SIGA-HYDRO

Response to Capacity Remuneration Mechanism Detailed Design Consultation Paper SEM-15-044

SIGA-Hydro is developing a Grid-Scale pumped Storage Plant (360MW) for commercial operation in 2022. SIGA-Hydro has reviewed the Capacity Remuneration Mechanism Detailed Design SEM-15-044 and welcome the opportunity to comment on it.

Section 2

A) Feedback on our minded to position to retain the all-island security standard of 8 hours LoLE.

The security standard of 8 hours LoLE is lower than that which applies currently in Northern Ireland and lower than in Great Britain. High security of electricity supply is essential for economic development. Increasing market penetration of intermittent resources tends to reduce security of supply and reduces incentives for investment in firm capacity. SIGA Hydro recommends a security standard of 3 hours, to match that in Great Britain; however we do recognise that any additional cost to deliver this improved security standard would be unwelcome.

Further analysis by the TSO on loss of load out-turn compared to expectation would be beneficial. We also note that future loss of load events may be related more to generation flexibility than adequacy. For example ramping deficits may be a significant contributor. In the long run it is the Value Of Lost Load (VOLL) that should determine if the security standard should be changed to 3 hours. The true value of VOLL may become more apparent as DSM increases the elasticity of demand.

B) Comments from respondents as to their preferred method of accounting for unreliability of capacity in determining the capacity requirement, along with reasons behind their preference.

SIGA-Hydro favours the "De-Rated Requirement" approach as this reflects the true value of the plant to generation adequacy. We suggest that the de-rating factor should be determined for each individual plant rather than each individual category of plant. Each plant's statistical contribution to LOLE should be used as the basis for the de-rating factor calculation. A generator contributes to resource adequacy if it reduces the LOLE in some periods. Conventional generators' contribution to adequacy is typically a function of the unit's capacity and forced outage rate; however in a system with high levels of variable generation this contribution can also depend on, for example, the generators' ability to start up and ramp quickly. Including such factors in the determination of generation adequacy is in line with the ENTSO-E Target Methodology for Adequacy Assessment[1].

C) Feedback on the options presented in relation to accounting for demand forecast uncertainty, along with rationale behind any position.

SIGA-Hydro favours the 'optimal scenario' approach based on minimised 'regret cost' as applied in Great Britain. This approach is economically rational and should provide the best economic outcome for electricity customers. As more comprehensive stochastic models become accepted there may be merit to moving to such models in the future

[1] See https://www.entsoe.eu/Documents/SDC%20documents/SOAF/141014_Target_Methodology_for_Adequacy_Assessment_after_Consultation.pdf

D) *Feedback on our minded to position to base the capacity requirement for the CRM on a single capacity zone*

Assuming that the second North-South interconnector is in place by 2019, we agree with the Regulatory Authorities minded position to have a single capacity zone for the CRM, with uniform CRM prices throughout the island of Ireland.

E) *Detail of any other considerations respondents felt that we should take account of when determining the capacity requirement for the CRM.*

We have no further comments on the capacity requirement for the CRM.

Section 3

A) *The approach to setting the Reliability Option Strike Price:*

a. Should we adopt the "floating" Strike Price approach, which is indexed to the spot oil or gas price?

The objectives of the CRM include shielding consumers from price spikes, addressing the "missing money" problem and providing a portion of the income certainty required by new build projects to make them investable. The approach to setting the Strike Price may have a significant impact on how a generator's revenue is balanced between the RO fee and energy revenue.

In an energy only market, the most expensive peaker must recover both its fixed and variable costs during the few trading periods during which it is dispatched. The 2016 BNE[2], dispatched for 175 hours per year at an average 60% load would need a market price of at least €700 per MWh to recover its costs. With a strike price of €200/MWh it would need to recover a substantial portion of its costs from the RO fee. A higher strike price would afford it the opportunity to recover more of its costs from the energy market, albeit at a higher risk. A lower strike price would reduce its energy revenue and necessitate higher bids into the RO auction.

In operation, the strike price effectively acts as a price cap on the market price. All generators must be able to recover their short run marginal costs (SRMC) within this price cap. Hence the strike price must be at least sufficient to allow the most expensive generator to do this, including start-up and no load costs. In principle we agree that since these costs are linked to fuel costs, it is reasonable to link the strike price to fuel costs. The New England approach, described in paragraph 3.2.4 appears appropriate. We suggest that the indexation may not be linear and should be formulated in such a way as to keep generators as revenue neutral as possible to changes in the strike price. Also the indexation function must not reduce the energy market income of certain types of generation more than others. It may also be necessary to consider a floor strike price.

The question also arises as to how the most expensive generator will recover its start-up costs. If a margin of say 10% to 20% is added to the strike price to allow for this, the generator might still not recover its costs. We therefore suggest that an "uplift" is added to the market price in the trading periods around the scarcity event such that the market price remains close to the

[2] See http://www.allislandproject.org/en/cp_current-consultations.aspx?article=879633f4-5b08-42e3-a889-4f86cf0b2667

strike price for sufficient time to allow the generator to recover its start-up costs. This may happen in any case and the uplift may need to be applied only rarely.

b. How do we choose the reference unit? Should it be based on actual plant on the system or a hypothetical best new entrant (BNE) peaking unit as currently used for setting the Annual Capacity Payment Sum?

The price-setting peaking plant is likely to be dispatched at part load during periods of system stress. The net efficiency of the current BNE peaker (which has a capacity of around 200MW) would be less than 25% if dispatched at loads of lower than 30% of base load. Many existing peaking units on the system have efficiencies of much lower than 25% at part load – for example, the peaking gas turbines in Northern Ireland have efficiencies of about 20% at half load. We suggest that the reference heat rate for calculation of the Strike Price should be that of the lowest efficiency peaking plant on the system, operating at 50% capacity. An additional margin should also be considered to allow for short term variations in fuel prices and fuel purchasing strategies.

Care should also be taken to ensure that the strike price is not set so high as to encourage very low bids into the RO auction since generators would expect to recover most of their costs from energy revenue. The impact of this would be to thwart the investment case for new efficient plant since the fixed revenue streams required for investment would be eroded.

c. Should we grandfather this reference unit where a multi-year RO is sold by new capacity?

New investment in generation will not happen without revenue certainty. As a new entrant we favour grandfathering of the reference unit. Multi-year ROs will also require index linking to ensure that project financing and consequently consumer costs are minimised.

B) The implementation of scarcity pricing in the I-SEM Balancing Market?

Administered scarcity pricing is being implemented in various electricity markets because market pricing does not always respond adequately to system scarcity events. Based on this experience elsewhere, we are in favour of administered scarcity pricing which would be related to the value of lost load and which would apply when further increase in demand would erode the reserve margin.

C) The choice of market reference price options from amongst the options presented and consistency with key objectives.

SIGA-Hydro favours option 3, the Day Ahead Market Price for the following reasons;

- The Intra Day market is not yet developed and may suffer from significant liquidity issues. For example the Nordpool market sees intraday volumes of just 2% of electricity consumption in the Nordic Region[3].
- While the balancing market may reflect scarcity in real time better than the other markets we believe that balancing markets are more to do with short term system security than long term generation adequacy and are therefore not appropriate. In particular, many generators are not technically capable of responding to unexpected scarcity events and delivering energy in the BM timeframe.

[3] See http://www.nordicenergyregulators.org/wp-content/uploads/2014/06/Nordic-Market-Report-2014.pdf

- The Day Ahead market will be the primary liquid spot market, it facilitates cross border trade and allows generators to hedge their risks

D) Whether the RO volume and/or the additional performance incentives should be load-following.

SIGA-Hydro favours load-following adjustment of the RO obligation. It is unlikely that there would be a significant volume of output by ineligible capacity during scarcity events so that Supplier risk should be small with load-following adjustment; Suppliers may also be able to hedge risk using suitable contracts for difference with ineligible capacity providers.

