Harmonised Transmission Tariff Methodology for Gas

Summary of Responses to Consultation Paper
Executive Summary

This paper provides a summary of the responses received to the Commission for Regulation of Utilities’ consultation (CRU/18/247) on the harmonised transmission tariff methodology for gas. That consultation examined the reference price methodology used to calculate tariffs for use of the gas transmission network, in addition to related aspects of the tariff structure.

The consultation paper was published on 11 December 2018 and the consultation period closed on 11 February 2019. In accordance with the EU network code on harmonised transmission tariff structures for gas (‘TAR NC’ or ‘the tariff network code’), the CRU is now publishing a paper summarising responses to the tariff consultation, as well as the responses themselves.

This paper provides a summary of responses only, it does not provide a CRU view of the responses themselves. The CRU has attached the full-length responses in the Appendix of this paper. The CRU will publish its decision on harmonised transmission tariff methodology for gas by 11 May 2019 and will respond to the consultation responses as appropriate in that paper.

By carrying out an open consultation on the proposed changes to the tariff methodology and by publishing all consultation responses, the CRU is meeting its core commitment to transparency. The CRU wishes to thank the respondents for their feedback. The responses will aid the development of the CRU decision on harmonised transmission tariff methodology for gas.

Responses received from stakeholders related to the following aspects of the transmission tariff methodology: reference price methodology and its components; treatment of shrinkage; entry/exit split; capacity/commodity split; liquefied natural gas (LNG) discounts; biogas tariff; virtual reverse flow; multipliers and seasonal factors; and, charges for Northern Ireland shippers.
Customer Impact Statement

The Commission for Regulation of Utilities (CRU) is the independent economic regulator for the natural gas, electricity and water sectors in Ireland. Our mission is to regulate water, energy and energy safety in the public interest.

The CRU is legally responsible for regulating the transmission and distribution network tariffs that Gas Networks Ireland (GNI) charges to users of the network. In December 2018 the CRU published a consultation (CRU/18/247) on the harmonised transmission tariff methodology for gas. That consultation examined the methodology used to calculate tariffs for use of the gas transmission network. Those tariffs allow GNI, as the network operator, to recover the allowed revenue set by the CRU to operate the network in a safe and efficient manner.

The tariff network code requires the CRU to publish all responses to the consultation as well as a summary of those responses. This paper is being published to fulfil these requirements. This paper does not provide any commentary and does not contain any decisions. Therefore, it has no direct impact on customers.

The CRU will publish its decision on harmonised transmission tariff methodology for gas by 11 May 2019, which will address as appropriate all consultation responses received.
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<tr>
<td>ACER</td>
<td>Agency for the Cooperation of Energy Regulators</td>
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<td>Art.</td>
<td>Article</td>
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<td>CWD</td>
<td>Capacity Weighted Distance</td>
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<td>CER</td>
<td>Commission for Energy Regulation (now known as the CRU)</td>
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<td>CRU</td>
<td>Commission for Regulation of Utilities</td>
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<tr>
<td>EU</td>
<td>European Union</td>
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<tr>
<td>GB</td>
<td>Great Britain</td>
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<tr>
<td>GNI</td>
<td>Gas Networks Ireland</td>
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<tr>
<td>I/C</td>
<td>Industrial/Commercial</td>
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<tr>
<td>IBP</td>
<td>Irish Balancing Point</td>
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<tr>
<td>IP</td>
<td>Interconnection Point</td>
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<tr>
<td>ISEM</td>
<td>Integrated Single Electricity Market</td>
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<tr>
<td>LNG</td>
<td>Liquefied Natural Gas</td>
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<tr>
<td>LRMC</td>
<td>Long-Run Marginal Cost</td>
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<tr>
<td>NBP</td>
<td>National Balancing Point</td>
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<tr>
<td>NI</td>
<td>Northern Ireland</td>
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<td>OUG</td>
<td>Own-use gas</td>
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<tr>
<td>PC4</td>
<td>Price Control 4</td>
</tr>
<tr>
<td>ROI</td>
<td>Republic of Ireland</td>
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<td>RPM</td>
<td>Reference Price Methodology</td>
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<tr>
<td>TAR NC</td>
<td>Commission Regulation (EU) 2017/460 of 16 March 2017 establishing a network code on harmonised transmission tariff structures for gas</td>
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<tr>
<td>TSO</td>
<td>Transmission System Operator</td>
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<tr>
<td>UAG</td>
<td>Unaccounted for gas</td>
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<tr>
<td>Term</td>
<td>Definition or Meaning</td>
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<tr>
<td>Allowed Revenue</td>
<td>The sum of transmission services and non-transmission services revenues that GNI is entitled to recover in a given period as the transmission system operator/owner, as approved by the CRU.</td>
</tr>
<tr>
<td>Annuitisation factor</td>
<td>The percentage of the expansion constant to reflect the annual remuneration of the cost of and on capital as well as associated operating costs.</td>
</tr>
<tr>
<td>Biogas</td>
<td>For the purposes of this consultation, biogas means gas produced from renewable non-fossil sources, mostly commonly by anaerobic digestion of biodegradable matter, which will meet the applicable gas quality specification set out in the Code of Operations when injected into the transportation network.</td>
</tr>
<tr>
<td>Capacity/commodity Split</td>
<td>The apportionment of revenue to be recovered from capacity-based transmission tariffs and commodity-based transmission tariffs.</td>
</tr>
<tr>
<td>Entry/exit split</td>
<td>The apportionment of revenue to be recovered from entry points and exit points.</td>
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<tr>
<td>Expansion constant</td>
<td>A numerical value of expanding the capacity of the system so that one unit of gas can travel over one kilometre.</td>
</tr>
<tr>
<td>Interconnection Point</td>
<td>A point connecting one entry-exit system to another entry-exit system.</td>
</tr>
<tr>
<td>Multiplier(s)</td>
<td>Outlines the pricing relationship between non-yearly capacity products and the annual capacity product.</td>
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<tr>
<td>Non-transmission services</td>
<td>Regulated services other than transmission services and other than services regulated by Regulation (EU) No 312/2014 that are provided by the TSO.</td>
</tr>
<tr>
<td>Primary Tariff</td>
<td>The set of tariffs (based on LRMC and distances) which reflect the differentials between the different entry or exit points.</td>
</tr>
<tr>
<td>Reference Price</td>
<td>The tariff for a firm capacity product with a duration of one year, calculated using the preferred reference price methodology. It should be noted that the reference prices for entry and exit are set separately.</td>
</tr>
<tr>
<td>Reference Price Methodology (RPM)</td>
<td>The methodology set or approved by the national regulator in order to calculate the reference price.</td>
</tr>
<tr>
<td><strong>Rescaling</strong></td>
<td>A secondary adjustment to primary tariffs to recover the transmission services revenue of the GNI.</td>
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<tr>
<td><strong>Seasonal Factors</strong></td>
<td>Allows for variations in the seasonal value of the same standard capacity products and thus creates incentives for the efficient used of the transmission system (e.g. encouraging more gas flows during the summer time).</td>
</tr>
<tr>
<td><strong>Shrinkage</strong></td>
<td>Shrinkage gas means own use gas and natural gas required to replace Unaccounted for Gas (UAG). Own use gas means natural gas which is used by GNI for the operation of the gas transportation network or any localised part thereof including at compressor stations and/or for pre-heating and venting purposes. UAG means natural gas which is lost or otherwise unaccounted for from the gas transportation network or any localised part thereof.</td>
</tr>
<tr>
<td><strong>Transmission services</strong></td>
<td>The regulated services that are provided by the TSO within the entry-exit system for the purpose of transmission.</td>
</tr>
<tr>
<td><strong>Virtual Reverse Flow (VRF)</strong></td>
<td>VRF is a ‘reverse flow’ service offered on a virtual basis, at the IPs, to enable gas shippers to virtually flow gas along a unidirectional pipeline.</td>
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</tbody>
</table>
1 Introduction

1.1 The Commission for Regulation of Utilities

The Commission for Regulation of Utilities (CRU) is Ireland’s independent energy and water regulator. The CRU was established in 1999 and has now has a wide range of economic, customer protection and energy safety responsibilities. The CRU’s mission is to regulate water, energy and energy safety in the public interest.

Under the Gas (Interim) (Regulation) Act, 2002, the CRU is responsible for regulating charges in the natural gas market. Under Section 14 of the Act, the CRU may set the basis for charges for transporting gas through the transmission system. The CRU does so in the best interests of gas consumers. Our goal is to ensure that the gas is safely and securely supplied and that the charges are fair and reasonable.

Information on the CRU’s role and relevant legislation can be found on the CRU’s website at www.cru.ie.

1.2 Background - review of the transmission tariff methodology for gas

The CRU is currently reviewing the methodology used to calculate the tariffs that are charged for use of the gas transmission network in Ireland. One aim of this review is to ensure compliance with Regulation (EC) 2017/460 (“the tariff network code” or “TAR NC”). TAR NC sets Union-wide rules which have the objectives of contributing to market integration, enhancing security of supply and promoting the interconnection between gas networks.

The second aim of the CRU’s review is to ensure that the gas tariff methodology continues to be fit for purpose; to take into account the unique characteristics of the Irish gas system; and, in so far as possible, to be future proofed should there be significant changes to the Irish gas system, such as the addition of a new gas supply point to the transmission system.

As part of this review, on 11 December 2018 the CRU published a consultation paper (CRU/18/247) on the reference price methodology that is used to calculate the reference prices and subsequent tariffs for use of the transmission network, as well as a number of associated elements of the tariff structure. The deadline for submission of responses was 11 February 2019.

1.3 Purpose of this paper and next steps

Under Article 26 (3) of the TAR NC, the CRU is required to publish a summary of the responses received to its tariff consultation, along with the responses themselves, within one month from the end of the consultation period. This summary paper, and the accompanying responses (see
Appendix), are being published in accordance with this legal requirement. This approach is different from the CRU’s usual approach as the CRU typically publishes consultation responses, alongside a CRU view, as part of a CRU decision.

The CRU notes that the aim of this paper is to provide a summary of the responses received to the consultation paper and not to respond to the consultation submissions themselves. The CRU will respond to submissions as appropriate in its decision paper on the harmonised transmission tariff methodology for gas. The CRU expects to publish this decision paper by 11 May 2019.

The following are the milestones that will follow the publication of this summary of responses:

- ACER publication of evaluation\(^1\) of the consultation by 11 April 2019
- CRU decision paper on tariff structure published by 11 May 2019
- CRU publication of tariffs for 2019/20 using updated tariff methodology by 31 May 2019

### 1.4 Related Documents

Documents published as part of the consultation are presented below:

- Harmonised Transmission Tariff Methodology for Gas Consultation Paper (CRU/18/247)
- Proposed Matrix RPM and counterfactual CWD RPM workbook (CRU/18/247a);
- NTLTG minutes and slides (CRU/18/247b);
- Diversity premium calculation workbook (CRU/18/247c);
- Capacity/commodity split impact assessment workbook (CRU/18/247d);
- Expansion constant calculation workbook (CRU/18/247e);
- Annuitisation factor calculation workbook (CRU/18/247f);
- Virtual Reverse Flow probability of interruption calculation workbook (CRU/18/247g); and,
- ACER’s consultation template, which has been filled out by the CRU is published by ACER at this clickable [link](https://acer.europa.eu/en/Gas/Framework-guidelines_and_network-codes/Pages/Harmonised-transmission-tariff-structures.aspx)

Relevant CRU papers and EU regulations:

- CRU Decision Paper on October 2017 to September 2022 Transmission Revenue for Gas Networks Ireland (CER/17/260)
- CRU Decision Paper on the Entry/Exit Tariff Methodology (CER/15/140);
- CRU Draft Decision Paper on the Entry/Exit Tariff Methodology (CER/15/057);

\(^1\) The ACER evaluation will be published at the following clickable [link](https://acer.europa.eu/en/Gas/Framework-guidelines_and_network-codes/Pages/Harmonised-transmission-tariff-structures.aspx)

\(^2\) [link]
- CRU Decision Paper on the Regulatory Treatment of the BGÉ Interconnectors (CER/12/087);
- Commission Regulation (EU) 2017/460 of 16 March 2017 establishing a network code on harmonised transmission tariff structures for gas; and,

The current reference prices and GNI’s simplified transmission tariff model are available at the following clickable link\(^3\).

Information on the CRU’s role and relevant legislation can be found on the CRU’s website at www.cru.ie.

\(^3\) https://www.gasnetworks.ie/corporate/gas-regulation/tariffs/transmission-tariffs/simplified-tariff-model/
2 Consultation Responses

2.1 Introduction

The CRU received 20 submissions to the consultation from the following stakeholders:

- Manx Utilities
- Aughinish Alumina
- Firmus Energy
- Vermilion Exploration and Production Ireland Ltd (VEPIL)
- Vermilion Energy Ireland Ltd (VEIL)
- Gas Networks Ireland (GNI)
- Equinor
- Nephin Energy
- Phoenix Natural Gas
- Irish Offshore Operators Association (IOOA)
- Electric Ireland
- Bord Gáis Energy (BGE)
- Tynagh Energy
- Green Gas AD Plant
- Mutual Energy
- Shannon LNG
- Renewable Gas Forum Ireland (RGFI)
- ESB Generation and Trading
- Shell Energy Europe Ltd
- Energia

In its consultation paper the CRU had 14 separate requests for comment; these are listed in table 1 below. Each request, and a summary of the stakeholders’ responses to that request, is contained in sections 2.2.1 to 2.2.14 of this paper.

An additional subsection, Section 2.2.15, summarises comments made by respondents that are not directly relevant to the requests for comment. The full text of the responses is contained in the appendix to this paper.

The CRU wishes to thank respondents for their feedback.
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<th>Topic</th>
<th>Query</th>
<th>Section</th>
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<td><strong>3A.</strong> What are your views on the CRU’s proposal to continue to apply the Matrix RPM?</td>
<td>2.2.1</td>
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<tr>
<td>Shrinkage</td>
<td><strong>4A.</strong> What are your views on the CRU’s proposal to class shrinkage as a transmission service and to recover the cost through the commodity element of the capacity/commodity split rather than through a separate flow-based charge? Also, what are your views on a date of implementation of gas year 2019/20?</td>
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<td>Entry/exit split</td>
<td><strong>4B.</strong> What are your views on the CRU’s proposal to continue to apply a 33:67 entry/exit split?</td>
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<td>Capacity/commodity split</td>
<td><strong>4C.</strong> What are your views on the CRU’s proposal to continue to apply a 90:10 capacity/commodity, taking into account the CRU’s proposal to incorporate shrinkage into the transmission services revenue?</td>
<td>2.2.4</td>
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<tr>
<td>Expansion constants and annuitisation factors</td>
<td><strong>4D.</strong> What are your views on the CRU’s proposal to update these components of the Matrix RPM?</td>
<td>2.2.5</td>
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<td>Discounts LNG</td>
<td><strong>5A.</strong> What are your views on the CRU’s proposal to not apply a discount for LNG entry points at this time? Also, do you agree with the considerations that the CRU proposes to take into account when coming to a decision on the possible provision of LNG discounts in the future?</td>
<td>2.2.6</td>
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<td>Biogas</td>
<td><strong>5B.</strong> What are your views on the CRU’s proposal to apply a single notional biogas entry point tariff to all biogas entry points? What are your views on how the notional point should be constituted?</td>
<td>2.2.7</td>
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<td>Biogas</td>
<td><strong>5C.</strong> What are your views on biogas distribution entry tariffs relative to transmission entry tariffs and the additional factors which may need to be taken into account in designing such a tariff?</td>
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<td>VRF</td>
<td><strong>6A.</strong> What are your views on the CRU’s proposed VRF tariff methodology and are the factors and magnitude of the factors proposed for the VRF tariff appropriate?</td>
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<tr>
<td>Multipliers and seasonal factors</td>
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<tr>
<td>Multipliers and seasonal factors</td>
<td><strong>7D.</strong> How should the CRU consider implementing a transitional approach in the case ACER recommend reducing the daily multiplier to a maximum of 1.5?</td>
<td>2.2.14</td>
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2.2 Summary of Responses

2.2.1 Reference price methodology (RPM)

Query: 3A. “What are your views on the CRU’s proposal to continue to apply the Matrix RPM?”

The majority of respondents agreed with the CRU’s proposal to continue to apply the Matrix reference price methodology (Matrix RPM).

Some of the respondents noted the stability and certainty offered by the Matrix RPM and considered that it is well-suited to the Irish gas market. Some respondents expressed the view that the Matrix RPM is well aligned with the principles of the TAR NC and produces stable tariff differentials which provide clear investment signals. Respondents also noted that a rigorous consultation process was held before the Matrix RPM was first implemented by CER/15/140.

One respondent (Shannon LNG) did not support the Matrix RPM, contending that it could lead to cross-subsidisation. This respondent was also of the view that it is more appropriate to use a multiplicative, rather than additive, rescaling factor. In addition, one respondent (Mutual Energy) considered that the differences between the Matrix RPM and the capacity-weighted distance (CWD) approach were not adequately described by the CRU, and that the Matrix RPM fails to meet the criteria set out in Art. 7 of the TAR NC.

2.2.2 Shrinkage

Query: 4A. “What are your views on the CRU’s proposal to class shrinkage as a transmission service and to recover the cost through the commodity element of the capacity/commodity split rather than through a separate flow-based charge? Also, what are your views on a date of implementation of gas year 2019/20?”

Some respondents were in favour of the CRU’s proposal to class shrinkage as a transmission service and some were against.

Amongst those in favour, respondents noted that all network users benefit from the maintenance of system pressures and access to wholesale markets that shrinkage provides. Two respondents (Manx Utilities and Aughinish Alumina) were of the view that the proposal would provide greater transparency in relation to shrinkage costs. Several respondents also considered that the proposal would make the 90:10 capacity/commodity split more cost-reflective and one respondent (Shell) considered that the proposal would ensure a level playing field for gas entering the Irish system from different supply points.
One respondent (VEPIL\textsuperscript{4}) opposed the proposal on the grounds that it is not cost-reflective to include “own-use gas” (OUG) in the commodity charge given that the amount of OUG used for compression is affected by the different pressures of gas entering the network at different entry points. Those respondents also questioned the TAR-NC compliance of the proposal, as the cost-drivers for shrinkage are neither technical nor forecast capacity.

Another respondent (Tynagh Energy) argued against the proposal on the basis that greater flow-based charges are preferable in general to avoid placing a disproportionate weight on power generators.

Several respondents had concerns about the transparency of the new proposal. BGE considered that the proposal should not go ahead unless at least the current level of transparency in relation to shrinkage costs can be maintained. BGE, along with a number of other respondents, expressed the view that GNI should monitor and report regularly on the shrinkage element of the commodity charge if the proposal is adopted. BGE and ESB Generation and Trading were also in favour of an incentive on GNI to reduce shrinkage costs.

In relation to when to implement the proposed changes, some respondents were in favour of implementing in 2019/20 while others considered that it would be more prudent to defer implementation until 2020/21, or later, to allow time for network users to amend their contracts (Shell), for the impacts on revenue recovery to be considered (GNI), and for GNI to revise its IT systems to prepare for the change (GNI). ESB Generation and Trading suggested in its response that GNI should ‘shadow-charge’ for gas year 2019/20 to give network users an idea of how tariffs would be affected by the changes.

2.2.3 Entry/Exit split

Query: 4B. “What are your views on the CRU’s proposal to continue to apply a 33:67 entry/exit split?”

The majority of the respondents who addressed this issue were in favour of retaining the 33:67 entry/exit split. Respondents approved of maintaining this split in the interest of stability and noted that the reasons for the selection of this split in 2015 still hold. One respondent (IOOA\textsuperscript{5}) expressed agreement but on the basis that the split reasonably reflects the split on the regulated asset base (RAB). One respondent (ESB Generation and Trading) indicated that greater justification of the cost split may be required to ensure compliance with the relevant ACER guidelines.

\textsuperscript{4} Vermilion Energy Production Ireland Ltd (VEPIL) is the operator of the Corrib gas field and responded to the questions on shrinkage (section 2.2.2) and the capacity/commodity split (2.2.4) on behalf of the Corrib partners (i.e. Equinor, Nephin Energy and Vermilion Energy Ireland Ltd (VEIL)), who also responded to this consultation. When comments are attributed to “VEPIL” in this paper, they are also attributed to the Corrib partners.

\textsuperscript{5} Equinor, Nephin Energy and VEIL concurred with the responses of IOOA. When comments are attributed to IOOA in this paper, they are also attributed to these three companies.
One respondent (Tynagh Energy) was opposed to the proposal on the basis that the unavailability of secondary exit capacity offsets the fact that retaining the 33:67 split minimises redistributive effects.

### 2.2.4 Capacity/Commodity split

**Query: 4C. “What are your views on the CRU’s proposal to continue to apply a 90:10 capacity/commodity, taking into account the CRU’s proposal to incorporate shrinkage into the transmission services revenue?”**

A variety of opinions were expressed on this topic, with a majority in favour of the proposal.

Several respondents were fully in support of the CRU’s proposal to continue to apply a 90:10 capacity/commodity split. Other respondents stated that the proposal is only appropriate if shrinkage is included in GNI’s allowed revenue or alternatively the capacity/commodity split should be adjusted to reflect actual system costs.

One respondent (VEPIL) was of the view that a 100:0 capacity/commodity split would be appropriate if own-use gas (OUG) was classed as a non-transmission service. In the case that there is no change (i.e. it remains outside the allowed revenue) a split of 95:5, moving towards 100:0, was VEPIL’s preference.

In disagreeing with the CRU’s proposal, one respondent (Tynagh Energy) argued for an 85:15 split on the basis that gas generators now lack certainty of the extent to which they will run each year due to increases in wind generation.

One respondent (ESB Generation and Trading) agreed with the CRU’s proposal but noted that greater justification of the 90:10 cost split may be required to achieve TAR NC compliance.

### 2.2.5 Expansion constant and annuitisation factor

**Query: 4D. “What are your views on the CRU’s proposal to update these components of the Matrix RPM?”**

A majority was in support of the CRU’s proposal to update these elements of the model. Several supported the proposal on the basis that it would increase the cost-reflectivity of tariffs. IOOA approved of the proposed changes on cost-reflectivity grounds but contended that further updates to these parameters were needed. That respondent argued that the expansion constants do not properly represent the cost of projects.

With regard to future updates to these parameters, IOOA was of the view that it would be more cost-reflective to update the expansion constants and the annuitisation factor on a yearly basis. In addition, that respondent argued that the fuel cost component of the annuitisation factor should be based on the actual price paid by GNI for OUG, rather than on national balancing point (NBP) prices.

By contrast, two respondents (GNI and ESB Generation and Trading) expressed the view that
updating the annuitisation factor and expansion constant every five years was appropriate in order to balance cost-reflectivity and stability.

One respondent (BGE) approved of the re-indexing of these parameters and of updating the parameters to account for the completion of the twinned pipeline in Scotland, but also argued that it is inappropriate to include opex and fuel costs in the annuitisation factor.

### 2.2.6 Discounts for LNG

**Query: 5A. “What are your views on the CRU’s proposal to not apply a discount for LNG entry points at this time? Also, do you agree with the considerations that the CRU proposes to take into account when coming to a decision on the possible provision of LNG discounts in the future?”**

Most respondents considered that discounts should not be applied at the present time, but respondents were divided on whether LNG discounts should be considered in the future.

Some respondents approved of the CRU’s proposal not to apply LNG discounts at the present time and were also in favour of the proposal to consider discounts for LNG on a case-by-case basis.

