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

The CRU is legally responsible for regulating the transmission and distribution network tariffs that Gas Networks Ireland (GNI), as the owner and operator of the network, charges to users of the network. In this paper the CRU is consulting 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.

Context

Different approaches to tariff setting for gas transmission services among European Union (EU) Member States makes using EU gas transmission networks more complex for network users, leading to inefficient use and development of the transmission networks, and, potentially, to inefficient gas trades. This can result in increased costs for the gas consumer. The EU network code on harmonised transmission tariff structures for gas (TAR NC)\(^1\) was published by the EU Commission, aiming to overcome such issues.

The central aspect of TAR NC requires that the CRU consult on the transmission tariff methodology, i.e. reference price methodology (RPM). The CRU is of the view that the current tariff structure and Matrix RPM is already largely compliant with the TAR NC. This is because the tariff reforms reached in 2015 in CER/15/140 were guided by the Framework Guidelines for TAR NC\(^2\). In addition, the current Matrix RPM is in line with the principles of tariff reform the CRU developed in CER/12/087.

In accordance with TAR NC, this consultation paper incorporates both consultations required under Article 26 and Article 28 as detailed in Section 1.3. With these consultations the CRU is not only aiming to ensure that a harmonised transmission tariff structure exists in Ireland, it also aims to ensure that the Irish transmission tariff methodology continues to appropriately reflect the unique characteristics of the Irish gas network and market, to the benefit of gas consumers. As such the CRU has undertaken a review of the tariff structure in the context of Ireland and assessed it against potential future gas market changes to ensure that the tariff structure is robust. This assessment has led to a number of the proposals set out in this consultation, which are discussed further below.

In order to inform the development of these proposals the CRU reconvened the Networks Tariff Liaison Group (NTLG) of stakeholders and worked closely with GNI, who provided a significant

---

\(^1\) Establishing a network code on harmonised transmission tariff structures for gas (Commission Regulation (EU) 2017/460).

amount of modelling analysis. The NTLG included a wide range of gas industry stakeholders, such as GNI, indigenous natural gas field producers and explorers, potential LNG and biogas developers, shippers, suppliers and end customers. The purpose of the NTLG was to provide a peer review and analysis of information to ensure that the tariff structure was considered in the context of the Irish gas market. Prior to the publication of this consultation paper the NTLG met three times.

**Key areas of review**

The CRU has been guided by several criteria which have led to the development of the proposals presented in this consultation paper and these criteria are referenced throughout this consultation paper. Firstly, the criteria in CER/15/057 which drew from the principles originally established in CER/12/087 (e.g. LRMC). These criteria are (1) predictability, (2) stability and (3) equity effect & promote effective competition. Secondly, the criteria set out in TAR NC Art. 7 (see Section 3.4.2 for detail) which can be summarised as (a) transparency, (b) cost-reflectivity, (c) non-discrimination and cross-subsidisation, (d) volume risk, and (e) cross-border trade.³

The CRU considers that the criteria and principles of the CRU’s tariff reform are consistent with the requirements of TAR NC Art. 7.

The CRU will consider responses and alternate views on all aspects of the tariff structure before coming to a decision on the tariff structure that will apply for the upcoming gas year 2019/20 and into the future.

The following are the CRU’s key proposals:

1. **Choice of reference price methodology**

The CRU is proposing to continue to apply the Matrix RPM as it is of the view that this RPM continues to be suited to the characteristics of the Irish gas market and that it complies with the principles and requirements of TAR NC. The current Matrix RPM has been updated by GNI to reflect the latest network topology. In addition, three future scenarios have been modelled to test the robustness of the Matrix RPM. These scenarios reflect potential new sources of supply via liquefied natural gas (LNG) and biogas injection facilities.

---

³ Compliance with these criteria should not lead to reference prices that are in breach of the requirements stated in Art. 13 of Regulation (EC) 715/2009.
2. Expansion constants and annuitisation factors

The CRU proposes to apply updated expansion constants and annuitisation factors to take into account the latest information, such as the additional length of twinned pipeline in Scotland and the CRU’s PC4 decision.

3. Shrinkage charges

Shrinkage gas is made up of both fuel gas used to operate compressors and unaccounted for gas. Currently, the cost incurred by GNI to purchase gas to replace shrinkage is recovered from gas shippers outside of the tariff structure through a separate flow-based charge. Shrinkage makes up a significant portion of the costs incurred by GNI as the TSO, approximately €9.7m in 2017/18.

Upon review the CRU has come to the view that given the fact that all network users derive a benefit of the pressures being maintained throughout the system and operated to meet gas flow instructions irrespective of location on the network, shrinkage represents a transmission service and should therefore be captured in the transmission services revenue portion of the allowed revenue.

The CRU is of the view that the most appropriate way for shrinkage costs to be recovered going forward is through the commodity element of the capacity/commodity split of the transmission charges rather than through a separate flow-based charge. Although the effect of including shrinkage in GNI’s allowed revenue is ultimately an increase in transmission charges, this proposal should not lead to significant increases in customers’ bills, as shrinkage charges were already passed through to end customers by suppliers.

The CRU proposes to implement this change beginning gas year 2019/20. The CRU is aware that this proposal may require changes to the Code of Operations, billing systems and possibly contracts both for GNI and gas shippers/suppliers. The CRU requests that stakeholders highlight to the CRU any reasons why it may have issues with an implementation date of gas year 2019/20.

4. Entry/exit split

The entry/exit split allocates the portion of allowed/transmission services revenue to be recovered from entry and exit. The CRU is of the view that its reasoning for setting the 33:67 entry/exit split in 2015 still applies. NTLG participants were in favour of retaining the current entry/exit split and the proposed policy provides regulatory stability.

Considering the above, and in the interests of stability, the CRU is proposing to continue to apply an entry/exit split of 33:67, respectively.

---

4 ROI transmission portion only.
5. Capacity/commodity split

The capacity/commodity split allocates the portion of transmission services revenue to be recovered from capacity and commodity charges. The CRU proposes to continue to employ a 90:10 capacity/commodity split. The CRU’s proposal to incorporate shrinkage costs into the transmission services revenue has the effect of increasing the cost-reflectivity of a 90:10 capacity/commodity split as shrinkage is the main variable cost associated with the quantity of gas transported. Given the importance of the cost-reflectivity principle in achieving a harmonised tariff structure, the CRU is of the view that this is a positive change.

It should be noted that the proposal to incorporate shrinkage costs into the transmission services revenue effectively increases the proportion of charges that are capacity-based. The capacity/commodity impact assessment indicates that the increased capacity-based element of charges rewards those users with a higher load factor and more stable demand. However, the CRU notes the potential negative impact this change could have on those with a lower load factor e.g. residential customers (estimated at less than half of 1% increase on an annual bill) and peaker power plants.

6. Discounts

TAR NC allows for the adjustment (i.e. discount) of tariffs at entry points from and exit points to storage facilities and at entry points from LNG facilities and infrastructure ending isolation.

There are currently no storage facilities in operation in Ireland and the CRU is not aware of any plans to develop gas storage infrastructure in Ireland. However, in the event that a storage facility began operation the CRU would apply at least a 50% discount in accordance with TAR NC.

Unlike storage, TAR NC allows for, but does not require, the application of discounts to LNG, with Art 9. 2. stating that “At entry points from LNG facilities, […] a discount may be applied to the respective capacity-based transmission tariffs for the purposes of increasing security of supply”. There are currently no LNG facilities in Ireland, however, there are LNG projects that could potentially be developed in the future.

The application of LNG discounts was discussed in detail at the NTLG meetings with participants sharing views both in favour of and against the application of LNG discounts. Building on the views and discussion at the NTLG, the CRU has examined in this consultation the relevant principles and issues that it considers relevant to the consideration of the case for, and potential level of, any LNG discount that may or may not be provided in future.

Based on current information, the CRU does not have sufficient evidence to determine that an LNG discount would be in the interests of Irish gas consumers at this time. Although an LNG facility may provide benefits to Irish gas consumers in relation to security and diversification of
supply, it is important to recognise that other supply sources also contribute to Ireland’s supply diversity and security. The proposed Matrix RPM also already produces a cost-based investment signal to support efficient new entry to the Irish gas market. Any specific LNG discount would distort the cost reflective investment signals provided to all new entry point sources under the Matrix RPM and could lead to less effective competition if by doing so it affects the investment signals provided to all sources of supply (new and existing). The proposed RPM balances a range principles and objectives (including those applied in CER/15/057) and the requirements of the RPM set out within TAR NC (see Section 3.4) and so granting any LNG discounts would be expected to have a significant impact on the balance of how these desired properties and principles are achieved within GNI’s overall transmission tariff structure.

The CRU is of the view that it is in the public interest to continue to consider the case for LNG discounts as more information becomes available. The CRU intends to consider the relative merits of the provision of LNG discounts on a project-by-project basis following an application which is submitted by LNG project developers. The CRU proposes to take into consideration the following non-binding conditions in order to assess applications for LNG discounts:

- The additional security of supply and diversification of supply benefit that an LNG entry point can provide relative to the cost-based investment signal for entry which is already provided under the Matrix RPM. This should be justified by evidence provided by project promoter(s) as part of analysis of the benefits provided by the new entry point\(^5\). In recognition that other entry points provide security and diversity of supply to the Irish gas market, the CRU may also consider the potential for new entry from other sources of supply when identifying the case for, and level of any discount.
- The impact of the LNG discount on other entry point tariffs under the RPM. For example, the CRU will consider the increase in tariffs at other entry points, tariff differentials and the resulting diversity premium that the LNG entry point would receive.
- Indirect impacts of the discount on Irish gas consumers, such as the impact on Irish gas prices.
- The tariff principles applied in CER/15/057 and the requirements of the RPM set out in Art. 7 of the TAR NC.

---

\(^5\) The CRU would expect a project promoter to provide quantified (e.g. the monetary value of any expected reduction in loss of supply to Irish gas consumers) and non-quantified evidence of the existence and scale of the additional security and diversification of supply provided by the LNG entry point under a range of possible scenarios and sensitivities.
7. Biogas entry point tariff

Ireland has the potential for the development of a number of biogas injection facilities in the coming years in line with GNI’s strategic plan to achieve 20% Renewable Natural Gas on the network by 2030. The CRU has considered the expected scale and possible number of these potential new entry points. In addition, the CRU has taken into account input provided at the NTLGs which highlighted that biogas injection facilities are likely to be located near to the point of production rather than having the flexibility to locate close to demand centres, and that simplicity is an important criterion against which any biogas tariff should be considered. The CRU also considers government policy on a low carbon energy future and notes the Government’s Energy White paper.

Taking into account the above the CRU is now proposing a tariff which will be applied to all biogas entry points and is calculated on the basis on a notional entry point. The CRU is considering two possible approaches that can be used to set the location of the single notional point: (1) a point based on the geographically dispersed location of the Gormanston (County Meath), Corracunna (County Cork) and Cappagh South (County Galway) transmission entry points; (2) a point based on a location that is close to a demand centre.

The CRU is also considering whether a similar notional entry tariff approach should be applied to distribution network tariffs and welcomes views on the additional factors which may need to be taken into account in designing such a tariff.

These proposals result in an indicative biogas entry tariff in the year 2019/20 of €109/MWh (approach one) or approximately €90/MWh (approach 2), relative to a Moffat entry tariff of €311/MWh.

---

6 Article 41(6)(a) states the following: “The regulatory authorities shall be responsible for fixing or approving sufficiently in advance of their entry into force at least the methodologies used to calculate or establish the terms and conditions for:

connection and access to national networks, including transmission and distribution tariffs, and terms, conditions and tariffs for access to LNG facilities. Those tariffs or methodologies shall allow the necessary investments in the networks and LNG facilities to be carried out in a manner allowing those investments to ensure the viability of the networks and LNG facilities;”

7 2015 Energy White Paper – Ireland’s Transition to a Low Carbon Future
8. Virtual reverse flow

Virtual reverse flow (VRF) is a ‘reverse flow’ service offered on a virtual interruptible basis, at the interconnection points (IPs), to enable gas shippers to virtually flow gas along a unidirectional pipeline, e.g. from Ireland to GB along the interconnectors. Currently, gas shippers wishing to avail of the VRF service pay an annual registration fee. At recent Code Modification Fora, the CRU has highlighted its intent to move to a tariff for VRF, which is based on the probability of interruption. Consistent with ENTSO-G guidance, the CRU is therefore proposing that the tariff for use of the VRF service should be set using the principles and requirements in TAR NC for standard interruptible capacity products. This proposed treatment is consistent with charging for use of a single entry-exit transmission system and will provide transparency and predictability to users of the VRF service of how the VRF tariff will be set, using TAR NC principles.

TAR NC Art. 16 requires the calculation of reserve prices for standard interruptible capacity products (e.g. VRF) by applying a discount to reflect the probability of interruption (Pro factor) and the estimated economic value (A factor) of the product.

In order to determine the appropriate tariff for VRF, the appropriate firm product from which to apply an interruptible discount must first be decided. As the Matrix RPM is based on the principle of a single entry/exit system, the CRU intends to treat the VRF product consistently with this. The CRU is of the view that the appropriate firm capacity tariff to which an interruptible discount should be applied is the relevant day-ahead reference price calculated by the Matrix RPM at the Moffat exit point and the Gormanston entry point. Given that VRF is a daily product, the CRU is of the view that multipliers and seasonal factors should be applied in order to reflect the value of short-term products and to reflect the seasonal variation in use of the gas transmission system.

Next, GNI has calculated the probability of interruption of the VRF product based on the number of days on which allocations of VRF were recorded and interruptions occurred. GNI has calculated that in the period September 2017 to September 2018 interruptions occurred on 22 of the 275 days in which VRF allocations were recorded. This results in a Pro factor of 8%.

Finally, with regard to the economic value of the product the CRU has relied upon analysis of VRF usage and the input provided by stakeholders to date.

The CRU has come to the view that where market participants use, or intend to use the VRF

---

8 For use of this service at Moffat the annual fee is €15,414 and for use at Gormanston it is €40,625.
9 As the VRF product is not currently in use at Gormanston, a Pro Factor cannot be calculated. The CRU proposes to apply the Moffat Pro Factor until the data required to calculate the Gormanston Pro Factor becomes available.
product, the actual and perceived likelihood of the service being interrupted is likely to have a more significant impact than the probability of interruption itself may reflect. Users of the product may need to hedge against the risk of interruption commercially, or physically, or may need to ensure access to alternative products at short notice. The CRU is of the view that this implies that a risk premium factor is needed to reflect the reduction in the value of the product beyond the probability of interruption itself. Without having received evidence from the market to indicate what a reflective level of this risk premium should be, the CRU is consulting on a risk premium of 10% for both the Moffat and Gormanston VRF products.

Interactions with cross-border trade have also been considered. In this respect, the CRU identifies interactions between the tariffs applied to the forward flow and VRF products. Therefore, while the relevant firm product against which the Moffat VRF product is priced is considered to be the exit tariff, to help reduce distortions to cross-border trade and to encourage the efficient use of the VRF product, the CRU considers it sensible to ensure that the post-adjustment VRF tariff is priced lower than the equivalent entry tariff (also reflecting the interruptible nature of the product). The CRU therefore intends to apply a further reduction of 30% to the A factor to reflect this consideration. This would apply to the Moffat VRF tariff only.

In order to reflect the CRU’s position of a risk premium of 10% and a reduction of 30% to reflect market interactions with GB, the CRU is consulting on an A-factor of 6 for the Moffat VRF tariff and an A-factor of 2.25 for the Gormanston VRF.

These proposals result in an indicative Moffat VRF reference price in the year 2019/20 of €272/MWh, and an indicative Gormanston VRF tariff of €77/MWh.¹⁰

9. Multipliers and seasonal factors

Multipliers and seasonal factors are applied to the reference price to set the tariffs for non-yearly capacity products. The CRU has examined the multipliers and seasonal factors in the context of the principles set out in Art. 28 and the characteristics of the Irish gas market. Art 28. also requires that the CRU considers the consultation responses before coming to a decision on both.

Firstly, it is apparent that the current interim multiplier¹¹ for the quarterly product does not provide an appropriate incentive to network users. This is reflected in the lack of use of the quarterly capacity product. The CRU is proposing a quarterly multiplier of 1.35.

Secondly, the CRU examined two approaches to calculating the multipliers and seasonal factors.

---

¹⁰ The prices presented here are the annual reference prices to which the multipliers/seasonal factors will be applied to derive tariffs for the daily VRF product.

¹¹ Calculated as the sum of the current monthly multipliers for the three months in each quarter.
Feedback from the NTLG participants indicated that there was not a desire to move significantly away from the current multipliers for non-yearly capacity products or to significantly alter the seasonal profile. As a result, CRU is currently proposing a minor adjustment to the monthly multipliers so that their sum comes within the bounds of the 1.5 limit as set out in TAR NC. This leads to a reduction of the daily multiplier from 2.89 to 2.79.

However, having conducted additional analysis since the NTLGs the CRU is of the view that it may be appropriate to consider additional alterations, such as a reduction in the seasonal factor variation, due to the points raised in Section 7.4. The CRU requests that stakeholders take these points into account in their submissions.

**Next steps**

The CRU has provided a table of requests for comment in Section 8.1 and invites comments on those questions and any aspects of this paper as outlined in Section 1.9. The CRU intends to publish a decision paper by 11 May 2019, having carefully considered the views of stakeholders. For further detail on next steps please see Section 8.2.
Public/ 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.

Gas Networks Ireland (GNI) owns and operates the gas network that supplies natural gas to customers in Ireland. The CRU is legally responsible for regulating the transmission and distribution network tariffs that GNI charges to users of the network. The CRU does so in the best interests of the consumer. These 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. In this paper the CRU is consulting on several components of the tariff structure such as the reference price methodology that is used in the calculation of tariffs for use of the transmission network.

Different approaches to tariff setting for gas transmission services among European Union (EU) Member States makes using EU gas transmission networks more complex for network users, leading to inefficient use and development of the transmission networks, and, potentially, to inefficient gas trades. This can result in increased costs for the gas consumer. The EU network code on harmonised transmission tariff structures for gas (TAR NC) was published by the EU Commission, aiming to overcome such issues.

With this consultation the CRU is aims to ensure that a harmonised transmission tariff structure exists in Ireland, and also to ensure that the Irish transmission tariff structure continues to appropriately reflect the unique characteristics of the Irish gas network and market, to the benefit of gas consumers. The CRU is of the view that the current tariff structure is already largely compliant with the TAR NC and as such the CRU’s current proposals are not expected to have a significant effect on gas consumers. This is because the tariff reforms reached in 2015 in CER/15/140, were guided by the Framework Guidelines on TAR NC.

If the proposals in this consultation document are carried out the average annual residential customer’s bill should not significantly increase (estimated at less than half of 1% increase on an annual bill). It is expected that the upward pressure placed on gas transportation costs resulting from the combination of proposals will be more than offset by the forecasted demands in 2019/20, leading to a decrease in tariffs between the gas year 2018/19 and 2019/20.

# Table of Contents

Executive Summary ................................................................. 1

Public/ Customer Impact Statement ........................................... 10

Table of Contents ........................................................................ 11

Glossary of Abbreviations and Terms .......................................... 14

1 Introduction ............................................................................. 17

1.1 The Commission for Regulation of Utilities ........................ 17
1.2 Background .......................................................................... 17
  1.2.1 Allowed revenue and tariff setting ................................. 17
  1.2.2 Network Code on harmonised transmission tariff structures for gas ......................................................... 18
1.3 Purpose of this paper ........................................................... 18
1.4 Current tariff structure .......................................................... 19
1.5 Review of current tariff structure to date ............................ 20
1.6 Timeline ................................................................................ 21
1.7 Related Documents .............................................................. 22
1.8 Structure of Paper ................................................................. 23
1.9 Responding to this paper ...................................................... 24

2 Irish Transmission System and Gas Market ............................. 25

2.1 Introduction .......................................................................... 25
2.2 Irish transmission network topology and gas supply ............. 25
2.3 Gas Market ............................................................................ 27
2.4 Potential future supply scenarios ........................................ 27
  2.4.1 Changes to topology ..................................................... 28
  2.4.2 Entry and Exit forecasts ................................................ 29
  2.4.3 Scenarios and demands .................................................. 31

3 Proposed Reference Price Methodology .................................. 32

3.1 Introduction .......................................................................... 32
3.2 Reference price methodologies ............................................ 32
  3.2.1 Proposed Matrix approach ........................................... 32
  3.2.2 Capacity weighted distance approach ........................ 33
3.3 Reference price comparison .................................................. 34
3.4 Assessment criteria .............................................................. 37
3.4.1 Criteria set out during tariff reform ................................................................. 37
3.4.2 Criteria set out in Art. 7 of TAR NC ................................................................ 42
3.5 Summary .............................................................................................................. 46
3.6 Request for comment .......................................................................................... 46

4 Review of RPM Components & the Tariff Structure ............................................ 47
4.1 Introduction .......................................................................................................... 47
4.2 Allowed revenue ................................................................................................. 47
4.3 Transmission & Non-transmission services ......................................................... 48
  4.3.1 Non-transmission service – Corrib Linkline ...................................................... 49
  4.3.2 Charges outside the scope of TAR NC .............................................................. 50
4.4 Shrinkage ............................................................................................................. 51
  4.4.1 Current approach ............................................................................................ 51
  4.4.2 Proposed approach ......................................................................................... 51
4.5 Entry/Exit split .................................................................................................... 53
  4.5.1 Current approach ............................................................................................ 53
  4.5.2 Proposed approach ......................................................................................... 53
4.6 Capacity/commodity split ................................................................................... 54
  4.6.1 Current approach ............................................................................................ 54
  4.6.2 Capacity/commodity split impact assessment .................................................. 54
  4.6.3 Proposed approach ......................................................................................... 56
4.7 Expansion Constants ............................................................................................ 57
  4.7.1 Introduction .................................................................................................... 57
  4.7.2 Updating the components .............................................................................. 57
4.8 Annuitsation factor ............................................................................................. 58
  4.8.1 Introduction .................................................................................................... 58
  4.8.2 Updating the components .............................................................................. 59
4.9 Summary ............................................................................................................... 59
4.10 Request for comment ......................................................................................... 60

5 Entry point considerations ...................................................................................... 61
5.1 Introduction .......................................................................................................... 61
5.2 Discounts .............................................................................................................. 61
  5.2.1 Storage discounts ........................................................................................... 61
  5.2.2 LNG discounts ............................................................................................... 61
5.3 Biogas entry tariff ............................................................................................... 68
  5.3.1 Location of the notional point ......................................................................... 69
  5.3.2 Implications for a distribution tariff ................................................................. 69
5.4 Request for comment ......................................................................................... 70

6 Virtual Reverse Flow ............................................................................................... 71
6.1 Introduction .......................................................................................................... 71
6.2 Defining the appropriate firm product ............................................................... 72
6.3 Estimating the Pro factor .................................................................................... 72
# Glossary of Abbreviations and Terms

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Definition or Meaning</th>
</tr>
</thead>
<tbody>
<tr>
<td>ACER</td>
<td>Agency for the Cooperation of Energy Regulators</td>
</tr>
<tr>
<td>Art.</td>
<td>Article</td>
</tr>
<tr>
<td>CWD</td>
<td>Capacity Weighted Distance</td>
</tr>
<tr>
<td>CER</td>
<td>Commission for Energy Regulation (now known as the CRU)</td>
</tr>
<tr>
<td>CRU</td>
<td>Commission for Regulation of Utilities</td>
</tr>
<tr>
<td>ENTSOG</td>
<td>European Network of Transmission System Operators for Gas</td>
</tr>
<tr>
<td>EU</td>
<td>European Union</td>
</tr>
<tr>
<td>GB</td>
<td>Great Britain</td>
</tr>
<tr>
<td>GNI</td>
<td>Gas Networks Ireland</td>
</tr>
<tr>
<td>I/C</td>
<td>Industrial/Commercial</td>
</tr>
<tr>
<td>IBP</td>
<td>Irish Balancing Point</td>
</tr>
<tr>
<td>IP</td>
<td>Interconnection Point</td>
</tr>
<tr>
<td>ISEM</td>
<td>Integrated Single Electricity Market</td>
</tr>
<tr>
<td>LNG</td>
<td>Liquefied Natural Gas</td>
</tr>
<tr>
<td>LRMC</td>
<td>Long-Run Marginal Cost</td>
</tr>
<tr>
<td>NBP</td>
<td>National Balancing Point</td>
</tr>
<tr>
<td>NI</td>
<td>Northern Ireland</td>
</tr>
<tr>
<td>PC4</td>
<td>Price Control 4</td>
</tr>
<tr>
<td>ROI</td>
<td>Republic of Ireland</td>
</tr>
<tr>
<td>RPM</td>
<td>Reference Price Methodology</td>
</tr>
<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>
</tr>
<tr>
<td>TSO</td>
<td>Transmission System Operator</td>
</tr>
<tr>
<td>UAG</td>
<td>Unaccounted for gas</td>
</tr>
<tr>
<td>Term</td>
<td>Definition or Meaning</td>
</tr>
<tr>
<td>-------------------------------------</td>
<td>------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td><strong>Allowed Revenue</strong></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><strong>Annuitisation factor</strong></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><strong>Biogas</strong></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><strong>Capacity/commodity Split</strong></td>
<td>The apportionment of revenue to be recovered from capacity-based transmission tariffs and commodity-based transmission tariffs.</td>
</tr>
<tr>
<td><strong>Correction Factor (K-Factor)</strong></td>
<td>An adjustment of the annual revenue for future gas years to rectify over or under recoveries of revenue in a previous gas year.</td>
</tr>
<tr>
<td><strong>Domestic Exits</strong></td>
<td>Exit Points that are within Ireland, excluding Interconnection Points.</td>
</tr>
<tr>
<td><strong>Entry/exit split</strong></td>
<td>The apportionment of revenue to be recovered from entry points and exit points.</td>
</tr>
<tr>
<td><strong>Entry/exit system</strong></td>
<td>A network of high pressure transmission pipelines which are the basis for the calculation for bringing gas onto the system (entry tariffs) and for taking gas off the system (exit tariffs).</td>
</tr>
<tr>
<td><strong>Equalisation</strong></td>
<td>A secondary adjustment applied to tariffs across a certain category of network users for the purposes of tariff stability. The result of equalisation is that the same tariff is charged at all the relevant (equalised) points.</td>
</tr>
<tr>
<td><strong>Expansion constant</strong></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><strong>Interconnection Point</strong></td>
<td>A point connecting one entry-exit system to another entry/exit system.</td>
</tr>
<tr>
<td><strong>Multiplier(s)</strong></td>
<td>Outlines the pricing relationship between non-yearly capacity products and the annual capacity product.</td>
</tr>
<tr>
<td><strong>Non-transmission services</strong></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>-------------------------------</td>
<td>----------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td><strong>Primary Tariff</strong></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><strong>Reference Price</strong></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><strong>Reference Price Methodology</strong></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>
</tr>
<tr>
<td><strong>Reserve Prices</strong></td>
<td>The reference price, which is an annual capacity price for a firm product, becomes the basis for the calculation of the auction prices for each of the non-yearly products, known as reserve prices. As there is no auction premium the reserve price is equal to the tariff for each of the capacity products.</td>
</tr>
<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>Secondary Adjustment</strong></td>
<td>An adjustment applied to primary tariffs for the purposes of revenue recovery or tariff stability.</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>
</tr>
</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 now has a wide range of economic, customer protection and safety responsibilities in energy. The CRU is also the regulator of Ireland’s public water and wastewater system.

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.

## 1.2 Background

### 1.2.1 Allowed revenue and tariff setting

The CRU’s role is to protect gas customers by ensuring that GNI spends customers’ money appropriately and efficiently to deliver necessary services. The CRU does this through what is called a Price Control, which is carried out every 5-years. The current 5-year Price Control period started on 01 October 2017 (PC4). A Price Control is an important process because the CRU must carefully consider the level of money, known as the allowed revenue, GNI needs to safely operate, maintain and invest in the gas network for the next 5 years.

This allowed revenue is recovered through transmission services revenue and non-transmission services revenue (see Section 4.2 for further detail). The transmission services revenue is then inputted to GNI’s transmission RPM to calculate the transmission tariffs on an annual basis. The tariffs allow GNI, as the network operator, to recover its transmission services revenue. The CRU’s decision paper on the Gas Entry/Exit Tariff Methodology (CER/15/140), provides the basis for the current tariff methodology/structure and GNI’s transmission tariff Matrix model. This tariff structure is now being consulted on to ensure compliance with the establishment of a European network code on harmonised transmission tariff structures for gas (TAR NC). It should be noted that this network code does not set the rules for setting tariffs for use of the gas distribution system. The setting of tariffs for use of the gas distribution system involves a separate methodology.

---

14 Commission Regulation (EU) 2017/460 of 16 March 2017 establishing a network code on harmonised transmission tariff structures for gas
1.2.2 Network Code on harmonised transmission tariff structures for gas

Regulation (EC) No 715/2009 set out the European Union (EU) wide rules, which have the objectives of contributing to market integration, enhancing security of supply and promoting the interconnection between gas networks. A crucial step in reaching these objectives is the European Commission Regulation (EU) 2017/460 of 16 March 2017 establishing a network code on harmonised transmission tariff structures for gas (TAR NC).

A varying approach to tariff setting for gas transmission services among EU Member States makes using EU gas transmission networks more complex for network users, can lead to inefficient use and development of the transmission networks, and, potentially, to inefficient gas trades. TAR NC is aiming to overcome such issues. Specifically, TAR NC aims at increasing the transparency of transmission tariffs and the methodologies used to set these tariffs.

Article (Art.) 26 and Art. 28 of TAR NC require the CRU to carry out two consultations. Art. 26 requires a periodic consultation, at least every five years, mainly relating to the reference price methodology. Art. 28 requires a consultation every tariff period (every year in Ireland), mainly relating to discounts, multipliers and seasonal factors. Both of these consultations are contained in this paper and the contents of each are detailed further in the following section. This consultation not only aims to ensure that a harmonised transmission tariff structure exists in Ireland, but also aims to ensure that the Irish transmission tariff structure continues to appropriately reflect the unique characteristics of the Irish gas network and market. Further detail on what the CRU is consulting on is contained in the following section.

1.3 Purpose of this paper

This consultation paper contains an examination of a number of aspects of the tariff structure as detailed below.

The periodic consultation defined in Art. 26 is to be carried out every five years, and in accordance with this article this paper contains the following:

- A description of the proposed reference price methodology (RPM), which includes both information on the components of the RPM and a justification of those components;
- A comparison of the indicative reference prices as calculated by the proposed RPM and the indicative reference prices calculated using the capacity-weighted distance (CWD) counterfactual;

---

15 The reference price methodology (RPM) is the same as the transmission tariff model. The RPM sets the reference price, or in simple terms, the tariff for annual firm capacity. For annual firm capacity the reference price is the same as the tariff. There are a number of additional capacity products which shippers can book for a shorter time period. The tariffs for these products are derived from the reference price for annual firm capacity, see Section 7 for further detail.
• Discounts for storage, and consideration of discounts for Liquefied Natural Gas (LNG) and other discounts possible under TAR NC;
• Results, components and the details of these components for the cost allocation assessments;
• An assessment of the proposed RPM against the criteria set out in Art. 7 of TAR NC;
• Some indicative information on the allowed revenue of the Transmission System Operator (TSO) i.e. Gas Networks Ireland (GNI);
• Indicative information on commodity-based transmission tariffs and non-transmission tariffs; and,
• Explanation of any change in the level of tariffs resulting from the changes proposed in this paper, both for the next gas year 2019 – 20 and over the course of the regulatory period.

The tariff period consultation defined in Art. 28 is to be carried out in advance of every tariff period (i.e. gas year), in accordance with this article this paper contains the following:

• Examination of multipliers and seasonal factors;
• Examination of any interruptible discounts; and,
• Discounts (this is already captured above but is a requirement for consultation on an annual basis).

As part of this consultation paper the CRU is also consulting on an enduring tariff methodology for Virtual Reverse Flow (VRF) and biogas distribution network entry tariffs.

1.4 Current tariff structure

The current tariff structure and transmission tariff methodology, referred to as the ‘reference price methodology’ (RPM) in TAR NC, is based on a tariff reform process begun by CRU in 2011.

As part of that process the CRU examined the principles of reform, which concluded in 2012 with the CRU publication CER/12/087. This decision paper set out a number of conclusions, which have led to the development and implementation of the current RPM. These conclusions were based on the fact that without reform, a lower utilisation of the interconnectors driven by the availability of other supply sources would have a significantly negative effect on consumers by increasing the cost of the marginal source of gas in Ireland. This would put upward pressure on the price of Irish wholesale gas. In addition, any new entry onto the system would further exacerbate the marginal price, thereby leading to even more ineffective competition. One of the key conclusions that resulting from CER/12/087 is that tariffs at each entry point to the Irish transmission system, should be set on a Long Run Marginal Cost (LRMC) basis.

Following CER/12/087, the CRU set about developing the tariff structure that is currently in place.
That process concluded in July 2015 with the publication of CER/15/140. The decisions reached in CER/15/140 were based on the reforms set out in the CRU’s 2012 decisions. CER/15/140 directed GNI to develop a new methodology for the calculation of entry and exit tariffs, which allocates the recovery of the transmission services revenue of GNI, between transmission network users. The chosen methodology, is known as the forward-looking Matrix methodology, or Matrix methodology for short. The principles in CER/15/057 that provided the basis for the CRU’s decision drew from the principles originally established in CER/12/087. These criteria are (1) predictability, (2) stability and (3) equity effect & promote effective competition.

It is worth noting that in the latter years of the reform process the CRU was guided by the tariff developments already taking place at an EU level, specifically the publication of the ACER Framework Guidelines on Tariffs and at the end of 2014, the publication of ENTSOG’s Draft Network Code on Tariffs. As a result, the CRU is of the view that the current reference price methodology (RPM) is already largely compliant with the TAR NC.

However, the aim of this consultation is not only to ensure compliance with TAR NC but also to ensure that the tariff methodology continues; to be fit for purpose, to take into account the unique characteristics of the Irish system, and in so far as possible, to be future proofed in the case that there are significant changes to the Irish system, such as the addition of a new gas supply point (i.e. entry point) to the transmission system.

1.5 Review of current tariff structure to date

As stated above a substantial amount of work was carried out to establish the current tariff structure, guided by the ACER Framework Guidelines on Tariffs. The CRU has, in that regard, picked up where it left off in 2015 with the development and publication of this consultation. The first step undertaken by the CRU as part of this project was a gap analysis, which highlighted areas within the current methodology where there is potential for non-compliance with TAR NC. The CRU then investigated any additional areas within the gas tariff structure that needed to be examined or re-examined to take into account the characteristics of the Irish gas network and gas market.

The CRU has been guided by several criteria, which have led to the development of the proposals presented in this consultation paper, and these criteria are referenced throughout this consultation paper. Firstly, the criteria in CER/15/057, which drew from the principles originally established in CER/12/087 (e.g. LRMC). These criteria are (1) predictability, (2) stability and (3) equity effect & promote effective competition. Secondly, the criteria set out in TAR NC Art. 7 which can be

16 ENTSOG’s Draft Network Code on Tariffs.
summarised (see Section 3.4.2 for detail) as (a) transparency, (b) cost-reflectivity, (c) non-discrimination and cross-subsidisation, (d) volume risk, and (e) cross-border trade.\textsuperscript{17}

The CRU considers that the criteria and principles of the CRU’s tariff reform are consistent with the requirements of TAR NC Art. 7.

In the development of this consultation the CRU has worked closely with GNI as the TSO. A number of the proposals within this paper have been guided by analysis undertaken by GNI and thoroughly reviewed by the CRU. GNI has updated the current RPM (i.e. the Matrix model) to reflect the latest network topology and potential new entry points. GNI has also added new functionality to the RPM. In addition, GNI developed a capacity weighted distance (CWD) counterfactual RPM in accordance with TAR NC. The CRU carried out a technical review of both RPM models to ensure they were robust and that the indicative modelling results presented in this paper are accurate. The updated Matrix model and the counterfactual CWD model are included in a single Microsoft Excel workbook that has been published alongside this consultation paper, see CRU/18/247a.

In addition, the CRU reconvened the Networks Tariff Liaison Group (NTLG). The NTLG included a wide range of gas industry stakeholders, such as GNI, indigenous natural gas field producers and explorers, potential LNG and biogas developers, shippers, suppliers and end customers. In addition, there was attendance from the Isle of Man (Manx Utilities) who rely on UK-Ireland Interconnector 2 as the primary source of delivering gas. For a list of participants, see Appendix B. Feedback from these participants provided the basis for many of the CRU’s proposals within this consultation paper.

The purpose of the NTLG was to provide a peer review and analysis of information to ensure that the tariff methodology was considered in the context of the Irish gas network and to ensure that the modelling inputs and parameters were scrutinised before the publication of this consultation. Prior to the publication of this consultation paper the NTLG met three times and initial modelling evidence was shared with participants. In addition, an open stakeholder forum prior to the NTLG meetings provided an introduction to the project.

The CRU wishes to thank the NTLG participants for their valuable contributions.

\textbf{1.6 Timeline}

The timeline of the consultation process, the decision approving the reference price methodology and the calculation of the tariff for gas year 2019/20 consists of the following stages:

\begin{itemize}
  \item[17]\textsuperscript{17} Compliance with these criteria should not lead to reference prices that are in breach of the requirements stated in Art. 13 of Regulation (EC) 715/2009.
Table 1.1: Project timeline

<table>
<thead>
<tr>
<th>Item</th>
<th>Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>CRU consultation paper published</td>
<td>11 December 2018</td>
</tr>
<tr>
<td>Two-month consultation period ends i.e. deadline for responses</td>
<td>11 February 2019</td>
</tr>
<tr>
<td>CRU publication of the responses received</td>
<td>by 11 March 2019</td>
</tr>
<tr>
<td>ACER publication of evaluation of the consultation</td>
<td>by 11 April 2019</td>
</tr>
<tr>
<td>CRU decision paper publication</td>
<td>by 11 May 2019</td>
</tr>
<tr>
<td>CRU publication of transmission tariffs for the gas year 2019/20</td>
<td>by 31 May 2019</td>
</tr>
<tr>
<td>Gas year 2019/20 begins</td>
<td>01 October 2019</td>
</tr>
</tbody>
</table>

1.7 Related Documents

The following documents and files have been published alongside this paper:

- Proposed Matrix RPM and counterfactual CWD RPM workbook (CRU/18/247a);
- NTLG 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 been filled out by the CRU and will be published by ACER at this clickable [link](#).

Some documents related to this publication are provided below:

- 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](#));
- 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.

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

1.8 Structure of Paper

This consultation paper is structured in the following manner:

- Section 1 provides an introduction and background, the purpose of this paper, related documents and how to respond to this consultation.
- Section 2 provides a summary of the Irish transmission network and gas market and details the supply scenarios modelled in this consultation.
- Section 3 introduces the proposed reference price methodology, compares it against the counterfactual capacity weighted distance methodology and assesses it against several criteria.
- Section 4 examines several the components of the tariff structure that are under review and presents the CRU’s proposals in these areas.
- Section 5 examines the application discounts at some entry points and a tariff for biogas entry points.
- Section 6 examines an enduring tariff for the virtual reverse flow service.
- Section 7 examines the multipliers and seasonal factors used to derive tariffs for non-yearly capacity products.
- Section 8 provides a summary of the CRU’s requests for comment.
1.9 Responding to this paper

The CRU invites responses to the proposals set out in this paper by 11 February 2019, preferably by email to gasnetworks@cru.ie. Alternatively, responses can be sent to:

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

Submissions on any of the points listed in this paper should be clear and specific, with analysis or rationale provided to support the views provided. Unless marked confidential, all responses may be published on the CRU’s website. Respondents may request that their response is kept confidential.

The CRU shall respect this request, subject to any obligations to disclose information. Respondents who wish to have their responses remain confidential should clearly mark the document to that effect and include the reasons for confidentiality.

Responses from identifiable individuals will be anonymised prior to publication on the CRU website unless the respondent explicitly requests their personal details to be published.

Our privacy notice sets out how the CRU protect the privacy rights of individuals and can be found here.\(^\text{18}\)

\(^{18}\) https://www.cru.ie/privacy-statement/
2 Irish Transmission System and Gas Market

2.1 Introduction

The gas transmission and distribution networks are a key element of the energy sector in Ireland, delivering fuel to power stations as well as serving industrial, commercial and household consumers.

This section provides a review of the key economic and technical characteristics of the Irish gas transmission system and the gas market. This includes the network topology, Irish gas supply and demand, and the design of the current entry-exit system. In addition, this section examines potential changes to the transmission network.

2.2 Irish transmission network topology and gas supply

The natural gas transmission network is 2,427km in length, consisting of high pressure steel transmission pipelines. There are both onshore (2,015km) and offshore (412km) pipelines. See Figure 2.1 for a map of the ROI transmission system. The offshore pipeline length is made up of portions of the two gas interconnectors (IC1 and IC2) that connect Ireland to Brighouse, Scotland. There is a sub-sea offtake point from IC2 that supplies the Isle of Man.

The onshore network covers the country in a ring-shaped fashion linking Dublin, Galway, and Limerick. It also consists of several spur lines to Cork, Waterford and lower pressure local area (regional) networks in large urban centres. In addition, the Mayo-Galway pipeline connects the ring-main to the Bellanaboy terminal, Co. Mayo, where gas from Corrib gas field enters the Irish transmission system. The addition of the Corrib entry point at the end of 2015, brings the total number of entry points on the system to three including the Moffat interconnection point (IP) in Scotland, and the Inch entry point, which is the entry point for gas from the Kinsale gas fields. In addition, to the Moffat IP there is also an IP with the Northern Irish (NI) gas transmission system at Gormanston. However, no commercial gas currently flows to NI from the Republic of Ireland (ROI) system, it is used for emergency support only. In the event that commercial flows to NI did occur the Gormanston IP could also become an entry point for virtual reverse flow\(^{19}\) (VRF) from the NI system to the ROI system.

The majority of gas demand in Ireland is currently supplied by the Corrib gas field, which supplied 60% of system throughput in the calendar year 2017. The Kinsale gas fields provided an additional

\(^{19}\) See section 2.3 for further detail on virtual reverse flow.
7%, with imports via the Moffat entry point in Scotland providing the remaining 33%. Ireland’s dependence on imports from Great Britain (GB) is increasing once again as production declines at the Corrib gas field, and this trend will continue unless new sources of indigenous supply are brought on stream. Potential new sources of supply are discussed further in section 2.4.

There are currently 113 exit points from the transmission network. Most of these exit points are points of entry to the distribution system, however these exit points also include the Gormanston IP, the Moffat IP exit (VRF only) and connections to large gas consumers such as power generators.

Figure 2.1: Gas Networks Ireland’s transmission system
2.3 Gas Market

Generally, Irish wholesale gas prices are set by the GB price of gas plus the cost of transporting gas from GB to Ireland via the interconnectors, as GB gas is the marginal source of gas supply to Ireland. The National Balancing Point, commonly referred to as the NBP, is the virtual trading location for GB natural gas. Therefore, the cost of gas at the NBP plus the cost of transportation to Ireland strongly influences the price at the Irish Balancing Point (IBP), i.e. the cost of wholesale gas in Ireland.

