TREATMENT OF GAS TRANSPORTATION CAPACITY COSTS IN COMMERCIAL OFFER DATA

A report to the Utility Regulator and the Commission for Energy Regulation

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TABLE OF CONTENTS

EXECUTIVE SUMMARY

Introduction

This report considers the treatment of gas transportation capacity charges for the purposes of submitting Commercial Offer Data (COD) within the SEM.

This report is written for the Regulatory Authorities (RAs) but contains Pöyry's independent views which are not necessarily those of the RAs. The role of the RAs throughout the project has been to provide information on the nature of gas trading and also to question the clarity of the ideas as we have developed them, but not to influence the direction of the findings in a meaningful way.

Our interpretation of the legal intent of the existing provisions within the generator licence and the Bidding Code of Practice (BCOP) is informed by careful reading of the relevant documents in the light of our experience of legal matters, but we wish to clarify that we are not qualified to make legal interpretations and that our views should be subjected to legal opinion in the event that the RAs choose to act on our advice.

We consider the following issues:

- the underlying economics of how gas network capacity should be valued in both the short- and long-term;
- the existing purchasing arrangements for gas capacity (including potential future changes); and
- the existing provisions which govern the submission of COD ('bidding') of gas capacity within the generator licence and the BCOP.

From the above, we have sought to assess how generators are required to reflect the cost of gas capacity in their COD in order to comply with their licence obligations. We have further sought to assess how, under this interpretation, the outcomes correspond to the underlying economics.

It is important to distinguish between the short-run marginal cost (SRMC) associated with gas capacity from an electricity and gas **system perspective** based on underlying economics (which we believe to be zero in most situations) and the SRMC from a **generator's perspective** based on the definition in the generation licence (which we believe may be non-zero in some cases under the current arrangements).

We have outlined options available for change should the RAs wish to improve the alignment between the bidding of gas capacity transportation costs and the underlying economics. If the RAs choose to act on any of our advice, any actions would need to follow the due regulatory process for change.

Underlying economics

Short-run economics

Our analysis of the underlying economics is that the marginal cost of providing gas network capacity in timeframes which correspond to the submission of COD is generally either zero (in cases when there is adequate gas capacity) or a high cost (related to the benefit foregone in cases where there is a shortage of capacity). Under most foreseeable circumstances, we do not expect gas network capacity to be inadequate in the coming years.

On the basis of this analysis, we conclude that in the near term, the inclusion of gas capacity as a marginal cost in COD would not be economically optimal from the perspective of the wider gas and electricity system. Such inclusion would risk distorting generation scheduling and dispatch (in terms of switching between gas and other fuels and also between gas-fired generators) and also risks distorting (inflating) the market prices and constraint costs, leading to deadweight loss to (the extent that demand is sensitive to the resultant prices), and also leading to transfers of wealth from consumers to producers in a way which cannot be justified by the underlying system economics.

At times when there is a shortage of gas capacity, we believe that there is economic justification for including a non-zero marginal cost of gas capacity into COD.

Long-run economics

In the long-term, new gas network capacity and new generation capacity may be required. Despite this, we believe that longer term fixed costs should not be included in COD (which is intended to cover SRMC), and further that there is no need for the fixed costs of technologies other than the best new entrant to be included in capacity payments. Investors who choose technologies with higher fixed costs than the best new entrant are free to do so to the extent that they hold an expectation that the additional outlay will be balanced by higher levels of operation and infra-marginal rent. The inclusion of these additional fixed costs explicitly within the COD and/or the capacity payments would distort investment decisions.

Existing procurement arrangements for gas capacity

Various alternatives for the procurement of gas capacity exist for generators in the SEM:

- buying daily capacity from the gas TSO (short-term ‘primary capacity’); or
- buying monthly or annual capacity from the gas TSO (long-term ‘primary capacity’); or
- buying entry and/or exit capacity from another market participant (‘secondary capacity’); or
- buying gas at the Irish Balancing Point (IBP) in ROI, which means that gas is effectively purchased on an ‘entry capacity paid’ basis

In the Republic of Ireland (ROI), gas generators rely on a combination of the longer-term and shorter-term products purchased from the gas TSO. There is some secondary activity, notably through transfers of exit capacity from the non-daily metered (NDM) sector; which is obliged to be purchased to cover a 1-in-50 year rule and so is systematically in surplus.

In Northern Ireland (NI), gas generators buy their gas capacity through long-term products only and the short-term capacity product (which requires 12 business days’ notice) is not generally used.

An Irish Balancing Point (IBP) exists in ROI for the trading of gas, but is not generally well used for the procurement of gas by ROI generators.

We note that the arrangements for both entry and exit capacity are subject to change. Two factors that may drive future change are the draft EU Capacity Allocation Mechanism (CAM) network code and the Common Arrangements for Gas project. We have not pre-supposed the outcomes to these changes.

Comparison of procurement arrangements and underlying economics

Figure 1 summarises our view of the economic value associated with gas capacity in the timeframe to which COD submissions relate, covering potential circumstances in which there is either a shortage of gas capacity or no shortage of gas capacity, and with and without a functioning IBP market.

Figure 1 – Summary of economic value of gas capacity in COD timeframes

Current		
	Entry	**Exit**
Capacity shortfall	Benefit foregone as a result of shortfall	Benefit foregone as a result of shortfall
No capacity shortfall	Zero	Zero

With a functioning IBP		
	Entry	**Exit**
Capacity shortfall	IBP	Benefit foregone as a result of shortfall
No capacity shortfall	IBP	Zero

We note that the 2012 Joint Gas Capacity Statement states that in the absence of Inch storage, there may be a capacity shortfall at the Moffat entry point during a 1-in-50 peak day (but not an average year peak day) in 2014/15. We have not considered whether or how a non-zero gas capacity cost should be reflected in the case of such a capacity shortfall. We note that a such capacity shortfall has is a very low probability of occurring in the next five years and so the costs of implementing a methodology for including a non-zero gas capacity cost for such a small number of days may outweigh the benefit of doing so.

We believe it is reasonable to assume that the economic value of gas capacity in the COD timeframes will be zero in the vast majority of days in the next five years.

Primary capacity products

The existence and pricing of monthly and daily products relate to wider regulatory obligations and in particular the conflict between the EU requirement for entry capacity to be available in the form of short term products available close to real time, and the requirement that the gas network costs (which are based on long run investment decisions) should be recovered from users of the system in a fair and stable way which does not lead to instability in the charging. This is essentially a trade-off between the long term economics of natural monopoly and the short term economics of sunk costs.

Secondary capacity products

Secondary capacity products are based on arbitrage between the regulated prices and quantity requirements for annual products and the regulated prices for monthly and daily products. We therefore believe that the secondary markets are generally unlikely to provide true signals of the economic value of gas capacity.

To the extent that a robust secondary market for gas capacity develops then, from the perspective of the generator, the cost of gas capacity could be considered a marginal cost. However from the perspective of the system as a whole, this marginal cost is unlikely to reflect the underlying economic value of gas capacity (which we believe is zero under most foreseeable circumstances in the coming years).

Representation of current short-term primary capacity products

We believe that a truly competitive electricity market without bidding rules would not lead to the inclusion of gas capacity at the price of the daily product as a short-run marginal cost (SRMC), because generators (or other gas shippers) would be able to deploy alternative capacity purchasing strategies and would compete to minimise the effective cost of gas capacity, while considering the impact of their gas capacity purchasing on their competitive position in electricity production.

Analysis of current market rules

Although the economic value of gas capacity in COD timeframes may be zero from a **system** viewpoint, the existence of secondary capacity and primary daily capacity may create a non-zero SRMC for an **individual generator**.

We have analysed the generation licence and BCOP in order to determine how generators are required to reflect the cost of gas capacity in their COD under different circumstances. It should be noted that we are not qualified to make legal interpretations and that our views should be subjected to legal opinion in the event that the RAs choose to act on our advice.

Calculating opportunity cost

The BCOP states that the opportunity cost of any cost-item shall comprise the value of the benefit foregone by a generator in employing that cost-item and should be calculated in the following way:

- If there is a R&GA market in the relevant cost-item, the opportunity cost of that item should reflect the prevailing **market price**.
- Where no R&GA market exists then the opportunity cost of that item should reflect the **replacement cost** which would be incurred in replacing that cost-item.

If there was a R&GA market for gas capacity (in the form of a secondary market or alternatively embedded within the IBP) then generators would be required to include the cost (based on the prevailing market price) in their COD. However we believe that neither IBP nor secondary activity can at present be considered R&GA. However, we note that should either the IBP or secondary activity develop in the future, they would be the appropriate reference for a generator's SRMC.

Use of replacement cost

We believe the use of replacement cost is valid for COD cost-items which can be used on a future Trading Day if they are not used on the Trading Day to which the COD refers. In this instance the '*benefit foregone*' is not having the component available for future use. The benefit foregone can be valued using the cost of replacing the cost-item so that its benefit for a future Trading Day can be retained.

We believe that the use of replacement cost to assess the opportunity cost associated with gas capacity which is already held at gate closure is not appropriate due to the time-limited nature of gas capacity (i.e. gas capacity that is not used on a given day cannot be carried forward for use on a future day).

We believe that there is '*good cause*' (as permitted by the BCOP) to use an alternative methodology by referring directly to the generator licence, which we outline below.

Appropriate method for calculating SRMC

The generation licence requires a generator to cost-items in a manner which reflects their SRMC. The generation licence states that the SRMC related to a generation unit in respect of a Trading Day is to be calculated as (some words removed for brevity):

> *the total costs that would be attributable to the … generation unit during that Trading Day if the generation unit were operating to generate electricity during that day;*
>
> ***minus***
>
> *the total costs that would be attributable to the … generation unit during that Trading Day if the generation unit was **not** operating to generate electricity during that day,*

If there is not a R&GA market for gas capacity (which we believe is currently the case), then the opportunity cost depends on whether or not the generator holds gas capacity:

- For generators which **hold** associated gas capacity at gate closure then there is no alternative value that can be realised for that capacity. Therefore the cost of this capacity is the same whether or not the generation unit is scheduled to operate, and the SRMC is zero.
- For generators which **do not hold** gas capacity at gate closure, the relevant difference in cost between generating and not generating is the cost of the primary daily gas capacity product (as long as that product can still be purchased after gate closure).

In summary, we believe the current market rules require gas-fired generators to assign a non-zero SRMC to gas capacity in the case where it is not held at gate closure but could be purchased after gate closure.

To paraphrase, capacity holdings at gate closure are effectively sunk costs (with no resale value) and any purchases after gate closure are a marginal cost. Generators should include gas capacity in their COD only to reflect the expectation that they will need to purchase additional capacity.

Reflecting Schedule Production Cost

The generation licence states that COD is only cost-reflective if the SRMC of a generator over the Trading Day is equal to its Schedule Production Cost.

