Response to SEM-15-044, I-SEM Capacity Remuneration Mechanism Detailed Design

For the attention of:

Brian Mulhern, Utility Regulator, Northern Ireland and Thomas Quinn, Commission for Energy Regulation

Prepared by:

Ger Fullam,

Managing Director,

Energy Information Centre Ireland Limited, Trading as Kore Energy

Tel: **+353 (0)1 808 5555**
Fax: **+353 (0)1 808 5554**
Mobile: **+353 (0) 87 2020 011**
Website: **www.kore.ie**

Date issued: **17 August 2015**

Registered Number 403186 (Ireland)

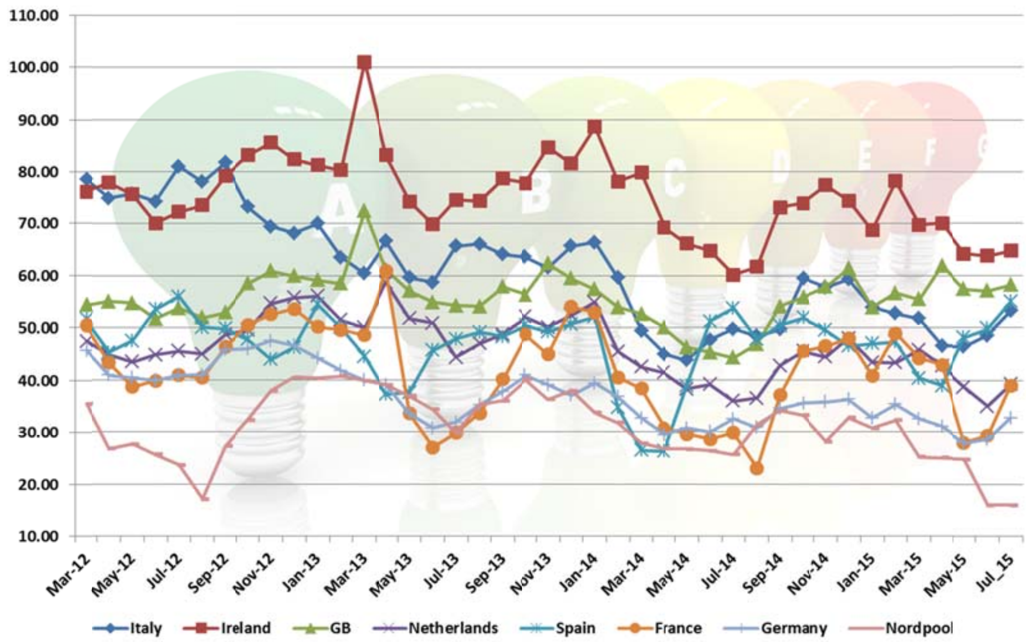
Registered for VAT: IE6423186E

Introduction

Kore Energy provides energy procurement and energy price risk management services to a significant number of large energy users in Ireland and currently manages circa 2,700 GWh of electricity on behalf of large electricity users. Our clients include 5 of the country's top ten energy users and global leaders in the pharmaceutical, IT and Food sectors.

We welcome the opportunity to respond to the Detailed Design Proposal for the Capacity remuneration Mechanism to be included in the integrated Single Electricity Market (I-SEM) to be launched in October 2017. The current Capacity Payment Mechanism (CPM) operating in the Irish Single Electricity Market has been a key supportuing factor in Irish electicity prices since the inception of the SEM in November 2007. By the end of 2015, Irish Energy Users will have paid over €4.5 billion in the form of capacity payments to power generators in Ireland. The benefit delivered to end users as a result of these payments is far from clear. Indeed, a comparison of Irish wholesale electricity prices against key European electricity markets over the past two years, as presented in Figure 1, below, illustrates the high premium in Irish prices relative to the rest of Europe.

