Integrated Single Electricity Market (I-SEM)

Energy Trading Arrangements Detailed Design

Building Blocks Consultation Paper

SEM-15-011

11 February 2015

Contents

1 INTRODUCTION

1.1 THE ETA DETAILED DESIGN PHASE

The Energy Trading Arrangements (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 High Level Design of the I-SEM.

Within the ETA Detailed Design there is a requirement first to establish the workings of the Energy Trading Arrangements at a high level to enable procurement of the market 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. These policy issues are being dealt with early in the detailed design in order to ensure that the markets work is as focused as possible on the detailed design issues.

1.2 I-SEM BUILDING BLOCKS

The Regulatory Authorities (RAs) have published three briefing papers on the I-SEM ETA Building Blocks and held three industry workshops. Following the workshops, the RAs sought comment from interested parties on the detail of the briefing papers and workshops and observations on the overall process. Fifteen non-confidential responses were received from interested parties and these were published on 9 January 2015.

The purpose of this Consultation Paper is to set out the key topics for consideration, their implementation in the current SEM and how they might be implemented in I-SEM.

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

- Treatment of Transmission Losses
- Treatment of Constraints
- Treatment of Firm Access
- Treatment of Priority Dispatch
- Treatment of Curtailment
- I-SEM De Minimis Level
- Policy for Currency in I-SEM
- Market Information in I-SEM

There are a number of topics that were discussed in the briefing papers and workshops but are not included in this consultation. These have not been included because having taken account of feedback from participants and having considered the overall ETA process, it was considered that these are better covered as part of the detailed markets design.

This Building Blocks Consultation Paper deals with a number of building blocks concepts (e.g. losses, firm access) at a high level. The detailed design of the Balancing market will determine the detailed treatment of the various different technologies (e.g. thermals, wind, DSUs and storage) in terms of pricing and settlement. In addition, for some technologies, there may be interactions between their treatment in the energy trading arrangements and other aspects of the energy market such as the CRM or system services.

2 TREATMENT OF TRANSMISSION LOSSES

2.1 INTRODUCTION

At a high level, transmission system losses refer to the difference between the amount of electricity injected into the transmission system and the amount of electricity taken off the transmission system.

In this chapter, the treatment of transmission losses in the current SEM is described for consideration in the I-SEM and potential implementation options are discussed.

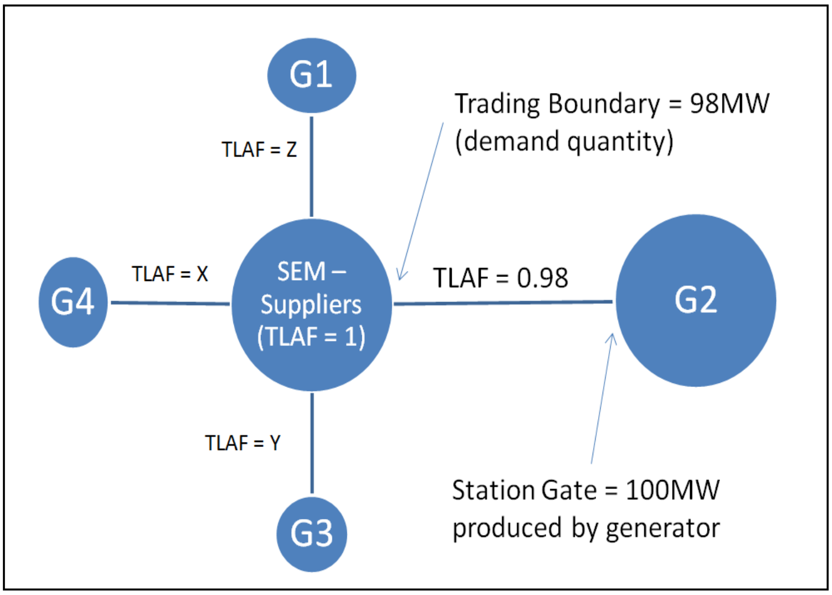
2.2 TREATMENT OF TRANSMISSION SYSTEM LOSSES IN SEM

The final High Level Design Decision[1] for the current SEM set out that Transmission Loss Adjustment Factors (TLAFs) would be calculated on a locational basis and would be applied to the outputs of each generator, with the loss adjustment factors being set ex-ante each year.

The treatment of transmission losses in the SEM was confirmed most recently by the SEM Committee in June 2012 (SEM-12-049). The current methodology in SEM uses the same principles (TLAFs calculated on a locational basis) as those in the original high level design but includes a compression calculation which tightens the range of the loss factors.

In SEM all transmission losses are accounted for by generators and interconnector users through an adjustment to their Commercial Offer Data. No losses are allocated to suppliers either in aggregate or individually. The supplier TLAF is accordingly set to 1.

[1] "SEM High Level Design Decision Paper", AIP/SEM/42/05. 10th June 2005. See Section 3.8.



Differences between the ex-ante set TLAFs and actual transmission losses are recovered from all suppliers by calculating the cost of losses, using the SMP in each settlement period and allocating this cost across supplier demand (i.e. global aggregation).

2.3 TRANSMISSION LOSSES IMPLEMENTATION IN I-SEM

The I-SEM HLD Decision did not explicitly signal any changes to the current policy on losses and therefore the approach to this issue has been to examine solutions for making the current policy work in I-SEM.

Feedback to the RAs at the ETA Workshops and in subsequent submissions has strongly suggested that the losses policy should be fully considered by SEM Committee and that a mere implementation of the current policy will not suffice. Many respondents stated that because losses play little part in a generator's decision to locate, they should be uniform and socialised.

However, other respondents felt that to re-open this policy decision now would be an unhelpful and contentious distraction and that the current method of calculating TLAFs on an ex-ante locational basis should continue. There was also some opposition to the approach for dealing with ex-ante trades (in the Day Ahead and Intraday Markets) at the Trading Boundary and physical notifications at the Station Gate.

While the SEM Committee notes this feedback, its initial view is that the implementation of I-SEM does not, of itself, necessitate a change in transmission losses policy. However, if respondents believe that there are specific reasons why the I-SEM may require the existing policy to be re-evaluated these should be set out in any response to this consultation paper. Nevertheless, even in the absence of any such arguments, the intention would be that the I-SEM implementation will be sufficiently flexible so as not to preclude any future consideration.

2.3.1 TREATMENT OF GENERATOR LOSSES

Day Ahead and Intraday Markets

Based on discussions at the working group and through the development of the briefing paper, it would appear that there is an approach for the I-SEM which maintains the current high level policy on transmission losses[2].

The traded volumes in the Day Ahead Market (DAM) and Intra Day Market (IDM) would be at the Trading Boundary, i.e. net of transmission losses. Market Participants would thus have to account for their losses in the price aspect of their offers to these markets.

The physical notifications of Market Participants would be at the station gate, i.e. gross of transmission losses. Market Participants themselves would be responsible for converting traded volumes to physical quantities at the station gate. Units would have to produce the correct gross volume at the station gate to be in balance.

The metered generation volumes of generators would then be adjusted by their individual TLAF in imbalance settlement.

As an example, under this approach, a generator with a TLAF of 0.98 which sells 98 MWh in the DAM would have to account for its own transmission losses in its offer price and would need to make a physical notification of 100 MW to the TSO.

Balancing Market

Notwithstanding the fact that trades in the IDM and DAM would be priced at the trading boundary, net of losses, there is the option in the Balancing Market of pricing balancing actions at either the trading boundary or at the station gate. Which option is adopted may depend on the format of offers and bids, in particular the extent to which they mirror the format of offers and bids into the DAM and IDM and possibly also the extent to which they are cost-reflective.

The possible advantage of referring balancing actions to the station gate is that offers and bids could be expressed in terms of the actual costs of the participant rather than having to always adjust these costs to take into account the applicable TLAF.

[2] The proposed approach will also work for generator DLAFs for distribution connected generators operating in the market.

Option (a): If balancing actions are priced at the trading boundary, the generator would be paid the offer price (or, if higher, the balancing price) on the lost-adjusted volume at the trading boundary, i.e. POij*(QMij*TLAFij),

I. where POij is the offer price (or the balancing price) for generator i in settlement period j;

II. QMij the MWh metered at the station gate; and

III. TLAFij the transmission loss adjustment factor.

Consequently, in order to cover its costs under this option, the generator having an incremental cost of €50.00/MWh and a TLAF of 0.98 would have to submit an offer price of €51.02/MWh (being €50/MWh divided by the 0.98).

The imbalance quantity for such a generator would be:

QEIij = QMij*TLAFij - QBOAij*TLAFij – QIDij - QDAij

I. where QEIij is the energy imbalance quantity (in MWh) for generator i in period j;

II. QBOAij is the quantity of accepted offers and bids as measured in MWh at the station gate; and

III. QDAij and QIDij are the MWh quantities sold in the day-ahead and intraday markets, respectively.

Option (b): If, on the other hand, balancing actions are priced at the station gate, the generator would be paid the offer price (or, if higher, the balancing price) on the metered quantity at the station gate, i.e. POij*QMij. Under this option, the generator could submit an offer price of €50/MWh, i.e. its avoidable cost, and would be guaranteed to cover its costs.