Since 2017 an electronic gas trading spot-market has been in place in Ireland.\(^{20}\) This allows buyers and sellers to trade gas at the IBP via a trading platform. A trading platform promotes liquidity at the IBP, thereby increasing gas price transparency and reducing the cost to shippers of matching supply and demand in Ireland. Increased liquidity and the development of a wholesale price for natural gas at the IBP should ultimately benefit Irish gas consumers by reducing costs.

Although there are no physical cross-border exit points currently used for the commercial flow of gas, there is a Virtual Reverse Flow (VRF) service in use at Moffat.\(^{21}\) VRF is a ‘reverse flow’ service offered on a virtual interruptible basis, at the IP, to enable shippers to virtually flow gas from ROI to GB.\(^{22}\)

The interaction between the sources of gas to Ireland and the tariff structure continues to be essential when considering the tariff structure in Ireland. As such it is important that the CRU assess the tariff structure against potential future changes to the sources of gas to Ireland to ensure that the structure is robust, that the principles and rationale set out in CER/12/087 continue to be met and that it complies with TAR NC.

2.4 Potential future supply scenarios

In compliance with Art. 26 of TAR NC the CRU must provide a description of the proposed RPM and a comparison of the indicative reference prices as calculated by the proposed RPM and the indicative reference prices calculated using the capacity-weighted distance (CWD) counterfactual.

As part of this comparison the CRU, with input from stakeholders, developed three potential gas supply scenarios to ensure that the proposed RPM is robust to changes in sources of supply. When forming these scenarios, the CRU has focused on potential supply scenarios within the next five years. The CRU is of the view that this period is suitable as the CRU will be required to carry

\(^{20}\) https://www.ebi.ie/
\(^{21}\) A VRF service is also in place at Gormanston, but as there are currently no commercial flows via this IP there is no practical way for a shipper to use VRF.
\(^{22}\) For example, if there is a total nomination of 100 units of gas for delivery from GB to ROI and a gas shipper in Ireland wishes to virtually transport 10 units of gas from ROI to GB, these 10 units are netted off the 100 units, resulting in the delivery of 90 units into the ROI gas network.
out a consultation in accordance with Art. 26 at least every five years. The list of potential scenarios presented in this consultation are by no means exhaustive, they help to provide an estimation of the effect on indicative reference prices and the stability of these reference prices, given potential significant changes to gas supply in Ireland.\(^2\)

### 2.4.1 Changes to topology

Following input from stakeholders at the NTLGs a number of potential new entry points have been added to the representative network topology. Depending on which entry points are active, different scenarios can be modelled and compared by calculating indicative reference prices under each scenario. By examining the indicative reference prices produced under each scenario the CRU can examine the impact of new entry supply and test whether an appropriate incentive for potential new entry is in place.

The CRU has included three potential scenarios in its analysis, these differ from the current supply points as follows:

1. A biogas entry point connects in 2019/20, supply from the Inch entry point ends after the year 2019/20;
2. A biogas entry point connects in 2019/20, supply from the Inch entry point ends after the year 2019/20, an LNG entry point connects at Foynes, Co. Limerick in the year 2021/22;
3. A biogas entry point connects in 2019/20, supply from the Inch entry point ends after the year 2019/20, an LNG entry point connects at Innisfree, Co. Cork in the year 2021/22.

<table>
<thead>
<tr>
<th>Entry Point</th>
<th>Current</th>
<th>Scenario 1</th>
<th>Scenario 2</th>
<th>Scenario 3</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>18/19</td>
<td>19/20</td>
<td>23/24</td>
<td>19/20</td>
</tr>
<tr>
<td>Moffat</td>
<td>✔️</td>
<td>✔️</td>
<td>✔️</td>
<td>✔️</td>
</tr>
<tr>
<td>Bellanaboy</td>
<td>✔️</td>
<td>✔️</td>
<td>✔️</td>
<td>✔️</td>
</tr>
<tr>
<td>Biogas</td>
<td>✔️</td>
<td>✔️</td>
<td>✔️</td>
<td>✔️</td>
</tr>
<tr>
<td>Inch</td>
<td>✔️</td>
<td>✔️</td>
<td>✔️</td>
<td>✔️</td>
</tr>
<tr>
<td>Foynes</td>
<td>✔️</td>
<td>✔️</td>
<td>✔️</td>
<td>✔️</td>
</tr>
<tr>
<td>Innisfree</td>
<td>✔️</td>
<td>✔️</td>
<td>✔️</td>
<td>✔️</td>
</tr>
</tbody>
</table>

Note: Users also have the ability to create a user defined scenario that allows the user to alter the demands at any of the entry/exit points and then calculate indicative reference prices under that supply and demand scenario.

\(^2\) Note: Users also have the ability to create a user defined scenario that allows the user to alter the demands at any of the entry/exit points and then calculate indicative reference prices under that supply and demand scenario.
2.4.1.1 Scenario 1
This scenario has been modelled on the basis that production at the Inch entry point is due to cease in March 2020 and a transmission connected biogas injection facility at Corracunna (County Cork) is expected to connect in 2020. All the scenarios contain a biogas entry point from 2019/20 onwards and the cessation of flows from the Inch Entry Point after the gas year 2019/20.
There is also a sensitivity for Scenario 1 that has removed the biogas entry point. Therefore, the user can see the difference in indicative reference prices taking into account the current supply points only (i.e. those active in the 2018/19 gas year).

2.4.1.2 Scenario 2
This scenario is used to model the effect of a new entry supply at Foynes, Co. Limerick. This is based on the potential location of the Shannon LNG facility, around 25km from Foynes on the Shannon estuary near Ballylongford Co. Kerry. Shannon LNG is a current Project of Common Interest (PCI)24.

2.4.1.3 Scenario 3
This scenario is used to model the effect of a new entry supply at Innisfree, Co. Cork. This is based on the potential location of the Next Decade LNG facility, which is a currently in the ENTSOG TYNDP 201825 project table. This project will be reviewed during the development of the upcoming fourth PCI list.

2.4.2 Entry and Exit forecasts
In addition to modelling potential changes to the network topology, it is also necessary to make an estimate of future gas demand in ROI and how this demand will be met by each supply/entry point. These forecasts have been developed by GNI and are an important step as the level of demand and supply has a significant effect on the level of tariffs. This supply and demand information is used to calculate the forecasted contracted capacity at entry points and exit points on an annualised basis26. The total forecasted contracted capacity and forecasted commodity at entry was assumed to be the same across each scenario.

A full table of supply and demand forecasts can be found within the ‘Input-Throughput and bookings’ tab of the RPM workbook, see CRU/18/247a.

24 European Commission – The list of the project of common interest (PCIs) by country – the (third) Union list of PCIs
25 ENTSOG TYNDP 2018
26 As capacity can be booked for different time lengths (i.e. annual, monthly, daily) it needs to be converted into a single annualised number so that it can be inputted into the RPM.
2.4.2.1 Supply

GNI calculated the forecasted contracted capacity and forecasted commodity at entry points across each scenario. These forecasts represent a commercial view and not physical peak flow. Supply is forecast using a merit order assuming demand is first met by indigenous gas. It is assumed in the supply point modelling that the following merit order will exist:

1. Indigenous renewable gas production (Biogas)
2. Indigenous natural gas production (Corrib and Inch)
3. Liquified Natural Gas
4. Moffat Entry

It should be noted that the actual flows that take place in the future are based on commercial arrangements between shippers and producers, and that these forecasts provide the best estimate of these flows given the information available to GNI.

2.4.2.2 Demand

Peak day flows\(^{27}\) of the relevant exit points within the model are used to apportion demand geographically. These peak day flow weightings are then applied to a commercial forecast of demand and the result is inputted into the RPM. The total forecasted contracted capacity and forecasted commodity at exit was assumed to be the same across each scenario.

When GNI forecasts capacity and commodity demands, the demand is assessed across three sectors: power, industrial/commercial (I/C) and residential. The following underlying demand assumptions are used to arrive at a total demand figure:

- Power sector demand is driven by assumptions around electricity demand, renewables, price of coal, constraints, interconnector flows.
- Industrial & Commercial sector demand is driven by historic demand, GDP and forecasted commercial growth.
- Residential sector demand is driven by historic demand, forecasted growth, efficiency.

2.4.2.3 Annualised capacity

Shippers can book capacity using capacity products of different time lengths (i.e. annual, quarterly, monthly, daily, within day). GNI need to convert these bookings into an annualised figure because the price of these products is derived as a multiple of the annual tariff (see below for example). This annualised figure is then inputted into the RPM and is one of many variables involved in the

\(^{27}\) Peak day flows are used to apportion total demand at exit as the system was designed for peak day flows.
calculation of the indicative reference prices.

Once demands are forecast, GNI next estimate the most efficient way to book capacity – this will result in a combination of short-term capacity bookings at entry and exit. For this estimation GNI considers gas shippers past behaviour including trades at entry.

**Example:** The price of a non-yearly capacity product is the multiple of the annual capacity tariff. As such, to derive this annual tariff, all short-term bookings are annualised for input into the Matrix model. This process uses the current multipliers to give the short-term booking a weighting to convert it into an equivalent booking. For example:

- Forecast of daily bookings in October = 200,000MWh/d
- Daily Multiplier for October = 0.661765%
- Annualised equivalent = 200,000MWh * 0.661765% = 1323.53MWh

**2.4.3 Scenarios and demands**

The following table details the potential supply scenarios that have been modelled and the annualised forecasted contracted capacity assumed for each scenario. A full table of supply and demand forecasts can be found in the 'Input-Throughput and bookings' tab of the RPM workbook, see CRU/18/247a.

The key point to take away from the scenarios is the effective reduction that the new sources of supply have on the projected bookings at Moffat.

**Table 2.2: Scenarios and annualised forecasted contracted capacity (GWh/d)**

<table>
<thead>
<tr>
<th></th>
<th>Projected 18/19 Bookings</th>
<th>Scenario 1</th>
<th></th>
<th>Scenario 2</th>
<th></th>
<th>Scenario 3</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>19/20</td>
<td>23/24</td>
<td>19/20</td>
<td>23/24</td>
<td>19/20</td>
<td>23/24</td>
</tr>
<tr>
<td>Moffat</td>
<td>128</td>
<td>155</td>
<td>206</td>
<td>155</td>
<td>22</td>
<td>155</td>
<td>100</td>
</tr>
<tr>
<td>Bellanaboy</td>
<td>82</td>
<td>72</td>
<td>43</td>
<td>72</td>
<td>43</td>
<td>72</td>
<td>43</td>
</tr>
<tr>
<td>Biogas</td>
<td>n/a</td>
<td>0</td>
<td>12</td>
<td>0</td>
<td>12</td>
<td>0</td>
<td>12</td>
</tr>
<tr>
<td>Inch</td>
<td>6</td>
<td>4</td>
<td>0</td>
<td>4</td>
<td>0</td>
<td>4</td>
<td>0</td>
</tr>
<tr>
<td>Foynes LNG</td>
<td>n/a</td>
<td>n/a</td>
<td>n/a</td>
<td>0</td>
<td>184</td>
<td>n/a</td>
<td>n/a</td>
</tr>
<tr>
<td>Innisfree LNG</td>
<td>n/a</td>
<td>n/a</td>
<td>n/a</td>
<td>n/a</td>
<td>n/a</td>
<td>n/a</td>
<td>0</td>
</tr>
<tr>
<td>Exits</td>
<td>280</td>
<td>289</td>
<td>313</td>
<td>289</td>
<td>313</td>
<td>289</td>
<td>313</td>
</tr>
</tbody>
</table>
3 Proposed Reference Price Methodology

3.1 Introduction

The reference price methodology (RPM) is defined in Art. 3(2) of TAR NC as “the methodology applied to the part of the transmission services revenue to be recovered from capacity-based transmission tariffs with the aim of deriving reference prices”. In simple terms, the RPM is the methodology approved by the CRU to calculate the annual tariffs at entry and exit, which allow GNI to recover their transmission services revenue. Art. 7 of TAR NC sets out the requirements that the RPM must meet, however, TAR NC does not explicitly state the type of RPM that should be used.

As highlighted in Section 1.4 the CRU is of the view that the current Matrix RPM is already largely compliant with TAR NC and in line with the CRU’s own principles of tariff reform. In this section the CRU provides reasoning as to why it is of the view that the proposed Matrix RPM is compliant with the TAR NC and provides a comparison to the indicative reference prices of the capacity weighted distance (CWD) counterfactual RPM as required by the TAR NC.

3.2 Reference price methodologies

This subsection provides an introduction to the Matrix RPM the CRU is proposing should be applied in Ireland and how this compares to the CWD counterfactual RPM which TAR NC requires reference prices for the proposed RPM to be compared to. Worked examples of both RPMs have been provided on slides numbered 62 - 72 of the NTLG 3 slides (CRU/18/247b).

One of the key differences between the two methodologies is that the Matrix RPM uses long run marginal costs (LRMC) to capture the costs of each entry-exit route, while the CWD RPM counterfactual does not account for LRMC and is simply a revenue recovery method. Both RPMs provide locational signals through the tariff structure, however each RPM provides the signal in a different way as highlighted below.

3.2.1 Proposed Matrix approach

The Matrix RPM is the CRU’s proposed RPM and the methodology currently employed in Ireland, although with some minor alterations as discussed in Section 4. The proposed Matrix RPM is based on forward-looking LRMC considerations. The model contains a representative network, which is based on actual pipeline distances between entry points and exit points. The model uses these distances and the expansion constants to approximate the cost of expansion between each entry and each exit point in a matrix.
To determine the reference price at each of the points, a mathematical formula uses least squares to minimise the total difference between the cost of the paths and the sum of the entry and exit reference price. Following this step, the ‘primary’ tariffs are rescaled to recover any transmission services revenue shortfall. Following a policy direction given to CRU by Government in 2001 the CRU postalises the domestic exit tariffs via the application of an equalisation adjustment in the RPM. As this equalisation only applies to domestic exit points it does not include the Gormanston IP exit point or any other non-domestic exit points.

As noted above, the cost of expansion is calculated using expansion constants. An expansion constant provides a numerical value for the cost of expanding capacity so that one unit of gas travels over a specified distance. This is measured in €/GWh/d/km. To determine the values of an expansion constant, actual pipeline and compressor capital and operating costs are used to forecast forward-looking costs. As the GNI system is comprised of both dry (onshore) and wet (subsea) pipelines, the CRU has calculated separate expansion constants to reflect the different costs associated with each. Both dry and wet expansion constants are comprised of pipeline costs and compression costs.

The expansion constant can be used to calculate the cost of building a pipeline (including compression) but it does not give any indication of the annual revenues that would be required to finance such an asset. In order to calculate the annual revenues an annuitisation factor is used. The annuitisation factor uses the capital costs of the assets, the cost of capital, the annual depreciation and the annual operating costs to calculate the average annual payment that would be made on this asset over the lifetime of the asset.

3.2.2 Capacity weighted distance approach
As set out in TAR NC the capacity weighted distance (CWD) approach is the counterfactual methodology against which the proposed RPM should be compared. The basics of the CWD approach is that it aims to ensure that the transmission services revenue is allocated according to the capacity and distance of each of the entry points.

This approach takes the transmission services revenue of the TSO and allocates it to each entry (and exit) point according to the capacity and the capacity weighted average distance of each of the points as well as the entry/exit split.\textsuperscript{28} Forecasted contracted capacity is used in this approach. As the CWD approach allocates all transmission services revenue proportionately to entry and exit points there is no requirement for rescaling.

\textsuperscript{28} In order for the CWD approach to calculate a reference price for a given entry or exit point, there must be a capacity booking value greater than zero. To facilitate the calculations of tariffs for active entry points with zero bookings, a negligible booking of 0.0001MWh has been applied to these points in the RPM workbook.
3.3 Reference price comparison

In this section the CRU provides a comparison of the indicative reference prices (i.e. indicative annual firm capacity tariffs) of the two RPMs. Figure 3.1 provides a comparison of the indicative 2019/20 reference prices as calculated by the proposed Matrix RPM and the counterfactual CWD methodology. As highlighted by the figure below the differentials between the entry points are similar under both methodologies, these differentials are discussed further in Section 3.4.1.

The main difference in the results is that the entry tariffs are larger under the counterfactual CWD methodology. This is a result of the counterfactual CWD having a 50:50 entry/exit split compared to the current and proposed 33:67 entry/exit split use in the Matrix RPM (see Section 4.5 for detail on the entry/exit split). When the entry/exit splits are aligned they produce very similar results, as highlighted by Figure 3.2.

Figure 3.1: Comparison of 2019/20 indicative reference prices under proposed matrix RPM (33:67) and CWD (50:50) counterfactual

Note: NTS (Non-transmission service) i.e. the Corrib Linkline element of the Bellanaboy tariff.

---

29 As each of the scenarios are identical until the year 2021/22 they produce the same results and have therefore not been included in the figure.
The indicative reference price at the equalized domestic exit points is highlighted in the figure below. The equalization of domestic exit points is considered further in Section 3.4.2.2. Figure 3.3 illustrates that any variation in exit price between the proposed RPM and the counterfactual is driven by differences in the entry/exit split.

However, there are significant differences between the RPMs when they are examined across the three scenarios in the year 2023/24. These differences can be examined by comparing the indicative reference prices in Figure 3.4 and
Figure 3.5. The volatility of the tariff at Moffat Entry under the counterfactual CWD is apparent, ranging from €416/MWh under scenario 1 to €731/MWh in Scenario 2, with a difference of €315/MWh. By comparison the proposed Matrix RPM produces a Moffat tariff ranging from €281/MWh under Scenario 1 to €406/MWh in Scenario 2, with a difference of €125/MWh. The indicative reference prices continue to be more volatile under the CWD methodology when the entry/exit split is set at 33:67, with a range of €208/MWh. Tariff stability is an important criterion that the CRU strives to achieve when setting tariffs as discussed further in the following section.

The exit tariffs are the same in each scenario as the demand at exit does not vary between scenarios.

*Figure 3.4: 2023/24 indicative reference prices under proposed Matrix RPM (33:67)*

Note: NTS elements included in total – Bellanaboy (€494/MWh), Foynes (€38/MWh), Innisfree (€4/MWh).
3.4 Assessment criteria

As set out in Section 1.4 the CRU aims to ensure that the tariff structure takes into account the unique characteristics of the Irish system and assess the proposed RPM, i.e. the Matrix RPM, against the criteria set out within TAR NC.

This subsection provides an assessment of the proposed Matrix RPM against the criteria and charging principles that the CRU has previously adopted for tariff reform and the requirements of the RPM as set out in Article 7 of the TAR NC.

3.4.1 Criteria set out during tariff reform

As part of the work carried out to establish the reforms reached in CER/15/140, the CRU assessed the potential RPMs against a number of criteria. In CER/15/057 the CRU set out criteria, which drew from the principles originally established in CER/12/087. These criteria are (1) predictability, (2) stability and (3) equity effect & promote effective competition.

The rest of this section examines whether the Matrix RPM, which the CRU proposes to continue to apply, continues to meet these criteria.
3.4.1.1 Predictability & stability

Introduction

As stability & predictability are interlinked they are examined together.

Predictability may be defined as meaning that for a given supply and demand scenario the inputs to a model can be estimated with a reasonable degree of accuracy, and therefore that the outputs of the model can be calculated for that given scenario. Predictability may be influenced by the transparency of the inputs to the RPM and the ability to reasonably understand how the RPM is functioning. The steps of the model, and the reasons for each step change should be understood by users.

Stability means that the outcomes of a chosen RPM are robust to fluctuations or perturbations (within the bounds of reasonable changes) to the inputs. This does not mean that tariffs must stay at the same level, but rather that the RPM should be able to absorb reasonable input changes, without significant impact on outcomes. In addition, stability should ensure that enduring cost signals are given to stakeholders to allow medium term planning.

Assessment

With regard to predictability, the components of the Matrix RPM, which are used in the calculation of primary tariffs (e.g. expansion constants, distances), do not change significantly from one tariff year to the next. The calculation of these components can be considered transparent as the CRU consulted on the derivation of these components as part of its tariff reform and publishes the detailed calculation of these components.

In addition, the publication by GNI of the simplified tariff model allows users to model, and estimate, the predicted impact that changes to variables such as demand and transmission services revenue, will have on reference prices.

As discussed further below, the primary tariffs produced by the Matrix RPM also result in predictable absolute differentials between entry points, which do not change as capacity bookings change over time or as new entry is added. Thus, the combination of these factors contributes to the overall predictability of the reference prices of the RPM.

With regard to stability, as highlighted by the graphs in Section 3.3, the proposed Matrix RPM appears to be relatively stable to changes in both supply and demand. This can be observed from comparisons of the reference prices produced by the Matrix RPM and the CWD counterfactual. Note that the CRU has not undertaken a review of the merits of the Matrix vs CWD RPMs, this was carried out as part of CER/15/057. Here the CRU is undertaking a comparison to illustrate the relative predictability and stability of the Matrix RPM.

Table 3.1 below illustrates how, under the proposed Matrix RPM all entry reference prices vary by the same amount (€119/MWh), i.e. the differentials are retained, across the three scenarios in the year 2021/22. By comparison, the CWD RPM (with the same entry/exit split) does not retain the
entry differentials and produces a Bellanaboy reference price that varies by €102/MWh and a Moffat reference price that varies by €210/MWh across the three scenarios in the year 2021/22. The Matrix RPM also appears to be stable to changes in demand over time as highlighted by the indicative reference prices in Appendix C.

