VIRIDIAN

Power & Energy

Fixed Cost of a Best New Entrant Peaking Plant & Capacity Requirement for the Calendar Year 2012

Consultation Paper

SEM-11-025

Viridian Power & Energy Response

10 June 2011

Executive Summary

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

The capacity payments mechanism (CPM) plays a vital role in the context of SEM design as the primary source of revenue for generators to recover their fixed costs. Any proposal to significantly change the CPM or dilute capacity payments will have detrimental consequences for future investment, will increase the perception of regulatory risk (increasing the cost of capital), and will place existing generators under significantly increased financial stress. As the overall capacity pot continues to be diminished on an annual basis it becomes increasingly difficult to support an investment (past, present or future) in this market.

This is the context in which Viridian Power and Energy (VPE) has consistently stressed the need to make realistic, evidence-based assumptions that reflect prevailing market conditions and that are founded in real world experience in the calculation of the BNE price and capacity requirement. The mechanism will only work as intended if payments reflect reality and prevailing market conditions to the fullest extent possible.

Based upon existing capacity payments in the SEM we could not justify a peaking investment. We, like others, are having great difficulty in getting banks to believe in the capacity payments mechanism. A key concern they have is that it is open to subjective annual change by the regulatory authorities (RAs) and is not therefore a practicable vehicle for investment[1]. A related and equally important concern they have is that the capacity pot is calculated based upon some clearly unrealistic assumptions that do not reflect prevailing market conditions.

The assumed WACC in this year's consultation is a very good example of the latter. The determination of an appropriate and credible WACC is a key factor in the calculation of the annual BNE Peaker. It is inappropriate to treat WACC in RoI different to NI (based on GB assumptions). The fact of the matter is that an investor choosing to invest in SEM, a single market with single revenue flows, will price the relevant risk into the investment decision, the relevant risk is SEM not GB assets.

[1] The movement from a 15 year to 20 year term in the BNE calculation a couple of years ago is one example of the substantial unpredictable change they have highlighted.

We highlight below the expert and independent views of RBS Global Banking and Markets which are relevant in the context of existing traded NI assets and the risk that needs to be associated with an NI BNE project:

> ***"UK regulated distribution networks, widely recognised as the most stable across the energy value chain, are currently trading in the region of 140bps - 160bps over the UK Gilt yield.***
>
> ***NIE's unrated 2018 bond is currently bid at Gilts plus 275 bps points, and its recently issued bond (rated BBB+) priced at Gilts plus 250bps.***
> ***ESB's BBB+ rated sterling bonds are quoted at Gilts plus 420 bps points and it is apparent that bond investors require a substantial premium for regulated distribution credits with an Irish connection.***
>
> ***Given that regulated distribution is viewed as the least risky end of the spectrum, it would be expected that financing of a generation facility would attract a debt premium, potentially significantly, greater than that attracted by regulated utilities."***
>
> **Peter Dooley, Managing Director Debt Capital Markets (RBS)**

In this response we strongly suggest the need for more realistic, up-to-date, evidence-based assumptions (that any rational investor would make) to safeguard the effectiveness and credibility of the mechanism, particularly in relation to:

1. Weighted average cost of capital (WACC)
2. Annual capacity requirement
3. Generator transmission use-of-system (TUoS) charges
4. Plant life assumption
5. Continued deduction of IMR and AS
6. Annualised fixed foreign exchange rate

Detailed comments

1. Weighted average cost of capital (WACC):

The WACC assumption this year, especially for Northern Ireland, is wholly inconsistent with reality and we therefore contest this strongly as follows:

a. **Debt premium** - the sector risk associated with Northern Ireland, as distinct from the rest of the UK, has not been appropriately accounted for in the debt premium;

b. **Risk free rate** - it is completely untenable to have such a divergent risk free rate assumed in the WACC for an equivalent electricity generation investment in Northern Ireland and in the Republic of Ireland when both jurisdictions operate in the same mandatory gross pool electricity market; and

c. **Equity risk premium** - the methodology applied in the estimation of the equity risk premium (ERP) is normalized to estimate a mid – long term view. This does not reflect current prices or give a reasonable estimate of the mid – long term view on ERP.

The WACC, as constructed, gives an unrealistically low outcome and does not reflect an appropriate cost of debt (risk free rate and debt premium) or equity risk premium relevant for the SEM or Northern Ireland.

There is robust economic and financial evidence to support these contentions, as detailed below, and on this basis we would urge the RAs to revise the assumed WACC applicable to the BNE investment in Northern Ireland.

We suggest a reasonable and prudent NI WACC assumption of **9.45%** (proposed 6.26%) reflecting an appropriate cost of debt of 8.15% and cost of equity 11.40%.

