Response by Energia to Single Electricity Market Committee Consultation Paper SEM-12-089

Treatment of Gas Transportation Capacity Costs

16 November 2012

The correct treatment of gas capacity costs in the SEM is for this cost to be included in all gas fired generators bids in the SEM, at the regulated price of firm daily capacity. Upon proper legal interpretation of the licence it cannot be said that such a cost is not a Short Run Marginal Cost, as defined in Condition 15.3. This approach respects the primacy of the licence. In valuing this cost one must have regard to the Bidding Code of Practice. Following developments in the gas markets of both the Republic of Ireland and Northern Ireland, in compliance with EU requirements, the relevant product is the firm daily capacity product available from the transporter, the price of which is set by the Regulatory Authorities. The important distinction between primary (firm) and secondary (interruptible) capacity in the context of the SEM is an important one and is one recognised by the CER.

Notwithstanding the overall simplicity of the conclusion stated in this response, this approach is also the only logically consistent approach considered to be available to the SEM Committee that satisfies the correct legal interpretation of the licence, stated regulatory policy (specifically gas capacity products and market power), and the apparent intention of the SEM Committee to address this issue as far back as 2007.

In consideration of this matter, and contrary to some of the arguments advanced in the consultation paper, it is necessary that the SEM Committee pay due regard to and where required are bound by the decision of the Supreme Court. Further to this any decision of the SEM Committee must also be consistent with the following;

1. It is not and never has been the intention of the relevant provisions of the Licence and/or the Bidding Code of Practice to reflect the trading behaviour of generators in the market. Instead these documents ensure that generators' bids are cost-reflective of their Short Run Marginal Cost, by reference to a specific approach to valuing the opportunity cost of all relevant cost-items on a trading day. As such it is the availability of a daily gas capacity product and not the use of it by generators that provides a basis for its legitimate and required inclusion in a generator's bids.
2. Accepting there are differences in the cost of primary daily gas capacity in RoI and NI, such a situation is not new and cannot legally form a basis for excluding such costs. It is not and has never been the intention of either the Licence or Bidding Code of Practice to only allow costs in the instance that they are common across both jurisdictions. In order for generators to comply with their licence requirements, it is imperative that they do so in a manner that is cost reflective to the generation unit(s). It is the availability of daily products that is relevant in the required approach. The availability or otherwise of daily products on a *day ahead basis* as an argument for excluding such products is an erroneous one and has no basis in the licence requirements of generators properly interpreted.
3. Finally, should the SEMC consider that there is not a recognised and generally accessible trading market in daily gas capacity products, (an erroneous assertion based on the submission contained herein), the BCoP contains further provisions such that one would determine the replacement cost of daily gas transportation capacity as the relevant Opportunity Cost to be included in a generator''s' COD. In this instance, the cost is unchanged and is equal to the regulated price of daily gas transportation capacity as set by the competent regulator.

It is therefore Energia's contention that all gas fired generators must reflect in their bids the cost of primary gas transportation capacity, the opportunity cost of which is to equal the regulated cost of firm daily capacity from the transporter.

1. Introduction

Energia welcomes this opportunity to respond the Single Electricity Market (SEM) Committee consultation on the treatment of gas capacity costs in the SEM. Unlike the majority of consultations published by the SEM Committee, this consultation is superfluous to the specific legal issue at hand but we recognise the procedural advantage of transparency in such matters.

As the question of the inclusion of gas capacity costs in COD is a legal matter, all comments relating to general economic and regulatory policy, while important in an overall economic context, are not relevant in the context of considerations pertaining to this matter. In matters such as this, the recent Supreme Court decision does not only provide the correct approach to considering the inclusion of this cost but it also places a strict limit on the SEM Committee's discretion to read into or interpret the relevant conditions of the generator's licence.

At the outset of this response it is important to recognise that gas fired electricity generators have not been permitted to bid in all of the costs attributable to the generation of electricity. By prohibiting the recovery of gas transportation capacity costs, the SEM Committee has created a distortion in the market that discriminates against gas fired generators in the application of the licence condition requirement ensuring cost recovery. Although the RAs primary objective is that of customer protection, this objective neither can (under the correct legal interpretation), nor should (ongoing inequitable distortion) determine the outcome of this consultation.

Within this response we consider first the status and legal interpretation of the formal regulatory structure governing the SEM (i.e. the licence) and draw a number of conclusions with respect to the relevant documents. Secondly market developments are reviewed. Thirdly, a number of fundamental issues are apparent in the consultation paper that on any reasonable reading appear contrary to the requirements and legal interpretation of the licence, and regulatory policy. Within this section eight specific issues are addressed. Fourthly, a selection of recent, relevant SEM Committee and RA decisions are reviewed. On the basis of the arguments forwarded in the preceding sections, the correct approach to the treatment of gas capacity costs in the SEM is then presented. Finally, the questions contained in Section 4 of the consultation paper are restated and summary comments provided.

2. Review of Generator Licence and BCoP

Due to the nature of this consultation, the SEM Committee has included a discussion of generator licence requirements as they relate to Commercial Offer Data (COD). Before considering these substantive sections of the consultation paper, it is first important to outline a number of general principles with respect to the licence, Bidding Code of Practice (BCoP) and their interaction to structure the discussion. General principles have been provided by way of the Supreme Court judgment of

Hardiman J[1] and thus reflect the correct legal position with respect to the relevant conditions and sections of these documents.