The imbalance quantity for such a generator would, as above, be:

QEIij = QMij*TLAFij - QBOAij*TLAFij – QIDij - QDAij

Thus the only difference between the two options is that in Option (a) the generator submits a price knowing that the price will be applied to the loss-adjusted metered quantity, whereas in Option (b) the price is applied to the metered quantity directly.

Although the offer prices may be different under the two options, the choice of option does not necessarily imply a change in the order of dispatch of plant with different TLAFs. Under Option (b), the TSO could continue to apply the current ex-ante TLAFs to the participant-submitted prices and dispatch in order of the adjusted prices. The outcome would then be identical to the current SEM.

Note that pricing balancing actions at the station gate would have no effect on settlements, with the only difference between the two options being nothing more than whether it is the participant or the TSO that makes the TLAF adjustment before dispatch.

However, the main differences arise where:

- Any future changes to TLAFs, be it application of current policy or otherwise, may have different impact on participants. i.e. Option (b) would require changes to the TSOs' systems whereas option (a) would require changes to each participant's systems while also noting that a system of being able to reflect costs directly, without having to adjust for TLAFs, may be simpler for new entrants.

- While option (a) is more consistent with the existing SEM, in that it is specific to the particular treatment of losses currently employed in dispatch, option (b) would be amenable to many different treatments of losses in dispatch, and thus may be a more flexible approach.

Finally, if a common merit order under the Electricity Balancing Network Code was progressed it is worth considering in the context of these options albeit that any changes should be implementable under each option.

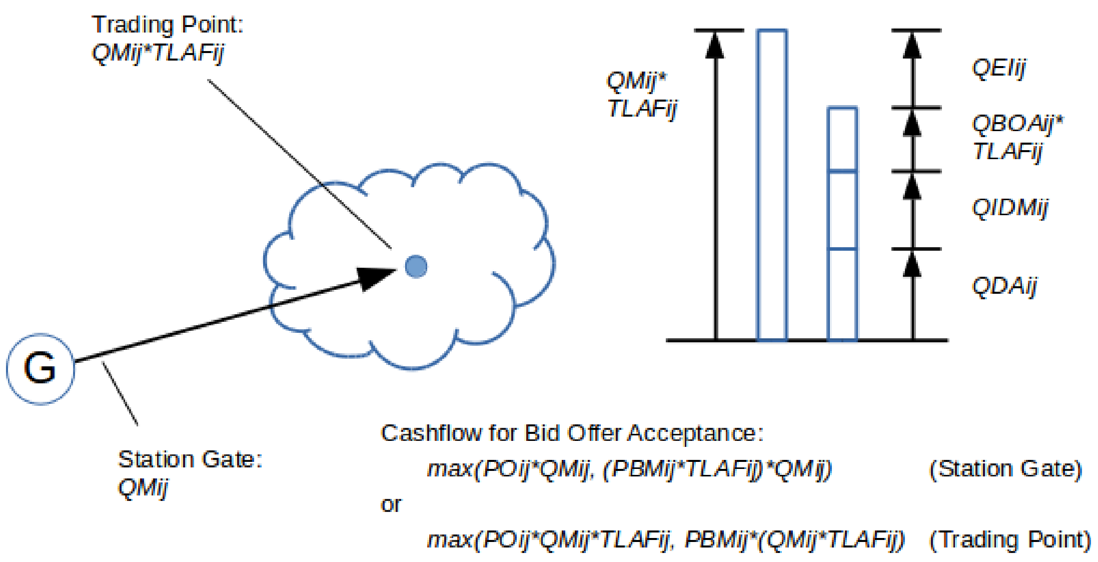


Figure: Bid Offers measured at Station Gate versus Trading Point/Boundary

2.3.1.1 GENERATOR LOSS FACTOR DETAILED WORKED EXAMPLE

The following is a worked example to help to explain the above proposed treatment of loss factors for generators according to Option (a).

Unit Capacity is 450MW at the station gate.
Unit TLAF is 0.98.

The Day Ahead Market (One hour Trading Period)

The unit's price at the station gate is 50 €/MWh.

The unit:

- submits an offer of 441MWh in the one hour trading period to the Day Ahead Market (DAM) (equivalent to 450MWh at the station gate) at 51.0204 €/MWh;
- is scheduled at 392MWh in the DAM (equivalent to 400MWh at the station gate) for the hour (comprising half hours X1 and X2);
- makes a physical notification equivalent to 400MWh (at the station gate) to the TSO for hour X.

The Balancing Market (Half hour Trading Periods X1 and X2)

The unit has no trades in the Intraday Market (IDM).

The unit has 50MW of unused capacity at the station gate to offer into the Balancing Market (BM) for half hours X1 and X2.

The unit

- submits an offer of 50MW to the BM with an offer price of 51.0204 €/MWh for each half hour X1 and X2;
- is dispatched up by 20.4082MW (at the station gate) by the TSO for half hour X1;
- is dispatched up by 10.2041MW (at the station gate) by the TSO for half hour X2.

Settlement

Assume that the unit sets the marginal clearing price in all markets.

In hour X the unit therefore receives:

(392MWh * 51.0204 €/MWh)
+ (20.4082MW * 0.98 * 51.0204 €/MWh * 0.5 hour)

+ (30.6123MW * 0.98 * 51.0204 €/MWh * 0.5 hour);

= €19999.996 + €510.204 + €765.307;

= €21275.51

The unit's costs at the station gate are:

(400MWh * 50 €/MWh)
+ (20.4082MW * 50 €/MWh * 0.5 hour)
+ (30.6123MW * 50 €/MWh * 0.5 hour);

= €20000 + €510.205 + €765.3075;

= €21275.51

By contrast, under Option (b), the unit will submit an offer of €50/MWh and will be paid

(392MWh * 51.0204 €/MWh)
+ (20.4082MW * 50 €/MWh * 0.5 hour);
+ (30.6123MW * 50 €/MWh * 0.5 hour);

= €19999.996 + €510.205 + €765.307;

= €21275.51

which reflects exactly its costs, and which is the same as under Option (a).

2.3.2 INTERCONNECTOR LOSS FACTORS

The loss factors on DC interconnectors will be incorporated within the DAM and most likely the IDM, as well as in dispatch. In the DAM and IDM, the relevant algorithms take loss factors into account when scheduling flows between bidding zones, such that if a 2% loss factor exists between bidding zones, the price differential must be at least 2% before exchanges between the bidding zones are scheduled.

The RAs put forward the following proposals for interconnector losses in the first briefing paper and they were discussed at the first Working Group. There are two potential methods for how this could be done as follows:

Utilise a Single Loss Factor

The two interconnectors between I-SEM and GB (Moyle and EWIC) have notably different loss factors, with Moyle losses being typically around 2% and EWIC losses around 6%.

With a single loss factor, the links between I-SEM and GB would be represented in EUPHEMIA with a loss factor equal to the weighted average of the loss factors on Moyle and EWIC. With this approach the aggregate loss factor would be set at a level different to the loss factor on each interconnector line (once the loss factors on the two ICs are different). The derivation of the aggregate loss factor is set out below.

	Loss Factor	Capacity (MW)
Moyle	2%	250
EWIC	6%	500
Combined	4.6%	750

While this approach would appear to be straightforward to understand and implement, it is likely that it would not be optimal. The loss factor by the nature of its inclusion in the market algorithm creates a dead band for trading between I-SEM and GB.

However, in this case the dead band arrived at does not represent either line correctly. Where the price differential between I-SEM and GB is between 2% and 4.6% no flow will happen between the two markets even though the price differential suggests that flows should occur through the Moyle. This would not represent an optimal outcome for either I-SEM or for the Moyle interconnector.

Conversely, price differentials between 4.6% and 6% would result in exchanges being scheduled over EWIC even though it would not be efficient to do so.

Utilise more than One Loss Factor

Under this approach, the Moyle and EWIC lines would each have their own individual loss factor in the market. Such an approach would see power flow between I-SEM and GB on the Moyle once the price differential reached 2% and power flow between I-SEM and GB on EWIC once the differential reached 6%. Such an approach would require a specific implementation of the I-SEM GB bidding zone border; initial discussions with those involved in developing the EU market algorithm EUPHEMIA have suggested that such an approach is possible.

The table below sets out the impact on I-SEM GB flows based on a number of different scenarios using the aggregate loss factors and the separate loss factors.

		I-SEM GB Price Differential			
		<2%	2-4.6%	4.6-6%	>6%
Aggregate Loss Factor	Moyle Flow				
	EWIC Flow				
Two Loss Factors	Moyle Flow				
	EWIC Flow				

Under the single loss factor approach, no trading occurs on either interconnector until the price differential between the two markets increases above 4.6%. With the two loss factors approach, trading will begin on Moyle whenever the price differential increases above 2%, and will begin on EWIC when the price differential reaches 6%.

The SEM Committee is of the view that the best approach for I-SEM is to represent the two interconnectors in market systems with their own loss factors and not to employ an aggregate loss factor. This view was shared by the majority of written responses following the three workshops. Other borders between Bidding Zones on mainland Europe will typically be represented by a single loss factor even though there may be more than one circuit, each having different loss factors. The difference is likely to be that the losses on the interconnection between I-SEM and GB are significantly higher than the losses on these other borders, given that the I-SEM / GB interconnection comprises of lengthy DC cables rather than potentially shorter circuits with no AC-DC conversion. Consequently, the inefficiency of scheduled exchanges on the I-SEM / GB border is likely to be higher as a consequence of using a single loss factor.

It could be that the same argument suggests that the EWIC and Moyle interconnectors should be represented by two or more virtual interconnectors with different loss factors. The losses on EWIC and Moyle could vary with power flow, and hence it may be appropriate to define virtual interconnectors to represent different flow levels. Pursuing such an approach would be contingent on the technical capabilities of the market systems and algorithm. If such an approach was to be pursued it will need to be considered in the implementation phase of I-SEM and will need to be discussed in conjunction with EUPHEMIA algorithm developers.

The implementation of the chosen methodology will also need to be considered in the context of the Intraday Market and the Balancing Market. The final design for the treatment of interconnector losses in the EU Intraday Market is not yet finalised and the implementation in I-SEM will need to be informed by this. However, it is expected that the principles for the treatment of losses in the Day Ahead Market should apply to the intraday market. Similarly, it is expected that the TSOs will take account of losses on the interconnectors using the same fundamental principles when developing cross border balancing arrangements.

It is also worth noting that Financial Transmission Rights (FTRs) hedge against congestion only and not losses and therefore congestion rent payable to FTR holders will not include losses. i.e. if there is a price difference between I-SEM and GB, but no flow on EWIC because of the losses deadband, then no payment would be made to the holder of an FTR.

2.3.3 OUTTURN LOSS FACTOR CORRECTION

The Transmission Loss Adjustment Factors (TLAFs) for generators in SEM are currently calculated in the year previous to implementation and published around four months before the start of the year. Separate TLAFs are calculated for each generator, varying by day and night and from month to month, by undertaking power system studies using assumed patterns of generation and demand. There is inevitably a difference between the losses allocated to the generators by these ex-ante calculated TLAFs and actual out-turn losses. The cost of these residual losses is currently dispersed pro rata on the proportion of non-quarterly hour demand meters in a supplier's demand portfolio as part of global aggregation.

It is proposed that this issue is addressed as part of the overall global aggregation solution in the markets Consultation Paper. This is primarily because outturn losses cannot be differentiated from the other constituents that make up global aggregation[3]. Further, global aggregation was not specifically discussed in the first three Rules Liaison Group Meetings. It is however scheduled for discussion in the upcoming workshops and therefore it would be pre-emptive to propose options at this stage.

2.4 SUMMARY

In summary, the SEM Committee has set out a number of issues in relation to the treatment of losses and makes the following proposals.

For Generators:

- Volumes that are traded in the DAM and the IDM should be at the trading boundary and therefore net of losses. This means that generators would account for their losses in their commercial offers in the ex-ante markets.
- Conversely the physical notifications made by generators to the TSO shall be at the station gate and therefore gross of losses. It is proposed that it will be the responsibility of the generator to convert its contracted trades from the DAM and IDM into a physical notification.

[3] Global aggregation also includes profile errors, meters errors, time-switch errors, theft, and CT/VT errors.

- Hence the metered generation volumes of generators will be adjusted by their individual Transmission Loss Adjustment Factor (TLAF) in imbalance settlement.

For Interconnectors:

- The loss factors for each interconnector should be represented separately in the market systems as opposed to employing an aggregate weighted loss factor.

Lastly it is proposed that the differences between ex-ante and outturn losses should be smeared across all suppliers through global aggregation. A decision in this regard will be considered in the context of the overall global aggregation solution for I-SEM in the markets paper.

3 TREATMENT OF CONSTRAINTS

3.1 INTRODUCTION

Constraints arise when the transmission network cannot accept all the generation in a given area because the proposed flow along a transmission line resulting from an economic schedule or dispatch exceeds either the thermal or voltage limits. The TSO may also need to dispatch generation away from the economic dispatch in order to provide sufficient generation in the right locations to supply ancillary services. The TSO resolves constraints on a least cost basis, by dispatching those generation plants that can best resolve the constraint. Hence, when constraints arise, some economic units may be turned off or down ('constrained down') and other units, that are un-economic or out of merit, may be turned on or up ('constrained up').

3.2 TREATMENT OF CONSTRAINTS IN SEM

The current policy in the SEM is that units which are the most economic to meet demand should not be at a financial disadvantage due to any constraints. Hence, an ex-post unconstrained market schedule is calculated, and used as the basis for setting SMP. Units whose output is adjusted either up or down due to constraints are compensated for any deviations from their Market Schedule Quantity (MSQ).

Specifically, units that are constrained down receive the difference between their offer price and the system marginal price (SMP), i.e. they keep their inframarginal rent for the portion of their MSQ that is above their dispatch quantity. Units that are constrained up receive their offer price for the portion of their dispatch quantity that is above their MSQ.

The current market arrangements require generators to bid their Short Run Marginal Costs (SRMC). This requirement is enforced through the Bidding Code of Practice and ensures that generators retain only their inframarginal rent when constrained down and, conversely, only receive their SRMC when constrained up.

3.3 IMPLEMENTATION OF CONSTRAINTS POLICY IN I-SEM

The I-SEM HLD Decision did not signal any changes to the current policy on constraint payments. Having considered this issue, the SEM Committee is minded that the treatment of constraints should remain the same in I-SEM as in the current SEM within the context of changing from an ex-post to an ex-ante market. The principle to be maintained is that a generator is entitled to receive the Day Ahead (or Intraday) price or be compensated for lost profits, as revealed through their offer prices, if they obtain a matched trade in these markets and are unable to generate to meet that trade due to a constraint. In essence this means that:

- a unit that obtains an ex-ante market position or that is dispatched up will receive at least its offer price, and
- a unit that is constrained down from its ex-ante market position (and which has firm access) will retain its inframarginal rent.

Given that the Balancing Market will be mandatory, it is expected that any deviation of plant away from its physical notification by the TSOs will be initiated through the Balancing Market, and thus constraints will be resolved as part of the Balancing Market.

The SEM Committee recognises that there are a number of issues with the implementation of the policy on constraints that will be resolved in the detailed design of the balancing market and imbalance settlement.

The specific issues and interactions are as follows:

Identification of energy and non-energy actions

The I-SEM High Level Design has stated that energy actions will be remunerated at the marginal balancing energy price while non-energy actions will be remunerated at the associated offer/bid price. This in itself illustrates the importance of the identification of energy and non-energy actions by the TSO, something which was re-iterated in the responses received following the workshops. This identification of energy and non-energy actions will then feed into the pricing of the actions. Methods to identify non-energy and energy actions will be discussed in the markets consultation paper.

Pricing

The exact basis for compensation will be consulted upon in the Markets consultation paper and decided in the Markets decision paper. One potential solution that would ensure that plants that are moved for constraint reasons receive fair compensation is as follows:

- a plant that is constrained down due to a dispatch instruction shall pay back the lower of its decremental bid price or the Balancing price; and
- a plant that is constrained up due to a dispatch instruction shall receive the higher of its incremental offer price or the Balancing price.

This simplifies the need to identify the reason for each and every action in the balancing timeframe; implicitly, any “in-merit” dispatch instruction will be settled at the balancing price, and any “out of merit” dispatch instruction will be settled at the unit’s offer/bid price.

While the TSO will use the least cost units to resolve a constraint, whether by constraining up or down specific units, there are instances where it may be limited as to which units could be dispatched due to specific location or operating capabilities.

The RAs are aware that some plants may have local market power, due to their location, when the TSO has no other options to resolve a constraint. In order to protect customers from the exercise of local market power in the resolution of constraints, the RAs will identify the appropriate local market power mitigation measures. This will be addressed in the market power workstream.

3.4 SUMMARY

The I-SEM HLD Decision did not signal any changes to the current policy on constraint payments.

One potential solution that would ensure that plants that are moved for constraint reasons receive fair compensation is as follows:

- a plant that is constrained down due to a dispatch instruction shall pay back the lower of its decremental bid price or the Balancing price; and
- a plant that is constrained up due to a dispatch instruction shall receive the higher of its incremental offer price or the Balancing price.

Measures to protect customers from the existence of local market power will be addressed in the market power workstream.

4 TREATMENT OF FIRM ACCESS

4.1 INTRODUCTION

This chapter examines the issues surrounding the treatment of firm access in the I-SEM.