The key areas of variance are the application of an appropriate **debt premium** of **3.25%** (proposed 1.75%), **risk free rate 4.90%** (proposed 1.75%) and **equity risk premium 5.20%** (proposed 4.75%).

Debt Premium

The regulators have proposed a debt premium of 175bp for NI that does not appropriately account for existing traded premiums on NI regulated assets. Such as the NIE Bond that was recently issued and that trades at a premium of 250bp *(see analysis below)*.

Case study NIE (supporting information)

Recently a bond was issued for the electricity grid in Northern Ireland (NIE). The bond was priced at a coupon of 6.375%, equaling to a debt premium of +250 bps, significantly above the 175bps debt premium suggested by the RAs.
NIE is a very stable, fully regulated business with predictable cash flows from suppliers / customers solely in Northern Ireland.

The relatively high debt premium above UK Government bond yield indicates that debt investors assume a higher cost of debt for Northern Irish utilities due to their exposure to RoI.

NIE yield vs. other GBP utilities bonds

ISSUER	CPN	MAT	RATING	BGG ALLQ SPREAD (Debt Premium)
NIE	6.375%	Jun-26	Baa1/BBB+	G+250
CE ELECTRIC	7.250%	Dec-22	Baa1/BBB+	G+165
EPNPLC	5.750%	Mar-24	Baa1/BBB+	G+142
EPNPLC	8.500%	Mar-25	Baa1/BBB+	G+140
EPNPLC	6.250%	Nov-36	Baa1/BBB+	G+141
LONPOW	5.375%	Nov-16	Baa1/BBB+	G+144
LONPOW	6.125%	Jun-27	Baa1/BBB+	G+137
ENW	8.875%	Mar-26	Baa1/BBB+	G+150
WPD	5.875%	Mar-27	Baa1/BBB	G+152
WPD	5.750%	Mar-40	Baa1/BBB	G+148

In addition to reflecting the appropriate cost of NI assets, one needs to consider an appropriate debt premium for the BNE unregulated peaking asset, this will naturally be at a premium to the NIE asset as outlined above reflecting revenue risk. An additional premium of at least 75bp would need to be added to the trading regulated instrument premium to reflect appropriately the nature of the asset *(see RBS MD expert opinion)*. It is considered that an appropriate rate for the debt premium should be 325bp. A further consideration which has not been included that would also effect the cost of debt would be the premium during the construction phase. Financing during construction activity commands higher debt margins due to the higher risk involved until project delivery. This has not been included in the debt calculation.

Risk free rate (RFR)

For Northern Ireland the proposed RFR does not reflect appropriately the risk of the all Island market and transference of risk from the ROI to the extent that revenues are generated from a single market.

An appropriate RFR may be calculated by adjusting the existing ROI country risk premium applied to the quantum of revenues expected to be received by NI generators from the ROI (estimated at 70%). This would result in a country risk adjustment for Northern Ireland of 3.15%[2] resulting in an overall **risk free rate of 4.9%** (1.75% + 3.15%).

This overall adjusted cost of debt would be 8.15% (3.25% + 4.90%) for Northern Ireland.

Equity Risk Premium (ERP)

The proposed 4.75% ERP is designed to be reflective of a normalized view. It is contested that a more appropriate basis for this valuation would be the application of the current value of the ERP.

Investors have access to investment opportunities globally; therefore, it is generally argued that a global Equity Risk Premium is applicable rather than a local or European ERP.

A methodology often used is the one by Damodaran, this would result in an **equity risk premium of 5.20%**. This would increase the overall cost of equity by 1.0% to 11.4% for Northern Ireland.

[2] (4.5% (being the mid-point between 3% - 6% CER Assumption for ROI) * 70%)

2. Annual capacity requirement

It is our considered view that the calculated capacity requirement for 2012 is materially under-stated for a number of reasons, namely:

a. It assumes that generator forced outages are completely independent events which is inaccurate given recent cold weather experience; For example SONI and EirGrid conclude on page 60 of the latest GAR: "We presume that the forced outage probability is the same at all times and not linked to the outages of other generators. In reality this is not entirely true, as extreme weather events make the simultaneous failure of generators more probable. This may lead to us overestimating system adequacy somewhat, especially since these failures are likely to coincide with periods of high demand". Given recent documented experience over the last two winters we struggle to understand why the RAs still continue to use this assumption as a basis for their calculations.

b. Extreme cold weather events are assumed to be discountable outliers in peak demand projections even though Ireland suffered two such events over the last two winters – a more prudent approach is required. We strongly suggest it would be prudent and responsible to calculate peak demand recognising that economic conditions are not necessarily the main driver and would note that all peak demand records (with the exception of the Summer night valley) have been set over the last two winters despite the economic downturn.

c. Assumed plant availability is inappropriately projected from expected improvements – this should be based on historical data on an-island basis.

3. Generator transmission use-of-system (TUoS) charges

In relation to generator TUoS charges the current published tariffs were used in the consultation paper in deriving the recurring costs estimate in the BNE calculation. We note significant changes to the indicative TUoS rates for 2012 as published in SEM-11-036 and would consider this a more appropriate predictor of future rates (that any rational investor would assume) than those currently used in the BNE calculation. It is therefore appropriate to use the indicative tariffs published in SEM-11-036 in calculating the cost of the BNE Peaker for 2012.

4. Plant life assumption

We have noted in previous years that 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. In this context we raised serious concerns about extending the plant life of the BNE from 15 to 20 years. We maintain that this is a fundamental change to the BNE methodology and one that should have featured in the medium term CPM review. Because it has not we again raise strong objections to the extended plant life assumption. In our view this is not justified based on real world financing practice and would at least need to be coupled with a review of consequential effects on WACC.

5. Continued deduction of IMR and AS

It is inappropriate to deduct infra-marginal rents from the calculation of the capacity pot and doing so in our view is contrary to the objectives of the CPM. Specifically, subtracting IMR introduces volatility into the pot size and into subsequent payments, and perversely reduces the pot at times when incentives to invest should be made stronger.

We also challenge the way in which ancillary services (AS) revenues are assumed and deducted from the BNE price. A rational and prudent investor would not assume the AS revenues deducted from the BNE price because there is no guarantee of being able to contract for all eligible services and no guarantee of AS revenues that rely on being synchronized to the grid because these are exposed to the risk of transmission constraints and outages.

6. Annualised fixed foreign exchange rate risk

The continued application of an annually fixed exchange rate by the RAs at a point in time is relevant for investment decisions in NI and contributes to regulatory risk by removing the flexibility for investors to hedge foreign exchange (FX) risk at their own volition as they would choose to do commercially.

This risk feeds into the project appraisal as there is risk over the application of year on year FX on capacity revenue streams. FX is a very fluid element of the revenue stream for a peaker and fixing the FX results in opportunity gains and losses by the NI investor. This further adds to the level of risk an investor will attribute to an NI investment decision which has not been valued or included within the cost analysis.

Annex 1 covers in more detail the points raised under 2 above.

Annex 1- Annual capacity requirement

As discussed above it is our considered view that the calculated capacity requirement for 2012 is materially under-stated for a number of reasons, explained in further detail below.

a. it assumes that generator forced outages are completely independent events which is factually inaccurate and imprudent in the context of ensuring security of supply, as evidenced below;

To substantiate the above we refer to All-island Generation Capacity Statement for 2011 – 2020 (published in December 2010) which provides a detailed account of the extremely cold weather conditions of January 2010 and the impact this had on the power system. This highlights in chapter 5 (page 59) that “Ireland experienced extremely cold weather between the 7^{th} and 9^{th} January 2010. Over this period, 23 generator trips and several transmission faults occurred. This resulted in, at one stage on January 9^{th}, over 1,700 MW of conventional generation forced out. This, combined with the unusually high demand, forced EirGrid to issue an alert at its National Control Centre, indicating a high risk of load-shedding”. Load shedding was only narrowly avoided in this instance by support from SONI, a new generator testing at the time being able to export its maximum generation onto the system, and the timely return of one of the tripped units before the evening peak.

SONI and EirGrid conclude on page 60: “We presume that the forced outage probability is the same at all times and not linked to the outages of other generators. In reality this is not entirely true, as extreme weather events make the simultaneous failure of generators more probable. This may lead to us overestimating system adequacy somewhat, especially since these failures are likely to coincide with periods of high demand”.

As the above document was being written in late 2010 the system operators were experiencing similarly harsh conditions which again led to systemic generator trips. We therefore refute the claim that the extreme weather conditions of January 2010 are necessarily atypical going forward and can be effectively written off as a very rare event.

We also refer to a regulatory authority letter dated 24th November 2010 issued to Huntstown Power Company Limited stating that the RAs were "…concerned by the potential for a 'common mode' failure where multiple plants are incapacitated by the same fault. A real example of this (although not IT related) happened in January 2010 where extreme weather conditions caused a number of plants to be unavailable when needed".

It goes on to say that "[f]rom an IT perspective the risk of common mode failure is higher than it has been in the past. For example there is a growing reliance on microprocessors in systems control and also an increased standardisation of software platforms for control systems".

In light of the above identified weather and potential IT-related common mode failures it is clearly inappropriate and imprudent to assume that generator forced outages are independent events. This will unambiguously overestimate system adequacy and will understate the capacity requirement which is highly inadvisable if security of supply is to be maintained. We therefore urge the RAs to revise the assumption that generator forced outages are independent events.