It was argued by Manx Utilities that ‘blanket’ discounts are not appropriate as large-scale entry gas should not be treated differently based on its source and BGE expressed the view that ‘straight’ discounts could conflict with TAR NC and distort signals for new entry. Electric Ireland considered that discounts are not appropriate currently as there are not yet any LNG facilities in Ireland. In terms of case-by-case assessment, BGE considered that the proposed approach would allow the CRU to determine the impact of individual LNG projects on security of supply and on gas flows from other entry points. Manx Utilities considered that the approach would allow the CRU to take account of market conditions at a given time in making its decision and Electric Ireland expressed the view that the approach would allow the CRU to determine the relative merits of projects and take into account new information.

By contrast other respondents (IOOA, Shell, ESB Generation and Trading) expressed general opposition to LNG discounts, as well as the proposal to assess projects on a case-by-case basis.

IOOA was of the view that LNG discounts should not be applied and, as the arguments are generic to all LNG projects, the matter should be closed with this consultation. IOOA and ESB Generation and Trading questioned the security of supply benefits LNG would bring to Ireland. Both Shell and BGE considered that an LNG discount would raise tariffs at Moffat and thus cause an increase in the wholesale gas price. Shell and ESB Generation and Trading pointed out that the Matrix RPM already contained an incentive for efficient new entry. IOOA, Shell and ESB Generation and Trading were opposed to assessing applications for LNG discounts on a case-by-case basis on the grounds that this would create uncertainty about tariffs.
Aughinish Alumina stated that it would welcome the increase in security of supply that investment in an LNG facility would bring but said that the investment should not lead to any increase in prices for gas customers.

Several respondents (IOOA, ESB Generation and Trading, BGE) considered that there should be a public consultation on any review of applications for LNG discounts.

Most respondents did not comment on the CRU's proposed criteria for assessing discounts. Two respondents (Shannon LNG and Manx Utilities) were of the view that the criteria appeared reasonable and ESB Generation and Trading considered that the both the benefits and the risks of LNG should be considered in any assessment. Shannon LNG was of the view that the downward pressure that LNG would bring to Irish gas prices should be taken into account by the CRU in assessing applications. This respondent also indicated its intention to apply for a discount in the future.

2.2.7 Biogas transmission entry tariff

Query: 5B. What are your views on the CRU’s proposal to apply a single notional biogas entry point tariff to all biogas entry points? What are your views on how the notional point should be constituted?

A majority of respondents agreed with the CRU’s proposal to apply a single notional entry point tariff to all biogas entry points. Respondents approved of the simplicity and stability of the approach and considered that it would be positive for investor certainty while the biogas industry is in its infancy.

One respondent (Green Gas) however expressed the view that there should be no biogas tariff as the industry requires incentivisation to compete with natural gas and provides a standalone benefit by ‘greening’ the network. This respondent also noted the benefit of avoided compression costs.

Another respondent (Shell) considered that the TAR NC consultation process is not the correct means of incentivising biogas; a technology neutral approach should be taken, and a separate consultation would be more appropriate. That respondent supported a “geographically dispersed model”, with an annual review of the system, if the TAR NC approach is taken.

ESB Generation and Trading expressed concern that the CRU’s RNG proposal may not comply with TAR NC Art. 6.3, which requires all entry points in an entry-exit system to be treated equally. That respondent also argued that a government subsidy was the best way to support biogas, and that neither of the CRU’s two proposed locations for the notional point was reflective of the likely location of the new entry.

In terms of the derivation of the notional point, most of those who commented on the issue were in favour of a geographically dispersed point, with some noting it represents likely sources of supply. However, some respondents favoured locating the point close to demand while the industry is in its infancy.

Several respondents considered that the CRU should review the biogas tariff as the number of biogas
connections grows.

**2.2.8 Biogas distribution tariff considerations**

Query: 5C. “What are your views on biogas distribution entry tariffs relative to transmission entry tariffs and the additional factors which may need to be taken into account in designing such a tariff?”

Many respondents did not express a view on this issue. Amongst those that did give an opinion, a number of respondents thought that the transmission and distribution tariffs should be designed to produce efficient locational signals to biogas producers as to where to connect to the network. Other factors which respondents believed the CRU should take into account included: any reinforcement costs needed for distribution-connected biogas to enter the transmission network (GNI), potential interruptions to the supply of biogas on the network (GNI), possible distortions to the Matrix RPM (Manx Utilities), and the fair and equitable development of the gas system (Energia).

One respondent (BGE) considered that there are currently no grounds for a differential between transmission and distribution tariffs for biogas but that the approach taken should be reviewed as the amount of biogas on the network increases.

Another respondent (RGFI) was of the view that distribution-connected biogas should be charged an exit tariff but not an entry tariff and that such an arrangement could be reviewed in c. five years. That respondent noted that distribution-connected biogas alleviates the need for transmission system reinforcement by avoiding that part of the network.

**2.2.9 Tariff for Virtual Reverse Flow (VRF)**

Query: 6A. “What are your views on the CRU’s proposed VRF tariff methodology and are the factors and magnitude of the factors proposed for the VRF tariff appropriate?”

The CRU received submissions expressing a range of views on this topic.

Several respondents expressed support for the proposal, including one (GNI) who proposed that use of the VRF be reviewed annually to monitor the effect of the tariff, and another (Tynagh) who argued that the costs of an interconnector should be applied proportionally to both virtual and physical flows.

A number of respondents were in favour of the principle of VRF charging but disagreed with individual elements of the tariff calculation. This included one respondent (Manx Utilities) who said that the calculation of the A factor was unclear and another (Aughinish Alumina) who questioned the need for a pro-factor as declining Corrib production is reducing the probability of an interruption to VRF. One respondent (ESB Generation and Trading) was supportive of the principle of VRF charging but stated that the proposed approach is incomplete and not transparent, and that implementation should be delayed until issues are resolved. This respondent took issue, inter alia, with the application of the proposed Moffat VRF risk premium and probability of interruption to the calculation of the Gormanston VRF tariff. Another respondent (BGE) agreed with most of the components of the proposed tariff but stated that the 30% discount for VRF was too high and would reduce the liquidity
Almost half of respondents who commented on the issue were opposed to the CRU’s VRF proposal. One respondent (IOOA) considered that the proposal was not cost-reflective and expressed concern that the proposed VRF tariff may reduce liquidity at the IBP and negatively impact future investment in gas projects in Ireland. In its response, IOOA offered an alternative charging system for VRF whereby the product would be deemed a non-transmission service.

One respondent (Shannon LNG) considered that the VRF tariff may be too high as the VRF service brings balancing flexibility to the Irish market without imposing costs. Another respondent (Shell) argued that the proposal is not cost-reflective and expressed a preference for the current registration charge on the basis that it covers the costs associated with providing the VRF service. Shell and IOOA also contended that multipliers should not apply to the VRF product as the product is not available on a long-term basis.

2.2.10 Application of commodity charges to VRF product

Query: 6B. “What are your views as to whether commodity charges should apply to use of the VRF product?”

A majority of respondents who commented on the question argued that commodity charges should not apply to virtual flows, mostly noting that the product adds no costs to the system. One respondent (IOOA) considered that the product saves costs by reducing OUG.

Three respondents were in favour of the commodity charge. One of these (Energia) contended that such a charge was necessary to preserve the principles of the tariff regime and minimise distortions in the application of the tariff methodology. BGE considered that the capacity/commodity split for VRF charges should be 90:10 for consistency.

2.2.11 Monthly multipliers

Query: 7A. “What are your views on the CRU’s proposal to reduce the current monthly multipliers to comply with the monthly multiplier bound of 1.5 as set out in the TAR NC?”

All the respondents supported the CRU’s proposal to reduce the monthly multipliers to a total of 150% of the annual product. Respondents generally considered that the proposal was good for stability because it avoids a significant change from their current levels. One respondent (Tynagh Energy) suggested that, if it was likely that ACER would recommend reducing the daily multiplier to 1.5, the monthly should be capped at 1.35 and the quarterly at 1.2.

2.2.12 Quarterly multipliers

Query: 7B. “What are your views on the CRU’s proposal to reduce the quarterly multiplier to 1.35?”

A majority of respondents was supportive of the CRU’s proposal to reduce the quarterly multipliers to a total of 135% of the annual product. Respondents considered that this reduction was prudent in
order to incentivise the booking of quarterly capacity.

One respondent (IOOA) agreed with the proposal but argued that the multipliers should not be reduced any further, in order to avoid a reduction in annual bookings and an increase in the yearly tariff.

Another respondent (Tynagh Energy) approved of the proposal but was in favour of a further reduction, to 120% of the annual product, to properly incentivise quarterly bookings.

In addition, there was a respondent who was of the view that any impact of the proposed changed on the use of the quarterly product should be monitored and discussed with stakeholders (ESB Generation and Trading).

2.2.13 Seasonal factors

Query: 7C. “Should a reduction in the range of seasonal factors be considered?”

A majority of respondents who addressed this question was opposed to a reduction in the range of seasonal factors. Several respondents expressed concern that such a change would result in system usage shifting to winter from summer, while several others argued against the change on the grounds of stability and predictability.

One respondent (Manx Utilities) considered that alterations to the seasonal factors should not be considered in the short-term but could be considered if ACER recommended reducing daily multipliers to 1.5 by 2023. Another respondent (Energia) stated that the seasonal factors should not be changed while the effect of the CRU's other proposed changes is monitored. That respondent also argued that all multipliers, including seasonal factors, should be reviewed periodically.

It was suggested by one respondent (ESB Generation and Trading) that the CRU should present analysis on seasonal usage patterns and whether these patterns were caused by capacity cost differentials.

A minority of respondents expressed support for reducing the seasonal factors. One of those (Tynagh Energy) contended that the difference between Q1 and summer tariffs had not changed fundamentally in the last decade, while the seasonal profile of gas usage in generation had reversed. Another (BGE) argued that the reduction may be necessary to incentivise use of short-term products and assist the roll-out of flexible generation to complement renewable generation.

On the same question, a respondent (Electric Ireland) stated that the CRU should reduce the factors if current usage is found to be inefficient, while another respondent (Shell) saw the merit in a reduction of the factors but considered that a transitional approach should be taken if large changes to the factors were needed due to an ACER decision in relation to daily multipliers.

2.2.14 Approach to reducing daily multipliers

Query: 7D. “How should the CRU consider implementing a transitional approach in the case ACER
recommend reducing the daily multiplier to a maximum of 1.5?”

Among respondents, there was a clear majority in favour of adopting a phased implementation approach if any change is required by ACER. Several respondents were of the view that it would be appropriate to evaluate the effects of any change beforehand and that a consultation should be held.

One respondent (GNI) advised the CRU to give consideration, *inter alia*, to the fact that changes to multipliers make forecasting more difficult and that, if users move away from annual products, the price of annual products will likely increase.

One respondent (Tynagh Energy) was of the view that, if the daily multiplier had to be reduced, it should be done by increasing the cost of annual bookings, reducing the cost of short-term bookings and reducing the seasonal difference in tariffs.

**2.2.15 Other comments**

In addition to comments on the specific questions posed by the CRU, three respondents (Mutual Energy, Firmus Energy and Phoenix Natural Gas) questioned the relevance and impact of certain elements of the proposed model on customers in Northern Ireland, while highlighting some concerns.
3 Summary

This paper provides a summary of the responses received to the Commission for Regulation of Utilities’ consultation (CRU/18/247) on the harmonised transmission tariff methodology for gas. This consultation examined the reference price methodology used to calculate tariffs for use of the gas transmission network, in addition to related aspects of the tariff structure.

Section 1 of this paper provides a background and the context for this publication, while Section 2 provides a summary of the responses. This paper provides a summary of responses only, it does not provide a CRU view of the responses themselves. The CRU has attached the full-length responses in the Appendix to this paper. The CRU wishes to thank these responders for their feedback. These responses will aid the development of the CRU decision on harmonised transmission tariff methodology for gas.

The CRU will publish its decision on harmonised transmission tariff methodology for gas by 11 May 2019 and will respond to the consultation responses as appropriate in that paper.

Responses received from stakeholders related to the following aspects of the transmission tariff methodology: reference price methodology and its components; treatment of shrinkage; entry/exit split; capacity/commodity split; LNG discounts; biogas tariff; virtual reverse flow; multipliers and seasonal factors; and, charges for N.I. shippers.
Appendix – Full length consultation responses

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Response by Energia to
Commission for Regulation of Utilities'
Consultation Paper
CRU/18/247

Harmonised Transmission Tariff Methodology for Gas
Consultation Paper – Art. 26 & 28

11 February 2019
1. Introduction
Energia welcomes the opportunity to respond to the Commission for Regulation of Utilities (CRU) on this consultation addressing requirements under the EU Network Code on Harmonised Transmission Tariff Structures for Gas (TAR NC) to consult on the gas transmission tariff methodology.

This relatively brief response includes a short general commentary on the general proposal to retain the Matrix Reference Price Methodology (Matrix RPM) and goes on to address some specific questions in the consultation paper. For a number of these questions, while we welcome their inclusion here, we do request that particular matters are kept under review over the coming years and that CRU remain prepared to make changes, where required in the interest of the gas system and gas users.

2. General Comments
As part of this substantive consultation, Energia acknowledges both the process of engagement undertaken by the CRU in the Network Tariff Liaison Group (NTLG) meetings and the significant amount of material that has been provided alongside this consultation. We endorse this approach for the present purposes, as well as for similar substantive consultations in the future.

As a general approach, Energia remains supportive of the Matrix RPM as it is applied in Ireland. Recognising the limited options available to CRU under the TAR NC, the proposed continuation of the Matrix RPM is consistent with the criteria set out by CRU and within the TAR NC, notwithstanding some concerns over the application of LRMC to this particular issue. Save for the specific points raised in the next section of this response, Energia is generally supportive to the retention of the Matrix RPM in the present circumstances.

3. Responses to Specific Questions
Capacity / Commodity Split

4C. What are your views on the CRU's proposal to continue to apply a 90:10 capacity/commodity, taking into account the CRU's proposal to incorporate shrinkage into the transmission services revenue?

It would appear that this proposal constitutes a material change to the 90:10 split, as currently implemented, with the inclusion of shrinkage as a commodity charge, a proportion of the remaining commodity charges would appear to somehow convert to capacity charges. There is a basis for the current 90:10 split and unless there is a significant reason to amend this, we suggest the retention of this split, updated for the inclusion of shrinkage; i.e. reassess the appropriate split in capacity:commodity following this proposed change to retain the 90:10 split as applied today.

Energia supports the inclusion of shrinkage in the commodity element of the transmission charges but we note that a process for monitoring and reporting on shrinkage levels will still be required, and should be made available to all gas shippers in a timely manner.

Energia

February 2019
Discounts LNG

5A. What are your views on the CRU’s proposal to not apply a discount for LNG entry points at this time? Also, do you agree with the considerations that the CRU proposes to take into account when coming to a decision on the possible provision of LNG discounts in the future?

The rationale for this proposed approach is reasonable at this point in time but will require constant monitoring and possible review at points in the future. While it is possible for a potential investor, through a number of assumptions/scenarios, to develop a business case for a specific LNG facility in the absence of a tariff and/or discount structure; it is not possible to develop a robust investment case and/or attract potential investors/funders. Therefore, if one considers LNG facilities to be likely, it is necessary that the CRU remain agile to respond to the market and in the interim it may be sensible to engage in periodic market tests to try to uncover prices and identify any regulatory barriers to LNG development.

Biogas

5B. What are your views on the CRU’s proposal to apply a single notional biogas entry point tariff to all biogas entry points? What are your views on how the notional point should be constituted?

Given the relatively small-scale of biogas development assumed over the medium term, the proposal to have a single notional biogas entry point tariff would appear to be sensible. The criteria for setting this notional point should, at a minimum, include a requirement to minimise distortions and promote the development of the gas system on a fair and equitable basis.

5C. What are your views on biogas distribution entry tariffs relative to transmission entry tariffs and the additional factors which may need to be taken into account in designing such a tariff?

As stated above, the criteria for setting distribution entry tariffs should, at a minimum, include a requirement to minimise distortions and promote the development of the gas system on a fair and equitable basis.

VRF

6A. What are your views on the CRU’s proposed VRF tariff methodology and are the factors and magnitude of the factors proposed for the VRF tariff appropriate?

Energia welcomes the proposed introduction of the VRF tariff and while the proposed discounts are considered to be somewhat generous to VRF, we acknowledge the objectives CRU is seeking to achieve through the proposed discounts. The proposed introduction of a VRF tariff is an important development in terms of the fair and equitable treatment of shippers on the system. While the proposal has a relatively small impact of overall tariffs, the realignment of incentives bring the system more inline with the overall principles of the tariff regime.
6B. What are your views as to whether commodity charges should apply to use of the VRF product?

Energia considers the inclusion of a commodity charge for use of VRF is both appropriate and necessary to preserve the principles of the tariff regime and to provide the correct incentives and minimise distortions in the application of the tariff methodology.

Multipliers and seasonal factors

7A. What are your views on the CRU’s proposal to reduce the current monthly multipliers to comply with the monthly multiplier bound of 1.5 as set out in the TAR NC.

Energia welcomes this proposal and calls on the CRU to kept this matter under review to ensure that the appropriate balance and incentives are provided to gas users.

7B. What are your views on the CRU’s proposal to reduce the quarterly multiplier to 1.35?

Energia welcomes this proposal and calls on the CRU to kept this matter under review to ensure that the appropriate balance and incentives are provided to gas users.

7C. Should a reduction in the range of seasonal factors be considered?

Given the different changes proposed in the consultation paper, there is an argument to retain the current seasonal multipliers and assess the impact of the proposed changes. As part of our call for periodic reviews of the tariff multipliers, we think it is necessary that the seasonal factors be included in this review and, if appropriate, a separate exercise be undertaken to review the efficiency and efficacy of the current approach.

7D. How should the CRU consider implementing a transitional approach in the case ACER recommend reducing the daily multiplier to a maximum of 1.5?

While Energia has no immediate views on the form of a transitional approach, we do support the proposal coming from the NTLG.
Gas Networks Team  
Commission for Regulation of Utilities  
The Exchange  
Belgare Square North  
Tallaght  
Dublin 24  

14 February 2019  

REF: CRU/18/247  

Shell Energy Europe Limited (SEEL) response to consultation on Harmonised Transmission Tariff Methodology for Gas  

Dear Sir/Madam  

Shell Energy Europe Limited (SEEL) offers the following comments in response to this consultation.  

Reference Price Methodology and entry/exit split  

SEEL supports maintaining the current Matrix Reference Price Methodology and tariff structure, including the 90:10 capacity/commodity split, for the reasons set out by CRU in that it delivers a more stable and less volatile approach to setting transmission tariffs. We further support maintaining the 33:67 entry/exit split with a view to maintaining regulatory stability and cost reflectivity.  

Shrinkage  

SEEL supports the proposal to include shrinkage costs in GNI’s allowed revenue through the commodity element of the capacity / commodity split. We agree with CRU that all network users derive a benefit from the pressures being maintained throughout the system and operated to meet gas flow instructions, irrespective of location on the network. Recovering shrinkage costs through the transmission services revenue will ensure a competitive level playing field for different sources of supply to Ireland.  

Given that amendments to the code of operations, billing systems and possibly contracts for GNI and shippers/suppliers, we suggest that the change is not implemented until gas year 2020/21, to afford network users sufficient time to amend their contracts and for GNI to propose the relevant changes to the code of operations and billing systems.
Virtual Reverse Flow (VRF)

We have, through IOOA, previously supported and remain in support of, the continuation of the existing VRF tariff structure of an annual registration fee, with neither capacity nor commodity charges, which is perceived to pay the incremental costs of providing the service. Day-ahead and within-day tariffs should reflect the short-run marginal cost of making capacity available but there is no such cost associated with a virtual reverse flow service, so we do not consider that the proposed VRF tariff is cost-reflective. For the same reason, a commodity charge should not be applied to the VRF tariff as it is a virtual service, which is not linked to GB’s regulatory asset base.

We would further argue that multipliers and seasons factors should not apply to the VRF tariff as multipliers and seasonal factors are designed to avoid discrimination and cross subsidies between long-term and short-term capacity products. Given that it is not possible to book long-term VRF, which is predominantly a balancing service and not a capacity product, then multipliers serve no purpose for this virtual service.

We agree with concerns expressed by other NTI participants that higher tariffs may discourage use of VRF and, therefore, a higher reduction of the tariff is required to prevent a decrease in utilisation of the VRF service and avoid the risk of unduly impeding liquidity at the IBP.

Multipliers and seasonal factors

SEEL supports the CRU proposal for a minor adjustment to the monthly multipliers so that their sum comes within the bounds of the 1.5 limit set by the TAR NC. Whilst we see merit in a reduction in the variation of seasonal factors to incentivise the use of shorter-term capacity products, we share the view of some NTI participants that more significant changes to account for the possible future requirement for multipliers for daily and within-day products to be limited further to 1.5 of the annual product by 1 April 2023, as per the TAR NC, should be effected by a transitional approach. We understand that the CRU will keep this topic under review as part of the obligation to conduct an annual consultation on multipliers.

Biogas entry point tariff

SEEL agrees with the principle of incentivising biogas injection in its infancy. However, we do not consider that the consultation on implementation of the EU Tariff Network Code (TAR NC) is the appropriate route for assessing the most efficient and economical way to incentivise renewable energy technology.

SEEL largely supports a technology neutral approach to tariffs to ensure that all options to decarbonise gas can compete on a level playing field. We accept, however, that approaches for incentivising renewable investment may need to be tailored to the specific market and there may be some merit in using tariffs in the first instance, for the Irish gas market. Our preferred approach would be to issue a separate consultation on the most appropriate route to incentivising renewable technologies, to avoid the risk of creating distortions in the type of low carbon technology incentivised.

Should the TAR NC approach be pursued, however, a geographically dispersed model, which reflects the likelihood that small-scale biogas entry will be located near to the point of production provides the most cost-reflective approach for setting the biogas tariff. In the interests of ensuring a level playing field for low carbon technologies, we consider that this approach should be reviewed on an annual basis.
LNG discount

SEEL concurs with CRU that the Matrix RPM already provides a cost-reflective incentive to new entry investment. As highlighted in the consultation, a discounted LNG tariff would increase tariffs at all other entry points, including Mountrath, which would increase the cost of wholesale gas in Ireland, potentially leading to increased costs to customers.

We do not believe that the merits of the provision of LNG discounts should be decided on a project-by-project basis as this could drive tariff uncertainty. Of course, should material changes in the conditions in the Irish gas marker arise, we agree it would be appropriate to revisit the topic through an open and transparent consultation.

Please do not hesitate to contact me, should you wish to discuss any aspect of this consultation.

Yours faithfully
Shell Energy Europe Ltd
Dear Cahir,

Harmonised Transmission Tariff Methodology for Gas Consultation Paper - Art. 26 & Art. 28

ESB Generation and Trading (ESB GT) welcomes the opportunity to respond to your consultation paper outlining the Republic of Ireland’s implementation of the EU Regulation 2017/460 establishing a network code on harmonised tariff structures for gas (TAR NC). Our general comments are provided below; answers to the specific consultation questions are provided in the Annex to this response.

As you are aware, ESB GT had concerns about the compressed timeline for stakeholder engagement and issues analysis. The later delays in provision of a functioning illustrative tariff model to stakeholders has shown that the initial front loading of the programme may not have been optimal. ESB GT respects the required consultation period of two months, and the May deadline for a CRU decision for TAR NC compliance, drove the issuance of the consultation paper and materials in mid-December. We note that the provision of interactive guidance on use of the tariff model took place after one month of the consultation period had already passed. The timings for publication and model guidance have meant that stakeholders have not been able to make use of the full two month consultation period.

