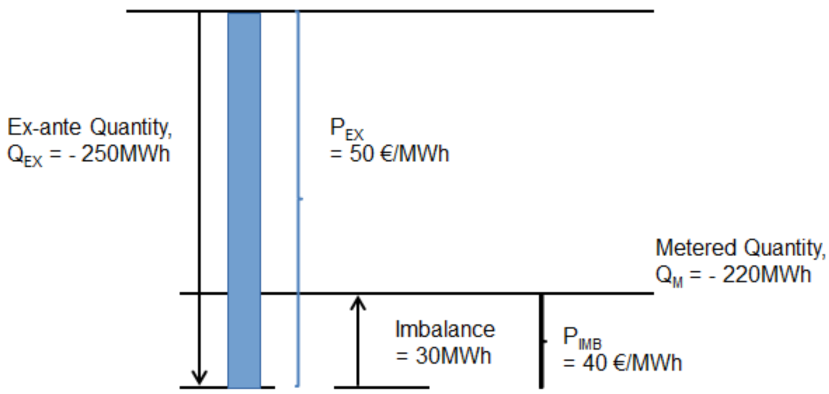
Cashflow = (50 €/MWh) * (- 250MWh)
+ (40 €/MWh) * (- 220MWh - (- 250MWh))

= (50 €/MWh) * (- 250MWh)
+ (40 €/MWh) * (- 220MWh + 250MWh)

= (50 €/MWh) * (- 250MWh)
+ (40 €/MWh) * (30MWh)

= - €12,500 + €1,200
= - €11,300

An alternative way to examine settlement is to break it down into individual discrete trades, as shown in the diagram below.



In this example cashflow for the supplier, in terms of individual trades, is comprised of:

5) Ex-ante trades of - 250MWh at a price of 50 €/MWh; and
6) An imbalance of + 30MWh at a price of 40 €/MWh.

The total cashflow is therefore equal to the sum of:

5) - €12,500;
6) + €1,200;

This is equal to - €11,300, which is the same cashflow as was calculated directly from the imbalance settlement algebra.

13 APPENDIX B ACRONYMS

BM	Balancing Market
BOA	Bid-Offer Acceptance
CACM	Capacity Allocation and Congestion Management
DAM	Day Ahead Market
DBC	Dispatch Balancing Cost
DS3	Delivering a Secure Sustainable Electricity System
EBNC/NCEB	Electricity Balancing Network Code / Network Code on Electricity Balancing
ETA	Energy Trading Arrangements
EUPHEMIA	Pan-European Hybrid Electricity Market Integration Algorithm (Price coupling algorithm, used to calculate energy allocation and electricity prices across Europe, maximising the overall welfare and increasing the transparency of the computation of prices and flows)
FPN	Final Physical Notification
IDM	Intraday Market
ISP	Imbalance Settlement Period
MDP	Meter Data Providers
NEMO	Nominated Electricity Market Operator
NIV	Net Imbalance Volume
OBK	Order Book
PAR	Price Average Referencing
PN	Physical Notification
RLG	Rules Liaison Group
RoCoF	Rate of Change of Frequency
SNSP	System Non-Synchronous Penetration
STOR	Short Term Operating Reserve
TSO	Transmission System Operator
XBID	Cross-Border Intraday