Table 3.1: Variation of indicative entry reference prices across scenarios in 2021/22 (€/MWh)

<table>
<thead>
<tr>
<th>2021/22</th>
<th>Bellanaboy</th>
<th>Moffat</th>
<th>Biogas</th>
</tr>
</thead>
<tbody>
<tr>
<td>Matrix Scenario 1</td>
<td>618.41</td>
<td>299.63</td>
<td>97.51</td>
</tr>
<tr>
<td>Matrix Scenario 2</td>
<td>737.63</td>
<td>418.85</td>
<td>216.73</td>
</tr>
<tr>
<td>Matrix Scenario 3</td>
<td>698.36</td>
<td>379.58</td>
<td>177.46</td>
</tr>
<tr>
<td><strong>Matrix variation</strong></td>
<td><strong>119.22</strong></td>
<td><strong>119.22</strong></td>
<td><strong>119.22</strong></td>
</tr>
<tr>
<td>CWD Scenario 1</td>
<td>637.31</td>
<td>294.07</td>
<td>99.93</td>
</tr>
<tr>
<td>CWD Scenario 2</td>
<td>739.50</td>
<td>504.11</td>
<td>171.31</td>
</tr>
<tr>
<td>CWD Scenario 3</td>
<td>696.05</td>
<td>414.80</td>
<td>140.96</td>
</tr>
<tr>
<td><strong>CWD variation</strong></td>
<td><strong>102.19</strong></td>
<td><strong>210.05</strong></td>
<td><strong>71.38</strong></td>
</tr>
</tbody>
</table>

The stability and predictability of entry tariff differentials is due to the inherent stability of the Matrix RPM and its two-step approach to setting reference prices. Firstly, the initial tariff for each entry point is calculated based on the expansion constant and distances between entry and exit points, meaning the absolute differentials between the entry points do not vary as capacity bookings change over time or as new entry is added. Secondly, as the proposed Matrix RPM applies a secondary rescaling adjustment to each initial tariff equally (i.e. additive approach)\(^{30}\) to recover the transmission services revenue, these absolute differentials from one entry point to the next are retained.

It is important that the proposed RPM produces a stable signal to investment. The CRU is of the view that with regard to stability, both in terms of overall tariff levels & differentials, the proposed Matrix RPM continues to meet this criterion.

3.4.1.2 Equity effect & promote effective competition

Introduction

The CRU has previously stated that tariff reform will inevitably impact on stakeholders, whether they are producers, shippers or end customers. The Irish gas system benefits from spare capacity and the current regime is based, in part, on ensuring that the signals to investors are appropriate to the requirements of the market in the medium term. The signals that are sent to new entry points should be reflective of the costs that are associated with providing entry capacity and should not

---

\(^{30}\) Rescaling is examined further in Annex 1.1.
give rise to inflated cost signals based on non-entry costs or assets.

Furthermore, the methodology should ensure that an equitable balance is struck between promoting effective competition & ensuring consumer welfare is maximised. This is measured by the level of tariffs and the diversity premium that accrues to entry points from each methodology.

In 2012 the CRU stated that “while promoting security and diversity of supply it is equally important to ensure that customers do not overpay for their supply”. This principle continues to apply and is an important principle to examine when assessing any changes to the tariff methodology.

The assessment of equity & the promotion of effective competition considers the principles of sending the right cost signals i.e. that the cost concept is sending the correct signals. In addition, the CRU examines the actual outputs of the proposed RPM and whether an equitable balance is being struck between producers & consumers. This can be measured by the level of the diversity premium.

Assessment

The proposed Matrix RPM is based on forward-looking cost LRMC considerations, which is represented using expansion constants. The CRU continues to be of the view that the benefit of a forward-looking cost concept is that it ensures reference prices are cost-reflective, by ensuring that entry is incentivised in the case where an entry point can beat the Moffat cost of expansion.

In addition, ACER has stated that incremental costs may be appropriate in expanding systems, either resulting from an increase in demand, or triggered by a change in the general system sourcing.31

Given the benefit of cost-reflectivity highlighted above and the following, CRU continues to be of the view that it is appropriate to apply a forward looking cost concept which results in signals that incentivise new efficient entry; (1) the decline of the Corrib gas field, (2) the expected end of production from the Kinsale gas field in 2019, (3) the likelihood that a number of renewable gas injection facilities will connect to the transmission system, (4) steadily growing demand, (5) the possibility of future indigenous natural gas production and (6) the recent interest from a number of LNG projects.

Given the above the CRU is of view that the forward-looking LRMC cost concept with entry tariff differentials helps to ensure equity and promote competition and is suitable in the context of Irish system, and therefore is sending the correct signals. In addition, the actual outputs of the proposed RPM and whether an equitable balance is being struck between producers & consumers has been examined.

31 ACER’s Framework Guidelines on Harmonised Gas Transmission Tariff Structures
The Moffat entry point was, and still is expected to be the marginal entry point for gas into Ireland. Thus, transportation tariffs for this entry point are likely to set the market price for gas in Ireland. If an indigenous entry point has lower transportation tariffs than the Moffat entry point, then some of this differential can be captured by the indigenous producer through the diversity premium. The diversity premium is a result of the forward-looking LRMC cost concept and reflects the saving that would result from an alternative source of entry supplying the system rather than expanding the supply at Moffat.

Table 3.2 below presents the estimated diversity premiums that may accrue to producers. It is apparent that there is a significant increase in the diversity premium in Scenario 2 and 3 following new LNG entry at Foynes and Innisfree. This increase is due to these new sources of supply meeting a significant portion of demand. For these new entry points the proposed RPM produces an entry tariff that is significantly lower than Moffat, mostly due to the fact that they are close to the demand centres on the network. Thus, these entry points are rewarded for being more efficient than the cost of expansion at Moffat.

The CRU is of the view that as the level of the diversity premium is based upon the principle of cost-reflectivity, it can therefore be deemed economically justified and as such there is not a disproportionate effect placed on customers.

Table 3.2: Estimated diversity premiums – no discounts

<table>
<thead>
<tr>
<th>Entry point</th>
<th>Est. 20.21</th>
<th>Est. 21.22</th>
<th>Est. 20.21</th>
<th>Est. 21.22</th>
<th>Est. 20.21</th>
<th>Est. 21.22</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bellanaboy</td>
<td>€13,754,312</td>
<td>€12,074,544</td>
<td>€13,754,312</td>
<td>€12,074,418</td>
<td>€13,754,312</td>
<td>€12,074,552</td>
</tr>
<tr>
<td>Innisfree</td>
<td>€0</td>
<td>€0</td>
<td>€0</td>
<td>€0</td>
<td>€0</td>
<td>€0</td>
</tr>
<tr>
<td>Moffat</td>
<td>€0</td>
<td>€0</td>
<td>€22,465,471</td>
<td>€n/a</td>
<td>€n/a</td>
<td>€n/a</td>
</tr>
<tr>
<td>Foynes</td>
<td>€n/a</td>
<td>€n/a</td>
<td>€n/a</td>
<td>€n/a</td>
<td>€n/a</td>
<td>€n/a</td>
</tr>
<tr>
<td>Biogas</td>
<td>€217,915</td>
<td>€638,960</td>
<td>€217,915</td>
<td>€638,960</td>
<td>€217,915</td>
<td>€638,961</td>
</tr>
<tr>
<td>Inch</td>
<td>€n/a</td>
<td>€n/a</td>
<td>€n/a</td>
<td>€n/a</td>
<td>€n/a</td>
<td>€n/a</td>
</tr>
<tr>
<td>Total Diversity Premium</td>
<td>€13,972,226</td>
<td>€12,713,504</td>
<td>€13,972,226</td>
<td>€35,178,849</td>
<td>€13,972,226</td>
<td>€27,780,017</td>
</tr>
</tbody>
</table>

32 The diversity premium numbers used in this paper are indicative of the maximum that may accrue to entry points. It is expected that the effects of competition would mean that new entry points supplying Ireland would undercut gas delivered from Moffat. Therefore, the diversity premium accruing to producers would be expected to be lower due to gas-on-gas competition. In addition, there are some simplifications within the diversity premium calculation, e.g. load factor of 1.3 (see CRU/18/247c). These figures are used to provide a rough estimation of the diversity premium only. It should also be noted that the diversity premiums accruing to producers presented in Table 3.2 have been calculated without the provision of discounts at entry points that can potentially be applied in accordance with Art 9. of TAR NC. The provision of discounts for entry points is discussed further in Section 5.
3.4.2 Criteria set out in Art. 7 of TAR NC

It is important that the adopted RPM is not only in compliance with the criteria of Art. 7, but that compliance with these criteria should not lead to reference prices that are in breach of the requirements stated in Art. 13 of Regulation (EC) 715/2009.33

In this section the CRU’s proposed RPM is assessed against the criteria of Art. 7 TAR NC that state that:

“The reference price methodology shall comply with Article 13 of Regulation (EC) No 715/2009 and with the following requirements. The reference price methodology:

- a) enables network users to reproduce the calculation of reference prices and their accurate forecast;
- b) takes into account the actual costs incurred for the provision of transmission services considering the level of complexity of the transmission network;
- c) ensures non-discrimination and prevents undue cross-subsidisation including by taking into account the cost allocation assessments set out in Article 5;
- d) ensures that significant volume risk related particularly to transports across an entry-exit system is not assigned to final customers within that entry-exit system;
- e) ensures that the resulting reference prices do not distort cross-border trade.”

In its guidelines ACER has summarised these criteria into the following headings, with a brief description of each provided below.

3.4.2.1 Transparency (a)

Introduction

This criterion is one of the main goals of TAR NC. Essentially network users should be able to understand the costs underlying transmission tariffs and be able to calculate the evolution of tariffs.

Assessment

This criterion is similar to the CRU’s own criteria of predictability & stability. The CRU believes that the criteria of transparency is met through both the CRU’s detailed publications and through the process of developing the proposals in this consultation.

Firstly, the CRU publishes detailed information regarding how it calculates GNI’s allowed revenue through its Price Control papers34, and how this allowed revenue is updated through its annual tariff

34 Gas Networks Ireland Price Control 4 – CRU document group
setting papers\textsuperscript{35}. These publications allow network users to understand the costs underlying transmission tariffs and the reasons for tariffs changing from one year to the next. In addition, the simplified tariff model developed by GNI provides network users the ability to replicate the tariffs and the ability to alter some of the inputs (e.g. demands, allowed revenue) to the RPM in order to forecast potential changes in the tariffs.

In terms of the process involved in developing this consultation, the CRU has aimed to make it both inclusive and transparent. To achieve this the CRU reconvened the Networks Tariff Liaison Group (NTLG). The NTLG included a wide range of gas industry stakeholders.

Although the proposed Matrix RPM could be considered more complex than some other potential RPMs such as postage-stamp. The CRU is of the view that this complexity is justified due to the importance the CRU places on cost-reflectivity and equity. The CRU has taken steps to assist stakeholders in their understanding of the Matrix RPM by including a RPM training session as part of the NTLG meetings. The CRU has also made available slides (see, CRU/18/247b presented at these meetings on its website alongside this is consultation, which readers of this consultation paper can examine for further clarity on the Matrix RPM.

Users of the RPM consultation workbook (see CRU/18/247a) also have the ability to create a user defined scenario that allows the user to alter the demands at any of the entry/exit points and then calculate indicative reference prices under that supply and demand scenario.

3.4.2.2 Cost-reflectivity (b)

Introduction

Essentially the tariffs should reflect the costs incurred by the TSO in the provision of transmission services. Ideally the chosen RPM strikes a balance between cost reflectivity and simplicity. Cost-reflectivity not only depends on the incorporation of cost drivers, but also on how the revenues are grouped and allocated to entry-exit points.

The CRU is of the view that the cost-reflectivity criterion can be considered fulfilled if the proposed RPM meets the following principles:

- All transmission services revenues are allocated to all entry and exit points;
- The same RPM is applied to allocate revenues to each entry or exit point;
- 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; and,
- The parameters used within the RPM reflect the network cost drivers.

\textsuperscript{35} Gas Networks Ireland Allowed Revenues and Tariffs – CRU document group
Assessment

The CRU is of the view that the criterion of cost-reflectivity is met by the proposed Matrix RPM as it meets all of the principles listed above.

Firstly, the TSO recovers all transmission services revenues from all entry and exit points, with a single RPM being used to recover these revenues.

In addition, the proposed RPM calculates references 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.

The proposed Matrix RPM incorporates the distance and capacity cost drivers by using expansion constants. An expansion constant provides a numerical value for the cost of expanding capacity so that one unit of gas travels over a specified distance. Both dry and wet expansion constants are comprised of a blend of pipeline costs together with compression costs, see Section 4.7 for further detail. In order to take distance into account the RPM contains a representative network, which is based on actual pipeline distances between entry points and exit points.

Although the proposed RPM could be considered complex, the CRU has mitigated this complexity by taking the steps highlighted in Section 3.4.2.1 above. The CRU postalises domestic exit tariffs via the application of an equalisation adjustment following a policy direction given to CRU by Government in 2001. This enhances equity, predictability and stability for all Irish gas consumers. Equalisation of all points with a homogenous group of points is compliant with the TAR NC and helps to reduce the complexity of transmission charges by applying the same exit charge to all domestic exit points. In addition to the policy direction from Government, the CRU further justified its reasoning for postalising exit tariffs in CER/15/057, stating that “Exit tariffs are not attempting to create economic signals to incentivise efficient new entry (or in this case exit connection) to the network in the same way as entry tariffs attempt to encourage efficient entry to the system. This is especially true given that the Irish system is a small system, where large fluctuations could disadvantage industry or gas customers in one region vis-à-vis another”.

3.4.2.3 Non-discrimination and cross-subsidisation (c)

Introduction

With regard to non-discrimination, this criterion means that one type of network user should not be discriminated against versus another. An example would be charging different prices to different network users for an identical gas transmission service. While cross-subsidisation is a result of tariffs that are not fully cost-reflective, with the deviation from cost-reflectivity resulting in a user of the entry-exit system being allocated a tariff that differs from the costs they cause to the system. However, as complete cost-reflectivity is impossible to achieve there will always be some level of cross-subsidisation, it is therefore important to ensure that there is no undue cross-subsidisation.
Assessment

The CRU is of the view that the proposed Matrix RPM allocates costs to all network users in a consistent manner, it therefore minimises the possibility of discrimination between network users. Similarly, the CRU is of the view that as the proposed Matrix RPM places significant emphasis of the cost drivers of the network, i.e. capacity and distance, it also minimises the possibility of undue cross-subsidisation.

Consistent with TAR NC requirements the CRU has undertaken the cost allocation assessments, as detailed in Art 5. The cost allocation assessments aim to evaluate whether any cross subsidisation occurs between intra-system and cross-system network use. However, as there are no transit flows via the ROI transmission network the test provides limited additional information in the Irish context to support the assessment of this criteria. There are two assessments, one relating to capacity-based transmission tariffs and one relating to commodity-based transmission tariffs. The CRU has presented the results of the cost allocation assessments in Appendix A, the results of both are ‘n/a’.

3.4.2.4 Volume risk (d)

Introduction

This criterion aims to avoid a situation whereby one group (e.g. intra-system network users) faces tariff increases to compensate for the diminishing use of the network by another group (e.g. cross-system network users).

Assessment

As there are currently no cross-system volumes, as highlighted in Appendix A, and with this expected to continue for the near future at least, the CRU is of the view that there is no volume risk.

3.4.2.5 Cross-border trade (e)

Introduction

Finally, assess whether the RPM ensures that the resulting reference prices do not distort the economic signals for cross-border trade.

Assessment

The CRU is of the view that the resulting reference prices do not distort the economic signals for cross-border trade as the Matrix RPM complies with the principles of cost-reflectivity and non-discrimination, and it does not result in undue cross-subsidisation.

One additional element of the RPM that has been considered by the CRU in the context of cross-border trade is the calculation of the VRF tariff. For further detail see Section 6.
3.5 Summary

The CRU is proposing to continue to apply the Matrix RPM as it is of the view that this RPM continues to be suited to the specific characteristics of the Irish gas market and that it is in compliance with TAR NC. In the next section the CRU examines and proposes some alterations to the components of the current Matrix RPM and tariff structure.

3.6 Request for comment

Parties are invited to comment on matters set out in this section, including the key proposals which relate to:

3A. The CRU’s proposal to continue to apply the Matrix Reference Price Methodology.

When responding, please provide your reasons for your views on the CRU’s proposals and propose alternatives with reasoning where you disagree with the CRU’s views.
4 Review of RPM Components & the Tariff Structure

4.1 Introduction

Having introduced the proposed Matrix RPM and the justification for this proposal in the previous section, the CRU now examines the components of the proposed tariff structure. This section provides detail on aspects of the tariff structure such as the capacity/commodity split and the entry/exit split.

4.2 Allowed revenue

The CRU’s role is to protect gas customers by ensuring that GNI spends customers’ money appropriately and efficiently to deliver necessary services. The CRU does this through what is called a Price Control, which is carried out every 5-years. The current 5-year period started on 01 October 2017 (PC4). A Price Control is an important process because the CRU must carefully consider the level of money, known as the allowed revenue, GNI needs to safely operate, maintain and invest in the gas network for the next 5 years.

The CRU sets the tariffs for the use of the gas network on an annual basis. As part of the annual process of setting tariffs for the upcoming gas year, the CRU collects annual cost information from GNI. The cost data is thoroughly reviewed, and the allowed revenue is updated as appropriate on a yearly basis.

TAR NC defines the allowed revenue as “…the sum of transmission services revenue and non-transmission services revenue…”.36 To date, when the CRU has referred to GNI’s allowed revenue, e.g. its PC4 decision paper and PC4 revenue model, it has reflected GNI’s transmission services revenue only, and has not included the non-transmission revenues GNI recover as operator of the Corrib Linkline (see Section 4.3).

Going forward, in accordance with the TAR NC definition, the CRU will include GNI’s transmission services revenue and non-transmission services revenue in its calculation of GNI’s allowed revenue. GNI’s non-transmission services revenue is negligible, accounting for less than 0.01% of its allowed revenue.37

36 The difference between these services is discussed further in the following section.
37 Information on the GNI’s transmission services revenue is included in the ‘Input- Allowed Revenue’ tab of the RPM workbook (CRU/18/247a), while a detailed explanation is provided in the CRU’s Price Control 4 decision paper (CER/17/260).
The transmission services revenue is entered into the RPM and recovered through the subsequent transmission tariffs, while the non-transmission revenue is recovered through non-transmission tariffs. See the Figure 4.1 below for a summary of how the allowed revenue is recovered.

Figure 4.1: Allowed revenue recovery and tariffs (source: ENTSOG)

4.3 Transmission & Non-transmission services

The regulated services offered by GNI can be split into two categories: transmission services and non-transmission services.

In the case of transmission services, these are paid for by network users through capacity-based transmission tariffs, i.e. those set by the Matrix RPM.

Non-transmission services are defined as “the regulated services other than transmission services and other than services regulated by Regulation (EU) No 312/2014 that are provided by transmission system operator.”

TAR NC Art. 4(1) sets out the criteria for distinguishing between transmission and non-transmission services. The defining characteristics of a transmission service are: (a) the costs of such service are caused by the cost drivers of both capacity and distance, and, (b) the costs of such service are related to the investment in and operation of infrastructure that is part of the regulated asset base for the provision of transmission services.

Meeting both criteria requires the classification as a transmission service, otherwise there is an
option to classify the service as either a transmission service or a non-transmission service.

The CRU has chosen to classify the Corrib Linkline as a non-transmission service as it is not part of GNI’s regulated asset base (see below). All other services have been classified as transmission services. As the Corrib Linkline is a non-transmission service, the revenue is recovered through a non-transmission service tariff. The calculation of this tariff is presented below.

4.3.1 Non-transmission service – Corrib Linkline

4.3.1.1 The Corrib Linkline

In 2004, the Corrib Partners commissioned the construction of a c. 150km transmission pipeline from the Corrib gas field production facility at Bellanaboy to the existing ring main at Cappagh South to deliver gas from the Corrib gas field to the Irish market. This pipeline is known as the Corrib Linkline and is part of the ROI transmission system. The construction of the Corrib Linkline was funded by the Corrib Partners and is not underwritten by Irish gas consumers i.e. it is not part of GNI’s regulated asset base. This distinguishes it from other assets which form the ROI transmission system. GNI operates the Corrib Linkline and recovers this cost from users of the Corrib Linkline through the Corrib Linkline element. The additional revenue is passed through to the Corrib Partners.

4.3.1.2 Calculation of the Corrib Linkline element

Following a consultation process the CRU decision, CER/15/141, set out the methodology for setting the tariff for the Corrib Linkline. This tariff is known as the Corrib Linkline element of the Bellanaboy entry point tariff.

The design of the Corrib Linkline element is based on a standard ‘building blocks’ calculation, whereby every year a set of revenues is calculated. The revenue regime is a target revenue regime. The target revenue and the resulting Corrib Linkline element are calculated using the following formulae:

1. \( \text{Annual target revenue} = \text{Depreciation} + (\text{asset value} \times WACC) + \text{operating expenditure} + \text{replacement capital expenditure} \)

2. \( \text{Corrib Linkline element} = \frac{\text{Annual target revenue}}{\text{throughput}} \)

For further detail and an explanation of the components of the formulae, see CER/15/141. The latest calculation of Corrib Linkline element, i.e. for the 2018/19 gas year, is contained in CER/17/138. The CRU does not propose any alterations to the methodology for setting the Corrib Linkline element as it is of the view that it is compliant with TAR NC as discussed in the following section.
4.3.1.3 TAR NC compliance

Art. 4(4) of TAR NC highlights the set of requirements for the tariffs applicable to non-transmission services: cost-reflectivity, non-discrimination, objectivity, transparency and minimising cross-subsidisation.

