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Dear Kevin and Priti,

FIXED COST OF A BEST NEW ENTRANT PEAKING PLANT & CAPACITY REQUIREMENT FOR THE CALENDAR YEAR 2010

Thank you for this opportunity to contribute to the above consultation.

The capacity payment mechanism (CPM) plays a vital role in the single electricity market (SEM) as the primary source of revenue for generators. The reduction in commodity prices has significantly limited the infra-marginal rent for generators from SMP, and thus highlighted the importance of capacity payments to recover fixed generator costs. The proposed reduction in capacity payments will eliminate signals for new entry and place existing generators under significantly increased financial stress.

The current consultation indicates an overall reduction of 15.1% in capacity payments from last year. This however understates the true reduction in capacity payments because of the dilution effect of new generators entering the SEM in 2010 (eg. Aghada, Whitegate, increased wind) and the artificially improved availability of existing plant which run less often because of reduced demand (reliability and maintenance issues become more apparent when running). Taking dilution effects into account Viridian Power & Energy (VP&E) has calculated the true reduction in capacity payments to an individual generator to be in excess of 25%.

In review of the consultation methodology VP&E has noted a number of fundamental inconsistencies that we suggest need to be addressed to ensure that the integrity of the CPM, as a stable security of supply mechanism, is maintained. These issues are:

1. The change from 15 to 20 years is a fundamental departure from the methodology adopted in all previous BNE OCGT calculations to date and in our view should be addressed in the CPM medium term review.

2. The 2010 BNE OCGT calculation has erroneously omitted provisions for forced and scheduled outages. VP&E suggests that the values for these parameters used in previous years are reasonable, albeit optimistic, assumptions.

3. The WACC assumed in the calculation does not reflect the current or projected future conditions in the financial markets. This is particularly true for the equity assumptions where the suggested equity risk premium is lower than the value proposed by OFWAT for stable regulated returns of water companies[1].

4. The output of an Alstom 13E2 was decided by the regulatory authorities (RAs) to be 180.2 MW in 2007 and 2008 yet somehow the output has increased to 190.1 MW in 2010. We understand that the underlying technology and emission limits have not changed in the interim. This increase needs to be clearly explained both in technical and regulatory stability terms.

One can understand the political pressure both the regulatory authorities are currently under to put downward pressure on prices. Given the separate nature of the capacity payment and the constant attacks it receives from customer groups one can also understand why the regulatory authorities would seek to put particular pressure on this payment. Despite this we would have hoped that the regulatory authorities would have strived to find the correct price rather than what we believe is an artificially low price and one we cannot reconcile with the actual costs of building a BNE plant in this market.

Let us use a concrete example. As the regulatory authorities are aware VP&E holds a number of consented sites on which we had planned to build peaking plants. Based upon the proposed BNE price we could not justify a peaking investment. More worryingly the move from a 15 year to 20 year basis could have a significant long term impact upon peaking investment. We, like others, are having great difficulty in getting banks to believe in the capacity payment mechanism. The main concern they have is that it is open to abuse by the regulatory authorities and therefore not a practicable vehicle for investment. The movement from a 15 year to 20 year term is just the sort of abuse they would have highlighted. It has in it the potential to end VP&E's interest in peaking development.

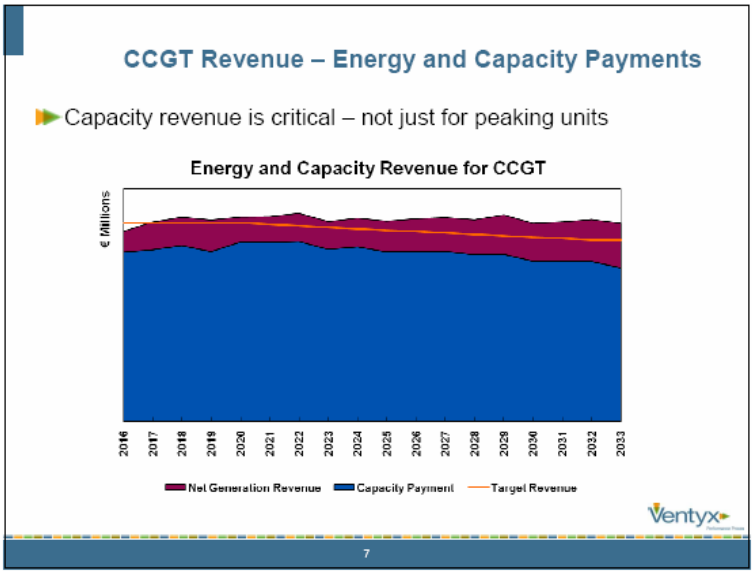
[1] http://www.ofwat.gov.uk/pricereview/pr09phase3/det_pr09_draftchap5.pdf

The document creates a sense that the rules about how prices are established are flexible and that values could be "cherry-picked" to deliver a lower capacity pot. This perception is damaging to confidence in the capacity mechanism. We suggest that all key variables such as currency, demand, etc are set at a fixed date in the future and that these values are adhered to whether or they are higher or lower than current rates.