E) The requirement for, and design of additional performance incentives, including:

a. The form of additional incentives;

From the commentary in the Consultation Paper, the issue of performance incentives for capacity mechanisms seems to be still evolving in overseas markets. The Great Britain incentive regime has been designed taking account of experience elsewhere and appears to be reasonable. However, its effectiveness has not been proved. An incentive scheme similar to that in Great Britain would seem to be a good starting position for the I-SEM CRM.

b. Scarcity based triggers for performance incentives

SIGA-Hydro favours performance incentives focussed on scarcity events with such events defined as periods when availability is less than demand plus operating reserve requirement.

c. Caps and floors on incentives;

SIGA Hydro favours incentive caps and floors similar to those applying in Great Britain. Project financiers are likely to be familiar and comfortable with this regime and this is important for new entrants seeking to raise investment capital.

d. Performance incentives for renewables and DSUs;

SIGA-Hydro believes that performance incentives will need to be tuned for renewables, DSU's and other energy limited providers.

Intermittent renewables will likely end up with a relatively low capacity credit/payment and any penalties could potentially transfer to the PSO levy so it is unclear how penalties could be effectively applied.

DSU's typically have a time dimension to their load reduction, somewhat analogous to energy limited generators. We therefore suggest that DSU's and other energy limited generation such as storage should not be subject to penalties for non-delivery of energy that is beyond their energy limit.

e. Performance incentives during the pre-commissioning phase;

SIGA-Hydro understand that the Regulatory Authorities intend to consult on this issue at a later stage. However, SIGA-Hydro strongly recommends that investment in appropriate new entry capacity be encouraged and that no unreasonable barriers to new entry should be put in place.

f. Detail of any other considerations respondents feel that we should take account of when determining policy in relation to product design

The question arises as to how generator technical capabilities will be included. For example a generator with a long start-up time may be fully available to start but may not have sufficient time to reach full output or even synchronisation before the scarcity event. Will such a generator be required to pay the difference between the reference price and the strike price for its undelivered capacity?

Section 4

A) The options presented in relation to the eligibility of plant supported through other mechanisms;

In general SIGA-Hydro favours the retention of capacity payments to plants supported by REFIT or similar where the subsidy payments are reduced by the amount of the capacity payment. This assumes that the capacity payment is related to the true value of the contribution of the subsidised units to generation adequacy. The residual PSO levy is then reduced and more accurately reflects the actual cost of supporting renewable generation. This is really a question of allocation of costs. Where renewables contribute to generation adequacy the costs should be allocated to capacity charges. Where a feed in tariff is required to incentivise build because capacity, energy and system services revenues are insufficient then this cost should be allocated to the PSO levy.

SIGA-Hydro agrees that generation in receipt of long term ancillary service contracts should not be over compensated through the CRM. DS3 is being designed to ensure that the system services required to achieve Ireland's renewables targets are delivered economically, efficiently and reliably. The current capacity payment mechanism deducts an ancillary service income component from capacity payments equally for all generators. Under the new I-SEM arrangements, system services and capacity may be procured separately and independently and hence this automatic deduction will not occur.

Both RO fees and DS3 system services payments will contribute to solving the missing money problem for capacity providers. DS3 payments in particular, solve the missing money problem for generators who choose to upgrade existing plant or build new more flexible plant at a higher cost in order to address the escalating need for the system services that are required to operate the power system in a secure and stable manner.

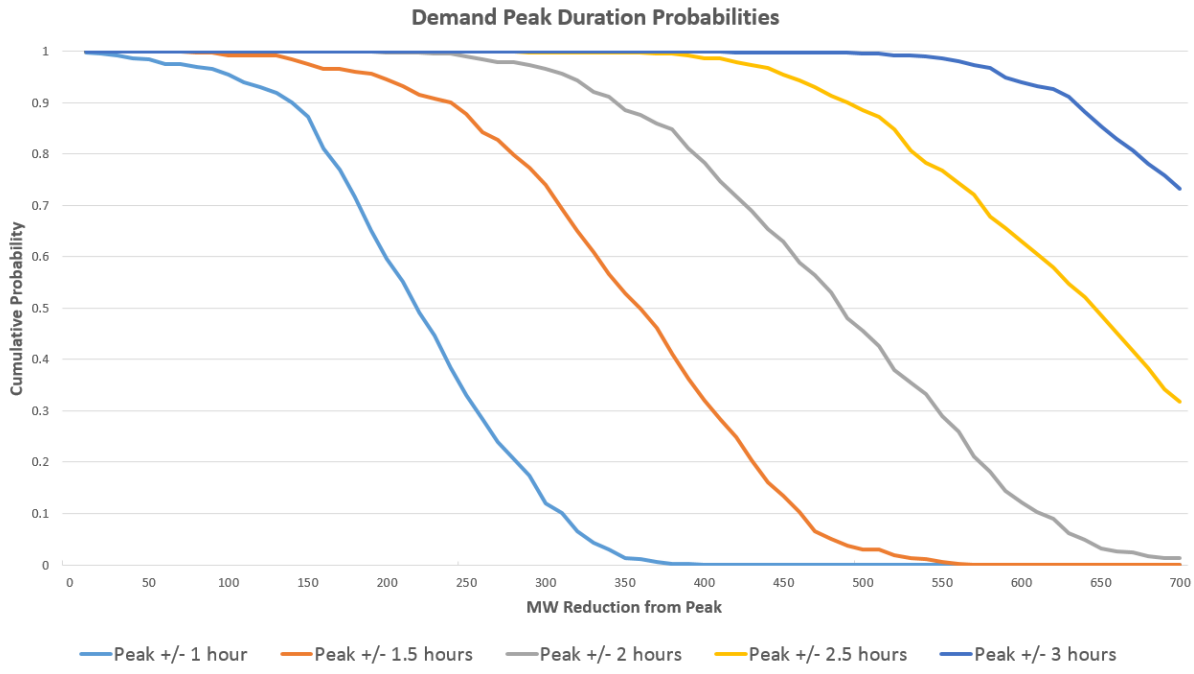
SIGA-Hydro suggests therefore, that the capacity auction and the DS3 auction are coordinated in such a way that new build plant can formulate cost reflective bids into both auctions. SIGA-Hydro understands that the detailed auction design will be the subject of future consultations.

B) The options for eligibility of demand side and storage providers

SIGA-Hydro supports the eligibility of demand side participation and favour Option 2 where DSUs receive a new energy payment for foregone consumption, but are subject to the same RO difference payments and any other incentives for physical performance as generators. The value of demand side response to the successful operation of electricity markets is undisputed and the necessary incentives must be put in place to ensure that sufficient demand response enters the

market to ensure efficient market operation. SIGA-Hydro also suggests that storage units are classified as DSUs when in demand mode where they can demonstrate fast acting and flexible demand reduction in response to under frequency events or other signals from the TSO as appropriate.

SIGA-Hydro strongly urges the RAs to ensure that storage is eligible. To demonstrate the value of storage to the system SIGA-Hydro have analysed the all island demand data for the years 2010 to 2014 inclusive. This analysis was carried out for all demand peaks greater than 5,500MW and shows that demand peaks reduce by over 400MW within 2.5 hours with a probability of 1 (within the data set studied)



This clearly demonstrates that storage with the capability to deliver energy over 2 to 5 hour timeframes makes a real and full contribution to generation adequacy.

C) Do you have a view on the technology vs plant specific approaches to de-rating?

The capacity requirement calculation will utilise an analytic method to estimate the volume of capacity to be procured to meet a defined security standard. This analytic method must including plant de-rating factors that ensure that the security standard is met and that ongoing system monitoring can demonstrate this. SIGA-Hydro suggests that a plant specific approach is required to achieve this. Plant de-rating for existing units should be based on historic performance. This should be reviewed for each auction to incentivise plant reliability. New plant should be de-rated based on international performance data for the same or similar plant. In particular, new plant de-rating factors should not be based on older existing plant as reliability data may not be representative of newer plant

D) Do you have a view on the historic, projection or hybrid approaches to de-rating?