As the Corrib Linkline element is derived from a target revenue, which is based on the actual capital and operational costs of the Corrib Linkline it can be considered cost-reflective and objective. It can also be viewed as non-discriminatory with no undue cross-subsidisation, as only users of the Corrib Linkline incur the cost of the Corrib Linkline element and those users are all charged equally. Finally, the Corrib Linkline element can be considered transparent as the CRU has published information regarding the methodology (CER/15/141) used to calculate the Corrib Linkline element and the calculation itself (CER/17/138).

4.3.2 Charges outside the scope of TAR NC

This section highlights charges that are outside of the scope of TAR NC. These charges do not correspond to network costs and are in place to encourage certain shipper behaviour. GNI is revenue neutral with respect to all these charges.

It is a requirement of GNI to establish a ‘disbursements account’ as set out in the Code of Operations (Part E Section 1.4). The disbursements account records the reallocation to Shippers of the net cost/income accruing to GNI in accordance with the methodologies set out in the Code so that, over the year, GNI is cash neutral. All the items are allocated according to each Shipper’s throughput as a proportion of the total throughput, except for the capacity overrun charges which are reallocated according to each Shipper’s proportion of the total monthly capacity holdings.

The following costs currently accrue to the disbursements account on a monthly basis:

- Cost of taking balancing actions;
- Payments/charges to Shippers as a result of Shipper imbalances (Imbalance Commodity Charges and Scheduling Charges);
- Capacity overrun charges incurred by Shippers;
- Costs of stock movements/Unaccounted for Gas (“UAG”).

In addition to those mentioned above, shippers are also billed shrinkage commodity and capacity charges on a monthly basis\(^{38}\). However, the CRU is proposing that from the beginning of gas year 2019/20 the total cost associated with shrinkage, which includes stock movements/UAG, will be included in GNI’s allowed revenue, as discussed in Section 4.4.

4.4 Shrinkage

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.

4.4.1 Current approach

As highlighted in Section 4.3.2, GNI currently recovers the costs of shrinkage outside of the transmission services revenue, from gas shippers on a monthly basis. The total cost of shrinkage includes both the shrinkage commodity and capacity charges and costs of stock movements/Unaccounted for Gas (“UAG”). Shrinkage makes up a significant portion of the costs incurred by GNI as the TSO, approximately €9.7m\(^3\) in 2017/18.

4.4.2 Proposed approach

As part of the NTLG meetings, several options on how to treat shrinkage in the context of TAR NC were discussed with stakeholders. Since the NTLG meetings the CRU has continued to consider the options available and how they fit within the TAR NC arrangements. Given the fact that all network users derive a benefit of the pressures being maintained throughout the system and operated to meet gas flow instructions irrespective of location on the network, the CRU is of the view that it represents a transmission service and should therefore be captured within the transmission services revenue portion of the allowed revenue.

Art. 4 of TAR NC envisages that transmission services revenue be recovered through capacity-based transmission tariffs. However, TAR NC also allows for a flow-based charge, i.e. commodity based, to recover the costs associated with the quantity of gas flow. The main cost incurred by any TSO relating to the quantity of gas flowed is shrinkage gas, the main component of which is compressor fuel. This is because as gas demand increases a TSO has to switch on more compressors to maintain system pressure, using more fuel.

The CRU is of the view that the most appropriate way for shrinkage costs to be recovered going forward is through the commodity element of the capacity/commodity split of the transmission charges rather than through a separate flow-based charge as it is currently treated. This is in accordance with how shrinkage is currently charged to users of the distribution network. The CRU proposes to implement this change beginning gas year 2019/20 and has therefore included

\(^{39}\) ROI transmission portion only.
shrinkage charges\(^{40}\) in the 2019/20 transmission services revenue in the Matrix RPM. The CRU is aware that this proposal may require changes to the Code of Operations, billing systems and possibly contracts both for GNI and gas shippers/suppliers. The CRU requests that stakeholders highlight to the CRU any reasons why it may have issues with an implementation date of gas year 2019/20.

In setting out this preference, the CRU note a number of additional factors of relevance for this consultation:

- **Increase in and potential volatility of tariffs**: Although the effect of including shrinkage in GNI’s transmission services revenue is ultimately an increase in transmission tariffs, this proposal should not lead to increases in customers’ bills, as shrinkage charges were already passed through to end customers by suppliers.

  Shrinkage costs are affected by a number of factors, many of which are non-controllable. For example, global gas prices directly impact on the extent of revenue that GNI must recover in relation to shrinkage. Currently, GNI bill the shrinkage capacity and commodity charges to shippers on a monthly basis, based on cost forecasts. GNI issue statements to gas shippers throughout the year to highlight any differences between forecast and actual costs, but shippers are not invoiced/credited until an external audit of the disbursements account has been completed at the end of the year.

  Moving to an annual tariff arrangement for shrinkage costs will recover costs in similar way, whereby shippers will be charged a flat commodity fee throughout the year based on forecasts, with a k-factor calculated at the end of the gas year and applied to the commodity fee for the next gas year to recover any variation. In addition, the CRU will request that GNI monitor shrinkage costs over the course of the year so that the CRU can advise shippers in the case that there has been any significant variation between the forecast and actual shrinkage costs.

- **Greater transparency and incentive to manage shrinkage costs**: Incorporating shrinkage costs into the transmission services revenue will result in greater scrutiny from the CRU as it will be reviewing shrinkage costs as part of the annual tariff setting process. In addition, its inclusion in the transmission services revenue enhances the ability of the CRU to employ financial incentives around shrinkage volumes when

---

\(^{40}\) Based on 2018/19 forecast of €14.7m for ROI transmission portion only. Increase from €9.7m due in part to gas price increase.
carrying out the next price control, as it currently does with distribution shrinkage volumes.

- **Impact on the effective capacity/commodity split**: As discussed further in Section 4.6 the CRU is proposing to continue to employ a 90:10 capacity/commodity split. The CRU’s proposal to incorporate shrinkage costs into the transmission services revenue has the effect of increasing the cost-reflectivity of the 90:10 capacity/commodity split, see Section 4.6 for further detail. However, incorporating shrinkage costs into the transmission services revenue thereby effectively increases the proportion of charges that are capacity based. Due to the relationship between the treatment of shrinkage and the capacity/commodity split, the CRU will consider both following stakeholder feedback as part of this consultation process before coming to a decision.

4.5 Entry/Exit split

The transmission services revenue to be recovered is allocated to entry and exit. The ratio of this allocation of revenues between entry and exit is known as the entry/exit split.

4.5.1 Current approach

The entry/exit split was considered as part of the tariff reform that has taken place since 2015. The CRU examined the impact of moving from an entry/exit split of 33:67 to 50:50 in CER/15/057 and CER/15/140.

The CRU came to the view that a 33:67 entry/exit split was most closely aligned with the allowed revenue split for the then existing tariff structure and that it was similar to the regulatory asset base (RAB) split of actual system assets. In addition, the CRU decided that the 33:67 split was appropriate as it minimised the redistributive effects across network users.

4.5.2 Proposed approach

The TAR NC does not have a specific requirement related to the entry/exit split, however it does employ the use of a 50/50 split in the counterfactual CWD reference price methodology.

The CRU is of the view that its reasoning for setting the 33:67 split as outlined in its 2015 decision paper continues to apply. Based on this view the CRU highlighted to the NTLG that it was minded to continue to apply a 33:67 split but was open to feedback from stakeholders as to why an alternative should be examined. In response, no participants requested that the CRU should examine an alternative entry/exit split.

Considering the above, and in the interests of regulatory stability, the CRU is proposing to continue to apply an entry/exit split of 33:67, respectively.
4.6 Capacity/commodity split

Following the apportionment of transmission services revenues to entry and exit, these revenues are subsequently allocated further for recovery through capacity and commodity tariffs. The ratio of this allocation of revenues between capacity and commodity is known as the capacity/commodity split.

TAR NC requires that the transmission services revenue is recovered through capacity-based charges and that flow-based charges, i.e. commodity charges, should only recover the variable costs associated with the quantity of gas transported. As highlighted in Section 4.4 the main variable cost associated with the quantity of gas flowed is shrinkage.

4.6.1 Current approach

The capacity/commodity split was also considered as part of the tariff reform that has taken place up to 2015. In the draft decision paper (CER/15/057), the effect of a move to a capacity/commodity split of 100:0 was examined. The CRU stated that it had no firm view on the capacity/commodity split to apply but considered a gradual transition to a 100:0 capacity/commodity split to be appropriate. The CRU requested feedback from stakeholders on the matter.

The response from stakeholders, as highlighted in CER/15/140, was that a clear majority of respondents (8 of 10) were in favour of maintaining a capacity/commodity split of 90:10. The CRU considered at the time that there were a number of benefits to retaining the current split, such as the stability provided to power generation during a time of change in the gas market and the potential redistributive effects across network users.

As the TAR NC preference is for capacity-based tariffs, for this consultation the CRU examined the possible effect on Irish gas consumers of moving to a split with a greater capacity element. The CRU requested that GNI carry out an impact assessment in order to understand the effect of changing the capacity/commodity split, and how this change would affect different customer categories. The results of this impact assessment are included below.

4.6.2 Capacity/commodity split impact assessment

GNI carried out an analysis of the impact of moving from a 90:10 capacity/commodity split to an alternative split such as 95:5 or 100:0. The analysis involved the calculation of indicative 2018/19 tariffs using the alternative splits with all other variables being kept equal. GNI then examined how these different tariffs may affect different customers based on their load factor. The load factor represents the relationship between a user’s average daily consumption and their peak day booking. The higher the load factor the flatter the profile i.e. average usage closer to peak day usage. An example of those with a high load factor would be baseload power generation or industrial/commercial users with a flat demand. An example of those with a low load factor would be peaker power generation or residential customers.
A user with an Estimated Annual Consumption (EAC) of 5,000,000 KWh was assumed and GNI derived their profile using three different load factors: 90% load factor, 50% load factor and 20% load Factor. The assessment assumes that the entry and exit bookings match. The calculation was examined in the case where the user books only annual capacity and then repeated using only daily capacity. Although a user is likely to use a mix of bookings, it is important to estimate the potential maximum effect on a user rather than taking an approach that is too conservative and underestimates the potential impacts on some customers. The results are highlighted in the table below and the impact assessment is published alongside this document, see CRU/18/247d.

<table>
<thead>
<tr>
<th>EAC of 5,000,000 KWh</th>
<th>Load factor</th>
<th>Capacity/Commodity 95:5</th>
<th>Capacity/Commodity 100:0</th>
</tr>
</thead>
<tbody>
<tr>
<td>Assuming annual bookings only</td>
<td>90%</td>
<td>-2.6%</td>
<td>-5.2%</td>
</tr>
<tr>
<td></td>
<td>50%</td>
<td>+0.5%</td>
<td>+0.9%</td>
</tr>
<tr>
<td></td>
<td>20%</td>
<td>+3.1%</td>
<td>+6.1%</td>
</tr>
<tr>
<td>Assuming daily bookings only</td>
<td>90%</td>
<td>+2.1%</td>
<td>+4.1%</td>
</tr>
<tr>
<td></td>
<td>50%</td>
<td>+3.3%</td>
<td>+6.6%</td>
</tr>
<tr>
<td></td>
<td>20%</td>
<td>+4.3%</td>
<td>+8.6%</td>
</tr>
</tbody>
</table>

The higher the load factor (i.e. flatter demand, e.g. baseload power generation, some I/C) the greater weighting commodity has relative to capacity. As a result, these users can potentially benefit from a move to a greater capacity element in the case that they make use of longer term bookings. However, in the case where a user with a higher load factor utilises daily bookings, the result will be an increase in their tariff. The movement to a zero-commodity element amplifies the effects, i.e. greater potential savings but also greater potential for cost increases.

The table above highlights that users with a middle and low load factor (i.e. more volatile demand, e.g. residential customers and peaker plants), for whom the commodity weighting is not as large, will have a resulting increase in costs regardless of the booking strategy employed. Once again, the movement to a zero-commodity element amplifies the effects of the 95:5 split.

This information was presented at the NTLG and the CRU requested input from stakeholders on their views. There did not appear to be a strong desire amongst participants to move to an alternative capacity/commodity split.

The CRU requested input from stakeholders as to whether any misalignment of the split chosen in the Republic of Ireland and Northern Ireland could have effects on power generation considering the recent go live of the ISEM. A participant was of the view that there should not be a significant
impact given that there is currently a misalignment of the capacity/commodity split.\textsuperscript{41} In addition, this participant stated that the capacity/commodity split is less important under ISEM given the flexibility in how costs can be recovered.

\textbf{4.6.3 Proposed approach}

The CRU is proposing to maintain a capacity/commodity split of 90:10. In reaching this proposal the CRU has taken into consideration a number of factors.

Firstly, as highlighted in Section 4.4.2, the CRU’s proposal to incorporate shrinkage costs into the transmission services revenue has the effect of increasing the cost-reflectivity of a 90:10 capacity/commodity split. This is because under the current arrangements it is unlikely that 10\% of the transmission services revenue (which doesn’t include shrinkage) reflects costs associated with the quantity of gas flowed. For example, it is estimated that the cost of shrinkage in 2018/19 will be approximately €14.7m. If this was to be included in the 2018/19 transmission services revenue it would make up approximately 7.5\% of the transmission services revenue, thereby making the proposed 10\% commodity allocation much more cost-reflective.\textsuperscript{42} Given the importance of the cost-reflectivity principle in achieving a harmonised tariff structure, the CRU is of the view that this change will ultimately be of benefit.

It should be noted that incorporating shrinkage costs into the transmission services revenue effectively increases the proportion of charges that are capacity-based. As highlighted in the capacity/commodity impact assessment the move to increased capacity-based charges rewards those users with a higher load factor i.e. more stable demand. The CRU notes the potential negative impact this change could have on residential customers (estimated at less than half of 1\% increase on an annual bill) and peaker plants.

Finally, the CRU notes that as the capacity/commodity split was discussed with stakeholders at the NTLGs prior to the CRU coming to a view on the treatment of shrinkage. Due to the relationship between the treatment of shrinkage and the capacity/commodity split, the CRU will consider both following stakeholder feedback as part of this consultation process before coming to a decision.

\begin{figure}
\end{figure}

\begin{figure}
\end{figure}

\textsuperscript{41} For reference Utility Regulator have proposed a 95:5 capacity/commodity split for NI.

\textsuperscript{42} The 2.5\% difference recovers other costs related to the quantity of gas flow e.g. CO2 emissions. Also, there are less quantifiable costs captured here such wear and tear on the compressors due to batch flows.
4.7 Expansion Constants

4.7.1 Introduction

The purpose of the expansion constant is to provide a numerical value to the cost of expanding the capacity on the system so that one unit of gas can travel over a specified distance. In this context it is expressed as €/GWh/d/km. To determine the values of an expansion constant, actual evidence of pipeline and compressor capital and operating costs is used. As the GNI system is comprised of both dry (onshore) and wet (subsea) pipelines, there are two separate expansion constants to reflect the different costs associated with each. Dry pipeline costs are modelled over a pipeline distance of 100km and wet pipeline costs are modelled over a pipeline distance of 200km.

Both dry and wet expansion constants comprise a blend of pipeline costs together with compression costs. These costs are calculated separately for several different pipeline-sizes: wet pipeline costs are calculated for 600mm and 750mm diameter pipes (to reflect the sizes of Interconnectors 1 and 2 respectively), while dry pipeline costs are calculated for 600mm, 650mm, 750mm and 900mm diameter pipes.

The cost for each size of pipeline is weighted by that size’s proportion of the dry or wet network, as appropriate. These weighted cost figures are then summed to calculate the overall wet and dry expansion constants.

The CRU noted in CER/15/057 that an important consideration of a forward-looking methodology is the stability of the expansion constant over time. In its decision paper, CER/15/140, the CRU added that any future review of inputs to the methodology should only occur where a significant change in material costs or technology necessitate such a review.

The CRU is now proposing to update the expansion constants and annuitisation factors to reflect the CRU's PC4 decision and GNI's completion of the construction of 50km of twinned pipe between Cluden and Brighouse Bay in south-west Scotland. The CRU continues to be of the view that the inputs should be stable and propose that any future reviews will take place as part of the CRU's Art. 26 consultation process, which is expected to take place every five years.

4.7.2 Updating the components

The CRU has undertaken a review of the calculation of the expansion constants and has updated the components to reflect the latest information. Firstly, in the proposed expansion constant calculation model (see, CRU/18/247e) all costs have been indexed to reflect 2018 prices. Secondly, the weightings for dry pipelines have been updated to account for the completion of the twinned pipeline in Scotland.

Indexing the costs to 2018 prices resulted in an increase of €26 in the wet expansion constant, which rose from €8,757 per GWh/d/km in the 2015 model to €8,783 per GWh/d/km in the updated model. This also put upward pressure on the dry expansion constant, but the re-weighting of dry
pipelines to account for the twinning work resulted in downward pressure leading to an overall
decrease in the dry expansion constant by €64, from €7,874 per GWh/d/km in the 2015 model, to
€7,810 per GWh/d/km in the proposed model.

There were questions raised regarding the technical parameters of the expansion constant
calculation at the NTLG. For example, whether the dry expansion constant could be calculated to
reflect the actual flow on one of the pipelines. The CRU is of the view that it is appropriate for the
expansion constants to reflect a theoretical pipeline on the transmission system rather than
undertaking an examination of the actual flow conditions of each pipeline.

The possibility of indexing the expansion constant was also raised at the NTLG. The CRU
continues to be of the view that the expansion constant should remain stable and believe that a
five-year review strikes an appropriate balance between stability and cost-reflectivity of the inputs.

4.8 Annuitisation factor

4.8.1 Introduction

The expansion constant can be used to calculate the cost of building a pipeline (including
compression) but it does not give any indication of the annual revenues that would be required to
finance such an asset. In order to calculate the annual revenues an annuitisation factor is used.
The annuitisation factor uses the capital costs of the assets and takes into account the cost of
capital, the annual depreciation and the annual operating costs to calculate the average annual
payment that would be made on this asset over the lifetime of the asset.

For gas networks assets, the interest rate is substituted with the WACC (weighted average cost of
capital) of the network business and the estimated annual operating cost (opex) is added to the
annual payment. In other words, the annuitisation factor, used in the context of gas transmission
charging, is applied to calculate a fixed annual payment that pays off, in present value terms, the
modelled incremental cost of the period of the depreciation period/asset life for the gas
transmission network.

The annuitisation factor is made up of a number of components; the details of each are set out
below.

Figure 4.2: Annuitisation factor formula

\[ WACC \times \text{pipeline capex} + \text{pipeline opex} + WACC \times \text{compressor capex} + \text{compressor opex} + \text{fuel cost} + \text{depreciation} \]

As can be seen above, the calculation of the annuitisation factor takes into account both
compressor and pipeline costs (opex and capex). Elements of the calculations from the wet
expansion constant are used to derive the annuitisation factor. In other words, the annuitisation
factor is calculated based on the capital costs (capex) and the operating costs (opex) for the average of the 2 subsea pipelines together with elements of the observed operating costs of the compressors in Scotland.

4.8.2 Updating the components
The components of the annuitisation factor remain unchanged since 2015 but the values of the inputs have been updated to reflect the latest data in order to enhance cost-reflectivity. An outline of the updates made to the inputs is given below. More detailed information on these updates is provided in Annex 1.3 and the calculation of the annuitisation factor provided in CRU/18/247f. The CRU proposes to make the following changes:

- The WACC has been updated to 4.63% to reflect the CRU’s PC4 decision.
- Pipeline capex has been indexed to 2018, resulting in annual depreciation costs of c. €6.8m.
- Pipeline opex has been updated to 1.35% of initial pipeline opex, to reflect PC4 allowances. This update, coupled with a 2018 index for initial capex, results in a yearly pipeline opex of c. €4.6m.
- Compressor capex has been indexed to 2018, resulting in annual depreciation costs of c. €2.2m.
- Compressor opex (excluding fuel costs) has been updated to 4.88% of initial compressor capex, to reflect PC4 allowances. This update, coupled with a 2018 index for initial capex, results in a yearly pipeline opex of c. €2.64. Fuel costs have been updated to reflect data on gas prices, exchange rates and utilisation of the compressors, resulting in annual costs of c. €9.7m.

These updates result in an annuitisation factor of 9.8%, which is a reduction from the 10.5% calculated in 2015.

4.9 Summary
All of the above variables have implications for the calculation of reference prices. In the next section the CRU will consider potential new entry points and examine the effect these points may have on the indicative reference prices.
4.10 Request for comment

Parties are invited to comment on matters set out in this section, including the key proposals which relate to:

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?

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

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.

4D. The CRU’s proposals to update the expansion constant and annuitisation factors.

When responding, please provide your reasons for your views on the CRU’s proposals and propose alternatives with reasoning where you disagree with the CRU’s views.
5 Entry point considerations

5.1 Introduction

In this section the CRU examines entry point considerations, such as the application of discounts and the treatment of biogas entry within the proposed Matrix RPM.

5.2 Discounts

TAR NC\textsuperscript{43} allows for the adjustment (i.e. discount) of tariffs at entry points from and exit points to storage facilities and at entry points from LNG facilities and infrastructure ending isolation.

5.2.1 Storage discounts

There are currently no storage facilities in operation in Ireland since the Kinsale gas fields began the blowdown of cushion gas. The CRU is not aware of any plans to develop gas storage infrastructure in Ireland and as such has not included storage in any of the scenarios examined as part of this consultation. However, in the event that a storage facility began operation the CRU would apply at least a 50% discount in accordance with Art. 9. 1., which states that “A discount of at least 50% must be applied to capacity-based transmission tariffs at entry points from and exit points to storage facilities”\textsuperscript{44}.

5.2.2 LNG discounts

Unlike storage, TAR NC allows for, but does not require, the application of discounts to LNG, with Art 9. 2. stating that “At entry points from LNG facilities, […] a discount may be applied to the respective capacity-based transmission tariffs for the purposes of increasing security of supply”.