We note that many generators will hold gas capacity for some, but not all of their potential output for the Trading Day. In this case, the current structure of COD does not facilitate the bidding of gas capacity in such a way that would appropriately reflect the SRMC associated with gas capacity over all possible patterns of scheduled production.

We believe that it is necessary for generators to estimate the expected cost of the additional requirement they have over their long-term holding for the Trading Day and bid as close to this estimated SRMC as possible so as to minimise any expected magnitude of any potential deviation between Schedule Production Cost and SRMC.

Required treatment under current market rules

Northern Ireland

We believe that COD must be cost-reflective at gate closure and not just at the time when it is first able to be submitted.

Gas capacity products in NI must be purchased at least 12 business days prior to use and therefore must be purchased before gate closure. As a result, the cost to a NI generator cannot be variable after this time and so it is not a SRMC at gate closure and so should not be included in COD of NI gas-fired generators.

Republic of Ireland

In ROI, there is the potential to buy primary entry and exit capacity after SEM gate closure. We therefore believe that gas-fired generators should reflect a non-zero SRMC for gas capacity to the extent that it is not held at gate closure and they are still able to purchase daily gas capacity when required.

For generators that do not hold gas capacity at gate closure, but require it on the Trading Day, the cost of the gas capacity is the currently the primary daily product.

In summary, we believe that gas capacity is only a marginal cost for incremental purchases but not for existing capacity holdings (which are effectively a sunk cost).

Gas capacity purchasing strategies

The actions of a generator ahead of time through their gas capacity purchasing strategies can create or eliminate a SRMC (from a generator's perspective) at gate closure.

A market with a high level of competition would naturally limit the extent to which a SRMC is created through a generator’s reliance on short-term capacity products. In this situation, we would expect that generators would tend to purchase long-term gas capacity products to cover (more than) their expected level of electricity production for most days, and they would balance the desire not to buy surplus gas capacity with the desire not to jeopardise their position in the merit order through buying more expensive short-term capacity products and bidding these into the electricity market.

In the SEM, there is currently significant concentration of generation ownership and this has given rise to market power concerns. The possibility exists that if an explicit ruling were given which required the inclusion of the cost of short-term gas capacity products in COD, generators could change their gas capacity purchasing strategies so as to increase the fraction of gas capacity that is purchased through short-term capacity products and so create an SRMC for bidding purposes. This would exert upwards pressure on SMP and associated generator revenues (which may more than offset the increased gas capacity purchase cost).

Impact of our view of the appropriate treatment

There are some changes (or clarifications) to the BCOP that could mitigate the impact of our view of the current treatment required by the generation licence:

- generators should not submit bids which would imply reliance on gas capacity overrun charges (in ROI) or unauthorised flow charges (in NI);
- COD should only reflect costs which are still marginal at gate closure; and

- COD should to the extent practicable be cost-reflective over the expected patterns of scheduled output and where this is not possible they should be submitted in a way which minimises deviations between SRMC and Schedule Production Costs, based on expectations.

Our assessment of the impact on SMP assumes that these changes / clarifications occur.

Our assessment of the impact on SMP does not allow for the possibility that generators change their gas capacity purchasing strategy and purchase an increased amount of capacity after gate closure.

Based on the treatment we believe is required by the generation licence and the existing pattern of gas capacity purchases, we have applied a simplistic approach that provides an order of magnitude assessment of the potential impact on SMP. In each case, the estimated impact is calculated relative to a situation in which no gas capacity costs are included in COD, which is a proxy for the economically correct outcome (absent a shortage of gas capacity). A full market modelling exercise is not in the scope of this report and these estimates are therefore indicative.

Figure 1 presents the summary of our analysis. We have estimated the amount of entry and exit capacity that was purchased by SEM market participants based on data provided by the RAs. Given this level of purchasing, we estimate that the impact of the bidding of exit capacity in 2012 would have had a €2.5/MWh impact on SMP and the bidding of entry capacity would have a €1.2/MWh impact on SMP.

This value may be lower if significant merit order switching occurs (for example NI gas-fired units operating ahead of ROI gas-fired units or increased interconnector imports).

Table 1 – Estimated impact based on analysis of 2012 outturn data

	Post-gate closure gas capacity purchased (TWh)	SMP impact (€m)	SMP impact (€/MWh)
Exit capacity	2.1	82	2.5
Entry capacity	1.4	38	1.2
Total		**120**	**3.6**

Note: The price impact is reported on a demand weighted basis

Options available for further change

Table 2 shows the hierarchy that we believe the current market rules dictate that generators should use to calculate the opportunity cost associated with gas capacity for the purpose of COD submissions (in descending order of preference noting that for exit capacity, the IBP is not relevant).

Currently, we believe that neither secondary activity nor the IBP is R&GA and so the primary product is the appropriate opportunity cost reference. We note that this could change in the future if activity related to secondary capacity or IBP increases. We also note that there could be differences in treatment between entry and exit capacity.

The RAs may conclude that their statutory objectives require them to act to improve the alignment between the bidding of gas capacity transportation costs and the underlying economics.

We believe that the options available for change can be broadly categorised as either:

- changes which impact the gas market which would affect which of the three alternative references for calculating the opportunity cost should be used; and
- changes to the SEM market rules which would mitigate the impact on SMP for a given opportunity cost reference.

Table 2 – Hierarchy of opportunity cost references

	Options for trading of entry capacity	Options for trading of exit capacity	Current rules for bidding	Current status – Pöyry view
1	Functioning IBP	N/A	IBP [+exit as appropriate]	Current IBP is not R&GA
2	Functioning market for secondary capacity	Functioning secondary trading	NBP + secondary prices	Secondary activity is not R&GA
3a	Long-term products	Long term products	NBP	Long-term products do not have a SR opportunity cost
3b	Daily products	Daily products	NBP + daily price [if not held at gate closure]	Daily products only have a SR opportunity cost if gas capacity is not held at gate closure
	Change here can move you up/down in the opportunity cost hierarchy		Change could mitigate the impact on electricity prices	

* Currently IBP is only is only a possible reference for ROI generators
* excludes gas transportation commodity charge

Mitigating the impact of primary products

We believe that the only way to completely negate the impact of the primary products on SMP is to either consider a change to the generation licence or to change some aspects of the current gas capacity products in ROI.

Options for change related to exit capacity are (noting that the implications for the gas market would need to be considered fully before any such change could be advocated and that we have not considered those issues in this report):

- removing the primary daily exit capacity product; or
- bringing the deadline for the purchase of primary daily exit capacity forward to before the EA2 gate closure (11:30am before the Trading Day).

Under our view of the required treatment of gas capacity in COD, we believe that either of these changes would mitigate around 69% of the estimated total impact on SMP, given the current entry / exit split of revenue recovery in ROI.

We note that the options for change at entry are more limited due to the requirements of the draft CAM network code and the harmonisation of capacity product at Moffat with GB. The only plausible option for change related to entry capacity (aside from a change to the generation licence) may be to examine the potential for mandatory booking of long-term primary gas capacity for a generator's expected output.

The impact of a R&GA secondary market

We believe that the current secondary activity is not R&GA market. However, should a R&GA secondary market emerge (or in contrary to our view, the current level of secondary activity is deemed R&GA), then options available to mitigate the impact on prices would be limited. In this case, the impact could only be mitigated by either stopping secondary activity before SEM gate closure (which may not be practicable or in compliance with the draft CAM network code) or through a change to the SEM generation licence.

The impact of a R&GA IBP

We believe that the IBP is not at present a R&GA market. Should the IBP become R&GA in the future, we would expect the IBP to include some coverage of the costs of entry capacity, since Ireland is a net importer of gas under most circumstances. However, we would expect that the IBP price would reflect the average long term rather than the marginal daily cost of gas capacity.

In the long term, we believe that the use of a functioning IBP would be a good outcome and would reflect the cost of gas in ROI and it would allow entry capacity costs to be appropriately reflected in COD.

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1. INTRODUCTION

1.1 The report

Pöyry Management Consulting ('Pöyry') was commissioned by the Utility Regulator and the Commission for Energy Regulation to undertake an assessment of the treatment of gas transportation capacity costs in Commercial Offer Data in the SEM.

This report is written for the Regulatory Authorities (RAs) but contains Pöyry's independent views which are not necessarily those of the RAs. The role of the RAs throughout the project has been to provide information on the nature of gas trading and also to question the clarity of the ideas as we have developed them, but not to influence the direction of the findings in a meaningful way.

Our interpretation of the legal intent of the existing provisions within the generator licence and the BCOP is informed by careful reading of the relevant documents in the light of our experience of legal matters, but we wish to clarify that we are not qualified to make legal interpretations and that our views should be subjected to legal opinion in the event that the RAs choose to act on our advice.

1.2 Background

Ireland and Northern Ireland have some of the highest gas transportation charges in Europe. In large part, this is due to the low population density compared to many other parts of Europe, which makes network costs a larger fraction of the overall cost of sourcing gas. Recent projects such as the 'Pipeline to the West' (€400m), the Mayo-Galway pipeline (€200m), the second interconnector (€297m) and the North West pipeline (£200m) have significantly added to the future revenue requirements from gas transportation tariffs in both NI and ROI. As a result, gas transportation tariffs are a large cost facing gas-fired generators in the SEM.

As one of the mechanisms to address concerns over market power in the SEM, generators must follow short-run marginal cost (SRMC) bidding principles. Licensed generators are required to submit Commercial Offer Data (COD) which are cost-reflective, that is which should be set to recover the SRMC of scheduled operation across a Trading Day.

Gas capacity (entry and exit) is now available for purchase at a daily resolution. This has led some generators to suggest that these charges should be defined as short-run marginal costs across a Trading Day. As a consequence, it is argued that the costs of gas capacity must be included within the COD of gas-fired generators, under the requirements of the generation licence.

This report is intended to inform the RAs' proposed decision following its consultation on the matter in September 2012[1].

1.3 Abbreviations

We have abbreviated Ireland (also known as the Republic of Ireland) to ROI and Northern Ireland to NI throughout the text. We have abbreviated Single Electricity Market to SEM.

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1 SEM-12-089, Treatment of Gas Transportation Capacity Costs, 27 September 2012

The SEM is jointly regulated by the Utility Regulator (UR) and Commission for Energy Regulation (CER) and these two bodies are jointly referred to as the Regulatory Authorities (RAs).

We have capitalised terms which have a formal definition under the SEM's Trading and Settlement Code – for example Trading Day.

The text frequently refers to the term 'recognised and generally accessible' and for brevity we have abbreviated this to R&GA.

For the purposes of this report, 'gate closure' means the SEM gate closure, which can be either the EA1, EA2 or WD1 gate closure as described in Section 4.1.

