An Coimisiún um Rialáil Fóntas

Commission for Regulation of Utilities

Gas Transmission Tariffs Article 30 Tariff Network Code Information 2019/20

Information Paper

Information Paper

Reference:	CRU/19/111	**Date Published:**	18/09/2019	**Closing Date:**	n/a

The Exchange, Belgard Square North, Tallaght, Dublin 24, Ireland
T +353 1 4000 800 | **F** +353 1 4000 850 | **www.cru.ie**

Executive Summary

In June 2019, the Commission for Regulation of Utilities (CRU) reviewed and published a decision on transmission tariffs for the gas year 2019/20. The gas year runs from 1 October 2019 to 30 September 2020. The approved tariffs will reduce the cost of gas transmission. For example, the cost of moving gas from Great Britain (GB) to the Republic of Ireland (RoI) will reduce in nominal terms by c.6.5% (versus current rates). This reduction in network tariff is estimated to have a small impact on residential gas customers' annual bill (a circa 0.48% or €3.65 decrease).

The CRU published its decision on the 2019/20 transmission tariffs in CRU/19/061. That document was published one month in advance of gas capacity auctions that were held in July 2019. Its publication was required under the Tariff Network Code[1] (TAR NC), specifically Article 29.

Article 30 of the TAR NC sets out further detailed information that must be published prior to the tariffs coming into force in October. This paper sets out the required information and also provides additional information with the aim of making it a useful guide for transmission tariffs. The document includes:

- an introduction to the methodology used to calculate the tariffs;
- an introduction to how the CRU sets Gas Network Ireland's (GNI) allowed revenue;
- a description of the annual process that the CRU follows to update GNI's allowed revenues;
- information required under Article 30 of TAR NC, containing:
    - detail on elements of the CRU's Allowed Revenue methodology;
    - detail on the parameters within GNI's tariff model; and,
    - other additional information used either directly or indirectly to calculate GNI's allowed revenue and the transmission tariffs.
- the variables that cause changes in the tariffs from one year to the next; and,

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

- the transmission tariffs for the gas year 2019/20

A simplified transmission tariff model is also being published alongside this paper. The model is available at the following link. Users can change the inputs into this model to try and estimate possible impacts of different scenarios on tariffs. As it is a simplified model, developed for ease of use and interpretation, it can only provide broad indications of tariff movements. It should not be relied upon for business decisions but rather should be used as a useful guide to further understand how tariffs may possibly react under different scenarios.

Public Impact Statement

Customers pay transmission tariff costs through their gas bill. They account for approximately 7%. It is important that the calculation of those costs are transparent, accessible and publicly available.

Gas transmission tariffs are set to reduce on 1 October 2019. This reduction was set out in an earlier publication in June of this year (CRU/19/061) and is estimated to reduce a residential gas customer's annual bill by just under half a percent or approximately €3.65 in a year.

This document provides further details on transmission tariffs and aims to create a single resource for all gas transmission tariff related information such as; (1) details of the tariff model that is used to calculate tariffs, (2) the process that the CRU follows in updating tariffs, and (3) how the CRU sets the allowed revenue for Gas Networks Ireland (GNI). This paper aims to assist customers in understanding how tariffs are calculated and what causes them to change from one year to the next.

Table of Contents

Glossary of Terms and Abbreviations

Abbreviation or Term	Definition or Meaning
AGI	Above Ground Installation
Capex	Capital expenditure
CAPM	Capital Asset Pricing Model
CNG	Compressed Natural Gas
CRU	Commission for Regulation of Utilities
DM	Daily Metered
EWIC	East West Interconnector
GNI	Gas Networks Ireland
GCS	Generation Capacity Statement
HICP	Harmonised Index of Consumer Prices
I/C	Industrial & Commercial
IP	Interconnection Point
LDM	Large Daily Metered
LRMC	Long Run Marginal Costs
NDM	Non-Daily Metered
Opex	Operating expenditure
RAB	Regulated Asset Base
RNG	Renewable Natural Gas
RPM	Reference Price Methodology
TSO	Transmission System Operator
VRF	Virtual Reverse Flow
WACC	Weighted Average Cost of Capital

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. The CRU's mission is to regulate water, energy and energy safety in the public interest.

Further information on the CRU's role and relevant legislation can be found on the CRU's website at www.cru.ie .

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.

In line with these powers the CRU published a decision on GNI's allowed revenues and transmission tariffs that will apply from 01 October 2019 to 30 September 2020[2], the CRU is now publishing additional information related to the calculation of allowed revenues and transmission tariffs, in accordance with Article 30 of the Network Code on rules regarding harmonised transmission tariff structures for gas (TAR NC)[1].

1.2 Purpose of the Paper

The purpose of this paper is to create a single resource for all tariff related information such as; (1) how the CRU sets tariffs on an annual basis, (2) the tariff methodology used, (3) the variables that cause changes in the tariffs from one year to the next and (4) the transmission tariffs for the gas year 2019/20 (published in CRU19061). The CRU has carried out this exercise in order to provide customers with tariff related information in the most transparent and easily accessible manner.

[2] Gas Networks Ireland Transmission Tariffs and Allowed Revenue 2019/20 – Information note CRU19061 .

1.3 Related Documents

Over the years there has been a large volume of tariff documentation published. The list below provides a handy list of transmission tariff documents published over the last few years.

- CRU Transmission Revenue Model 2019/20 (CRU/19/061a)
- CRU Distribution Revenue Model 2019/20 (CRU/19/062a)
- GNI's Simplified Transmission Tariff Matrix Model
- CRU Corrib Linkline Model (CRU/19/061a)
- Decision on October 2017 to September 2022 Transmission Revenue for Gas Networks Ireland (CER/17/260)
- