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Response to Integrated Single Electricity Market (I-SEM) Capacity Remuneration Mechanism Parameters Consultation Paper

SEM-16-073

On behalf of
AES Kilroot Power Ltd and AES Ballylumford Ltd

21st December 2016

Capacity Remuneration Mechanism Parameters Consultation Paper

Introduction

AES welcomes the publication of the consultation document on I-SEM Capacity Remuneration Mechanism (CRM) Parameters Consultation Paper (SEM-16-073) and the opportunity to provide comments on the issues raised. AES would like to submit the following consultation response to the Regulatory Authorities.

AES is a global energy company with assets in the all island market consisting of CCGT plant, coal and gas fired conventional units, additional distillate fired peaking gas turbine plant and new technology Battery Energy Storage Array (BESA). AES is a non-vertically integrated independent generator which owns and operates Kilroot and Ballylumford power stations in Northern Ireland with a combination of merchant and contracted base load, mid merit and peaking plant. The responses to this consultation are therefore conditioned by the nature of our current position and portfolio of assets operating in the SEM.

CRM PARAMETERS – HIGH LEVEL MESSAGES

This response is submitted with reference to the specific questions raised in the consultation paper and based on our current knowledge of the detail that is available on the design of the I-SEM. The answers requested to the questions set out in the relevant sections in the consultation paper are set out below and AES would also like to submit the following high level messages.

AES believes that there are significant issue identified in the CRM Parameters consultation paper which have substantial consequences on the effective functioning of the Capacity Market and Secondary Market and also on the ability of Market Participants to effectively recover sufficient costs to enable ongoing operation in the I-SEM.

Administrative scarcity pricing presents issue of transparency and the visibility of scarcity signals in near and real time to enable a generator to effectively fulfil any obligation under its Reliability Option contract. Real time visibility of reserve position, proximity to load shedding in both the day ahead and balancing markets, target operating reserve and forecast target operating reserve is required in addition to visibility of any TSO actions taken in advance of and to avoid load shedding.

AES supports the position that the stop loss process should be structured to ensure that there is sufficient incentive for a generator to continue to deliver capacity relative to its Reliability Obligation following any exposure to uncovered difference payments during a loss period. The Stop Loss billing period should be set at one month where the potential for scarcity in consecutive billing periods is reduced, or, there needs to be a reduction in the billing period stop loss limit to 0.125 X Annual Option Fee if progressed on a weekly basis.

The New Capacity Investment Rate Threshold parameter is a significant entry signal for new capacity and determines the threshold for access to 10 year contracts it is important that it is set at a level that allows and encourages new investment to compete in the CRM auction. AES is of the view that the proposed threshold is too heavily weighted for new plant, rules out enhancement or refurbishment of existing plant and views that the value needs to be lower to allow for the availability of longer contracts for enhancement for existing capacity and/or new capacity as originally intended.

The I-SEM CRM bid is to be a representation of the missing money the unit is required to recover from the capacity mechanism to cover its fixed costs with the quantity determined by predicted energy and system services revenue. With energy revenue heavily dependent on commodity prices and the expected increase in system services revenue not materialising this places increased pressure of capacity revenue to cover fixed costs. For marginal plant with limited running the proposed cap will not cover the fixed costs of the units. The BNE methodology needs to be revisited in light of the I-SEM development to revise views on IMR in light of scheduling risk, increased credit and collateral requirements, and a contract period of 10 years duration.

AES also supports the approach of having the ability to recover start and operating regime related VOM through the energy market where VOM covers start and operating regime related maintenance costs, consumables and waste disposal related to running. This approach seems to be at odds with the proposals identified in the consultation on Offers in the I-SEM Balancing Market which has a different view on fixed and variable cost recovery. This paper stated that maintenance costs are not considered variable in nature and therefore not eligible cost items for inclusion in offers. AES has concerns and disagrees with the position that it specifically excludes sunk costs, depreciation and costs to capital. Investors will have a need to recover these costs.

