Power NI Energy Limited
Power Procurement Business (PPB)

I-SEM

Balancing Market Principles Code of Practice

Consultation Paper

SEM-17-026

Response by Power NI Energy (PPB)

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Power Procurement Business

Introduction

Power NI Energy – Power Procurement Business ("PPB") welcomes the opportunity to respond to the consultation paper on the proposed Balancing Market Principles Code of Practice (BMPCOP) for the I-SEM.

General Comments

PPB has previously commented extensively in its response to the consultation on the Complex Bid Offer Controls in the I-SEM Balancing Market and the objections raised in that response, to the extent not addressed, remain as objections to the decisions set out in the decision paper and to the proposed approach.

The proposed BMPCOP is not truly a principles document but has been transposed into a more prescriptive document that adds no greater clarity and instead increases the uncertainty for participants. This is particularly the case for participants whose units are mid-merit and whose running is heavily driven by wind production and constraints and who, for example, do not buy fuel based on an index but who must, to deliver the flexibility required by the TSOs, buy gas over a number of within day transactions. The proposed BMPCOP reduces flexibility for the true SRMC to be incorporated and will result in an inefficient outcome.

The prescriptive approach means that all possible "eligible" cost items need to be identified in advance which is virtually impossible. For example, some of the CCGT units PPB trade in the market can also operate in open cycle mode and hence provide very useful flexibility to the TSOs to help manage the system. However, the SEMC has indicated that the systems that are being developed will not be able to facilitate mutually exclusive bidding of the units in both combined and open cycle modes. An alternative approach may be to change the pricing to reflect open cycle operation within day. However, is such circumstances it remains impossible to amend the Technical Offer Data and therefore if the TSOs were to dispatch the unit it would be exposed to imbalance costs as a consequence of this further IT system limitation. These imbalance costs would therefore need to be included in the Bid offer data but the prescriptive definition proposed for the BMPCOP does not currently enable such costs to be included. Our detailed comments below on the proposed BMPCOP identify further examples.

We therefore disagree that the proposed approach provides clarity since there will be many outcomes that cannot be foreseen that will impact on a unit's marginal costs but which would be potentially disallowed depending on the interpretation of the BMPCOP taken. As can be seen from our comments below which identify significant gaps, there would be significant effort required to seek to identify all potential costs. We do not believe this to be a viable process as there would inevitably be cost items that cannot be forseen and hence there would need to be a rigorously defined process to enable very swift variations to be made. The initial identification would necessarily be time consuming and most likely contentious and the ongoing change process would place a significant burden on the MMU (assuming they would be the party charged with agreeing variations and new costs at short notice).

There is also an inconsistency in the SEMC position that bid controls are needed in the Balancing Market (BM) because it is not competitive and hence the controls are needed to deliver the SRMC prices that a competitive market would deliver. The SEMC also indicates that the other markets do not require any bid controls because they are competitive (i.e. on the SEMC definition, they must be delivering SRMC prices) but in parallel the SEMC indicate in their decision paper (paras 7.3.3 and 7.3.4) that in I-SEM generators can bid what they like in these other markets. This is clearly contradictory since the SEMC's interpretation of "competitive" equates to "SRMC" prices.

Therefore, either the markets are not competitive (if a generator can bid any cost it likes) or alternatively, the SEMC agrees that competitive prices in competitive markets are not always based on SRMC. This implies that the SEMC proposals for the BM go beyond what is required to replicate a competitive market and we consider the proposals, as currently drafted with prescriptive "eligible costs", will result in costs that are even lower than the true SRMC because they seek to exclude legitimate marginal costs.

At noted above PPB does not agree with a number of the decisions made in SEM-17-020 and our view remains that there is no need to change the existing framework and all that is required is a few simple changes to enable it to function in I-SEM. This is the only feasible approach to ensure generators are not forced to generate at a loss because they are restricted from bidding in and receiving their genuine marginal costs. Such an outcome is unsustainable and will increase customer costs in the longer term.

Following from this, the detailed comments that follow should not be interpreted as conferring any agreement.

Specific Comments on the proposed Balancing Market Principles Code of Practice

Paragraph 2

The drafting in this paragraph is not wholly correct as while PPB has a licence obligation, as an Intermediary for the generating units it trades, it is not the “licensed generator”. Also the reference to “Single Market Operation Business” is not strictly correct.

