Markets

ACPS for the Trading Year 2016

If you have any questions in relation to our response, please don't hesitate to contact me at connor.powell@sserenewables.com

Summary

Thank you for the opportunity to respond to the Regulatory Authorities consultation on proposed setting for the Annual Capacity Payment Sum (ACPS) for the 2016 Trading Year. To secure energy for its customers, SSE is involved in energy portfolio management and electricity generation. Our long-term priority for the businesses in our Wholesale segment is sustainability in energy production through a diverse portfolio of assets.

Our assets help to keep the lights on by being available to produce energy when required and flexible enough to respond to changes in demand when they occur. As a major investor in and operator of electricity generation capacity in the SEM, SSE depends on good regulatory practice in order to make investment and operation decisions.

This includes a legitimate expectation that the Regulatory Authorities adhere to existing high level design principles for the Capacity Mechanism[1] which was originally intended to provide a relatively stable pattern of capacity payments to pay for the fixed costs[2] of the generation fleet. Stable and predictable earnings encourage the maintenance of a diverse fleet, avoid 'blocky' entry and exit onto the system and excessively cyclical earnings that add to risk premiums and prevent new entry.

Market redevelopment under the I-SEM project is already reducing certainty around earnings and substantive unjustified movements in the ACPS prior to I-SEM go-live do not help. Both customers and investors lose out as a result of increases in risk and price volatility. This was reflected in the high level design principles of the capacity mechanism:

"Price Stability
The CPM should reduce market uncertainty compared to an energy only market, taking some of the volatility out of the energy market."

*"**Simplicity***
The CPM should be transparent, predictable and simple to administer, in order to lower the risk premium required by investors in generation. A complex mechanism will reduce investor confidence in the market and increase implementation costs."

Investors also have a legitimate expectation that the Regulatory Authorities follow previous decisions[3] in the medium term review:

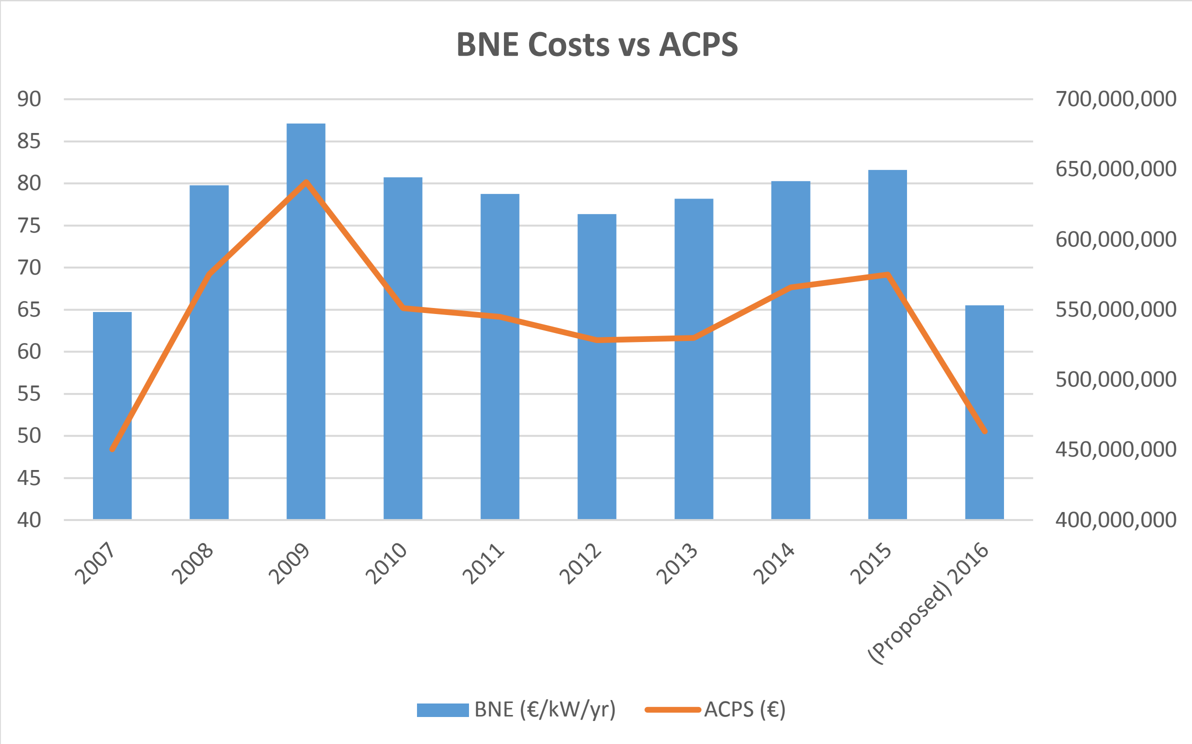
"The SEM Committee believe that the current CPM is generally working well and that there is no compelling need to make major changes to the current design and methodology but there is a requirement to make some minor changes."

