Endesa Ireland response to SEM/10/046
CPM Medium Term Review

Endesa Ireland welcomes the opportunity to respond to the consultation on “CPM Medium Term Review” following three years since the implementation of the current mechanism for capacity payments.

Our main concerns relating to the capacity payment are its volatility, unpredictability and lack of transparency. We are supportive of measures taken by the RAs to improve the transparency of the capacity requirement calculation through the holding of a public forum in November 2009 in which the inputs and methodology used for this calculation were outlined as well as a demonstration of the Adcal model. However, we consider that further measures are necessary in order to ensure an adequate level of predictability and stability for market participants.

Historic volatility of the capacity payments has been due in part to the fact that the RAs have not cited a fixed source for the inputs to the calculation of the Annual Capacity Payment Sum (ACPS). This was particularly evident in the 2010 decision, when the RA’s changed the plant life from 15 to 20 years and in the 2011 decision where the WACC utilised was below expected values. Both changes resulted in significant reductions to the ACPS. For calculation inputs like WACC and plant life, Endesa Ireland considers that the RAs should consult with market participants to select a single source for this data that could be used consistently in the calculations.

We are very concerned by the RA’s proposals to reduce volatility through including Infra Marginal Rent (IMR) that would be earned by the BNE plant at equilibrium (when the 8 hours loss of load comes into effect) in the calculation of the ACPS. In this event, a PCAP of €1,000/MWh or Value of Lost Load (VOLL) of €10,390/MWh would come into effect for the two new options proposed. Option 1 uses the VOLL for estimation of IMR while option 2 uses PCAP. We see no merit in using VOLL for determining IMR and consider that its use can be discounted as the SMP cannot rise to VOLL as long as PCAP continues to be less than VOLL. If this were to be used PCAP should be set equal to VOLL. In reality, the SMP has only hit PCAP once, this happened in January 2010 and that event was re-priced, thereby removing the PCAP event. Therefore, in practice, no generator has ever earned IMR from the PCAP event, leading us to conclude that both of these options are unreflective of reality and should not be explored further.

We would be more supportive of maintaining the Status Quo option, which involves using Plexos runs to evaluate IMR. We consider it significant that only once was IMR greater than zero in the BNE Fixed Cost calculation. We consider it noteworthy that this was in the 2007 calculation, when margins were relatively tighter, and Huntstown II was only operating for a portion of the year; once Huntstown II was fully commissioned the IMR remained at zero. Given that we are entering an extended period of surplus capacity, we consider that IMR will continue to remain at zero in the coming years if distillate technology continues to be used for the BNE peaking unit.

If the plant technology were to be set as a gas-fired OCGT, the RAs have indicated this would reduce the ACPS due to a significant increase in IMR and SMP. We would agree that the ACPS would decease but disagree that IMR would increase to a level of almost €8.8 million as presented in table 5.2 of the consultation paper.

On a related point, recovery of gas capacity costs continues to be a serious gap in market design which has yet to be addressed despite the RA's insistence that prices should reflect costs. We would not object to this being treated as a fixed cost or a Short Run Marginal Cost (SRMC). We would consider it legitimate for gas capacity costs to be treated as SRMCs especially given that it is required under EU law for short-term capacity products to be available. It is also noteworthy that in a study published by the RAs into the impact of wind on the SEM in 2020[1], they included short term gas capacity costs in the bids of the OCGT. The lack of implementation of this requirement in NI is no reason to disallow this cost in the SEM.

For ancillary service payments, there is no guarantee that these services would be required, therefore we consider that a rational investor would not anticipate revenue from ancillary services. It has also been noted by CEPA[2] that it is unlikely that the BNE plant would be required for operating reserve and that provision of leading/lagging power factors would most likely not be required from a marginal plant. If ancillary services are to be included, we would suggest the RAs base their estimations on average AS income of peaking units on the island. In addition, we consider that the penalties incurred by the peaking units on the island should be included in the costs of the BNE.

The RAs have stated that the Forced Outage Probability (FOP) used is the historic FOP in NI for the 5 years prior to SEM implementation. Endesa Ireland agrees that the FOP should reflect best performance, but we consider that the FOP being utilised is unrealistic (and also not currently achieved in NI). As this is an all-island market, we consider it inappropriate to utilize the FOP for a single jurisdiction and would suggest using a rolling average FOP based on actual FOPs.

To further reduce volatility and improve predictability, we propose fixing the BNE plant technology and the associated costs and for a period of three to five years. The only change during this period should be in the determination of the annual capacity requirement. This would provide significant improvements in predictability and stability in the determination of the ACPS.

[1] http://www.allislandproject.org/en/market_decision_documents.aspx?article=f8de4cfd-9a6b-4c04-8018-b89e74d0f6ba

[2] "Cost of a Best New Entrant Peaking Plant for the Calendar Year 2011", Initial Report, May 2010