Power NI Energy Limited
Power Procurement Business (PPB)

I-SEM

CRM State Aid Update, 2019/20 T-1 Capacity Auction Parameters and Enduring Storage De-rating Methodology

Consultation Paper

Response by Power NI Energy (PPB)

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Power Procurement Business

Introduction

PPB welcomes the opportunity to respond to the RAs consultation on the Capacity Remuneration Mechanism (CRM) detailed design consultation on Auction timings, the CRM Parameters for the 2019/20 T-1 Auction and on the Enduring Storage De-Rating Methodology.

General Comments

We provided a comprehensive response to the previous CRM parameters consultation and following the first T-1 auction for 2018/19, our general views remain unchanged and for ease of reference we repeat our main comments.

The CRM represents the revenue stream that should enable recovery of the residual revenues that generators need to ensure revenue adequacy in the I-SEM. While superficially this may not seem to be as important a consideration for customers, it is vital as it sets the overall context of the I-SEM as a market into which investors will make their decisions on whether or not to invest. If there is a revenue adequacy shortfall or if regulatory risks are higher than in other markets then capital will not be committed into the I-SEM and customers will end up bearing higher costs to compensate and to ensure security of supply is not compromised.

Our primary issue with the CRM parameters is that the SEMC has imposed price regulation in the CRM in a similarly prohibitive manner as it has imposed for the offers in the Balancing Market, adopting a blanket approach when the primary objective of managing market power should be to apply targeted and focused actions on the source of the problems and letting competition prevail in the wider market among those who do not possess market power and who are already commercially incentivised.

The measures imposed in the BMPCOP mean generators can be operating at a loss in the Balancing Market and when aggregated with the bids caps for existing generators in the CRM, there is no scope to capture any Inframarginal revenues in the CRM that would contribute to remunerating the capital and debt invested in the generating assets or to provide any return on those assets.

Such an imposition risks destroying any incentive to invest in the I-SEM, be that in new capacity which would have to take regard of the non-recovery of costs once its maximum 10 year contract expires, or be that in decisions in how to maintain and refurbish existing capacity. The decision to allow partial recovery of unavoidable future investment costs in Unit Specific Price Caps

(USPC), while welcome, still leaves a risk that the generator may not recover all of its investment (since the investment cost must generally be smeared over at least 5 years) since the generator has no guarantee that it will obtain an RO contract for future years. This makes it very difficult for existing generators and results in a high risk of a distorted outcome that is uncompetitive and inefficient and which cannot represent the least cost outcome for customers and is not therefore a sustainable market framework.

In our December 2016 response we included a report from NERA which concluded that the SEMC proposals, as proposed in 2016, would distort the market, skewing it towards expensive new capacity and which they concluded would be inefficient and expensive for customers. The decision paper published in April 2017 (SEM-17-022) which established the framework for the 2018/19 T-1 capacity auction included only two significant changes to the proposals relating to Net Going Forward Costs (NGFC), namely providing for the inclusion of a portion of any unavoidable investment costs and providing for a 10% uplift as a margin for NGFC uncertainty. For reasons, including as noted above in relation to no guarantee of recovering the residual investment cost, we consider neither of these amendments have any material impact on NERA's original conclusions.

Responses to the Specific Questions

Chapter 3. Auction Timings

Q1: Do you have any comments on the indicative auction timetable set out in this section?

It is important to ensure the timing of the first T-4 auction is co-ordinated and aligned with the DS3 programme. It would also be preferential to have all the transitional T-1 auctions completed prior to the first T-4 auction as that would help reduce risk in the transition.

Based on that timetable with transition T-1 auctions planned for December 2019, the proposed T-4 auction for CY 2022/23 would need to be substituted by a T-1 Auction for CY 2022/23. This would facilitate the conclusion of all the transitional T-1 auctions (including the additional one for CY 2022/23) in 2019 and then holding the first T-4 auction in Spring 2020 for CY 2023/24 and stabilising with the enduring autumn T-4 auctions thereafter. The inclusion of an additional transitional year is also merited given the wider delays in CACM compliance (including XBID).

Further, we consider the T-4 auctions should have a lead time of at least the full 4 years and hence the enduring arrangements should ensure this. Under our suggestion, this would leave the first T-4 auction with a lead time of less than 4 years but that would be for only one year.

Further in relation to the enduring T-4 auctions, conducting auctions in September means participants would have to complete their analysis and derive auction strategies in July and August which coincides with holidays and is therefore generally difficult from a resourcing perspective and would create risks for participants. It would be better to hold the auctions in October which would reduce the participation risk.

Finally holding residual T-1 auctions in March provides only a 7 month lead time which is very tight. We don't see any reason not to continue holding those T-1 auctions in December each year.