In the sections below VP&E debate in more detail the points above and other relevant issues:

<u>The Importance of CPM for All Generators to Recover Fixed Costs</u>

Note a webcast from Ventyx, 23 July 2009[2] indicates that capacity payments are the primary revenue for CCGT as well as OCGT, see their recent slide below:



<u>Life Time Extension</u>

Ad hoc alterations to the CPM in the short term would seriously undermine the credibility of the mechanism and its ability to ensure efficient investment in flexible generating capacity and the orderly exit of existing plant from the market. On this note VP&E has serious concerns about the proposal to extend the plant life of the Best New Entrant (BNE) peaker from fifteen to twenty years. This is a fundamental change to the BNE methodology which according to our estimations (on a like-for-like basis) is solely responsible for an 11%+ reduction in the BNE price from last year. Such a fundamental change is a medium term CPM review issue requiring careful analysis, debate and industry feedback and is not something to be introduced on an ad hoc basis. In our view a clear distinction should be made between economic life and technical life. Technically it might be feasible to extend the plant life by five years but this would undoubtedly increase the average output degradation of

[2] http://now.ventyx.com/content/adv-072309

the plant, would alter the maintenance cycle at extra cost, and may trigger some lifetime extension modifications. It would also likely require retrofit of new technology to remain competitive in the market and remain compliant with evolving environmental regulations. Plant life should also coincide with financing tenure which is fifteen years at best and typically shorter. Full consideration of these and related issues should feature in the medium term CPM review. In the meantime it would be appropriate for the BNE peaking plant for 2010 to revert to a fifteen year life assumed since the beginning of the SEM.

It is surprising, especially given the extended plant life, that overall output degradation of the BNE plant for 2010 is only 2.5% on distillate and 2% on gas. This compares with 3% assumed last year. A life time extension would certainly increase the degradation experienced by the machine.

Outages

The BNE OCGT calculation is designed to recover costs for a new entrant peaker. As with all generators the BNE OCGT will be subject to planned and unplanned outages, during which the peaker will receive no capacity payments, because it is unavailable. These outages need to be allowed for in calculating income per kW available. We note that in previous years it was assumed that planned outages of 13 days are typical and a forced outage rate of 2% was applied[3]. These are somewhat optimistic assumptions but not completely unrealistic.

Cost of Capital

It is unquestionable that the credit crunch has had a significant adverse impact on the financing landscape for companies both from a debt and equity perspective. It therefore seems illogical that considering the economic changes that have taken place over the last twelve months that the WACC proposed provides a reduction of 0.9% and 0.3% for Northern Ireland (NI) and the Republic of Ireland (ROI) respectively.

Whilst we would largely concur with the basis of the calculation of the cost of debt and specifically the debt premium which in the main reflects the deterioration that has been seen in recent financings, we would not concur with the basis of the calculation of the **cost of equity** which principally results in the reduced WACC proposed.

The main areas of concern in the calculation of the cost of equity are in the determination of the equity risk premium and the equity beta.

Equity risk premium – the proposal outlines a reduction of 0.75% in both jurisdictions to 4.75% from 5.5%. The basis of the proposal is from decisions which relate to regulated

[3] These outage assumptions were incorporated into the BNE price by reducing the effective plant output.

assets and which pre-date the credit crunch. It is unrealistic to assume that there has not been a step change in investors' assessment of risk in light of recent economic events. Therefore we believe the equity risk premium will have increased from recent historic levels[4]. Ofwat have recently determined in their draft determinations for the UK water companies an equity risk premium of 5.4% "given the economic conditions within which the cost of capital is set". It should be equally noted that this is the equity premium that has been determined for regulated water assets which are relatively low risk assets as opposed to a BNE investor of an integrated utility which may not have regulated assets within its base and will have a higher level of risk. We therefore believe as a minimum that the equity risk premium should be 6%.

Equity beta - the proposal outlines a reduction in the asset beta from 0.6 last year to 0.5 in both jurisdictions. Last year the SEM Committee acknowledged that "0.6 is toward the low end of the range quoted for generation assets" of 0.5 to 0.8. Therefore it seems illogical that when combined with the current economic climate that there has not been an increase in the asset beta. The asset beta of 0.5 equates to an equity beta of 1.25. It should be noted that a comparable equity beta for a company such as AES is 1.5. We believe as a minimum that the asset beta should be 0.6.

Other considerations:-

Gearing levels have remained unchanged at 60%. Again in light of recent changes to the financing landscape, it is highly likely the level of gearing will reduce in future financings and historic levels are no longer a reliable guide. Ofwat have proposed a gearing level of 57.5% for the fully regulated water asset companies. A BNE investor without the asset backing of regulated assets is likely to see gearing levels of 50% in future financings. This has been confirmed by discussions with our financial advisers.

Risk free premium has been proposed at 1.87% in the ROI and 1.75% in the UK. It is difficult to clearly penetrate the basis of the figures from the information provided however it should be noted that Ofwat have at the same time determined a risk free rate of 2.0% for the UK also based on ten year maturities.

<u>Output Anomalies</u>

It is unclear how the output of the Alstom GT13E2 increases from 180.2 MW as stated on page 39 of the consultants' report to 190.1 in table 3.3 on page 14, and why this differs from the output values decided by the RAs in 2007 and 2008 using the same technology. VP&E note that the same fuel type applies in all cases and that environmental standards have not changed in the interim.

[4] Note that the long-run historical risk premiums are significantly higher, as identified by Ibbotson and others. Arguably the current economic malaise proves that equity risk premiums of the recent past were incorrect.

Regulatory Risk Associated with Varying Jurisdictions

VP&E question the approach of choosing the cheapest jurisdiction in an all island market. It seems inherently unfair to potential investors based in the ROI or NI for the BNE price to be based on an uncertain jurisdiction from one year to the next. A better approach would be to choose a mid point between the BNE price in ROI and NI.

Choosing a BNE based in Northern Ireland this year with the BNE price denominated in euros brings into sharp focus the currency risk created by alternating jurisdictions. We note that exchange rate assumptions were not specified in last year's BNE consultation process (or in previous years) and were not entirely relevant. However it is hugely relevant this year and the assumed rate of 1.12 euros to the pound (which dates back to at least 15 June 2009) cannot be replicated or hedged by a potential BNE investor[5]. The consultants' report (accompanying the consultation paper) notes that the exchange rate of 1.12 euros to the pound was the spot rate at the time of developing the document and is viewed as the best indicator of future rates. Based on past experience, especially over the last twelve months, this assumption is unrealistic and cannot be justified.

Although investors should generally face exchange rate risk where applicable, it is unrealistic for them to absorb an exposure they cannot hedge against. This will only discourage investment and make financing even more difficult. VP&E would favour an alternative methodology that would fix the exchange rate at prevailing rates at an openly stated future point in time. Potential investors would then have the option of locking in at that rate, taking a forward position or even an open exposure at their discretion.

The consultation paper states on page 34 that "considering the unprecedented times, the RAs are minded to revisit the forecasts above with the TSOs to ensure that they still reflect the actual demand trend. This activity may take place during July 2009 ahead of any decision of the capacity requirement for 2010". For regulatory stability of the CPM it is important that this approach does not constitute "cherry picking". If the RAs are minded to update key parameters such as demand then we suggest that currency and other key factors should be updated as well.

Capacity Requirement

We note the significant reduction in the capacity requirement based on the demand reduction needs further clarification. While the basic methodology is described we cannot find any of the input data used in the CREEP (Adcal) model used to create the 7.1% reduction in capacity requirement.

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[5] VP&E have spoken to the currency dealers of a major financial institution and confirmed at the time of writing that achievable rates for selling euros is 1.152 and buying euros is 1.1650.

Fuel working capital

We note that distillate storage costs for both distillate and dual fuel options assume a strategic stock of 3 days at maximum plant load. This is consistent with the RAs decision to require generators to hold a strategic fuel stock for a peaker plant (3 days continuous stock of fuel). However, it does not account for commercial stocks of at least another ½ day supply which any peaker would hold to maintain availability above the strategic stock level. Hence fuel stocks should rationally include an uplift of at least 16.7% and the tank size and associated cost should be upscaled accordingly. We also note that potential degradation of fuel stocks may warrant further investigation.