Overall ESB GT is pleased that the CRU has made use of previous work and upheld decisions made following the 2015 NTLG and consultation process. The stakeholder group discussions of several key issues and grounds for their resolution has been welcome. This follows the TAR NC principles of transparency, stability and predictability. ESB GT supports the CRU’s intention to continue in its prioritisation of these principles in gas transmission charging.

Yours sincerely,

Regulation
ESB GT
Annex: Response to 8.1 Request for Comment

3A: What are your views on the CRU’s proposal to continue to apply the Matrix RPM?

ESB GT supports the CRU’s proposal to continue to apply the Matrix reference price methodology (RPM). We support the CRU view that the original grounds for selection of the Matrix RPM remain valid. The use of a methodology based on long run marginal cost (LRMC) is appropriate for a gas network which continues to expand and gas sources continue to change. It supports efficient new entry investment and competition, provided that no distortive elements are subsequently applied to the methodology.

The CRU has outlined its view of compliance with TAR NC Article 7. ESB GT generally supports the CRU’s assessment.

Under Article 7 (a), TAR NC requires that the RPM allows network users to reproduce and forecast the reference prices. ESB GT agrees that the RPM itself has been clear and transparent. We do not believe that it is over-complex. The illustrative spreadsheet model provided allows the user to reproduce some tariff scenarios, including user defined scenarios, but it is limited by the anonymization of Exit points. This means that forecasting the potential impact of a new offtake location, for example, is very difficult.

The principle of cost-reflectivity under Article 7 (b) is more clearly upheld under a LRMC approach than under the capacity weighted distance (CWD) counterfactual. CWD is a cost allocation method, using distance and capacity as elements in a calculation to carve up allowed revenues.

ESB GT agrees that the principles of non-discrimination and no undue cross-subsidy under Article 7 (c) are features of the Matrix RPM as presented. Any differential treatment of specific points or types of point will need to be considered thoroughly prior to implementation.
4A: What are your views on the CRU’s proposal to class shrinkage as a transmission service and to recover the cost through the commodity element of the capacity/commodity split rather than through a separate flow-based charge? Also, what are your views on a date of implementation of gas year 2019/20?

ESB GT understands the CRU’s grounds for the classification of shrinkage charges as transmission services and inclusion within the commodity charge: we welcome the intention to continue with a 90:10 split of capacity and commodity charging in the interests of stability. ESB GT supports the application of the full commodity charge (i.e. including shrinkage) at all points, as the benefits of system usage, including access to wholesale markets, accrue to all network users.

ESB GT highlights the recent issues that GNI has had with shrinkage management and the late communication of those to stakeholders. While we understand the specific problem to be resolved, it is a clear signal that greater scrutiny is justified in this area. Increased volatility of the commodity charge stemming from the inclusion of shrinkage is also a concern. ESB GT therefore supports the CRU’s proposals for greater transparency and frequent information provision from GNI, with closer regulatory oversight. The shrinkage element share of the commodity charge should be clearly defined and reported, as well as the constituents of the shrinkage cost itself. Forecasts should be made throughout the year, together with updates on performance against forecast. Shippers should be able to ask questions and challenge GNI’s performance. There should be no surprises to stakeholders at year end.

A shrinkage incentive on GNI is appropriate. ESB GT notes that National Grid is incentivised to reduce shrinkage costs via an incentive legislated for within its licence. It provides detailed information on the measures it takes and the costs it incurs. For example, National Grid is measured against a market benchmark on its price risk management and assessed on its volume efficiency based on outward conditions. It is clear that consideration should be given to adequate legislative measures for targeting and monitoring of performance in the case of incentivising GNI.

Concerning implementation timelines, ESB GT notes that GNI has indicated that it needs additional time to update systems and prefers 2020 introduction of this change. We support GNI’s preference on this matter. ESB GT recommends that GNI is tasked with providing shadow commodity charge pricing throughout Gas Year 2019, in order to provide an indication of the impact of this change and potential for annual volatility. In addition, we recommend that GNI provides regular
forecast and performance methodologies and updates to stakeholders in preparation for implementation the following year. Improvements can then be incorporated in a timely fashion.

4B: What are your views on the CRU’s proposal to continue to apply a 33:67 entry/exit split?

ESB GT understands the CRU grounds for maintaining the 33:67 entry/exit split of charging. We note that TAR NC is not in itself prescriptive on this, but the counterfactual approach and ACER’s framework guidelines suggest a 50:50 as a general principle. Detailed justification of the cost split may be required.

4C: What are your views on the CRU’s proposal to continue to apply a 80:10 capacity/commodity, taking into account the CRU’s proposal to incorporate shrinkage into the transmission services revenue?

ESB GT welcomes the continuation of the current split with the intention of supporting stability of the tariff regime (see our response to 4A above).

ESB GT has concerns regarding TAR NC compliance. Shrinkage, including Unaccounted for Gas (UAG), is permissible as a commodity charge as it is predominantly driven by the volume of gas flowed. The figures presented indicate that shrinkage constitutes 7.5% or less of the GNI allowed revenue rather than the 10% commodity share requested. Reductions in shrinkage achieved through targets placed on GNI should serve further to decrease the actual proportion of flow-driven costs in future. Greater justification for the 10% commodity share may therefore be required.

4D: What are your views on the CRU’s proposal to update these components of the Matrix RPM?

ESB GT supports the CRU’s proposed updates to the expansion constant calculation. The proposals appear transparent and justified, as new assets have been constructed and up to date information is available. We also support making updates every five years rather than on an ad hoc basis. ESB GT agrees that this period should provide a balance between stability of the expansion factor and relevance of the calculation elements.
5A: What are your views on the CRU’s proposal to not apply a discount for LNG entry points at this time? Also, do you agree with the considerations that the CRU proposes to take into account when coming to a decision on the possible provision of LNG discounts in the future?

ESB GT supports the CRU proposal not to apply a discount for LNG entry points. We consider that applying a discount would undermine the LRMC RPM’s intention to incentivise efficient new entry investments. Differential treatment of specific points would be distortive and anti-competitive in this context, counter to Article 7 (c) of TAR NC. Due to the nature of the Irish gas system, applying a discount to an individual entry point would also have an impact on the price of wholesale gas: the revenue that is not recovered due to the discount must be recovered from other entry points, and while Moffat is the marginal source of gas, transport costs there are integral to the wholesale gas price. The increased wholesale price would be passed through to end-users, with value accruing to the LNG player. This is demonstrated in Table box 1 and section 5.2.2.3 of the consultation paper.

ESB GT does not believe that the gas transmission charging regime is the correct method to support LNG or any other new entrant. If government policy is to support diversity of gas supply, for example, then this should be via a clear and transparent approach, such as a PSO paid by all energy users.

In addition to the above points, the proposal to provide discounts for LNG entry points on a case by case basis presents further issues. Firstly, it adds uncertainty to the regime: we would be concerned of major changes to the tariff regime within the five year tariff period. Secondly, once granted, a discount would be reviewed annually under Article 28 1 (c) by consultation, and may therefore change adding to the uncertainty. Thirdly, the Irish gas market will not be capable of accommodating more than one LNG regasification unit due to scale. Therefore the first project that is able to make sufficient justification to CRU will effectively be picked as “winner”, regardless of whether it would be the best project for the market in the long-term by comparison with others. Finally, TAR NC compliance on grounds of cross-subsidy, competition and discrimination may be an issue.

In terms of the criteria for any project assessment, with excess capacity in GB LNG terminals and in the interconnector pipelines, the efficiency of new construction in achieving diversity of supply should be considered. ESB GT adds that balance will need to be applied when considering submission. For example, while LNG can provide access to global markets, it also provides exposure to global price shocks. The diversity of supply does not guarantee any security of supply or security of price level. Unlike pipeline gas, LNG may take days to arrive when it is needed.
Stakeholders should be able to review and to challenge any cases put forward for LNG entry.

5B: What are your views on the CRU’s proposal to apply a single notional biogas entry point tariff to all biogas entry points? What are your views on how the notional point should be constituted?

Similar to our points under 5A above, it appears counter-intuitive to create a LRMC with the aim of achieving efficient new entry investment and then undermine it with differential treatment of particular entry points. In addition it is not clear that the proposal for RNG entry points complies with TAR NC Article 6.3, which specifies that the same RPM shall apply to all entry and exit points in a given entry-exit system.

We accept that clustering of homogenous points is acceptable under TAR NC. This can be seen to apply in Ireland with the equalisation of tariffs at all exit points, as well as the intended approach in other markets. For RNG entry points, we agree with the statement at 5.3.1 that it is important that the tariff is broadly reflective of the likely location of new production sources. Neither of the options presented appears to meet this objective. Option 1 provides a construct based on three locations, all or none of which may eventually be the site of a RNG production facility. Option 2 suggests a location close to a demand centre, when RNG production tends to be sited close to the source of the digestion materials, usually agricultural waste or crops, and likely to be remote from demand. ESB GT suggests that actual proposed projects and site locations would be better considered as inputs to the development of a notional point.

The concept of RNG entry is outlined as small-scale in the consultation paper. GNI’s 2018 Ten Year Network Development plan discussed the strategic objective of increasing RNG volumes up to 20% of Irish gas demand by 2030. It is likely that even if this level were to be reached, much of this gas would be injected to distribution networks and consumed locally, which would lead to more efficient investment in infrastructure and best value to the consumer. The SEAI has published comprehensive analysis which suggests that there is a total biogas potential in Ireland of 1,044 ktoe of which 534 ktoe would be available for injection into the gas network as biomethane.\(^1\) SEAI also shows that there might be sustainability criteria concerns with the 1,044 ktoe figure given the significant reliance on carbon intensive grass production. While the SEAI analysis shows the outer limits for biomethane injection, there is a possibility that the charging decision

\(^1\) SEAI (2017): Assessment of Costs and Benefits of Biogas and Biomethane in Ireland.
made today could have unintended consequences in future for tariffs at other entry points. Therefore, and similar to our response to 5A above, government policy to support RNG may be more appropriate and transparent targeted directly rather than via gas transmission tariffs. We would draw parallels to the connection of wind generation to the electricity system, where the developer picks up the costs and the costs are subsumed in the REFIT/PSO/RESS payment. This avoids multiple subsidies for a single technology. It also avoids the need to remove the favourable biogas entry tariff should biogas emerge at scale in the future.

ESB GT notes that GNI is yet to discuss the issue of transmission level RNG injection with stakeholders. ESB GT has offered to engage with GNI on the scoping and development of any work in this area, with specific concerns about gas quality specification and stability, and potential impact on equipment.

5C: What are your views on biogas distribution entry tariffs relative to transmission entry tariffs and the additional factors which may need to be taken into account in designing such a tariff?

ESB GT has no views to contribute on this question.

6A: What are your views on the CRU's proposed VRF tariff methodology and are the IIf yes are factors and magnitude of the factors proposed for the VRF tariff appropriate?

ESB GT is supportive of the principle to apply TAR NC aims to the VRF tariff calculation. Article 6 3 states that a single RPM should be used for all entry and exit points in a given entry-exit system; provision is made for Interruptible tariffs in Article 16.

The proposed approach, including derivation and application of the adjustment factors, is incomplete and intransparent however.

- Limited data for the Interruption element at Moffat has been presented on the basis of days when VRF allocations were recorded and were interrupted.
- It is noted in the consultation paper that the data is incomplete and will be updated, but with no indication of a timeline.
- For Gormanston, where there is no forward flow and therefore neither VRF allocations nor interruptions to analyse, the CRU has taken the Moffat VRF probability of interruption as a parallel. This seems unjustified; the probability factor should surely be zero.
- The application of a 10% risk premium at Gormanston, based on the perception of the reduction in value of the product beyond the probability of
Interruption itself, seems unreasonable. The risk premium at Gormanston is entirely theoretical; it could be zero or 100%.

- For Moffat, a 10% risk premium is proposed. We have not been able to evaluate this figure in the time provided.
- The 30% market interaction factor at Moffat is used to address the impact of the 33:67 entry:exit split, decreasing the VRF tariff to just below the forward flow tariff. ESB GT agrees that it appears strange for a firm product to be cheaper than an interruptible product, and for moving gas from a higher price to a lower price market. We have not been able to evaluate this figure in the time provided.
- The observation that a higher VRF may lead to more TSO balancing actions requires analysis.
- ACER will require detailed and transparent justification of the approach, and calculations behind it, in order to assess compliance.

In light of the above comments, ESB GT suggests that more work is required prior to the implementation of changes to the VRF tariff methodology. We support continued work on this issue with the aim of TAR NC compliance as soon as practicable, and note that question 4A above offers the option for change to become effective from 1 October 2020.

69: What are your views as to whether commodity charges should apply to use of the VRF product?

Interpreting Article 4.3 of TAR NC on flow-based tariffs, as there is no physical flow driving costs the commodity charge should be set at zero. It could be argued that the presence of virtual flow is driving some costs which should be recovered, but this is likely to be an administrative fixed cost rather than variable to virtual flow volumes and therefore does not fit with the Article 4 definition.

7A: What are your views on the CRU’s proposal to reduce the current monthly multipliers to comply with the monthly multiplier bound of 1.5 as set out in the TAR NC.

ESB GT supports the CRU proposal to make minimal change in order to comply with TAR NC. The intentions of stability and predictability of the tariff regime are welcomed.
7B: What are your views on the CRU’s proposal to reduce the quarterly multiplier to 1.35?

ESB GT foresees no issues with this proposal. We recommend that if the proposed change is made, use of the quarterly product is monitored. If the CRU can determine any effects or impacts, they should be discussed with stakeholders. ESB GT notes that annual consultation on multipliers (at IFs) is provided for in Article 28 of TAR NC.

7C: Should a reduction in the range of seasonal factors be considered?

ESB GT does not support a reduction in the range of seasonal factors as outlined in Figure 7.1. We support minimal change in this area on the grounds of stability and predictability of the regime. The discussion of seasonal factors in the consultation paper includes some conjecture around seasonal usage patterns and whether they are driven by capacity cost differentials. It would be helpful to present analysis on this issue to support conclusions, such as elasticity of demand and the costs to the gas system of winter peaks.

7D: How should the CRU consider implementing a transitional approach in the case ACER recommend reducing the daily multiplier to a maximum of 1.5?

As ACER is not due to make a decision on this issue until 2021, for implementation in 2023, ESB GT supports a pragmatic approach: should a decision be reached which requires change, further consultation will be needed. This can be conducted with the annual Article 28 consultation on multipliers. Our current view is that implementation should take a phased approach to reduce the daily multiplier. We support the CRU in not taking pre-emptive action, as the change may not be required.
Gas Networks Team,
Commission for Regulation of Utilities,
The Exchange,
Belgard Square North,
Tallaght,
Dublin 24
11th February 2019

Re: CRU Consultation Paper ‘Harmonised Transmission Tariff Methodology for Gas’ (CRU/16/247)

The Renewable Gas Forum Ireland (RGFI) welcome the opportunity to respond to the CRU consultation paper ‘Harmonised Transmission Tariff Methodology for Gas’. RGFI is an Industry forum representing the interests of a broad range of stakeholders involved in the entire renewable gas supply chain across the island of Ireland. RGFI is committed to influencing, supporting and delivering policies and initiatives that promote the development of the renewable gas industry in Ireland as an economically viable and environmentally sustainable component of the overall energy mix. RGFI is an advocacy group on behalf of gas consumers seeking the supply renewable natural gas (Biogas) to decarbonise Heat, Transport and Power Generation sectors. RGFI sets out its views below on the Biogas entry tariff proposals addressed in the consultation paper.

5B. The CRU is proposing to introduce a notional point which will be used to set a single tariff for biogas entry points. What are your views on the CRU’s approach to apply a notional biogas entry point and how this point is constituted?

RGFI supports the option to introduce a single notional tariff based on a location close to a demand centre. The renewable gas industry is in its infancy, with flows at only one entry point anticipated in 2019. Opting for a tariff based on one location appears more appropriate at present that choosing a number of geographically dispersed locations. Over time, as the industry develops, the choice of entry point location can be revisited and the actual locations of entry points factored into the re-calibration of the tariff.

It is worth noting that the GNI connection policy places an incentive on biogas entry points to locate close to the existing network: an AD producer seeking to connect to the GNI network must pay 30% upfront of the cost of a connection from their plant to the network, with an economic appraisal performed to ensure the remaining 70% will be recovered through network tariffs. For plants producing less than 40 GWh, a direct connection will not be economically viable and they will deliver their gas via tanker to a shared entry point. Shared entry points will be strategically located on the existing network. Therefore, biogas entry points will not be imposing costs (i.e. generating increased tariffs) on existing network users.

Renewable Gas: For your Future
Biogas producers will welcome a simple and stable biogas tariff arrangement. This will ensure the required building blocks are in place to facilitate predictable investment decisions to be made and allow for the development of a renewable gas industry in Ireland.

5C. What are your views on biogas distribution entry tariffs relative to transmission entry tariffs and the additional factors which may need to be taken into account in designing such a tariff?

RGFI notes that the current distribution tariff system does not charge entry tariffs but that all costs of the distribution system are charged at exit. For biogas entering the distribution system, RGFI is proposing that the status quo remains in place: that there is no entry tariff introduced and all tariffs continue to be charged on all volumes of gas when they exit the network.

As with the transmission system, the GNI connection policy places the same incentive on biogas entry points to locate close to the existing distribution network. For plants producing less than 25 GWh, a direct connection to the distribution network will not be economically viable and they will deliver their gas via tanker-based solution to a shared entry point.

There is also benefit to gas flows directly entering the distribution network as such flows are by-passing the transmission system and avoid or alleviate the need for potential reinforcement.

RGFI is proposing that biogas directly entering the distribution system should not incur an entry tariff initially. A review can be carried out in c. 5 years to examine the development of the biogas industry and its impact on the distribution network. At that stage, consideration could be given to changing the distribution tariff methodology to an entry-exit system if merited.

Conclusion

RGFI believes that the CRU should allow the biogas industry in Ireland to develop before making any policy decisions regarding biogas tariffs. The industry is in its infancy and it needs stable and predictable tariff arrangements to be set for the medium term to encourage renewable gas to enter the network.

Yours sincerely,

[Signature]

Renewable gas for your future

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Re: Shannon LNG Response to Harmonised Transmission Tariff Methodology for Gas Consultation Paper – Art. 26 & 28

VIA EMAIL

Dear Sir or Madam,

We are pleased to submit Shannon LNG’s responses to the CRU’s requests for comment set forth in the Harmonised Transmission Tariff Methodology for Gas Consultation Paper – Art. 26 & 28.

Yours faithfully,

Shannon LNG Limited

Enclosure
Responses to CRU Harmonised Transmission Tariff Methodology
for Gas Consultation Paper – Art. 26 & 28

The CRU has requested input from stakeholders, including us, on the proposed methodology to be adopted in Ireland in accordance with the EU network code on harmonised transmission tariff structures for gas (the TAR NC). We appreciate the opportunity to provide our views and feedback to the CRU as part of this important process.

Below we have set forth our responses to the requests for comment included in the CRU’s consultation paper. We have strived to make our responses as clear and concise as possible, but we are available to elaborate on or clarify any of our responses if that would be helpful to the CRU’s analysis and decision-making.

Thank you in advance for your consideration of our feedback.

1. CRU Request for Comment 3A: The CRU’s proposal to continue to apply the Matrix Reference Price Methodology

**Response Part 1 – Concerns with Matrix RPM**

We believe that the Capacity Weighted Distance methodology (CWD), which is the default under the TAR NC, would be the fairest and most appropriate approach to determining entry point tariffs consistently with the rest of the EU.

To evaluate the impact of using the CRU’s proposed Matrix Reference Price Methodology (Matrix RPM) as compared with CWD, we ran the GNI tariff model using scenario 2 for 2020/21 using the two methodologies. To ensure that we compared the Matrix RPM with the approach taken elsewhere in the EU, we ran the model with CWD using an entry/exit split of 50:50 and 33:67 (which has been proposed to be used by other EU member states such as Belgium). The results were as follows:

<table>
<thead>
<tr>
<th>Entry point</th>
<th>Matrix RPM</th>
<th>CWD 50:50</th>
<th>CWD 33:67</th>
</tr>
</thead>
<tbody>
<tr>
<td>Moffat tariff</td>
<td>€419.66</td>
<td>€763.80</td>
<td>€504.11</td>
</tr>
<tr>
<td>Foyles tariff</td>
<td>€241.78</td>
<td>€351.06</td>
<td>€231.70</td>
</tr>
<tr>
<td>Differential</td>
<td>€177.88</td>
<td>€412.74</td>
<td>€272.41</td>
</tr>
</tbody>
</table>

The large disparity between the Moffat-Foyles differential using the Matrix RPM compared with the result using CWD (particularly with a 50/50 entry/exit split) concerns us, as it appears to evidence cross-subsidization by the users of the Foyles point to cover costs of the network that should be borne by the users of the Moffat entry point.

**Response Part 2 – Concerns with Rescaling Methodology**

We believe that if the Matrix RPM is used, it would be more appropriate and more consistent with the approach taken by the European Network of Transmission System Operators for Gas (ENTSO-G) to use a multiplicative, rather than an additive, rescaling factor.

As noted in the consultation paper, the ‘primary’ tariffs set by the Matrix RPM do not fully recover GNI’s transmission services revenue, and to make up this shortfall a ‘rescaling factor’ is applied. CRU’s proposed methodology uses an additive rescaling factor, which means that the same amount is added to every entry point.
We first wish to respectfully point out that the use of an additive rescaling factor appears to conflict with the ENTSOG information manual, which recommends using a multiplicative factor that retains the relative differential between entry points. We note that the CRU is observing the ENTSOG recommendations in the areas of virtual reverse flow and seasonal multipliers but has yet to do so in this crucial issue.

More concretely, we believe the use of additive rescaling may cause the type of "undue cross-subsidization" the CRU and the TAR NC seek to avoid. Based on our review of the costs identified in the CEPA report for PC5, we have estimated that the use of additive rescaling results in undue cross-subsidization of up to €15 million per annum from the users of the Foynes entry point to the users of the Mothaf entry point. This can be corrected by using multiplicative rescaling.

2. CRU Request for Comment 4A: The CRU's proposal to class shrinkage as a transmission service and to recover the cost through the commodity element of the capacity/commodity split

Response: We do not agree with this proposal. It is our understanding that shrinkage consists mostly of the cost of compressors in Scotland, and accordingly we believe that the cost of these compressors should be charged to the users of the Mothaf entry point. In our view, its inclusion in the tariff as proposed would cause undue cross-subsidisation in conflict with the principles of the TAR NC.

3. CRU Request for Comment 5A: The CRU's proposal to not apply a discount for LNG entry points at this time and the proposed considerations to take into account when coming to a decision on the possible provision of LNG discounts in the future

Response Part 1 – Intent to Submit LNG Discount Application

We note that “The CRU’s intention is that LNG developers would have one opportunity to provide evidence per project as part of an application in relation to the provision of discounts and the justification for any LNG discount”. We intend to make such an application and to address the issues covered in Section 5.2.2 of the consultation paper and other relevant considerations at that time.

Response Part 2 – Comments on Proposed Conditions to Assess LNG Discount Applications

We agree with the proposed conditions. In our view, one of the important items to be considered in connection with any of the listed conditions is the downward pressure on the cost of gas to Irish consumers that would result from the entry of a new source of gas into the Irish market.

