Single Electricity Market

Treatment of Gas Transportation Capacity Costs

Consultation Paper

27 September 2012

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CONTENTS

1 INTRODUCTION

Since 1 November 2007 the Northern Ireland Authority for Utility Regulation ("**The Utility Regulator**") and the Commission for Energy Regulation ("**CER**"), together referred to as the Regulatory Authorities ("**RAs**"), have jointly regulated the all-Island wholesale electricity market known as the Single Electricity Market ("**SEM**") covering both Northern Ireland and the Republic of Ireland.

As part of the 2007 Decision Paper on the Bidding Code of Practice (AIP-SEM-07-430)[1], gas transportation capacity costs were explicitly addressed by the Regulatory Authorities, concluding:

> *"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."*

The SEM Committee ("**SEMC**") has received correspondence from a number of parties regarding the inclusion of the cost of short-term gas transportation capacity within Commercial Offer Data.

Chapter 2 of this consultation paper firstly describes the gas transportation capacity market in the Republic of Ireland and Northern Ireland.

Chapter 3 presents some issues for consideration in answering two key questions: **Has the market for gas transportation capacity sufficiently developed since the publication of the Bidding Code of Practice to allow the cost of such to be included in Commercial Offer Data? If so, what should be the Opportunity Cost of such gas transportation capacity?**

[1] http://www.allislandproject.org/en/market-power-decision.aspx?article=7fdc1ef8-3e0e-4267-9b82-0a2c65b1056f

Chapter 4 provides a summary of questions for response.

2 GAS MARKETS IN REPUBLIC OF IRELAND AND NORTHERN IRELAND

Republic of Ireland (ROI)

Short term gas transportation capacity products at interconnection points were mandated through Regulation EC 1775/2005. Short term monthly and daily products were introduced in late 2007 at entry points onto the onshore gas transmission system and at transmission system exit. Within day products were made available in June 2008. Short term products are offered by the transporter and are priced as a percentage of the annual product. Buying capacity on a monthly basis for a whole year would mean paying almost twice as much as buying annual capacity, and almost three times as much if it is bought on a daily basis rather than an annual basis.

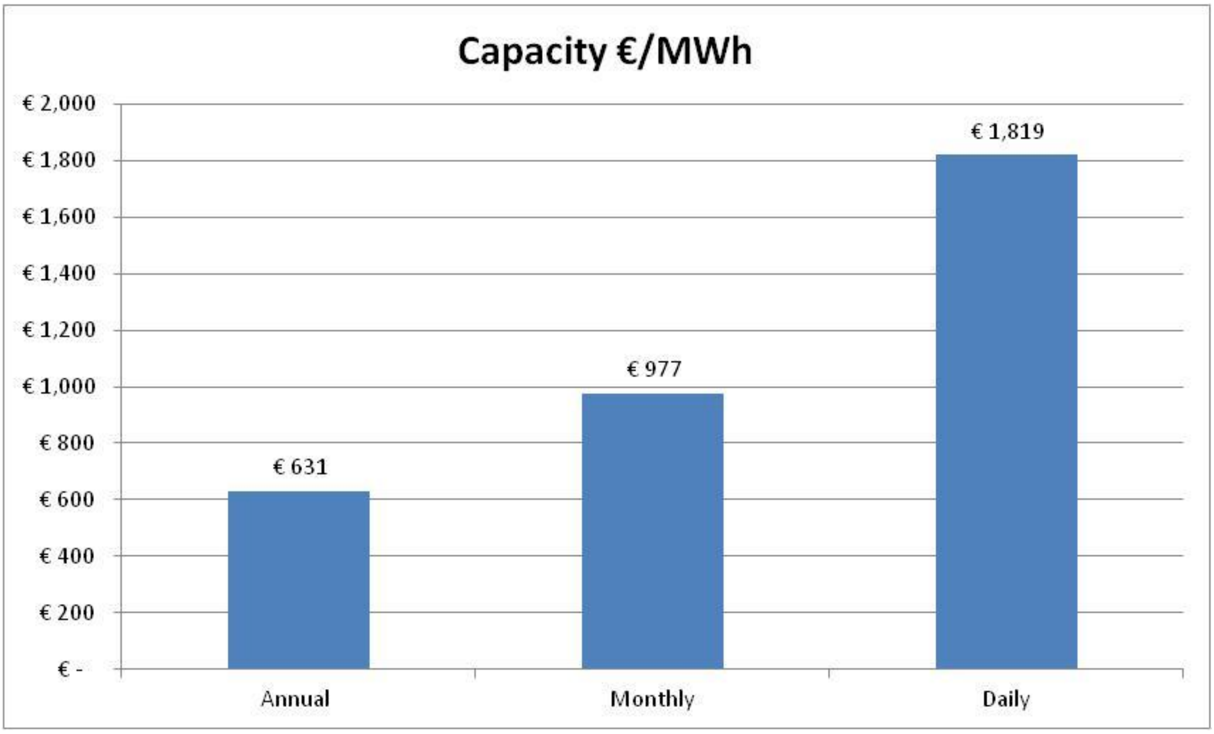

Chart 2.1: *Cost of purchasing one MWh of capacity on an annual basis using three different methods (ROI)*