SECTION 2 ADMINSITRATIVE SCARCITY PRICING PARAMETERS

2.3.1 The SEM Committee welcomes views on all aspects of this section, including whether you prefer Option 1 (as set out in Section 2.2 above), Option 2 or some intermediate option for the shape and slope of the ASP function, and why

- AES believes there is a transparency issue regarding the visibility of scarcity signals for market participants, such as the real time reserve position, proximity to load shedding in both the day ahead and balancing markets. This would be improved by providing visibility of target operating reserve and forecast target operating reserve which should be made available by the TSO in near and real time to enable market participants to take action if required under RO. Similarly visibility is also required for the involuntary load shedding point
- Whilst AES accepts that early controlled load shedding could prevent a system collapse the impact of this is that the ASP rises to Full ASP, thus FASP occurs not when actual load shedding would occur but when the TSO decides to take load shedding actions. Rules need to be defined as to when the TSO can take early load shedding actions thus triggering Full ASP prior top actual FASP and this should be reflected in the ASP function curve.
- With respect to the Shape and Slope of the ASP function – AES favours Option 1 a simple linear function introducing ASP at a relatively low factor given the current concerns regarding scheduling risk the lack of transparency of key scarcity factors in real time and the market participant’s ability to predict scarcity and take appropriate action.

SECTION 3 COST RECOVERY AND CHARGING

3.4.1 The SEM Committee welcomes views on all aspects of this section, including:
A. Which of Options 1 to 3, as set out in Section 3.2, do you think is most appropriate, and why? Alternatively, what other definition of the Supplier Charging Base would you chose and why?

- AES views that the recovery of Reliability Option Fee payments to capacity providers and the socialisation fund contributions to cover any short fall in difference payments to suppliers should be over a broad supplier charging base when LOLP is expected to be high.
- Of the options proposed AES favours Option 3 – a broader based supplier charge focused on a broader day time period from 7am to 11pm recognising that peak demand may not be the primary driver of scarcity and that scarcity could occur over a wider range of time periods over the year thus spreading the capacity charge across all customer segments and resulting in a more equitable approach.
- This option also reflects a position closer to the current approach but accepts that the position can be kept under review.

B. Which LIBOR (or other such reference rate) should be used as the BIR, and what the values of the SPR and DPR should be?

- No preference

SECTION 4 RELIABILITY OPTION PARAMETERS

4.6.1 The SEM Committee welcomes views on all aspects of this section, including:
A) Do you agree with the SEM Committee's proposed approach to set the DSU floor price at €500/MWh?

- DSU Floor Price – AES acknowledges the desire to incentivise DSUs to provide demand response at times of system scarcity and therefore the necessity to ensure that the strike price set affords the opportunity for DSUs to recover their costs for reducing demand.
- AES accepts the level of DSU floor price based on the SEM Committee's calculation of demand reduction costs and therefore recognising that the strike price cannot fall below €500/MWh.

B) On the assumption that the gas index will be a reference price related to gas obtained from the GB system, do you agree with the carbon intensity factor? Do you have another comments on the approach to setting the gas or oil carbon intensity factors?

- AES supports the adoption of a gas intensity factor in the formula and agrees that as it is likely that NBP Gas will provide the majority of the gas used in Ireland and Northern Ireland, that the gas carbon intensity factor should reflect this.
- The choice of index is an important factor and the RAs should consult with market participants on the indices to be used and should update the index daily rather than monthly due to the potential exposure on fuel cost for generators if required to use a monthly index.

C) Do you agree with the approach to setting transport adders set out in section 4.4?

- AES supports the inclusion of transport adders in the formula for calculation of the strike price and that these should be consistent with the delivery point for the relevant fuel index chosen.
- Where there is a difference in transport adders between Ireland and Northern Ireland, AES also supports the proposal to use the higher of the applicable values in the strike price calculation.

D) Do you that the Billing Period Stop-Loss Limit should be set to 0.5 times the Annual Stop-Loss Limit (i.e. 0.75 times the Annual Option fee)?