There are currently no LNG facilities in Ireland. However, there are LNG projects that could potentially be developed in the future. Scenario 2 for example includes a potential LNG entry at Foynes and Scenario 3 includes a potential LNG entry at Innisfree (see Section 2.4).

The application of LNG discounts was discussed in detail at the NTLG meetings with participants sharing views both in favour of and against the application of LNG discounts. Building on the views and discussion at the NTLG, this subsection sets out the relevant principles and issues that the CRU considers relevant to the consideration of the case for, and potential level of, any LNG discount that may or may not be provided in future. It then sets out the CRU’s proposed position regarding its future regulatory policy for LNG discounts.

\textsuperscript{43} Art. 9 – Adjustments of tariffs at entry points from and exit points to storage facilities and at entry points from LNG facilitates and infrastructure ending isolation.

\textsuperscript{44} Unless and to the extent a storage facility which is connected to more than one transmission or distribution network is used to compete with an interconnection point.
The CRU has identified a range of issues that are considered relevant to the assessment of LNG discounts in the context of Ireland. These include:

- The security and diversity of supply benefits an LNG facility may provide Irish gas consumers, relative to other sources of supply to the Irish market.
- The impact an LNG discount could have on other entry point tariffs, investment signals and competition in the Irish wholesale gas market.
- The impact an LNG discount may have on the wholesale gas price and consumers costs given the structure of the Irish gas market.
- The RPM principles applied in CER/15/140 and the general requirements of the RPM as set out in Art. 7 of the TAR NC and the impact on these desired properties on the RPM if granting an LNG discount.

5.2.2.1 Security of supply benefits

The CRU notes that an LNG entry point could bring security of supply and diversity benefits to Irish gas consumers and by extension to the European gas market. By providing access to a global gas market and by introducing an additional point of supply redundancy within the Irish gas market, the development of an LNG facility may allow Ireland to reduce its dependence on other sources of gas and benefit from greater resource diversity. This may also facilitate the connection of additional gas demand within the Irish market and could enhance price competition for gas in future while reducing Ireland’s exposure to gas market shocks.

However, it is important to note that other supply sources also contribute to the security and diversity of supply to the Irish gas market. TAR NC states that an LNG discount may be applied to network tariffs for the purposes of increasing security of supply. Given other sources of supply also contribute to supply security in Ireland, on equity grounds (one of the principles that was adopted by the CRU to inform the development of the existing Matrix based transmission tariff structure (see CER/15/140)), it may not be appropriate to grant an LNG network tariff discount even if the new facility is considered to contribute to supply security and diversity.

In addition, as discussed further in Section 5.2.2.2 below, it is important to recognise that any specific LNG discount will distort the cost reflective (LRMC based) investment signals provided to all new entry point sources under the Matrix RPM. Consequently, granting an LNG discounts for security of supply purposes could lead to less effective competition if by doing so it effects the investment signals provided through the tariff structure to all sources of supply (new and existing).

Therefore, although an LNG facility may provide security of supply and diversity benefits, the CRU notes that equity and promotion of effective competition were both high-level design principles that informed the decision-making process on the current tariff structure and would need to be considered alongside security of supply.
5.2.2.2 Investment signals for new entry and gas market competition

A key decision of the CRU’s tariff reform paper, CER/15/140, was that where new entrants could be shown to be more efficient (i.e. be cheaper) than the Moffat tariff, which sets the wholesale price of gas in Ireland (see discussion below), then they should be incentivised to enter the market based on cost-reflective charging principles. The cost-reflective nature of the arrangements was intended to introduce signals for efficient new entry while ensuring that Irish gas customers did not overpay for the security of supply benefits that a new supply source could provide.

Within the Matrix RPM, cost-reflective signals for entry are provided via the difference between the cost of entering a unit of gas (€/MWh) into the transmission system at Moffat and the cost at the relevant entry point. When considering the possible application of discounts to entry points it must therefore be recognised that the Matrix RPM already provides an incentive to new entry investment. This investment signal is not present in some other RPMs such as the postage stamp methodology which applies the same tariff to all entry points and exit points. While sending an investment signal to new entry in a postage stamp approach may require the application of discounts, the Matrix RPM does not in principle require discounts to incentivise entry as the RPM itself provides a cost reflective investment signal to incentivise efficient new entry.

The text box below examines the effect of applying an arbitrary 50% discount to the LNG entry points in Scenarios 2 and 3, in order to provide an example of the effect of a discount on the cost reflective premium that already exists under the Matrix RPM. As set out in this section, discounts will not necessarily be applied and, if the CRU does decide to introduce discounts, they could be of any size. A 50% discount is purely illustrative and was chosen to provide an example of the potential effect of a discount. It should not be considered a representation of the CRU’s view on the application of discounts or the appropriate size of a discount. The methodology used to apply the entry point discount in the proposed Matrix RPM is presented in Annex 1.1.
This text box examines the effect of the application of a discount on the diversity premium resulting from the transmission tariff structure for LNG entry points.

The CRU notes that the numbers presented are indicative of the maximum premium that may accrue to entry points. It is expected that the effects of competition would mean that new entry points supplying Ireland would undercut gas delivered from Moffat, in some periods of the year at least. Therefore, the diversity premium accruing to producers may be expected to be lower due to competition between supply points, particularly within certain periods of the year when Moffat may no longer be the marginal source of gas.\textsuperscript{45}

Table 5.1 below presents the estimated diversity premium with a 50% LNG discount at the Foynes entry point.

\begin{table}[h]
\centering
\begin{tabular}{|c|c|c|c|c|c|}
\hline
Entry point & Est. 20.21 & Est. 21.22 & Est. 20.21 & Est. 21.22 \\
\hline
\text{Scenario 2 - No discount} & & & & \\
\hline
Bellanaboy & €13,754,312 & €12,074,418 & €13,754,312 & €12,074,418 \\
\hline
Innisfree & n/a & n/a & n/a & 0 \\
\hline
Moffat & €0 & €0 & €0 & €0 \\
\hline
Foynes & n/a & €22,465,471 & n/a & €45,699,826 \\
\hline
Biogas & €217,915 & €638,960 & €217,915 & €638,960 \\
\hline
Inch & n/a & n/a & n/a & 0 \\
\hline
\text{Total Diversity Premium} & €13,972,226 & 35,178,849 & €13,972,226 & 58,413,204 \\
\hline
\end{tabular}
\caption{Estimated diversity premium – effect of 50\% LNG discount in Scenario 2}
\end{table}

The effect of a 50\% discount at the LNG entry point in Scenario 2 is an increase in the diversity premium to €58m from €35m, of which it is estimated that €46m will accrue to the LNG project on an annual basis.

5.2.2.3 Impact on wholesale gas prices and costs

In considering the appropriate tariff arrangements for prospective new LNG entry points, it is also important to consider the implications of any LNG entry point tariff (including or not including a discount) on the tariff levels at other entry points and on the wholesale Irish gas price.

As discussed above, generally, Irish wholesale gas prices are set by the GB price of gas plus the cost of transporting gas from GB to Ireland via the interconnectors, as GB gas is the marginal

\textsuperscript{45} In addition, there are some simplifications within the diversity premium calculation, e.g. load factor of 1.3 (see CRU/18/247c). These figures are used to provide a rough estimation of the diversity premium only.
source of gas supply to Ireland. The National Balancing Point, commonly referred to as the NBP, is the virtual trading location for GB natural gas. Therefore, the cost of gas at the NBP plus the cost of transportation to Ireland, which includes the cost of the Moffat entry tariff, strongly influences the price at the Irish Balancing Point (IBP), i.e. the cost of wholesale gas in Ireland.

Discounting the tariff at an entry point would require the revenue that would otherwise be recovered to be spread across all entry point tariffs through an increased secondary adjustment. This increases the tariffs at all other entry points including Moffat, thus causing a further increase in the cost of the wholesale gas price in Ireland and leading to increased costs for customers.

The consumer cost of the effect of new entry i.e. increased diversity/security of supply, can be roughly estimated by comparing the difference between the forecasted entry tariff at Moffat before and after the new entry point, and then by multiplying the difference in the tariff in €/MWh by the total forecast demand in Ireland. This calculation assumes that Moffat entry tariff sets the wholesale price of gas in Ireland as the marginal source and that gas supplied through the other entry points is effectively priced up to this level.46

Applying this methodology, to Scenario 2, the cost to the consumer of the increased diversity/security of supply provided by the LNG entry point joining the network in 2021/22 is estimated to be €24m, rising to €51m in the case that this entry point receives a 50% discount.

This demonstrates that the increased revenue recovery that is transferred to other entry points as a result of the provision of LNG discounts, has the potential to significantly increase the wholesale cost of gas in Ireland. The CRU considers this potential negative effect on Irish consumers, would need to be balanced against any additional security of supply benefits an LNG facility can demonstrate it provides Irish consumers within the context set out in Section 5.2.2.1 above.

5.2.2.4 TAR NC Principles

The CRU also considers that the provision of any LNG discount in Ireland should take into account the general requirements of the RPM set out in Article 7 of the TAR NC.

One of those requirements is for NRAs to consider the costs incurred for the provision of transmission services in developing the RPM. For the reasons discussed above, LNG discounts would be expected to affect the cost-based investment signals naturally provided by the proposed Matrix RPM. Consequently, the overall tariff structure may take less account of the costs incurred

46 As discussed in the text box above, it is expected that in practice the effects of competition would mean that new entry points supplying Ireland could undercut gas delivered from Moffat. In the future, Moffat might also no longer be the price setting supply source throughout the year, and the costs to customers might therefore fall.

47 This cost is based on the assumption that the increased cost of transportation of GB gas will increase the costs of all gas in ROI as GB provides the marginal source of gas against which other supply will price up to.
of providing access to GNI’s network once LNG discounts are applied, with the potential knock on impacts on supply competition discussed above.

Any application of an LNG discount may also need to be consider the requirement to ensure non-discrimination and prevent undue cross-subsidisation in the choice of RPM. The views of some European stakeholders of the impact of LNG discounts on the principles of non-discrimination and prevention of cross-subsidisation in network tariffs is for example referenced in CEER’s 2017 report on the LNG participation in European gas markets.48

5.2.2.5 Proposed policy position

Based on current information, the CRU does not have sufficient evidence to determine that an LNG discount would be in the interests of Irish gas consumers at this time. Although an LNG facility may provide benefits to Irish gas consumers in relation to security and diversification of supply there is limited current evidence of the scale of project benefits.

As discussed above, it is also important to recognise that other sources contribute to supply diversity and security in Ireland and that the proposed Matrix RPM already produces a cost-based investment signal to support efficient new entry to the Irish gas market.

The proposed RPM balances a range principles and objectives (including those applied in CER/15/140 (stability, predictability, equity and promotion of effective competition) and the requirements of the RPM set out within the TAR NC (see Section 3.4). Granting LNG discounts would be expected to have a significant impact on the balance of how these desired properties and principles are achieved within GNI’s overall transmission tariff structure, given the impacts on Irish consumers and other users of the gas network discussed above.

However, the CRU considers it is in the public interest to continue to consider the case for LNG discounts as more information becomes available. Informed by the discussion above, the CRU sets out below a number of non-binding conditions it proposes to apply for the consideration of the case for, and level of LNG, discounts that may be provided in future. Based on these criteria, the CRU intends to consider the relative merits of the provision of LNG discounts on a project-by-project basis following an application which is submitted by LNG project developers.

The CRU’s intention is that LNG developers would have one opportunity to provide such evidence per project as part of an application in relation to the provision of discounts and the justification for any LNG discount. Project developers could renew an application for a discount should new material information or changes in conditions of the Irish gas market arise which lead to a need for the CRU to re-consider its position. In the event that a discount is provided, the level of the discount would be considered as part of the annual Art. 28 consultation process as required by TAR NC.

The CRU proposes to take into consideration the following non-binding conditions in order to assess applications for LNG discounts:

- The additional security of supply and diversification of supply benefit that an LNG entry point can provide relative to the cost-based investment signal for entry which is already provided under the Matrix RPM. This should be justified by evidence provided by project promoter(s) as part of analysis of the benefits provided by the new entry point. In recognition that other entry points provide security and diversity of supply to the Irish gas market, the CRU may also consider the potential for new entry from other sources of supply when identifying the case for, and level of any discount.

- The impact of the LNG discount on other entry point tariffs under the RPM. For example, the CRU will consider the increase in tariffs at other entry points, tariff differentials and the resulting diversity premium that the LNG entry point would receive.

- Indirect impacts of the discount on Irish gas consumers, such as the impact on Irish gas prices.

- The tariff principles applied in CER/15/140 requirements of the RPM set out in Art. 7 of the TAR NC (see section 3.4.2 for principles).

- Article 41(6)(a) of Directive 2009/73/EC (ensuring viability of networks e.g. revenue recovery).

The CRU welcomes the views of stakeholders on these considerations.

\[49\] The CRU would expect a project promoter to provide quantified (e.g. the monetary value of any expected reduction in loss of supply to Irish gas consumers) and non-quantified evidence of the existence and scale of the additional security and diversification of supply provided by the LNG entry point under a range of possible scenarios and sensitivities.

\[50\] Article 41(6)(a) states the following: “The regulatory authorities shall be responsible for fixing or approving sufficiently in advance of their entry into force at least the methodologies used to calculate or establish the terms and conditions for:

- connection and access to national networks, including transmission and distribution tariffs,
- and terms, conditions and tariffs for access to LNG facilities. Those tariffs or methodologies shall allow the necessary investments in the networks and LNG facilities to be carried out in a manner allowing those investments to ensure the viability of the networks and LNG facilities;”
5.3 Biogas entry tariff

In addition to potential entry from LNG project developers, Ireland has the potential for new ‘small-scale’ renewable sources of gas, particularly biogas. It is therefore important to consider the tariff arrangements which will apply to these new types of entry over the forthcoming tariff period.

The CRU considers it important to take into account the expected scale and possible number of these potential new sources of entry in order to develop tariff arrangements which are simple and practicable. For example, in comparison to the Moffat entry point which has projected annual bookings of between approximately 206GWh in scenario 1 2023/34, projected supply from the modelled biogas entry point for the same year is of the order of 12GWh. Over the coming years, there are ambitions in Ireland for a number of biogas projects which are likely to be of a similar scale, some of which may seek to connect to the transmission system.

In NTLG meetings, biogas developers asked the CRU to consider the development of tariff arrangements for biogas which are simple and pragmatic. Stakeholders who were not representing the interests of biogas producers generally agreed with the focus on simplicity and practical application of a tariff arrangements for these entry points. The CRU also considers government policy on a low carbon energy future and notes the Government’s Energy White paper\(^{51}\).

As such, the CRU proposes to introduce a single tariff for biogas entry points which is based on a single ‘notional entry point’ located on the Irish gas system. This will effectively mean that all biogas entry points who wish to connect to the transmission system face an equivalent tariff, regardless of location.

While the CRU accepts that this reduces the locational signal present within the Matrix RPM, it considers that this arrangement has the following advantages:

- **Simplicity**: The tariff arrangements are simple and transparent. This is particularly important given that some biogas producers may not be as familiar with the gas market and tariff arrangements as larger gas producers.
- **Stability**: The notional point approach will enhance the stability of the tariff arrangements biogas producers who may be more affected by volatility of gas tariffs due to their smaller scale.
- **Investor certainty**: The notional point arrangement provides a clear market signal to potential new entry sources in relation to the transmission tariffs they will face. This provides additional certainty to investors.

5.3.1 Location of the notional point

After deciding upon a proposal for a notional point arrangement for biogas entry, the CRU has considered the location of the notional point. The CRU is considering two approaches:

1. A single notional tariff based on the geographically dispersed location of the Gormanston (County Meath), Corracunna (County Cork) and Cappagh South (County Galway) transmission entry points, which are included in the model.
2. A single notional tariff based on a location that is close to a demand centre.

In developing the first proposal the CRU has taken into account the fact that biogas, and other small-scale entry is likely to be located near to the point of production rather than having the flexibility to locate close to demand centres. In addition, while the impacts of the choice of location may be low while volumes of entry are small, the RPM will provide a signal to new small-scale entry points and, as such, it is important that the tariff is broadly reflective of the likely location of new production sources.

In developing the second proposal the CRU has considered the importance of incentivising biogas injection given that the industry is currently in its infancy in Ireland. By setting the location of the notional tariff close to a demand centre the CRU will have created a reference price for biogas entry that is the lowest possible under the Matrix RPM.

The exact location of the entry point used to set the reference price in the second proposal is to be decided. As such the reference prices and any diversity premiums presented in this paper and the additional documents have been calculated under the first proposal only. However, it is estimated that the indicative biogas reference price in the year 2019/20 would be €109/MWh in the first proposal and approximately €90/MWh in the second, relative to a Moffat entry tariff of c. €311/MWh.

5.3.2 Implications for a distribution tariff

While not within the requirements of TAR NC, it is important to consider interactions between the transmission and distribution tariffs for biogas entry points. Given the small scale of potential new entry projects, producers may be faced with a choice of whether to connect to the transmission or distribution network. It is therefore important that the transmission and distribution tariffs are aligned so that, to the extent possible, producers face economically efficient signals of the optimum point of connection.

The CRU is therefore considering whether a similar notional entry tariff approach should be applied to distribution tariffs and welcomes views on the additional factors which may need to be taken into account in designing such a tariff.

52 Note that in the CWD RPM the biogas location is based on the Corracunna entry point only.
5.4 Request for comment

Parties are invited to comment on matters set out in this section, including the key proposals which relate to:

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?

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?

When responding, please provide your reasons for your views on the CRU’s proposals and propose alternatives with reasoning where you disagree with the CRU’s views.
6 Virtual Reverse Flow

6.1 Introduction

Virtual Reverse Flow (VRF) is a ‘reverse flow’ service offered on a virtual interruptible basis, at the Interconnection Points, to enable shippers to virtually flow gas from ROI via Moffat and into ROI via Gormanston. VRF is a day-ahead interruptible product. Currently, the CRU sets an annual registration fee for the use of this service at Moffat (€15,414) and Gormanston (€40,625) in order to recover the cost of developing and administering the VRF service.

There have been a number of discussions regarding the appropriate charge/tariff for VRF at the Code Modification Fora, chaired by the CRU, over the last number of years. At the fora the CRU has highlighted its intent to move to a tariff for VRF, which is based on the probability of interruption. Consistent with ENTSO-G guidance, the CRU is therefore proposing that the tariff for use of the VRF service should be set using the principles and requirements in TAR NC for standard interruptible capacity products. This proposed treatment is consistent with charging for use of a single entry-exit transmission system and will provide transparency and predictability to users of the VRF service of how the VRF tariff will be set, using TAR NC principles.

TAR NC Art. 16 specifies the calculation of reserve prices for standard interruptible capacity products by applying an adjustment to the reserve prices for the corresponding standard firm capacity products. The adjustment can be applied either ex-ante (before the event) or ex-post (after the event). Given the CRU has previously proposed to develop a VRF tariff based on the probability of interruption it is therefore proposing to calculate the adjustment based on the ex-ante approach, which involves an upfront calculation based on the probability of interruption and the estimated economic value of the product and is consistent with TAR NC.

The formula for calculating the adjustment which should be applied is set out in the TAR NC and is as follows:

\[ D_{i_{ex-ante}} = Pro \times A \times 100\% \]

Where:

- \( D_{i_{ex-ante}} \) is the level of an ex-ante adjustment;
- \( Pro \) factor is the probability of interruption;
- \( A \) is the adjustment factor which should reflect the estimated economic value of the interruptible capacity product. The TAR NC restricts the \( A \) factor to being equal to, or greater than one (i.e. it can only increase the level of reduction).

The proposed calculation of the probability of interruption (Pro-factor) and the economic value of the product are discussed within this section.
6.2 Defining the appropriate firm product

In order to determine the appropriate tariff for VRF, the appropriate firm product from which to apply an interruptible adjustment must first be decided.

To determine this, the entry or exit point, which is of most relevance to the products in question must be identified. The Moffat VRF product provides the ability for market participants to book capacity for the commercial flow of gas from Ireland to Great Britain across the Moffat interconnector. Hence, the CRU considers that, as a starting principle, the appropriate point on which to base the VRF tariff should be the Moffat Exit point. Following the same logic, the CRU identifies the Gormanston Entry point as the appropriate point on which to base the Gormanston VRF tariff.

In addition, the CRU is of the view that the appropriate firm capacity tariff to which an interruptible adjustment should be applied is the relevant day-ahead reference price calculated by the Matrix RPM at the Moffat exit point and the Gormanston entry point. Given that VRF is a daily product the CRU is of the view that multipliers and seasonal factors should be applied in order to reflect the value of short-term products and to reflect the seasonal variation in use of the gas transmission system.

6.3 Estimating the Pro factor

As set out in the formula, the probability of interruption of the VRF product should be included within the adjustment.

GNI has calculated the probability of interruption of the VRF product at Moffat in the last year based on the number of days on which allocations of VRF were recorded and interruptions occurred. In the period September 2017 to September 2018 GNI has calculated that interruptions occurred on 22 of the 275 days in which VRF allocations were recorded. This results in a Pro factor of 8%, see CRU/18/247g. The CRU notes that currently GNI does not have the full suite of data available to calculate the Pro factor using the methodology set out in TAR NC. As this data becomes available GNI will update the methodology used to calculate the Pro Factor.