The Licence

"*For the purposes of this summary it is sufficient to note that the price elements of the offer, or "bid", which each electricity generator must make for the sale of its product into the SEM are not at the generators' discretion. Instead, the price is required to reflect the Short Run Marginal Cost of the generator. That is, in the language of the licence, the prices required to be "cost reflective". Thus, the generator is prohibited from bidding at a price which either exceeds, or is lower than, its Short Run Marginal Cost. This is the effect of Condition 15 of the standard licence to generate electricity*."[2]

Although part of Condition 15.3 has been reproduced in the consultation paper, it is instructive to consider the wider provisions of Condition 15 and how they align with the correct legal interpretation of the document and rules in the SEM.

Condition 15: Cost Reflective Bidding in the Single Electricity Market

(1) The licensee shall ensure that the price components of all commercial offer data submitted to the Single Market Operation Business under the Single Electricity Market Trading and Settlement Code, whether by the licencee itself or by any person acting on its behalf in relation to a generation unit for which the licensee is the licensed generator, are cost reflective.

(2) For the purposes of this condition, the price component of any commercial offer data shall be treated as cost reflective only if, in relation to each relevant generation unit, the Schedule Production Cost related to that unit in respect of the Trading Day to which the commercial offer data submitted by or on behalf of the licensee apply is equal to the Short Run Marginal Cost related to that generation unit in respect of that Trading Day.

(3) For the purposes of paragraph 2, the Short Run Marginal Cost related to a generating unit in respect of a Trading Day is to be calculated as:

(a) The total costs that would be attributable to the ownership, operation and maintenance of that generation unit during that Trading Day if the generation unit were operating to generate electricity during that day;

minus

(b) The total costs that would be attributable to the ownership, operation and maintenance of that generation unit during that Trading Day if the generation unit was not operating to generate electricity during that day.

the result of which calculation may either be a negative or a positive number.

(4) For the purposes of paragraph 3, the costs attributable to the ownership, operation and maintenance of a generation unit shall be deemed, in respect of each relevant cost item, to be the Opportunity Cost of that cost item in relation to the relevant Trading Day.

(5) The Commission may publish and, following consultation with the holders of Generation Licences and such other persons as the Commission considers

[1] *Viridian Power Limited v. Commission for Energy* [2012] IESC 13 at 46 (Hardiman J.). Available at: http://supremecourt.ie/Judgments.nsf/60f9f366f10958d1802572ba003d3f45/8dc0b6c9a57dde37802579ad00527392?OpenDocument&Highlight=0,viridian

[2] [2012] IESC 13 at 9.

appropriate, from time to time by direction amend, a document to be known as the Bidding Code of Practice which shall have the purposes of:

(a) Defining the term Opportunity Cost

(b) Making provision, in respect of the calculation by the licensee and other generators of the opportunity cost of specified cost items for the treatment of

(i) The cost of fuel used by generators in the generation of electricity;

(ii) The value to be attributed to credits issued under the Emissions Trading Scheme established by the European Commission;

(iii) Variable operational and maintenance costs;

(iv) Start up a no load costs;

(v) Any other costs attributable to the generation of electricity.

(c) Setting out such other principles of good market behaviour as in the opinion of the Commission should be observed by the licensee and other generators in carrying out the activity to which paragraph 1 refers.

(6) The licensee shall, in carrying out the activity to which paragraph 1 refers, act so as to ensure its compliance with the requirements of the Bidding Code of Practice.

(7) The Commission may issue directions to the Licensee for the purposes of securing that the Licensee, in carrying out the activity to which paragraph 1 refers, complies with this licence and with the Bidding Code of Practice, and the Licensee shall comply with such directions.

In the context of the discussion contained in the consultation paper, it is important to make a number of points in relation to the construction, interpretation and requirements under the licence. These can be summarised as;

1. The term "total costs" is to be interpreted with recourse to its ordinary and natural meaning and could equally be considered to be "all costs", of the same kind.[3]
2. "*[I]t is not lawful for an operator in this market to engage in below cost selling, or to exclude any actual costs from the category of "total costs*".[4]
3. The definition of "total costs" is to refer to all cost items incurred by the generator in generating electricity with respect to a trading day, as determined by Condition 15.3. This condition is separate and distinct from the method of valuing these costs.
4. There is no reference in the relevant licence condition (Condition 15) to a day-ahead requirement or any temporal restrictions on costs considered to be within the "total costs" of generating, as outlined in Condition 15.3.
5. Condition 15.4 requires the value of such costs to reflect the "Opportunity Cost" of the cost item on the relevant trading day. The methodology for determining the "Opportunity Cost" is provided for in Condition 15.5 and determined in the BCoP. The implication of this provision is *inter alia* to allow for actual accounting costs incurred by the generator to differ from the costs submitted in bids.

[3] [2012] IESC 13 at 40.
[4] [2012] IESC 13 at 49.

6. "*[T]here is nothing in the language of Condition 15.7 which suggests that the Commission is given any power of interpretation of the licence…There is nothing in the terms of the licence, in my view, which confers on the Commission any powers of interpretation over the terms of the licence itself*."[5]

The BCoP

"*Accordingly, in relation to the terms of the licence and the BCOP one must first note the primacy of the licence. It contains the provision just quoted authorising the issue of the BCOP. It goes on to define what the BCOP may contain. The BCOP, therefore, is a document derivative from the licence and whose scope is defined by the licence.*

The licence first establishes the obligation of cost reflectiveness and the obligation to quantify one short-run marginal cost in terms of "total costs"."[6]

The relevant paragraphs of the BCoP are reproduced here[7];

General Principles

6. When calculating the Short Run Marginal Cost of a generation set or unit in respect of a Trading Day, constituent cost-items are to be valued at their Opportunity Cost, and so that a reasoned explanation of the calculation of that Opportunity Cost is capable of being given to the Authority or the Commission (as appropriate) on request.