See point C above

E) Do you have a view on grandfathering of de-rating factors?

SIGA-Hydro do not agree with grandfathering de-rating factors as it distorts the true contribution of the unit to generation adequacy. However for new plant we highlight the need for stable and predictable RO income so that project funding costs and consequently consumer costs can be minimised.

F) Do you have a view on options presented with respect to the non-firm generation?

Dispatchable capacity should be free to bid for Reliability Options up to its de-rated output capability. Existing non-firm generators, if eligible, should be free to bid for Reliability Options up to its average 'capacity credit' at the implementation date of I-SEM with new plant that enters service after this date being free to bid up to its marginal capacity credit.

G) What evidence should an aggregator be required to show physical backing?

Aggregators should be required to demonstrate physical backing by test at some time prior to the start of its contract

H) Should there be a maximum size of unit that can bid into the RO auction via an aggregator, and if so what is that threshold?

The 10MW maximum capacity for bidding through an aggregator seems reasonable and is compatible with the current SEM.

I) Should there be a minimum size below which a capacity provider may not bid directly into the RO auction, and must bid via an aggregator? If so what is that threshold?

A minimum capacity for direct bidding of 1MW would give a reasonable balance between maximising market participation and controlling market administration costs.

J) What pre-qualification criteria should be applied?

For new build, prequalification criteria are essential to ensure that speculative projects are removed early and only those projects that are likely to succeed are eligible to participate in the auction. Notwithstanding this, SIGA-Hydro urge the RAs to accommodate special cases and projects, such as Grid-Scale Pumped Storage where the characteristics of those projects differ significantly from conventional generation. Such an approach by the RAs is consistent with previous decisions (e.g; DS3 for specific contract durations[4]).

The Grid-Scale Pumped Storage Plant currently in development by SIGA-Hydro is a major infrastructure investment. The Project represents a strategic investment of national importance with proven and definitive public interest benefits. Modelled on the ESB owned Pumped Storage Plant (Turlough Hill, Wicklow), the SIGA-Hydro Project is capable of making a significant

[4] See page 5 of SEM-14-108 available at http://www.allislandproject.org/en/transmission_current_consultations.aspx?article=11d55fa2-e9cd-454c-aaa5-d689d434db20

contribution to improving Ireland's security of supply, to facilitating the development of the renewable energy sector and to reducing the costs of electricity production in Ireland.

Projects of this nature are generally 'once in a lifetime' and necessitate substantial upfront investment in the early feasibility and planning stages. They have long pre-construction lead-in times and are costly. At this point in the time, SIGA-Hydro is well advanced and intend to participate in both the CRM and DS3 Auctions (Qtr. 1, 2017) and also ISEM (Qtr. 4, 2017). Therefore, it is critical that no entry barriers are (unintentionally) created which would exclude SIGA-Hydro (given the unique nature and characteristics of the project investment) from competing and participating in the Auction and Prequalification processes commencing in 2016/2017.

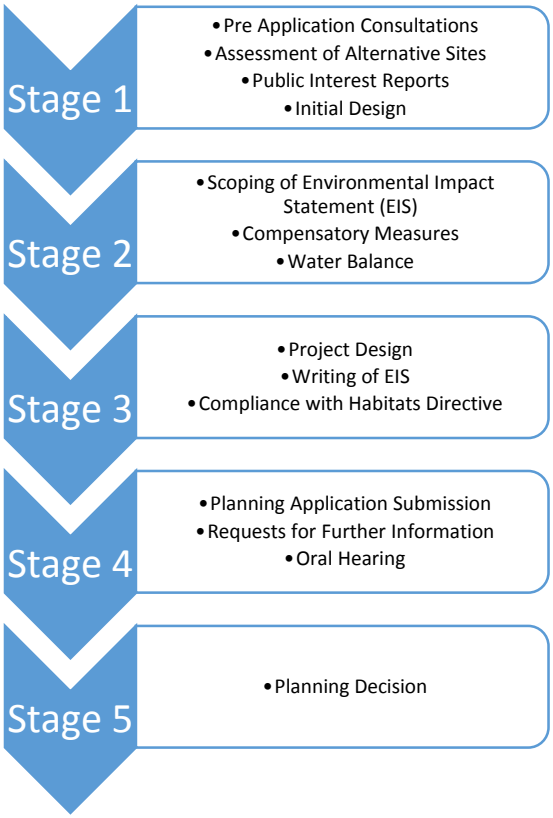
SIGA-Hydro fully support the implementation of a prequalification process to eliminate risks of potential market manipulation (such as bed-blockers, speculative and unviable projects). We refer to the comments below in line with the suggested criteria on page 79 of the consultation document;