2. UNDERLYING ECONOMICS

Before we review the appropriate treatment of gas capacity costs under the current market arrangements, we consider the underlying economics of the matter. We note that the underlying economics do not have any direct influence on the treatment of gas capacity transportation costs as required by the generator licence and the associated Bidding Code of Practice (BCOP). However, the underlying economics may indicate the appropriate direction in the event that there is scope for interpretation of the precise wording, or scope for changes in supporting arrangements which may better meet the overall objectives of the RAs.

This section is structured around a set of questions:

- What is the marginal cost of gas capacity over different timeframes?
- How should gas capacity costs be treated in order to maximise the economic surplus?
- What is the rationale for average cost pricing of gas capacity?
- What is the purpose of short-term gas capacity products?

2.1 What is the marginal cost of gas capacity?

What is the underlying marginal cost to the system as a whole of providing gas capacity to market participants? The answer to this depends on the timeframe considered.

In the short-run (when the amount of capacity available is constant – as would be the case over the timeframe of the Trading Day), then there are two alternative values for the marginal cost of meeting demand for gas capacity:

- if there is sufficient gas capacity, then the marginal cost is very **close to zero** as the maintenance and operational costs incurred in providing network capacity for an additional unit of gas are very low; OR
- if there is insufficient gas capacity, then the marginal cost is likely to be **extremely high** as the effective cost is the un-served gas capacity requirements of those customers whose needs are not able to be met.

For the purposes of this report, we assume that the capacity/commodity split used in the gas transportation tariff calculations in NI and ROI are appropriate. This implies that the commodity charge in both NI and ROI appropriately reflects the short-run marginal cost (SRMC) of transporting gas, and that the capacity charges relate only to the cost of the network itself and not the cost of using it. Based on this assumption, we consider that the variable costs (recovered through per-MWh commodity charges) are outside the scope of this discussion.

In the long-run, total capacity is not fixed. Therefore the long-run marginal cost of meeting demand for gas capacity can include the cost of new capacity additions/replacement if required. However, in economic terms from a short term system perspective (i.e. the timeframe under consideration), the effective marginal cost of gas capacity is either zero (in cases with a surplus of gas capacity) or the cost of shortage (in cases with insufficient capacity). Under most circumstances, there is a demonstrable surplus of gas network capacity in both ROI and NI, and we therefore consider that the economically correct outcome would be that the gas capacity charges component of short-run marginal costs should generally be at or near zero.

2.2 Likelihood of a capacity shortfall

We note that the 2012 Joint Gas Capacity Statement states that in the absence of Inch storage, there may be a capacity shortfall at the Moffat entry point during a 1-in-50 peak day (but not an average year peak day) in 2014/15. This risk does not occur from 2015/2016 onwards as a result of the commencement of flows from the Corrib field (which is expected to be in April 2015). There is also a concern about a capacity shortfall at the Moffat entry point in the longer term (2018/19 onwards) in the absence of Inch storage and other new sources of storage or supply.

If a capacity shortfall does occur, then Moffat entry capacity would have a very significant SRMC (which would represent the benefit foregone as a result of the un-served gas capacity requirement). In this case, it would be economically correct to include a non-zero gas capacity cost in COD. We have not considered whether or how a non-zero gas capacity cost should be reflected in the case of such a capacity shortfall. We note that a such capacity shortfall has is a very low probability of occurring in the next five years and so the costs of implementing a non-zero gas capacity cost for such a small number of days may outweigh the benefit of doing so.

2.3 What treatment would maximise the economic surplus?

Standard micro-economic theory suggests that pricing services at their short-run marginal cost maximises social welfare because:

- it promotes efficient provision and consumption of the service in the short-run; and
- (on the assumption that efficient investment decisions mean that short-run marginal costs to tend to long-run marginal costs) it promotes efficient investment in and use of the service in the long-run.

Assuming that the commodity charge adequately reflects the SRMC of transporting gas, we believe that:

In scheduling and dispatching generators over a Trading Day, at times when there is sufficient gas capacity, it would maximise the economic surplus not to include any cost associated with gas capacity transportation charges within Commercial Offer Data.

In these circumstances, any inclusion of gas capacity costs in COD would lead to a lower economic surplus. Examples of possible loss in efficiency include:

- More expensive sources of electricity generation (most notably coal and interconnector imports) may be used when the underlying short-run marginal cost of gas-fired generation would have been lower.
- Lower consumption of electricity by consumers (and consequent deadweight loss), because the cost of consumption is higher than the true short-run marginal cost of provision.

2.4 What is the rationale for average cost pricing?

One of the defining characteristics of a natural monopoly (such as a gas transmission network) is that SRMC falls with increased output, and this typically means that the SRMC is less than the average cost of delivering the service. If prices are set to SRMC, the gas transmission owner may fail to recover the cost of ownership and operation (except at times when there is expected to be a scarcity of capacity).

As a result gas transmission networks across Europe typically have regulated tariffs or allowed revenue set to reflect the average cost of operation and ownership. This ensures that the gas transmission owner receives sufficient revenue to fund operation and ownership. Average cost pricing can distort usage signals but is considered necessary to ensure that the capital required for investment can be sourced.

Average cost pricing should be imposed in such a way as to minimise the loss in efficient usage and investment. This can be done by:

- recovering the costs over as broad a base as possible, therefore minimising the 'per unit' impact of the mark-up on marginal cost; and
- the use of price mark-ups that are inversely related to the price elasticity of demand of each sector.

2.5 Long-term economics

In the long-term, new gas network capacity and new generation capacity may be required. Despite this, we believe that longer term fixed costs should not be included in commercial offer data, and further that there is no need for the fixed costs of technologies other than the best new entrant to be included in capacity payments. Investors who choose technologies with higher fixed costs than the best new entrant may do so, presumably on the expectation that the additional outlay will be balanced by higher levels of operation and infra-marginal rent. To include these additional fixed costs explicitly within the commercial offer data and/or the capacity payment would distort the investment decisions.

Capacity payments are based on the least cost generation capacity, as a backstop. At the time of any actual investment, the choice of technology and fuel will be considered. Investors may choose to face increased fixed and capital costs in return for lower marginal costs (and, by implication, higher operation levels and greater infra-marginal rent). If considering an alternative to the best new entrant (currently a distillate-fired OCGT), increased fixed and capital costs could include higher turnkey costs, gas connection and gas capacity costs. For CCGTs, there are alternatives relating to water or air cooling and also the plant efficiency, flexibility and overhaul regime. There is no need under the current SEM arrangements for any of these elements to be considered explicitly other than for the selection of the best new entrant.

We consider that the capital cost of investing in CCGT rather than OCGT and the associated costs associated with gas connection and gas capacity are part of the operation of the market – essentially investors strike a balance between higher fixed costs and lower marginal costs. To require all gas-fired generators to include gas capacity costs in their commercial offer data would distort this balance.

2.6 What is the purpose of short-term gas capacity products?

Historically, most gas capacity in ROI and NI was sold under annual capacity contracts. EU Regulation 715/2009 mandates short-term capacity products be offered to the market at entry points. In ROI, a monthly and daily gas capacity product is currently offered at entry. Although not required by 715/2009, monthly and daily products are also offered at exit. In NI, a daily gas capacity product is offered.

Short-term gas capacity products have the following benefits:

- they add flexibility to the market for smaller or more seasonal consumers thus promoting competition;

- they facilitate competition by ensuring that as many market participants as possible can access the market; and
- they allow participants to take advantage of short-term opportunities to source gas from alternative sources increasing competition.

The short-term flexibility these products introduce is most useful when the network is capacity constrained (i.e. when the capacity available is less than the needs of the network users).

When the network is not capacity constrained, such flexibility is less valuable. Short-term products can further exacerbate the deviation from a marginal cost pricing approach as they are typically priced at a multiple of the long-term product.

3. CURRENT GAS TRANPORTATION ARRANGMENTS

3.1 Overview

The vast majority of gas consumed in the Island of Ireland is sourced from the GB market via the National Grid system exit point at Moffat and then through either the Scotland Northern Ireland Pipeline (SNIP) to Northern Ireland (NI) or through one of the two interconnectors (IC1 and IC2) to Republic of Ireland (ROI). The capital and operating costs of the gas transmission infrastructure (SNIP, IC1, IC2 and the onshore networks) in NI and ROI are recovered through regulated tariffs.

Table 3 – Gas transmission network characteristics

Item	Unit	RoI	NI
Annual revenue requirement	€m	190	56
Capacity / commodity split	%	90% / 10%	75% / 25%
Volume demand	TWh	54.8	16.0
Peak demand	GWh/day	269.8	89.2
Fraction of demand from power sector	%	61%	68%

Source: CER and UREGNI. Values quoted refer to 2012.

Currently, NI and ROI have separate tariff regimes. In NI, a postalised tariff regime is in place, with no distinction made between the locations of entry or exit points. In ROI, an entry/exit regime is in place under which market participants book entry capacity and exit capacity independently of each other.

3.2 Gas capacity transportation arrangements in ROI

3.2.1 Introduction

In **ROI**, entry and exit capacity on the gas transmission network can be purchased from Gaslink via regulated prices. Exit capacity is sector specific but entry capacity is not. The relevant categories of capacity are:

- Entry capacity;
- Large Daily Metered (LDM) exit capacity;
- Daily Metered (DM) exit capacity; and
- Non-Daily Metered (NDM) exit capacity.

Primary capacity can be bought from Gaslink for durations of a day, month, year or multi-year. Both annual and monthly capacity booking periods must start on the first day of a calendar month. The annual and monthly products must be purchased 8 days before the commencement of the relevant month.

Daily capacity can be purchased up to 03:00 within the relevant day, which is five hours before the end of the gas trading day[2].

[2] The gas year is one year from 01 October. The gas trading day is 24 hours from 06:00.

Participants who deliver or remove gas from the system without sufficient gas capacity are charged an 'overrun' charge which is 8 times the daily gas capacity cost. There is some tolerance and caps that are applied to limit the overall exposure of the market participants to overrun charges.

3.2.2 Secondary transactions

Secondary transactions of gas capacity occur between market participants in ROI. There are two types of transactions that can occur:

- a trade of capacity at the same entry or (far less commonly) exit point; or
- a transfer of capacity between exit points.

These trades and transfers can occur up to 01:45 on the Trading Day.

Participants are required to purchase sufficient long-term primary NDM exit capacity to cover their expected NDM demand during a 1-in-50 peak day. For much of the year, this level of exit capacity may be comfortably in excess of their requirements and so much of the secondary trading is from NDM exit capacity holders to other participants who wish to purchase exit capacity. It is currently possible to transfer NDM exit capacity to become DM exit capacity or LDM exit capacity.