"The SEM Committee also recognise the need for stability in the longer-term signals so as to provide investor confidence as one of the aims of the mechanism should be to provide

[1] SEM (2005), Capacity Payment Mechanism and Reserve Charging High Level Decision Paper
[2] This matches fixed costs, which are similarly, relatively stable for a given generation unit.
[3] SEM (2012), CPM Medium Term Review Final Decision Paper

***certainty to the investors**, if they build reliable plants and maintain them properly, so that the plants are ready to produce and provide a product to consumers when needed."*

The proposed decision paper on the 2016 ACPS, ***SEM-15-032*** appears to reweight the high level principles of the CPM and reintroduce substantial volatility into the BNE element of the ACPS calculation. Given stable demand, certain components of the BNE calculation appear to have been used as a tool to adjust the overall level of Annual Capacity Payment Sum downwards:



If the increase in volatility reflected a sharp drop in annualised fixed costs at Irish generation units the ACPS would be ***stable*** and ***predictable*** – the reduction in capacity payments would somewhat reflect real and predicted reductions in participant costs**.** However, elements of the BNE decision are outliers – they do not reflect recent regulatory determinations and economic reality. For example, the WACC chosen contrasts with the April 2015 regulatory determination by the Utility Regulator[4] which stated that:

*"The Utility Regulator has also considered SONI's specific circumstances in setting an appropriate WACC level. As SONI have higher operational gearing than traditional utilities some components within the WACC are higher than those applied in other price controls. It is proposed to set the WACC at the pre-tax level of **5.42%**."*

[4] SONI is a regulated, price controlled entity which, despite relatively high operational gearing, should enjoy a lower cost of capital relative to that required by an investor wishing to build a peaking plant that will operate in an as yet undefined power market.

Or CMA analysis[5] that found a very different estimate of pre-tax WACC across vertically integrated[6], generation only and retail supply businesses over a period covering January 2007 to March 2014:

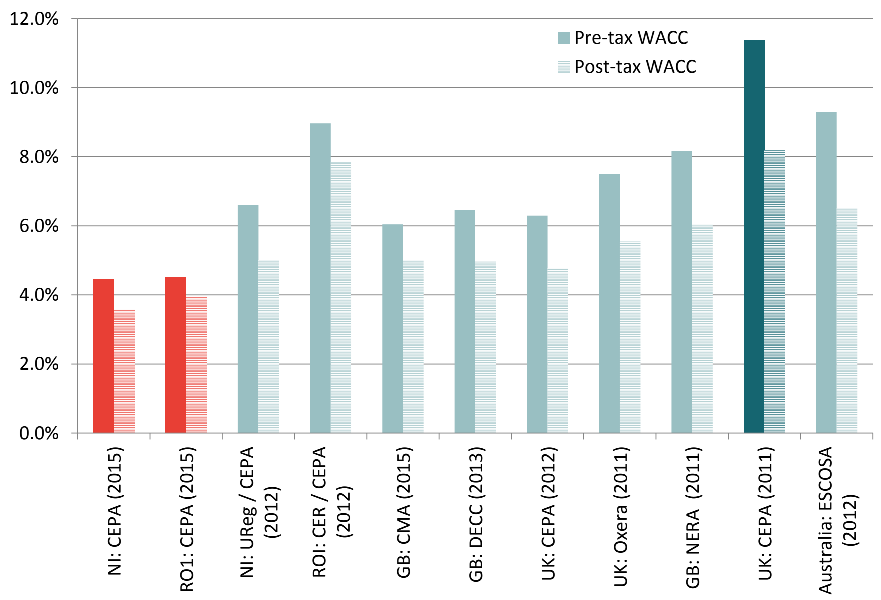
TABLE 1 **CMA estimates of the WACC for the elements of the energy value chain**

	Vertically integrated	*Generation*	*Retail supply*
Real risk-free rate (%)	1.0–1.5	1.0–1.5	1.0–1.5
Nominal risk-free rate (%)	4.0	4.0	4.0
Equity risk premium (%)	4.0–5.0	4.0–5.0	4.0–5.0
Asset beta	0.5–0.6	0.5–0.6	0.7–0.8
Pre-tax Ke (%)	9.6–10.3	9.6–10.3	9.3–11.0
Pre-tax cost of debt (Kd) (%)	5.0–6.0	5.5–7.0	-
Gearing (%)	20.0–40.0	20.0–40.0	0
Tax rate (%)	27.0	27.0	27.0
Pre-tax WACC (%)	**7.7–9.5**	**7.9–9.7**	**9.3–11.0**

Source: CMA analysis.

