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RE: Capacity Remuneration Mechanism Consultation Paper (SEM-15-044)

Dear Sirs,

Tynagh Energy Limited (TEL) welcomes the opportunity to respond to the Integrated Single Electricity Market Capacity Remuneration Mechanism (CRM) Detailed Design Consultation Paper (SEM-15-044).

TEL commends the RAs on their decision to include an explicit capacity mechanism within the High Level Design (HLD) of the I-SEM. In arriving at this decision the RAs recognised the importance of total remuneration from energy payment, capacity payments and ancillary services being sufficient to ensure security of supply[1]. However TEL would argue that in order for security of supply to be achieved a broad range of capacity types will be required. This will include both intermittent and conventional generation across baseload, mid-merit and peak capacity providers.

In designing the CRM we should be mindful of the lessons learnt from the Capacity Payment Mechanism (CPM). The CPM Medium Term Review found that while the mechanism had been broadly successful in meeting its objectives any future CRM should reward capacity providers in accordance with performance and provide signals for new entry / investments and exits if required[2]. This is the primary challenge of the new CRM.

The SEM is currently experiencing a period of overcapacity and thus exit signals are required. It is important that in designing these signals, a broad range of capacity providers can continue to exist in the I-SEM. The exit signal should be directed at non-performing plant and not solely at plant with either high variable or fixed costs that are reliable capacity providers. TEL would advocate a cautious approach to ensure that plant exits are orderly and minimise "regret costs" for consumers. It is far cheaper to keep existing plant open than to finance new build.

The CRM should provide a stable price signal to capacity providers. This will ensure that the correct long term entry and exit signal is provided to the market. A boom and bust capacity market will not deliver a stable signal and TEL would argue against the use of a vertical demand curve (i.e. single capacity requirement) as this will result in the cleared price at auction being either the price cap or price floor.

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[1] SEM-14-045
[2] SEM-12-016

The use of the Day Ahead market as the reference price in conjunction with strong physical performance incentives will ensure a stable signal to capacity providers while directing exit signals at non-performing plant. This physical performance incentive should be separate from any scarcity pricing or difference payment required under the Reliability Options.

TEL recognises the benefit of scarcity pricing in creating a financial incentive for generators to physically generate where power has been sold day ahead. However the decision on when scarcity pricing should apply and how it is determined is best dealt with through the Balancing Market workstream. Overcapacity in the I-SEM may result in a lack of scarcity events for a number of years and so physical performance incentives should apply every year. These need to account for the specific nature of the central dispatch market of the I-SEM and not disadvantage generators that have not received dispatch instruction from the TSO.

The following pages contain TEL's answers to the questions posed by the RAs in the consultation paper.

I trust that these comments will prove helpful and should you have any queries, please do not hesitate to contact me.

Yours sincerely,

John O'Connor.

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2. Capacity Requirement

a. Should the existing security standard of 8 hours be retained or should we move to a new security standard of 3 hours or other standard?

While the CPM in the SEM uses an 8 hour LOLE to calculate the Annual Capacity Payment Sum this does not have a direct impact on the volume of capacity that receives capacity revenue. It could be argued that the true standard employed by the RAs in both jurisdictions is in fact much more stringent. Interventions, such as the 2004 temporary stand-by peaking capacity and 2005 CADA supported generation in ROI and more recently the contract awarded for additional generation capacity in NI in 2014, imply that the true standard is closer to zero hours LOLE.

The security standard chosen for the CRM will have a direct impact on the volume of generation that will be in receipt of capacity revenue. The question should not therefore be whether to retain the existing standard, but should be what the appropriate standard to introduce is.

Settling a higher LOLE may provide too harsh an exit signal which could very quickly move the system from a state where there is an abundance of capacity to one where additional capacity is required. The cost of providing additional capacity at short notice would be a far greater cost to consumers that setting a lower LOLE and retaining more of the existing capacity on the system.TEL would advocate a cautious approach to ensure consumer "regret costs" are minimised. Setting the standard of 3 hours LOLE would be a cautious approach during the transition and would be consistent with the standard set by France and the UK.

b. How should the CRM account for unreliability of capacity providers?

TEL believes that de-rating capacity providers is the most appropriate method of accounting for their unreliability as this would provide a buffer among successful capacity providers in the event that a provider is unavailable when required.

c. How should the CRM account for uncertainty over the future level of demand?