Cost Reflectivity of Price Quantity Component

Paragraph 5

This paragraph highlights the need for flexibility in relation to the determination of SRMC and the current drafting cannot be complied with (as is acknowledged) because the SRMC curve may not be capable of being reflected due to the requirement for monotonically increasing bids (as specified in paragraph 9) which means that the bids have to be distorted and as a result can no longer represent the correct SRMC cost curve and as a result is immediately in conflict with the obligation.

Paragraph 7

This paragraph requires that the SRMC for bids is to be determined by the cost of increasing (or decreasing) output by 1MWh from the Relevant Output Level (ROL), i.e if the ROL is 100MWh then the cost of increasing output from 100MWh to 101MWh. However this is contradicted by the definition of “Relevant Output Level” which is defined as the level of output that is reached when an offer is accepted (i.e. if the ROL is 100MWh then this is the movement from 99MWh to 100MWh which is different to how it is described in paragraph 7.

Paragraph 9

As highlighted above this paragraph places an obligation to deviate from SRMC which contradicts the wider obligation to bid SRMC prices. This is also in conflict with paragraph 10 which requires that no startup or no load costs to be included in P/Q pairs when paragraph 9 suggests the costs should be transferrable since that is the only way to achieve a best fit. A similar issue could exist where the number of representative intervals referenced in paragraph 8 exceeds the ten P/Q pair limitation that is imposed and hence could again restrict compliance with the SRMC obligation.

Cost Reflectivity of Start-up Cost Component

Paragraph 11

The definition of startup cost requires the cost to be derived on the assumption that the unit is offline. This means a generator is unable to reflect a shutdown cost where the unit is running. This would not be an issue if it was guaranteed that any shutdown would be enacted using the Simple bids, in which case the decremental bids/offers could reflect the cost of shutting down. However where there is scope for such decisions to be settled based on the Complex Bids/Offers then participants should be free to bid in the shutdown cost where that represents a marginal cost.

Cost Reflectivity of No Load Costs Component

Paragraph 13

The drafting states that the No Load cost "shall reflect the fuel cost…". However this is clearly incorrect as there are additional costs in addition to fuel, including for example, other costs identified as Eligible Cost Items including fuel transportation and emissions costs and other consumables. This is clearly incorrect and is confirmed by the reference to "Eligible Costs" in paragraph 14 and by the drafting in paragraph 27. There is also a conflict between the first and second half of the paragraph. The first half reflects the principle of SRMC but the second half then corrupts this principle by enabling adjustment to facilitate wider limitations relating to incremental costs having to be monotonically increasing. This conflict again highlights that the SEMC recognises that SRMC cannot be mechanistically defined yet the BMPCOP seeks to be selectively prescriptive.

Eligible Costs in relation to price-Quantity Component

Paragraph 16

This paragraph refers to fuel costs that are "incurred". However as we highlighted in our response to the previous consultation, these can only be predictions of the costs that will be incurred since the actual cost will only be known after the event.

Paragraph 18

The paragraph states that the licensee should select its "chosen fuel price index". However as we have previously highlighted, marginal gas fired generators, whose output is directly correlated to wind output, and who are providing flexible output to the system can generally only purchase gas in the spot market and these fuel costs are not reflected by any "index". This again highlights the need for flexibility rather than seeking to be prescriptive and requiring alignment with some index that does not actually reflect the true marginal cost.

It must also be recognised that during the last 4 hours of the gas day, it is not possible to renominate gas volumes and hence the generator is exposed to the cost of Balancing gas as its marginal cost in this period which again is not reflected by any index but which is the basis of its SRMC.

Paragraphs 20 & 21

The same issues identified in the previous paragraph apply to gas transportation where the cost of gas capacity that cannot be booked because of restrictions in the gas market arrangements means the charges are much higher because the only option available is to incur the overrun costs. These are not penalty charges but reflect the marginal cost of capacity in that window where capacity cannot otherwise be purchased.

It is further perverse that there is only reference to gas transportation costs when there are transportation costs for all other fossil fuels that the BMPCOP excludes.