Water injection costs

We note that water injection costs assume three days water storage and treatment capability for 3 days of water injection at 1:1 water to fuel (mass basis) ratio at maximum plant load. This is consistent with strategically required fuel stocks for a peaker plant (3 days continuous stock of fuel). However, it does not account for commercial stocks of at least another ½ day supply which any peaker would rationally hold. Hence water injection costs should include an uplift of at least 16.7% to account for a larger tank and 3.5 versus 3 days of continuous water supply.

Water injection costs should also be included in working capital because it is materially expensive to fill the tanks with demineralised water. Based on VP&E's experience the cost of filling a 3.5 day supply of demineralised water is approximately €50,000. This does not account for the inevitable degradation of the demineralised water and the need to replace this periodically, which would warrant further scrutiny.

We also question the cost of water connection being zero for the Belfast West site because this does not take into account the increased capacity in the water system that would be required for the power plant.

Infra marginal rent

We note that infra marginal rent is assumed to be zero on the basis of Plexos modelling. VP&E have always argued consistently against deduction of infra marginal rent from the BNE price because this substantially increases the forecasting error and is perverse in nature because it reduces capacity payments when needed most. To continue including infra marginal rent, albeit zero for 2010, is counterintuitive and adds no value. Instead it creates a perception of risk that this could be significant in the future and hence discourages efficient investment.

Ancillary services revenue

VP&E note that ancillary service contracts are entered into on a voluntary basis and new rates have yet to be finalised by Eirgrid and SONI, but look to be significantly reduced soon. VP&E would welcome further information on the assumptions used in calculating ancillary services revenue for the BNE OCGT. It appears that the revenue in the consultation paper is based on an unrealistic assumption that the plant incurs no penal performance incentives, trip charges, or short notice declaration charges. VP&E note that all plants are subject to forced outages and that a realistic allowance for this must be included in the calculation.

We also observe that ancillary services revenue is based on plant output of 190.1MW. We have questioned this output assumption elsewhere in this response and we would accordingly expect that any changes to output would feed into the assumed ancillary services revenue.

<u>Site procurement cost</u>

Site procurement costs have fallen 63%. This reduction seems excessive, even in current market conditions. We note that the Belfast West site chosen is part of the land-bank area reserved by NIAUR for generation construction in the future. Would this site be made available to merchant investors through an auction process to establish a commercial rate? A site with planning for power generation would be worth considerably more than normal. Has this been accounted for and how?

Included for information below is VP&E's response to the CPM medium term review.

Yours sincerely

K Hannafin

Kevin Hannafin
Senior Regulation Analyst

VP&E response to Medium Term CPM Review Scoping Paper

As currently designed the Capacity Payment Mechanism (CPM) is integral to the Single Electricity Market (SEM) and is a necessary corollary to energy payments in a market constrained by short run marginal cost (SRMC) bidding principles[6].

According to the proposed high level SEM design published 31 March 2005 (AIP/SEM/06/05) the Regulatory Authorities (RAs) have noted that the CPM should provide the following advantages over an energy only market[7]:

(1) More stable market prices with less price spikes required each year to ensure revenue adequacy
(2) Added revenue certainty and predictability for generators and hence greater security of supply for consumers
(3) Reduced risk of regulatory or political intervention and hence reduced risk premiums for investors and consumers
(4) Greater transparency of energy pool prices, which by corollary is conditional upon transparency of CPM calculations and payments themselves
(5) More helpful in dealing with market power and promoting competition

The Global credit crunch has placed an unprecedented premium on any potential risk or revenue uncertainty. In this environment extra emphasis may be warranted on reducing the cost of capital for the long run benefit of consumers – principles 2, 3, and 4 are especially important in this context.

System marginal prices (SMP) in the SEM have fallen dramatically since the beginning of 2009 in line with significantly reduced commodity prices and demand. At the same time credit conditions have tightened beyond all expectations. The CPM in this context should serve to stabilise generator revenues and provide certainty and predictability for future investment and security of supply. Any change to the CPM must be tempered with the need to maintain consistent, stable and predictable investment signals and revenue streams. The credibility of the CPM would be seriously undermined at this stage by radical change or by political intervention to reduce capacity payments. Instead the focus should be on improving the CPM in line with the principles set out above. This means that reform should stabilise prices for generators and consumers, improve revenue certainty and predictability for generators, minimise political and regulatory intervention (and the potential thereof), improve

[6] We have consistently raised a concern through the SEM design process that a CPM + SRMC regulated market may not be sufficient to remunerate generation capacity in the market. The failure to include real costs, such as gas transportation capacity, in SRMC increases this concern.