Under the SEM, users – in particular generators - may be granted both firm and non-firm transmission access. Firm access entitles the user to deliver energy on to the transmission system up to a specified MW level or receive compensation in the event that the access is denied as a result of a lack of transmission capacity. Firm access is typically provided once not only the “shallow” connection, connecting the user to the transmission system, is completed but also any reinforcements to other parts of the transmission system, the so-called “deep reinforcements”, that might be necessary to accommodate the additional power flows caused by the connection of the new user, are completed.

Non-firm access entitles users to deliver energy on to the transmission system over and above any firm access level in the event that transmission system conditions make this possible; no compensation is provided, however, in the event that such non-firm access is not possible. Non-firm access can be granted once the shallow connection assets are completed but prior to the completion of deep reinforcements.

4.2 TREATMENT OF FIRM ACCESS IN SEM

When a new generator is connected to the transmission system the Connection Agreement will specify the amount of firm and non-firm access available at the relevant Trading Site. The amount of firm access initially granted under the Connection Agreement is the Shallow Connection Capacity (SCC), up to which the generator is entitled to sell power or receive compensation if it is constrained down.

The generator then has non-firm access from this level (SCC) up to the Maximum Export Capacity (MEC) as stated in the Connection Agreement. A generating unit has no right of access to the transmission system for output above the SCC stated in the Connection Agreement and therefore the generator is not entitled to be compensated in the event that the TSO constrains the generator down from a level above its SCC.

Generators with firm access in SEM are compensated through constraint payments where their output is constrained down in dispatch to a level below their market schedule quantity.

Generators with non-firm access in the current SEM which are dispatched by the TSO are then assigned availability in the ex-post pool equal to their actual dispatch level, allowing them to be scheduled up to this level in the ex-post market if they are in merit. However, this current treatment works only in the context of an ex-post unconstrained pool.

4.3 FIRM ACCESS IMPLEMENTATION IN I-SEM

The current pool market arrangement in SEM does not allow generators to achieve a firm market position before the ex-post market run. These ex-post processes allow generators' actual dispatch levels to be inputted to the market calculations as availabilities (where these dispatch levels are greater than their firm access quantities), ensuring that market schedule quantities have taken firm access levels into account.

The implementation of the current SEM Committee policy cannot be achieved in the same manner in the I-SEM as it is in SEM. The Day Ahead and Intraday Markets in I-SEM are firm ex-ante markets so the current ex-post setting of availability will not be possible. The purpose of this section is to put forward options for dealing with generators where some or all of their output is provided on a non-firm access basis.

Based on scoping and discussion through the ETA workshops it would appear that a key question is whether or not generators with non-firm access should be allowed to participate in the ex-ante markets at a level above their firm access quantity.

If generators with non-firm access are permitted to participate in the ex-ante markets, the question then arises as to their treatment in the balancing market where they are constrained down in their non-firm region by the TSO.

The principle outlined in the first of the following options is that the generator would take on the financial risk of being able to generate and deliver any quantity contracted for in an ex-ante market in excess of its firm access quantity (FAQ). If there is sufficient transmission capacity available, the TSO will dispatch a generator in excess of its FAQ. If sufficient transmission capacity is not available, the TSO will dispatch up to the maximum of FAQ or available transmission. Therefore any difference between dispatch quantity/metered output and the ex-ante forward contract position will be settled at the balancing market price.

Based on the above there are two options that are considered for discussion:

1. Generators can contract ex-ante in excess of FAQ, but are financially responsible if unable to deliver, and are settled at the balancing market price;
2. Generators' ex-ante transactions may not exceed their FAQ.

4.3.1 PARTICIPATION IN EX ANTE MARKETS

The first issue discussed here is whether plant with non-firm access should participate in ex-ante market timeframes for any generation capacity in excess of their FAQ. On face value it may be that there are valid reasons why non-firm plant should only participate in the balancing market given that it only becomes clear close to real time that the non-firm capacity is available.

FAQs are granted to a Trading Site once the Associated Transmission Reinforcements (ATRs) are completed. Hence a generator will only receive an FAQ for its non-firm quantity once the TSOs have completed the transmission works required to facilitate the generator's full MEC.

However, there are other issues on this that merit consideration.

To limit participation of non-firm generation to the balancing market will by its nature limit participation in the DAM and IDM. This will reduce liquidity and potentially reduce robust price discovery in these markets.

In addition, it is likely that a significant amount of the non-firm access on the system is associated with wind generation. Wind generation has priority dispatch in real time and therefore has access to the grid once available to generate and where the grid can accommodate it.

In light of the above, the SEM Committee is of the view that it may not be practical or sensible to limit participation in the ex-ante markets (DAM and IDM) to firm access quantities only.

4.3.2 SETTLEMENT OF CONSTRAINTS AND NON-FIRM ACCESS

As discussed in the previous section, the SEM Committee is of the view that there should be no limitations on participation in the DAM and IDM due to non-firm access. The subsequent issue to this is how non-firm generation is treated in the event that a constraint binds and the generator in question has its output reduced in the non-firm range by the TSO.

The briefing paper published by the RAs on this issue put forward a number of options for dealing with the settlement of non-firm constraints.

a) The plant must buy back any non-firm volumes at the Imbalance price. In such a scenario, its own decremental bid price would be ignored in the setting of the Imbalance price in this instance.

b) The plant must bid to buy back any non-firm volumes in the Balancing Market at the DA price, or some price related to its actual trades (including trades in the IDM).

c) The plant must trade itself out of its trades for any non-firm volume in the IDM if notified that it will not be dispatched above its firm access level by the TSO in time.

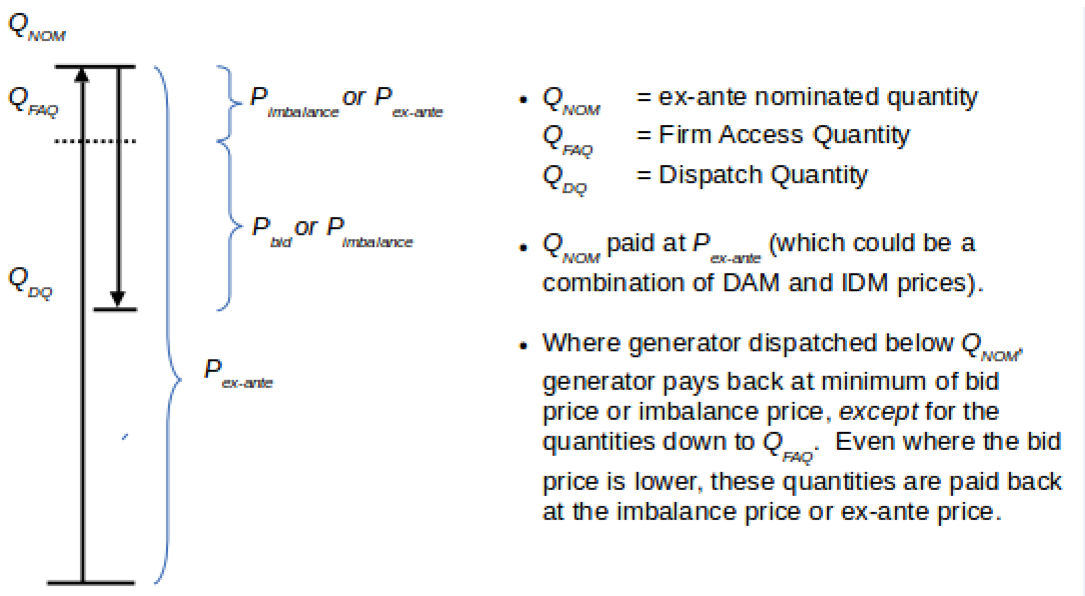


Figure: Dispatching down with non-firm access

The three options put forward above and which were discussed at the ETA working groups appear to cover the range of options available. In addition, it would appear that any option that requires participants to bid in a certain way to reflect previous trades may be less optimal.

Upon further consideration however, it would appear that option c) is not a standalone option but rather something that should occur where it is feasible to do so. In other words, under either option a) or option b) the plant will have the opportunity to trade itself out of its trades for any non-firm volume in the IDM where the TSO has notified (where possible) that it will not be dispatched above its firm access level. The question then is which of the two options a) and b) above is preferred in the event that after the IDM gate closure, a plant has contracted some or all of its non-firm access quantity in the ex-ante markets and has not traded out this position in the IDM (either by the plant choosing not to or where the TSO was unable to notify in time).

Option (a) exposes the non-firm generator to imbalance price risk. Arguably this may be regarded as an inevitable consequence, and reflecting the lower value, of non-firm access. If generators are dispatched down relative to their ex-ante position then it is likely that demand was lower than expected, or the availability of e.g. wind generation higher than expected. This would be likely to result in the imbalance prices at which non-firm generators are cashed-out being low in the event of said generators being dispatched down.