4. CRU Request for Comment 6A: The CRU proposal to interpret virtual reverse flow (VRF) as an interruptible product and to produce a VRF tariff

Response:

We view VRF as bringing very important balancing flexibility to the Irish gas market without imposing any new costs on the infrastructure already in existence. In light of this, we believe that the indicative VRF tariff of €272 per MWh may be too high and could have a negative effect on Irish Balancing Point liquidity and new investment.

5. CRU Request for Comment 6B: Whether commodity charges should apply to the use of VRF

Response: We believe there should not be a commodity charge, as VRF adds no new cost to existing infrastructure.
6. CRU Request for Comment 7A: The CRU's proposal to reduce the current monthly multiplier to comply with the bound of 1.5.

Response: We agree with this proposal.

7. CRU Request for Comment 7D: Implementation of a possible ACER proposal reducing the daily multiplier to maximum of 1.5.

Response: We are concerned by such a significant reduction and would suggest evaluating the effect of the reduction in the quarterly multiplier before moving forward with this.

8. Other CRU Requests for Comment (4B, 4C, 4D, 5B, 5C, 7B, 7C)

Response: Other than as covered in our response to request for comment 4A, at this time we do not have any further comments to those items.
Consultation on the Harmonised Transmission Tariffs for Gas.
Mutual Energy response — February 2019

Mutual Energy welcomes the opportunity to respond to this consultation on behalf of its three wholly owned subsidiaries Premier Transmission Limited (PTL), Belfast Gas Transmission Limited (BGTL) and West Transmission Limited (WTL), which are each TSOs holding licences to convey gas in Northern Ireland (“NI”)

2. Whilst this consultation ostensibly concerns a neighbouring jurisdiction, we are responding due to deficiencies in how the significant potential detrimental impact of these proposals on NI has been considered and presented which, without correction, would lead to an apparent failure to comply with the relevant regulations.

1 Interaction between GB, NI and ROI gas transmission systems

All gas flowing into Northern Ireland currently comes from Moffat in Scotland via the Scotland to Northern Ireland pipeline (SNIP) which connects to the GNI(UK) system at Twynholm and runs towards the coast, supplying Stranraer in GB and crossing the Irish Sea to Ballylumford in Northern Ireland.

The commercial arrangements for SNIP’s interface with the GNI system are set out in a Transportation Agreement (“TA”) between GNI and PTL. This agreement resulted from the intention to share infrastructure and “avoid the proliferation of pipes in Scotland and the Irish Sea” and is enshrined by the provisions of an Intergovernmental Treaty from 1993 between the Government of the United Kingdom of Great Britain and Northern Ireland and the Government of the Republic of Ireland (“ROI”).

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2 PTL also holds a licence in GB
2 SNIP is owned and operated by Premier Transmission Ltd.
The TA currently provides for the transportation of up to 8 mscm/d of gas to Northern Ireland via Twynholm in Scotland and no gas currently flows into Northern Ireland or through Twynholm other than that which the TA provides for.

We note that whilst not explained (or even mentioned) anywhere in the consultation document the accompanying model includes Twynholm as an exit point with an exceptionally high tariff. It is therefore presumed that the calculated tariffs for Twynholm and Gormanston exit in this model would apply to shippers who wish to transport gas to Northern Ireland from Moffat but outside of the TA arrangements or from some other entry point to the GNI system. However, we also note that arrangements are in place for gas to flow from Moffat and the GNI (UK) system to the Isle of Man but no separate tariff has been calculated for that route outside of these arrangements. Additionally, an entry point at Gormanston is modelled but none at Twynholm. It is therefore not clear how flows to anywhere other than the Republic of Ireland are dealt with under the proposed tariff methodology as there is no explanation or consistency of approach.

We are very concerned that Indicative tariffs published alongside this consultation, and the application of the Matrix RPM, distort cross-border trade, providing inefficient Investment signals and we provide more detailed comments below.

2 Compliance with criteria set out in Art. 7 of TAR NC

We see a number of issues with the CRU's assessment of the compliance of the Matrix RPM with article 7 of the TAR NC. Page 2 of the consultation document states "Compliance with these criteria should not lead to reference prices that are in breach of the requirements stated in Article 13 of Regulation (EC) 715/2009". It appears to us that the listed criteria have not been complied with which leads to the conclusion that the reference prices are in breach of the requirements of that regulation.

2.1 Cost reflectivity

One of the CRU's own principles for satisfying this criterion is: "These revenues are allocated to each entry and exit point relative to a reasonable proportion of the costs for using the network via the entry or exit point in question"

With regard to the indicative exit tariffs at Twynholm and Gormanston this is clearly not the case. The Twynholm exit tariff calculated under the matrix approach is more expensive than any other exit tariff on the network (except the pre-discounted Moffat VRF tariff). It is not possible for gas to physically move from the Republic of Ireland to Twynholm, so this tariff is effectively a charge for moving gas the short distance from Moffat to Twynholm.

According to the unit cost assumptions in the tariff model, an estimate of the annualised costs of the infrastructure required between Moffat and Twynholm to service Northern Ireland (8 mscm/d) is approximately €4.6m per annum. Applying the Moffat entry tariff of €3.11/MWh plus the €493/MWh Twynholm exit tariff included in the model would result in capacity costs of around €70m for 8 mscm/d, which is obviously many multiples of the actual cost of providing the infrastructure and absolutely not cost-reflective. Such a tariff is clearly prohibitively expensive when compared to building the required infrastructure so would distort cross border trade and investment. While it is intuitively obvious that the Twynholm exit tariff is not cost reflective, this is further evidenced by the disparity between the outputs of the CWO approach - €208/MWh (or €155/MWh using 50:50 capacity commodity split) versus €493/MWh under the Matrix RPM.
Effectively the same point applies with regards to the Gormanston exit tariff. The South-North Pipeline ("SNP", which is part of the Northern Ireland gas network) connects directly to GNI's IC2 interconnector at Gormanston and gas cannot physically flow to Gormanston from any other ROI entry point. Any shipper that wishes to flow gas across GNI's interconnector and into Northern Ireland makes no use of GNI's onshore gas network but under these proposals would pay a total tariff (Moffat entry and Gormanston exit) which is 97% of that paid by a shipper exiting at any point on GNI's network. This equates to Northern Ireland shippers making a double contribution to the cost of GNI's interconnectors which was found to be legally unsound in 2014 and, whilst the CRU has since reformed the derivation of tariffs, much of that legal advice is relevant as a response to this consultation, particularly around compliance with 715/2009. As with the Twynholm tariff, the Gormanston tariff under the Matrix RPM does not compare well with that under the CWD approach (being 36% higher) or indeed the cost of putting infrastructure in place.

2.2 Non-discrimination and cross-subsidisation

The CRUs assessment states that there are no transit flows via the ROI transmission network so have given this criterion little attention. This ignores the fact that transit flows are possible (from Gormanston to NI) and the reason why there are no transit flows -- it is uncompetitive due to the current (and proposed) tariff arrangements for moving gas via Gormanston. These tariffs mean this transit route will only be chosen as an absolute last resort but, regardless of whether there are any flows, transit tariffs have been calculated and quoted so should be assessed as such.

It also seems that if Twynholm is considered an exit point then flows between Moffat and Twynholm would be considered transit flows - since two transit exit points have been included in the tariff calculation, it does not therefore seem that the consultation is wholly compliant with the requirement to perform cost allocation assessments as per Article 5 of the TAR NC. If these cost allocation assessments were carried out using the Twynholm capacity tariff calculated under the Matrix RPM, the result would vastly exceed the 10% recommended in Article 5 (6). As per Article 5 (6) justification for these results is required from the perspective of ensuring non-discrimination and preventing undue cross-subsidisation.

The results of this assessment based on transit gas moving to Northern Ireland from Moffat via Twynholm suggest that application of the Matrix RPM tariff would result in Northern Irish consumers subsidising costs elsewhere on the network as a result of being charged tariffs which are not cost-reflective and appear discriminatory towards Northern Irish consumers.

2.3 Cross-border trade

As per the above, the consultation document disregards the negative influence of the tariffs calculated under the Matrix RPM on potential cross-border trade with Northern Ireland, choosing to focus only on assessing VRF products' impact on cross-border trade. There are currently no flows from ROI to Northern Ireland via Gormanston as the Gormanston exit tariff is a barrier to such ROI to NI trade. Continued use of the Matrix RPM to calculate a Gormanston tariff will do nothing to improve cross-border trade at that connection point. The effect of the chosen methodology is that a party wishing to flow gas to Northern Ireland via Moffat and the Gormanston interconnection point is subsidising the costs of the wider ROI gas network by paying a tariff which is unrelated to any costs they are driving.

2.4 Transparency

We recognise that there has been a great deal of industry engagement on this topic and publication of relevant information. Where we take issue with transparency is around how the Matrix RPM has been described and its results presented.

The consultation document characterises the Matrix RPM as a distance related methodology but in effect it is largely a postalised tariff where location and the assets used have little to no bearing on the tariff paid. It seems that whilst it does have capacity and distance inputs, it does not adequately take these into account resulting in the large variances that we have highlighted versus the CWD approach. 67% of capacity revenues relate to uniform exit tariffs whilst nearly 60% of the entry revenues relate to a uniform ‘adder’ element so approximately 75% of the total required revenue has been postalised. This is described as ‘scaling’ but the ‘adders’ are identical so bear no relation to the tariffs they are applied to. The apparent complexity of the Matrix RPM means this effective postalisation is not abundantly clear in the consultation document and the justification for using the Matrix RPM instead of CWD is insufficient – this appears to have been avoided by presenting the two methodologies as being alike. Under the cost reflectivity criterion in section 3.4.2, the consultation document states: "the proposed RPM calculates reference prices based on the network costs drivers of capacity and distance in approximating the specific costs of each path. These are the same cost drivers that underpin the allocation of transmission services revenue under the CWD methodology that has been set out in TAR NC." Whilst this statement is not necessarily false, it is misleading in terms of the limited impact of these cost drivers on the tariffs calculated under the Matrix RPM.

TAR NC Article 26 requires “where the proposed reference price methodology is other than the capacity weighted distance reference price methodology detailed in Article 8, its comparison against the latter accompanied by [the indicative reference prices subject to consultation].” This required comparison appears to have been presented only selectively in section 3.3 as the Gormanston and Twynholm exit tariffs are not presented and, as we have highlighted, their inclusion would have demonstrated significant variances between transit tariffs calculated by the two methodologies.

3. Jurisdictional issues

Notwithstanding the arguments made above, because the possibility for transit flows has been ignored, it is not clear from the consultation if the proposed tariffs would apply to transit shippers to Northern Ireland or if there will be a further consultation on this matter.

All of Northern Ireland’s gas is currently supplied without leaving the UK and it is not physically possible for gas to move from the Republic of Ireland to Twynholm. Given that Moffat to Twynholm gas flows are wholly located in Great Britain, we would have expected detailed discussion and agreement with neighbouring regulators to be referenced in the consultation paper and it is not clear if these discussions have taken place. The tariff at Twynholm is much too large to credibly represent the cost of transporting gas from Moffat to Twynholm and the methodology applied is therefore shifting Republic of Ireland network costs to UK consumers (in both Northern Ireland and Scotland) for gas that never leaves the UK. It would therefore be entirely appropriate that the views of regulatory bodies empowered to protect the interests of UK consumers should be represented in this consultation, particularly in light of the issues raised in 2014 over the then planned Gormanston exit tariff.
4. Concluding remarks

We have highlighted a number of potential compliance issues with this consultation and would welcome clarification on the justification for Matrix RPM instead of CWD, the assessment of the former against the requirements of Article 7 of the TAR NC and the treatment of gas not being consumed in the Republic of Ireland.

On a simple commercial level, we do not see how the tariffs calculated under the Matrix RPM for Twynholm or Gormanston exit can be justified as they are so far in excess of the CWD results and the cost of building additional infrastructure that they cannot be expected to generate any revenue. Whilst we are primarily representing Northern Irish Interests, setting these tariffs at an economic level would also benefit Republic of Ireland consumers as NI shippers using these routes would contribute to costs that will otherwise be borne by ROI consumers.

If the tariffs were implemented as presented, the ultimate unfortunate conclusion could be that Northern Ireland is perversely incentivised to invest in additional pipes rather than use GNI (UK) infrastructure in Scotland which would unnecessarily increase costs for everyone. A more sensible outcome would be that flows to Northern Ireland via Gormanston and Twynholm are treated as transit flows with tariffs that reflect the cost of the infrastructure required.
Gas Networks Team,
Commission for Regulation of Utilities,
The Exchange,
Belgard Square North,
Tallaght,
Dublin 24

11 February 2018

Dear Sir or Madam,

We thank the Commission for the opportunity to make a submission on the “Harmonised Transmission Tariff Methodology for Gas”. GreenGas AD Plant is a state of the art Anaerobic Digestion facility. We accept organic materials and convert the energy contained in these materials into a usable form, such as electricity. We do this in a very safe and environmentally conscious way.

We wish to make comment on the following two CRU proposals.

5B. The CRU is proposing to introduce a notional point which will be used to set a single tariff for biogas entry points. What are your views on the CRU’s approach to apply a notional biogas entry point and how this point is constituted?

5C. What are your views on biogas distribution entry tariffs relative to transmission entry tariffs and the additional factors which may need to be taken into account in designing such a tariff?

Ireland faces significant challenges in meeting its emissions targets for greenhouse gases. Analysis has shown that biogas is one of the most prominent routes of providing an economical; secure energy supply while reaching these targets. This is due to biogas being considered a ‘carbon neutral’ energy source, as the carbon released originates from organic...
materials, which have offset emissions during their lifetime. Biogas has a number of environmental, social and economic benefits. As such, biogas should be afforded all the necessary supports and mechanisms to provide access to the gas and electrical grids.

We disagree with the adoption of any Biogas Entry Tariff. Biogas requires incentivisation for its adoption to be successful. The SEAI publication, “Assessment of Cost and Benefits of Biogas and Biomethane in Ireland” makes a case for biogas adoption; however, no reference to a biomethane transmission tariff is made in this publication and needs to be accounted for in any incentive for biomethane injection. Biogas cannot compete with Natural Gas and should be seen as a standalone benefit to the gas network providing a means to green the network.

Biomethane injected into the gas grid only uses part of the grid pipeline network and should not be subjected to single-entry point criteria. Those using the transmission network will face additional compression costs. Those using the distribution network should be rewarded for avoiding the transmission network and the introduction of gas in new areas of the network. Such an approach has been adopted in Germany. The Gas Network Tariff Ordinance (GasNW) lays down a bonus for avoided network tariffs of 0.7 €cent / kWh biomethane as a reward for not using the transmission pipeline.

We thank the Commission for the opportunity to comment, and we welcome the opportunity to be involved in any discussion on the topic.

Yours faithfully,
Gas Networks Team  
Commission for Regulation of Utilities  
The Exchange  
Belgard Square North  
Tallaght  
Dublin 24

11th February 2019

RE: TEL Response to the Harmonised Transmission Tariff Consultation

Dear Sir/Madam,

TEL appreciate the opportunity to respond to this consultation. We believe that it was an excellent consultation – from both GNI and CRU. The level of interaction was extremely useful.

TEL acknowledges that the gas network needs to be paid for to ensure safe and secure supplies of gas. The issue for TEL and many power generators is the knock-on impact on capacity bookings of Ireland’s Renewable Energy policy. Between the huge growth in wind and the impact of the Moyle and BWIC Interconnectors, annual Gas Capacity purchases contain significant risks for power generators.

While a stable and secure cash flow is a high priority for the Gas Network, this has to come with an understanding of the position of power generators. TEL urge that where possible many of the decisions from this consultation show this understanding.

In regard to the specific questions asked:

34. What are your views on the CRU’s proposal to continue to apply the Matrix RPM?

TEL agree with this proposal.

44A. What are your views on the CRU’s proposal to class shrinkage as a transmission service and to recover the cost through the commodity element of the capacity/commodity split rather than through a separate flow-based charge?

TEL disagree, and believe that this should be recovered as a separate flow based charge. As explained in our opening paragraphs where possible we would prefer to see a higher proportion of charges coming through on a flow basis, otherwise this will put a disproportionate weight on power generators.

48. What are your views on the CRU’s proposal to continue to apply a 33:67 entry/exit split?

While TEL appreciate that there is a strong argument that having a higher exit split will minimise the redistributive effect, we believe that this is offset by the inability to purchase secondary exit capacity. We believe that a higher split for entry, possibly 55:45 would be more equitable.
4C. What are your views on the CRU's proposal to continue to apply a 90:10 capacity/commodity, taking into account the CRU's proposal to incorporate shrinkage into the transmission services revenue?

Although the TAR NC requires markets to move towards a 100% capacity regime, TEL would like to see a greater weighting towards commodity. Currently power generators are lacking certainty as to their running due the huge increase in wind generation. As I type there is only one CCGT on in the wholesale market. Power generators cannot continue to make large annual purchases of capacity when there is no certainty of their running. By having a higher weighting to commodity this risk is at least somewhat reduced. TEL propose an 85-15 split.

As well as providing a truer reflection of costs a higher weighting towards commodity will also allow power generators to cover their costs as they will be able to bid in the commodity component into market bids and offers. However, incorporating a separate flow-based charge into commodity will not improve the position for power generators.

4D. What are your views on the CRU's proposal to update these components of the Matrix RPM?

TEL agrees with this proposal.

6A. What are your views on the CRU's proposed VRF tariff methodology and are the if yes are factors and magnitude of the factors proposed for the VRF tariff appropriate? 6B. What are your views as to whether commodity charges should apply to use of the VRF product?

TEL support the introduction of a VRF tariff regime. An enhanced VRF product has been operational since April 2016 with a nominal fee applied for the use of this service. VRF flows are dictated by forward flows from Mammal that a shipper pays for, essentially subsidising the use of this service for VRF users. The costs of using an I&C should be applied proportionately, be that physically or virtually, and as such an appropriate VRF tariff is required. The introduction of a cost reflective tariff will "keep" more Irish gas on the Island and will allow GNI to operate their network in a more stable fashion and reduce the instances where compressors etc. on Mammal have to be ramped up/down on a continual basis.

7A. What are your views on the CRU's proposal to reduce the current monthly multipliers to comply with the monthly multiplier bound of 1.5 as set out in the TAR NC.?

The need for a reliable cashflow is very important both for GNI and the infrastructure on the island, but that reliability need not be provided for purely by purchases of annual capacity. Greater flexibility has to be available to all participants. If it is likely that ACER will recommend reducing the daily multiplier to a maximum of 1.5, then the monthly should be capped at 1.35 and the quarterly at 1.2.

7B. What are your views on the CRU's proposal to reduce the quarterly multiplier to 1.35?

TEL support a reduction in quarterly multipliers. The current pricing structure is not fit for purpose and quarterly products are rarely if ever used as a result. Any change in structure will only be a success if it is used. There are a limited number of participants who may require this product, but if the product is available it should be priced at a competitive level. A competitively priced quarterly product may be very beneficial for an I&C LDM unit that has a seasonal load profile and wishes to lock-in their costs for those quarters without taking a yearly position.

From a power generation perspective, a product such as this could be very attractive for mid-marginal CCGT units. Having a lower quarterly multiplier is also likely to reduce the cost of electricity in the market as the marginal costs of gas units are likely to fall. If the purpose of reducing the multiplier is for a greater increase of bookings from CCGT units, the proposed 1.35 multiplier is likely to still be too high. The reduction is not enough and is unlikely to
incentivise a move away from a combination of annual and daily bookings. TEL believe that a multiplier of 1.2 is likely to be needed to see a take up of the product for participants. It would be disappointing if after this process there were still no takers for this product due to the price being too high.

7C. Should a reduction in the range of seasonal factors be considered?
Yes, the divergence in tariffs between Q1 and the Summer months has not fundamentally changed in the last ten years, however gas use has changed. Ten years ago, power generators used considerably more gas in the winter than the summer, whereas now the reverse is the case. In TEL’s case alone it used nearly 4 times as much gas in Q3 as in Q1 2018. It seems very plausible that a levelling of seasonal factors may see an increase in annual bookings.

7D. How should the CRU consider implementing a transitional approach in the case ACER recommend reducing the daily multiplier to a maximum of 1.6?
This should be implemented by increasing the cost of annual and reducing the cost of shorter-term products, while reducing the seasonal differences in tariffs. This should commence in 2019/20.

Yours sincerely,
11th February 2019

RE: Harmonised Transmission Tariff Methodology for Gas – Consultation Paper, Articles 26 & 28 (the Consultation) – CRU/18/247

Dear Sir, Madam,

Bord Gáis Energy (BGE) welcomes the opportunity to respond to the above noted Consultation regarding a Harmonised Gas Transmission Tariff Methodology. BGE has been an active participant in the workshops held before and during this Consultation and we appreciate the inclusive process adopted by the CRU and GNI in conveying proposals and enabling open discussion.

Our responses below are provided in order of the questions put forward in the Consultation but at a high level BGE wishes to emphasise that unless we can be guaranteed that there will be increased transparency, or at least a retention of the current level of transparency, in shrinkage costs then we cannot agree with the proposal to move away from the current monthly charging approach for shrinkage to an annual flat k-factorled fee. Simultaneously, we are in favour of maintaining the capacity commodity split of 50:50 for reasons outlined in answer 4 and submit that shrinkage should only form part of this split if we have confidence around the level of transparency and monitorability of the shrinkage as explained further in our answer to question 2 below. Finally, we understand the consideration being given to the introduction of a VRF tariff but believe that the level of discount being proposed, particularly the 30% reduction to reduce the tariff below forward flow tariffs at MoMaf, is unjustified at this point in time and perversely incentivises liquidity away from the IBP. This is particularly as we do not believe that with declining sources of gas supplies at present the case for an attractive alternative route to balancing outside of the IBP is as yet warranted. We urge the CRU to consider the impact on IBP liquidity, the perverse nature elements of the discount and the impacts the overall level of proposed VRF discounts could have before making a decision on this as further discussed in answer 8 below.

BGE’s views on the consultation questions outlined in order of the questions as set out and labelled in the Consultation, immediately below.

1. Proposed RPM - Question 3A: What are your views on the CRU’s proposal to continue to apply the Matrix RPM?

BGE agrees with the CRU’s proposal to maintain the current Matrix model as the Reference Price Methodology going forward.

The Matrix model has allowed stability of revenues to date since its inception and the range of scenarios modelled pursuant to this Consultation demonstrate continued stability. Overall we believe the Matrix model upholds the principles established under CER/16/057 (predictability, stability, equity and promotion of effective competition). Furthermore the key TAR Network Code principles of cost-reflectivity and avoidance of undue discrimination are also better met through continuation of the Matrix over the GWDA model in our view not least due to the fact that the forward-looking nature of the Matrix model better strikes a balance between rewarding efficient new entry and ensuring that customers do not overpay for their supply. Considering the significant debates and subsequent rationalised decision
in favour of the Matrix model in 2015, we do not believe there are sufficient grounds to warrant re-opening of the choice of RPM at this point in time.

2. Shrinkage - Question 4A: What are your views on the CRU’s proposal to class shrinkage as a transmission service and to recover the cost through the commodity element of the capacity/commodity split rather than through a separate flow-based charge? Also, what are your views on a date of Implementation of gas year 2019/20?

BGE is not in favour of the change in approach to the recovery of shrinkage costs proposed by the CRU due to a concern over the transparency in the make-up of the cost being left if the change is applied. Our preference is for shrinkage costs to continue being recovered from gas shippers outside of transmission services revenue on a monthly basis unless an improvement or at least the continuation of this transparency can be guaranteed.