Figure 1: Irish wholesale electricity prices versus key European wholesale markets: €/MWh



Basis: SEM and GB Betta prices = monthly average day ahead baseload power prices, €/MWh. Remainder of market prices = prices on final working day of month prior to supply

1 Concern at lack of evaluation of price impact and impact on customers from I-SEM CRM proposal

Given the significant adverse impact that the current CPM has had on Irish electricity prices since 2007, we are concerned at the lack of information included in the I-SEM detailed design in relation to the cost impact of the proposed CRM on electricity prices, on end users and on the competitiveness of electricity supplies in Ireland. We also note that there is very little reference in the Consultation Paper to the operation of the existing CRM in terms of its high cost impact on end users. If the Regulatory Authorities have not carried out a comprehensive cost/benefit review of the current CPM in place, we are concerned that the proposed design of the I-SEM may not address that issue.

We urge the Regulatory Authorities (RA) to address this issue and to provide some meaningful information to electricity users, particularly large energy users, with regard to the likely cost impact on them arising from the implementation of the proposed decisions in relation to the I-SEM CRM. In the meantime, we are pleased to provide our responses to the various issues raised in the Consultation, as detailed below.

2 Kore Energy response to selected SEM Committee questions in relation to Capacity Requirements

2A) All-Island security standard of 8 hours LoLE

Kore Energy agrees that the security standard of 8 hours LoLE should be retained. The Eirgrid review of moving to alternative, higher, security standards has not provided any reasonable case in favour of this. We note, in particular, the Eirgrid costing of €14.4 to €19.2 million arising from the provision of the extra 220 MW of capacity required to fulfil the higher security standard of 3 hours LoLE and we note that the resultant benefit as measured by the Value Of Lost Load parameter (VOLL) may be a similar amount or less. In reality, end users would absolutely incur the cost of the increased security standard while they may or may not realise any equivalent benefit.

2B) Accounting for unreliability of capacity in determining the capacity requirement

Kore Energy agrees that capacity providers should only be eligible for capacity contracts based on the de-rated requirement of their generators. This more accurately reflects how capacity will actually be provided and it limits the potential for generators being paid for capacity that they will, in practice, be unable to provide.

2C) Options presented in relation to accounting for demand forecast uncertainty

We believe that the "optimal scenario" approach, as outlined, should be adopted, primarily as it is the most flexible approach and will ensure that demand forecasts are more likely to reflect the dynamic nature of an all-Island market impacted by an increasing level of intermittent generation and an increased impact, over time, from inter-connectors.

2D) Proposal to base the capacity requirement for the CRM on a single capacity zone

Kore Energy agrees that the capacity requirement and CRM auction should be treated as a single zone. In the first instance, this makes sense given the expected 2019 completion date for the new North – South interconnector. In addition, as the use of imperfections charges will allow for the recovery of any "zone related" constraint costs, prior to the completion of the interconnector, we believe that the avoidance of the complexity of multiple zone capacity auctions is preferable.

3 Kore Energy response to questions arising in relation to product design

3A) Strike Price

Kore Energy supports the use of a floating strike price but preferably one that is indexed to the spot (within day) gas price rather than the spot oil price. We favour the use of a within day gas price for a number of reasons:

The All-Island fuel mix for 2014, as published by the CER, confirms that natural gas accounted for 41.66% of the mix, versus oil at just 1.06%.

A gas fired generator responding to a capacity scarcity event will absolutely be exposed to the opportunity or the cost of the within day gas price while an oil fired peaking plant, due to its fuel reserve capacity and the nature of physical oil delivery, may or may not be exposed to the spot oil price on the day of physical electricity supply.

Where large energy users engage in indexed or flexible electricity supply contracts, these contracts are generally indexed to natural gas prices. In fact, we are not aware of any instance where an end user supply contract is linked to oil price movements. The use of the within day gas price as a reference in the strike price will facilitate Energy Suppliers in continuing with their approach to gas indexed electricity pricing, a facility that is very beneficial to end users.