The Frontier Economics Report commissioned by the Electricity Association of Ireland illustrates just how much of an outlier the SEM Committee's proposed decision is on a crucial element of the BNE calculation:

Figure 1. Pre-tax and post-tax WACC estimates



Source: Frontier Economics

[5] CMA (2015), Energy Market Investigation, Analysis of cost of capital of energy firms

[6] This is backward looking (reflecting a higher tax rate and a range of market periods) but more reflective of observed data and conditions over a period in which an investor in the BNE would have been expecting their plant to operate.

Using inputs that sit a considerable distance away from observed market data and recent regulatory determinations will not achieve the capacity mechanisms stated aim. Without following a robust and rigorous process for the determination of the ACPS, investors and existing operators cannot hope to recover fixed costs through the design of the existing SEM market[7] - this is bad for both generators and consumers in the long run. Ireland is a small system – if regulatory uncertainty requires that exit and entry is unnecessarily 'blocky' and cyclical as a result of large risk premiums being required by investors and operators, consumers will suffer unnecessarily.

Each component of the BNE calculation must be carefully considered and properly evidenced to ensure the capacity mechanism accurately reflects economic reality – we are not convinced that SEM-15-032 does.

SSE recommends that:

- **The BNE technology must be chosen with regard to DS3 earnings or the BNE calculation must be reopened for the 2017 Trading Year.** Partial fixing of most components with a reopener for DS3 is not realistic.
- **Grid Code Compliance must be included as a criterion for plant selection and filtering or alternatively penalties must be included in BNE costs.**
- **The pre-tax real WACC for NI should sit in the range of 6.09% to 6.80%, with the RoI figure sitting in a range of 5.32% to 6.06% as evidenced in the Frontier Economics paper prepared for EAI.** The RoI and NI WACCs chosen by the RAs consultants are unrealistic.
- **Start costs cannot only be accounted for once in the IMR methodology** – the BNE plant would need to incur multiple start costs to capture multiple hours of IMR at PCAP.
- The strategic reserve style contract placed by the NI TSO must exclude the capacity from the unconstrained market or the ADCAL LOLE calculation must be adjusted to reflect the fact that the TSOs are aiming for a lower unconstrained security standard. **SSE believes that the LOLE applied in the BNE calculation should be revised downward to reflect the observed long-run equilibrium system position.**

Our response covers a number of the elements of the consultation paper used to determine BNE components – we hope that the SEM Committee carefully consider our own comments and the two reports commissioned by the members of the Electricity Association of Ireland before issuing their final decision on the ACPS for the 2016 Trading Year.

Technology and EPC

Technology

The RAs have chosen to dismiss second-hand plants, interconnectors, storage and AGUs for the purposes of technology selection and opted for an **Alstom GT13E2**.

As other respondents previously stated in their responses to SEM/12/078, the selection of the 2012 BNE did not even fully take into account compliance with the existing Grid Code let

[7] We would also note that both Regulatory Authorities have duties to ensure generation licence holders can finance their activities.

alone new requirements or ancillary service opportunities – the CEPA report included with the proposed decision still does not include Grid Code Compliance as an element of gas turbine plant selection or filtering. Grid Code Derogations are increasingly difficult to achieve, even for smaller plant – the RAs cannot assume zero cost for non-compliance.

The paper also states that:

"It is worth noting that the DS3 framework offers more services than the current HAS arrangements. In light of this, the BNE Peaking Plant may be expected to have additional revenue opportunities in 2017. It is proposed that this aspect be reviewed for the calculation of the 2017 ACPS."

SSE would note that, if the plant chosen is an **Alstom GT13E2** running on distillate, it must be technically capable and available[8] to perform these enhanced services for their revenue to be deducted from its fixed costs – the standard unit chosen would not be capable of offering much more than standard products without upgrades or alterations.

This would suggest that the BNE technology must either be chosen with regard to DS3 for the purposes of this year's calculation[9], or that the entire calculation should be repeated for the 2017 Trading Year. Simply applying a *"suitable deduction"* (and one would assume, suitable upgrades) implies perfect foresight on the part of the investor – this is not realistic.