Forecasting future demand is by its nature prone to uncertainty. TEL would caution against any approach that results in a single demand forecast for any future period (vertical demand curve). Experience from ISO-NE is that a vertical demand curve will result in a boom and bust cycle in the CRM[3] i.e. if the capacity bidding into the auction is below the requirement, the clearing price at auction will be the price cap; however if the available bids are above the requirement, the clearing price at auction will be the price floor.

This effect is likely to be exacerbated in the I-SEM with the indivisibility of plant size, (particularly in a relatively small system) where the capacity margin/deficit can be sensitive to a small number of investment decisions[4]. This was in fact one of the reasons that RAs determined that a CRM was a necessary component of the I-SEM HLD. To resolve this issue ISO-NE has implemented a sloping demand curve. TEL would urge the RAs to consider a similar mechanism or at the very least, implement an upper and lower band for future demand forecast to ensure that the clearing price at auction is stable.

d. How should interconnectors be treated?

[3] *ISO New England Inc.*, 147 FERC ¶ 61,173 (2014)

[4] SEM-14-045

The generators on the far side of the interconnector are the capacity providers not the interconnector owner. Capacity providers in neighbouring jurisdictions should be eligible for participation in the I-SEM CRM so long as they are appropriately de-rated and exposed to the same performance incentives as capacity providers in the I-SEM. In the event that the performance incentives are implemented but no capacity providers in neighbouring jurisdictions are registered in the I-SEM CRM then any payment due to providers in neighbouring jurisdiction should be refunded to consumers to reduce the cost of procuring capacity.

e. How should determination be made of how much capacity should be procured through each specific auction?

As stated previously the RAs should look to the lessons learned in ISO-NE and implement a method of adjusting the capacity requirement that enables a range of acceptable capacities to be procured while delivering a stable clearing price at auctions. Adjustments will need to be made where capacity providers are ineligible or choose not to participate. These adjustment should only be to the maximum amount necessary to account for the value of the provider in question to system security i.e. the capacity provider should be de-rated to the lower of the technology specific de-rating factor or the average capacity factor of the generator over the preceding 12 months.

f. How should the CRM treat locational signals?

The CRM should be a single zone regardless of whether the ETA is retained as a single zone or split into two zones. The CRM should provide a long term price signal for generation entry and exit. Retaining a single zone is a simpler solution and will reflect the enduring conditions once the North South Interconnector is commissioned. If the decision is made to split the ETA into two zones prior to the completion of this piece of infrastructure this will result in higher energy prices in the constrained zone. Splitting the CRM into two zones would result in a double payment as the capacity price in the constrained zone would also be higher.

3. Product Design

a. How should the strike price be determined?

The strike price will act as a cap on energy revenue. The RAs recognised that the regulatory risk of price caps in energy-only markets create the "missing money" problem i.e. prices do not reach a high enough level to remunerate investment. This was cited as one of the reasons for explicitly including CRM as an element on the I-SEM HLD.

In the I-SEM capacity providers should be able to recover their variable costs from energy revenue otherwise the CRM will create a "missing money" problem rather than solving one. It is important that the strike price is set at a level that would ensure that these variable cost are recoverable from the ETA. It therefore follows that the strike price should be variable based on the variable costs of a reference unit.

b. How should the reference unit be chosen?

The reference unit chosen should be a hypothetical unit. To ensure generation adequacy the I-SEM CRM needs to ensure that baseload, mid-merit and peak capacity providers can finance their activities. The CER has a statutory duty to ensure that licence holders are capable of financing their activities[5]. The choice of either a BNE or the SRMC of the marginal unit would present too sharp an exit signal to peak capacity providers.

[5] Electricity Regulation Act, 1999

If a BNE were chosen any unit less efficient than the BNE would not recover its variable fuel costs so therefore would be forced to close immediately. If the marginal unit were chosen then this unit would need to rely solely on the CRM to cover fixed cost and make a return on investment. This marginal unit may be unsuccessful in the auction or the clearing price due to over capacity may be too low resulting in the plant closing. There would therefore be a new marginal unit at a lower strike price and the process would repeat unit the capacity margin was too low, resulting in additional cost for consumers. Choosing a hypothetical unit would avoid this.

c. If a hypothetical unit is chosen, should a conservative approach be adopted?