Furthermore, upon closer consideration it would appear also that option b) may not be an appropriate solution in I-SEM. Option b) as currently envisaged would give the opportunity to the generator to trade any volumes above its FAQ in the ex-ante market while having no exposure to the BM. In other words, the revenues received on the non-firm access quantity in the ex-ante markets is simply returned through a decremental bid price reflective of these trades in the event the TSOs cannot accommodate the non-firm quantity, thereby avoiding any exposure should the imbalance price be higher than the revenues obtained in the ex-ante markets. The SEM Committee welcomes opinions on this view.

A number of responses received following the ETA workshops suggested that it is not possible to comment on the treatment of non-firm access before the details of the balancing market are fully established. While the details of the imbalance pricing methodology will be established in the next markets Consultation Paper, the SEM Committee nevertheless seeks in this current consultation views on the principles discussed above.

In summary, it is proposed that option a) is the most effective way to treat non-firm access in I-SEM. It may be the case that simply prohibiting trading of non-firm access quantities is worth considering but this requires careful consideration of the impact on the ex-ante market (in terms of liquidity, price discovery, etc).

4.3.3 TREATMENT OF FIRM ACCESS WORKED EXAMPLE

The following is a worked example to help illustrate some of the ideas in this section.

Unit capacity is 450MW at the station gate.
Unit has 300MW firm access and 150MW non-firm access.
Unit TLAF is 0.98.

<u>The Day Ahead Market</u> (One hour Trading Period)

The unit's price at the station gate is 50 €/MWh.

The unit:

- submits an offer of 441MWh to the Day Ahead Market (DAM) at 51.0204 €/MWh;
- is scheduled at 441MWh in the DAM for hour X (comprising half hours X1 and X2);
- nominates a position of 450MW (at the station gate) to the TSO for hour X.

<u>The Balancing Market</u> (Half hour Trading Period)

Assume:

- The unit has no trades in the Intraday Market (IDM).
- The unit submits a buy bid to the Balancing Market (BM) at a bid price of 51.0204 €/MWh for half hours X1 and X2.

- The TSO cannot dispatch the unit above its firm access quantity of 300MW (at the station gate) in either X1 or X2. The TSO dispatches the unit to 300MW (at the station gate) in X1 and to 250MW in X2.
- The BM clearing price in both X1 and X2 is 55 €/MWh.

<u>Settlement</u>

Assume the unit sets the marginal clearing price in the DAM.
In hour X the unit receives from its DAM trade:

- 441MW * 51.0204 €/MWh * 1 hour;
- €22500.

In X1, the unit is 'cashed out' at the Imbalance price of 55 €/MWh for its non-firm portion of 147MW (150MW non-firm access quantity scaled by the TLAF of 0.98) in the BM. Note that its own buy bid of 51.0204 €/MWh is ignored both in generator payments and in the setting of the Imbalance price.

Thus in half hour X1 the generator pays back:

- 150MW * 0.98 * 55 €/MWh * 0.5 hour;
- €4042.50.

In X2 the unit is 'cashed out' at the imbalance price of 55 €/MWh for its non-firm portion of 150MW (at the station gate) and constrained down a further 50MW of firm access quantity. Note that its own bid of 51.0204 €/MWh is ignored both in generator payments and in the setting of the Imbalance price for the non-firm quantity but that it is used, in the case of an energy balancing action, on the 50MW firm access quantity to set the Imbalance price or, in the case of a non-energy action, to determine generator payments but not the Imbalance price.

Thus, in X2, if the action is a non-energy balancing action, the generator pays back:

(a) in respect of the non-firm access quantity
    - 150MW * 0.98 * 55 €/MWh * 0.5 hour;
    - €4042.50

(b) In respect of the firm access quantity
    - 50MW * 0.98 * 51.0204 €/MWh * 0.5 hour;
    - €1250

4.4 SUMMARY

In summary, the SEM Committee's initial view is that:

- It may not be practical or sensible to limit participation in the ex-ante markets (DAM and IDM) to firm access only and therefore there should be no restriction on participation in any of the market timeframes.
- Where a generator trades in the ex-ante markets for its non-firm volumes and subsequently has its output reduced then it should be cashed out at the imbalance price.
- To the extent possible the TSO should notify the generator if its non-firm access quantity cannot be facilitated thereby affording the generator the opportunity to trade out of its position in the IDM.

5 TREATMENT OF PRIORITY DISPATCH

5.1 INTRODUCTION

Priority dispatch can be described as the obligation on TSOs to dispatch energy from certain generators ahead of other generators as far as secure operation of the electricity system permits[4]. In SEM, priority dispatch is afforded to renewable generators as well as other plants such as high efficiency CHP, peat and waste–to-energy. Priority dispatch is afforded to specific plant or types of plant through legislation[5].

5.2 TREATMENT OF PRIORITY DISPATCH IN SEM

Priority dispatch of generation in the current SEM is achieved primarily through the dispatch principles employed by the TSO. Payments for priority dispatch plant are determined in the Trading and Settlement Code by registering plant with priority dispatch as price taker generation. All plant with priority dispatch then receives the market price set by price making generation meeting schedule demand.

5.3 PRIORITY DISPATCH IMPLEMENTATION IN I-SEM

The I-SEM HLD Decision has not signalled any changes to the current policy on priority dispatch. After considering the matter, the SEM Committee is minded that the current policy should continue in I-SEM. However, it will have to be established exactly how priority dispatch will apply, and be implemented, in I-SEM.

The implementation of priority dispatch in the current SEM arrangements is facilitated through the single ex-post pool configuration. The configuration of the I-SEM is significantly different given the existence of firm ex-ante markets and a Balancing Market.

It does appear that the Balancing Market and Imbalance Settlement are the timeframes where the implementation of priority dispatch will be important. This is

[4] EU Directive 2009/28/EC states "Member States shall ensure that when dispatching electricity generating installations, transmission system operators shall give priority to generating installations using renewable energy sources in so far as the secure operation of the national electricity system permits and based on transparent and non-discriminatory criteria."

[5] Specifically, the SEM Committee decision on Priority of Dispatch states that the SEM Committee has decided to adhere to an 'absolute' interpretation of priority dispatch whereby economic factors are only taken account of in exceptional situations and where this can be done in a manner that does not threaten the delivery of renewables targets. In addition, parties with mandatory priority dispatch under EU Directives (renewables, qualifying hybrid plants, high efficiency CHP) shall be given priority over those afforded priority dispatch at the discretion of a Member State (peat). The SEM Committee has also determined that priority dispatch is facilitated in the SEM by affording qualifying parties the option to register as Price Takers.

because market participants have control of their positions prior to the balancing market in the DAM and IDM.

- In the Day Ahead Market units with priority dispatch can act as proxy "price takers" by submitting offers at PFLOOR (-€500/MWh); and
- In the Intraday Market, which will have continuous trading, units with priority dispatch will likely seek to match the highest buy price available given that there will be no clearing price. Hence such plants would not have any "priority" when it comes to achieving a trade.

Given the above, the SEM Committee is of the view that the balancing market is the timeframe where specific actions will be taken to implement priority dispatch.

5.3.1 PRIORITY DISPATCH IN THE BALANCING MARKET

Briefing Paper 1.2 and ETA Workshop 1.2 discussed a proposal whereby, consistent with current policy, Priority Dispatch (PD) plant could elect to be price-taking in the balancing market. This would avoid the obvious perversity of the TSO being obliged to accept balancing market offers, irrespective of price, and allow the TSO to maximise the output of PD plant, which would then receive the prevailing market price for its balancing market quantities. It was proposed that this could be achieved by:

I. all priority dispatch generation offering into the balancing market at a notional price floor;
II. all priority dispatch generation offering into the balancing market at zero price; or
III. an explicit price-taking mechanism that does not rely on an explicit bid price.

Discussions also recognised that, as now, not all PD plant might wish to generate whatever the price. Hence it was proposed, again consistent with existing policy, that such PD generation could, as now, opt to become price-making, enabling it to submit offer prices and allow the TSO to accept such offers only when in merit. It was acknowledged that, in the current SEM, the process of switching between price-making and price-taking status requires 29 days' notice, and it was questioned whether I-SEM would necessitate this timescale being shortened. The remainder of this discussion addresses the treatment of priority dispatch plants which do not opt to become price making.

The RAs have reflected on the responses given by participants at the workshop and in subsequent written responses. Additional thought has been given to the problem, and there may be a more straightforward approach that will be simpler to implement, place less administrative restrictions on PD generators and yet better respect the rights of PD generation than the approach discussed previously.

A Revised Approach

The principle of operation of the SEM is that generators provide their cost information to the TSO and the TSO decides on the appropriate running regime of each generator, whilst the TSC ensures that generators' revenues cover their costs thus providing incentives for efficient plant choice and operation. This is the approach taken for typical price-making generation. In addition, a facility is provided whereby generation can, in effect, require the TSO to run it to the greatest extent that system security and safety will allow. This is the price-taking mechanism. The current SEM requires generation to opt for one mechanism or the other with, as noted, changes between the two requiring 29 days' notice.