Chapter 4. <u>Capacity Year 2019/20 T-1 Parameters</u>

Q1: Do you agree with the SEM Committee's minded to position to keep the parameters (excluding capacity requirement and de-rating factors) for the CY2019/20 capacity auction consistent with the CY2018/19 parameters?

Our general comments above re-express our concerns with some of the key parameters.

Notwithstanding those concerns and if the SEMC is not minded to reconsider those issues then we acknowledge that it would be sensible to keep the parameters consistent. However, we believe the Price cap should be retained at the Sterling Value given that the BNE unit was determined to be located in N. Ireland. Hence, rather than the Sterling price caps being determined from the applicable exchange rate (as stated in paragraph 4.5.6), the Euro price caps should be determined relative to existing Sterling price cap.

Chapter 6. <u>De-Rating Factors</u>

Q1: Do you agree with the proposed modification to the treatment of outages for small and embedded capacity in GB in the interconnector de-rating methodology?

The impact of smaller units on the GB market is not yet clear and therefore we believe it would be imprudent, until there is greater clarity and more importantly considered analysis on the impact, to amend the treatment of small generation in the interconnector de-rating methodology.

Q2: Do you agree with the use of a least-worst regrets approach to the choice of GB generation scenario used to set EMDF?

We believe the use of a least worst regrets approach is a logical extension to reflect the greater uncertainty over the supply/demand scenarios.

Q3: Do you agree with the approach that the EMDF need only be determined for the GB market for CY2019/20 in the absence of interconnection with other markets?

We agree with the approach proposed.

The question does however raise a further question of the modelling of the GB market and whether its interconnection to the other EU markets need to be reflected in the potential that those markets have the capacity to supply energy to GB or are requiring exports from GB into those markets. This situation may also be affected by BREXIT which could distort flows on interconnectors between GB and France / Netherlands which historically have flowed electricity into GB. Any reduction in such flows would reduce the value of Interconnector capacity into Ireland and this is implicitly recognised by the Minister’s support for the Celtic Interconnector when expressing the importance of direct connections into the EU.

Q4: Do you have any response to the storage related questions raised by the TSOs in their paper, which are listed in paragraph 6.3.3 above.

A: Do participants have any comments on the methodology for calculating DRFs for storage units as described in this paper?

We do not see any justification for inflating DRFs for storage capacity. The methodology established determines the value to system security with and without the capacity and this determines the "average" contribution for that capacity. The paper notes in section 4.2 that as the volume of storage increases, the incremental contribution to reducing LOLE decreases. Therefore the contribution, and hence DRF, of any additional storage capacity must, in accordance with this principle actually contribute less than the "average" of existing capacity and should have a lower DRF than that determined for the existing storage capacity. The proposal to actually inflate the "average" is therefore counter to the initial premise that the contribution to LOLE reduces as the generation volume increases.

We note the concerns that applying a lower marginal DRF undervalues the contribution for existing capacity. The solution is not to inflate the DRFs for all capacity but to reflect (and effectively grandfather) DRFs for storage units to reflect that the first MW will contribute the most and that subsequent additions will have a reduced DRF to accurately reflect the impact of their addition which should be applicable to them only and not at some stage dilute the DRF for existing exits (e.g. after the new units become existing in a subsequent auction and hence change the volume of existing capacity).

The paper states that the approach of calculating the Storage Adjustment Factor is to reach an "unbiased" outcome to avoid giving existing storage "preferential treatment", but it also recognises that by applying this factor it will over-estimate the benefit of new storage to system adequacy.

The paper also states in the last paragraph of Section 4.3 that "There is a risk that, as the component units that comprise the existing storage change, the average existing storage unit may become less representative…". This surely completely undermines the average methodology outlined as it is a surety that commissioned storage will exhibit large variability from a MW and MWh perspective. The methodology employed should be agnostic to development concerns.

In summary, we consider the proposed approach to be flawed and inefficient which will distort investment decisions as a consequence of delivering erroneous market signals and which could also impinge on the DS3 arrangements. The least cost approach must recognise the diminishing value of additional storage and hence that timing is a component of the value that should be reflected in the investment decision. Hence our proposal that a “time-stamping” approach must apply that grandfathers DRFs (relatively) to ensure that incremental storage capacity obtains a DRF reflective of its marginal contribution, given that it is additional to existing capacity.

These economic principles should apply at all times and not just if significant quantities seek to connect. At that point an investment decision has been substantially progressed and a change thereafter would confer “preferential treatment”. The fundamentals reflecting the fact of diminishing contribution should be established at the outset to avoid inefficient outcomes.

B: In the absence of significant historical data, do participants consider it reasonable to apply system-wide outage statistics to new technologies (such as batteries)? If not, please provide alternative with justification.

It is not reasonable or prudent to apply system-wide outage statistics to new technologies. To do so runs a high degree of risk that performance may not conform to averages achieved by more conventional units that have demonstrated their performance and that uncertainty increases the risk to Security of Supply for customers.