Yes - The RAs should adopt a cautious approach in selecting the hypothetical unit. The specification of the hypothetical unit and the methodology for the calculation of its costs should be sufficient to ensure that its costs are higher than the operating costs of the most expensive I-SEM generator that could be scheduled / dispatched in a scarcity event (including its start and no load costs).

d. Should the reference unit be grandfathered?

There should be one strike price for all capacity providers in the CRM. The methodology for determining the strike price in each period should be set at the start of the I-SEM CRM design process. This will avoid regulatory uncertainty and provide a stable signal for entry and exit.

e. How should scarcity events be defined?

The definition of scarcity should be consulted on as part of the Balancing Market workstream.

f. Which option for Market Reference should be implemented?

The option which should be implemented is 100% Day Ahead. The Day Ahead market is the most stable indicator of capacity adequacy, it is the most accessible market and therefore most equitable. The RAs had suggested that the use of multiple reference markets under option 4 would reduce the risk for baseload generators. While this may be true it would increase the risk for mid-merit and peak generators and would therefore be inequitable.
However using the Day Ahead market with a high strike price will significantly reduce the risk to capacity providers, so strong physical performance incentives should also be implemented to ensure that the costs and benefits are equally distributed between consumers and capacity providers. These performance incentives should be above and beyond scarcity pricing and should place more than just the capacity revenue of the capacity provider at risk.

g. Should a load following obligation be implemented?

A load following obligation should be implemented. This will ensure that the headroom created by the de-rating of capacity providers is sufficient during outage season to allow for secondary trading to mitigate risk.

h. Should physical performance incentives be implemented?

As stated above, physical performance incentives should be implemented to ensure that capacity providers are providing the security of supply for which they are being contracted.

i. What form should physical performance incentives take?

The physical performance incentives that are implemented should take account of the central dispatch nature of the I-SEM and not disadvantage generators that have not received dispatch instruction from the TSO. The value at risk to generators should be in excess of the annual capacity revenue (perhaps capped at 105%). This will ensure that exit signals are strongest for unreliable capacity providers and will ensure that all capacity providers have "skin in the game". Non-performing generators should be charged and over-performing generators should be paid (whether or no they have been successful at auction) with any surplus paid back to consumers to reduce the cost of purchasing system security.

j. Should performance incentives only apply at times when the system meets a physical definition of system stress, or should they apply at all times? (Scarcity based)

Depending on how system stress is defined it may be a number of years before it is experienced in the I-SEM due to over capacity. However performance of capacity providers should be incentivised every year to ensure that exit signals are strongest for non-performing generators.

k. Should limits be placed on the size of performance incentives? (Caps & Floors)

Performance incentives should be capped but there should be the possibility for capacity provider to lose more that the annual capacity revenue. This will ensure that older unreliable generators with no outstanding debt are not incentivised to bid low in a capacity auction at the expense of more efficient and reliable generators that would require a higher clearing price at auction due to outstanding debt obligations.

l. Should Renewables & DSUs be <u>exempt</u> from performance incentives?

Neither renewable nor DSUs should be exempt from performance incentives.

m. Should incentives & penalties be applied during pre-commissioning phase?

Prior to commissioning a generator is unreliable and does not provide security of supply. A generator should therefore not receive capacity revenue prior to commissioning. The penalty that should apply is a forfeiture of capacity revenue in favour of the reliable capacity providers that are providing reliable capacity in line with the physical performance incentive mechanism. Any surplus should then be returned to consumers.

4. Eligibility

a. How should plant receiving support under other mechanisms be addressed?

All supported generators should be eligible.

b. Should renewables not receiving support under other mechanisms be included?

All renewable generators should be eligible.

c. Should bidding be mandatory or discretionary for eligible generators?

Where penalties in the CRM have the potential to be in excess of the annual revenue from the CRM, bidding should be discretionary.

d. How should non-firm generation be treated?

Non-firm generation should be eligible to bid at the same de-rating factors as other generators of the same technology but should also therefore be exposed to the same physical performance incentives.

e. Should the capacity requirement be adjusted to account for generators not participating in the CRM?

The capacity requirement should be adjusted to account for generators not participating in the CRM by reducing the capacity requirement by the lower of the technology specific de-rated capacity or the average capacity factor for the previous 12 months of the generator in question. This will ensure that the true value of the generator meeting security of supply standards is taken into account and there is not an assumption that the generator would have cleared a volume at auction.

f. How should DSM be treated in the CRM?