7. The Opportunity Cost of any cost-item shall comprise the value of the benefit foregone by a generator in employing that cost-item for the purposes of electricity generation, by reference to the most valuable realisable alternative use of that cost-item for purposes other than electricity generation.

8. In calculating the value of the benefit foregone in employing a cost-item for the purposes of electricity generation, the following principles shall, unless it can be demonstrated to the satisfaction of the Authority or the Commission (as appropriate) that there is good cause not to, be applied:

(i) where there exists a recognised and generally accessible trading market in the relevant cost-item, the Opportunity Cost of that item should reflect the prevailing price of the cost-item, which may be for immediate or future delivery or use as appropriate to the circumstances of the relevant generator, having regard to:

(a) costs the relevant generator would incur in offering that cost-item for sale, or acquiring that cost-item, on a recognised and generally accessible trading market;

(b) reasonable provision for the variability of the prevailing price of a cost-item on a recognised and generally accessible trading market;

(ii) where no recognised and generally accessible trading market exists in the relevant cost-item the Opportunity Cost of that item should reflect the costs which would be incurred by the relevant generator in replacing that cost-item; and

(iii) reasonable provision for increased risks to plant and equipment as a result of the operation of a generation set or unit may be included.

[5] *Viridian Power Limited v. Commission for Energy* Regulation [2011] IEHC 266 at 38.
[6] [2012] IESC 13 at 46.
[7] AIP-SEM-07-430 at 10/11.

Similar to the exercise undertaken with respect to the licence, some summary remarks on the status and interpretation of the BCoP are useful in the context of the consultation paper.

1. "*It will be noted that BCOP is not permitted to derogate from the requirements of cost reflectiveness, or the requirement to calculate short-run marginal cost by reference to "total costs"*."[8]
2. "*Paragraph 6ff of the Bidding Code of Practice appears to me to be concerned with matters of calculation and not of the exclusion of any item from the category of "total costs"*."[9]
3. "*Paragraph 7 says that the opportunity cost shall comprise the value "of the benefit foregone" by a generator in employing that cost item for the purpose of electricity generation. This is to be done "by reference to the most valuable realisable alternative use of that cost item for purposes other than electricity generation".*

   This paragraph, again, does not appear to me to exclude any item from the category of "total costs"."[10]
4. "*Paragraph 8 of the BCOP provides method of calculating the value of a benefit foregone, and talks in terms of market price, where there is a market in the item in question, or the costs of replacing it where there is not.*"[11]
5. The BCoP is entirely related to the methodology to be applied in valuing costs and it is this methodology that is to apply, unless there is "good cause not" to employ it[12]. Importantly, where the methodology is not to be followed, it will require an alternative method of valuation to ensure compliance with the licence requirement for "total costs" determined under SRMC to be fully recovered.
6. "*It therefore appears that the appellants are not merely entitled but are obliged to make sure that the offer price which they make to the Regulator is equal to their short-run marginal costs of generation.*"[13]

In summary, the requirements of the Licence and BCoP are clear with respect to the price component of a generator's COD. All bids must be cost reflective with respect to the trading day and as such must reflect all costs as identified under licence Condition 15.3. These identified cost-items are to be included in generator's bids on the basis of their Opportunity Cost. Opportunity Cost is not a general term in this context or one that is open to interpretation. Attempts to equate opportunity cost with a general concept of the value of the benefit foregone (para. 7) are inconsistent with paragraph 8 of the document which expressly provides the approach to be employed in its calculation (para. 8). As already seen, the opportunity cost of a cost item is to be determined with reference, where possible, to the market price/cost of the item on a trading day, alternatively it is to equal the replacement cost of the cost-item.

[8] [2012] IESC 13 at 47.
[9] *ibid.*
[10] [2012] IESC 13 at 48.
[11] *ibid*.
[12] *ibid.*
[13] [2012] IESC 13 at 49.

3. Short term gas capacity products

Regulation 1775/2005/EC, which came into force prior to the SEM on 01 July 2006, introduced inter alia , two important requirements that gas markets in Member States would have to comply with; namely the sale of unused primary capacity on a firm day ahead basis and also the introduction of secondary gas capacity trading.

Gaslink has offered daily capacity products to Irish shippers since 01 October 2007 and a within-day gas capacity product since 04 June 2008. As noted in the consultation paper regulated short term daily gas capacity products are now available in Northern Ireland. Importantly in the context of this consultation, these products are firm day-ahead products made available by the transporter at a regulated price set by CER/UREGNI.

Under the Gaslink Code provisions relating to secondary capacity transfers are provided for. This facility makes it possible for shippers to trade gas transportation capacity for a particular trading day on either a regulated (with BGE) or unregulated (with other counterparties) market. While it is possible for parties to trade firm gas capacity, this practice is uncommon relative to the trading of interruptible capacity in the secondary market.