The CER require that Bord Gáis Energy offer its NDM exit capacity to be offered to the secondary market on a '*transparent, non-discriminatory basis and with a regulated floor-price in place*'. Bord Gais Energy have typically offered this capacity on a non-firm ('*interruptible*') basis and can recall it if required.

Counterparties other than Bord Gáis Energy are free to set the price for secondary capacity transfers. These transfers can be on a firm or non-firm basis as negotiated between the counterparties.

There were exit capacity transfers of 3.2TWh in 2011 (of which 1.2TWh were from Bord Gais Energy's NDM exit capacity holding). There were entry capacity transfers of 1.6TWh. Although these numbers are significant, they are small relative to the overall size of the ROI gas market which has an overall demand of approximately 55TWh of which 33TWh is from the power sector[3].

3.2.3 Potential change to ROI gas transportation tariffs

As part of the CER's review of the regulatory treatment of the interconnectors, the CER have proposed[4] a single gas transmission regulatory asset base (RAB) instead of a separate onshore and offshore RAB. The single gas transmission RAB will be recovered 50% / 50% between entry and exit:

- the exit charge will be a regulated tariff as currently; and
- the entry charge will be set through an auction with an LRMC reserve price.

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3 Gaslink, Network Development Statement, 2011/12 to 2020/2021.

4 CER-12-013, The Regulatory Treatment of the BGÉ Interconnectors , Feb 2012

3.2.4 Gas capacity purchasing deadlines in ROI

Table 4 presents the current deadlines for the daily capacity product purchases and secondary capacity transactions in ROI. The future potential requirements are also highlighted.

Table 4 – Status of daily capacity & secondary capacity requirements

	Entry capacity (Primary)	Entry capacity (Secondary)	Exit capacity (Primary)	Exit capacity (Secondary)
Current deadline for purchase	03:00 on the Trading Day	01:45 on the Trading Day	03:00 on the Trading Day	01:45 on the Trading Day
Modifications in process	No Mod in process	No Mod in process	No Mod in process	Mod A046: Restrict transfers between sectors, but no change to deadline.
Existing legal requirements (Regulation 715/2009)	Daily product, but no time specified	*'network users who wish to re-sell … on the secondary market shall be entitled to do so'*	Daily product, but no time specified	*'network users who wish to re-sell … on the secondary market shall be entitled to do so'*
Future legal requirements (Draft CAM code)	Hourly auctions of within-day capacity until 00:30	*'functionalities for … secondary capacity shall be provided'*	n/a (at discretion of the Member State)	n/a (at discretion of the Member State)

Source: CER, EU, ENTSOG

3.3 Gas capacity transportation charges in NI

The majority of gas capacity in NI is paid for on an annual basis.

There is no distinction between entry and exit capacity in the NI system.

Daily gas capacity can be purchased, but only with 12 business days' notice. There has been very limited usage to date of the daily gas capacity product.

The PTL transportation code imposes 'unauthorised flow charges' for participants who remove gas from the network without capacity above a tolerance level. The charge is based on a charge equivalent to 10 times the cost of purchasing annual capacity (through the postalised charge) for that day would have been.

3.3.1 Transfers

It is possible to transfer capacity between market participants in NI, although to date this has not happened. The PTL code permits capacity transfers as follows:

- at the same exit point with at least 10 business days' notice (or a shorter period as PTL may consent to); and
- at a different exit point with at least 30 business days' notice (or a shorter period as PTL may consent to).

3.3.2 Changes to the NI gas market

We note that the NI gas market arrangements may change either as a result of the 'Common Arrangements for Gas' (CAG) project or because of separate developments in order to comply with EU legislation.

The implementation of CAG could result in short-term gas capacity products in NI being offered on similar timescales to ROI.

We note also that the EU gas target model's requirement that primary entry capacity products to be offered within-day will apply equally to NI as ROI.

3.4 Summary of current charges

The 2012/13 gas year transportation charges for ROI and NI are shown in Table 5 and Table 6.

Table 5 – Annual gas transportation tariffs from NBP

Transportation charges from GB NBP to a ROI Generator Unit		
	Capacity	**Commodity**
	Capacity cost (€ per MWh_{th}/d)	Commodity cost (€/MWh_{th})
Entry (Moffat) capacity	340.8	0.15
Exit capacity	491.3	0.24
Total	**832.1**	**0.39**

Transportation charges from GB NBP to an NI Generator Unit		
	Capacity	**Commodity**
	Capacity cost (£ per MWh_{th}/d)	Commodity cost (£/MWh_{th})
Transmission tariff	434.1	0.71

Source: Gaslink, Premier Transmission Limited.

Note: This reflects the impact of the mid-year revision to the ROI tariffs published in CER-13-080

Table 6 – Short term gas capacity product premiums on annual product

	NI: Daily	ROI: Daily	ROI: Monthly
October	2.41	2.41	1.56
November	2.41	2.41	1.61
December	4.31	4.31	2.08
January	7.52	7.52	3.64
February	8.58	8.58	4.60
March	6.42	6.42	3.12
April	2.41	2.41	1.61
May	1.46	0.18	0.12
June	1.46	0.18	0.12
July	1.46	0.18	0.12
August	1.46	0.18	0.12
September	1.46	0.18	0.12
Average	**3.45**	**2.91**	**1.57**

Note: Entry and exit multipliers in ROI are the same
Source: Gaslink, Premier Transmission Limited.

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4. CURRENT FRAMEWORK FOR BIDDING

The current legal framework for the submission of COD ('bidding') is embodied in:

- generation licence conditions;
- the Bidding Code of Practice;
- the published decision of the SEM Committee; and
- relevant court rulings.

The generation licence takes precedence over the BCOP and other regulatory decisions. An extract from the relevant sections of some of these documents is included in 0 and they are also reviewed in this section.

4.1 Commercial Offer Data

Market Participants in the SEM are required to submit COD in respect of each of their Generator Units (except for those classed as autonomous) for each Trading Day. The standard COD categories for conventional generators are:

- **Price Quantity Pairs**: a minimum of one and a maximum of 10 Price Quantity Pairs, each of which sets out a quantity (in MW_e) up to and equal to which the associated price applies. Price Quantity Pairs must be strictly monotonically increasing with only one price for each quantity and are expressed in €/MWh or £/MWh.
- **No Load Cost**: one No Load Cost, which is the element of operating costs which is invariant with the level of output. No Load Costs are expressed in €/hour or £/hour.
- **Start Up Costs**: a minimum of one and a maximum of three Start Up Costs, which reflect the costs associated with starting up the Generator Unit from cold, warm or hot states. Start Up Costs are expressed in £ or € per start.

From 21 July 2012, the SEM intra-day modification allows market participants to resubmit their COD intra-day[5]. There are therefore multiple gate closures for COD submission. A summary of the current gate closure times is set out in Table 7.

Table 7 – Current SEM gate closures

Market run	Trading Day periods covered	Gate closure	Market schedule issued
Ex-ante 1 (EA1)	06:00 to 06:00*	09:30 (TD-1)	11:00 (TD-1)
Ex-ante 2 (EA2)	06:00 to 06:00*	11:30 (TD-1)	13:00 (TD-1)
Within Day 1 (WD1)	18:00 to 06:00*	08:00 (TD)	09:30 (TD)

Note*: For the purposes of running the market clearing engine, the COD are used for the following 6 hours until 12:00 on the following day. For all final settlements, the data pertaining to each Trading Day are separated.

5 SEM modification 18_10, Intra-Day Trading in the SEM

4.2 Generation licence requirements

The generation licences in ROI and NI require that COD submitted by generators are '*cost-reflective*'. This is defined to mean that the COD submitted for each licenced generator must reflect their short-run marginal cost (SRMC) for that Trading Day.

The generation licence states that the SRMC related to a generation unit in respect of a Trading Day is to be calculated as (some words removed for brevity):

> *the total costs that would be attributable to the … generation unit during that Trading Day if the generation unit were operating to generate electricity during that day*
>
> ***minus***
>
> *the total costs that would be attributable to the … generation unit during that Trading Day if the generation unit was **not** operating to generate electricity during that day*

The generation licence states that the cost that should be used in this calculation should be the opportunity cost.

The licence permits the RAs to publish the BCOP (which sits within the framework and definitions set by the licence) which may further define opportunity cost, which may make provision for the treatment of various cost items and which permits the RAs to define '*principles of good market behaviour*' to be observed by licenced generators.

4.3 Bidding Code of Practice

The BCOP was published in July 2007 and sets out the methodology for calculating the opportunity cost associated with each cost-item[6]. The BCOP sits within the requirements of the licence and cannot contradict it.

The BCOP states that 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. This is done in the following way:

- If there is a R&GA market in the relevant cost-item, the opportunity cost of that item should reflect the prevailing **market price** of the cost-item.
- Where no R&GA market exists then the opportunity cost of that item should reflect the **replacement cost** which would be incurred in replacing that cost-item.

If '*good cause*' can be demonstrated, then the value of the benefit foregone (and so opportunity cost) may be calculated in an alternative manner.

The BCOP does not currently contain a dedicated section outlining the principles of good market behaviour, however the generation licence does permit the RAs to amend the BCOP to include such a section.

4.4 Viridian Power Limited vs. Commission for Energy Regulation

The February 2012 ruling by the Irish Supreme Court on the ROI carbon levy made the following statements which are clarify the requirements of the generation licence and BCOP[7]:

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6 SEM-07-430, 'The Bidding Code of Practice – A Response and Decision Paper', 30 Jul 2007

- *'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'*
- *'the generator is prohibited from bidding at a price which either exceeds, or is lower than, its Short-run Marginal Cost'*
- *'total costs includes all costs, each and every cost item'*

4.5 Possible market changes

In this section, we highlight some of the potential market changes that may materialise which could be of relevance to the treatment of gas capacity costs in COD.

4.5.1 A change to the trading day definition

The electricity and gas target model both require a change to the definition of the trading day:

- For **gas**, the draft CAM network code defines the gas trading day as of **05:00 to 05:00** Irish time[8].
- For **electricity**, the draft CACM network code defines the electricity trading day as **23:00 to 23:00** Irish time (although the timing for the core SEM arrangements could potentially be unchanged, depending on the outcome of the Market Integration project)[9].

This may change the timing of gate closures and gas capacity purchasing deadlines in the future.

4.5.2 EU electricity target model

The requirements of the EU Target Model raise significant challenges for the SEM design, which is fundamentally different from the approach used in most of North West Europe. The RAs have launched a Market Integration Project which may result in change to the current bidding and pricing arrangements in the SEM, due for implementation by end-2016. The High Level Design is expected to be finalised in May 2014. The potential changes are wide ranging and are as yet unclear. Some specific potential changes which could be of relevance:

- The likelihood of the implementation of additional intra-day gate closures or continuous intra-day trading.
- Potential changes to the structure of COD to accommodate increased intra-day trading and to align with a regional price coupling algorithm. Potential changes here could include:
  - A simpler bidding structure, which could mean Price Quantity Pairs only (with perhaps some block bids) in place of the current complex bidding structure.
  - The bidding of different prices for individual periods instead of a single price for the Trading Day.
- Modification of the generation licences to reflect the changes as a result of the Market Integration project.