BGE’s primary concerns centre on losing the transparency of the current level of shrinkage costs (comprising fuel costs and Unaccounted for Gas (UAG)), if the proposal proceeds. At present, shrinkage comes through as a stand-alone pass through monthly charge, with UAG costs clearly indicated therein. This gives suppliers clear insight into such losses, the cost of which can be rationalised to customers. Our view is that if UAG cannot be distinguished easily, which will likely be the case if it is incorporated into the capacity/commodity split then: suppliers will have a more difficult time deciphering what the attributable cost is; it will not help the CRU in resolving complaints by customers about varying shrinkage charges between suppliers; and, it will make it more difficult for the CRU to monitor efficiencies in UAG and whether progress towards reducing shrinkage is being made by GNI on an annual basis.

Moreover, from the CRU’s perspective we note that the reconciliation process to date has not been straightforward with regard shrinkage and the process will be more administratively burdensome if the CRU cannot easily distinguish shrinkage costs within transmission service revenues. One possible approach however to guaranteeing continued transparency if the proposal is adopted is to oblige GNI to include details on shrinkage, at least to the level of transparency that we currently have via our monthly invoices, in their annual performance reports.

Furthermore, we note that the current monthly charge approach which is passed through, raises a gas cost volatility risk for customers. A flat fee applied annually with a k-factor approach would dampen such volatility in turn mitigating cash flow risks and leading to better predictability for customers. We support reducing volatility in gas costs, but we cannot however accept any loss in transparency in the make up and value of shrinkage costs, pursuant to any move away from the current approach.

On a related point, we note the CRU’s position that incorporating shrinkage into the capacity/commodity split would better enable a financial incentive to be placed on GNI to reduce these costs. BGE believes that such an efficiency incentive should be placed on GNI as early as possible given that full transparency as to the drivers and levels of UAG is still in fact lacking. Indeed, we believe that such an Incentive can be applied regardless of whether shrinkage is a separate charge outside of transmission revenue or incorporated (but separately distinguishable e.g. as a line item) in transmission revenues.

A potential issue with the proposal that also needs to be addressed however is the risk of an inequitable increase in customers’ bills should a flat annual fee that is k-factored be applied. Notwithstanding that shrinkage is passed-through to end customers, a move to the proposal to use an annual tariff arrangement with a flat commodity fee and k-factor at gas year end to apply to the following year's commodity charge could result in future customers paying for a previous customer's shrinkage cost, where that previous customer has moved onto another supplier.¹ This could give rise to more incidents of complaints by customers to the CRU (and suppliers alike) and we urge the CRU to consider how this might be addressed depending on their decision in this regard.

¹ Which is contrary to the current monthly recovery approach which sees actual costs based on throughput being levied on the customer that caused the shrinkage cost in question
BGE supports the CRU’s stance that the same level of compression costs (a uniform charge) should be applied to all entry points on the system to not only maintain consistency in approach within the system but also to avoid undue discrimination and promote effective competition.

Finally, with regard to retaining the current approach to shrinkage cost recovery, BGE assumes but would welcome confirmation that should this proposal proceed then GNI will not be permitted the opportunity to earn a rate of return on shrinkage given that such a right could have the perverse incentive for GNI to increase shrinkage costs.

Regarding the timing of the proposed change should it go ahead, given GNI’s views that the changes are of high materiality, high value and further work on how to include the changes in transmission revenue as well as billing system changes are required to accommodate the changes, we do not believe that implementation should apply before gas year commencing October 2020. We would ask that advance foresight of the costs of making the change and how these will be levied on users would be relayed well in advance of any such implementation.

3. Entry/ Exit split - Question 4B: What are your views on the CRU’s proposal to continue to apply a 33:67 entry/exit split?

BGE acknowledges that the current 33:67 entry/exit split should maintain regulatory stability and that there is insufficient rationale at this point in time to justify a move away from the current approach.

4. Capacity/ Commodity split - Question 4C: What are your views on the CRU’s proposal to continue to apply a 90:10 capacity/commodity, taking into account the CRU’s proposal to incorporate shrinkage into the transmission services revenue?

BGE favours retaining a 90:10 capacity: commodity split. Key among the reasons for this view are that a move towards 100% capacity would negatively impact on low volume customers many of whom will play a key role in the transition to a low carbon energy market. It could also add unrecoverable costs for gas fired generators who are limited in bidding their commodity throughput costs into, and thus recovering those costs from, the market due to balancing market bidding rules.

As outlined in our answer to question 2 above, subject to an improvement in or at least retention of the current level of transparency in shrinkage costs being maintained, we could accept their inclusion in the capacity/commodity split. Until such time as we can have confidence in the transparency of shrinkage costs and their monitorability however we cannot support their inclusion in this split.

Finally, we would welcome further clarity on the CRU’s view that inclusion of shrinkage in transmission services revenue will increase the capacity element when (per the TAR NC) flow-based charges (which is what the CRU view shrinkage costs as) are recoverable via the commodity element. This implies that a reduction in the capacity element is the most likely outcome?

5. Expansion constants and annuitisation factors - Question 4D: What are your views on the CRU’s proposals to update these components of the Matrix RPM?

BGE supports continuation of the current approach to modelling expansion constants. We do not believe there are sufficient grounds to reopen this methodology or the technical parameters of the expansion constant. We tend to support the CRU, GNI perspective that compressibility calculations were debated in detail in 2015 and that the calculation should not reflect actual projects given it is designed around a hypothetical gas transmission system which must consider these compression costs. The proposed indexation of all costs to reflect 2018 prices as well as previous years and updating of the weightings to account for completion of the twinned pipeline in Scotland suffices in our view maintains consistency in methodology and strikes the balance between principles of stability, transparency and cost-reflectivity in particular.
With regard to the annuitisation factor, BGE remains of the view that it is inappropriate to include Opex and Fuel Costs in the calculation as these are directly related to Shrinkage, a cost passed currently passed through to customers and paid by them already. We urge the CRU to reconsider the inclusion of Opex and Fuel Costs in the annuitisation factor considering its recoverability outside of transmission service revenues.

6. Discounts LNG - Question 5A: What are your views on the CRU’s proposal to not apply a discount for LNG entry points at this time? Also, what are your views on the considerations that the CRU proposes to take into account when coming to a decision on the possible provision of LNG discounts in the future?

BGE supports the CRU’s proposal to review the rationale for whether a discount should be applied to LNG facilities on a case by case basis, particularly from a consumer cost perspective considering potential Moffat tariff impacts. The potential impact of a straight discount at this stage on signals for new entry, together with the CRU’s noted conflicts with the TAR NC principles, makes it difficult to justify a straight discount for LNG at this point in time. Instead, by facilitating LNG applications on an ad hoc basis (in a timely manner to facilitate market entry planning), consideration of discounts on a case by case basis depending on what the impact is on security of supply and flows at other entry points, should better serve consumer interests. Critically however, we ask the CRU to confirm that they will consult on any such applications for discounts that arise in future, before a final decision on such is made.

Notwithstanding the two existing gas interconnectors and indigenous source of gas supplies, BGE believes that there is scope for additional security of supply benefits to be provided by LNG facilities, but these are best assessed through public consultation at the point in time an LNG application is made.

7. Biogas - Question 5B: What are your views on the CRU’s proposal to apply a single notional biogas entry point tariff to all biogas entry points? What are your views on how the notional point should be constituted?

BGE is a strong advocate of biogas/ renewable natural gas (RNG) not least given the role it can play in the transition to a low carbon energy system. The increasingly evident role for RNG in this transition and the evolving policy in the area all point to the need for a RNG entry tariff that is simple, transparent and makes it attractive for RNG to enter either the transmission or distribution systems. We are thus in favour of the CRU’s proposal to apply a single-entry tariff for all biogas entry points based off a national geographic location using the average of proposed entrant sites (the three sites), rather than based off a demand centre location. This approach should positively increase investor certainty in this currently nascent industry. As new connection points materialise, we suggest that the CRU retains the right to review this approach at a future date in line with connection point growth.

The single tariff notional/ point-based approach in our view also best achieves a balance among the principles of predictability, stability, competition, transparency and non-discrimination.

8. Biogas - Question 5C: What are your views on biogas distribution entry tariffs relative to transmission entry tariffs and the additional factors which may need to be taken into account in designing such a tariff?

At present, the impacts of a growing number of biogas connections on the transmission and distribution networks is unknown without which knowledge a differential between the two tariffs cannot be warranted. There thus appears to be a case for aligning tariffs and methodology for RNG between transmission and distribution connected entrants with a view to enabling investment at both levels and to help minimise any barriers to RNG development. Similar to our view in answer 7 above, the case for reviewing this approach may become pressing should large volumes of RNG join the network over time and we believe the CRU should consider reviewing this approach in the medium- longer term.

In general, consistency in approach and a level playing field as between transmission and distribution connected RNG should better promote their market entry. We note that further consultation is planned by the CRU before a decision on this would be taken but at present we deem a notional entry single
9. VRF - Question 6A: What are your views on the CRU’s proposed VRF tariff methodology and are the factors and magnitude of the factors proposed for the VRF tariff appropriate?

In general, BGE believes that the use of the Moffat exit and Gormanstown entry points as the basis for the VRF interruptible product tariff methodology is sensible. As VRF is a daily product, we further support the use of multipliers and seasonal factors to reflect the value of short-term products and seasonal variations in gas transmission system usage.

In terms of the proposed calculation formula, we believe that in principle the resulting tariff should not perversely undermine the liquidity of the Irish Balancing Point (IBP). Under the current proposed calculation, IBP liquidity is in our view undermined on foot of the level of discount being proposed for this VRF tariff. This is intuitively in our view given that with the indigenous gas resources at the Corrib field being in decline, and, given the dearth of possible new sources of indigenous gas in the short-medium term the necessity of enabling access to balancing by greatly increasing accessibility to another market (GB) (to the detriment of IBP), is not warranted at this point in time.

In terms of the breakdown of the proposed formula, we can support the setting of the “Pro” or probability factor at 8% and see the proposed “Pro” approach as transparent. Furthermore, given the lack of VRF product usage at Gormanstown it seems appropriate to apply an equal 8% factor to Gormanstown until a better factor can be assessed – an annual review of the Pro factor should apply however.

With regard to the “A factor” or economic value of the product, we note the choice of a 10% risk premium factor for both VRF products to reflect the perceived likelihood of the service being interrupted which users may seek to hedge. While the chosen percentage is in our view quite subjective, we have no objection to this level at this point in time.

We do however have concerns over the arbitrarily high 30% discount applied to the VRF tariff merely to bring it down below the Moffat tariff to encourage flows in the direction of Ireland to GB. While we accept the CRU’s desire to make it easier to flow gas from Ireland to GB, given the likely impact we foresee that this will have on the user liquidity of the IBP, we cannot support a calculation approach that applies an arbitrary figure that has the effect of making the discount so large, it is perverse. We therefore accept the proposed Pro factor and risk premium of 10% elements but do not support the basis or rationale for the 30% discount element. When the case for a heightened need for an alternative route to balancing outside the IBP becomes evident (e.g. when a new source of gas supply in the Irish system is imminent) the discount approach could be reviewed at that point in time. To accommodate potential new gas sources and consequential need for a VRF, provision should be made for the CRU to revisit this factor on a yearly basis, rather than setting it for five years at a time.

Finally, notwithstanding that the VRF product may not always be available at a time when a user may want to use it, we agree with the CRU that another discount factor should not be added to reflect the potential unavailability of the product given the high unlikelihood of such lack of availability arising. We also support the CRU’s view not to increase the reduction in the Moffat VRF tariff to prevent a reduction of both VRF and forward flow capacity bookings which may lead to revenues being recovered across a lower volume of capacity bookings. Such rationale is too subjective at this point in time.

10. VRF - Question 6B: What are your views as to whether commodity charges should apply to use of the VRF product?

BGE is in favour of including a commodity element in the VRF product. For consistency in treatment in exit points we suggest that the capacity/commodity split should also be 50:50. This will also in our view help mitigate the negative impact a VRF discount is likely to have on IBP liquidity, which, as outlined in our answer to question 9 above is not warranted at this point in time given the current range of gas sources.

We do not support the argument reflected in the Consultation that a higher VRF would reduce the value of using the NSP for balancing which could discourage IBP participation and result in more balancing actions being undertaken by the system operator. On the contrary we believe that IBP liquidity would be undermined by a low VRF tariff.
11. Multipliers and seasonal factors - Question 7A: What are your views on the CRU’s proposal to reduce the current monthly multipliers to comply with the monthly multiplier bound of 1.5 as set out in the TAR NC?

We agree with this proposal as it keeps the status quo including for example the same seasonal profile of multipliers which is positive from a stability perspective.

12. Multipliers and seasonal factors - Question 7B: What are your views on the CRU’s proposal to reduce the quarterly multiplier to 1.35?

We agree with this proposal. Quarterly bookings should be better incentivised, and this proposal achieves that aim in our view.

13. Multipliers and seasonal factors - Question 7C: Should a reduction in the range of seasonal factors be considered?

Further to the NTLG discussion and noting the further work done by the CRU as flagged in its Consultation, we support the proposition that a reduction in the variation of seasonal factors may be necessary to incentivize use of shorter-term capacity products. BGE is in favour of applying option 2 (the flatter profile, as per the TAR NC, to monthly products).

Our main rationale for this choice is that with increasing renewable generation on the system and increased necessity for complementary flexible generation and those with lower load profiles, lower tariffs would better assist their roll out. The option 2 flatter profile approach would also incentivise the use of low carbon gas units over high carbon oil units through increased competition which is overall better for consumers and in achieving low carbon objectives. Finally, while GNI may see lower annual bookings the shorter-term products would be in higher demand with the flatter profile; option 2 approach and these bookings could on balance see increased monthly revenues for GNI.

14. Multipliers and seasonal factors - Question 7D: How should the CRU consider implementing a transitional approach in the case ACER recommend reducing the daily multiplier to a maximum of 1.5?

At present BGE has believes a transitional move towards this approach would be best but suggests that the CRU revisit the issue with stakeholders at such time as ACER makes a determination on this.

Summary and conclusion

In summary, BGE urges the CRU and GNI to consider our key concerns and proposed outcomes particularly in relation to the following issues:

i. Shrinkage: BGE can only support a change from the current methodology to the proposed new annual flat fee k-factored methodology, if an improvement (or at least maintenance) of the current transparency we have with regard shrinkage, can be guaranteed. One way of doing so for example is by specifying that a breakdown of shrinkage costs is included in annual GNI performance reports. While a flat fee approach would reduce gas cost volatility for customers for example, if transparency in what costs are attributable to shrinkage are lost than it will become extremely difficult for suppliers (and the CRU) to justify shrinkage costs for customers and could also impact any incentives on GNI to improve shrinkage costs. We believe a GNI incentive on shrinkage should be adopted as early as possible regardless of the approach ultimately chosen.

ii. BGE favours retention of the 90:10 capacity: commodity split not least due to the negative impact on low volume customers (that will play a key role in decarbonisation) a move towards higher capacity element would have but also due to the possible limitations it could place on gas generators seeking to recover gas costs under electricity balancing market bidding rules. We can support inclusion of shrinkage in this split also only if assurance around the level of transparency and monitorability of shrinkage, on at least an annual basis, can be given;
iii. With regard to the VRF tariff methodology, BGE can accept the Pro factor (8%) and proposed risk factor (10%) proposals. We believe however that the chosen VRF should not be set at such a level that IBP liquidity is pervasively impacted. In this regard, we believe that the application of the 30% reduction is arbitrarily chosen simply to reduce the tariff below forward flows at Mofat. We consider this to be unreasonable particularly as we do not believe that with declining sources of gas supplies at present the case for an attractive alternative route to balancing outside of the IBP is as yet warranted. We urge the CRU to consider the impact on IBP liquidity, the perverse nature of elements of the discount and the impacts the overall level of proposed VRF discounts could have especially on IBP liquidity before making a decision on this as further discussed in answer 9 above.

At a high level our views on the other elements of the consultation can be summarised as follows but we ask the CRU to refer to the respective answers above for further context and detail:

iv. BGE supports retention of the Matrix model as its re-opening is considered unwarranted at this stage. Furthermore, it best maintains in our view the balance between rewarding efficient new entry and ensuring that customers do not overpay for their supply;

v. Similarly, there is little rationale to move away from the 33.67 entry/exit split at this time with a view to maintaining regulatory stability;

vi. We support continuation of the current approach to modelling expansion constants, the merits of which were well debated in 2016. We however remain of the view that it is inappropriate for the annuitisation factor to include OPEX and Fuel Costs in the calculation as outlined in answer 5 above;

vii. A straight LNG discount at this time without further justification or insight on impacts on security of supply and flows at other entry points, cannot be warranted as being in the consumer interest. Instead, LNG discounts should be assessed only on a case by case basis and subjected to public consultation in a timely manner;

viii. The policy for Biogas/ RNG is evolving and the role it can play in decarbonisation is increasingly evident. A simple, transparent approach to these tariffs should thus be adopted along the lines of a single-entry tariff for all biogas entry points based on national geographic location using the average of proposed entrant sites (the three sites). This should increase investor certainty and help growth in this nascent industry. Alignment of these tariffs on the transmission and distribution side is also considered prudent to incentivise development of the industry. The CRU should however review the approach as increasing connection levels so require;

ix. Please see answers 11-14 above for our views on multipliers and seasonal factors. We agree with the proposed reductions to the monthly and quarterly multipliers. With regard seasonal factors, we prefer application of Option 2 (the flatter profile to monthly products) mainly as lower tariffs would better assist the roll out of complementary flexible generation and those with lower load profiles needed in an increasingly decarbonised system.

I hope that you find the above suggestions clear and helpful. Please do not hesitate to contact me should you wish to discuss any of the above in further detail.

Yours faithfully,

Bord Gáis Energy

{By email}
Electric Ireland Response:
Harmonised Transmission Tariff Methodology for Gas Consultation Paper

CRU/18/247
11th February 2019
Respondent’s Details

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General Comments

Electric Ireland (EI) welcomes the opportunity to respond to the CRU consultation on Harmonised Transmission Tariff Methodology for Gas. The key points for Electric Ireland and our customers are discussed below. Consistent with all of our responses, Electric Ireland views these questions from the perspective of a standalone supplier and as a representative of the customer. Electric Ireland recognise the importance of a robust reference price methodology to support efficient gas trading and obtain cost reflective tariff structures for consumers and we are broadly supportive of the consultation proposals.

Specific responses to the individual consultation questions are provided below.

Responses to Consultation Questions

3A. What are your views on the CRU’s proposal to continue to apply the Matrix RPM?

Electric Ireland supports the proposal to continue to apply the Matrix Reference Price Methodology. It is suited to the characteristics of the Irish gas market and it complies with the TAR NC.

4A. What are your views on the CRU’s proposal to class shrinkage as a transmission service and to recover the cost through the commodity element of the capacity/commodity split rather than through a separate flow-based charge? Also, what are your views on a date of implementation of gas year 2019/20?

Electric Ireland supports the proposal to class shrinkage as a transmission service.

4B. What are your views on the CRU’s proposal to continue to apply a 33:67 entry/exit split?

Electric Ireland supports the continuation of the 33:67 entry/exit split.

4C. What are your views on the CRU’s proposal to continue to apply a 90:10 capacity/commodity, taking into account the CRU’s proposal to incorporate shrinkage into the transmission services revenue?

Electric Ireland broadly supports this proposal.

4D. What are your views on the CRU’s proposal to update these components of the Matrix RPM?

Support the proposal to update the expansion constant and annuitisation factors.
5A. What are your views on the CRU’s proposal to not apply a discount for LNG entry points at this time? Also, do you agree with the considerations that the CRU proposes to take into account when coming to a decision on the possible provision of LNG discounts in the future?

Electric Ireland supports the proposal to not apply a discount for LNG on the basis that there are currently no LNG facilities in Ireland. There is merit in the proposal for the CRU to consider the case for LNG discounts in future as more information becomes available. Assessing LNG proposals on a project-by-project basis to determine the relative merits of each project and the suitability of introducing LNG discounts.

5B. What are your views on the CRU’s proposal to apply a single notional biogas entry point tariff to all biogas entry points? What are your views on how the notional point should be constituted?

The introduction of a single notional biogas entry point tariff is a suitable approach and appears to satisfy the stated requirements for a simple and pragmatic arrangement.

5C. What are your views on biogas distribution entry tariffs relative to transmission entry tariffs and the additional factors which may need to be taken into account in designing such a tariff?

Electric Ireland supports that the transmission and distribution tariffs should be aligned in order to produce economically efficient signals for point of connection.

6A. The CRU is proposing to interpret VRF as an interruptible product and to introduce a VRF tariff which takes into account the probability of interruption and the economic value of the product. What are your views on the CRU’s proposed VRF tariff methodology and are the factors and magnitude of the factors proposed for the VRF tariff appropriate?

Electric Ireland supports treating the VRF as an interruptible product.

6B. What are your views as to whether commodity charges should apply to use of the VRF product?

No comment.

7A. What are your views on the CRU’s proposal to reduce the current monthly multipliers to comply with the monthly multiplier bound of 1.5 as set out in the TAR NC.

Electric Ireland agree with the proposals to align with the limits set out in the TAR NC.

7B. What are your views on the CRU’s proposal to reduce the quarterly multiplier to 1.35?

No comment.

7C. Should a reduction in the range of seasonal factors be considered?

A reduction in the variation of seasonal factors should be considered if it can be demonstrated that the current seasonal profile is not sufficiently incentivising efficient use of the network. The CRU should consider maintaining and monitoring the current seasonal factors with a view to reducing them if required.
7D. How should the CRU consider implementing a transitional approach in the case ACER recommend reducing the daily multiplier to a maximum of 1.5?

A phased transitional approach should be implemented as noted by NTLG participants.
Mr. Cahir O'Neill,
Gas Networks Team,
Commission for Regulation of Utilities,
The Grain House,
The Exchange,
Belgard Square North,
Dublin 24,
D24 PX50

11 February 2019

By email: gasnetworks@cru.ie

Re: Response to CRU Consultation CRU/18/247

Dear Cahir,

IOOA's members welcome the opportunity to respond to the CRU's consultation on the Harmonised Tariff Methodology for Gas and our response is detailed below. IOOA's members have two main concerns - the ongoing uncertainty about the LNG discount, and the proposal for VRF.

LNG: IOOA's members are very concerned about the discretion which CRU is retaining in relation to discount LNG entry for future LNG entry points. We note the criteria for review are 'non-binding'. Including an undertaking in the forthcoming Decision Document that there would be a public consultation before any such discount, is essential to retaining the transparency of the Irish pricing regime.

VRF: The methodology proposed produces excessively high prices for VRF which have the potential to disrupt the market and cross-border trade. Given that there is no reasonable justification for claiming that there are real costs, beyond the IT and administration costs in the current charge, IOOA's members contend that this is an unnecessary and potentially damaging proposal. We have outlined the issues - in terms of cost, excessive prices, the disruption to the immature Irish trading market, especially in its relationship to the adjacent NBP hub and the impact on cross-border trade - in detail in the appendix to this letter.

IOOA's members are of the opinion that Article 4.1 of the EU tariff network code does not require the VRF product to be included as a transmission service and suggests that it be charged as a non-transmission charge either retaining the existing pricing or as a capacity charge based calculated on expected usage. If this is not done, we have argued for changes in the methodology and calculations which are more aligned with the nature of the product and would generate a more reasonable rate - albeit not actually cost related. While we recognise the CRU's attempt to create transparency in the calculations that should not be at the expense of relevance.

The CRU have to some extent recognised the excessive nature of the charge and have applied an adjustment to bring the price down. IOOA's members have presented evidence that this 'fix' is inappropriate. More appropriate is to keep the rate at a level which clearly cannot have perverse
effects on the market by using a more appropriate calculation, with a better relationship to the level of costs involved.