Such performance variations may not just apply to general availability but once a fault occurs, the mean time to repair of storage may be very different to the "average" and indeed may be very different within the overall storage class depending on the technology and configuration adopted. Any such differences should also be captured and reflected in DRFs.

A more prudent approach would be to reflect the uncertainty by applying an uncertainty scalar to each new technology which can then be increased as experience and performance is proven. Where there is evidence of the performance in other worldwide markets that have similar conditions to those prevailing in Ireland, then the scalar could be applied to that "evidential performance". If no such data exists or the environment in which it has operated elsewhere is not applicable to how the units would operate in the conditions prevailing in Ireland, then the scalar would need to be set to reflect that deficit of evidence.

This is akin to what has historically happened when commissioning new generation capacity where its capacity was ignored until it had completed an extensive reliability run to prove its capability and that it would not disrupt the secure operation of the system.

C: ***Regarding Storage Units with Storage Volume sizes that are not a multiple of 30 minutes: Do participants have any comments on the TSO's preferred methodology for calculating DRFs for such storage units, i.e. interpolating between storage sizes? What other options do they believe may be more appropriate?***

The rounding approaches are too blunt and hence not worth pursuing. The linear interpolation is a simple proxy but a review of its application to the DRFs shown in Table 1 shows that it would be relatively consistent at the top end of the time range (from 3.5 hours upwards) but that would break down at the lower end where the relationship is less linear. An alternative would be to determine a best fit logarithmic or polynomial equation for the curve and use that to determine intermediate values.

D: ***Should storage units be allowed to apply a DECTOL to their De-rated Capacity? Please provide arguments to support your response.***

The opportunity to apply a DECTOL should be available to all units and should not be technology specific.

E: ***Should specific DRF values be published for units with energy storage volumes of 6.5 hours or greater? Are participants aware of potential projects that might make such a change appropriate?***

The use of a curve rather than using linear interpolation would enable the DRF to tend towards a maximum figure.

Q5: Do you have any response to the other energy and run-hour limited generation related questions raised by the TSOs in their paper which are listed in paragraph 6.3.5 above.

F: Do participants consider that a unit's run-hour limitations (due to emission restrictions or otherwise) should be reflected in the Capacity Market Auction? If so, what mechanisms should be applied. If not, please provide rationale.

Run-hour limitations must be reflected in the DRFs since clearly a unit that has such limited hours capability exposes a greater risk that it will have exhausted its hours and hence is not capable of contributing to security of supply. This is little different to a technology class that has poor availability and this should be reflected in the DRFs.

The example shown for a mandatory adjustment is not a viable approach as it ignores that there are LOLE risks outside the winter peak hours and hence an analysis would need to take account of a range of scenarios. This is further complicated by the fact that historically limitations are not linked to MWh but merely hours synchronised and also can be applied to a "stack" that is common to a number of units.

G: Do participants have any comments on the proposed approach for de-rating DSUs with limited Maximum Down Time?

The DRFs for Demand Side Units should similarly reflect the impact Maximum Down Times on their contribution to security of Supply. Further the application of system wide outage characteristics to DSUs is not appropriate and again scalars should be applied until experience and history are obtained to provide confidence that the capacity will deliver as and when expected. DSUs have been active in the SEM for a number of years and hence there should already be some evidence of their performance, albeit that has been in a market with surplus capacity and hence the risk of being utilised has been lower than would be expected where capacity is at equilibrium.

It isn't obvious that the curves derived for storage units is transposable for use with DSUs (further compounded by the proposed use of the Storage Adjustment Factor) and further analysis would be required to assess if there is any correlation or whether a distinct table is required for DSUs.

Chapter 7. Long Stop Date and Termination of New Capacity

Q1: Do you agree with our revised proposals for long Stop Dates and Substantial Financial Completion Dates as set out in the sections, and summarised in Table 4?

The revised proposals are clearly more rational.

The risks are not just to Security of Supply but also increase the risk to other participants as the failure of other capacity to deliver will most likely increase both the number and duration of occasions when prices exceed the RO strike price. As a result participants’ bids into the capacity market would not have reflected this higher risk and hence the price in the capacity market will be under-stated because they have under-valued that risk.

We note the proposals to consider emergency capacity auctions. However it isn’t clear what governance arrangements will provide for such an outcome and it is also unclear if the clearing price paid to the units that secured capacity in the original auction would be increased if the clearing price in the emergency auction were to exceed the clearing price in the original auction.

The proposals provide discretion to the SEMC to set to Substantial Financial Completion at less than 18 months for capacity awarded one year contracts in T-1 auctions. This is very loose framework and some principles and/or rules should be set out to define the conditions under which such discretion would be exercised.