The publication of information by the SEM Committee on secondary capacity trading[14] during the consultation period does not reflect this important distinction. Generators in the SEM are required to provide firm bids to the market operator[15], it is therefore important for gas fired generators to back their bids with a firm gas capacity product. The publication is short on detail and does not distinguish between interruptible and firm capacity, however, Energia's experience in the market is that what capacity is traded is overwhelmingly interruptible. The use of interruptible products leaves the generator open to the risk of incurring overrun charges in the SEM, the pricing of interruptible capacity is intended to reflect this risk. Additionally, it is of note that the apparent liquidity provided for in the charts is not sufficient to run a single CCGT in the SEM at full load on a daily basis in even the most liquid quarters presented. The secondary capacity market cannot therefore be considered to be a market with sufficient liquidity to support the trading of gas capacity for generators. Unfortunately the information provided does not allow for further precision in respect of this point due to the likelihood of double counting in the presented figures (note 3),

As already noted, in the context of this consultation the distinction between firm and interruptible capacity is an important one. This distinction is lucidly highlighted by the CER in a recent decision paper published in September 2010 on Bord Gáis Networks (BGN) short term tariffs.

> "*The CER does not consider that the comparison of secondary and short term capacity constitutes a constructive assessment. It should also be noted that the current price of secondary capacity does not, in our view, reflect the very low probability of interruption.*

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[14] SEM/12/101. Available at: http://www.allislandproject.org/en/mmu_current_consultations.aspx?article=bf4f81f2-248a-4a41-95da-086b6e427e90

[15] Generators are obliged by their Licence and their Connection Agreement to respond to dispatch instructions, if they are interrupted on a day they will be obliged by their Licence and their Connection Agreement to overrun their gas capacity.

> *It is not intended that the cost of short term capacity will ever align with that of secondary capacity and short term capacity products should not be interpreted as a simple substitute for existing secondary capacity. The CER is of the view that the cost of short term capacity should be examined in the context of firm annual capacity.*"[16]

This decision draws important distinctions between the two products and shows the relevant long term comparator for short term products to be firm annual capacity.

4. Irrelevant Considerations in the Consultation Paper

Within the consultation paper there are a number of instances of remarks, arguments or conclusions that appear to contradict or simply do not reflect the legal certainty with which a matter such as this is to be considered. In addition to this, a number of the arguments advanced erroneously assert a relationship between this matter and the separate issue of the regulated price of secondary gas capacity.

The price of gas capacity

The consultation paper (page 5) discusses the relative cost of purchasing different gas capacity products over the course of a year. It highlights that the relative cost of purchasing a monthly product for the full year is almost twice as much as an annual product, with daily capacity for the same period costing almost three times as much. The differences in these regulated tariffs are substantial but have been set following careful consideration by the RAs and are designed to meet stated regulatory objectives.

Albeit important to ensure that energy prices are as low as possible for customers, the relative price disparity between gas capacity products is not a basis upon which one could seek to prohibit their inclusion in generator's bids. Such an approach would set an alarming precedent and would be contrary to the license and BCoP. The principle of cost recovery in the market and the mechanism through which this is achieved is, by reflecting market prices, blind to the relativity of input prices. It is an equivalent and equally absurd proposition to consider the regulator capping the price gas generators could include in their bids in response to a surge in the world price of gas due to a natural disaster.

Northern Ireland units

It has been asserted in the consultation paper (page 7) that as a result of regulated short term gas capacity products in Northern Ireland not being available on a day-ahead basis, they are precluded from being included in the COD of gas plants in Northern Ireland. This statement is without basis with reference to the licence and BCoP, wherein no such day-ahead requirement is stated. Further to this, units in Northern Ireland are equally bound to comply with their licence requirements and include all costs that arise from the application of Condition 15.3. This unquestionably includes the cost of gas transportation capacity.

Furthermore, it could be argued that where short term (daily) products are available to generators in both Northern Ireland (NI) and the Republic of Ireland (RoI), and given there are common rules in the SEM, to allow for different approaches in the

[16] CER/10/166 at 7. Available at: http://www.cer.ie/en/gas-transmission-network-decision-documents.aspx?article=669d71a3-5b85-4726-b7f6-042aa25331ba

respective jurisdictions could be contrary to the EU Commission rules on cross-border trade. Such a distortion in cross border trade would breach of Directive 2009/72/EC (in particular Articles 36(b), 37(1)(b) and 38(2)(a)). Similarly, if it is to be argued that the daily product in Northern Ireland is not a daily product, this could be seen to be in breach of Article 14 of Regulation EC 715/2009.

Commercial decisions and licence requirements

An issue arising on multiple occasions within the consultation paper relates to an apparent argument forwarded by the SEM Committee that generators are obliged to bid the costs of the products they have booked. The first example of this is contained midway through page 8 but it also forms the basis for related discussions forwarded subsequently on pages 10, 11, 13 and 14. The argument being advanced is fundamentally wrong and displays an incorrect reading of the relevant licence requirements and application of the BCoP. Rather than importing commercial decisions and activity into generators bids, the express intention of the relevant requirements is to create a level playing field by implicitly removing contracted costs from the definition of Opportunity Cost.

It is clear from the exposition of the Licence and BCoP contained herein that units with different load factors will, with respect to costs such as gas capacity, have the same opportunity cost as provided for under the BCoP. The relevant section from the paper deserves more consideration and is reproduced for reference;

> "*Because the cost of purchasing daily short term regulated capacity can be as much as three times higher than the daily average cost of purchasing annual capacity, it may still be more economic for baseload units to purchase annual capacity rather than short term capacity. However, for peaking plant and for some mid-merit plant (with low load factors), it may be more economic to purchase short-term capacity as and when it is needed. The total cost faced by the generator for these units is therefore not the same irrespective of whether or not the unit is operating on any particular day*."[17]

There are a number of points to note;

1. The price of gas capacity products is regulated and provides commercial signals to generators to adopt particular gas capacity purchasing strategies.
2. Generators are obliged to include in their bids all costs that are attributable to the SRMC, as defined, of generation with respect to a trading day. This condition holds equally for all generators and is not cost dependant.
3. All generators are required to include such costs in a manner consistent with the approach contained in the BCoP. While the accounting costs of generators may differ, this is immaterial to the exercise generators are obliged to undertake. On this basis, the cost of gas capacity will be the same for all generators, within their respective jurisdictions. If the words 'total cost' are to be read in light of the meaning given to them in the licence, the final sentence of the extract reproduced above is manifestly incorrect.

[17] SEM/12/089 at 8.

Where the consultation paper attempts to distinguish between the gas capacity costs applicable to different generators by reference to their running profile and equate this to the concept of benefit foregone, such an approach, with respect to generator's bids, must be considered to be materially wrong. The opportunity cost of all cost items in generator's bids is based on the expressed methodology in the BCoP.

The consultation paper also addresses the availability of secondary capacity in RoI and would appear to suggest that the availability of such a market could vary the cost of annual capacity for generators. While the rationale for including such a discussion in the paper is somewhat unclear, as it would not appear to fall neatly within the recognised licence and BCoP framework, there are a number of other fundamental shortcomings in relation to secondary capacity products in the context of this consultation. It has been clearly stated that such products are unsuitable as a substitute for primary capacity product and such products are recognised to present significant problems for the operation of the SEM market power mitigation strategy.

Primary and secondary gas capacity

Following on from the previous discussion, the consultation paper appears to consider primary and secondary gas capacity products to be freely interchangeable for the purpose of considering the type of gas capacity products generators may include in their COD. Having provided a brief discussion of the differences between the products in the consultation paper (page 5), the paper then is silent on the significant difference between firm and interruptible products, and the significant potential impacts of this on the operation of gas fired generators in the SEM. Such an omission is a fundamental issue and is one that is addressed in Section 5. For the purposes of this section, it is sufficient to conclude that there are considered, both by the CER and industry, to be significant differences between primary and secondary products such that they are not substitutes, particularly for the purpose of electricity generation in the centrally dispatched, gross mandatory pool market of the SEM.

Value of the benefit foregone

Although related to previous discussions, it is fundamentally wrong to assert that generators are to reflect some subjective concept of the value of benefit foregone (paragraph 7 of the BCoP) in their application of the BCoP (page 10). The BCoP outlines a clear methodological approach to valuing benefit foregone (paragraph 8) and this concept is not, contrary to some arguments that appear to be advanced in the consultation paper, to be read in any way other than to qualify the statement in paragraph 7 as to how benefit foregone is to be incorporated into generators bids.

Attributing value to primary capacity

The discussion of this issue in the consultation paper (page 10), exhibits a clear misunderstanding of the relevant provision of the BCoP, such that the argument advanced by the SEM Committee is fatally flawed. This criticism relates to the following statement; "Because regulated capacity can only be bought but not sold, the SEM Committee do not consider there to be a recognised and generally accessible trading market in regulated capacity."

On proper and careful consideration of the BCoP one finds that the requirement in paragraph 8(1)(a) is for "*costs the relevant generator would incur in offering that cost-item for sale, **<u>or</u>** acquiring that cost-item, on a recognised and generally accessible trading market*". [emphasis added] Therefore, as only one of either of these is required, it does not preclude the primary market from being a recognised and generally accessible trading market. Absent a definition of what constitutes a recognised and generally accessible trading market, it would appear that the provision in paragraph 8(1)(a), along with the characteristics of the primary gas capacity market (recognised and generally accessible), must lead one to accept, on the basis of the ordinary and natural meaning of these words, that the primary gas capacity market is such a market under the BCoP. It cannot, for example, be reasonably suggested that an auction or the market for CfDs in Ireland (where there is generally only a single seller) are not recognised and generally accessible markets. Neither the generally accepted concept of a market nor the BCoP require that goods can be both bought and sold by a participant before such markets can be considered to be recognised and generally accessible markets.

Notwithstanding this contention, and complementary to the discussion on the applicability of this requirement to generators in Northern Ireland, it would seem to require a somewhat implausible argument to deny the universality of the following statement contained in the consultation paper.

> "*Assuming that there is no recognised and generally accessible trading market in regulated capacity then, by reference to paragraph 8(ii), it would be the replacement cost that should apply. This would appear to be the regulated price for regulated capacity*."[18]

Therefore, regardless of the approach taken, the appropriate price is the regulated price of daily capacity.

Perverse incentives

References to potentially perverse incentives in the consultation paper (page 11) are due in their entirety to the fundamental defects in argument and interpretation already considered within this section. A perverse reading and application of the requirements on generators pursuant to the licence and BCoP, brings about potentially perverse outcomes. If objectively read and acknowledging the separate issue of the pricing of short term tariffs, adherence to the correct reading of the licence and BCoP will prevent such perverse incentives from materialising.

[18] SEM/12/089 at 10.

Capacity Payment Mechanism

As part of the discussion on the Capacity Payment Mechanism (CPM) the SEM Committee advance a tentative argument reproduced in the following section;

> "*Therefore, although the BNE is not a dual-fuel plant, the cost of annual gas transportation capacity was considered within the calculation of the CPM. It could therefore be argued that generators would be getting remunerated for the cost of gas transportation capacity twice if they were also required to include the cost of short-term capacity within their Commercial Offer Data*."[19]

The matter of double-recovery is an important one and must be addressed. Gas capacity costs are correctly included in the cost of BNE calculation for the gas fired dual-fuel plant technology type at present as a fixed cost. With gas capacity costs included in the COD of generators, gas capacity ceases to be part of the fixed costs of the dual-fuel unit and would no longer be included in the BNE calculation for these units. Should, in future, this unit be selected as the BNE, on a cost-minimisation basis, capacity payments would not recover the fixed costs of gas capacity. If, on the same basis, the distillate unit continues to be selected as the BNE, the CPM will not have a gas capacity element in the calculation and gas-fired generators will, analogous to the previous example, recover the cost of gas transportation capacity through their COD.

Notwithstanding this issue, generators are required under licence to include all costs relevant to generating on a trading day. In accordance with this requirement, there can be no argument that costs required to be include in a generator's COD should be recovered either through CPM or Infra-marginal Rent (IMR).

On the question in the consultation paper as to whether, having permitted the inclusion of gas capacity costs, the SEM Committee may wish to revisit the BNE calculation for selection of the lowest cost unit, we believe that such a review would have significant negative impact on the perception of regulatory risk in the SEM. Having decided a multiannual approach BNE earlier this year, an approach generally welcomed by investors and market participants, and ultimately to the benefit of customers, the perceived costs of intervention must be balanced against the magnitude of such a change. Based on the recent decision paper (CER/12/078), the materiality of such a change is negligible.

5. Previous SEM Committee & RA Decision Papers

It must be recognised as part of this consultation that the issues for consideration do not arise in isolation and that there is existing regulatory decisions that must be considered as part of this process. It is important that the RAs are consistent in their approach and application of the market rules, once properly interpreted. Any contradiction of previous decisions, unless shown to be illegal, or any failure to consistently apply the principles of previous decisions would have serious implications for regulatory risk and may be construed as the exercise of regulatory

[19] SEM/12/089 at 12.

discretion, a power considered to be unavailable to the SEM Committee and RAs in matters such as this.

Bidding Code of Practice – Decision Paper (AIP/SEM/07/430)

Having already discussed in some detail the relevant provisions of the BCoP this discussion briefly addresses the genesis of the document where the matter of gas capacity costs were explicitly addressed. The concluding views of the RAs with respect to this issue are given here;

> "*Without the ability to buy or sell gas transportation capacity for a trading day, as is the case currently in Ireland, payments for capacity on gas transportation networks are best understood as (semi) fixed costs. This means that, to meet licence conditions applying both in Northern Ireland and the Republic of Ireland, such costs should not be reflected in price bids submitted to the Market Operator. This means that the fixed costs of gas transportation would be recovered through either the CPM or the energy market through infra-marginal rents or both.*
>
> *The Regulatory Authorities are conscious that the trading of gas capacity is currently undergoing change, not least due to EC Directive compliance. As gas transportation capacity markets develop, costs which are currently incurred on an annual or monthly basis may become capable of being traded in such a way that allows them to be reflected in bids.*"[20]

Notwithstanding the validity, or otherwise, in light of market developments in the year this document was produced, of the RA's claim that gas transportation capacity could not be bought or sold with respect to a trading day, it is this argument specifically that has prohibited the inclusion of gas transportation capacity costs in generators COD. Clearly within this document the RAs foresaw the introduction of daily gas capacity products and indicated the possibility that such a development may allow such costs to be reflected in bids. It is a shortcoming of the regulatory process that such a review has not taken place to date although some discussion of the issue has been contained in successive annual BNE calculation consultation and decision papers (see SEM-11-025). Fundamentally, these papers have not addressed the issue of primary gas capacity, as was foreseen in the BCoP decision paper, rendering this review long overdue.

Short Term Products – Decision Paper (CER/10/166)

As is discussed in this response as well as in the consultation paper, both primary and secondary daily gas capacity may be available in RoI, with only primary daily capacity available in NI. The important distinction between primary and secondary capacity products is that primary products are firm and secondary products are, typically, interruptible. The importance of firmness cannot be overstated in the context of gas-fired electricity generation in the SEM where generators are required to make firm bids to the market operator. This difference has been expressly recognised by the CER.

[20] AIP-SEM-07-430 at 5.

"*The CER does not consider that the comparison of secondary and short term capacity constitutes a constructive assessment. It should also be noted that the current price of secondary capacity does not, in our view, reflect the very low probability of interruption. It is not intended that the cost of short term capacity will ever align with that of secondary capacity and short term capacity products should not be interpreted as a simple substitute for existing secondary capacity. The CER is of the view that the cost of short term capacity should be examined in the context of firm annual capacity.*"[21]

It is clear and without qualification from this recent CER decision paper that the relevant comparator for an annual gas capacity product is the short term product and that importantly, secondary capacity "should not be interpreted as a simple substitute".

Treatment of Carbon – Decision Paper (SEM/08/032)

In considering the treatment of carbon, specifically bidding the opportunity cost of EU carbon allowances, the SEM Committee determined that these costs should be included in accordance with the licence and BCoP requirements equating to their market price, despite a proportion of credits were made available at zero cost. The SEM Committee's rationale for this decision is provided here.

"*In the light of the various responses to the Consultation Paper on the Bidding the Opportunity Cost of Carbon, the SEM Committee has decided against allowing greater flexibility in the bidding of carbon.*

The SEM Committee is persuaded by those responses that such a step at this stage of the SEM would:

- *create regulatory risk;*
- *raise the cost of capital and harm investment, particularly in clean technologies and renewable sources of generation;*
- *distort market price signals;*
- *inhibit efficient entry/exit decisions;*
- *make the monitoring of the SEM more difficult; and*
- *diminish the effectiveness of the bidding principles as a market power mitigation tool.*

The SEM Committee concludes that the disadvantage of regulatory action outweigh the advantages."[22]

In respect of some of the discussion contained in the current consultation paper, similar issues arise around flexibility for generators in including the cost of gas capacity in their bids. There have been no developments in the intervening period that would suggest that the SEM Committee should deviate from this previously held position. This position is reinforced by the findings of SEM Committee decision and the report of their consultants (CEPA) discussed below.

[21] CER/10/166 at 7.
[22] SEM/08/32 at 6.

SEM Market Power and Liquidity – Decision Paper (SEM/12/002)

Earlier this year the SEM Committee, supported by the findings of CEPA in a detailed report on market power in the SEM (SEM/10/084a), endorsed the findings of the CEPA report and the current approach to market power mitigation in the SEM. The view that the current approach, (i.e. MMU, BCoP and DCs), should be retained as important and central features of market power mitigation in the SEM was shared by many industry respondents. The SEM Committee concluded that;

> *"In view of the effectiveness of the BCoP, MMU and DCs to date in the SEM, and given current and predicted SEM spot market power levels, the SEM Committee will maintain a robust market power mitigation strategy through these instruments for the foreseeable future. The SEM Committee would review these market power mitigation measures in the future if the spot market became significantly less concentrated."*[23]

Consistent with the views expressed in the CEPA report, the SEM Committee accepted the need to ensure the current approach to market power mitigation should continue unchanged in light of the market structure of the SEM. It would therefore appear to be outside the scope of this current consultation to consider relaxing the importance of the BCoP and MMU.

In summary, recent decision papers from the SEM Committee and RAs have;

- Foreseen the introduction of daily capacity products and the implications for the SEM as far back as 2007 which suggests that this current review is long overdue.
- Found there to be significant differences between primary and secondary short term gas capacity products such that they could not be considered to be substitutes. The relevant comparator for short term primary capacity is annual capacity.
- The market power issues in the SEM require continued, unaltered adherence to the market power mitigation strategy (i.e. BCoP, MMU and DCs). The SEM would require significant structural change before consideration be given to the relaxation of any of these instruments of market power mitigation.

6. Treatment of Gas Capacity Costs in the SEM

Having considered the relevant governing documents, their correct legal interpretation, perceived shortcomings of the consultation paper and recent regulatory decisions, the remainder of this response focuses on the two central questions posed in the consultation paper, specifically;

(i) Is gas transportation capacity a SRMC as defined by the generator licence?

If the answer to this is yes, then;

(ii) What is its Opportunity Cost?

[23] SEM/12/002 at 11.

It seems clear that under any normal interpretation of the license that the introduction of daily gas transportation capacity products made gas capacity a cost of generation, capable of being valued under the methodology provided for in the BCoP. Arguably, with respect to the decision of the Supreme Court and the totality of costs to be recovered, provision for gas capacity costs possibly should have been considered prior to the introduction of such costs. Nevertheless, the availability of daily gas capacity products that are firm and that have a transparent, regulated price make the inclusion of such costs a necessary and trivial exercise for generators.

Notwithstanding the overall conclusion of the previous paragraph, there are three specific issues that provide further clarity in support of the overall conclusion.

1. It is not and never has been the intention of the relevant provisions of the Licence and/or BCoP to reflect the trading behaviour of generators in the market. Instead these documents ensure that generators' COD is cost-reflective of their SRMC by reference to the opportunity cost of the relevant cost-items on a trading day. As such it is the availability of a within day product and not the use of it by generators that provides a basis for its legitimate and required inclusion in a generator's COD.[24]
2. Accepting there are differences in the cost of primary daily gas capacity in RoI and NI, such a situation is not new and cannot legally form a basis for excluding such costs. It is not and has never been the intention of either the Licence or BCoP to only allow costs in the instance that they are common across both jurisdictions. In order for generators to comply with both the Licence and BCoP, it is imperative that they do so in a manner that is cost reflective to the generation unit(s).
3. Finally, should the SEMC consider that there is not a recognised and generally accessible trading market in daily gas capacity products, the BCoP contains further provisions such that one would determine the replacement cost of purchasing daily gas transportation capacity as the relevant Opportunity Cost to be included in a generator's COD. In this instance, the cost is unchanged and is equal to the regulated price of daily gas transportation capacity as set by the competent regulator.

It is therefore Energia's contention that all generators must reflect in their COD the cost of primary gas transportation capacity, the opportunity cost of which is to equal the regulated cost of firm daily capacity from the transporter.

In conclusion, it is considered important to reiterate a number of other points of direct relevance to the consultation;

- In approaching this issue, one must recognise the primacy of the licence.
- Generators are obliged under licence to recover all costs of generating, as defined by SRMC.
- With respect to express licence conditions, there is no scope for discretion to be exercised by the SEM Committee or the RAs.

[24] See the discussion on Commercial decisions and licence requirements in Section 4 of this response.