In addition to regulated short term products, there exists secondary trading for unused firm capacity. There is some regulation of this segment as the CER currently sets a floor price for secondary capacity sales from the Non Daily Metered ("**NDM**") sector. However, there is little transparency of this market other than this floor price set by CER (the RAs do not actually see the settled price for trades). This capacity is interruptible, in that in the sale of this capacity from one shipper to another, it can be called back by the selling shipper. Regulated capacity purchased from Gaslink cannot be called back and is therefore firm.

Northern Ireland

Short term daily gas transportation capacity products have been available in Northern Ireland since 1 July 2012[2]. This daily capacity needs to be purchased at least 12 days in advance of when it is expected to be needed. It is possible that day-ahead daily gas capacity could be offered in future, and the design of these products may be dependent on the outcomes of the Common Arrangements for Gas ("**CAG**")[3] arrangements.

[2] http://www.uregni.gov.uk/news/gas_regulation_infringement_tariff_decision_paper_and_license_modifications

[3] http://www.allislandproject.org/en/cag_overview.aspx

3 CONSIDERATIONS

3.1 HAS THERE BEEN SUFFICIENT DEVELOPMENT OF THE GAS TRANSPORTATION CAPACITY MARKET TO ALLOW COSTS TO BE INCLUDED IN BIDS?

The Cost-Reflective Bidding in the Single Electricity Market Condition in generators' licences requires generators to submit Commercial Offer Data equal to the Short Run Marginal Cost ("**SRMC**"), which is to be calculated as follows:

> *(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 be either a negative or a positive number.*

While there does now exist the ability to buy or sell gas transportation capacity for a trading day, it is important to bear in mind that this ability varies between RoI and Northern Ireland.

In RoI, regulated short term gas capacity products have been available since late 2007, and there is a semi-regulated secondary market for unused firm capacity.

In Northern Ireland, regulated short term daily gas capacity products are now available. However, these cannot be purchased on a day-ahead basis and need to be purchased at least 12 days in advance. It is therefore difficult to argue that the cost of such capacity would be seen as forming part of SRMC when Northern Ireland generators were formulating their day-ahead Commercial Offer Data. This situation may change with the introduction of CAG, bringing with it harmonised products, or if more products are developed in Northern Ireland in line with IME3. However, there is no certainty of this happening, what these products would be, or if there will be secondary products available.

It is proposed that, irrespective of whatever costs are permitted within the Commercial Offers of units based in RoI, no allowance should be permitted within Commercial Offers for units based in Northern Ireland. *However, views and opinions on the inclusion of the cost of gas transportation capacity in the Commercial Offer Data of units in Northern Ireland are welcomed within consultation responses.*

For this reason, the proposals below only consider the inclusion in Commercial Offer Data of the cost of short term gas transportation capacity in RoI.

Without the availability of short-term products, gas transportation capacity would have to be purchased on an annual basis for all units. There would be no opportunity to buy or sell it on a short-term basis and the cost would be classed as fixed. The total cost faced by the generator would be the same irrespective of whether or not the unit was operating on any particular day.

However, the availability of short-term capacity products now means that it is not necessary to purchase annual capacity; monthly or daily products can be purchased as and when they are needed. Some participants may even choose to buy annual capacity for part of their load, and 'top-up' the remainder of their load with short-term capacity.

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.

Furthermore, the availability of secondary capacity in RoI, whereby participants can buy and sell unused firm capacity, means that even for a generator (whose generation unit is based in RoI) who holds long-term gas transportation capacity, the cost faced by the generator is not the same irrespective of whether or not the unit is operating on any particular day; if the unit does not operate, it may be able to sell its unused capacity.

The SEM Committee is therefore consulting on whether it should adjust its position (in view of the development in the market for short term gas transportation capacity in RoI) so as to allow the costs of such capacity to be included in Commercial Offer Data.