[7] See page 24 of above referenced paper available online @ http://www.allislandproject.org/en/high-level-design-consultation.aspx?article=f87b8dba-3fd8-48cb-9562-6a9e278a1830

transparency, and be competitively neutral, treating all generators and technology types equally.

In the interests of fairness, as per CPM objectives, Viridian Power and Energy (VP&E) suggest that CPM reform should not consider discrimination being built into the CPM. Among other things this means that all generators get paid on availability and rightly wind generators are not available when there is no wind resource.

Adding greater complexity to the current design would be unhelpful and inconsistent with CMP objectives. On this note Viridian Power and Energy (VP&E) do not consider the CPM an appropriate mechanism to incentivise generator flexibility. We do however recognise this is an important issue to address with increasing penetrations of wind going forward and suggest that it can be more easily achieved with greater transparency and focus through the ancillary services mechanism[8].

Improving transparency should be made a key priority of CPM reform. Calculation of the capacity requirement would particularly benefit from this as the process is opaque at the moment. Recently the RAs held a workshop to review the best new entrant (BNE) input parameters. This level of enhanced transparency and interaction with market participants is a welcome development and it would be worthwhile extending this exercise to calculating the capacity requirement. The system operators should be required to calculate an all-island capacity requirement using a standard methodology in a transparent manner, with full consultation on the inputs to this calculation. There should not be scope for interpretation in the figures used, by either the system operator or regulatory authorities. Any opportunity for interpretation will reduce the confidence investors place on the capacity value when making new generation investments.

Certain additions to the CPM are necessary and should be welcomed, particularly the introduction of demand side participation. According to the SEM design paper published 31 March 2005 "[t]he Regulatory Authorities view demand side participation as an important contribution to both competition in the all island energy market and as a potential contributor to security of supply". The CPM could be designed to promote demand side participation but this is surprisingly not included within the scope of the review. We note that Eirgrid continues to use legacy mechanisms for demand side participation, in particular, for example, powersave and winter peak demand reduction scheme (WPDRS). These mechanisms were expected to fall away with the introduction of the SEM, but they are still being used extensively. We suggest that the review considers replacing these mechanisms with market led arrangements based on the SEM design.

[8] We have previously written to the regulatory authorities separately on this and would be happy to discuss our proposals further if that would be useful.

Given that CPM volatility is a well understood impediment to financing peaking plant it is also surprising that this has not been automatically included within the scope of the medium term review. This should be included within the scope and addressed appropriately otherwise new flexible generation capacity may not be delivered to provide adequate security of supply for the electricity customers on the island of Ireland. We are aware of a separate consultation about volatility of the BNE calculation methodology however that paper only considers one of many aspects of volatility in the current CPM. Consideration of CPM volatility should include the BNE calculation methodology, variation in the capacity requirement used to calculate the size of the capacity pot, and volatility and complexity in the distribution of the capacity pot.

In appendix I to this letter we address the specific questions raised in the consultation document.

Please do not hesitate to contact us if you would like to discuss further or to arrange a meeting if that would be helpful.

Yours sincerely

K Hannafin

Kevin Hannafin
Senior Regulation Analyst

Appendix I

Consultation Point 1: The RAs welcome comments and backup material from participants in relation to any historical analysis they have carried out in relation to the CPM.

VP&E Response

We have no analysis to provide at this stage but we can suggest the following areas that would benefit from analysis:

(1) Identifying the statistical relationship between availability and generation margins would be useful in understanding why availability might have improved. This is based on the premise that generators with low utilisation tend to have high availability.
(2) Quantifying the contribution demand side response has made to security of supply to date
(3) Identifying the evolution of capacity payments as a proportion of total SEM payments to generators since the market began
(4) Calculating capacity payments made when availability was absent for system constraint reasons

Consultation Point 2: The RAs welcome comments from participants in relation to the impact of the CPM on consumers and the methodology for payments by suppliers

VP&E Response

We are aware that some consumers have raised concern about the volatility of capacity charges. Given this it would be useful to explore whether capacity charges can be set out for consumers in advance, as applies to imperfections charges. This would provide greater certainty to consumers and facilitate more accurate charging by suppliers.

We would also welcome a review of how demand side response initiatives might help consumers meet environmental targets as well as provide capacity and increased flexibility to the system.

Consultation Point 3: The RAs welcome comments from participants in relation to incentives that could be introduced within the Capacity Payment Mechanism or covered under the Ancillary Services mechanism.