- AES supports the position that the stop loss process should be structured to ensure that there is sufficient incentive for a generator to continue to deliver capacity relative to its Reliability Obligation following any exposure to uncovered difference payments during a loss period.
- The Billing period for imbalance and difference payments has now been defined as one week with the capacity period for capacity charges and difference payments settlement defined as one month. The stop loss limit will apply to the weekly imbalance billing period enabling the real possibility of a scarcity event lasting for more than one billing period and rapidly reducing the option fee revenue earned and thus the incentive under the Reliability Option. This would be less significant if the billing period were set at one month where the potential for scarcity in consecutive billing periods is reduced. AES supports a billing period of 1 month or a reduction in the billing period stop loss limit to 0.125 X Annual Option Fee if progressed on a weekly basis.
- In light of the recent emerging thinking on locational issues, the 3 year closure notice period requirement cannot be relied upon given derogation applications would be looked on favourably and in any event is unlikely that insolvent generation would remain in the market regardless of a grid code notice requirement.
- The locational issues emerging thinking and decision on transitionary auctions to have a 2 stage process – unconstrained auction followed by the addition of plant required to satisfy regional security of supply concerns and the nature of the sloping demand curve will afford the option procuring sufficient capacity to reduce the likelihood of scarcity below the security standard envisaged.

SECTION 5 NEW BUILD, TERMINATION AND PERFORMANCE BONDS

5.4.1 The SEM Committee welcomes respondents' views on the issues raised in this section. In particular, the SEM Committee welcomes respondents' views on whether:
A) You agree with the approach of setting the New Capacity Investment Rate Threshold at around 50% of the gross investment cost of the BNE plant, currently estimated at €310/kW? If not, what is an appropriate maximum size of termination fee for new capacity which achieves an appropriate balance between protecting consumers by the failure of new capacity to deliver, and not providing a barrier to entry for new capacity?

- New Capacity Investment Rate Threshold – As this parameter is a significant entry signal for new capacity and determines the threshold for access to 10 year contracts it is important that it is set at a level that allows and encourages new investment to compete in the CRM auction.
- AES supports the concept of the New and Enhanced Capacity Investment Rate Threshold as was the original intention of the threshold i.e. to ensure that only plant making substantial financial commitment is eligible for a contract of 10 year duration however the proposed value to be set at €310/kW is too high and effectively rules out even significant plant upgrade.
- The threshold is too heavily weighted for new plant and rules out enhancement or refurbishment and AES views that the value needs to be lower to allow for the availability of longer contracts for plant enhancement for existing capacity or new capacity as originally intended. This was to be a combined threshold price for new and enhanced (CRM 2 decision)

but refurbishment projects will not be able to get above this threshold thus eliminating refurbishment investment from longer term contracts.

B) You think that the SEM Committee's indicative schedule of termination fees set out in paragraph 5.3 is appropriate? Please provide evidence for your answer.

- AES accepts the CRM 2 decision requiring termination fees for failure to deliver capacity awarded through the RO T-4 Auction process but did not agree that a participant should provide a performance bond in advance of the auction as a surety of cover for the termination fees. If a performance bond is required it should be required following the auction when there is clarity on the award of capacity and certainty for a project to proceed based on contract length awarded.
- Whilst AES accepts that some element of the termination fees can be offset by OEM liquidated Damages for delay which would normally be up to a maximum of 15% of the contract value and therefore it will not be possible to offset all of the delivery risk with LDs.
- The CRM 2 decision also determined that the termination fees and hence performance bond should start at a lower level rising progressively over the project lifetime providing incentive to declare failing projects early.
- AES is concerned that the bond level is set very high and will present a barrier to entry if participants are not able to pass through their potential liabilities and may cause participants to reflect any residual exposure in an explicit premium to the EPC or reflect any exposure in auction bids submitted.
- As with any project delays can be caused by external factors not in the control of the participant, for example the process of securing connections gas or electric, to the systems would be under the control of the system owners and may be constrained by 3rd party resources. AES views that the Participant should not be exposed to termination fees if delays outside of their control.

C) It is appropriate to place termination fees on capacity that does meet the definition of New Build, and if so, at what level, including:

a. Minor refurbishment or other upgrades to capacity which does not meet the financial threshold to qualify as New Build;

b. Unproven DSUs;

c. Any other capacity provider which has not already demonstrated its ability to physically deliver; or even

d. All existing capacity

- AES does not support the imposition of performance bonds and termination fees on additional capacity that does not meet the new capacity investment rate threshold for the reasons quoted i.e. confidence in existing capacity to deliver, need to provide incentives for DSUs and the short term duration of RO contracts for existing plant and new capacity below the threshold.
- AES does not believe that the grid code closure notice period of 3 years presents a feasible risk mitigation measure as has been made evident at a number of workshops plant that is unsuccessful in obtaining an RO contract will, in all eventuality, not continue to operate.