The I-SEM does not need to have the same rigid distinction between these two modes of operation. Specifically, if the requirement for physical notifications to reflect ex-ante market positions was relaxed for certain participants, then generators would submit both:

A. a physical notification, being the quantity on which they wish to receive the prevailing market price. This prevailing market price is the imbalance price, except to the extent to which part or all of the quantity may be covered by an ex-ante traded position[6]; and
B. offers (and bids) indicating prices at which the generator is willing to generate more (or less) depending on the TSOs' determination as to whether these quantities are in merit.

Thus, in effect, under I-SEM generators could simultaneously elect a quantity of their output to be price-taking, i.e. (A) above, and a quantity of their output to be price-making, i.e. (B) above. Unlike the current SEM it is not necessary to choose whether *all* of the generator's output is subject to one regime or the other.

Thus, this revised option for implementing priority dispatch under I-SEM is that priority dispatch generation:

I. may observe prices in the day-ahead and subsequent intraday markets, trading in them as it sees fit;
II. on the basis of observing prices and possibly trading in the ex-ante markets, decide on the physical notification reflecting the output at which it wishes to run given the prevailing market conditions;
III. submit any incs and decs reflecting the price at which it is willing to deviate from its physical notification.

The SEM Committee recognises that this approach is largely the same for priority dispatch generation as for any other generator.

6 Note that in the current SEM, a price-taking generator may similarly have part or all of its quantities covered by a contract for difference.

These solutions do not necessarily guarantee that the TSO will dispatch the offers (and bids) of PD generation such that it is guaranteed that the PD generation will maximise its commercial advantage. Rather it places the obligation on the priority dispatch generator to submit a notification with reflects full expected or required running. This could raise the question as to whether priority dispatch generation could update their final notifications closer to real time than the end of the intraday market.

5.4 ABSOLUTE PRIORITY DISPATCH

As noted above, the "absolute" interpretation of priority dispatch requires that the TSO will redispatch non-PD plant subject only to system security and safety, and irrespective of cost, in order to accommodate the output of priority dispatch generation. This includes counter-trading on the interconnector, i.e. accepting bids to buy power from GB.

A feature of I-SEM may be that suppliers can submit physical notifications of the expected level of demand of their customers and then, acting as Balancing Service Providers (BSP) in I-SEM, submit offers to sell power back, i.e. reduce demand, and bids to buy additional power, i.e. increase demand. Thus it is for consideration whether, under I-SEM, the TSO will be obliged to accept any bid from demand BSPs, irrespective of price, that allows an increase in priority dispatch generation. At least in principle, such bids could be large and negative, implying that suppliers could be paid to increase demand. A floor of zero, for example, could be placed on the price at which such bids would be accepted.

These are not issues that necessarily relate to the I-SEM market design but are issues concerning the way the TSOs dispatch the system which arise as a result of the greater flexibility of I-SEM design. Moreover, it may well be that enough generators, notwithstanding their priority dispatch status, submit bids to reduce output that the issue of dispatching them at any cost no longer arises. Views are welcomed as to the relevance and interpretation of absolute priority dispatch in light of the I-SEM design.

5.5 SUMMARY

EU legislation on Priority Dispatch means that the TSOs must dispatch energy from certain (i.e. renewable generators) ahead of other generators, as far as secure operation of the electricity system permits. In SEM, this is implemented by registering renewable generation as price takers.

Priority Dispatch in I-SEM will most likely be implemented through the Balancing Market and Imbalance Settlement.

As in SEM, Priority Dispatch generation may wish to forego its Priority Dispatch status and become a price maker. It is therefore proposed that generation that is eligible for priority dispatch should:

I. observe prices in the DAM and IDM, trading in them as they see fit;
II. on the basis of observing prices and possibly trading in the ex-ante markets, decide on the physical notification reflecting the output at which it wishes to run given the prevailing market conditions;
III. submit any incs and decs reflecting the price at which it is willing to deviate from its physical notification.

Views are also welcomed as to the relevance and interpretation of absolute priority dispatch in light of the I-SEM design.

6 TREATMENT OF CURTAILMENT

6.1 INTRODUCTION

In the context of the discussions in this section curtailment generally refers to situations where there is more wind generation available at aggregate level than can be accommodated on the system due to the need to respect, for example, the System Non-Synchronous Penetration (SNSP) limit. In these situations the TSO must turn down a proportion of all wind generation in order to maintain total system security.

The TSOs' Operational Rule for the determination of whether an action is due to a constraint or curtailment is as follows[7]:

- If the Control Centre assumed it had control over every price taking generation unit in tie break on the island of Ireland and the security issue presented could only be resolved by reducing the output of one or a small group of price taking generation units in tie break then that reduction is deemed a constraint and logged as such.
- If the Control Centre assumed it had control over every price taking generation unit in tie break on the island of Ireland and the security issue presented could be resolved by reducing the output of any or all of the price taking generation units in tie break then that reduction is deemed a curtailment and logged as such.

6.2 TREATMENT OF CURTAILMENT IN SEM

In the current SEM there is no distinction between actions taken to relieve constraints and curtailment in terms of settlement to participants. All curtailment actions are treated as constraint actions in settlement. The SEM Committee provided clarity on its 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.

6.3 TREATMENT OF CURTAILMENT IN I-SEM

The specifics of the treatment of curtailment in the I-SEM will be developed as part of the wider development of the detailed balancing market design and therefore at

[7] See SEM-13-010(ii)

this building blocks stage the intention is to pose a number of questions for discussion which will inform that detailed design.

The SEM Committee is of the view that there are issues within the treatment of curtailment that can be considered ahead of the detailed market design. The section below sets out a number of questions for consideration.

1. How should the SEM Committee decision on curtailment compensation be implemented?

To implement the SEM Committee decision on curtailment compensation it will be necessary to have a mechanism in place to recoup revenues achieved by the wind generator in the DAM, IDM and BM. There are likely two high level approaches that can be taken to achieve this, namely through mandated bidding behaviour or through post processing of generator revenues.

I-SEM is due to go-live in Q4 2017 and the SEM Committee decision on the termination of compensation for curtailment will not apply until Q1 2018. Therefore whatever methodology is chosen to recoup these revenues will not apply for the interim period between I-SEM go-live and 1 January 2018.

Mandated Bidding Behaviour

Wind generators could be required to bid a decremental price into the Balancing Market based on its revenues from the ex-ante markets. All curtailment would be treated as an out of merit dispatch instruction by the TSO, and hence settled at the decremental price submitted.

This would have the advantage of allowing curtailment compensation to be dealt with through generator behaviour rather than in central systems. However, it could be difficult to implement for the generator who would constantly have to have a complex methodology underlying its decremental bid. It could also be difficult to monitor by the relevant authorities.

Cash Out and Post Processing

The second option would be to cash out deviations from DAM and IDM transactions of wind generation in the imbalance market during a curtailment event in the same way as any other generation deviation is cashed out. This would have advantages in that detailed specific rules for tracking of dispatch instructions for curtailment versus constraints would not need to be imported into the core market arrangements and therefore there should be less chance of distortion of the market.

Generators without ex-ante market transactions would be paid the balancing 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.

There would be the option to then carry out a form of post processing of generator revenues to take into account the net revenues earned on curtailed volumes (assuming the day-ahead price is higher than the balancing price, when renewable energy plants are curtailed). The post processing would involve consideration of the revenues earned in the DAM and IDM and would therefore require a high level of cooperation and information sharing across the different market timeframes. In the event that the balancing price was higher than the day ahead price then generators would need to be "made whole" for the losses made on their curtailed volumes.

2. Is there a distinction in treatment to be made between trades in the DAM and IDM versus trades which are executed in the BAM or settled in imbalance settlement?

Trades executed in the DAM and IDM are commercial agreements between buyers and sellers to trade electricity and generators notify these positions to the TSOs. Trades executed in the BM or settled in imbalance settlement might be considered differently in that they represent output that was not marketed by its owner and is spilled into the BM or imbalance settlement.

It is therefore worth considering whether the SEM Committee decision on the treatment of curtailment post 2018 should apply differently to DAM and IDM trades than to BM and imbalance settlement output. By treating them differently, this would mean that DAM and IDM trades would be cashed out at the balancing price in a curtailment event and any upside or downside would be retained or borne by the generator.

There are arguments to be made for and against treating the DAM/IDM trades differently.

- The compensation could be significant. In 2013 the total amount of dispatched-down wind generation in Ireland and Northern Ireland was 196GWh of which 72% represented curtailment. Approximately 55% of curtailment occurred overnight between 23:00 and 09:00 when demand levels are lower but prices tend to be lower then also, and approximately 45% occurred during 'day time' hours of 09:00 to 23:00. Therefore in 2013, based on an average overnight SMP of €48.81 and an average 'day time' SMP of €77.72, the cost of compensating curtailment was approximately €8.7m. Further to this it needs to be considered that curtailment levels are expected to increase in future years as the level of installed wind capacity increases. It also needs to be considered that the €8.7m figure may not be directly comparable for I-SEM since the I-SEM context needs to consider the percentage of trades in DAM and IDM versus imbalance settlement.