Initial Fuel Working Capital

The paper states that:

"CEPA/Ram has estimated an initial fuel storage fill cost of €3.63m for a distillate plant and €3.06m for a dual fuel plant. This is based on a requirement to run for 72 hours full load, an additional 0.5 days of commercial running and an oil price of US$58.13/ barrel. It is assumed that unused fuel is sold back at the end of the plant life."

We do not accept the calculation of fuel working capital – delivery of approx. 65,000 barrels equivalent distillate running fuel to an industrial site in Northern Ireland would typically cost more than an ICE Brent Crude contract pulled from a screen on a single trading day.

Transmission Use of System

SSE believes that a more robust calculation rather than a simple average should be performed to find generator TUoS charges for the notional site – the 2013 decision stated that:

"It is considered beyond the scope of the BNE calculation to assess site-specific GTUoS charges for a BNE site, especially in RoI where a notional site is assumed."

A complex calculation isn't needed to ensure cost reflectivity – the RAs simply need to take an average for generators that connected over a defined point in time – for example, the last 3 years – this would ensure that the new BNE can cover the above average reinforcement costs passed through to new generators in the transmission use of system charge.

Weighted Average Cost of Capital

[8] As defined by the final DS3 system services procurement framework definitions of availability, not existing definitions of availability.
[9] The cost of regulatory uncertainty around DS3 would then be reflected in the ACPS.

As an integrated UK utility which fits the primary assumptions[10] for the BNE investment in a peaking plant – we are concerned that the CEPA report found an out-turn range for the pre-tax WACC set at **3.93%** to **5.05%** for Northern Ireland. For a plant in Northern Ireland, a rational investor would expect some additional risk premium, but even on a forward-looking basis for a standalone UK peaking plant investment this estimated range is exceptionally low.

We would refer the SEM Committee to the Frontier Economics report commissioned by the EAI for comprehensive analysis of the CEPA report, but we would like to see the final decision properly justify the following assumptions for components of the pre-tax WACC:

Choice of new entrant

The choice of a vertically integrated utility financing a project at group level is questionable – this will explicitly avoid calculating the marginal WACC for a standalone generation investment. By trying to use an 'average' WACC for this investor, **the SEM Committee is in effect saying that the vertically integrated utility is investing in a hybrid asset that partially has characteristics of both a regulated network asset and a wholesale market asset.** This is unrealistic and distorts the risk profile of the asset.

Asset beta

CEPA propose to widen the asset beta from 0.5 to 0.6 in their WACC calculation – this mirrors the range estimated by the CMA. Given that the BNE is not being delivered in the larger GB market, it seems necessary to 'aim up' and use the 0.6 asset beta figure **given the market reform and regulatory intervention risks that face a generator building a standalone asset in Northern Ireland.**

Northern Ireland Risk Premium

The analysis carried out by CEPA partially looks at whether an explicit risk premium is required for the cost of debt, by comparing the NIE 2026 bond to similar debt issued by UK distribution companies:

"This analysis does not indicate that an explicit premium is required for NI relative to the UK. ***It should be noted that NIE falls under ESB ownership*** *(the CMA state that they cannot be certain what effect this has),* ***itself being state owned.***

CEPA acknowledge that this is an imperfect analysis[11] but do not look for other comparators to confirm or disprove their dismissal of the NI risk premium. PNG bond yields – which were considered previously in 2013 – appear to have been selectively dropped from the analysis, despite a clear risk premium over GB comparators that is shown in observed yields.

Indexation

The CEPA analysis uses the Bank of England breakeven rate (a forecast of RPI inflation) rather than using a forecast of CPI inflation - **this leads to an underestimate of the real cost of debt which should be corrected in the final decision.**

Gearing

The CMA observed data on gearing levels of energy firms is shown below:

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[10] Credit Quality etc

[11] NIE is, in effect, a state owned TAO and DSO – a very imperfect comparator.