D) Performance Bonds should be required for 100% of termination fees, and should this vary by type of capacity?

- With respect to performance bonds, different organisations internally treat the requirement for a performance bond differently i.e. if treated as cash it will significantly deteriorate the returns on the project. AES treats a performance bond as a cash put aside which in a competitive bidding environment will make it difficult to increase the bid to incorporate the bond and stay competitive.

- Others may treat the performance as a financial liability and only include the annual bank fees in their projected cash flows.

SECTION 6 AUCTION PARAMETERS

Net CONE

6.6.1 Do you agree with the proposed adjustments to the BNE calculation approach set out in section 6.2.8 to 6.2.10 If not, explain why.

- AES support the methodology of setting the Auction price cap as a multiple of net cone however this will only be binding on new build capacity due to the separate existing plant price cap and also that the price cap should be set at a value high enough to incentivise new investment.
- AES supports the proposed adjustments to the IMR calculation for derating decisions however the adjustment to include a level of ASP affecting IMR will require assumptions on the number and duration of scarcity events.
- Outage rates – the proposed reduction of the forced outage rate to 5% for the BNE reference plant results in an slight increase in IMR thus reducing the net cone value and hence the auction price cap.
- The RO strike price caps the revenue and reducing the IMR that a peaking generator could earn as the CONE is based on a peaking open cycle gas turbine generator. If the current methodology sets the strike price at €500/MWh for 3 hours this would see a reduction in the IMR due to the lower price cap caused by the strike price as opposed to the market price cap currently set at €1000/MWh. This would result in a slight increase in the auction price cap and therefore AES supports the option of using the Strike price of €500/MWh as the pool cap in the revised BNE calculation and adding 4 hours of partial scarcity.

Auction Price Cap

6.6.2 Do you agree with the choice of multiple of 1.5 x Net CONE in setting the Auction Price Cap?

- Little evidence is set out for the decision of 1.5 as the multiplier for net CONE other than typical market convention. Whilst it is true that existing capacity providers have been able to endure capacity payments of less than CONE to cover their missing money, the Auction price cap is designed to limit the bid of a new entrant and the existing capacity was remunerated under the existing and more predictable capacity mechanism.
- The formula would result in an auction price cap of €116.71/de-rated kWp.a. however the BNE formula would need to be recalculated for the I-SEM circumstances due to:
    - Revised term of 10 years as opposed to 20 years
    - Revision of WACC due to higher risk to investment under I-SEM
    - Higher credit and collateral requirements
    - Different IMR assumptions under I-SEM and strike price impact
    - Different generic forced outage rate used.

Existing Capacity Price Cap

6.6.3 Do you agree with the proposed methodology of estimating a generator's Net Going Forward Costs (NGFC) at:

Max[(Fixed operating costs – gross infra-marginal rent from the energy and ancillary service markets),0] + Expected Reliability Option difference payments

- AES supports the principle of being able to submit a bid higher than the existing capacity price cap limit up to the level of the individual unit's net going forward costs if higher that the bid cap and also the concept of unit specific bid limits in the context of local security of supply resolution.

- The formula for capturing the net going forward costs seems appropriate. Although as with the BNE formula, the impact of scarcity, partial scarcity and the strike price of €500/MWh should also be taken into account in determining the envisaged IMR.