- However, not compensating for DAM and IDM trades could act as a disincentive for wind to partake in these markets. Were this to be significant, the resulting omission of zero marginal cost wind from the DAM could act to increase the DAM price. The demand in 2013 for example was circa 33 TWh. Were, for example, reduced participation in the DAM and IDM to increase prices by €1/MWh the total cost to the market would be circa €33m.

- It is extremely difficult to quantify the potential cost of compensating DAM and IDM trades versus the potential increase in DAM costs by lower participation of wind generation.

- Creating disincentives to trade in the DAM could affect the liquidity of that market and could ultimately have detrimental effects on the integrity of price formation.

6.4 SUMMARY

In summary, two options are proposed in respect of how the SEM Committee decision on compensation for curtailment should be implemented in I-SEM.

- The first would mandate a bidding behaviour on wind generators whereby they would be required to bid a decremental price into the Balancing Market based on their revenues from the ex-ante markets.
- The second option would involve cashing out the generator in a curtailment event in the same way as any other generator deviations are cashed out, followed by the option to carry out post processing where the prices in the ex-ante markets are higher than the BM prices for the curtailed energy. In the event that the balancing price was higher than the day ahead price then generators would need to be "made whole" for the losses made on their curtailed volumes.

The SEM Committee has also put forward for discussion whether the decision on the treatment of curtailment post 2018 should apply differently to DAM and IDM trades than to BM and imbalance settlement output.

7 DE-MINIMIS LEVEL

7.1 INTRODUCTION

This chapter examines the issues surrounding the mandatory participation of smaller generators in the I-SEM.

The I-SEM HLD Decision states that participation in the ex-ante markets will not be mandatory in the new market arrangements. However all participants will be mandated to participate in the Balancing Market (BM) in keeping with their technical ability to do so. The mandatory requirement of the BM could have a significant impact on smaller participants and to a lesser extent the TSOs and the Market Operator.

From the smaller participants' perspective, they may not have adequate resources for market participation given the financial and administrative burden involved. It should also be noted that electricity generation may not be a central business of many of these participants.

From the TSOs' perspective, it becomes impractical to dispatch smaller units to balance the system. Similarly the Market Operator or other parties may consider it impractical to enter into legal and/or commercial agreements with smaller units.

7.2 DE MINIMIS THRESHOLD IN SEM

Currently, generators are mandated to participate in the SEM if they have a Maximum Export Capacity (MEC) of 10MW or greater under a single connection agreement. This 10MW threshold is referred to as the De- Minimis Threshold in the Trading and Settlement Code. Generation below this threshold can participate in the SEM on a voluntary basis. Where a generator decides not to enter the market, they instead have the option to contract with suppliers whereby their generation is netted against that supplier's demand[8].

The tables below detail the size demographic of generation in Ireland and for wind on its own on an all-island basis. As can be seen there is 666MW of installed generation in ROI and 574MW of wind on an All-Island basis that is below the De Minimis Threshold.

[8] This generation can be netted against up to the three suppliers in the retail systems

All-Island Wind Generation

Threshold (MW)	Sites	Installed MW
< 5	89	240
< 7.5	110	360
< 10	135	574
< 12.5	148	715
< 15	157	838
< 17.5	170	978
< 20	177	1171
< 22.5	186	1356
< 25	191	1474

All Connected Generation in Ireland

Threshold (MW)	Sites	Installed MW
< 5	201	349
< 7.5	220	463
< 10	244	666
< 12.5	255	786
< 15	261	868
< 17.5	274	1071
< 20	278	1146
< 22.5	287	1336
< 25	294	1499

7.3 DE MINIMIS THRESHOLD IN I-SEM

The I-SEM HLD Decision has not signalled any changes to the current policy on the De Minimis threshold. However, it needs to be considered whether the current level should be kept in I-SEM or whether it should be changed given the time that has passed since the establishment of SEM and in order to reflect the impacts that new market arrangements may have on participants.

One option may be to align the De Minimis Threshold with the 5MW Grid Code given that generators are required to comply with both. Reducing the De Minimis Threshold from 10MW to 5MW would mandate an additional 334MW of wind generation on an All-Island basis.

Another view may be that the De Minimis Threshold should be increased given that the I-SEM will likely carry more risk and have a greater administrative burden than the SEM. Increasing the threshold to 20MW for example would allow 597MW of additional wind capacity to voluntarily choose whether or not to enter the I-SEM.

It is worth noting that there are benefits to suppliers netting contracted De Minimis generation against their demand. Specifically, suppliers pay a use of system charge (TUoS and/or DUoS), a capacity payments charge, an imperfections charge and a MO charge, all of which are based on demand usage (€/MWh consumed). A reduction in demand results in a reduction in these charges that would otherwise be higher if the generation had not been netted against their demand. However allowing a greater number of generators to net their generation against demand means the said charges are allocated over a reduced generation and demand base resulting in a higher €/MWh charge to participants.

In addition, the De Minimis threshold has an impact in terms of liquidity in the I-SEM market places. As shown in Section 7.2, setting the threshold at 5MW compared to 20MW would result in a difference of 931MW of wind generation and demand participation in the market. This is not an insignificant amount.

Regarding arrangements for non-participant trading in the I-SEM it would appear that the current arrangements are fit for purpose. The I-SEM will continue to allow netting of De Minimis generation against the demand of the supplier they have contracted with. Further, the HLD Decision stipulates that the current arrangements will continue i.e. the intermediary arrangements, supplier 'lite' and trading sites. The I-SEM will also provide for an aggregator of last resort to be available for wind generation at market go-live.

Lastly, there may be merit in considering whether a minimum level should be introduced, below which units may not participate in the I-SEM, or below which units can only participate through an aggregator. While it is unlikely that very small units would enter the I-SEM given the administrative requirements, it could also prove to be inefficient and impractical for the Market Operator to enter legal/commercial agreement with participants of this scale. As an example of minimum level in other European markets, the minimum contract size in the NordPool DAM 'Elspot' is 0.1MWh per hour which means that a generator with an installed capacity of less than 100kW could not get a contract position in the DAM unless participating through an aggregator.

7.4 SUMMARY

Currently, generators are mandated to participate in the SEM if they have a Maximum Export Capacity of 10MW or greater under a single connection agreement. It needs to be considered whether the current level should be kept in I-SEM.

There may also be merit in considering whether a minimum level should be introduced, below which units may not participate in the I-SEM, or below which units can only participate through an aggregator.

8 TREATMENT OF CURRENCY

8.1 INTRODUCTION

This chapter examines the issues surrounding the treatment of currency in the I-SEM.

The SEM covers two currency areas with trading in both euro and pounds sterling. In the current SEM, there is no discrimination between participants on the basis of currency. In practice this means that participants submit offers into the market in their local currency and cost changes between the time of trading and financial settlement are socialised across the entire market.

8.2 TREATMENT OF CURRENCY IN SEM

The SEM has always operated on the basis of two currencies. Paragraph 6.4 of the Trading and Settlement Code (TSC) recognises that payments and charges are made based on the currency that applies in the jurisdiction of the participant's trading unit. However, paragraph 6.3 recognises that all internal calculations are based in euro, thereby creating a currency cost (or benefit).

Northern Ireland participants submit offers in pounds sterling and ROI participants submit offers in euro. Before the start of each Trading Day SEMO publishes a Trading Day Exchange Rate between euro and pounds sterling. This Exchange Rate is used to convert pound sterling offers into euro offers. All Settlement information and cash flows are calculated in euro. Payments to NI participants are then converted back to pound sterling after the Trading Day using the Trading Day Exchange Rate published for the Trading Day in question. The Trading Day Exchange Rate is also applied to the Fixed and Variable Market Operator Charges.

A surplus or shortfall of payments in over payments out is then likely to arise due to changes in the actual exchange rates between the time when offers are submitted on D-1 and the time when settlement occurs.

This surplus or shortfall determines the cost for each payment and charge for each trading period in domestic currency using the trading day exchange rate (the rate applicable when the trade happened), and then again using the invoice day exchange rate (the rate applicable when the bills are calculated) and determines the difference for each line item. These are then summed to come up with the total currency cost. This calculation is done on both euro and sterling values (which results in a zero cost for all euro values).

In a separate process, the total market trade is calculated and each participant is allocated their share of the cost based on their trade expressed against the total trade. This calculation is repeated on M+4 and M+13 resettlement.

8.3 TREATMENT OF CURRENCY IN I-SEM

In the context of I-SEM, the first question is whether the current policy can be continued or whether it needs to be revised. This issue was discussed in Briefing Paper and Working Group 1.3 and comments were received on the matter from a number of respondents.

The EU cross border market places will operate and be settled in euro[9]. However it should still be possible to accommodate more than one currency in I-SEM. For example, the GB markets allow participants to submit offers and to be paid in pound sterling while the power exchanges carry out the intermediate conversions between pound sterling and euro. The balancing market and imbalance settlement should be capable of accommodating two currencies as they do today.