Detailed Response: Our detailed response to all questions is provided in Appendix 1 of this letter. IOCA’s members are available to meet with the CRU and its economic advisers to discuss our response in more detail. I shall be in contact in due course to schedule a meeting.

Yours sincerely,
Appendix 1 – IOOA Response to CRU Consultation CRU/18/274

Proposed RPM 3A. What are your views on the CRU’s proposal to continue to apply the Matrix RPM?

IOOA’s members support the continuation of the matrix RPM in Ireland as the approach is predictable, is stable, is understood by the market, and retains investment signals for new entry.

Shrinkage 4A. What are your views on the CRU’s proposal to class shrinkage as a transmission service and to recover the cost through the commodity element of the capacity/commodity split rather than through a separate flow-based charge? Also, what are your views on a date of implementation of gas year 2019/20?

IOOA’s members will each make their own submission on this issue.

Entry/exit split 4B. What are your views on the CRU’s proposal to continue to apply a 33:67 entry/exit split?

The proposed approach by the CRU is acceptable as long as the entry exit split reasonably reflects the RAB entry exit split.

Capacity/commodity split 4C. What are your views on the CRU’s proposal to continue to apply a 90:10 capacity/commodity, taking into account the CRU’s proposal to incorporate shrinkage into the transmission services revenue?

IOOA’s members will each make their own submission on this issue.

Expansion constants and annualisation factors 4D. What are your views on the CRU’s proposal to update these components of the Matrix RPM?

From a cost reflectivity perspective, the IOOA supports the proposed update of the expansion constants and annualization factors. However, as explained below, further updates to its starting level and ongoing yearly updates are necessary to bring the cost reflectivity to an acceptable level.

IOOA’s members consider that the expansion constants used in the model are too low. The CRU has used the expansion constant to derive a NTS component for the two potential LNG entries. For 50 km at Foyles the NTS element is calculated at 38.27 EUR/MWh peakday capacity. The current 2018/2019 Linkline NTS element (~150 km) is equal to 494.24 EUR/MWh. Using the CRU model for deriving the Linkline element with a stable maximum Linkline capacity of 103.87 GWh/day for the whole project period would result in a (2018/2019) level of 214 EUR/MWh peakday. Using 150 km and the Foyles element would only result in 3 x 38.27 = 115 EUR/MWh peakday. Based on this calculation the expansion constants used in the model represent only 54% (115/214) of the value as applicable for Linkline.

In an earlier stage we commented that real capacities (like the 103.87 GWh/day for Linkline), should be taken into account. But even if the theoretical capacity of around 125 GWh/day for Linkline was being considered, the Linkline element would have been 178 EUR/MWh peakday. So from a theoretical perspective the expansion constants in the model represent only 65% (115/178) of the value of Linkline. It is clear that expansion constants are too low and don’t represent reasonable projects. GNI need to update the expansion constants to reflect this or otherwise explain the differences as shown above.
IOOA's members also consider that the expansion constants should be indexed for inflation on a yearly basis. This would be consistent with the yearly indexation used for other elements in PC4 as input for the yearly tariff calculation and the yearly indexation of the Linkline element. If expansion costs are not indexed, this would imply that revenues are moved to the tariff adder, which reduces the cost reflectivity.

With respect to the annuitisation factor IOOA's members propose to have a yearly update as well. As part of this yearly review the fuel element could also be updated. In addition, we are concerned that the fuel price used in the annuitisation factor is not cost reflective as it only references NBP prices and does not take into account the cost of gas delivered to Ireland. IOOA's members consider that the fuel cost component of annuitisation should be indexed to a (rolling) average of the actual shrinkage gas price paid by GNI; this would be cost reflective—the current use of NBP prices only is underestimating the annuitisation factor.

Yearly indexation of expansion constants and annuitisation factor improves the cost reflectivity and avoids big tariff jumps that occur when calculated once every 5 years, so it results in stabler and more predictable tariffs. For transparency reasons this yearly update should be published by CRU/GNI together with the yearly publication of the updated tariffs.

Discounts LNG 6A. What are your views on the CRU’s proposal to not apply a discount for LNG entry points at this time? Also, do you agree with the considerations that the CRU proposes to take into account when coming to a decision on the possible provision of LNG discounts in the future?

The IOOA agrees strongly with the arguments presented in the second and subsequent paragraphs of section 5.2.2.1 of the consultation paper which demonstrate why a discount should not be given on the entry charge for LNG terminals. Article 9 of TARC NG states that a discount may be given “for the purpose of increasing security of supply”. The IOOA notes that the opening paragraph refers to wider potential benefits of LNG, which may or may not be delivered, but it is only in relation to increasing IEPS security of supply that a discount could be considered.

IOOA's members greatest concern is that, notwithstanding the CRU's clear conclusion that new entry from LNG should be treated equitably with other entry which also contribute to security of supply, this issue remains open throughout the period this review covers. The CRU states that it intends to consider representations from any LNG project as to why the project might qualify for a discounted tariff. The IOOA does not see that the impact of new LNG is linked to a specific project—i.e. it is generic to any LNG entry point and its relation to the market and so the conclusions in this consultation should hold. Moreover, at the recent public consultation meeting, the CRU team stated that this could be done as part of the annual review process and it would not require public consultation. This is completely at odds with the principles of stability, predictability and transparency; if stakeholders cannot rely on such a basic component of the pricing structure and we consider that the issue of LNG discounts should be closed with this consultation.

However, should the CRU be prepared to consider representations from LNG producers - and the IOOA see no basis for such consideration given what has been presented in this consultation - these project specific arguments must be presented in full in a further public consultation. The analysis in Text Box 1 (Pg 64 CRU/18/247) shows the size of the potential cross-subsidy from consumers to the LNG terminal users—€23m. Other sources of subsidy which the LNG projects
have acquired or are in the process of bidding should be taken into consideration before any discount is discussed.

IOOA's members do not see how security of supply would be significantly improved by the addition of LNG entry. The Irish system already benefits through GNI's over-investment with the fully twinned UK interconnectors with the projects themselves justified on the grounds of security of supply. Security and diversity of supply is also supplied by the Corrib and Celtic Sea gas fields, in the future by biogas, and with power station fuel switching as part of the mix. The CRU has expressed itself content with the current level of security of supply and therefore it is difficult to see how LNG would improve it significantly.

The IOOA have concerns about how a Security of Supply evaluation might be conducted. GNI has applied a merit order assumption to its analysis, placing LNG above Moffat Entry (para 2.4.2.1). This is not what we would expect in terms of LNG delivery. Availability of LNG in Ireland is dependent on the dynamics of a global market. In GB for example the LNG share of supply has varied considerably, falling from a high of 26bcm in 2011 to a mere 5bcm in 2017 (National Grid's Gas Ten Year Statement 2018). Moreover, delivery has lagged behind the market signals which determine where LNG tankers will divert to land their cargo. This means that LNG cannot be relied on to be present on the network when it is needed. Scrutiny by all stakeholders bringing alternative experience of market operations rather than GNI’s merit order approach and the LNG project's evaluation is what would be required and needs public consultation.

Biogas 6B. What are your views on the CRU's proposal to apply a single notional biogas entry point tariff to all biogas entry points? What are your views on how the notional point should be constituted? 6C. What are your views on biogas distribution entry tariffs relative to transmission entry tariffs and the additional factors which may need to be taken into account in designing such a tariff?

Charging for biomethane should be kept as simple and transparent as possible, especially at the early stages of the industry's development. With that in mind, within the methodology it would be reasonable to have a single 'notional' entry point for biogas on to the transmission system as it is difficult to predict where the plants will be located and the driver for biogas plant developers is likely to be availability of feedstock rather than small differences in entry tariffs.

If choosing a notional Entry Point it is important that it reflects as far possible the area where Biomethane is expected to develop. We understand from presentations by GNI on the potential for Biomethane in Ireland that the source of feedstock will be dominated by grass. This implies that notional entry point should be located in Ireland's agricultural heart land.

As regards entry to the distribution system, it is a part of the gas transport system we are not familiar with so do not feel able to comment in the absence of any proposals.
VRF 6A. What are your views on the CRU’s proposed VRF tariff methodology and are the if yes are factors and magnitude of the factors proposed for the VRF tariff appropriate?

The IOOA considers that the proposed solution is not appropriate because the calculation does not relate to the service provided and it will create unreasonable distortions in the Irish gas market.

The proposal does not provide appropriate economic signals in relation to the use of capacity and does not promote effective market operation. The calculation itself is inappropriate with no relationship to real economic costs and creates perverse and damaging effects on the market. The IOOA judges that the CRU proposal has been insufficiently thought through and something causing such disruption to the market should not be implemented when there is poor justification in terms of cost-reflectivity.

IOOA’s members objections to the current proposal cover the following issues
- the lack of cost reflectivity in the proposed solution;
- the Impact on VRF as a balancing tool;
- disruption to the nascent IBP market;
- impact on investment.

Our response below covers in detail the problems with the proposal in the Consultation Paper and suggests more appropriate calculations

The lack of cost reflectivity in the proposed solution

The issue of cost-reflectivity effect both the fundamental problem that reverse flow creates no new costs on the system, except some IT and administration costs to manage the transactions, and that the Matrix model has been inappropriately applied.

- Use of the Exit Price.

The calculation being used for the reference price does not work. At €285, the Primary Exit charge (i.e. before the Adder) delivered by the Matrix, is the highest raw tariff on the system, either entry or exit. It is perverse that the allocated cost associated with an entirely notional exit at Moffat is greater than for any other point on the system. To take a service which is notional and set its reference price as the highest on the system is clearly creating a cross-subsidy between export and import.

Because exit charges were postalised, the 2014/2015 tariff consultation was focussed on ensuring that the optimisation model produced reasonable results for entry, so the effect of the model optimisation on exit - in particular, a notional exit which the system has not been designed to serve - has never been exposed to proper scrutiny. Clearly the large difference between entry and exit at Moffat raises these questions. It is IOOA members’ view that comparing the virtual Moffat exit to a firm exit onshore in Ireland and force-fitting it into the Matrix model is inappropriate and leads to overcharging for VRF and to cross-subsidy.
Over recovery of the adder.

In addition to our concerns about the way the Matrix model is used, the IOOA considers that the cost recovery adder is being misapplied. The adder in the proposal uses the Entry/Exit split and so the Exit charge, as proposed, carries the cost of the exit assets (67% of the overall RAB). Since the Entry/Exit split is clearly linked to the physical assets on the system which relate to Entry and Exit points, the attribution of the Exit adder to Moffat flow (whether Real or Virtual) is inappropriate.

Over-recovery of costs.

VRF actually saves costs, increasing the effective usage of the system without building any additional capacity. This boosts GNI’s revenues without any additional cost thereby generating an additional K Factor which is redistributed creating cross-subsidy from exports to imports.

Application of seasonal multipliers.

The use of the forward flow multipliers is not appropriate. Multipliers are aligned with seasonal gas demand and uplifted to incentivise annual against shorter period capacity bookings, to avoid cross-subsidy between types of use. VRF exists only as a daily product and so cannot be optimised in this way, so the annual aggregate 278% uplift when compared to an annual product is not appropriate. There should be no net uplift so we propose that the standard daily forward flow multipliers are used but divided by 2.78. While IOOA’s members contend that there is seasonality in the value of the interruptible service, driven by the probability of interruption at different times of year, we accept that this cannot currently be calculated due to difficulties interpreting the limited operational data. These limitations, which are indeed referred to by the CRU on page 72 of the consultation document, are intrinsic to an immature balancing and trading market, and further underline the IOOA’s contention that the CRU and GNI should not be implementing this change at this time.

Interruptibility.

There are also serious questions about appropriateness of the Interruptibility calculation – the simple calculation using the days on which VRF has been allocated and then interrupted does not reflect the uncertainty of availability which shippers experience.

Classic interruption relates to regular service which one can forego for a short period of time, when displaced by higher value activity; it usually relates to assets which are provided for peak day activity. This is the type of service for which the Interruptibility calculation, envisaged by TAR NC and used by GNI, is appropriate. The VRF service offered by GNI however is an occasional activity which will be taken opportunistically when demand (i.e. excess gas) and supply (i.e. adequate forward flow) coincide. The probability of interruption should therefore take account of the offer (which is constrained) as well as an actual interruptions once the gas is in the system. In the section below on alternative formulations we describe a more appropriate calculation for this type of service.

The simple linear interruption factor of 8% does not recognise that interruptions are likely to be higher at the very time when the service is most needed during periods of relatively low demand. However, this is also when the forward usage of Moffat is likely to be lower than
average, increasing the likelihood of interruption. In GNI’s future scenarios when LNG is
injected, Moffat may be providing only 9% of Ireland’s supply so the interruption levels
could be very high. The probability of interruption on a day during low levels of flow is more
indicative of the value of this product especially as it applies to long-term investment
decisions. The calculation used is based on historic data in a period of considerable
uncertainty. In addition, it is clear that the level of VRF utilisation is falling as the number of
IBP counterparty trading agreements increases and companies trade out imbalances at the
IBP rather than through VRF to the NBP (VRF Allocations: Oct’17 - 104GWh Vs Oct’18
246GWh; Nov’17 188GWh Vs Nov’18 11GWh¹). In such a scenario the risk of interruption will
fall even further based on GNI’s calculation. Both are important reasons why the price
should not be referenced against actual interruptions but on the constrained offers. Under
the GNI formulation if nobody uses it, it becomes firm; with the current proposal this product
will never be used in winter due to the extortionate high price. The price of the product
needs to be robust over a range of scenarios not just relevant to what has already
happened in the short-term.

A more appropriate calculation for the VRF interruptibility is presented below.

The Impact on VRF as a balancing tool

The IIOA considers that the accumulating effect of non-cost reflective calculations in deriving the
tariff will have a severe effect on the Irish Market. IIOA’s members recognise that currently VRF
is more of a balancing tool than a premeditated export tool. In consequence, if VRF is
unreasonably priced and not cost reflective it will distort the balancing market, widening spreads at
the IBP. This will have a negative effect on IBP liquidity as shippers/traders will be deterred from
doing business in Ireland.

- The asymmetry between long and short.

The proposed tariff creates an enormous imbalance between the cost of excess gas and shortfall on any day in the winter months. This is caused by the application of multipliers to
an already high price; reverse flow is a day ahead or within the day product where daily
multipliers are to be applied, whereas forward flow for balancing will mostly be shipped
using existing booked forward flow capacity. Thus, there is no equivalence of the forward
and reverse flow products so the buy-sell spread can be excessive without possibility of risk
mitigation through a portfolio of capacity products. This is especially problematic in Ireland
as there is no storage injection option where short-term excess gas can find a home without
export.

- Incumbent advantage.

Importers to Ireland with existing capacity bookings always have the option to turn down
their forward flow to balance, those with production or LNG terminals in Ireland, or new
entrants in the trading market are tied to VRF; incumbents will have greater market power
than new investment. In the longer-term it will discourage new investment for supplier
entering the network in Ireland.

¹ Source: GNI Transparency Platform
Incentive to systematic under-delivery.

The asymmetry of the cost of being long or short will create adverse behaviours; suppliers will always bias their nominations to under-deliver, rather than expose themselves to the buy-sell spread.

Disruption to the nascent IBP market

The IBP is still in the early stages of development, essentially a balancing market rather than a trading hub. Two of the important signifiers of an effective market, things which will tend to higher levels of liquidity, are a small buy-sell spread consistent with risk and clear economic alignment with adjacent effective hubs. As we have discussed above, these features will be adversely affected by this proposal.

![IBP SAP vs NBP SAP](image)

**Figure 1 – IBP SAP vs NBP SAP (Source: EBI & National Grid)**

In its proposal for the VRF tariff, the CRU has recognised the importance the price has in market interactions concerning cross-border trade. IIOA’s members consider that this problem has arisen because an inappropriate calculation has set the VRF tariff artificially high. The way the CRU has addressed the problem is in Section 6.4.1.4 where an additional component of the A factor has been introduced with the aim of bringing the post-adjustment price below the equivalent entry tariff. This is based on the assumption that the price at the IBP is the NBP plus the cost of transportation. Above in Figure 1 is analysis comparing prices at the NBP and the IBP over
December ‘18 and January ‘19 which show a much more complicated picture. For periods the prices track very closely with almost no, indeed sometimes a negative, differential. At other periods there is a significant spread opens up, though not as great as the spread suggested by the VRF price. Immature and illiquid markets do not perform according to theoretical assumptions. What the data implies is that one cannot assume ‘an equivalent entry tariff’ to which the VRF is simply tagged. IOOA’s members therefore argue that tariff should be set based on the actual costs of service which is low enough to avoid the potential of distortion.

Impact on effective hedging in the Irish market.

If the VRF price is excessive and distorted, then the basis risk - the uncoupled and unpredictable component of price differential - between the IBP and NBP and other liquid trading hubs will become too wide, undermining the ability to manage risk through effective hedging using the NBP, or other established prices, and increasing the costs of Irish gas users, shippers, generators, traders, suppliers and producers. The effectiveness of any hedge shippers put in place will be greatly reduced. So, inappropriate VRF charges will delay the development of the IBP as a reliable reference price for hedging.

Impact on imbalance costs.

Imbalance costs for shippers will rise in the new IBP balancing regime scheduled to commence in March 2019 if the current VRF tariffing proposals is implemented. VRF will become a benchmark price for speculative imbalance bids which, on days when the transporter is selling, will influence the imbalance market price and associated disbursements account.

Instability in pricing.

If the charges proposed are introduced, it represents a major change in pricing structure and therefore cost for those availing themselves of the service or relying upon the availability of the service to achieve fair, reasonable and transparent prices in Ireland. The change will have a major disruptive effect, where existing long-term contract structures are predicated upon the availability of the service; the change may disrupt the commercial balance and reasonableness of those agreements. Some consideration should be given to the phasing of the changes.

Impact of VRF as the benchmark price for bilateral agreements.

VRF is not simply about revenue collection for GNI. Excessive VRF cost will force shippers to use bilateral arrangements, swaps, involving shippers with forward capacity. In this event, additional and unnecessary transaction costs are incurred, only the incumbents have adequate forward flow capacity to effectively offer such a service (which they may choose not to do). At one level, this effectively discriminates against new entrants and smaller suppliers as they cannot offset their Moffat Entry costs, giving the incumbents a competitive advantage. At the next level, it permits incumbents to deter new entrants from entering the market place at all - which would clearly be anti-competitive. The high VRF price will set the price for swaps but the benefit will be seen in economic rent to holders of Moffat capacity and not as revenue to GNI.
Impact on investment

- VRF is beneficial to the system and Ireland overall, increasing capacity bookings and usage, maintaining liquidity and reasonable pricing (bid/offer spreads) at the IBP, encouraging investment by giving developers a reliable and reasonable backstop price. Without such a price the risk of doing business in Ireland will be seen as much higher than it needs to be, reducing the appetite to invest and, for those that do invest, increasing the Internal Rate of Return required for equity and the cost of funds as banks assess the risks.

- Investors are unlikely to commit to new developments (indigenous gas and LNG (and possibly even biomethane)) if they lose the ability to manage their supply demand position. Far better to land an LNG cargo in GB with a deep liquid market than Ireland with potentially better prices but no liquidity, wide bid offer spreads and an expensive route to the rest of Europe.

Alternative proposal

The IOQA considers that VRF should not be implemented as a transmission service but as a non-transmission service.

- Since the CRU has not been able to propose a tariff on a reasonable cost reflective basis it should not be implemented in this way at this time. The charge as proposed is unjustifiable, in its components, and excessive in its out-turn; we have outlined above the impact such an excessive charge will have on the market. Article 4.1 of TAR NC requires a transmission services charge only when both criteria 1(a) and 1(b) are satisfied and it is our view that neither criterion is – the cost drivers are not related to technical / contracted capacity and distance is immaterial nor is there any infrastructure investment in the RAB associated with the service. Implementing the charge in this way is CRU’s choice even though it is not properly understood. Moreover, the presentations at the NTLO meetings and the Public Session have reflected ongoing uncertainty about how it could be applied; this has not been resolved in the Consultation Document.

- Implementation of a capacity charge.

The only justifiable costs to consider are those already incorporated in fee for service (IT & regulatory costs). These could be reformulated as a capacity charge on the basis of expected usage.

Should the CRU decide to go ahead with the decision we consider the following as at least bringing the calculation closer to something reasonable.

- Use the Entry charge as the Exit Charge.

As we noted above the Exit charge being delivered by the Matrix model is absurd, being by some distance, the highest of any charge on the system entry or exit. By replacing it with the same charge as the Entry charge there would at least be a notional relationship to the assets being used. This applies also to the adder. The 33% allocation of adder to entry is on the basis of the RAB assets attributable to the Entry and Exit parts of the system and clearly VRF relates to the Entry part.

- Expansion coefficients
We also note that no consideration has been given to the expansion constants which provide the essential economic link between assets - pipelines and compression - and the tariffs. When the current Entry/Exit was established, consideration was given to zero or negative expansion constants (see CER/15/067, p22). At the time there was no consideration of VRF being within the tariffing regime so there was no benefit to including negative expansion coefficients but they should now be considered. We have not so far attempted to model it.

Replace the interruptible calculation with one which better reflects the uncertainty facing users of the service. For shippers, placing their gas sales and planning their risk management, the uncertainty is much more about constraints on availability than interruption on the day. By considering the maximum daily forward flow at Moffat as reference for the starting point of available VRF capacity, there is much higher probability of interruption. Using the data provided by CRU for the period August 2017 – September 2018, the maximum forward flow was 176.5 GWh/day. Assuming that the maximum forward flow for each day of the period is 176.5 GWh/day and the that the interrupted VRF volumes each day are the allocated VRF plus the difference between the actual forward flow and the maximum forward flow for the period there is a 65% probability of interruption.

Do not apply the 276% uplift to create daily multipliers for this product as there is no possibility of incentivising shippers to book annual capacity; this is not relevant when there is no annual capacity product. Nor is there a need to ensure cost recovery because the cost of the asset is being recovered in the forward flow. The multipliers would be as the daily multipliers divided by 278%.

<table>
<thead>
<tr>
<th>Month</th>
<th>VRF Daily multiplier</th>
</tr>
</thead>
<tbody>
<tr>
<td>October</td>
<td>0.23%</td>
</tr>
<tr>
<td>November</td>
<td>0.23%</td>
</tr>
<tr>
<td>December</td>
<td>0.41%</td>
</tr>
<tr>
<td>January</td>
<td>0.72%</td>
</tr>
<tr>
<td>February</td>
<td>0.82%</td>
</tr>
<tr>
<td>March</td>
<td>0.62%</td>
</tr>
<tr>
<td>April</td>
<td>0.23%</td>
</tr>
<tr>
<td>May</td>
<td>0.02%</td>
</tr>
<tr>
<td>June</td>
<td>0.02%</td>
</tr>
<tr>
<td>July</td>
<td>0.02%</td>
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<tr>
<td>August</td>
<td>0.02%</td>
</tr>
<tr>
<td>September</td>
<td>0.02%</td>
</tr>
</tbody>
</table>
Apply a Risk Premium more relevant to Ireland

The Risk Premium which has been applied does not to take into account the features of the Irish gas market which mean that the consequence of falling to find a home for surplus gas in Ireland is much greater than for other European markets.

- There is no storage in Ireland which can accommodate surplus gas.
- VRF is the only access to other gas markets.

For producers, this leaves only the option to cut back deliveries. Since Irish offshore gas is operating on a depletion basis, the value of the reduced volume will only be realised at the end of the field life, and probably not even then since curtailment is sub-optimal and may reduce the total recoverable gas.