The SEM Committee would welcome views and opinions of consultees on the inclusion of the cost of short term gas transportation capacity within Commercial Offer Data. Has there been sufficient development of the gas transportation capacity market to allow costs to be included in bids?

3.2 IF GAS TRANSPORTATION CAPACITY IS TO BE INCLUDED IN SRMC, WHAT IS THE OPPORTUNITY COST?

The section above has described the different types of product available and their relationship to short run marginal cost. This section asks the question: *"If there has been sufficient development in the trading of gas transportation capacity and the costs of such are to be classified as Short Run Marginal Cost, what is the Opportunity Cost that should be included in Commercial Offer Data?"* To analyse this, the 'bidding in' of the regulated capacity and secondary capacity has been assessed against the generation licence and the Bidding Code of Practice.

Bidding Code of Practice (BCoP)

The Bidding Code of Practice states that when calculating the Short-Run Marginal Cost, constituent cost-items are to be valued at their Opportunity Cost. The Opportunity Cost of any cost-item shall comprise the benefit foregone by a generator in employing that cost-item for the purposes of electricity generation.

The relevant paragraphs of the BCoP are highlighted below:

> *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;*

Subject to the SEM Committee deciding to disapply the principles in paragraphs 8(i) and 8(ii) if it is satisfied that there is good cause to do so in this situation, these principles require the following logical approach.

For baseload units and mid-merit plants with high capacity factors, it should still be more economic to purchase annual or monthly capacity rather than purchase short term daily capacity. Where such generators are in a position, in respect of a trading day, to dispose of such longer-term capacity (in the form of a tranche of non-firm or secondary capacity for that trading day) rather than using it to generate electricity, the value of the benefit foregone by such generators in generating electricity on that trading day would appear to correspond to that of the relevant tranche of secondary capacity.

However, for peakers and some mid-merit units it may be more economic to purchase capacity as and when it is needed, rather than purchasing annual or monthly capacity. Such generators may have a choice between acquiring firm regulated capacity or acquiring non-firm secondary capacity for a trading day. The value of the benefit foregone by such generators in generating on that day may therefore correspond to that of the relevant tranche of regulated or secondary capacity.

Attributing a Value to Primary Capacity

Firstly, considering the value to be attributed to regulated capacity for this purpose, if it can be established that a recognised and generally accessible trading market exists for this cost item within the meaning of paragraph 8(i), it would be this that should be used as a basis for calculating Opportunity Cost. 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. *However, views are welcome on this within consultation responses.*

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.

Attributing a Value to Secondary Capacity

Secondly, considering the value to be attributed to secondary capacity for this purpose, if there is a recognised and generally accessible market for secondary capacity then, applying paragraph 8(i), the market price of this capacity would be the most appropriate to reference when constructing Commercial Offer Data.

However, if secondary capacity is not traded on a recognised and generally accessible trading market then, by reference to paragraph 8(ii), it would be the replacement cost of such capacity that should apply.

A recent data gathering exercise by the RAs has demonstrated that the availability of secondary capacity appears to be high and there is a significant amount of capacity traded in this manner.

However, there is little transparency of the trading of this capacity, apart from the floor price set by CER; the actual price at which secondary capacity trades between generators is not generally visible to the RAs. This would make it difficult for the SEM Committee's Market Monitoring Unit ("**MMU**") to assess the 'bidding in' of the cost of secondary capacity.

Therefore, the price that is bid in could be either:

- The sale price, where that price can be justified by referencing prices at which secondary sales have recently taken place;
- The floor price, if no sales have taken place.

Views are welcomed on:

- *Is there a recognised and generally accessible trading market in secondary capacity?*
- *If so, how should the market price of secondary capacity be determined?*
- *If not, how should the replacement cost of secondary capacity be determined?*

Risks Associated with Choice of Capacity Products

Should generators who have purchased longer-term capacity have the choice of purchasing the regulated daily capacity product or the daily secondary capacity product, there is a risk of a perverse incentive on such generators to purchase the daily product, simply because of its ability to be included in Commercial Offer Data. This would be a particular concern for generators in a position to exercise market power.

There is also a risk that, in any event, different generators would possibly bid in different costs for gas transportation capacity. Some would include the cost of the regulated primary product, whilst others would include the cost of the secondary product. This option may also allow for competitive behaviour between generators, however, it would be complicated to monitor and could reduce transparency in the SEM.