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7 Viridian Power Limited v. Commission for Energy [2012] IESC (Hardiman J.)

8 ENTSOG, Network Code on Capacity Allocation Mechanisms, Sep 2012

9 ENTSO-E, Network Code on Capacity Allocation and Congestion Management, Sep 2012

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5. ANALYSIS OF CURRENT MARKET RULES

This section assesses the current market rules in order to determine what the SRMC associated with gas capacity is for a market participant in ROI and NI for the purposes of COD submission. We note that the SRMC associated with gas capacity for a market participant may be different from the underlying SRMC of the gas network owner of providing gas capacity.

5.1 Current RA direction on gas capacity charges

The Decision Paper which accompanied the BCOP stated that:

'*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 … such costs should not be reflected in price bids submitted to the Market Operator*'.

As a result of this decision, generators have to date included the commodity element of the gas transportation charge in their COD, but have excluded the capacity elements of the gas transportation charge[10].

The Decision Paper which accompanied the BCOP also stated that:

'[gas transportation capacity] *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*'.

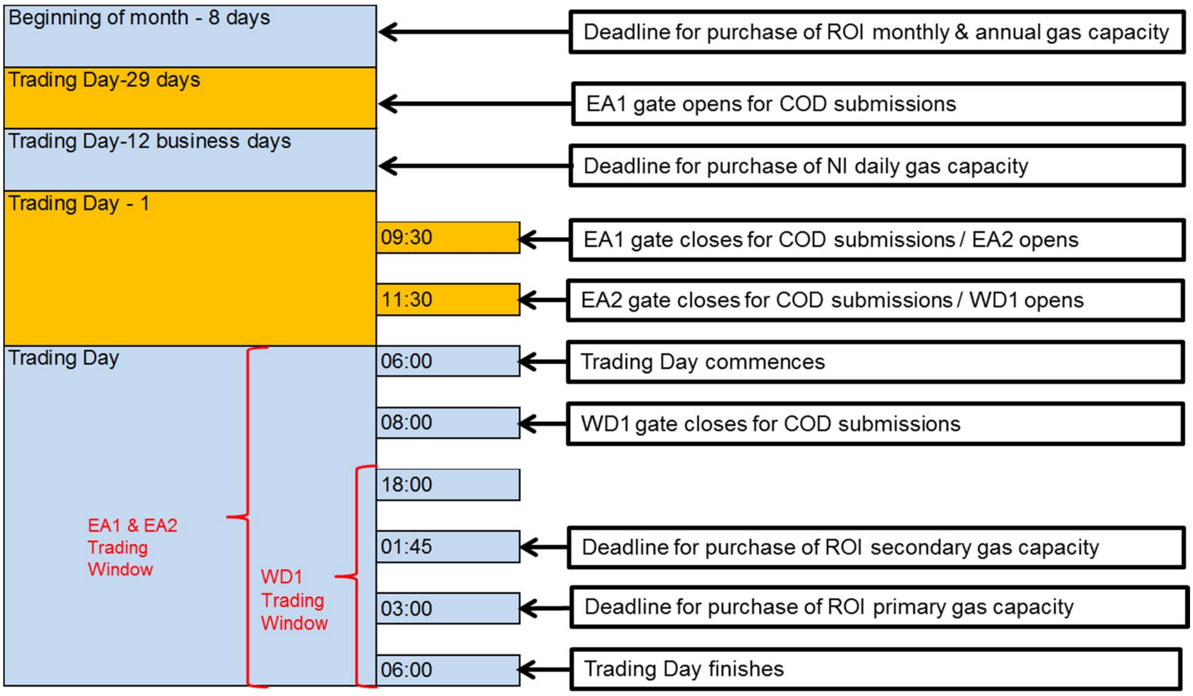
As a result of the implementation of short-term gas capacity products and correspondence received from some market participants, the SEM Committee published a paper on the treatment of gas capacity costs in COD in September 2012.

5.2 Timeline of key events

Figure 2 presents the timeline of key relevant events in the gas and electricity markets of ROI and NI. It should be noted that both the electricity and gas trading day currently spans 24 hours from 06:00.

10 The exception to this is Huntstown 1. Energia Group has stated in their 2012 Second Quarter Results that they have commenced the inclusion of gas capacity transportation costs in the COD of Huntstown 1 from 1 October 2012.

Figure 2 – Timeline of key events



* EA1, EA2 and WD1 are gate closures by which COD relating to the Trading Window should be submitted.

5.3 Starting assumptions

We believe that the following interpretations and assumptions are reasonable:

- There is a requirement in the ROI and NI generation licence that COD must be '*cost-reflective*'. We believe that this means that COD must (to the extent practicable) **always** be cost-reflective and not simply cost-reflective at the time at which they are submitted (which can be at any point up to 29 days before the Trading Day). COD must therefore be cost-reflective at each gate closure.
- The WD1 gate closure occurs within the Trading Day and is for the Trading Window which refers to the second half of the Trading Day. We consider that COD submitted at the WD1 gate must be cost-reflective for the second half of the Trading Day (and not the entire Trading Day).
- We do not consider that it would be good market behaviour for generators to submit COD that would systematically lead them to incur the charges listed below:
  - **Overrun charge (ROI gas)**: We do not believe that generators should plan on the possibility of removing gas from the ROI system without capacity, thus incurring gas capacity overrun charges in ROI.
  - **Unauthorised flow charges (NI gas)**: We do not believe that generators should plan on the possibility of removing gas from the NI system without capacity, thus incurring gas capacity unauthorised flow charges in NI.
  - **Uninstructed Imbalance charges (SEM)**: We do not believe that generators should plan on the possibility of not complying with an electricity dispatch instruction and incur an Uninstructed Imbalance charge within the SEM.

- Although some secondary transactions of gas capacity may be non-firm, if the likelihood of non-firm capacity being interrupted is sufficiently low, then it may still constitute good market behaviour to rely on this capacity.
- The generation licence requires that a generator's outturn Schedule Production Cost is equal to its SRMC for the Trading Day. We believe that (where possible) the COD submitted should be capable of ensuring that this is the case across all possible patterns of scheduled operation. However, it may not be possible to do so across all possible patterns of scheduled operation given limitations in the structure and frequency of resubmission of COD. Should this be the case, COD should be submitted in a way which minimises deviations between SRMC and Schedule Production Costs, based on expectations.
- We have assumed that the gas commodity charge in NI and ROI appropriately reflects the short-run marginal cost of transporting gas, and that the capacity charges relate only to the cost of the network itself and not the cost of using it.

5.4 Are secondary transactions currently a R&GA market?

One of key questions is whether secondary gas capacity transactions in ROI (for entry and exit capacity independently) is '*recognised and generally accessible*', which provides gas capacity for '*use as appropriate*' by the generator. Should this be the case then it would be this market that should be used in the calculation of the relevant opportunity cost.

5.4.1 Secondary transactions in ROI

We believe that the current characteristics of secondary transactions in entry and exit capacity mean that it is **not** a R&GA market for the following reasons:

- the volume is low relative to the size of the market[11];
- there is no reporting of prices of individual transactions either individually or on average over a given period;
- there is no facilitated trading platform such as a bulletin board or anonymous, cleared trading system;
- secondary capacity cannot be resold more than once (i.e. the only option for the buyer is to return the capacity to the seller); and
- the majority of participants who responded to the consultation were of the opinion that secondary transactions were not a R&GA market. Given the non-transparent nature of the trading, this opinion by those who actually access the market becomes important.

Although secondary transactions may not currently be R&GA it may become so the future. Should secondary capacity trading become R&GA (whether for entry or exit capacity), this could be the price reference on which to base that part of the SRMC of gas capacity for the purpose of COD submissions.

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[11] There were exit capacity transfers of 3.2TWh in 2011 (of which 1.2TWh were from Bord Gais Energy's NDM exit capacity holding). There were entry capacity transfers of 1.6TWh. These values are low relative to the overall demand in the ROI gas market of 50TWh of which approximately 30TWh is from the power sector.

It should be noted that there is a Gaslink code modification which proposes to stop participants transferring NDM exit capacity to another participant or within their own portfolio[12]. The modification would also stop transfers between LDM and DM exit capacity and vice versa. This is likely to decrease the level of secondary transfers of exit capacity if approved.

5.4.2 Secondary transactions in NI

There is some scope for secondary capacity transfers in NI, but this has never occurred to date. We therefore believe there currently are no grounds for considering this as a R&GA market for gas capacity in NI.

5.5 Are IBP trades currently a R&GA market?

The Irish Balancing Point (IBP) is a notional point on the gas network at which market participants may exchange quantities of Natural Gas within the Transmission System[13].

Some trading does occur at the IBP, however overall liquidity is low and there is little transparency of pricing. We believe that the IBP is unlikely to be considered a R&GA market because of this.

5.6 Does contracted position matter?

One respondent to the consultation stated that:

'… 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****'*

Neither the generation licence nor the BCOP excludes the contracted position of a generator at gate closure in calculating opportunity cost. We believe that the contracted position is not relevant if:

- there is a R&GA trading market for resale of the cost item; or
- it can be used on a future day, if not used on the Trading Day.

These conditions apply for the majority of COD cost-items. However, in the case of gas capacity, these conditions do not apply and so we believe that the contracted position is relevant and should be considered.

5.7 Use of replacement cost

The BCOP directs that in the absence of a R&GA market, the opportunity cost of a given cost-item should be based on the cost which would be incurred in replacing that cost-item.

We believe the use of replacement cost is valid for COD cost-items which can be used on a future Trading Day if they are not used on the Trading Day to which the COD refers. In this instance the '*benefit foregone*' is not having the component available for future use.

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12 The Code of Operations Modification Proposal A046 which was resubmitted by Gaslink on 6 February 2012. This proposal is currently on hold but may be implemented from October 2013.

13 Gaslink, Overview of the Code of Operations, December 2010

The benefit foregone can be valued using the cost of replacing the cost-item so that its benefit for a future Trading Day can be retained.

Gas capacity for a given Trading Day is clearly time-limited. Gas capacity held for 1 January 2013 (for example) can only be used on that Trading Day and is not valid on any future Trading Day. This means that for gas capacity that is held at gate closure there is no future benefit foregone by using the product on a given Trading Day.

We believe that the use of replacement cost to assess the opportunity cost of gas capacity may be problematic in situations where a generator already holds gas capacity at gate closure. We believe that there is '*good cause*' (as permitted by the BCOP) to use an alternative methodology[14].