The IOOA believes the factor should be very much greater if the Risk Premiun of 10% is benchmarked from France and Germany where many options are available to suppliers interrupted from one of multiple shipping choices, IOOA suggest 50% would be more appropriate in Ireland.

6B. What are your views as to whether commodity charges should apply to use of the VRF product?

Throughout Europe (views expressed during tariff network code consultation process) it is acknowledged that VRF services save shippers money by reducing fuel gas consumed, and in many cases this has the potential to reduce variable and perhaps fixed costs. Charging a commodity charge does not reflect the incremental cost of providing the service especially if own use gas is brought into the commodity charge as is currently proposed.

Multipliers and seasonal factors 7A. What are your views on the CRU’s proposal to reduce the current monthly multipliers to comply with the monthly multiplier bound of 1.5 as set out in the TAR NC.

The IOOA supports the pragmatic approach by CRU on the reduction of the current monthly multipliers, to have the sum added up to 150%. This would imply continuation of the relative low summer monthly factors which has been proved to be successful to attract further demand i.e. use of the GNI transmission system during the summer. So these relative low summer multipliers have resulted in a better utilisation of the GNI system which is in the benefit of all network users.

7B. What are your views on the CRU’s proposal to reduce the quarterly multiplier to 1.35?

The IOOA supports to have the quarterly multiplier somewhat lower than the summation of the three respective monthly multipliers, this to incentivise quarterly bookings. Lowering it from the 1.5 (for monthly) to the proposed 1.35 would definitely works as an incentive. We think the proposal is reasonable, however, if CRU would want to amend their initial 1.35, we would recommend to change it upwards in the direction of 1.5 rather than changing it downwards. This to avoid the lowering of yearly bookings, which would result in the increase of the standard yearly charge, to ascertain the same yearly income for GNI.

7C. Should a reduction in the range of seasonal factors be considered?
The IOOA does not support a reduction in the range of seasonal factors. As explained above under 7A, low summer monthly factors have resulted in a better utilisation of the GNI system by higher usage during summer. We expect certain companies have based their investments on these low summer capacity costs, and increase the summer capacity would endanger their profitability.

7D. How should the CRU consider implementing a transitional approach in the case ACER recommend reducing the daily multiplier to a maximum of 1.5?

The IOOA is of the opinion that reducing the daily multiplier to a maximum of 1.5 would have an enormous impact on booking behaviour of shippers, unpredictable income for GNI and therefore unpredictable and unstable tariffs for network users. If ACER would come to such a recommendation we would recommend CRU to consult on this issue at that time and if deemed necessary to adjust the daily multipliers for Ireland, to use a transitional period for implementation. This to minimise the detrimental effects on unpredictable income and tariffs and the instability of tariffs.
Consultation on Harmonised Transmission Tariff Methodology for
Gas (Ref: CRU/18/247)

Phoenix Natural Gas Ltd. Response

11 February 2019

About Us

Phoenix Natural Gas Limited ("PNGL") is the owner and operator of the largest gas distribution
business in Northern Ireland ("NI"), covering an area that encapsulates almost half of the population
of NI, including Greater Belfast, Larne and East Down (the "Licensed Area").

As a distribution network operator, PNGL is responsible for developing and maintaining the pipeline
network in its Licensed Area and providing a 24/7 operational and transportation service platform to
both gas suppliers and gas consumers. PNGL’s network currently makes gas available to c.330,000
potential properties of which more than 215,000 are already connected. The NI Authority for Utility
Regulation ("NIAUR") has recognised PNGL’s growth prospects in its latest gas distribution network
price control determination which runs to 2022, and set PNGL challenging targets to further expand
its network into East Down and to increase gas penetration to maturity throughout its existing
network. As PNGL’s current distribution charge is set based on its ability to continue to expand its
network and to increase connections through the marketing of natural gas to new end consumers,
stability in gas transportation charging is a key driver of realising this network growth. The proposals
therefore in this consultation are concerning.

Introduction

PNGL welcomes the opportunity to respond to the Commission for Regulation of Utilities ("CRU")
consultation on Harmonised Transmission Tariff Methodology for Gas.

Although there are currently no cross-border flows to NI, PNGL note that the NI Capacity Statement
published by Mutual Energy ("ME") and Gas Networks Ireland ("GNI") (UK) Ltd. in December 2018
highlights that use of Gormanston is required to meet severe winter peak demands.

PNGL thought it necessary to assess the impact the proposed tariffs would have on NI consumers
should the proposals within this CRU consultation be accepted and this response aims to set out our
conclusions in this regard.

It is however not clear from the consultation if the proposed tariffs would apply to transit shippers
to NI therefore our comments in the remainder of this response assumes that they do.
Tariff Assessment

PNGL has always argued that the current tarifing arrangements at Gormanston are penal and we continue to believe that this consultation proposal does nothing to change this view. We are further alarmed at the proposed tariff suggested for Twynholm in the consultation paper and believe that this:

- Will increase costs for NI shippers utilising the Scotland to NI Pipeline ("SNIP");
- Will increase significantly NI gas consumers bills at a time when NI has the highest level of fuel poverty within the UK; and
- Will act as a barrier to shippers wishing or needing to utilise the GNI Interconnector system via Gormanston and the South North Pipeline.

PNGL has concerns regarding the below proposed Exit Capacity tariffs:

1. Twynholm

   All gas requirements for NI are currently supplied through SNIP without leaving the U.K.

   Using the forecast capacity and flow figures from the NI Forecast Postalised Tariff calculation and the Twynholm tariffs (as per the CRU Consultation Transmission Tariff Model), PNGL has calculated that the costs incurred by ME for utilising Twynholm will significantly increase. Our calculations show that this would result in costs of c.£45m being incurred by ME. Comparing this to the current estimated costs of £5m\(^1\) we would appreciate an explanation of how such an alarming increase is justified especially when:

   - Compared to the tariff determined from the Capacity Weighted Distance approach (318% lower); and
   - Considering that this cost is for transporting gas within the U.K. from Moffat to Twynholm.

PNGL has calculated that an extra £40m added to the NI Postalised regime will increase NI Postalised tariffs by 39% resulting in an estimated annual increase of c.£35 to domestic customer bills in the PNGL Licensed Area.

2. Gormanston

   As noted above, for a number of years, the penal Gormanston Exit Capacity tariff has been a barrier to shippers wishing to utilise this system point. The proposed Exit Capacity tariff is 35-45% higher than those published for NI for the period 18/19 to 22/23.

Summary

In summary, PNGL has determined that the proposed tariffs for Twynholm and Gormanston will result in penal price increases for NI consumers and has the potential to have a significant impact for network operators, such as PNGL, looking to expand its network and to maximise connections. Therefore, PNGL would request urgent discussion between the NIAUR, the CRU and the NI gas industry to address this issue and agree on a solution that works for both NI and the Republic of Ireland.

\(^1\)Scottish Costs in Table 13, http://gmo-ni.com/assets/documents/2017-08-01-GT17-final-determination-redacted-final_0.pdf
A copy of this response has been forwarded to the NIAUR for consideration.
Mr. Cahir O'Neill,
Gas Networks Team,
Commission for Regulation of Utilities,
The Grain House,
The Exchange,
Belgard Square North,
Dublin 24,
D24 PX0

11 February 2018

By email: gasnetworks@cru.ie

Re: Response to Consultation Paper on Harmonised Transmission Tariff Methodology for Gas:
CRU/18/247

Dear Cahir,

Nephin Energy, as a new owner of 43.5% of the Corrib field, has welcomed the opportunity to participate
in the NTIG consultations and now submits its comments on the CRU’s proposals.

Our views are contained in IOOA’s submission apart from our responses to Q4A and 4C which are covered
in the letter from Vermillion Exploration and Production Ireland Limited (VEPIL), the operator of the Corrib
gas field, on behalf of the Corrib partners.

We have two very serious concerns, firstly that the issue of whether there should be discounts for LNG
entry points (5A) remains open despite the CRU’s strong argument in the Consultation Paper that they
are not justified. Since this opinion is being consulted on, it is essential that any decision which overturns
It is also consulted on and Nephin are seeking assurance that such consultation would take place.

Secondly, we have made strong representations about the proposed VRF tariff (5A) which we believe is
incorrectly set and at a level damaging to markets in Ireland and to cross-border trade. This has been
created by flawed application of the rules for forward flow, which produces perverse outcomes, when
there is actually no necessity to define VRF as a transmission service.

Our responses to the specific questions are as follows:-

Proposed RPM

Q. A. What are your views on the CRU’s proposal to continue to apply the Matrix RPM?

As in IOOA’s letter, continuation with the Matrix RPM is pragmatic.
Shrinkage

4A. What are your views on the CRU’s proposal to class shrinkage as a transmission service and to recover the cost through the commodity element of the capacity/commodity split rather than through a separate flow-based charge? Also, what are your views on a date of implementation of gas year 2019/20?

As in the Corrib Partners’ letter sent by VEPIL, we are not in favour of the proposal to class shrinkage as a transmission service and recover cost via the commodity element.

Entry/Exit Split

4B. What are your views on the CRU’s proposal to continue to apply a 33:67 entry/exit split.

As per IDOA response, we are content to see this continue as it is connected to the RAB.

Capacity/commodity split

4C. What are your views on the CRU’s proposal to continue to apply a 90:10 capacity/commodity, taking into account the CRU’s proposal to incorporate shrinkage into the transmission services revenue?

As in the Corrib Partners’ letter sent by VEPIL, our response is dependent on the outcome of 4A but would favour a move to greater capacity weighting.

Expansion constants and annuitisation factor

4D. What are your views on the CRU’s proposal to update these components of the Matrix RPM?

As per the IDOA response which in particular demonstrates that current expansion constants when benchmarked against real projects are too low. The factors in the Matrix need to be realistic and hence should be updated annually.

Discounts LNG

5A. What are your views on the CRU’s proposal to not apply a discount for LNG entry points at this time? Also, do you agree with the considerations that the CRU proposes to take into account when coming to a decision on the possible provision of LNG discounts in the future?

As detailed in IDOA’s letter, Nephin agree with the CRU that there is no case for discounts on LNG Entry and that any change from this position would require public consultation.

Bilogas

5B. What are your views on the CRU’s proposal to apply a single notional biogas entry point tariff to all biogas entry points? What are your views on how the notional point should be constituted?

As in IDOA’s letter, Nephin are content with the single point which should represent the source of the supply.

5C. What are your views on biogas distribution entry tariffs relative to transmission entry tariffs and the additional factors which may need to be taken into account in designing such a tariff?

As in IDOA’s letter, Nephin believe that this is not an issue for them to advise on.
VRF

6A. What are your views on the CRU's proposed VRF tariff methodology and are the factors and magnitude of the factors proposed for the VRF tariff appropriate?

IOOA have provided a very detailed response on this which Naphin supports.

6B. What are your views as to whether commodity charges should apply to use of the VRF product?

As detailed in IOOA's letter we believe a commodity charge is inappropriate.

Multipliers and seasonal factors

7A. What are your views on the CRU's proposal to reduce the current monthly multipliers to comply with the monthly multiplier bound of 1.5 as set out in the TAR NC.

As detailed in IOOA's response Nepbin support minimal change.

7B. What are your views on the CRU's proposal to reduce the quarterly multiplier to 1.35?

As detailed in IOOA's letter, this is an appropriate change.

7C. Should a reduction in the range of seasonal factors be considered?

As detailed in IOOA's response, Nepbin support the current position.

7D. How should the CRU consider implementing a transitional approach in the case ACER recommend reducing the daily multiplier to a maximum of 1.5?

As detailed in IOOA's response, any significant change should be phased.

Yours sincerely

[Signature]

Registered in Ireland No 616570
Registered Office 25-28 North Wall Quay, Dublin 1, D01 HLD4
Mr Cahir O'Neill
Commission for Regulation of Utilities
The Grain House
The Exchange
Belgard Square North
Dublin 24
Republic of Ireland

11th February 2019

Dear Cahir,

Equinor fully supports the IOOA & Corrib partners response to the CRU’s consultation on Harmonised Tariff Methodology for Gas. If you have any questions, please let me know?

Yours sincerely,

[Redacted]

Equinor
Tariff Network Code Consultation

GNI’s response to the CRU’s consultation paper on the Tariff Network Code
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14 Reduction in Seasonal Factor range
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16 Summary
GNI would like to thank the CRU for the opportunity to respond to this consultation paper. GNI acknowledges the breadth of the TAR NC guidelines, and appreciates the time afforded to relevant parties to provide a response to the consultation paper.

GNI has recorded its responses to the proposals, as laid out in the ‘Harmonised Transmission Tariff Methodology for Gas (CRU/18/247), and reference the proposal and its relevant section within the consultation paper.

In the context of the timings of this consultation, GNI also wishes to highlight that the tariff setting process for gas year 2019/20 has already begun, and the tariffs for this period will require finalisation by end of May 2019.

Request for Comment 3A

The CRU’s proposal to continue to apply the Matrix Reference Price Methodology.

GNI are in agreement with continuing to apply the Matrix RPM for the transmission network as we consider the Matrix methodology best serves the unique characteristics of the network, while also enabling customers to reasonably estimate future tariffs.

Request for Comment 4A

The CRU’s proposal to class shrinkage as a transmission service and to recover the cost through the commodity element of the capacity/commodity split rather than through a separate flow-based charge. Also, what are your views on a date of implementation of gas year 2019/20?
While GNI understands the interpretation of the TAR NC with regard to flow-based costs and their inclusion as a transmission service, we believe that this aspect of the proposal requires further consideration and discussion with respect to its implementation in practice, along with the associated implications of the change. GNI would agree that the inclusion of the shrinkage cost within the overall allowed revenue would be in line with the concept of a single gas system where all users who have access to, and use of the system, contribute to the operation and integrity of the system.

GNI see a number of issues which need to be fully considered, including how the gas shrinkage costs will be brought in and included in the revenue calculation, the effect on shippers with particular reference to existing supply contracts, and the required systemisation and the development of the IT systems to enable the change, from a billing and account perspective.

The inclusion of the Shrinkage costs in the overall revenue will increase the risk on GNI of within year changes in gas prices and will therefore increase the obligations on GNI to manage any within year volatility and cash flow issues. Further consideration needs to be given as to how this will be incorporated and managed.

With respect to GNI’s practical approach of including the transmission cost within the allowed revenue, there are significant challenges in systemising the proposed change and it would not be possible for this to be completed for October ‘19, i.e. for the 19/20 gas year. The business rules on what is to be implemented have yet to be determined along with any associated implications for the users of the gas network. GNI resources are already assigned to a number of other high priority projects, and based on the current commitments to these projects it would prove impossible (and inefficient) to reassign these resources in order to prepare these systems for the 19/20 gas year. Therefore further planning, design and discussion needs to occur to allow this change to be implemented in an appropriate manner.

Furthermore, GNI would highlight that it is necessary, in the interests of end customers, to carry out additional analysis on the potential impacts to revenue recovery, impacts on existing supply contracts and resultant transmission tariffs based on this proposal and GNI would urge the CRU to work with industry participants and GNI to determine an appropriate implementation date on the basis that it is decided to progress with this change.

For the reasons above, if this change is to be implemented, GNI would propose implementing this from gas year 2020/21 at the earliest.

Request for Comment 4B
The CRU’s proposal to continue to apply the 33:67 Entry/Exit split.

GNI agree with the application of the 33:67 Entry/Exit split, and with the reasons for the application of this split, given in the consultation paper.
Request for Comment 4C

The CRU’s proposal to continue to apply a 90:10 capacity/commodity, taking into account the CRU’s proposal to incorporate shrinkage into the transmission services revenue.

GNI would agree with the application of the 90:10 Capacity/Commodity split, and with the reasons for the application of this split, given in the consultation paper.

Request for Comment 4D

The CRU’s proposals to update the expansion constant and annuitisation factors.

GNI are in agreement with the proposals to update both the expansion constants and annuitisation factor for incorporation in the Matrix tariff model. GNI are of the view that the updates to the expansion constants and annuitisation factor are appropriate and are the correct balance between remaining consistent with previous approaches and attempts to ensure suitable additional information is included, and updated, where necessary.

GNI also agree that any updates necessary to the expansion constants and annuitisation factor should be reviewed and undertaken every 5 years. This would ensure the stability of these inputs to the tariff modelling in the intervening period while ensuring cost reflectivity.

Request for Comment 5A

The CRU’s proposal to not apply a discount for LNG entry points at this time. Also, what are your views on the considerations that the CRU proposes to take into account when coming to a decision on the possible provision of LNG discounts in the future?

GNI agrees with the CRU’s conclusions on the non-application of LNG discounts at this time. GNI would be keen to highlight that the current, and proposed RPM methodology, allows for the full recovery of GNI’s allowed revenue, as set through the Price Control process. It is critical to highlight that, should a discount for LNG be applied in the future, the full recovery of GNI’s allowed revenue would need to be taken as a pre-requisite to the calculation of such a discount and any associated tariff changes.
With regard to the current, and proposed, RPM, it is worth noting that the Matrix approach can be viewed as intrinsically providing an incentive and reward to those potential new entrants to the transmission network (inclusive of LNG entry points), where those entrants prove to be more efficient than the marginal source of supply i.e. Moffat. This is in the form of a ‘diversity premium’, which looks to reward those new entry points located close to the demand on the network.

A key consideration in the calculation of any LNG discount is that it would have the implication of increasing the amount of revenue recovered from other, non-LNG entry points, thereby increasing the level of tariffs for those entry points. The impacts of those tariff increases on customers should be a key consideration for the CRU.

Request for Comment 5B

The CRU is proposing to introduce a notional point which will be used to set a single tariff for biogas entry points. What are your views on the CRU’s approach to apply a notional biogas entry point and how this point is constituted?

With regard to the tariff development for biogas, and in the context of establishing an approach to biogas entry on the transmission network, it is worth noting the relative infancy of this industry. Any initial tarifing approach to biogas transmission entry points will need to be reviewed as this industry grows.

With the above in mind, GNI agree with the proposed establishment of a single notional transmission tariff as an initial approach, and its relative advantages of simplicity, stability and investor certainty. The stability and predictability of a single notional transmission tariff should help to alleviate any barriers to the initial development of this area.
With regard to the notional point options considered in the consultation paper, GNI believe that the option of a single notional point located close to the centre of demand (option 2 in the consultation paper) may be the most suitable approach for establishing a biogas transmission tariff, at this time. While recognising the price signal from the tariff as per option 1, GNI are of the view that the price signal from option 2 is more appropriate, at this time, given the infancy of this industry and the initial expected proximity of biogas entry to demand.

It would also be challenging to initially base this tariff on the geographically dispersed points as per option 1 in the consultation paper, as currently, the number of active points for biogas is in its infancy, and there is no certainty over where additional points would be located.

In the absence of a specifically agreed single notional biogas transmission point within the transmission tariff model, GNI would suggest that the Gormanston Entry tariff is adopted. Of the available points currently within the model, the Gormanston Entry tariff would best represent a point close to the centre of demand for biogas. While the establishment of this single tariff will help to achieve those advantages of stability and investor certainty, GNI would reiterate the need to review not only the tariff itself, but also the approach being used to set this tariff, as this industry grows. GNI would suggest that a period of 5 years, whereby this single tariff will be in place for all biogas transmission entry points until a further review of conditions is performed, is sensible.

Request for Comment 5C

What are your views on biogas distribution entry tariffs relative to transmission entry tariffs and the additional factors which may need to be taken into account in designing such a tariff?

Currently, all of GNI’s allowed revenue for distribution is recovered via a distribution exit tariff. While there is currently no entry tariff (or entry tariff methodology) in place for the distribution network, the ability of biogas to directly connect onto both transmission and distribution networks may warrant a revisit of this structure.

With any review of the distribution tariffing structure, a number of factors will need to be taken into account. The relative infancy of this industry would mean that further analysis is required to fully explore the relationship between distribution and transmission connected biogas points, ensuring that equal parameters are established for both areas, whilst mitigating any risks of creating distortions in decisions around connecting to one network, or the other.

Other factors that GNI believe need to be taken into account include, but are not contained to;
potential interruption to the supply of biogas on the network,
the ability for distribution connected biogas developers to supply onto the transmission network, and any associated costs for reinforcement to the network.
approaches to tariff development which take into account the characteristics of the distribution network
approaches to tariff development which don't give rise to undue cross-subsidisation
in the event of an entry tariff for distribution being introduced, how this would be applied across the distribution network

Request for Comment 6A
The CRU is proposing to interpret VRF as an interruptible product and to introduce a VRF tariff which takes into account the probability of interruption and the economic value of the product. What are your views on the CRU's proposed VRF tariff methodology and are the factors and magnitude of the factors proposed for the VRF tariff appropriate?

GNI view the proposed VRF methodology as being appropriate. The approach to determine an initial 'Probability of Interruption' factor is suitable given the current interactions of the VRF product. GNI understands and agrees with the adjustment factors being used to further scale the VRF adjustment, as an initial approach.

GNI would note that the interactions with the VRF product may evolve with the introduction of the new interruptible VRF tariff, and any changes in behaviour will need to be analysed on a continuous basis in order to determine if the interruptible adjustments require updating for future periods. GNI would propose that this would be undertaken annually.

Request for Comment 6B
What are your views as to whether commodity charges should apply to use of the VRF product?
GNI's view is that the commodity charge, which reflects the variable costs of the system, should be applied.

Request for Comment 7A
The CRU is proposing to reduce the current monthly multipliers to comply with the monthly multiplier bound of 1.5 as set out in the TAR NG.

GNI would like to highlight that any movement in the current multipliers needs to be aligned to achieving cost reflectivity and efficient use of the network itself. A reduction in the multipliers may have unintended impacts on the level of annual capacity bookings, which in turn may have consequences on the level of tariffs for annual products. There needs to be a balance between
complying with the TAR NC directives for multiplier bounds, and ensuring that the areas of cost reflectivity and efficient network use are maintained.

With the above in mind, GNI support the reduction of the current monthly multipliers to the multiplier bound of 1.5. This will have the effect of compliance with the TAR NC guidelines in this area, and will also ensure continuity with the use of these multipliers, which GNI believe best represents the efficient use and underlying costs of the network.

Request for Comment 7B

The CRU is proposing to reduce the quarterly multiplier to 1.35.

Similar to the monthly multipliers, it is worth noting that any reduction in the quarterly multipliers will need to be approached with the objective of ensuring that the efficient use of the network is being achieved. GNI would reiterate that any movement away from annual capacity bookings would impact on the level of annual capacity tariffs.

GNI agrees with the reduction in the quarterly multipliers with the objective of representing the underlying costs and efficient use of the transmission system. The level of quarterly multiplier of 1.35 seems reasonable to GNI, based on the proposed movement in the monthly multipliers.

Request for Comment 7C

Should a reduction in the range of seasonal factors be considered?

Multipliers of short term products need to set the correct incentives for utilisation of the gas network. Those users who are contributing to the costs need to be incentivised to book the appropriate levels of capacity. Those users who have a requirement for higher capacity in the winter periods should be required to pay for those costs and potential users of the gas network in periods of lower demand, i.e. the summer, should be incentivised to use the gas network thus resulting in an overall efficient outcome.

GNI are therefore of the view that while a rebalancing between winter and summer seasonal factors may be appropriate, the actual overall seasonal profile is appropriate and that a reduction in the range of seasonal factors does not need to be considered.
Request for Comment 7D

How should the CRU consider implementing a transitional approach in the case ACER recommend reducing the daily multiplier to a maximum of 1.5?