TABLE 7 **Gearing levels of energy firms**

%

Company	*2006*	*2007*	*2008*	*2009*	*2010*	*2011*	*2012*	*2013*	*Average*
Six Large Energy Firms									
Centrica plc	13.9	6.3	4.3	19.0	17.2	19.5	20.2	22.9	*15.4*
SSE plc	18.2	14.3	23.1	33.3	36.1	30.3	32.5	27.9	*27.0*
EDF SA	24.9	9.3	25.0	37.8	39.7	51.5	64.5	45.1	*37.2*
E.ON SE	13.2	18.2	42.0	38.9	39.5	45.8	46.9	43.2	*36.0*
Iberdrola SA	31.0	30.8	49.0	44.1	45.6	49.2	51.5	48.6	*43.7*
RWE npower AG	1.0	2.2	14.5	28.9	37.8	52.0	49.9	50.3	*29.6*
Average	***17.0***	***13.5***	***26.3***	***33.7***	***36.0***	***41.4***	***44.2***	***39.7***	
VI firms (non-UK)									
Enel S.p.A.	22.0	57.4	69.3	67.1	68.6	71.5	71.2	69.9	*62.1*
Gas Natural Fenosa	19.5	19.1	37.2	60.2	64.0	56.7	54.3	45.8	*44.6*
EnBW AG	23.9	16.3	21.0	38.2	36.1	35.2	36.2	34.4	*30.2*
Verbund AG	14.6	14.6	23.5	32.8	31.0	38.5	42.6	45.7	*30.4*
Fortum Oyj	19.4	14.8	32.9	27.6	26.9	34.1	40.1	36.5	*29.0*
Contact Energy Limited	13.3	9.3	12.9	23.6	27.1	21.8	27.3	25.6	*20.1*
TrustPower Limited	14.3	15.1	18.5	24.1	24.1	26.0	25.1	27.4	*21.8*
NRG Energy Inc	57.1	44.9	58.7	52.1	61.8	69.0	66.3	62.8	*59.1*
Origin Energy	0.0	24.8	24.3	7.6	6.0	5.8	23.7	26.1	*14.8*
AGL Co	36.5	31.7	23.6	6.4	22.6	24.1	34.1	37.5	*27.1*
Generation firms									
GDF Suez	10.3	26.5	32.0	36.2	43.1	55.7	61.1	47.8	*39.1*
Drax plc	9.7	14.1	11.0	3.5	0.0	0.0	0.0	0.0	*4.8*
AES Corp	53.6	55.5	77.5	69.6	65.9	71.6	72.6	67.9	*66.8*
AEP Corp	43.6	43.6	56.1	50.3	50.3	46.9	46.7	45.0	*47.8*
UK retail only firms									
Good Energy Group plc							0.0	18.0	*9.0*
Telecom Plus plc	0.0	0.0	0.0	0.0	0.0	4.2	0.0	0.0	*0.5*
Just Energy	0.7	1.5	2.7	1.5	12.1	19.3	27.4	49.2	*14.3*

Source: Bloomberg data, CMA analysis.

The gearing level of 60% chosen by the SEM Committee conflicts with observed data – the idea of an investor securing debt financing equal to 60% of the value of the power plant with an expected debt to EBITDA ratio of 8 and an investment grade credit rating is not credible. A 60% gearing level would be more appropriate for a company in the process of (re)financing an existing network of regulated assets, rather than a company building a standalone green-field peaking plant. The CEPA paper suggests that the gearing was based on guidance from the SEM Committee – we think it is important that an independent assumption is used for this variable. **Frontier Economics suggest a gearing level of 30% for the BNE - this is more realistic.**

Proposed WACC

The CEPA estimates are outliers - **we believe that an overall pre-tax real WACC of above 6% would be required** for the BNE investor in Northern Ireland. **CEPA's estimates are markedly below recent regulatory precedent in GB and Northern Ireland – they are selective, and do not reflect the true cost of capital for the BNE investor.**

Inframarginal Rent and Ancillary Services

The Pöyry Management Consulting note commissioned by the EAI and submitted alongside the EAI response finds that:

"The formulation of the Infra-Marginal Rent (IMR) discount is potentially inconsistent in a number of areas, each of which would lead to systematic under-payment to generators against the stated intention of the CPM."

We would refer the RAs to the Pöyry critique – we believe that a number of areas have been overlooked in the IMR calculation for the 2016 ACPS – most crucially, the expectations of inframarginal rent are predicated on a probabilistic unconstrained security standard that is not being adhered to by either TSO. The final decision must properly justify the following assumptions/decisions for the calculation of inframarginal rent:

Start costs

In the 2013 decision, the RAs state that:

"The RAs acknowledge that start costs should have been included within the original calculation. However, we do not agree with the statement that start costs should be included for each and every trading period within the eight hour period when the BNE would be scheduled to run. The RAs contend that it is reasonable to assume in the calculation for these eight hours to be consecutive and therefore only one set of start costs would be included."