As the VRF product is not currently in use at Gormanston, a Pro Factor cannot be calculated. The CRU is of the view that, until a probability of interruption for the Gormanston VRF product can be calculated, it is beneficial to treat the two VRF products on a consistent basis. The CRU therefore proposes to apply the Moffat Pro Factor until the data required to calculate the Gormanston Pro

---

53 The CRU notes that given the extent of data available, incorporating seasonality into the calculation of the probability of interruption would not be sufficiently well evidenced and thus an annual Pro factor is proposed.
6.4 Estimating the A factor

The A factor is intended to reflect the estimated economic value of the interruptible capacity product. There are a number of elements that the CRU has considered incorporating into this factor:

1. A **risk premium** to account for the fact that interruption of the product has an impact on its value which is greater than the percentage reduction in availability.

2. A factor which reflects **availability** of the product as well as probability of interruption of capacity that is allocated.

3. A weighting to encourage use of the product and thus enhance GNI **revenue recovery**.

4. A **market interaction factor** to reflect the value of the VRF product in comparison to market-based alternatives and to reflect considerations of cross-border trade.

6.4.1.1 Risk premium

Where market participants use, or intend to use the VRF product, the actual and perceived likelihood of the service being interrupted is likely to have a more significant impact than the probability of interruption itself may reflect. Users of the product may need to hedge against the risk of interruption commercially or physically or may need to ensure access to alternative products at short notice.

The CRU agrees that this implies that a risk premium factor is needed to reflect the reduction in the value of the product beyond the probability of interruption itself. Without having received evidence to date from the market to indicate what a reflective level of this risk premium should be, the CRU proposes a risk premium of 10% for both the Moffat and Gormanston VRF products. The CRU welcomes views in response to this proposal, wherever possible supported by evidence to demonstrate the extent of possible impact.

6.4.1.2 An availability factor

The Pro factor which has been estimated above reflects the likelihood that VRF allocations are recorded but subsequently interrupted, e.g. for technical reasons.

However, the VRF product is unlike other interruptible products in that it is not always available to be booked ex ante – i.e. the product is not always available to be used. This is because the availability of the product is itself dependent on forward flow capacity bookings. Some stakeholders have proposed that in addition to reflecting the probability of interruption, a VRF reduction should reflect the potential for the product to be unavailable at a time when they would like to use it.

However, analysis of flows over Moffat show that a lack of availability of the product due to limited
forward flow bookings is highly unlikely. In the last year, recorded VRF flows have not reached above 40% of the forward flows across the Moffat interconnector. Therefore, while the need for an availability factor may arise should use of the VRF product increase to a level in which lack of availability of the product becomes more likely, the CRU does not propose to apply an availability factor to the Moffat VRF tariff at the current time.\textsuperscript{54}

\textbf{6.4.1.3 Revenue recovery}

In discussion of the A factor, the TAR NC refers to Article 41(6)(a) of Directive 2009/73/EC. This article refers to the need for tariff methodologies to allow the necessary investments in the networks and to ensure viability of the networks. The CRU notes this as suggesting an emphasis on ensuring that tariffs are designed appropriately to ensure revenue recovery for gas transportation network companies.

The tariff arrangements for VRF may have some impact on revenue recovery for GNI. All else equal, a higher VRF tariff would allow for greater cost recovery from users of the VRF product. However, higher tariffs may also discourage use of the product, particularly where commercial alternatives exist for trading gas directly between counterparties in Ireland and GB. Where a higher VRF tariff does lead to lower use of the VRF product, this may have a knock-on impact on forward flow capacity bookings. On each occasion that VRF is replaced by a commercial exchange, this suggests that a forward flow booking no longer takes place.

It has therefore been suggested by some stakeholders that a higher reduction is required in order to prevent a reduction of both VRF and forward flow capacity bookings which may result in revenues being recovered across a lower volume of capacity bookings.

The CRU understands the concerns raised however considers it likely that this impact would be of low materiality. Over the last year, use of the VRF product as a percentage of forward flows has averaged 3.5%. As the liquidity of the IBP trading platform potentially increases in coming years, the use of VRF may continue to decline regardless of the level of tariff applied.

The CRU does not propose to increase the reduction applied to the Moffat VRF tariff to reflect concerns raised in this regard.\textsuperscript{55}

\textsuperscript{54} With regard to VRF at Gormanston the CRU will monitor the availability of the product in the event that usage of the VRF product occurs.

\textsuperscript{55} With regard to VRF at Gormanston the CRU will monitor its effect on revenue recovery at a time when usage of the VRF product at Gormanston occurs.
6.4.1.4 Market interaction

Finally, the CRU has considered whether to interpret the ‘economic value’ of the VRF product with regard to alternatives which exist for market participants and in relation to the importance of cross-border trade.

Consideration of alternative products

Counterparties in Ireland and GB can enter into commercial agreements to trade gas between the NBP and IBP directly rather than by making use of the forward flow and VRF products. It could therefore be argued that VRF is only valuable to the extent that it provides an alternative option to a commercial ‘swap’ of gas.

However, the CRU considers it important to evaluate the impact on the Irish gas consumer of setting the tariff in this way. While use of the VRF product is low, the CRU believe that the level of the tariff can nevertheless impact on the Irish gas market less directly. It has been suggested that the VRF tariff plays a role in the commercial agreements which are made between the counterparties to cross-border trades. A relatively high VRF tariff may benefit those who intend to flow from GB to Ireland within these commercial arrangements. A relatively lower tariff may benefit those who intend to virtually flow gas in the opposite direction. Particularly where this flows through into longer-term contracts, it is anticipated that this may impact on the IBP price.

Additional cross-border trade considerations

Interactions with cross-border trade have also been considered. Some stakeholders have suggested that the VRF product plays an important role in the market as it allows for positions to be balanced through access to the GB market (NBP). In this way, they suggest that it is an important product for the continued development of the traded Irish gas market and supports market integration between GB and Ireland. They argue that a higher VRF tariff would reduce the value of this option, potentially discouraging participation in the IBP and resulting in more balancing actions being undertaken by the system operator.

The CRU notes that the VRF product is used to ‘net off’ forward flow gas bookings. Since the price at the IBP is generally assumed to be the NBP price plus the costs of transportation, the CRU assumes that use of the VRF product would be even lower than current levels should the VRF tariff be higher than the forward flow tariff. Shippers would in effect be paying a premium to (virtually) flow gas from a higher priced to lower priced market.

In this respect, the CRU identifies interactions between the tariffs applied to the forward flow and VRF products. Therefore, while the relevant firm product against which the Moffat VRF product is priced is considered to be the exit tariff, to help reduce distortions to cross-border trade and encourage efficient use of the VRF product, the CRU considers it sensible to ensure that the post-adjustment tariff is priced lower than the equivalent entry tariff (also reflecting the interruptible nature of the product).
The CRU therefore intends to apply a further reduction of 30% within the Moffat VRF product to reflect this consideration. As the Gormanston VRF product is already less than the equivalent exit tariff the CRU does not propose to apply this further reduction to the Gormanston VRF product.\(^{56}\)

6.4.1.5 A-factor proposal

Based on the discussion above, the CRU has therefore determined that the A-factor should reflect an additional ‘risk premium’ for users of the VRF product. In order to reflect the CRU’s position of a risk premium of 10% and a further reduction of 30% to reflect market interactions with GB, the CRU is consulting on an A-factor of 6 for the Moffat VRF tariff and an A-factor of 2.25 for the Gormanston VRF tariff.\(^{57}\)

6.5 Summary of position

In summary, the CRU proposes the following positions in relation to the VRF tariff:

- Interpreting VRF as an interruptible product and introducing a tariff methodology based on interruption relative to a firm capacity product.
- Using the formula set out in the TAR NC to define the VRF tariff.
- The appropriate firm product on which the VRF tariff is based is the daily tariff the Moffat exit point and the Gormanston entry point.
- Analysis of the probability of interruption over the last year implies a P-factor of 8%. For Gormanston, the CRU assumes a P-factor of 8%.
- This P-factor of 8% is combined with an A-factor of 6 and 2.25 for Moffat exit VRF and Gormanston entry VRF, respectively.

Commodity tariff

- In addition to capacity-based tariffs for VRF, the CRU is required to also consider the application of a commodity tariff. As the focus of engagement with stakeholders has been on the development of a capacity tariff, the CRU has not yet come to a view on the application of commodity tariffs for the VRF product. The CRU welcomes stakeholder views on whether a commodity tariff should be applied.

The CRU welcome stakeholder’s views on the factors that have been included within the VRF tariff and on the magnitude of each factor which should be incorporated.

\(^{56}\) Functionality is to be added to the Matrix RPM to allow for the application of different discounts for separate VRF products.

\(^{57}\) Note that as the A factor is a multiplicative term within the TAR NC, the 10% and 30% discounts are achieved by applying an A-factor of 6. The A-factor will be kept under review as part of the annual Art. 28 consultations.
Based on the positions set out above, the indicative reference prices are presented in the table below. The prices presented are the annual reference prices to which the multipliers/seasonal factors will be applied to derive tariffs for the daily VRF product.

### Table 6.1: Indicative VRF reference price

<table>
<thead>
<tr>
<th>Moffat VRF Exit</th>
<th>Cap</th>
<th>Commodity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capacity</td>
<td>272</td>
<td>TBC</td>
</tr>
<tr>
<td>Commodity</td>
<td>TBC</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Gormanston VRF Entry</th>
<th>Cap</th>
<th>Commodity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capacity</td>
<td>77</td>
<td>TBC</td>
</tr>
</tbody>
</table>

#### 6.6 Request for comment

Parties are invited to comment on matters set out in this section, including the key proposals which relate to:

**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?

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

When responding, please provide your reasons for your views on the CRU’s proposals and propose alternatives with reasoning where you disagree with the CRU’s views.
7 Multipliers & Seasonal Factors

7.1 Introduction

The proposed Matrix RPM sets the reference price, or in simple terms, the tariff for annual firm capacity. For annual firm capacity the reference price is the same as the reserve price. The reserve price is used to auction the capacity.\(^58\)\(^59\) There are a number of additional capacity products which shippers can book for a shorter period. In Ireland there are quarterly, monthly, daily and within-day capacity products.\(^60\)

The TAR NC sets out a number of requirements for how the reserve prices for these non-yearly capacity products are derived. There are two parameters:

- **Multipliers**: These are used to determine the multiple of the yearly capacity product tariff, which is applied to the relevant non-yearly capacity product to calculate the relevant tariff. The multiplier should be constant for any capacity product type – e.g. all monthly products will have the same multiplier.

- **Seasonal factors**: Seasonal factors are used to derive a profile for the reserve prices of the capacity products across the year. This leads to differentiation of the reserve prices for a capacity product at different times of year based on the principle of cost-reflectivity – i.e. that requirements for capacity during periods of high utilisation are more likely to lead to additional network costs and, potentially to requirements for additional infrastructure investment.

7.2 Current multipliers and seasonal factors

On 1st November 2015 Regulation (EC) 984/2013 establishing a network code on capacity allocation mechanisms in gas transmission systems (CAM NC) was implemented in Ireland by GNI as the TSO. CAM NC requires TSOs across the EU to offer a standardised range of capacity products at Interconnection Points, namely annual, quarterly, monthly, daily and within-day products. In addition, the CAM Network Code mandates that these capacity products must be offered via an auction process. Firm capacity at either side of an interconnection point must be offered as a bundled product between adjacent TSOs. To facilitate the standardised products and bundling, GNI offer these capacity products on the PRISMA capacity booking platform at the Moffat

\(^{58}\) In Ireland the floating payable price approach is used, for further detail see Annex 1.2.

\(^{59}\) As there are no auction premiums in Ireland the reserve price is the price paid for the capacity products, in other words, there is no difference between the reserve price and the tariff.

\(^{60}\) As the within-day capacity product is set at the price of the daily capacity product it is not necessary to detail its cost in this section.
and Gormanston IPs.

The existing multiplier and seasonal factor arrangements have been developed over a number of years. The methodology considers the allocation of historic peak demand days across the months of the year and uses these as a proxy for the probability of incremental demand in that month triggering investment. This implies a monthly tariff profile across the year as a percentage of the annual product tariff. In order to encourage long term bookings, a scaling factor is then applied to increase the relative attractiveness of the annual product in comparison to the short-term products. In addition, while the probability of peak demand days over the summer months was considered to effectively be zero, a minimum tariff was set for these periods. In total, the sum of the monthly product tariffs equated to 210% of the annual product tariff. Daily product tariffs were then set as a percentage of the monthly product tariffs with a further compensation factor for the use of the shorter-term product.

Over subsequent years, revisions have been made to these arrangements. In 2010, the monthly tariffs in the winter and shoulder months were reduced to encourage use of the short-term product, with a corresponding reduction in the daily product tariffs. This led to an effective multiplier of 1.9 (190%) for the monthly product and 3.42 (342%) for the daily product.

In 2012 the CRU, in decision paper CER/12/1431, reduced the monthly tariffs in the summer months to 1% of the annual product to encourage their use. This resulted in the existing monthly and daily multipliers of 1.55 (155%) and 2.89 (289%), respectively, see Table 7.1 below.

In CER/16/013, the CRU set a quarterly multiplier which consists of the sum of the monthly multiplier. This maintains shippers in a neutral position vis-à-vis the monthly capacity multipliers.

<table>
<thead>
<tr>
<th>Month</th>
<th>Quarterly %</th>
<th>Monthly %</th>
<th>Daily %</th>
</tr>
</thead>
<tbody>
<tr>
<td>October</td>
<td>44.12%</td>
<td>13.24%</td>
<td>0.66%</td>
</tr>
<tr>
<td>November</td>
<td>13.24%</td>
<td>0.66%</td>
<td></td>
</tr>
<tr>
<td>December</td>
<td>17.65%</td>
<td>1.18%</td>
<td></td>
</tr>
<tr>
<td>January</td>
<td>92.65%</td>
<td>30.88%</td>
<td>2.06%</td>
</tr>
<tr>
<td>February</td>
<td>35.29%</td>
<td>2.35%</td>
<td></td>
</tr>
<tr>
<td>March</td>
<td>26.47%</td>
<td>1.76%</td>
<td></td>
</tr>
<tr>
<td>April</td>
<td>15.24%</td>
<td>13.24%</td>
<td>0.66%</td>
</tr>
<tr>
<td>May</td>
<td>1.0%</td>
<td>0.05%</td>
<td></td>
</tr>
<tr>
<td>June</td>
<td>1.0%</td>
<td>0.05%</td>
<td></td>
</tr>
<tr>
<td>July</td>
<td>1.0%</td>
<td>0.05%</td>
<td></td>
</tr>
<tr>
<td>August</td>
<td>3.0%</td>
<td>1.0%</td>
<td>0.05%</td>
</tr>
<tr>
<td>September</td>
<td>1.0%</td>
<td>0.05%</td>
<td></td>
</tr>
<tr>
<td>Total</td>
<td>155.0%</td>
<td>155.0%</td>
<td>288.75%</td>
</tr>
</tbody>
</table>
7.3 Reviewing the methodology

The CRU has undertaken a review of the calculation multipliers and seasonal factors, considering the requirements of Art. 28 and the characteristics of the Irish gas market.

Firstly, it is apparent that the current interim multiplier for the quarterly product does not provide an appropriate incentive to network users. This is reflected in the lack of use of the quarterly capacity product. The CRU is proposing a quarterly multiplier of 1.35.

Secondly, the CRU examined two possible approaches to updating the multiplier/seasonal factor profile and presented these options to the NTLG.

The first approach is based on the current methodology employed by the CRU. It involves retaining the current seasonal profile spread with a reduction of the monthly multipliers so that their sum comes within the bounds of the 1.5 limit as set out in TAR NC. The effect of this approach on the multipliers is included in the table below.

<table>
<thead>
<tr>
<th>Month</th>
<th>Quarterly %</th>
<th>Monthly %</th>
<th>Daily %</th>
</tr>
</thead>
<tbody>
<tr>
<td>October</td>
<td>38.43%</td>
<td>12.81%</td>
<td>0.64%</td>
</tr>
<tr>
<td>November</td>
<td>12.81%</td>
<td>0.64%</td>
<td></td>
</tr>
<tr>
<td>December</td>
<td>17.08%</td>
<td>1.14%</td>
<td></td>
</tr>
<tr>
<td>January</td>
<td>80.69%</td>
<td>29.89%</td>
<td>1.99%</td>
</tr>
<tr>
<td>February</td>
<td>34.16%</td>
<td>2.28%</td>
<td></td>
</tr>
<tr>
<td>March</td>
<td>25.62%</td>
<td>1.71%</td>
<td></td>
</tr>
<tr>
<td>April</td>
<td>13.27%</td>
<td>12.81%</td>
<td>0.64%</td>
</tr>
<tr>
<td>May</td>
<td>0.97%</td>
<td>0.05%</td>
<td></td>
</tr>
<tr>
<td>June</td>
<td>0.97%</td>
<td>0.05%</td>
<td></td>
</tr>
<tr>
<td>July</td>
<td>2.61%</td>
<td>0.97%</td>
<td>0.05%</td>
</tr>
<tr>
<td>August</td>
<td>0.97%</td>
<td>0.05%</td>
<td></td>
</tr>
<tr>
<td>September</td>
<td>0.97%</td>
<td>0.05%</td>
<td></td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>135.0%</strong></td>
<td><strong>150.0%</strong></td>
<td><strong>278.44%</strong></td>
</tr>
</tbody>
</table>

The second approach involves deriving the multiplier/seasonal factor profile by applying the methodology which is set out within Art. 15 of TAR NC. The resulting monthly profile is presented in Figure 7.1 alongside the monthly multipliers calculated under approach one for comparison.

---

61 TAR NC requires that by 31 May 2019, multipliers for quarterly and monthly products are within 1.5 of the annual product and that the daily products are within 3 of the annual product.
The key difference between the two approaches is that average monthly forecasted flow data is used in the TAR NC approach (approach two), while the CRU’s methodology (approach one) is based on historic estimation of occurrence of peak flows. As gas demand in Ireland is relatively consistent throughout the year, the TAR NC methodology results in a much more muted seasonal profile. As the occurrence of peak flows has historically only ever occurred in non-summer months, the CRU methodology results in greater seasonal variation.

### 7.4 Proposed approach

The CRU has examined the multipliers and seasonal factors in the context of the principles set out in Art. 28 and the characteristics of the Irish gas market. Art. 28 also requires that the CRU considers the consultation responses before coming to a decision on both. It is also important to note that the Utility Regulator (UR) in NI have stated that it intends to maintain its policy of alignment with the ROI system’s multipliers/seasonal factors.62

As discussed, the CRU is proposing a quarterly multiplier of 1.35 and the reasons for this are elaborated on in the discussion below. The CRU requests input from stakeholders on what they believe to be an appropriate multiplier for the quarterly product.

---

62 Paragraph 7.14 UR Consultation on Harmonised Transmission Tariffs for Gas
With regard to the methodology, feedback from the NTLG participants indicated support for approach one, as there was not a desire to move significantly away from the current multipliers for non-yearly capacity products or to significantly alter the seasonal profile. Participants noted the potential for negative distributional effects resulting from more significant change. The CRU is also of the view that the current seasonal profile, in the context of the Irish system, is more consistent with the requirements of Art. 28, e.g. facilitating economic and efficient utilisation of the gas infrastructure and improving the cost-reflectivity of reserve prices given that peak winter demand periods are expected to be a key driver of GNI costs.

The CRU is proposing approach one having considered the NTLG feedback and the principles of Art. 28. However, having conducted additional analysis since the NTLGs the CRU is of the view that it may be appropriate to consider additional alterations in the context of the following, and the CRU requests that stakeholders take these points into account in their submissions:

- The CRU is considering whether a reduction in the variation of seasonal factors may be necessary to incentivise the use of shorter-term capacity products. It is possible that the higher cost of capacity in winter months combined with the multipliers for non-yearly capacity products is perversely increasing the use of annual capacity.
- A counterpoint to this could be that demand experienced across the year is relatively flat\(^{63}\). This could indicate that the current seasonal profile is incentivising efficient utilisation of the network.
- As the current interim multiplier for the quarterly product does not provide an appropriate incentive to network users the CRU is proposing a quarterly multiplier of 1.35. The introduction of a reduced multiplier for quarterly products will potentially reduce the cost for seasonal users of the network, by helping shippers optimise their capacity booking portfolios.
- TAR NC also includes a 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 in the case that ACER makes such a recommendation by 1 April 2021. NTLG participants noted that this change would be significant and that a transitional approach to a reduced daily multiplier would be preferred.
- As these topics come under Art. 28 they will be consulted on annually and thus is an area that the CRU will therefore keep under review. This provides the CRU the opportunity to employ a phased approach to any decisions and monitor the effects of any changes.

\(^{63}\) For example, there was only a reduction of 20% between the month with the maximum and minimum average daily allocation.
7.5 Request for comment

Parties are invited to comment on matters set out in this section, including the key proposals which relate to:

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 NC.

7B. The CRU is proposing to reduce the quarterly multiplier to 1.35.

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

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?

When responding, please provide your reasons for your views on the CRU’s proposals and propose alternatives with reasoning where you disagree with the CRU’s views.
8 Summary

Within Section 3 the CRU provided justification for its proposal to continue to implement a Matrix RPM, both in the context of the Irish gas market and TAR NC compliance. In Section 4, the CRU examined the components of Matrix RPM in detail and has proposed some alterations to the current Matrix RPM. In Section 5, the CRU considered entry points in the context of potential new supply via biogas injection and LNG. In Section 6, the CRU examined VRF and proposed an enduring tariff. Finally, in Section 7, the CRU proposed an update to the multipliers and seasonal factors.

In the Table 8.1 below, the CRU provides a summary of the questions the CRU has posed in this consultation paper.

Based on the proposals outlined in this paper the CRU has provided, in Appendix C, a table of the indicative reference prices under Scenario 1, alongside the current reference prices in gas year 2018/19. A full list of the indicative reference prices under each scenario is available in the ‘All Results’ tab of the RPM excel workbook (CRU/18/247a).