6.6.4 Do you agree with the proposed process and data inputs to calculate NGFCs as set out in 6.3

- AES accepts the definition of net going forward costs for a capacity provider as set out in the formula in section 6.3.7 and agrees that expected Reliability Option difference payments should be included in the consideration. However an important aspect is the definition of the fixed operating costs element.
- In determination of fixed operating costs component of the NGFC AES has identified an issue with respect to using non fuel operating costs as a proxy for fixed operating and maintenance costs.
- In the context of unit bidding in the CRM for a multi-unit station the fixed costs for the whole station must be allocated against the units being offered. There is a risk that not all of these units will be cleared in the auction resulting in a risk of under recovery of costs. Therefore an appropriate portion of the station fixed costs must be included in each offer to ensure adequate cost recovery.
- With respect to NFOC, AES supports a position which better defines fixed operating and maintenance costs similar to that defined in the PJM market i.e. including LTSA costs, labour, Statutory, major inspection and overhaul consumables, maintenance and minor repairs, admin and general asset management, property taxes, insurance and working capital.
- AES also supports the approach of VOM recovery through the energy market where VOM covers start and operating regime related maintenance costs, consumables and waste disposal which is related to running.
- This approach seems to be at odds with the proposals identified in the consultation on offers in the I-SEM Balancing Market which has a different view on fixed and variable cost recovery. This paper stated that maintenance costs are not considered variable in nature and therefore not eligible cost items for inclusion in offers. AES has concerns and opposes the position that it specifically excludes sunk costs, depreciation and costs to capital. Investors will have a need to recover these costs – somewhere!!!
- This combined with the investment threshold has a detrimental Impact on plant upgrade/enhancement projects which are prevented from recovering investment through longer term contracts due to investment threshold.

6.6.5 Do you agree with the proposed approach of setting the Existing Capacity Price Cap at 0.5 x Net CONE? If not explain why, your preferred alternative approach and your rationale for the alternative.

- AES understands the desire to set the existing capacity price cap at a level designed to place competitive pressure on capacity prices whilst also allowing capacity offers to bid their net going forward costs without having to apply for a unit specific limit.
- Based on the design of existing current multi-unit power stations with high fixed costs and the number of ageing units on the Northern Ireland and Ireland system the existing plant price cap of €38.90/kW represents a significant challenge.
- As is the intention of the I-SEM design the CRM bid should be a representation of the missing money the unit is required to recover from the capacity mechanism to cover its fixed costs with the quantity determined by predicted energy and system services revenue. With energy revenue heavily dependent on commodity prices and the expected increase in

system services revenue not materialising this places increased pressure of capacity revenue to cover fixed costs. For marginal plant with limited running the proposed cap will not cover the fixed costs of the units.

- At a price of €38.90/kW with an expected capacity requirement of approximately 7400MW, assuming the auction cleared at the price cap, represents a capacity revenue of €288 M. This results in a reduction of approximately 44% of the capacity revenue from the existing CPM which represents a substantial reduction and with no foreseeable increase in System Services revenue to offset this reduction as was expected and will result in a considerable number of units applying for bid specific limits.

6.6.6 Do you think that the NFOC costs reported by generators to the RAs as part of the SEM Generator Financial Reporting are a good proxy for the Fixed Operating and Maintenance costs that a capacity provider may need to recover via the I-SEM CRM, or do you think that the NFOC contain material variable cost which can be recovered via the energy / ancillary services market? If the latter, how big an adjustment should the SEM committee make to exclude any variable elements of the NFOC from NGFCs included in the Existing Capacity Price Cap?

- As stated earlier with respect to NFOC, AES supports a position which better defines fixed operating and maintenance costs similar to that defined in the PJM market i.e. including LTSA costs, labour, Statutory, major inspection and overhaul consumables, maintenance and minor repairs, admin and general asset management, property taxes, insurance and working capital.
- AES also supports the approach of VOM recovery through the energy market where VOM covers start and operating regime related maintenance costs, consumables and waste disposal which is related to running.
- As stated earlier there is an inconsistency in the approach to the recovery of NFOCs with BM offer paper.

6.6.7 Why are reported SEM generator NFOC/FOM costs substantially higher than international benchmarks? Do you think that existing SEM generators have material scope to cut fixed operating and maintenance costs, and if yes, do you think that this should be reflected in the Existing Capacity Price Cap? Explain why.