Views are welcomed on:

- *Is there a risk of a perverse incentive of the sort identified above?*
- *Is there also a risk associated with complication and lack of transparency as identified above?*
- *If so, how (if at all) should the SEM Committee exercise its discretion to disapply the principles in paragraphs 8(i) and 8(ii) to tackle such a risk?*

It is important to be cognisant of the fact that paragraph 8 of the Bidding Code of Practice states that the principles within paragraphs 8(i) and 8(ii) will apply unless it can be demonstrated to the RAs that there is good cause not to. *The SEM Committee therefore feels it is important to ask, irrespective of the answers to the questions above, if there is any good cause why the principles within paragraphs 8(i) and 8(ii) of the Bidding Code of Practice should not be applied.*

3.3 CAPACITY PAYMENTS MECHANISM

The inclusion of the cost of short term gas transportation capacity in Commercial Offer Data may have implications for the Capacity Payments Mechanism; the cost of gas transportation has already been considered within the cost of a Best New Entrant when calculating the Annual Capacity Payment Sum.

The Best New Entrant ("**BNE**") for the 2013 to 2015 Annual Capacity Payment Sums is a distillate plant located in Northern Ireland[4]. As part of the calculation of the BNE the cost of locating it in RoI and running it as a dual-fuel plant were also calculated. Within this calculation, the annual cost of gas transportation capacity was considered.

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.

If the BNE was changed in the future to running on gas then, in accordance with the existing position that gas transportation capacity costs should be excluded from Commercial Offer Data, the calculation of its costs would include the cost of annual gas transportation capacity.

[4] http://www.allislandproject.org/en/cp_decision_documents.aspx?article=75c548a7-34ee-497c-afd2-62f8aa0062df

In fact, it could be argued that those units which purchase short-term capacity instead of long-term capacity are actually benefitting; the CPM is recompensing them for the cost of annual capacity, yet they are purchasing shorter term capacity as and when they need it.

The Decision Paper on the CPM Medium Term Review[5] states that the BNE will remain constant for three years. However, the inclusion of the cost of short term gas transportation capacity could be classified as a material change to the Single Electricity Market, and may warrant re-opening the calculation of the BNE Peaker.

If the cost of short-term gas transportation capacity is required to be included within Commercial Offer Data (in RoI), should the price of the BNE be recalculated?

3.4 POTENTIAL METHODOLOGY FOR INCLUSION OF GAS TRANSPORTATION COSTS WITHIN COMMERCIAL OFFER DATA

Depending on the answers to the questions above, there are a number of ways that the cost of short term gas transportation capacity could be included within Commercial Offer Data:

Method 1

If there is a recognised and generally accessible trading market in for a transportation capacity type, it would be the market price of this capacity which should be included in Commercial Offer Data.

Method 2

If there is not a recognised and generally accessible trading market in a gas transportation capacity type, the replacement cost of gas transportation capacity should be included in Commercial Offer Data. The cost to be included in Commercial Offer Data would depend on whether the replacement cost was that for secondary capacity or regulated capacity.

If the replacement cost is deemed to be the price of secondary capacity, it could be included in Commercial Offer Data as either the sale price or the floor price.

If the replacement cost is deemed to be the price of regulated capacity, this may not be a cost to all market participants. There are generators for who it would not be economic to purchase regulated daily capacity and therefore this should not be a cost to them.

[5] http://www.allislandproject.org/en/cp_decision_documents.aspx?article=5ce2db5f-6c79-4454-9779-53dd7fae8dba

Method 3

If it is accepted that gas transportation costs may have an opportunity cost to some generators in the SEM, it could be left to individual participants to determine the most appropriate method for its inclusion. The MMU would assess each set of Commercial Offer Data to determine if they were reasonable and cost reflective.

With this option, different generators would possibly bid in different costs for gas transportation capacity. Some would include the cost of the regulated product; others would include the cost of the secondary product, while others who purchased long term capacity may not be including any costs. This option may also allow for competitive behaviour between generators, however, it would be complicated to monitor and could reduce transparency in the SEM.

4 RESPONSES

The consultation period shall be four weeks. Responses to this paper should be submitted, preferably in electronic format, by 5pm on 26 October 2012 to:

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Utility Regulator
Queens House
14 Queen Street
Belfast
BT1 6ED

kenny.dane@uregni.gov.uk

Although the RAs welcome comments on all aspects of this consultation paper, comments would be particularly welcome on the following areas:

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?

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

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?

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?

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?

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?

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

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

Where possible, please provide as much evidence and justification for your comments as possible.

Unless marked confidential, all responses will be published by placing them on the AIP website at the following address http://www.allislandproject.org/.

Respondents may request that any or all of their response is kept confidential. The RAs shall respect this request, subject to any obligations to disclose information. Respondents who wish to have their responses remain confidential should clearly mark the document(s) to that effect and include the reasons for confidentiality.