DSM should be treated equitably and exposed to the same obligation and physical performance incentives as other capacity providers.

g. Any views on how other potential capacity sources and energy limited plant might be treated?

Other potential capacity sources and energy limited plant should be treated equitably and exposed to the same obligation and physical performance incentives as other capacity providers.

h. How should de-rating be approached for:

i. Dispatchable capacity;

A single technology specific de-rating factor should be applied to all dispatchable capacity providers benchmarked to international best practice. This de-rating factor should be applied to the maximum generation, corrected for atmospheric conditions, demonstrated by the generator in the previous 12 months.

ii. Intermittent capacity;

The capacity value that intermittent capacity provides during system stress should be the de-rated capacity factor that applies. As more intermittent capacity connects to the system the de-rating factor is likely to increase. New capacity providers should be provided with a profile of the de-rating factors that will apply in the first 10 years based on the projected level of intermittent capacity connected in future years and this profile should be grandfathered.

iii. Interconnectors?

As discussed previously, it is capacity provider and not the interconnector owners who should be eligible to participate in the CRM. The capacity value that capacity providers in neighbouring jurisdictions provide during system stress should be the de-rated capacity factor that applies.

i. How should the de-rating framework be constructed across these various options?

As discussed above, the de-rating should be technology specific and benchmarked against international best practice. Grandfathering for intermittent generation should be available but this should take account of projected levels of intermittent connections over the first 10 years.

j. How should aggregators and PPA providers be treated?

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There should be no minimum size of generator that can participate via an aggregator however there should be a maximum size set. Generators above a certain size should be capable of participation in their own right. Evidence of physical generation should be provided by way of PPAs or similar exclusive contracts.

k. What are your views on prequalification for:

i. Existing Plant;

Strict pre-qualification criteria should be determined.

ii. New & Refurbished plant?

Pre-qualification criteria should apply equally to new and refurbished plant. New and refurbished plant that are successful should be subject to implementation agreements with detailed milestones and a security bond to ensure that the capacity will be delivered.

5. Supplier Arrangements

a. How should the recovery of CRM option fees from Suppliers be achieved?

No comment

b. Any views on how the potential mismatch in payments flow and CRM charging should be treated?

No comment

c. Should supplier credit cover arrangements be broadly similar to that in the SEM?

No comment

d. What, if any, credit cover arrangement should be introduced for capacity providers?

Where physical performance incentives are implemented credit cover will be required from capacity providers. This should be set at the lowest level possible while ensuring the CRM is protected from the risk of default.

e. Should the costs of exchange rate variations be borne by capacity providers or mutualised across the market?

The cost of exchange rate variations should be mutualised across the market.

6. Institutional Arrangements

a. Is the institutional framework outlined sufficient and suitable?

Changes to CRM terms and conditions should only be permitted where absolutely necessary to provide investor certainty. Drafting of all agreements / rules should be subject to consultation.

b. Should the TSO carry out the Capacity Market Delivery role?

Yes

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c. **Should the MO responsible for imbalance settlement in the new arrangements also be responsible for the settlement of capacity payments and charges?**

Yes due to the synergies that exist between these two functions.

d. **Are the outlined governance arrangements suitable for implementation of the I-SEM capacity mechanism?**

No comment

e. **Which options for contractual arrangements are the most appropriate as assessed against the listed criteria?**

The rules based approach would be the most appropriate as it would be the most practical and cost effective and would provide an appropriate basis for development and, where necessary, modification in a straight forward manner. However capacity providers who are successful at auction will require some form of individual capacity agreement in order to make a project bankable.

f. **Are implementation agreements required for new entrants participating in the capacity auctions?**

Yes implementation agreements and bonds should be required from new entrants participating in capacity auctions. These implementation agreements will need careful consideration and design.

g. **Should there be any other milestones in addition to "financial commitment" and "substantial completion" milestones?**

As above.

h. **How should each milestone be measured?**

As above.

i. **What is an acceptable time window for demonstrating each milestone has been met?**

As above.

j. **What should be the consequences of failing to meet a milestone?**

As above. The ultimate consequence for failing to deliver the capacity should be the loss of the capacity contract but this should only be implemented as a last resort.

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