5.8 Approach to calculating opportunity cost of gas capacity

We believe that it is appropriate to refer directly to the generation licence to correctly calculate the SRMC of gas capacity. The generation licence states that the SRMC related to a generation unit in respect of a Trading Day is to be calculated as (some words removed for brevity):

> *the total costs that would be attributable to the … generation unit during that Trading Day if the generation unit were operating to generate electricity during that day;*
>
> ***minus***
>
> *the total costs that would be attributable to the … generation unit during that Trading Day if the generation unit was **not** operating to generate electricity during that day,*

The generation licence states that the cost used in this calculation should be the opportunity cost. The BCOP states that the opportunity cost should be the '*value of the benefit foregone*'.

If there is not a R&GA market for gas capacity (which we believe is currently the case), then the opportunity cost depends on whether or not the generator holds gas capacity:

- For generation capacity which **holds** associated gas capacity at gate closure then there is no alternative value that can be realised for that capacity. Therefore the cost of this capacity is the same whether or not the generation unit is scheduled to operate, and the SRMC is zero.
- For generation capacity which **does not hold** gas capacity at gate closure, the relevant difference in cost between generating and not generating is the cost of the primary daily gas capacity product (as long as that product can still be purchased after gate closure at the time when the scheduling of the unit becomes more clear).

5.9 Alternative cases for opportunity cost

Table 8 presents our analysis of the possible options for the calculation of the opportunity cost of gas capacity.

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14 We note that '*good cause*' has been used before with respect to opportunity cost. In the case of the Dublin Bay CCGT, the SEM Committee considered that there was '*good cause*' not to use the prevailing market price to calculate the opportunity cost of gas. This was because the gas contract did not permit the resale of unused gas and so no alternative use (and hence value) was realisable. This is outlined in SEM-08-069.

We have considered the different options for the calculation of the SRMC associated with gas capacity transportation depending on:

- whether the generation capacity holds gas capacity at gate closure; and
- the timing of gate closure.

Although all gate closures are before 01:45 on the Trading Day currently, we have considered the potential outcomes should there be additional gate closures later in the Trading Day.

The bullet points below use the reference numbers in the table to provide a commentary.

Table 8 – Options for calculating the opportunity cost of gas capacity

Northern Ireland (Gate closures prior to 06:00)

	Unauthorised flow charge	Daily product	Long-term product	Zero
Generation capacity holding gas capacity at gate closure	3	4	4	4
Generation capacity not holding gas capacity at gate closure	3	4	4	4

Republic of Ireland (Gate closures prior to 01:45)

	Secondary price	Overrun charge	Daily product	Long-term product	Zero
Generation capacity holding gas capacity at gate closure	1	3	5	5	5
Generation capacity not holding gas capacity at gate closure	1	3	6	6	6

Republic of Ireland (Gate closures between 01:45 to 03:00)

	Secondary price	Overrun charge	Daily product	Long-term product	Zero
Generation capacity holding gas capacity at gate closure	2	3	5	5	5
Generation capacity not holding gas capacity at gate closure	2	3	6	6	6

Republic of Ireland (Gate closures after 03:00 to 06:00)

	Secondary price	Overrun charge	Daily product	Long-term product	Zero
Generation capacity holding gas capacity at gate closure	2	3	5	5	5
Generation capacity not holding gas capacity at gate closure	2	3	7	7	7

Included for completeness, but no gate closures occur after 01:45 currently

- Possible option given the assumptions listed
- Not a possible option given the assumptions listed
- Not a possible option unless secondary market trading becomes 'recognised and generally accessible'

Note: In ROI, secondary capacity may be purchased until 01:45 and the primary daily capacity product may be bought until 03:00

1. The expected price of a secondary transaction should be used as a basis for calculating the opportunity cost if there were a R&GA market for secondary capacity. As outlined in Section 5.4, we believe that there is not a R&GA market for secondary capacity. We note that this could change in the future and if this occurs it would be the appropriate reference for calculating the opportunity cost for gate closures occurring prior to 01:45 on the Trading Day in ROI.

2. As secondary capacity cannot be purchased in ROI from 01:45 onwards, it cannot be considered to be an opportunity cost after this time.
3. We believe that it is not appropriate for ROI generators to bid in such a way that would systematically expose them to overrun charges (for removing gas from the network without associated capacity holding) and so the overrun charge is not an appropriate price reference. Similarly for NI generators, we do not believe it is appropriate to bid in such a way that would systematically expose them to unauthorised flow charges.
4. The last window to purchase gas capacity in NI is 12 business days before the Trading Day. Gas capacity must be purchased in order for the generator to declare their capacity available (otherwise an unauthorised flow charge would be incurred if they are dispatched). Therefore the opportunity cost of gas capacity is the same whether or not the generator operates over the Trading Day and the SRMC of the gas capacity is zero as a result (in the absence of a R&GA market for secondary capacity).
5. For generation capacity holding associated ROI gas capacity at gate closure we believe that the opportunity cost of gas capacity is the same whether or not the generator is operating (as a R&GA market for secondary capacity does not exist currently, there is no '*benefit foregone*' in not operating as there is no '*realisable alternative use'*). The SRMC of the gas capacity is zero as a result. We believe that there is '*good cause*' not to use the concept of replacement cost in the calculation of the opportunity cost of gas capacity if gas capacity is held at gate closure, as outlined in Section 5.4.2.
6. For generation capacity that does not hold gas capacity at gate closure, the opportunity cost of operating (in the absence of a R&GA market for secondary capacity) is the primary daily product price until 03:00 (after which time it cannot be purchased).
7. After 03:00, no gas capacity product can be purchased and so for any gate closure after this time the generation capacity which does not hold gas capacity after the deadline for the purchase of primary capacity will incur an over-run charge for removing gas from the system. We believe that the overrun charge is not an appropriate price reference to include in COD (as outlined in Section 5.3).

5.10 Generators holding partial gas capacity at gate closure

We note that in the vast majority of cases (under current market conditions, and those expected in the future), gas-fired generators will not rationally hold gas capacity at gate closure for their full potential output for the Trading Window. This occurs because most gas-fired generators do not typically operate at maximum output overnight.

As well as requiring that generators reflect their SRMC in their COD submissions, the generation licence has the **additional** requirement that outturn Schedule Production Cost should reflect SRMC.

Under the current COD structure and gate closure timings, ROI generators that hold partial gas capacity at gate closure cannot bid in such a way that their Schedule Production cost will reflect their SRMC across all possible patterns of scheduled operation. This is because the SRMC associated with gas capacity can vary across the day from being zero (if generators are operating within the bounds of their gas capacity holding) to being non-zero (if generators are operating outside the bounds of their gas capacity holding). This cannot be reflected within COD currently as generators can only bid a single set of Price Quantity Pairs for the Trading Window.

If a generator cannot reflect their SRMC across all possible patterns of scheduled output, we believe the generator should (in an attempt to comply with their generation licence) bid as close to its estimated marginal cost (of gas capacity) as possible so as to minimise any expected deviation between Schedule Production Cost and SRMC.

6. TREATMENT REQUIRED BY THE CURRENT MARKET RULES

In this section, we present our view of the treatment of gas capacity costs in COD that is required by the current market rules (specifically under the current timing of gate closures and current pattern of secondary transactions in ROI and NI).

6.1 Northern Ireland

As outlined in Section 5.4.1, we believe there is no R&GA market for secondary gas capacity in NI.

As outlined in Section 5.9, we believe that the current requirement to purchase daily gas capacity before all gate closures means that the opportunity cost of gas capacity in COD submissions should be zero in all cases.

6.2 Republic of Ireland

As outlined in Section 5.4.2, we believe there is no R&GA market for secondary gas capacity in ROI.

Given that all gate closures in SEM currently occur before 03:00 (the deadline for the purchase of the primary daily gas capacity product) we believe that the treatment of gas capacity costs in COD depends on whether the generators holds gas capacity at gate closure.

6.2.1 Methodology

We note that in the vast majority of cases, gas-fired generators will not rationally hold gas capacity at gate closure their full potential output for the Trading Window[15].

Such generators cannot reflect their SRMC across all possible patterns of scheduled output. In this case, we believe the generator should bid as close to its estimated marginal cost as possible so as to minimise any expected magnitude of any potential deviation between Schedule Production Cost and SRMC. We believe they should do this in the following way:

15 We note that it may be possible that a generator does not hold any gas capacity at gate closure. In this case, a generator can reflect the SRMC associated with purchase of daily gas capacity over all possible scheduled production profiles. Such generators should reflect the pure incremental cost of gas capacity in their Price Quantity Pairs, expressed as a per-MWh addition to their incremental prices. Gas capacity associated with potential no-load gas consumption and start-up gas consumption can be included in the COD element for those items.

For the Trading day, the incremental gas capacity cost should be calculated as:

- The expected daily gas capacity requirement should be based on expectations of the market schedule
- No Load cost and Start Up cost should not be adjusted. These costs (based on the market schedule) should be included in the expected daily gas capacity requirement.
- The incremental cost should be reflected in Price Quantity Pairs accounting for plant thermal efficiency and transmission losses

The expected gas capacity requirement should reflect the expected market schedule. We note that this may mean that generators who are constrained on above their scheduled production profile may incur daily gas capacity charges that are not remunerated for through constraint payments. Although this is a somewhat perverse outcome, we believe that generation licence requirement that a generator's outturn SRMC should equal its **Scheduled** Production Cost requires generators to bid in this manner. Generators are incentivised to minimise the occurrence of this through the purchase of long-term gas capacity products.

6.2.2 Worked example

Figure 3 presents a worked example using the March 2013 exit capacity cost in ROI.

Figure 3 – Worked example for March 2013 exit capacity

For a 400MW CCGT with 75% capacity holding, expected scheduled output for the day is 50% of its maximum

$$\text{incremental cost of gas capacity to be bid} = \frac{(€8.6/\text{MWh}) * (0\text{MWh})}{50\% * 400\text{MW} * 24\text{h}}$$

$$\text{incremental cost of gas capacity to be bid} = €0.00/\text{MWh}$$

For a 400MW CCGT with 75% capacity holding, expected scheduled output for the day is 90% of its maximum

$$\text{incremental cost of gas capacity to be bid} = \frac{(€8.6/\text{MWh}) * (15\% * 400\text{MW} * 24\text{h})}{90\% * 400\text{MW} * 24\text{h}}$$

$$\text{incremental cost of gas capacityto be bid} = €1.43/\text{MWh}$$

For a 400MW CCGT with 0% capacity holding, expected scheduled output for the day is 30% of its maximum

$$\text{incremental cost of gas capacity to be bid} = \frac{(€8.6/\text{MWh}) * (30\% * 400\text{MW} * 24\text{h})}{30\% * 400\text{MW} * 24\text{h}}$$

$$\text{incremental cost of gas capacity to be bid} = €8.60/\text{MWh}$$

6.2.3 Portfolio holdings at entry

At entry, market participants with more than one Generator Unit or with a retail customer base will have a single entry capacity holding for the consumption of their portfolio. In this case, market participants will need to assign gas capacity to their retail customer base and between their Generator Units prior to performing the calculation above.