In relation to choosing the reference unit for the calculation of the strike price, we favour using the hypothetical costing of a best new entrant (BNE) plant. This will ensure that the strike price reflects current technology and generating costs available to the market while also incentivising efficient investment. We do not support "grandfathering" reference units when offering long term agreements for new build capacity as this has the potential to distort (typically to a higher level) strike prices over time, impact adversely on wholesale and retail electricity prices.

3C) Market Reference Price (MRP).

We favour the use of Day Ahead prices as the MRP, primarily as we view the objective of facilitating inter-connector trading and day ahead market liquidity as being key success factors for the I-SEM. Nonetheless, we recognise that the Day Ahead market will not reflect the impact of forced outages on within day market prices and we therefore see the Spilt Market Price (Option 4b) as a reasonable compromise.

3D) RO volume should be load following.

We agree that the RO volume should be load following for the reasons outlined in the consultation document.

3E) Additional performance incentives.

We favour the introduction of performance based incentives on generators providing capacity. However, we note that some of the incentives outlined may result in a "free bet" being available to generators as the penalties to be applied will never exceed 100% of the capacity revenue received in any given year. We do not believe that this is an efficient way in which to incentivise the provision of capacity. In particular, in the event that a generator has bid for ROs for a unit that could not have been available to generate, then the penalty should exceed the value of the capacity revenue.

4 Eligibility

4A) Options relating to eligibility of plant supported through other mechanisms

We hold the view that supported plant (REFIT or other supports) should not be permitted to avail of capacity payments. We note that any capacity payments made to supported generators should lead to a reduction in the amount payable under the PSO levy (via the REFIT element paid to wind generators and supports paid to peat fired and other generators). If this is the case, then the "make-whole" payment should be made via the PSO levy, thus ensuring transparency in the cost of REFIT contracts while also ensuring that the value of the capacity market is not distorted.

4B) Demand Side Units

We believe that the SEM Committee should make all reasonable efforts to facilitate demand side units continued participation in reducing demand at times of supply scarcity. In that regard, option 1, where the DSU does not receive an energy payment but is exposed to RO difference payments is clearly not aligned to a position where DSUs will continue to provide a meaningful reduction to managing supply and demand in the I-SEM. In the worked examples of money flows for options 2 and 3, the calculations do not properly take account of the cost impact on the DSU in providing the 1 MW load reduction. It is assumed that there is an avoided cost value in this whereas, in practice, the majority of load reductions will be provided at a cost of running back-up generators or a decrease in production efficiency. We favour the use of Option 3, where DSUs do not receive a new energy payment for foregone consumption but are also exempt from RO difference payments. We agree that they should be subject to other incentives for physical performance.

4F) Non-firm generation

In relation to non-firm capacity, we do not believe that the argument in favour of it being eligible is strong. By virtue of its non-firm nature, its reliability in providing capacity at times of system stress will be significantly diminished. However, in the event that non-firm capacity can actually provide capacity at times of system stress, we would assume that the market price at that time will provide an appropriate incentive for it to run.

5 Supplier Charging Issues and Options

5A Recovery of CRM option fees from Suppliers

We strongly favour the recovery of CRM costs from Suppliers on a profiled basis with a proper weighting towards times that there is a high probability of supply scarcity. This will ensure that the cost impact of that higher demand will be borne by the segments of the market driving that demand while it will also ensure that there are efficient market signals for the reduction of load during those times. We also support the position that the allocation of the charges should be flexible over time, as the balance of conventional and renewable or intermittent generation may drive a change in the periods experiencing supply scarcity. For the benefit of planning by end users, we would urge that any change of this nature would be signalled well in advance and at least 12 months ahead of implementation.

Summary

Again, we thank the Regulatory Authorities for the opportunity to respond to this consultation. We also re-iterate our concerns about the lack of information about the potential cost impact on end users arising from the implementation of the I-SEM CRM and we would like to receive detail on this form the RAs at the earliest opportunity.

END.