Planning consent

The planning process in Ireland allows for two possible routes to achieving planning consent; the local authority route and the Strategic Infrastructure Development (SID) route. The latter provides for applications for permission for specified private and public strategic infrastructure developments to be made directly to an Bord Pleanála[5]. Strategic infrastructure developments generally relate to major energy, transport and environmental infrastructure projects and to health infrastructure.

The SIGA-Hydro Project is classified as major energy infrastructure with planning consent being issued in accordance SID. SID offers a pre-defined process with the aim to fast-track and streamline the planning consent process for Projects demonstrating strategic national importance. Planning consent preparation for the SIGA-Hydro Project has already commenced and a planning application will be made directly An Bord Pleanala as an SID Project. The SID process has a number of pre-determined stages as outlined below;

[5] See http://www.pleanala.ie/sid/sidapp.htm



Grid-Scale Pumped Storage Projects require unique site characteristics due to the requirement for a substantial elevation difference between the upper and lower reservoirs. This limits the number of potential sites, places onerous requirements on the planning applicant and also extends the length of planning consent process compared conventional energy projects and smaller projects.

The SID planning process for the SIGA-Hydro Project is expected to take 18-24 months with significant upfront capital investment. SIGA-Hydro urges the RAs to consider different stages within the planning process in the prequalification criteria (more specifically, in special cases for Projects such as Grid-Scale Pumped Storage applying under the SID route). In the event, planning consent has not yet issued, but substantial progress can be demonstrated and a decision for planning consent is expected in the short term, then it would be reasonable for such Projects to meet the prequalification criteria.

In addition, given the long construction programme for pumped storage (min. 4 years) any failure to deliver the contracted capacity on time will be known years in advance of the contracted delivery year, which will allow the RAs to re-tender the capacity.

A prequalification requirement for full planning consent for new Grid-Scale Pumped Storage in Ireland is unreasonable. However, SIGA-Hydro recognise the need to reduce the risk of a new plant that is awarded a contract not showing up. SIGA-Hydro suggest the following prequalification criteria are applied (to SID Projects) to mitigate this risk from a planning perspective;

- Planning Stages 1 and 2 of the SID Process as outlined above has been completed and a spend has been incurred that demonstrates the intention to complete the planning process on award of contract

- A Statement of Assessment from an independent, recognised and experienced energy infrastructure planning consultant is commissioned and submitted as part of the prequalification criteria
- A project plan with planning application milestones is submitted against which progress after award of contract can be monitored. As Stages 1 and 2 must be complete by the auction, this phase of the planning process is expected to take 9 to 15 months. The above relates to SID Projects only.

SIGA-Hydro also wish to point out the construction programme for the SIGA-Hydro Project is 4 years from Financial Close, with Financial Close only occurring after the contract offers for CRM and DS3. This means the 4 year Implementation Agreement will need to be extended to accommodate the SIGA-Hydro Project. This contrasts with the UK auction where delivery was required 4 years after the auction. As previously mentioned, we view this extended lead time as an additional risk mitigation advantage since any risk of non-delivery due to a failure to achieve planning consent will be evident more than 4 years before expected delivery thereby allowing sufficient time to re-auction the ROs without any risk to generation adequacy.