- The BCoP cannot derogate from the express conditions of the licence (i.e. cost reflectivity).
- There is no day-ahead requirement contained within either the licence or BCoP that could prevent Northern Ireland generators from including the cost of daily gas capacity in their bids. In fact, the licence obligation requires them to include such costs.
- The licence and BCoP are constructed in such a way as to prevent commercial positions (either positive or negative) from affecting bids. Consideration of this matter is outside the scope of this consultation.
- The relevant comparator for an annual gas capacity product is recognised by the CER to be primary (firm) daily capacity. Secondary capacity should not be seen as a simple substitute.
- The relevant product is therefore the daily capacity product. The (regulated) price of this product and the associated impact on wholesale market prices is outside the scope of this consultation.
- The capacity payment mechanism is appropriately designed to prevent double-recovery of costs. In the context of the BNE approach adopted this year (multiannual), the expected adverse impact of regulatory change on the perception of regulatory risk around the BNE is considered to outweigh all other impacts which are expected to be negligible.
- The importance of the current market power mitigation approach in the SEM has recently been confirmed by the SEM Committee and external independent consultants. There is no basis for deviating from this approach or relaxing its application.
- By prohibiting the recovery of gas transportation capacity costs, the SEM Committee has created a distortion in the market that discriminates against gas fired generators in the application of the licence condition requirement ensuring cost recovery. From a legal and regulatory perspective, this must now be addressed.

7. Consultation Questions

In response to the request for comments in the final section of the consultation paper to the following specific issue, summary comments are provided to assist with the task of reviewing the response.

1. ***Has there been sufficient development in the trading of gas transportation capacity since the publication of the Bidding Code of Practice to allow the cost of such to be included in Commercial Offer Data? If so, why? Is this situation different between Northern Ireland and RoI?***

Under the correct legal interpretation of the licence, generators have been obliged to include gas capacity costs in their bids, at a minimum, from the date of the introduction of short term (daily) capacity products in compliance with EU requirements. Such products have been in RoI since 2007 and were introduced in NI in 2012. This issue is dealt with in detail in Sections 2, 4, and 6 of this response, with an outline of market developments provided in Section 3.

2. ***Should the cost of gas transportation capacity be included in the Commercial Offer Data of units in Northern Ireland?***

Yes, further to the introduction of primary (daily) gas capacity in NI it should be included on an all-island basis. See response to Question 1 and specifically discussions contained in Sections 2 and 4 of this response.

3. ***Should the cost of gas transportation capacity be included in the Commercial Offer Data of units in the Republic of Ireland? Is there any good cause why the principles within paragraphs 8(i) and 8(ii) of the Bidding Code of Practice should not be applied?***

Yes, this matter is considered to be long overdue and should have been an enforced licence obligation on generators since 2007. In the context of this consultation, there is no good cause or legal basis for departing from the approach specified in paragraphs 8(i) and 8(ii) of the BCoP. It must also be recognised that, on proper legal interpretation of the licence, the BCoP cannot derogate from the requirement of cost reflectivity in the licence and as such, application of such an approach would merely require the determination of an alternative valuation methodology for a correctly identified SRMC. Additionally, with respect to Condition 15 of the licence the Superior Courts have also determined that the RAs have no discretion in the interpretation of costs and as such there is no scope for the promotion of more general regulatory objectives. See specifically Sections 2 and 4 of this response.

4. ***If the cost of gas transportation capacity is to be included in the Commercial Offer Data (of units in the Republic of Ireland) is there a recognised and generally accessible trading market in short-term gas transportation capacity? Is this recognised and generally accessible trading market in secondary capacity or regulated daily capacity?***

Gas transportation capacity must be included in the COD of all gas fired generators. There is a recognised and generally accessible market in regulated daily capacity in RoI and arguably in NI. Even where there is not a recognised and generally accessible market, the replacement cost (paragraph 8(ii)) of regulated daily capacity is equivalent to the price of regulated daily capacity. This outcome could arguably be used as justification for the presence of a recognised and generally accessible market. Specifically see Sections 3, 4 and 5.

There are significant shortcomings with respect to secondary capacity which have been recognised by the CER and the consideration of such a product in this context would appear contrary to wider regulatory policy. Notwithstanding this and the shortcomings of the published data on secondary market trades, it would appear that is market does not exhibit sufficient liquidity in the context of power generation requirements. See specifically Sections 3, 4 and 5.

5. ***If the cost of gas transportation capacity is to be included in the Commercial Offer Data (of units in the Republic of Ireland) and there is no recognised and generally accessible trading market in short-term gas transportation capacity, what is the replacement cost?***

See response to Section 4 and associated discussion contained in the response.

6. ***If the cost of gas transportation capacity is included in the Commercial Offer Data (of units in the Republic of Ireland), should the price of the BNE be recalculated?***

On consideration of the publicly available information with respect to the BNE for 2013, and in light of the change in approach to a multiannual basis to support regulatory certainty, the cost of intervention is likely to far outweigh the negligible effects of any recalculation. See the discussion contained in Section 4.

7. ***Which of the methods outlined in Section 3 is the most appropriate for accounting for the cost of short term gas transportation capacity?***

As all of the methods outlined in the consultation paper are based on a number of irrelevant considerations which, in some instances, are considered to be contrary to licence requirements, we do not endorse any of the methods advanced.

The correct treatment of gas capacity costs in the SEM is for this cost to be included in all gas fired generators bids in the SEM, at the regulated price of firm daily capacity. See the discussion contained in Section 6, with reference to Sections 2, 3, 4 and 5.

8. ***Are there any other methods for valuing gas transportation capacity which have not been included in Section 3?***

See response to Question 7.