VP&E Response

As noted in our cover letter VPE are not in favour of discrimination being built into the CPM. This is in keeping with the CPM objectives of fairness and simplicity. Incorporating flexibility criteria into the CPM would be discriminatory, introduce significant complexities to what is already a complex mechanism and would inevitably reduce transparency. We agree however that generation should be rewarded for providing flexibility to the system and believe that the ancillary services mechanism is the best way of achieving this.

Consultation Point 4: The RAs welcome comments from participants in relation to the timing and distribution of Capacity Payments as described in Sections 7.4 and 7.5.

VP&E Response

We remain unconvinced that ex post capacity payments based on relative LOLP increases availability and suggest that CPM objectives might be better facilitated with the fixed capacity payments stream parameters increased. This would provide greater certainty to investors and capital providers hence reducing the cost of capital to the long run benefit of consumers, without wholly removing short-term signals in the CPM. Such an approach would also align the half hourly capacity signal to generators with the capacity payments by suppliers.

Consultation Point 5: The RAs welcome comments from participants in relation to the Capacity Requirement Calculation and what parameters should be considered in the review.

VP&E Response

As noted in our cover letter, VP&E's key concern in relation to the capacity requirement calculation is the current absence of transparency. We can comment further once we have a better understanding of the model and assumptions used in calculating the capacity requirement but for now we note the following:

1) The system operators should be required to calculate an all-island capacity requirement using a standard methodology in a transparent manner. There should not be scope for interpretation in the figures used, by either the system operator or regulatory authorities. Any opportunity for interpretation will reduce the confidence investors place on the capacity value when making new generation investments

2) All plant availability should be based on historical data and not projected from expected improvements. If improvements in performance do materialise then they will automatically be factored in future historical data.

Consultation Point 6: The RAs welcome comments from participants in relation to the calculation of WACC and the approaches that could be used in calculating the various WACC parameters.

VP&E Response

We have no particular issue with the Capital Asset Pricing (CAPM) methodology per se and consider it a reasonable approach. However it is essential that the assumptions and parameters that feed into the model are realistic and achievable. They should be based on actual real financing arrangements and not derived from a theoretical basis that cannot be replicated in the all-island market.

Consultation Point 7: The RAs welcome comments from participants in relation to impact of Infra Marginal Rent on the BNE Peaker.

VP&E Response

VP&E are strongly against the deduction of Infra Marginal Rent from the BNE price because this substantially increases the forecasting error and is perverse in nature because it reduces capacity payments when needed most.

Consultation Point 8: The RAs welcome comments from participants in relation to impact of exchange rate fluctuations may have on the CPM

VP&E Response

Exchange rate risk has to be managed by market participants. We cannot suggest any improvements at this point in time.

Consultation Point 9: The RAs welcome comments from participants in relation to the Treatment of Wind within the CPM.

VP&E Response

We note that the RAs have a separate workstream on wind and we look forward to contributing to that.

At this point we note the government (and EU) targets for energy from renewable sources and that any reduction in capacity payments to wind will only increase payments through support mechanisms, and thus gives no clear benefit for consumers. We have not seen any conclusive analysis to date to show that the capacity payment to windfarms is unduly generous when all aspects of the effect of wind on the market are considered.

Consultation Point 10: The RAs welcome comments from participants in relation to the Interconnector treatment within the CPM.

VP&E Response

We struggle to see justification for changing the treatment of the Interconnector (IC) within the CPM. For example giving the IC a capacity value when it is not flowing would be difficult to justify. However we would look forward to further analysis from the RAs if they think a change can be justified.

Consultation Point 11: The RAs welcome comments from participants in relation to the relationship between the Ancillary Services and the CPM.

VP&E Response

We are not convinced that ancillary services revenue should be deducted from the BNE price given the volatility this can add to the CPM and we would therefore welcome justification for this approach.

Consultation Point 12: The RAs welcome comments from participants in relation to any other aspects of the CPM that should be included in the scope of the Medium Term Review

- As noted in our cover letter demand side participation should be added to the scope of the medium term review because of the security of supply, financial and environmental benefits it could bring.
- From a security of supply perspective the BNE OCGT should be a dual fuel unit. Measures to incorporate this into the CPM should be included within the scope of the medium term review.
- The treatment of non-firm generators within the CPM is worthy of analysis. Such analysis might consider whether payment for capacity is equitable in all cases, particularly if network constraints were such that the generator cannot contribute to security of supply.