Paragraph 23b

This paragraph claims that the value of CO_2 credits will be the same for everyone. This is clearly incorrect since the SRMC for any generator will reflect its cost of buying such permits. However as again identified in response to previous consultations, each generator will have different access to the carbon market (e.g. depending on counter-parties it can access, credit arrangements, etc.) and there will be timing differences given there tends to be a minimum clip size. Hence a baseload generator will be able to trade on a more regular basis and hence there will be a narrower time interval between the time when forecasting the price when bidding and when the generator has accumulated sufficient volume to be able to trade that volume. This basis risk will be different for each generator and is a component of their individual SRMCs.

Paragraph 24

The drafting appears to contemplate that incremental and decremental costs will be the same but there are clearly circumstances where an incremental cost creates sunk costs that are not then avoided and therefore are not components of decremental costs. Again the drafting creates uncertainty rather than clarity.

Eligible costs in relation to Start-up Costs

Paragraphs 25 & 26

PPB trades a CCGT unit that is comprised of 2 gas turbines and one steam turbine. However to provide flexibility to the market the unit trades as two units in the energy markets. As a consequence of providing this flexibility, there are coupling costs that are incurred when one half is starting up and coupling with the other half that is already running. Such costs are clearly costs of starting up the unit and must be capable of being included but the drafting in the paragraphs makes no provision for such costs.

Valuation of Cost Items at Opportunity Cost

Paragraph 32

Sub-paragraph (a) refers to market value or spot price for the “operating day”. However this conflicts with paragraph 5 which requires the curve to reflect SRMC for an imbalance settlement period.

A further issue is that the complex bids are not defined for each individual imbalance period but generators must submit a single curve that applies for the remainder of the trading day. We have highlighted above that costs change across the trading day and not just spot prices but also tariffs and an example is gas transportation charges. In this example, the cost of gas transportation for the 1 October trading day will have low capacity costs for the period from 11pm to 5am but which then have a step increase from 5am when the multipliers increase to be the October multipliers. As a result there is no single “value” that covers all periods in the remainder of the day for which the complex bid offer data must cover.

This again highlights the folly of seeking to prescriptively define how costs are derived when there are a multitude of exceptions that cannot be precisely defined or even fully contemplated and which may emerge due to changes in legislation, other markets, etc.

Energy, Emissions or Time Limited Units

Paragraphs 36 to 38

These paragraphs seek to address energy limited units. However the same constraints can exist for gas fired units. For example, a unit may hold some annual gas transportation capacity that is a sunk cost and hence for this capacity there is no marginal cost. However a generator would normally want to utilise this capacity when it is most valuable such that it maximises its inframarginal rent to contribute towards this sunk cost. Hence if the generator held sufficient sunk capacity to operate for 12 hours, it would seek to reflect this in period where IMR is likely to be highest e.g. from 07:30 to 19:30 hours and for any generation outside this period it would be incurring the cost of additional daily capacity for which it would be economically efficient to include in its costs outside this window.

This is no different to the scenarios outlined in paragraph 36 and represents "benefit foregone" if the unit were required to generate at 01:00 when there is unlikely to be any IMR compared to what it could capture by generating over the peak period. The BMPCOP must therefore accommodate any unit that could be exposed to benefits foregone.

Gas Transportation Costs

Paragraphs 42 & 43

As discussed in our response in the previous section, the gas market arrangements relating to both Entry and Exit charges means that there are time when the gas capacity must be valued on the basis of the incremental cost of additional capacity but also taking account of the foregone benefit.

As also highlighted above in our comments on paragraphs 20, 21 and 32, the cost of gas capacity in the window when it is not possible to buy any more capacity is the factored charge that would be imposed on the utilisation of unbooked capacity.

Change Management

Paragraph 44

The paragraph only makes reference to consultation with holders of generation licences when there are other participants such as PPB who participate as Intermediaries and are obligated to comply with the code in accordance with their licence. All parties who have an obligation to comply with the code should be consulted.

Interpretation

Paragraph 46

The reference in the definition of “Eligible cost Item” is incorrect and should refer to “pursuant to section V of ..”.

The definition of “Incremental Fuel Cost” only makes reference to “handling” which would not appear to cover more general delivery costs

As noted in our comments on paragraph 7, the definition of “Relevant Output Level” is contradictory.