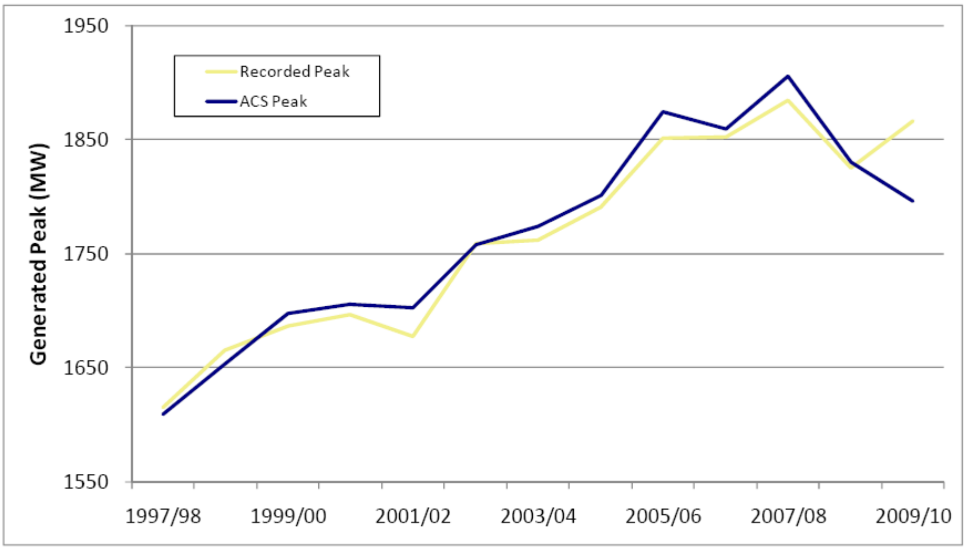
b. extreme cold weather events are assumed to be discountable outliers in peak demand projections – a more prudent approach is required;

Peak demand projections based on historic data removes the true impact of extreme weather events by applying a normalization correction. We understand that SONI has always used this approach and that Eirgrid has only recently adopted it. We seriously question the treatment of extreme cold weather events as discountable outliers in peak demand projections and would suggest a more prudent approach in this regard.

We again reference the All-island Generation Capacity Statement for 2011 – 2020 and specifically the following extract from Dermot Byrne's foreword on page 1:

"Despite an overall generation surplus, there have been times both last winter and more recently where we have seen periods with very tight margins. These have been due to extremely cold weather causing problems with both generation plant and transmission infrastructure. Section 6 looks at the problems that extreme weather events can cause to TSOs, and shows how SONI and EirGrid correct historical demand peaks to take temperature into account. We will look to develop this methodology further with the regulatory authorities to incorporate extreme weather events appropriately, and I look forward to sharing this with you".

This would indicate that the current methodology needs to be revised to incorporate extreme weather events appropriately. We understand that the current methodology, as recently adopted by Eirgrid, adjusts peak demand to a temperature standard using an Average Cold Spell (ACS) correction. This effectively dampens extreme temperature effects in peak demand projections and results in a systematic under-prediction of peak demand in extreme cold weather events. This under-prediction can be clearly seen in the winter of 2009/10 as illustrated in table 1 below (extracted from page 21 of the All-island Generation Capacity Statement for 2011 – 2020).



In light of recent extreme cold winters we question the prudency of assuming that such occurrences will be extremely rare events going forward that can be easily discounted from peak demand projections and would urge the RAs and system operators to revise this approach, which could easily be done in the short term by not applying the ACS adjustment.

In our response to last year's BNE and Capacity Requirement consultation we noted how demand forecasts are seemingly made with sole reference to the state of the economy. We strongly suggested it would be prudent and responsible to calculate peak demand recognising that economic conditions are not necessarily the main driver and provided examples from January 2010 when all peak demand records (with the exception of the summer night valley) were set in the midst of Ireland's deep recession. Many of those records were subsequently surpassed in December 2010, again driven by extreme cold weather and not economic prosperity. These events highlight the need for a revised methodology.

c. **assumed plant availability is inappropriately projected from expected improvements – this should be based on historical data on an all-island basis.**

The assumed FOP rate of 4.23%, based on the weighted average FOP for Northern Ireland (NI) plant for the period 2002-2006, is not reflective of FOP rates in the SEM and does not act as a behavioral incentive to improve performance as claimed by the RAs. We note the RAs claim in this year's consultation that "improved system availability suggests an improvement in FOP rates" and we would disagree with this inference. The more likely explanation is that reduced energy demand associated with the economic downturn has simply increased the perceived availability of generators that are dispatched (and hence tested) less frequently. This would be revealed by rigorous and frequent availability testing of low merit order plant which we consider necessary.

Given the above we strongly suggest that all plant availability should be based on historical data and not projected from subjective expected improvements. If improvements in performance do materialise then they will be automatically factored into future historical data. This would be consistent with the treatment of the Moyle interconnector where the assumed FOP is correctly based on historical data.