The implementation of the two currency solution should consider the lessons of the SEM and aim to find as simple a solution as possible. It should take cognisance of one key factor:

- Currency risk arises when payments cross the jurisdictional border within the I-SEM for a non-spot transaction (i.e. the transaction is committed to at one point in time and settlement takes place later, when the exchange rate may have changed).

8.3.1 DUAL CURRENCY IMPLEMENTATION

The Day Ahead and Intraday markets are likely to have quick settlement turnaround. There is also no revision of these markets (that is, no M+4/M+13/etc.). As such, the currency risk in these markets is small as it represents the potential movement of the exchange rate across a short period. This will represent a significantly smaller exposure than in the current SEM arrangements.

Currency risk in the Day Ahead market can be determined by calculating an Ireland/Northern Ireland market surplus position. This is not dependent on actual metering (which will be used in the balancing market) but on market positions. Therefore, if the aggregate market result shows 400MW surplus generation in Ireland, this means that in the market 400MW of load in Northern Ireland was served by this generation and it was therefore exported from Ireland to Northern Ireland, thereby incurring a currency risk.

Although it would potentially involve a more complex implementation, a similar approach could be implemented in the Intraday market and balancing arrangements.

[9] Article 47.1 of ENTSOE's Final Draft Network Code on Capacity Allocation and Congestion Management states "All Nominated Electricity Market Operators shall ensure that Orders submitted to the Price Coupling Algorithm shall be expressed in terms of Euros and make reference to Market Time."

This will depend somewhat on the design of the Intraday market which is ongoing at EU level. The EU Intraday market will need to cater for a number of currencies.

The balancing market and imbalance settlement should be capable of accommodating two currencies as they do today.

8.3.2 TREATMENT OF CURRENCY COSTS

The costs associated with currency can likely be treated in two ways;

- They can be socialised and invoiced as a single line item on all players

- They can be treated in a similar manner to Dispatch Balancing Costs (DBC) in the current SEM and levied on all suppliers through a tariff.

The first option is a continuation of the existing SEM implementation. However a number of participants have expressed the view that this is an overly complicated and onerous method of recovering a relatively small amount of money. This existing methodology could however, be amended to allow the currency costs to be levied ex-post on a sub-set of participants, most likely suppliers.

The second option above involves carrying out an ex-ante projection of currency cost and constructing a tariff on this basis. Any differences between the ex-ante assessment and the ex-post actual amount would be carried over in a correction factor. This would have the advantage of giving certainty to suppliers at the start of the tariff period but would have the potential disadvantage of additional working capital cost for the market operator. However, given the faster turnaround time expected for payments in the DAM and IDM in I-SEM than the current SEM, it should be that overall credit exposure would decrease.

The majority of respondents to the first round of ETA Briefing Papers and Working Groups supported the second option above namely to forecast the currency costs and recover it through a tariff.

The SEM Committee sees merit in such an approach once it achieves the underlying objective with regard to facilitating dual currency. Providing additional certainty to suppliers, if even for a small amount of money, should be advantageous also.

8.4 SUMMARY

In summary, the SEM Committee is minded that

- The I-SEM should operate on the basis of dual currency as the SEM does now.

Currency costs should be projected ex-ante and charged to suppliers as a tariff. Any differences between the projected and actual should be treated as a correction factor.

9 MARKET INFORMATION

9.1 INTRODUCTION

The publication of market information plays an important role in facilitating efficient market operation and transparency. As a general principle, the more information that is made available the more it helps market participants make informed decisions on investment and their interactions with the market. The publication of market information may also provide part of a check on price manipulation through particular bidding strategies, primarily as it provides for the wider scrutiny of market behaviour, and consequent reporting to the market monitor.

9.2 MARKET INFORMATION IN SEM

The publication of market data in the SEM is governed by Appendix E of the Trading and Settlement Code and Agreed Procedure 6 (AP6). Appendix E outlines the obligations on SEMO including timelines while AP6 outlines the method by which data is published.

To encourage investment and competition, the SEM has adopted high levels of transparency of market information. However, the release of market information must be balanced with the possibility that the publication of commercially sensitive information may actually impair competitiveness. Moreover, the publication of information can, on the one hand, potentially provide opportunities for collusion or market manipulation while, on the other, greater transparency may conversely make such manipulation easier to detect.

The SEM includes the concept of private and public reports. Private reports cover information that is deemed confidential and is shared only with the participant to which it relates. Private information is retrieved through the central market systems. Public reports are made available on the SEMO website and also through the central market systems and in some cases a dedicated FTP server. Any interested parties may submit data queries through the market helpdesk and, subject to commercial sensitivity, SEMO will make the requested information available through this avenue. Finally, certain market communications, e.g. use of the alternate solver, are notified to participants through market messages on the SEMO website and related email alerts.

9.3 MARKET INFORMATION IN I-SEM

It will have to be determined what information will be made publicly available and where it is more appropriate for some data items to be restricted to the individual participant to which they relate. It will also be necessary to outline associated timescales for the publication of public information – this being an area where the balance between providing up to date information so that participants can respond commercially to market signals, and concerns over potential manipulation of market power or gaming, will need to be balanced. Further, categories of market data currently published should be examined and it should be decided whether or not these will be made available on a public website or provided to Market Participants only through market reports via registered interfaces.

9.3.1 EU MARKET TIMEFRAMES

Trading arrangements at the Day Ahead and Intraday timeframes will be largely determined at a European level, with I-SEM representation on the decision making bodies. However, this is not to say that local arrangements for issues such as data publication cannot be determined at a jurisdictional level so long as they are Network Code compliant.

SEMO publishes significant volumes of information (both public and private market participant data) including commercial offer data soon after the trading day. This is published on a unit by unit basis. In other power exchanges individual offers and bids tend not to be published but an aggregate bid curve is published for the Day Ahead market. Only concluded deals tend to be reported for the Intraday market.

Given that there will be local arrangements for the NEMO in I-SEM it should be possible to seek to have all commercial offers and bids and associated data published or at least to have the systems available to do so. However, the offers and bids in cross border markets will likely not be available to I-SEM participants.

9.3.2 BALANCING MARKET

The design of the balancing market is largely within the discretion of the Member State. Therefore, it is anticipated that there should be nothing precluding the continuation of the current levels of data publication.

In this context it will also be necessary to consider what additional public information is required to support participants in being balance responsible.

- For example, it may be that the market wishes to see more information published on the aggregate notifications and TSO demand forecasts which could be used as an indicator of whether the system will be long or short. This should give suppliers a better indication of their own likely position.
- Market Participants in their responses to HLD consultations have suggested that greater information should be published by the TSO in relation to wind forecasts.

9.3.3 ADDITIONAL PUBLICATION REQUIREMENTS

With the implementation of I-SEM and other EU initiatives such as REMIT and MAD II it will be necessary to consider what other information should be made available to participants and to the public. Additionally, elements of the I-SEM design may require consideration of regulations which are not currently applicable, e.g. provisions of FTRs may be covered by MiFID II. Opportunities for a holistic and synergistic approach to market information should be considered in the detailed design.

In this context, other markets have, for example, a facility for making the market aware of any significant issues such as a loss of plant, etc[10]. Such a facility could see participants as well as the TSO publish information to the market, for example if a participant knew that one of its units was on forced outage it would post this information to a market notice board immediately.

9.4 SUMMARY

In terms of the market systems being put in place for the I-SEM, it is prudent to ensure that there is a capability to publish as much information as possible. This is especially so in the case of the balancing market where there will be less influence from the EU marketplaces. This will ensure that the decisions in the market are not unduly influenced by the system implementation. Questions around any restrictions on the publication of information should be dealt with as part of implementation.

One important question related to this is whether there is information not currently published that should be. The SEM Committee is of the view that additional publications from the TSOs and market operator would be useful. As mentioned above, the TSO could publish aggregate notifications and their assessment of expected demand. Also, the TSO could publish aggregate wind notifications and TSO expected wind output.

Finally, the SEM Committee sees merit in the establishment of a market bulletin board to aid transparency.

[10] See for example the Nordpool Spot message portal https://umm.nordpoolspot.com/

10 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 will consider responses as part of the development of a decision on the detailed design of the trading arrangements. The SEM Committee will publish a further Markets Consultation Paper which will consider the detailed design of the DAM, IDM, BM and Imbalance Settlement. Responses to this consultation paper will be considered in the context of developing the detailed design of the trading arrangements.

Therefore the SEM Committee is minded not to make a specific decision on the Building Blocks concepts until a decision is being made on the overall detailed design of the trading arrangements in Quarter 3 2015.

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 25 March 2015. Please note that the SEM Committee intends to publish all responses unless marked confidential[11].

[11] While the SEMC does not intend to publish responses marked confidential please note that both Regulatory Authorities are subject to Freedom of Information legislation.