- AES does not believe there is much scope for fixed cost reduction in the I-SEM due the inherent design of older multi-unit power stations, the relative age of the existing fleet of units in operation, the considerable scheduling risk that exists in the new energy market and the lack of foreseeable increase in system services revenue as was envisaged through the DS3 system services.
- As stated earlier in the context of unit bidding in the CRM for a multi-unit station the fixed costs for the whole station must be allocated against the units being offered as there is a risk that not all of these units will be cleared in the auction. Therefore there exists a risk of under recovery of costs and an appropriate portion of the station fixed costs must be included in each offer to ensure adequate cost recovery.
- A considerable number of generating units on the system are approaching the later stages of operation and as units get older fixed and variable costs tend to increase due to life extension program costs or upgrades to comply with regulation changes etc.
- The uncertainty around scheduling in the energy markets and associated lack of predictable revenue from the DS3 system services stream will result in additional missing money risk which will be reflected in the offers to the capacity market as each unit attempts to recover sufficient revenue to enable it to continue in operation.

- For the above reasons AES does not believe that generators have material scope to reduce fixed operating and maintenance costs and a considerable number will have to apply for unit specific bid limits.

Demand curve parameters

6.6.8 Which of options A, B or C with respect to the demand curve set out in Section 6.4 do you think is appropriate for the first transitional auction, and why?

- AES supports the position that the derated capacity requirement for the first transitional auction should be set at a level that is consistent with delivering a security standard requirement of 8 hours LOLE as a minimum and is reflected in the demand curve by the horizontal demand curve at the auction price cap up to the capacity requirement and vertical at the capacity requirement down to net CONE.
- With respect to the demand curve options provided AES favours Option A as the best compromise between procuring additional capacity and ensuring sufficient capacity is successful through the transition period to be able to compete in the T-4 auction delivery time frame.

6.6.9 Do you have any other comments on the shape and/or positioning of the demand curve for the first transitional auction?

- No Comments.

Locational parameters

6.6.10 If the SEM Committee proceeds to incorporate locational requirements within the I-SEM CRM, do you agree that the costs/risk of implementing local demand curves (as opposed to a minimum requirement) outweighs the benefits?

- AES understands from the Locational Issues Emerging Thinking workshop help in November that the RAs are minded to determine the capacity requirement in the form of nested areas with capacity requirements specified in MW within an all island capacity requirement such that the All island capacity requirement (MW) must be greater than the sum of the Dublin area capacity requirement (MW) and the NI capacity requirement (MW).
- The auction process selected was an initial unconstrained auction followed by additional capacity required to ensure security of supply which appears to indicate a single all island demand curve will be used. AES agrees that a single demand curve would be appropriate.

SECTION 7 LOAD FOLLOWING FOR SECONDARY TRADING

7.2.1 Do you have any comments on the approach to setting the load following parameter set out in the section? Specifically do you agree with the granularity of the parameters, the proposed historically based methodology, and proposed governance approach? If not, why not and what other arrangements would you propose?

- AES supports the approach of allowing the trade of the capacity available between derated capacity and the load following requirement as this presents additional capability for buying or selling capacity in the secondary market to cover outages etc. AES accepts the need for prudence to ensure there is sufficient capacity to support system security objectives and supports the benefit of enhancing liquidity and competition in the secondary market.

- AES supports the view that there should be sufficient spare capacity to cover planned and a degree of forced outages and that the load following parameters could be set ex ante for the whole capacity year. Incorporation of the outage planning data gives generators the opportunity to manage their planned outage exposure in the secondary market as soon as practicable.
- AES would like to see products of the granularity of monthly, weekly, daily – weekday and weekend day and time of day (if this can be incorporated) are required to cover planned and forced outage periods as required with the FPFCQSF set as appropriate for each period and accounting for seasonal variation in demand and wind forecast. Shorter term products would allow for more accurate forecasting to be included in the setting of the FPFCQSF i.e. set at an appropriate time in advance of the relevant period.
- AES supports a governance approach which facilitates a more dynamic setting of the Load following parameters of the SEM that incorporates demand forecast and therefore the SEMCo approved methodology may be more appropriate as this could lead to additional volume being made available for secondary trade.

7.2.2 Do you think that capacity providers should be able to trade against load following margin in calendar year +2 and any subsequent years, and should the parameters for subsequent years be scaled to 75% of the calendar year Y+1 values or some other percentage?

- No Preference