GNI’s view is that multipliers for short term products need to be set in a manner which creates the appropriate incentives for those users of the network who have long term requirements and are driving costs through the requirement for peak demands, particularly at periods of higher overall network demand, i.e. winter.

In the event that ACER recommend reducing the daily multiplier to a maximum of 1.5, GNI would strongly recommend that a full assessment of the implication of this proposed reduction be undertaken to ensure unintended consequences do not emerge.

When users move away from annual products to short term, there is a likelihood that prices for annual products will increase, so a balance needs to be struck between lower multipliers and rising prices. In addition, if the multipliers are set too low there is a risk that users who have a higher peak requirement, and are driving higher costs as a result, would end up being subsidised by those users who book annual capacity but are not necessarily driving the short term peaks.

Adjustments to the multipliers also increase the difficulty in forecasting demand for tariff calculation and in the event it is decided to reduce the tariff multipliers the transition should be managed in a way that minimises the uncertainty and volatility associated with the forecasting of demands for tariff calculations purposes.

In summary GNI are of the view that the multiplier levels as per the consultation are appropriate, a full impact assessment should be completed. In the event that further changes are considered and multipliers should also result in appropriate incentives to ensure efficient utilisation and payment for the gas network.

Summary

GNI note the varied topics and proposals contained within this consultation paper, and would like to thank CRU for the opportunity to respond to these proposals.

GNI wish to highlight that a key objective is the setting of the 2019/20 tariffs, thereby ensuring that the required data is available for the PRISMA trading platform towards the end of May 2019 with a view to publishing those finalised tariffs one month prior to the annual capacity auction, which occurs at the beginning of July 2019.

The setting of the 2019/20 tariffs will rely on the finalisation of the transmission tariff model, which in turn will require updating to reflect the decisions of the TAR NC consultation. These decisions will
need to be implemented in a timely manner to allow the updating of the model and the setting of the 2019/20 tariffs within the required timelines.

GNI have highlighted through this consultation response paper where there are real challenges in implementing some of these proposals for the 2019/20 tariff setting process, which has begun in earnest. Where those areas are not deemed feasible to implement for the 2019/20 tariff setting process, GNI will work with CRU to have these in place for the 2020/21 gas year.
Mr. Cahir O'Neili,
Gas Networks Team,
Commission for Regulation of Utilities,
The Grain House,
The Exchange,
Belgard Square North,
Dublin 24,
D24 PXW0

11 February 2019

By email: gasnetworks@cru.ie

Re: Response to CRU/18/247 Consultation

Dear Cahir,

I would like to thank you for the opportunity to respond to the tariffing consultation. I confirm that Vermilion Energy Ireland Limited (VEIL) fully supports the IOOA response to the CRU/18/247 consultation that is being submitted today. VEIL also fully supports the shrinkage letter that is being submitted today by the Corrib operator.

Yours sincerely,

[Signature]

VERMILION ENERGY IRELAND LIMITED, branch registration number 903714, 4th Floor Embassy House, HadAm Park Lane, Argyle Road, Dublin 4, Ireland, VAT: IE 660218HR

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Mr. Cahir O’Neill,
Gas Networks Team,
Commission for Regulation of Utilities,
The Grain House,
The Exchange,
Belgard Square North,
Dublin 24,
D24 PXW0

11 February 2018

By email: gasnetworks@cru.ie

Re: Response to Question 4A and Question 4C of CRU/18/247

Dear Cahir,

Vermilion Exploration and Production Ireland Limited (VEPIL), the operator of the Corrib gas field, is responding on behalf of the Corrib partners (Equinor, Nephin Energy and Vermilion) to the specific question of shrinkage and its linkage to the capacity/commodity split as outlined below:

Shrinkage 4A. What are your views on the CRU’s proposal to class shrinkage as a transmission service and to recover the cost through the commodity element of the capacity/commodity split rather than through a separate flow-based charge? Also, what are your views on a date of implementation of gas year 2019/20?

Is the proposed commodity charge cost-reflective, non-discriminatory, objective and transparent?

The recovery of the Un-Accounted for Gas (UAG) component of shrinkage through the proposed commodity charge is cost-reflective, non-discriminatory, objective, and transparent so all shippers should pay for this. The Corrib partners consider, however, that the proposal to apply the proposed commodity charge to GNI’s Own Use Gas (OUG) consumed in GNI’s compressors is not cost-reflective and is discriminatory as detailed below.

Without doubt the different pressures of gas entering the system at different entry points affects the amount of gas consumed for OUG purposes. Indeed in September 2018 at a Code Mod meeting, GNI presented the data in the chart reproduced below.
Figure 1 - Total Shrinkage Consumption

Figure 1 above details the UAG and OUG consumption from Jan’14 to Jun’18. As can be seen above there was a step reduction in OUG consumption post-Corrib commissioning when compared to OUG consumption pre-Corrib commissioning (Corrib commissioning was a gradual process increasing flowrates from the field hence the gradual reduction in OUG during the Corrib commissioning phase). This illustrates previous arguments made by NTLG participants that new entry points that deliver gas into the Irish network at the ring main pressure of 70 barg reduce the flow of gas at MoM and the associated OUG.

From the above graph ¹, comparing gas year 2014/15 OUG to gas year 2016/17 OUG, the addition of Corrib flows gives a reduction of the order of 37% in OUG consumption (10.4 million therms) which at current prices (assumed 55p/therm) is a value save to all shippers of STGES.7million per year. This coupled with a 17% increase in annual gas demand² from 47.1 GWh/year (2014/15) to 55.1 GWh/year (2016/17) means that the actual effect of Corrib flows has reduced OUG consumption by circa 50% between 2014/15 and 2016/17 which makes the value savings to shippers more of the order of STGES7.7million. This value save to all Irish shippers is predominately due to the commencement of Corrib flows and the associated reduction in OUG due to lower flows at MoM.

It is clear that the proposal by GNI to include OUG in the commodity element of the capacity based charge is not cost-reflective and is discriminatory to shippers entering gas into the GNI network at the Bellanaboy entry point with Bellanaboy shippers paying a portion of the cost of compression for other entry points to get their gas to the IBP.

¹ GNI Provided the Corrib partners with this data file
² GNI 2018 Network Development Plan - Draft
Entry / Exit Equivalence

A single entry / exit system can only be considered if all entry points are equivalent; the current proposal by the CRU for the regulatory treatment of OUG is not cost-reflective and is discriminatory towards Bellanaboy shippers so the entry / exit approach proposed is not equivalent for all entry and exit points.

Compliance with Article 4.1 of the EU Tariff Network Code

UAG - It is questionable whether the proposed approach by the CRU meets the specific criteria of Article 4.1 of the tariff network code since the cost drivers for UAG are not technical or forecast capacity of the network or distance; the drivers for UAG are more gas network leakage and metering issues. The Corrib partners consider that UAG could be considered as a non-transmission service and charged as a commodity charge to all shippers accordingly.

OUG - For OUG the same rationale applies. While technical and / or forecast capacity determines the length and size of pipelines and associated compression requirements (and maximum potential daily OUG consumption) within a gas network, technical and / or forecast capacity in conjunction with distance of the network does not determine the quantity of OUG consumed on a day; gas demand drivers (e.g. wind generation, ambient temperature, coal switching price etc.) in conjunction the configuration of deliveries at each Irish entry point, each having a different gas delivery pressure, determines the requirement for GNI compressors to operate, consuming the associated OUG. This proposed treatment of OUG by the CRU does not meet the specific criteria of Article 4.1 of the tariff network code since the cost drivers for OUG are not technical or forecast capacity of the network, nor distance.

From the Corrib partners’ perspective, the proposed tariffing of OUG would be more akin to a non-transmission charge levied on those entry points where the OUG is required (to get gas to the IBP on the island of Ireland at the appropriate pressure) as this would be a cost-reflective and non-discriminatory approach. Consideration should be given to levying a non-transmission charge relevant to those points based on an each entry point’s OUG consumption in getting gas from a relevant entry point to the IBP on the island of Ireland. This is similar to that proposed by National Grid for the St Fergus Compression fee in GB (See Vermillion letter to CRU dated 22 October 2018 for more detail) in which gas entering at St Fergus that requires compression by National Grid is charged an additional fee for the associated OUG.

Implementation Date

GNI should ensure that Ireland is network tariff compliant and implement this for the next gas year.

Capacity/commodity split. 4C. What are your views on the CRU’s proposal to continue to apply a 90:10 capacity/commodity, taking into account the CRU’s proposal to incorporate shrinkage into the transmission services revenue?

The Corrib partners are of the opinion that, if OUG is defined as a non-transmission charge then there is little which can be deemed flow related on the GNI network and a 100/0 split would be appropriate.

If there is no change to the proposed treatment of shrinkage as outlined in the consultation paper then the Corrib partners would support a move to 100% capacity, accepting that 95/5 would be a moderate
move in that direction. We have responded in detail above on the proposed treatment of shrinkage which fails to recognise the different contributions to system pressure made at different entry points.

Yours sincerely,
11 February 2019

Gas Networks Team
Commission for Regulation of Utilities
The Exchange
Belgard Square North
Tallaght
Dublin 24

RE: Consultation CRU/18/247 Harmonised Transmission Tariff Methodology for Gas

Dear Sir or Madam,

Firmus energy welcomes the opportunity to respond to the consultation CRU/18/247 on Harmonised Transmission Tariff Methodology for Gas. We would be grateful if we could be included in your distribution list for any further consultations on this matter, or indeed any matter relating to tariff arrangements which might potentially impact Northern Ireland shippers.

Firmus energy notes that the CRU are consulting on the reference price methodology for calculating transmission tariffs for the Republic of Ireland, however the RPM workbook model under CRU/18/247a incorporates Twynholm in its calculations. As there is no further clarification in the consultation on the inclusion of Twynholm in the modelling, it is unclear as to why it is included for the calculation of Transmission Tariffs in the Republic of Ireland.

As a Northern Ireland shipper, firmus energy seek confirmation from CRU that the proposed methodology for Transmission Tariffs will not impact the cost of shipping gas from Moffat via Twynholm to Northern Ireland.

Firmus energy would welcome and encourage CRU to engage with NIAUR and wider industry stakeholders in Northern Ireland on this matter, particularly should any cost in Northern Ireland be anticipated.

We look forward to further engagement as part of this consultation process.

Yours faithfully,
Commission for Regulation of Utilities

Harmonised Transmission Tariff Methodology for Gas Consultation Paper – Art. 26 & 28

Aughinish Alumina Ltd Response
Gas Networks Team
Commission for Regulation of Utilities
The Exchange
Belgard Square North
Tallaght
Dublin 24

This response is non-confidential

Introduction;
Aughinish is the single largest manufacturing consumer of natural gas in Ireland. Aughinish operate an energy intensive manufacturing process where energy costs account for about 30% of operating costs. Having converted from 100% oil based production, we are now 100% gas operated with the ability to run on dual fuel.

General Comments;
Aughinish welcome this opportunity to contribute to the Harmonised Transmission Tariff Methodology for Gas Consultation Paper.

Proposed RPM;
What are your views on the CRU's proposal to continue to apply the Matrix RPM?

Aughinish agree with the CRU's proposal to continue to apply the Matrix RPM as gas tariff's should be set using a forward looking approach. The Matrix RPM allows for such an approach through its use of Long Run Marginal Cost. Stable tariff differentials resulting from the Matrix RPM provide a clear signal for future investment. Aughinish also welcome the reduction of tariff volatility through the use of the Matrix RPM as opposed to the less predictable CWDA model.

Shrinkage;
What are your views on the CRU's proposal to classify shrinkage as a transmission service and to recover the cost through the commodity element of the capacity commodity split rather than a separate flow-based charge? Also, what are your views on a date of implementation of gas year 2019/2020?

Aughinish support the proposed inclusion of shrinkage as a transmission service under the allowed revenue model. We view Shrinkage as the cost of maintaining pressure in the network system and therefore agree it should be treated as a transmission service.

Aughinish are also in favour of the enhanced transparency in relation to total costs that this change will provide. It has been noted in recent NTLG meetings that the inclusion of Shrinkage under the transmission service revenues will closer reflect the 90:10 capacity/commodity split currently in place. Aughinish are of the view that revenues should be accounted for based on where costs are incurred, and therefore this change should be adopted for the 2019/2020 gas year.
Entry/exit split;

*What are your views on the CRU’s proposal to continue to apply a 33:67 entry/exit split?*

Aughinish agree with the CRU’s proposal to continue with the 33:67 entry/exit split currently in place. The rationale for adopting this split in 2015 has not changed and it is important to select a split that will reduce redistributive affects across system users.

Capacity/commodity split;

*What are your views on the CRU’s proposal to continue to apply a 90:10 capacity/commodity, taking into account the CRU’s proposal to incorporate shrinkage into the transmission services revenue?*

Aughinish believe that the proposal to continue with a 90:10 capacity/commodity split should only be taken if shrinkage is included under the allowed revenue model. We question the appropriateness of this split today, as without the inclusion of shrinkage costs, commodity costs to the network are below 10%. If shrinkage costs are not included as a transmission cost from gas year 2019/2020, Aughinish view a 95:5 split as being a better representation of system costs.

The CRU have noted a gradual transition to a 100:0 split be appropriate, but have refrained from doing so during a time of change in the Irish electricity and gas markets. Aughinish would welcome greater transparency on the CRU’s plan to adopt this split in future.

Expansion constants and annulisation factors;

*What are your views on the CRU’s proposal to update these components of the Matrix RPM?*

Aughinish agree with the proposal to update the above components as the Matrix RPM should include costs reflective of current prices.

Discounts LNG;

*What are views on the CRU’s proposal to not apply a discount for LNG entry points at this time? Also, do you agree with the considerations that the CRU proposes to take into account when coming to a decision on the possible provision of LNG discounts in the future?*

Aughinish would welcome the increase in security of supply through an investment in a LNG facility and believe EU support should be considered to encourage such an investment. The development, should not lead to any increase in gas costs to end users of gas.

Biogas;

*What are views on the CRU’s proposal to not apply a single notional biogas entry point tariff to all biogas entry points? What are your views on how the notional point should be constituted?*

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Aughinish Alumina Limited, Aughinish Island, Askeaton, Co Limerick, V94 V8F7 – Ireland
Tel: +353 (0)61 501500, Fax: +353 (0)61 501542, aughinish@me.com
Aughinish agree with the CRU’s proposal to apply a single notional entry point tariff for Biogas in order to promote simplicity and investor certainty. This decision is unlikely to materially affect other tariffs due to the relatively small amounts of gas forecasted during the early years of production.

VRF;

What are views on the CRU’s proposed VRF tariff methodology? Are the factors and magnitude proposed for the VRF tariff appropriate?

Aughinish welcome the introduction of a tariff for VRF and believe that similar to other daily products, a seasonal multiplier should be applied to reflect seasonal variation. Aughinish question the need for a probability of interruption factor to be applied to this tariff as it is well documented the supply from the Corrib field continues to decline. This ongoing reduction is a signal that the chances of interruption to VRF decreases each week.

Multipliers and seasonal factors;

What are views on the CRU’s proposal to reduce the current monthly multipliers to comply with the monthly multiplier bound of 1.5 as set out in the TAR NC?

Aughinish have no objection to the reduction in monthly multipliers in order to comply with the TAR NC.

What are your views on the CRU’s proposal to reduce the quarterly multiplier to 1.35?

Aughinish agree that due to the lack of use of quarterly capacity products, the seasonal multipliers need to be reduced below the monthly number of 1.5. We believe that this initial reduction is adequate over the next number of years in order to determine how uptake is affected. Any large reductions would reduce the stability of tariffs by encouraging participants to move away from annual bookings.

Should a reduction in the range of seasonal factors be considered?

Aughinish do not believe there is a need to reduce the range of seasonal factors applied to short-term capacity products. The current factors incentivise gas usage during summer months allowing for a relatively stable gas demand during the gas year. Any reduction in seasonal factors would likely shift loads away from summer to winter months. A reduction in seasonal factors would also reduce the incentive to book annual products, leading to tariff price volatility.

How should the CRU consider implementing a transitional approach in the case ACER recommend reducing the daily multiplier to a maximum of 1.5?

Aughinish believe that the current daily factors allow for efficient use of the network and that there should not be any reduction made prior to ACER’s decision.
Summary

Aughinish agree with the proposal to continue with the Matrix RPM.

Aughinish suggest that Shrinkage should be included under the transmission revenue from October 2019 as it is a cost of operating the network. If Shrinkage is not included, Aughinish believe the 90:10 capacity/commodity split is not reflective of system costs. Under this scenario, a ratio of 95:5 would be more appropriate.

Aughinish believe an incentive should be given to promote investment in an LNG facility, but not at a cost to end users of gas.

Aughinish welcomes the introduction of a VRF tariff, however it is questionable whether a probability of interruption factor is needed due to the decreasing volumes of indigenous gas supply.

Aughinish agree that there should be an incentive given to encourage the use of quarterly capacity products. The proposed reduction is adequate as a further decrease may have increase tariff volatility. No changes should be made to daily products unless instructed by ACER. Aughinish are of the opinion that the current daily tariffs service the system well by ensuring efficient use of the network all year round.

As always, Aughinish is at your disposal if further clarification is needed.

Best Regards,
HARMONISED TRANSMISSION TARIFF METHODOLOGY FOR GAS,
Consultation Paper CRU/18/247

Manx Utilities Response, 8 February 2019

Manx Utilities welcomes the opportunity to comment on the Consultation Paper of 11 December 2018. Manx Utilities broadly welcomes the proposed solutions outlined in the Paper and we are pleased that the Commission is minded to adopt a pragmatic approach with as little change as possible to the existing methodology to ensure compliance with the TAR NC.

In response to the specific questions highlighted for comment in the Paper:

3A. What are your views on the CRU’s proposal to continue to apply the Matrix RPM?
As implied above we are absolutely supportive of the decision to retain the Matrix RPM. The existing methodology was developed following long and rigorous consultation with industry with the TAR NC in mind. We believe that it is fair, robust and provides a wholly desirable level of certainty and tariff stability in comparison with the target model’s counterfactual methodology.

4A. What are your views on the CRU’s proposal to class shrinkage as a transmission service and to recover the cost through the commodity element of the capacity/commodity split rather than through a separate flow-based charge? Also what are your views on a date of implementation of gas year 2019/20?
Although there may be counter arguments with respect to transparency and the socialisation of these costs across all entry points we are nevertheless supportive of this proposal. The classification of shrinkage as a transmission service is simple to implement and makes a 90:10 capacity/commodity split a more cost reflective proposition. We further believe that this will provide more certainty in respect of shrinkage costs that shippers will face and there will be sufficient scrutiny and transparency for shippers through the Commission in the tariff-setting process. We would note that it is likely to be a significant improvement on current arrangements which are on the whole fairly opaque and difficult to understand or reconcile.
Should this proposal be adopted we can see no justification for any delay in implementation beyond Gas Year 2019/20. The commodity charge is an existing charge for which billing processes already exist and we can see no need for any systemisation or IT requirements to implement this immediately.

4B. What are your views on the CRU’s proposal to continue to apply a 33:67 entry/exit split?
We very strongly support this proposal and are in absolute agreement with the CRU’s position that the reasoning for the setting of the 33:67 entry/exit split in 2015 still applies. This split not only better reflects the actual regulatory asset base but its retention is very important in terms of regulatory stability and to ensure that distortions do not occur that would unfairly impact end users on the Isle of Man.

4C. What are your views on the CRU’s proposal to continue to apply a 90:10 capacity/commodity split, taking into account the CRU’s proposal to incorporate shrinkage into the transmission services revenue?
We are fully supportive of this proposal provided that shrinkage costs are incorporated as transmission services revenue into the commodity charge. In the event that this is not implemented we would expect to see the capacity/commodity split adjusted in order to better reflect actual costs, and in order to be compliant with the TAR NC.

4D. What are your views on the CRU’s proposal to update these components [expansion constants and annuitisation factors] of the Matrix RPM?
We agree with all of the proposals to update the expansion constants and annuitisation rates.

5A. What are your views on the CRU’s proposal to not apply a discount for LNG entry points at this time? Also, do you agree with the considerations that the CRU proposes to take into account when coming to a decision on the possible provision of LNG discounts in the future?
We are in full agreement with the approach proposed by the Commission. We do not believe that blanket discounts for LNG are appropriate, as in reality large scale entry gas is entry gas regardless of whether it is from an interconnector, gas field or ship. It is not analogous to storage in this regard. It is however appropriate for the Commission to consider whether it may be appropriate to apply discounts on a case-by-case basis taking particular notice of market conditions at the time. The considerations set out by the Commission for the purposes of considering discounts in the future appear reasonable at this time.

5B. What are your views on the CRU’s proposal to apply a single notional biogas entry point tariff to all biogas entry points? What are your views on how the notional point should be constituted?
We have no particular commercial interest or knowledge of the renewable gas market, but given the likely size of the market initially and the underlying policy objective to encourage the development of this market the adoption of a single
notional entry point tariff would seem sensible, for the stated reasons of simplicity, stability and investor certainty.

In respect of the location of the notional point we would regard the choosing of a single notional point based on the geographically dispersed location of the three transmission entry points to be more logical than taking a location close to a demand centre, as it is likely to be at least more reflective of costs as they actually are.

5C. What are your views on biogas distribution entry tariffs relative to transmission entry tariffs and the additional factors which may need to be taken into account in designing such a tariff?
We have no particular opinion on this but would merely note that there will need to be careful consideration by industry of whether producers should be incentivised towards transmission or distribution connection and the effects of any such incentive in introducing distortions to the Matrix RPM.

6A. What are your views on the CRU's proposed VRF tariff methodology and are the factors and magnitude of the factors proposed for the VRF tariff appropriate?
We agree in principle with the methodology adopted but as we are not active in this market would defer to those shippers with better commercial experience as to the potential effects of such proposals. We would find it difficult to disagree with the proposed Pro Factor (and underlying methodology used to derive it); however, the basis on which the A Factor has been estimated is not wholly clear to us. We would note that adjustments could presumably be made to the A Factor subsequently should it prove that the VRF Tariffs as proposed have significantly impacted on the take up and use of the VRF product or are acting as a barrier for the use of these products.

6B. What are your views as to whether commodity charges should apply to use of the VRF product?
Logically we would argue that applying commodity charges to VRF would amount to a form of double-charging as VRF flows are, by definition, virtual. We believe that commodity charges should therefore not apply.

7A. What are your views on the CRU's proposal to reduce the current monthly multipliers to comply with the monthly multiplier bound of 1.5 as set out in the TAR NC?
There is clearly no choice as to whether to do this and we agree with the proposal as to how to effect this change; it would appear to be sensible to retain as much stability with current pricing arrangements as possible in the short-term at least.

7B. What are your views on the CRU's proposal to reduce the quarterly multiplier to 1.35?
We completely agree with this proposal as there is at present no incentive at all for booking quarterly products.
7C. Should a reduction in the range of seasonal factors be considered?
We would agree that the current methodology based on the estimation of occurrence of peak flows is more appropriate in the context of the Irish system and this should not be altered in the short-term at least. Any changes to the seasonal factors could be considered in alignment with any requirement to limit multipliers for daily and within-day products to 1.5 in April 2023, should this be recommended by ACER in 2021.

7D. How should the CRU consider implementing a transitional approach in the case ACER recommend reducing the daily multiplier to a maximum of 1.5?
In the event of this being recommended it would be sensible for Industry to consider all of the multipliers, including monthly and seasonal factors, as a whole for implementation in 2023. Following the outcome of any such review it might be necessary to implement any agreed changes in a phased manner in order to minimise the impacts of such changes.