We disagree. Regardless of whether the assumption that PCAP will be reached for 16 half hour periods of unconstrained load loss is correct, **the assumption that those 16 half hour periods of PCAP would be consecutive under equilibrium conditions is clearly unsupportable.** This assumption is unjustified based on a simple glance at high SMP events since SEM go-live. Start costs cannot only be accounted for once in the IMR methodology – the BNE plant would need to incur multiple start costs to capture multiple hours of IMR at PCAP.

All-Island Security Standard

The ADCAL approach used to calculate the theoretical level of generation needed to meet a LOLE of 8 hours would closely fit the IMR methodology – ***if*** the TSOs had not explicitly intervened to pay for capacity that reduces the BNE investor expectation of returns through inframarginal rent.

The ***Security of Electricity Supply in Northern Ireland*** paper jointly published by the Utility Regulator and the Department of Enterprise, Trade and Investment states that:

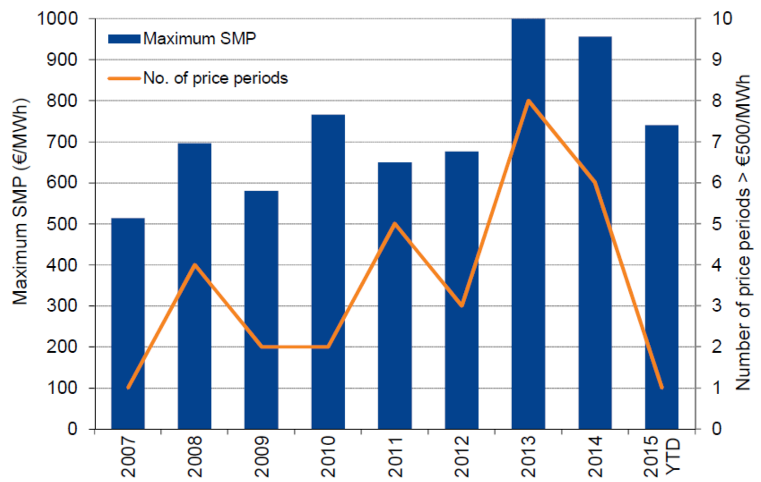
"SONI's Winter Outlook statement for the 2014/15 winter period concludes that there will be sufficient generation capacity in Northern Ireland to ensure the appropriate level of security of supply is maintained over the winter period. ***The 200MW surplus from 2016 meets the generation security standard and therefore in normal operational situations is satisfactory.*** *However, in the event of a prolonged outage of a large generation plant, or of the Moyle interconnector, this margin may not be sufficient."*

The probabilistic analysis finds that the existing 200MW surplus safely meets the (lower) 4.9 hour LOLE Northern Ireland generation security standard, but SONI in agreement with the Utility Regulator have chosen to bilaterally contract for an additional 250MW of plant available from January 2016 for a three year period. The terms of the strategic reserve contract have not been made publicly available, but they do not appear to prevent the capacity from participating in the unconstrained market[12] from the 2016 Trading Year onwards.

[12] Diluting both the recovery of unsupported capacity through participating MWh of availability and expectations of IMR.

The intervention by the Northern Ireland TSO therefore has a material impact on the IMR assumptions the BNE investor would make – they can conclude that the unconstrained 8 hour LOLE is never achieved in reality as a result of TSO intervention and apply a suitable deduction to the energy market earnings. The Pöyry note illustrates observed high price periods:

Figure 1 – Historical maximum SMP and frequency of high price periods (>€500/MWh) observed in SEM (€/MWh, nominal)



*2015 YTD: Prices until 12th June

Source: SEMO, restricted to assessment of EP2 runs over relevant period

Either the strategic reserve style contract placed by the TSO must ensure that the capacity cannot participate in the unconstrained market or the ADCAL LOLE calculation must be adjusted to reflect the fact that the TSOs are clearly aiming for a lower unconstrained security standard. Most European systems already apply a lower reliability standard – SSE believes that the LOLE applied in the BNE calculation should be revised downward to reflect the observed long-run equilibrium system position too.

DS3 Payments

As mentioned earlier in our paper, SSE believes that the BNE technology must either be optimised with regard to 'known' DS3 information for the purposes of this year's calculation, or that the entire calculation should be repeated for the 2017 Trading Year. It is not consistent to fix and index every other BNE term while leaving an additional deduction for enhanced services open – this is an unfairly selective approach to a regulatory determination that is central to the functioning of the SEM.