We believe that for the purposes of the calculation of opportunity cost associated with gas capacity, generators should assign their gas entry capacity holding across their portfolio in a manner which would mimic behaviour in a fully competitive market.

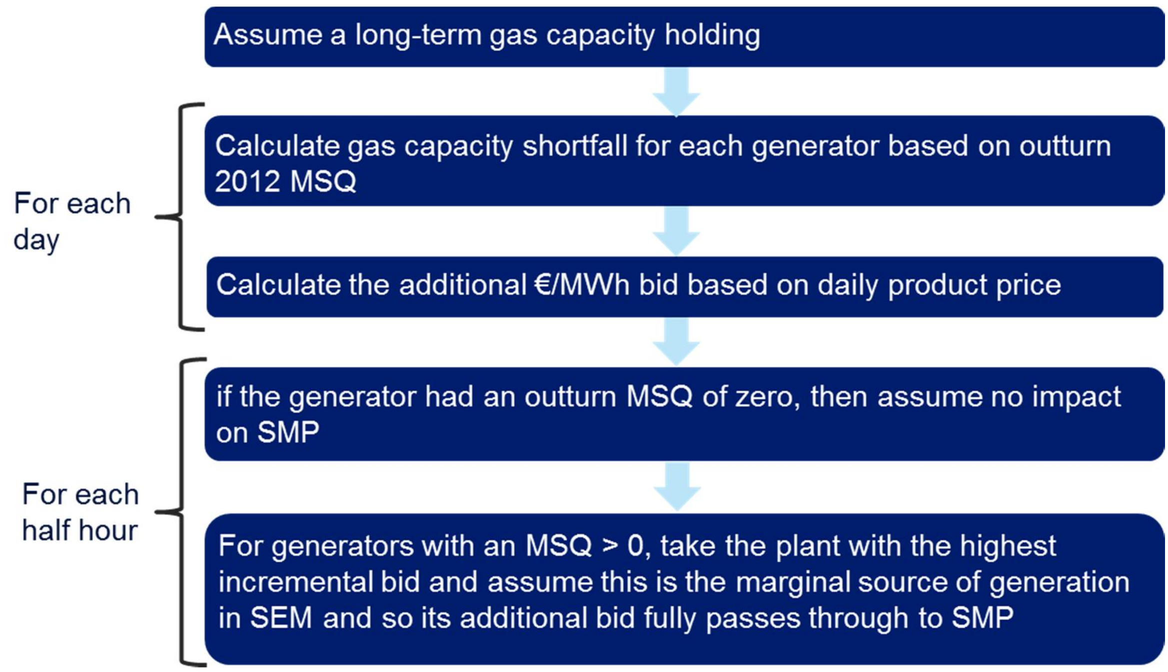
6.3 Potential price impacts

We have assessed the price impact of generators bidding the opportunity cost associated with gas capacity that they do not hold at gate closure.

6.3.1 Potential impact on SMP of the recommended treatment

We have estimated the SMP impact of the treatment we believe is required by the current market rules relative to a situation where no gas capacity costs are included in COD. We have done this by analysing 2012 market outturn data. We have analysed the eight largest gas fired generators by capacity to assess the potential impact on SMP. Although this does not include all ROI gas fired generation, we believe that these generators do represent the vast majority of ROI gas fired generation[16]. The approach we have taken is outlined in Figure 4.

Figure 4 – Approach to assessing the potential impact on SMP



Note: We have abbreviated Market Schedule Quantity to MSQ

We note that this is a simplistic approach that will provide an order of magnitude assessment of the potential impact on SMP. A full market modelling exercise is not in the scope of this report.

16 Sealrock CHP has been excluded as it operates as a priority dispatch plant and so does not submit Price Quantity Pairs (although we note that it does have the option of becoming a Price Maker if it wishes.

In doing this, we have made the following simplifying assumptions (ranked in an indicative order of importance):

- Market Schedule Quantities (i.e. the merit order) are not impacted by the increased bids of these units;
- in each period, the gas fired generators with the highest additional 'adder' is the marginal unit and so this is fully passed through to the SMP;
- we have not included any provision for gas associated with start-up;
- we have used full-load efficiencies to calculate gas consumption; and
- the plants have perfect foresight of their expected Market Schedule Quantity.

Figure 5 shows the pattern of daily scheduled output for the generators analysed in 2012.

Table 9 presents the results of this analysis and the impact on SMP across a range of patterns of gas capacity holding at gate closure.

Figure 5 – 2012 pattern of daily gas consumption from large ROI CCGTs

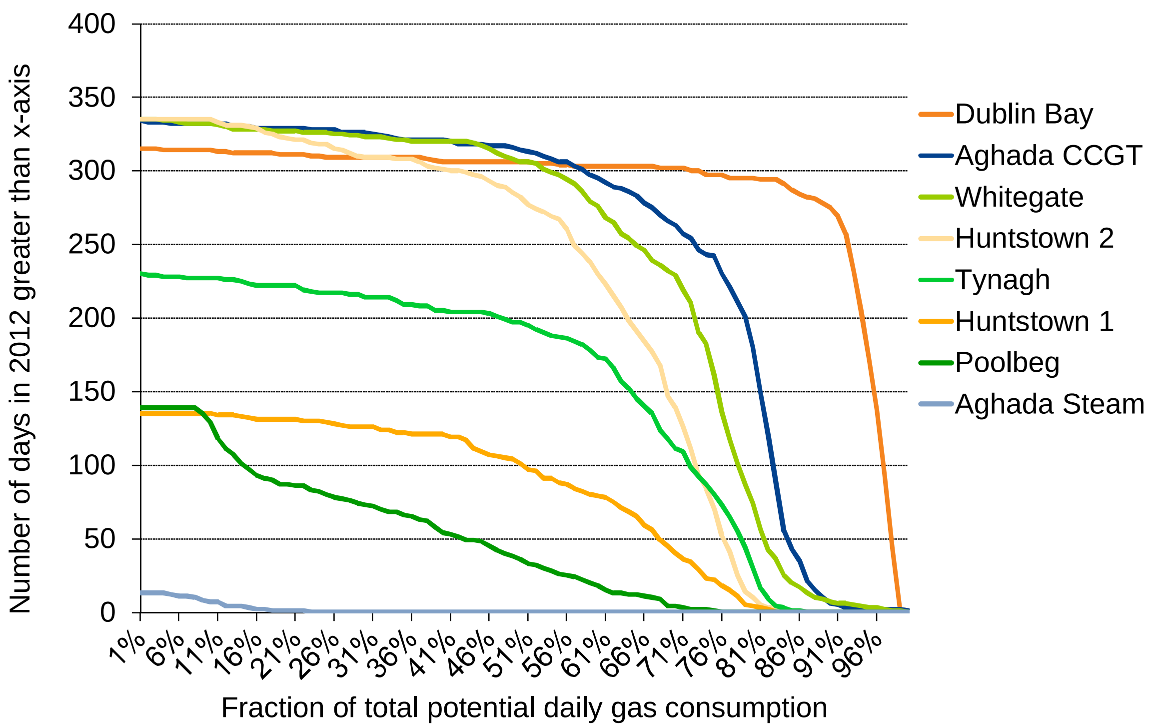


Table 9 – Gas capacity holding at gate closure and estimated SMP impact

		Gas capacity holding at gate closure if required to be sufficient for all but …					
		10 days	50 days	100 days	150 days	200 days	366 days
Dublin Bay	%	98%	97%	96%	95%	94%	0%
Aghada CCGT	%	89%	84%	82%	80%	79%	0%
Whitegate	%	88%	81%	78%	75%	72%	0%
Tynagh	%	81%	78%	71%	64%	47%	0%
Huntstown 2	%	80%	76%	72%	68%	63%	0%
Huntstown 1	%	78%	67%	50%	0%	0%	0%
Poolbeg CCGT	%	67%	42%	14%	0%	0%	0%
Aghada Steam	%	8%	0%	0%	0%	0%	0%
Capacity shortfall at gate closure	TWh	0.1	0.4	1.5	3.6	4.6	25.4
Impact on SMP: Entry capacity	€/MWh	0.1	0.4	1.2	3.0	3.4	6.0
Impact on SMP: Exit capacity	€/MWh	0.1	0.6	1.8	4.3	4.8	8.6

Note: Gas capacity holding at gate closure expressed as % of total potential daily consumption

We have estimated the SMP impact based on gas capacity purchasing strategies observed in 2012. Table 10 presents the summary of our analysis. Data provided by the RAs show that 1.9TWh of exit capacity was purchased post-gate closure and 1.2TWh of entry capacity was purchased post-gate closure[17]. Given this level of purchasing, we estimate that the impact of the bidding of exit capacity in 2012 would have had a €2.5/MWh impact on SMP and the bidding of entry capacity would have a €1.2/MWh impact on SMP.

This value may be lower if significant merit order switching occurs (for example NI gas-fired units operating ahead of ROI gas-fired units or increased interconnector imports).

Table 10 – Estimated impact based on analysis of 2012 outturn data

	Post-gate closure gas capacity purchased (TWh)	SMP impact (€m)	SMP impact (€/MWh)
Exit capacity	2.1	82	2.5
Entry capacity	1.4	38	1.2
Total		**120**	**3.6**

Note: The price impact is reported on a demand weighted basis

6.3.2 Potential impact on capacity payments

The BNE peaker has to date been an oil-fired OCGT. This is because the cost of a gas connection and paying for gas capacity make the capital and fixed costs of a gas-fired OCGT are more expensive compared to an oil-fired OCGT. The benefit of greater infra-marginal rent (under the methodology for its calculation) due to lower operating costs is not sufficient to outweigh these.

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17 We have included all secondary capacity activity even if it occurred before gate closure on the basis that it could rationally have occurred after gate closure

It is possible that the BNE peaker could become gas-fired if the treatment of gas capacity costs in COD change. However, we believe this is very unlikely to occur because:

- In NI, we do not believe that gas capacity is a biddable cost, so there would be no impact on the BNE peaker cost calculation for NI.
- In ROI, the BNE's infra-marginal rent could increase if gas capacity that is not held at gate closure is a biddable cost. However, the improved infra-marginal rent as a gas-fired OCGT (compared to an oil-fired OCGT) would still not be sufficient to outweigh the additional cost of the gas connection and so the BNE peaker would still be oil-fired in ROI.