Connection Agreement

A signed connection agreement requires an MEC bond of €10,000/MW to be put in place by the generator[6]. For a 360MW pumped storage plant this would amount to €3.6m. Investing this amount in the absence of a firm contract for both DS3 and ROs is not prudent or even feasible. We suggest the following prequalification criteria are applied from a connection perspective;

- A completed connection application has been submitted to the TSO
- The project is eligible to be processed outside of the gate process by direction of the CER as detailed in CER/09/099[7]
- A requirement that a direction will be issued by the CER within 6 months of both DS3 and RO contracts being awarded

Property Rights

Any property rights requirements must be designed to minimise the risk of a new build being delayed or hampered due to property issues. We suggest the following prequalification criteria are applied from a property perspective;

- Signed landowner consent confirmation for the land on which the plant is to be constructed
- Signed landowner consent confirmation for any pylons that are required for the connection
- Confirmation from local authority or other relevant party that licenses can be provided for road opening or similar where underground cables are proposed

[6] See http://www.eirgrid.com/media/GeneralConditionsofConnectionandUseofSystem(July%202013).pdf
[7] See http://www.cer.ie/docs/000767/cer09099.pdf

Financial Commitment

We agree that a financial commitment is required and suggest that applicant credit cover of €5,000/MW be provided. This is similar to the credit cover required for the UK capacity auction[8]. This amount is also in line with the substantial financial commitment discussed in paragraph 6.7.4 of the consultation document

Business Plan

The purpose of the business plan requirement is to demonstrate the credibility and economic viability of the project. We suggest that a detailed business plan would not be appropriate as it would require us to provide economic data in advance of the auction that could potentially influence other bidders should it become publically available. In any case our DS3 and RO auction bids will represent the income required to ensure the economic viability of the project.

For new build it may be reasonable to require a construction plan to be submitted so that progress can be monitored and any risk of non-delivery will become evident early.

Status under Subsidy Schemes

Ref Section 4 point A above

Credit Worthiness

A credit worthiness requirement that can ensure the economic viability of the developer is reasonable but should not impose financial requirements that are in addition to the financial commitment requirement above.

K) *Detail of any other considerations respondents feel that we should take account of when determining policy in relation to eligibility.*

Care should be taken in selecting eligibility criteria so that there are no inappropriate barriers for difficult-to-develop but worthwhile potential market entrants, such as pumped storage capacity.

Section 5

A) *Whether the recovery of CRM option fees from Suppliers should be on a flat, profiled, or focused basis*

We have no preference as long as payment due to capacity providers is fully secure.

B) *Whether the Supplier credit cover arrangements for the I-SEM CRM should be broadly similar to those under the SEM, and whether / what credit cover arrangement should be introduced for capacity providers.*

We have not preference as long as payment due to capacity providers is fully secure.

C) *Whether the costs of exchange rate variations (arising from differences in the €/£ exchange rate at the time capacity is procured and its subsequent delivery) should be borne by capacity providers or mutualised across the market.*

We favour mutualised exchange rate risk in order to provide income certainty for capacity providers.

[8] See Paragraph 59 of the UK capacity regulations available at http://www.legislation.gov.uk/ukdsi/2014/9780111116852/pdfs/ukdsi_9780111116852_en.pdf

Section 6

A) Are the outlined governance arrangements suitable for implementation of the I-SEM capacity mechanism?

The proposed governance arrangements seem suitable.

B) Which options for contractual arrangements are the most appropriate, as assessed against the listed criteria?

As new entrants with a requirement for a long-term capacity contract with certainty of payment, we favour the separate counterparty model with a counterparty having high credit-worthiness. This option is also compatible with the listed criteria as well as being similar to arrangements in other electricity markets.

C) Are implementation agreements required for new entrants participating in the capacity auctions?

Onerous performance bonds would be a barrier to new entry of capacity. If such a bond were required, an implementation agreement would be appropriate to govern its administration, reduction and cancelation. The milestones suggested (substantial financial commitment and substantial completion) are reasonable. We have discussed this issue further in Section 4 above in the context of prequalification. A large portion of the bond should be reduced at substantial financial completion and the bond should be reduced pro rata with capacity delivery (in cases where capacity may enter service in stages).