8.1 Request for comment

<table>
<thead>
<tr>
<th>Topic</th>
<th>Query</th>
<th>Section</th>
</tr>
</thead>
<tbody>
<tr>
<td>Proposed RPM</td>
<td>3A. What are your views on the CRU’s proposal to continue to apply the Matrix RPM?</td>
<td>3</td>
</tr>
<tr>
<td>Shrinkage</td>
<td>4A. 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 through a separate flow-based charge? Also, what are your views on a date of implementation of gas year 2019/20?</td>
<td>4.4</td>
</tr>
<tr>
<td>Entry/exit split</td>
<td>4B. What are your views on the CRU’s proposal to continue to apply a 33:67 entry/exit split?</td>
<td>4.5</td>
</tr>
<tr>
<td>Capacity/commodity split</td>
<td>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?</td>
<td>4.6</td>
</tr>
<tr>
<td>Expansion constants and annuitisation factors</td>
<td>4D. What are your views on the CRU’s proposal to update these components of the Matrix RPM?</td>
<td>4.6 &amp; 4.7</td>
</tr>
<tr>
<td>Discounts LNG</td>
<td>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?</td>
<td>5.2</td>
</tr>
</tbody>
</table>
### 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?  
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?

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

### 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.  
7B. What are your views on the CRU’s proposal to reduce the quarterly multiplier to 1.35?  
7C. Should a reduction in the range of seasonal factors be considered?  
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?

### 8.2 Next steps

The CRU will consider responses from stakeholders on the above and all aspects of the tariff structure before coming to a decision on the tariff structure that will apply for the upcoming gas year 2019/20 and into the future.

The following are the milestones that follow the publication of this consultation:

- Two-month consultation period i.e. deadline for responses is close of business 11 February 2019
- CRU publication of the responses received by 11 March 2019
- ACER publication of evaluation of the consultation by 11 April 2019
- CRU decision paper on tariff structure published by 11 May 2019

---

64 The ACER evaluation will be published at the following clickable link.
1 Annex

1.1 Application of discounts in the Matrix RPM

This section considers how a discount is applied in the proposed Matrix RPM. Art. 6.4(c) states that rescaling (i.e. application of secondary adjustment to all entry points to recover GNI’s transmission services revenue) is applied to all entry or exit points, or both. In the proposed Matrix RPM discounts are applied to the reference prices, following this step additive rescaling is applied to all entry points to recover any revenue shortfall due to the provision of a discount. This rescaling retains the same relative discount as before the rescaling. Consider the example provided in Figure 1.1 below for a further explanation.

In this example and in the CRU’s proposed Matrix RPM the additive rescaling approach has been applied. The CRU is proposing to continue this approach. Participants at the NTLG requested that the effect of a multiplicative approach be examined and subsequently the application of a multiplicative approach was modelled by GNI, with its effect presented at the third NTLG.  

An assessment of the effect of additive and multiplicative rescaling was examined at the third NTLG, which can be found on slide number 21 of the NTLG 3 slides (CRU/18/247b).

---

Figure 1.1: Application of entry point discount

<table>
<thead>
<tr>
<th>Pre-discount</th>
<th>50% discount applied to one point</th>
<th>Revenue shortfall recovered by rescaling – retaining the relative discount</th>
</tr>
</thead>
<tbody>
<tr>
<td><img src="image1.png" alt="Diagram" /></td>
<td><img src="image2.png" alt="Diagram" /></td>
<td><img src="image3.png" alt="Diagram" /></td>
</tr>
</tbody>
</table>

Imagine a network with two entry points, both of which have the same tariff of €10/MWh and both supply the system with 10MWh (20MWh total system demand). The TSO’s allowed entry revenue is €200.

It is decided that a 50% discount should be applied to entry point 1, which reduces the tariff at this point to €5/MWh. However, this results in a revenue shortfall for the TSO of €50 (10MWh* €5/MWh + 10MWh* €10/MWh = €150).

The €50 revenue shortfall must then be recovered from all entry points, however the relative discount needs to be retained. This results in an additional ~€16.7 to be recovered from the discounted point and ~€33.3 from the other point.

This results in the tariff at entry point 1 rising to ~€6.7/MWh and the tariff at entry point 2 rising to ~€13.4/MWh (10MWh* ~€6.7/MWh + 10MWh* ~€13.4/MWh = ~€200).

Note that the discounted tariff at entry point 1 is now €6.7/MWh, which is 50% of the original tariff of €10/MWh. However, the tariff of ~€6.7/MWh at entry point 1 is discounted by 50% relative to the tariff of ~€13.4/MWh at entry point 2.
1.2 Payable price approach

The reserve price is used to auction capacity products. TAR NC allows for the option to set the reserve price as either a floating payable price or a fixed payable price.

In a floating payable price approach, if the user books annual capacity for more than one tariff year, it will not know reserve price it will have to pay for the following gas year until it is published (in Ireland the gas year and tariff year are aligned). This means that all users pay the same reserve price in the same gas year, regardless of when the annual capacity was booked.

In a fixed payable price approach, a user may book annual capacity for more than one gas year and pay the year one reserve price in all other years (subject to adjustment through a published indexation and risk premium), even if the reserve price changes in later years. Therefore, different network users could be paying different prices depending on when they booked capacity.

In Ireland the floating payable price approach is used, and the CRU is proposing to continue to apply this approach as the risk of a change in GNI’s revenues is shared evenly between all network users. This approach is also more cost-reflective as the reserve price paid by a user in any year reflects the transmission services revenue of GNI in that year.

1.3 Annuitisation factor

A detailed outline of the updates made to the annuitisation factor since its original calculation in 2015 are given below, with the calculation itself available in CRU/18/247f/.

**WACC**

As explained above, the WACC is the rate of return that GNI may earn on its assets during a price-control period. In 2015 the annuitisation factor was calculated based on the WACC for PC3 of 5.2%. In the proposed model, the calculations have been updated so that they are based on the PC4 WACC of 4.63%.

**Pipeline capex**

As in the 2015 model, pipeline capex is defined as the average cost of the 200km wet pipelines and the wet expansion constant is employed to calculate this cost. The fact that the wet expansion constant has been updated to reflect 2018 prices, has therefore caused the capex for the average subsea pipeline to increase in the proposed model- from c. €338m to c. €340m. This capex is assumed to depreciate over 50 years, giving annual depreciation costs of c. €6.8m.

**Pipeline opex**

In the 2015 model, direct annual pipeline opex was calculated to be 1.2% of the initial pipeline capex. This calculation was based on data from the PC3 decision. In the proposed model, this percentage reflects PC4 allowances and results in a new figure of 1.35%. This higher percentage
value, coupled with slightly higher initial capex due to indexation, has caused the yearly pipeline opex to rise by roughly €0.5m in the proposed model, from c. €4.06m to c. €4.6m.

**Compressor capex**

As compressor capex is also calculated based on the wet expansion constant, the 2018 index of costs for the wet expansion constant has caused compressor capex to increase slightly, to c. €54.2million in the proposed model. As in 2015, compressor capex is assumed to depreciate over 25 years. The cost of a new compressor in year 26 is incorporated, in present value terms, into the total capex amount to be recovered. The lower WACC has resulted in a higher present value of this capex: year 26 compressor capex is c. €16.7m in the proposed model, versus c. €14.5m in the 2015 model.

The result is a yearly depreciation cost of roughly c. €2.2.

**Compressor opex**

Similar to pipeline opex, direct annual compressor opex (excluding fuel costs) is calculated as a percentage of the initial compressor capex. In the 2015 model, annual compressor opex was calculated to be 6.1% of the initial compressor capex, based on data from the PC3 decision. In the proposed model, the compressor opex calculation has been updated so that it is based on revenue allowances for the PC4 period. This results in a lower annual compressor opex figure of 4.88% of the initial capex. Largely because of this percentage decrease, annual compressor opex is c. €2.64m in the proposed model, compared with c. €3.3m in 2015.

**Fuel costs**

Fuel costs reflect gas that is used to power the compressors. This is based on a number of factors such as the average utilisation of the compressors over the last 5 years and the efficiency of the gas turbines that drive the compressors. These result in a MWh of gas figure, which is required to provide motive power to the compressor stations. The price of this gas is calculated based on the monthly average price of gas together with average exchange rates over the same five-year period.

In the proposed model, GNI have updated the data on gas prices and exchange rates and the data now spans the period October 2013 to September 2018.

Data on compressor fuel consumption is used to calculate the average utilisation of the compressors and GNI have updated the data on compressor fuel consumption so that it spans the period January 2013 to December 2017 (previously January 2010 to December 2014). Comparing these two periods, average utilisation of the Beattock Compressor was 13% higher in the period ending December 2017, while average utilisation of the Brighouse Bay Compressor
was 12% lower. Total average utilisation of both compressors was 1% higher in the period ending December 2017, compared with the period ending December 2014.

Lower gas prices in the new data ranges were largely responsible for the drop in annual fuel costs from c. €10.8m in the 2015 model, to c. €9.7m in the proposed model.

Summary

CRU have undertaken a review of the calculation of the annuitisation factor and updated the components to reflect the latest data. The change which has had the most significant effect is the update to the WACC from 5.2% to 4.63% to reflect the CRU’s PC4 decision. As a result of the proposed updates, the annuitisation factor has reduced to 9.8% from 10.5%.
Appendix A – Cost Allocation Assessments

Article 5 of TAR NC requires that cost allocation assessments are carried out as part of the consultation and these assessments are included in this appendix. The cost allocation assessments aim to evaluate whether any cross subsidisation occurs between intra-system and cross-system network use based on the proposed reference price methodology. There are two assessments, one relating to capacity-based transmission tariffs and one relating to commodity-based transmission tariffs. In the case that assessments indicate that the degree of cross-subsidisation is greater than 10%, the CRU is required to provide a justification.

As there are no transit flows via the ROI transmission network, there is no possibility of cross-subsidisation occurring between intra-system and cross-system network users. Nonetheless as it is required as part of Art. 5 the CRU has presented the results of the cost allocation assessments below.

The cost allocation assessment relating to capacity-based transmission tariffs is based on the cost drivers of forecasted contracted capacity and distance as these are the cost drivers that underpin the Matrix RPM. The cost allocation assessment relating to commodity-based transmission tariffs is based on the cost driver of forecasted amount of gas flows. The data used in the cost allocation assessments is forecasted for the gas year 2019/20.

The results, the components and the details of the components for the cost allocation assessments relating to the transmission services revenue to be recovered by capacity-based transmission tariffs and commodity-based transmission tariffs respectively are presented in Figure 0.1 and Figure 0.2 below.

The formula does not provide for zero cross-system flows and as such the result is not applicable.
### Figure 0.1: Capacity cost allocation assessment

<table>
<thead>
<tr>
<th></th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capacity revenue (€)</td>
<td>163,762,801</td>
</tr>
<tr>
<td>Entry share</td>
<td>33%</td>
</tr>
<tr>
<td>Exit share</td>
<td>67%</td>
</tr>
<tr>
<td>Entry revenues (€)</td>
<td>54,041,658</td>
</tr>
<tr>
<td>Exit revenues (€)</td>
<td>109,720,943</td>
</tr>
<tr>
<td>Entry revenues dedicated for Intra</td>
<td>54,041,658</td>
</tr>
<tr>
<td>Exit revenues dedicated for Cross</td>
<td>0</td>
</tr>
<tr>
<td>Exit revenues from Intra</td>
<td>109,720,943</td>
</tr>
<tr>
<td>Exit revenues from Cross</td>
<td>0</td>
</tr>
<tr>
<td>Revenue for Intra</td>
<td>163,762,801</td>
</tr>
<tr>
<td>Revenue for Cross</td>
<td>0</td>
</tr>
</tbody>
</table>

| Cost driver for Entry Intra | 83,991,401 |
| Cost driver for Exit Intra  | 96,574,979  |
| Cost driver for Intra       | 180,566,380 |
| Cost driver for Entry Cross | 0           |
| Cost driver for Exit Cross  | 0           |
| Cost driver for Cross       | 0           |

<table>
<thead>
<tr>
<th></th>
<th>TEST</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ratio intra</td>
<td>0.9069</td>
</tr>
<tr>
<td>Ratio cross</td>
<td>n/a</td>
</tr>
<tr>
<td>CAA</td>
<td>n/a</td>
</tr>
</tbody>
</table>

### Figure 0.2: Commodity cost allocation assessment

<table>
<thead>
<tr>
<th></th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Commodity revenue (€)</td>
<td>18,195,845</td>
</tr>
<tr>
<td>Entry share</td>
<td>33%</td>
</tr>
<tr>
<td>Exit share</td>
<td>67%</td>
</tr>
<tr>
<td>Entry revenues (€)</td>
<td>6,004,629</td>
</tr>
<tr>
<td>Exit revenues (€)</td>
<td>12,191,216</td>
</tr>
<tr>
<td>Entry revenues dedicated for Intra</td>
<td>6,004,629</td>
</tr>
<tr>
<td>Exit revenues dedicated for Cross</td>
<td>0</td>
</tr>
<tr>
<td>Exit revenues from Intra</td>
<td>12,191,216</td>
</tr>
<tr>
<td>Exit revenues from Cross</td>
<td>0</td>
</tr>
<tr>
<td>Revenue for Intra</td>
<td>18,195,845</td>
</tr>
<tr>
<td>Revenue for Cross</td>
<td>0</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th>TEST</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ratio intra</td>
<td>0.1610</td>
</tr>
<tr>
<td>Ratio cross</td>
<td>n/a</td>
</tr>
<tr>
<td>CAA</td>
<td>n/a</td>
</tr>
</tbody>
</table>
## Appendix B – NTLG Participants

<table>
<thead>
<tr>
<th>Organisation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Aughinish Alumina</td>
</tr>
<tr>
<td>Bord Gáis Energy</td>
</tr>
<tr>
<td>Bord na Mona</td>
</tr>
<tr>
<td>CRU</td>
</tr>
<tr>
<td>Electric Ireland</td>
</tr>
<tr>
<td>ElectroRoute</td>
</tr>
<tr>
<td>Energia</td>
</tr>
<tr>
<td>Equinor</td>
</tr>
<tr>
<td>ESB</td>
</tr>
<tr>
<td>Flogas</td>
</tr>
<tr>
<td>GNI</td>
</tr>
<tr>
<td>IBEC</td>
</tr>
<tr>
<td>IOOA</td>
</tr>
<tr>
<td>Manx Utilities</td>
</tr>
<tr>
<td>Naturgy</td>
</tr>
<tr>
<td>Nephin Energy</td>
</tr>
<tr>
<td>Next Decade</td>
</tr>
<tr>
<td>Ormonde Organics</td>
</tr>
<tr>
<td>Pardus</td>
</tr>
<tr>
<td>Predator Oil &amp; Gas</td>
</tr>
<tr>
<td>Renewable Gas Forum Ireland</td>
</tr>
<tr>
<td>Shannon LNG</td>
</tr>
<tr>
<td>Shell</td>
</tr>
<tr>
<td>SSE</td>
</tr>
<tr>
<td>Tynagh Energy</td>
</tr>
<tr>
<td>Vermilion</td>
</tr>
</tbody>
</table>
## Appendix C – Indicative Reference Prices €/MWh

The information above is a table of the indicative reference prices under scenario 1 and these prices are based on the proposals outlined in this paper and may therefore be subject to change.

### Indicative Transmission Reference Prices - Scenario 1

<table>
<thead>
<tr>
<th></th>
<th>2019/20</th>
<th>% Change</th>
<th>2020/21</th>
<th>2021/22</th>
<th>2022/23</th>
<th>2023/24</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Domestic Exit</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>capacity</td>
<td>€ 18/19 monies</td>
<td>410.451</td>
<td>5.0%</td>
<td>431.004</td>
<td>429.918</td>
<td>422.419</td>
</tr>
<tr>
<td>commodity</td>
<td></td>
<td>0.236</td>
<td>0.5%</td>
<td>0.244</td>
<td>0.241</td>
<td>0.235</td>
</tr>
<tr>
<td><strong>Gormanston Exit</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>capacity</td>
<td>€ 18/19 monies</td>
<td>388.093</td>
<td>-0.5%</td>
<td>408.653</td>
<td>407.577</td>
<td>400.083</td>
</tr>
<tr>
<td>commodity</td>
<td></td>
<td>0.236</td>
<td>0.5%</td>
<td>0.244</td>
<td>0.241</td>
<td>0.235</td>
</tr>
<tr>
<td><strong>Moffat VRF Exit</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>capacity*</td>
<td></td>
<td>272.277</td>
<td>n/a</td>
<td>282.968</td>
<td>282.409</td>
<td>278.512</td>
</tr>
<tr>
<td>commodity</td>
<td></td>
<td>0.113</td>
<td>n/a</td>
<td>0.117</td>
<td>0.117</td>
<td>0.113</td>
</tr>
<tr>
<td><strong>Moffat Entry</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>capacity</td>
<td>€ 18/19 monies</td>
<td>310.818</td>
<td>-4.9%</td>
<td>305.025</td>
<td>299.630</td>
<td>291.425</td>
</tr>
<tr>
<td>commodity</td>
<td></td>
<td>0.113</td>
<td>0.3%</td>
<td>0.117</td>
<td>0.117</td>
<td>0.113</td>
</tr>
<tr>
<td><strong>Bellanaboy Entry</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>capacity</td>
<td>€ 18/19 monies</td>
<td>629.595</td>
<td>-0.1%</td>
<td>623.802</td>
<td>618.407</td>
<td>610.202</td>
</tr>
<tr>
<td>commodity</td>
<td></td>
<td>0.113</td>
<td>0.3%</td>
<td>0.117</td>
<td>0.117</td>
<td>0.113</td>
</tr>
<tr>
<td><strong>Biogas Entry</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>capacity**</td>
<td></td>
<td>108.698</td>
<td>n/a</td>
<td>102.905</td>
<td>97.510</td>
<td>89.304</td>
</tr>
<tr>
<td>commodity</td>
<td></td>
<td>0.113</td>
<td>n/a</td>
<td>0.117</td>
<td>0.117</td>
<td>0.113</td>
</tr>
<tr>
<td><strong>Inch Entry</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>capacity</td>
<td></td>
<td>122.324</td>
<td>-0.9%</td>
<td>n/a</td>
<td>n/a</td>
<td>n/a</td>
</tr>
<tr>
<td>commodity</td>
<td></td>
<td>0.113</td>
<td>0.3%</td>
<td>n/a</td>
<td>n/a</td>
<td>n/a</td>
</tr>
<tr>
<td><strong>Gormanston VRF Entry</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>capacity*</td>
<td></td>
<td>76.849</td>
<td>n/a</td>
<td>72.098</td>
<td>67.674</td>
<td>60.946</td>
</tr>
<tr>
<td>commodity</td>
<td></td>
<td>0.113</td>
<td>n/a</td>
<td>0.117</td>
<td>0.117</td>
<td>0.113</td>
</tr>
</tbody>
</table>

### Illustrative Transmission Transportation Costs

<p>| | | | | | | | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Transmission Transportation Cost of UK Gas</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>capacity</td>
<td>€</td>
<td>721.269</td>
<td>0.7%</td>
<td>736.029</td>
<td>729.548</td>
<td>713.844</td>
<td>692.776</td>
</tr>
<tr>
<td>commodity</td>
<td></td>
<td>0.350</td>
<td>0.4%</td>
<td>0.361</td>
<td>0.358</td>
<td>0.349</td>
<td>0.335</td>
</tr>
<tr>
<td><strong>Transmission Transportation Cost of Bellanaboy Gas</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>capacity</td>
<td>€</td>
<td>1,040.046</td>
<td>1.9%</td>
<td>1,054.806</td>
<td>1,048.326</td>
<td>1,032.621</td>
<td>1,011.553</td>
</tr>
<tr>
<td>commodity</td>
<td></td>
<td>0.350</td>
<td>0.4%</td>
<td>0.361</td>
<td>0.358</td>
<td>0.349</td>
<td>0.335</td>
</tr>
<tr>
<td><strong>Transmission Transportation Cost of Biogas Gas</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>capacity</td>
<td>€</td>
<td>519.149</td>
<td>n/a</td>
<td>533.908</td>
<td>527.428</td>
<td>511.724</td>
<td>490.656</td>
</tr>
<tr>
<td>commodity</td>
<td></td>
<td>0.350</td>
<td>n/a</td>
<td>0.361</td>
<td>0.358</td>
<td>0.349</td>
<td>0.335</td>
</tr>
<tr>
<td><strong>Transmission Transportation Cost of Inch Gas</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>capacity</td>
<td>€</td>
<td>532.775</td>
<td>3.6%</td>
<td>n/a</td>
<td>n/a</td>
<td>n/a</td>
<td>n/a</td>
</tr>
<tr>
<td>commodity</td>
<td></td>
<td>0.350</td>
<td>0.4%</td>
<td>n/a</td>
<td>n/a</td>
<td>n/a</td>
<td>n/a</td>
</tr>
</tbody>
</table>

Note: * Multipliers/seasonal factors to be applied to derive daily tariff. ** Based on approach one in Section 5.3.1.
The forecast overall increase in the transmission cost of UK gas\textsuperscript{66} in the year 2019/20 is due to the inclusion of shrinkage costs into the allowed revenue. However, much of this upward pressure on tariffs is significantly offset by both the increased demands as a whole and the greater proportion of supply from the Moffat entry point. In terms of overall costs these proposals should not lead to an increase in costs for shippers as the upward pressure placed on tariffs by the shrinkage proposal should be offset by the removal of separate shrinkage charges outside of the transmission services revenue.

The indicative reference prices are forecast to decrease over the period in Scenario 1 as the trends noted above that place downward pressure on tariffs continue.

\textsuperscript{66} Moffat entry charge + domestic exit charge.