We also note that the CPM Medium Term Review decision paper included a decision to fix the BNE price for three year intervals (the first from 2013 to 2015).

7. OPTIONS AVAILABLE FOR CHANGE

The RAs may conclude that their statutory objectives require them to improve the alignment between the bidding of gas capacity transportation costs and the underlying economics. This section presents some options that would either:

- further ensure the robustness of our view of the appropriate treatment outlined in Section 6; or
- further limit the extent to which gas capacity transportation costs are reflected in SMP over and above the treatment outlined in Section 6.

7.1 Hierarchy of opportunity cost references

The hierarchy that we believe should be used to calculate the opportunity cost associated with gas capacity for the purpose of COD submission is presented in Table 11 in descending order of preference (noting that for exit capacity, the IBP is not relevant). We have included some additional commentary below the table, which provides the rational for this hierarchy.

Table 11 – Hierarchy of opportunity cost references

	Options for trading of entry capacity	Options for trading of exit capacity	Current rules for bidding	Current status – Pöyry view
1	Functioning IBP	N/A	IBP gas price [+exit as appropriate]	Current IBP is not R&GA
2	Functioning market for secondary capacity	Functioning secondary trading	NBP gas price + secondary prices	Secondary activity is not R&GA
3a	Long-term products	Long term products	NBP gas price	Long-term products do not have a SR opportunity cost
3b	Daily products	Daily products	NBP gas price + daily price [if not held at gate closure]	Daily products only have a SR opportunity cost if gas capacity is not held at gate closure

Change here can move you up/down in the opportunity cost hierarchy

Change could mitigate the impact on electricity prices

Note: this excludes network use of system/commodity costs

1. **IBP**: We believe that if there were a R&GA IBP which represented the cost of gas in ROI, then this would be the most appropriate reference for the opportunity cost of gas in ROI including entry (but not exit) capacity. This would remove the requirement to purchase entry capacity for gas separately (noting that some implicit cost of gas capacity may be included in the IBP price), but would still require ROI exit capacity to be purchased.
2. **Secondary market**: In the absence of a R&GA IBP, and for exit capacity, if there were a R&GA secondary market, then this would be the most appropriate reference for opportunity cost of gas capacity, if gas capacity were required by a market participant.

3. **Primary product**: In the absence of a R&GA IBP or secondary market, then the primary daily product would be the most appropriate reference for the opportunity cost of gas capacity. In these circumstances, we believe that gas capacity only has an opportunity cost to the extent that it is not held at gate closure, and at times when the daily product remains accessible for purchase.

On economic grounds we would suggest that a traded price for the secondary products or the primary products should not be considered to represent a marginal economic value of gas capacity, whereas a functioning IBP should represent such a cost.

7.2 Options available

7.2.1 Options not assessed

We have assumed the following are changes that would either not permitted under legislation or are items that the RAs would be very reluctant to undertake:

- a reduction to the Regulatory Asset Base of the gas transmission assets in either ROI or NI;
- a change in the entry/exit split for the recovery of allowable gas revenues in ROI;
- a change to the structure of COD; and
- a change to the way the Capacity Payment Mechanism is calculated.

We note also that the EU Target Model Next Steps Decision Paper stated that there was a commitment to '*maintaining the current structure of SEM until 2016*'[18].

7.2.2 Options available

Table 12 and Table 13 present the options available for change to the RAs. We have categorised options according to whether they related to the primary gas capacity products, the secondary activity in gas capacity or the IBP. We have also made a distinction between options that are related to the gas market and options that are related to the SEM market rules.

We note that options related to the SEM are broadly about attempting to mitigate the impact of a given opportunity cost reference. Options related to the gas market are broadly related to changing the opportunity cost reference (e.g. from secondary activity to the primary product for example).

We would make the following points in relation to the table:

- There are some SEM rule changes are possible which would mitigate the impact of our view of the current required treatment, as outlined in Section 6. We believe that the only way to completely negate the impact is to either consider a change to the generation licence or to change some aspects of the current gas capacity products in ROI.
- The CAM network code (which requires within day auctions of primary capacity and secondary capacity to be made available to the market and secondary activity to be facilitated) mean that the scope for change at entry may be limited.

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[18] 'Implementation of the European Target Model for the Single Electricity Market, Next Steps Decision Paper, SEM-13-009', SEM Committee, 15 February 2013.

- Should a R&GA secondary market emerge, then options available to the RAs would become limited with the only way to mitigate the impact would be through a change to the generation licence.

Development of an IBP

We note that the IBP is not generally well used for the procurement of gas in Irish power stations. However, we believe that in a potential future in which the IBP is a robust market for the procurement of gas for use in power stations in the SEM, this would provide a good alternative to the separate inclusion of gas and gas entry capacity products.

This would allow both short-term and long-term capacity costs to be included in an appropriate manner. However, we consider that the IBP is currently not at present a R&GA market as defined in the BCOP and that at present it is not a suitable reference.

Table 12 – Options available for change (I)

SEM rule changes that would mitigate the impact of primary products

Measure	Effect	Risks
BCOP clarification that COD must reflect costs which are still marginal at gate closure	NI gas capacity charges are not biddable under present arrangements	Low
BCOP clarification that generators should not rely on 'over-run' or 'unauthorised flow' charges	Stop these charges being used as an opportunity cost in COD submissions	Low
Use the '**good clause**' to justify not using the cost of the daily gas capacity holdings as a replacement cost if secondary product is not R&GA)	ROI daily capacity only biddable to the extent that it is not held at gate closure	We believe this is the correct approach to calculating opportunity cost, but could be subject to a legal challenge
BCOP clarification on the method for bidding partial gas capacity holdings	Combined with the previous measures, estimated impact of ~€99 million pa on SMP charges	May be non-compliant with the generation licence
Define '**good market behaviour**' gas capacity purchasing principles for the purposes of bidding: *a) 'in a manner which mimics behaviour in a fully competitive market'; OR* *b) 'bid as if the [full] gas capacity requirement has been purchased through annual products'*	Further minimise the impact of daily capacity on COD and SMP pricing	Monitoring (a) could be difficult (a) and in particular (b) are legally questionable – generators should bid based on their actual not theoretical holding

Gas market changes that would mitigate the impact of primary products

Measure	Effect	Risks
Increase multiplier for primary daily products	Decrease reliance on daily product but increase the price effect when used. Outcome difficult to determine.	Impact on non-power sector and storage providers. May not be compliant with CAM.
Decrease multiplier for primary daily products	Increase reliance on daily product but decrease the price effect when used. Outcome difficult to determine.	May cause revenue recovery issues for Bord Gais Networks.
Exit: **Do not offer** primary daily product OR **move the deadline** to before SEM gate closure	Preclude primary exit capacity from being included in SMP	
Entry: **Do not offer** primary daily product OR **move the deadline** to before SEM gate closure	Preclude primary entry capacity from being included in SMP	May not be compliant with CAM.
Define gas capacity purchasing principles *a) 'in a manner which mimics behaviour in a fully competitive market'; OR* *b) purchase their [full] capacity requirement through annual products*	Minimise the impact of daily capacity on COD and SMP pricing	Impact on non-power sector and storage providers, unless they were treated separately.

Table 13 – Options available for change (II)

SEM rule changes that would mitigate the impact of the secondary market

Measure	Effect	Risks
Proceed with a **generation licence change** to exclude any costs associated with gas capacity transportation tariffs	Remove impact on SMP	Extended process and could also be subject to legal challenge

Gas market changes that would stop a secondary market being used a reference

Measure	Effect	Risks
Further **define 'recognised and generally accessible'**	Confirm secondary activity cannot be used as a reference market for SR opportunity cost	
Entry: **Disallow** secondary trades to occur OR **move deadline** for notification to before SEM gate closure	Preclude secondary capacity (which is not marginal from a system perspective) from being included in SMP	May not be compliant with CAM
Exit: **Disallow** secondary transfers to occur OR **move deadline** for notification to before SEM gate closure	Preclude secondary capacity (which is not marginal from a system perspective) from being included in SMP	Impact on non-power sector and storage providers. May not be compliant with CAM.

Changes related to the IBP

Measure	Effect	Risks
Promote liquidity and trading at the IBP	Limit the impact of entry capacity on SMP	Limited competition at IBP may give rise market power issues
Promote an IBP & dictate that it should reflect NBP + commodity element of transportation cost	Limit the impact of entry capacity on SMP	Legally questionable – generators should bid based on their actual not theoretical holding

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ANNEX A – EXTRACTS FROM KEY DOCUMENTS

This Annex presents extracts from some of documents that are relevant to this discussion. The highlighting of the text is Pöyry's addition.

A.1 Extract from Generation Licence

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 Licensee 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 generation 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 generation 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 be either 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 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 costs 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 and no load costs; and

(v) any other costs attributable to the generation of electricity; and

(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.

8. The Licensee shall retain each set of Commercial Offer Data, and all of its supporting data relevant to the calculation of the price component of that Commercial Offer Data, for a period of at least four years commencing on the date on which the Commercial Offer Data is submitted to the Single Market Operation Business.

9. The Licensee shall, if requested to do so by the Commission, provide the Commission with:

   (a) a reasoned explanation of its calculations in relation to any Commercial Offer Data; and

   (b) supporting evidence sufficient to establish the consistency of that data with the obligations of the Licensee under this Condition.

10. In any case in which Commercial Offer Data are submitted to the Single Market Operation Business which are not consistent with the Licensee's obligation under paragraph 1 of this Condition, the Licensee shall immediately inform the Commission and provide to the Commission a statement of its reasons for the Commercial Offer Data submitted.

A.2 Extract from the Bidding Code of Practice

DEFINITION OF OPPORTUNITY COST

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 for *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.

9. Subject to paragraph 12, all Commercial Offer Data submitted in respect of a generation set or unit are to reflect the costs relating to that generation set or unit when considered on a stand-alone basis

A.3 Definitions

A.3.1 Trading and Settlement Code

- **Trading Day**: means the period commencing at 06:00 each day and ending at 06:00 the next day.
- **Trading Window**: means the Trading Periods in a Trading Day in respect of which Generator Units may submit Commercial Offer Data and Technical Offer Data.
- **Schedule Production Cost**: means *the implied cost incurred* by a Generator Unit, as determined from the Accepted Price Quantity Pairs, No Load Costs and Start Up Costs and other relevant Commercial Offer Data and Technical Offer Data, of Output in accordance with the *Market Schedule Quantity*.

A.3.2 Oxford English Dictionary

- **Cost**: '*That which must be given or surrendered in order to acquire, produce, accomplish or maintain something; the price paid for a thing*'
- **Market**: There are 2 alternative definitions provided
  - '*A regular gathering of people for the purchase of commodities*'; or
  - '*An area or arena where commercial dealings are conducted*'.

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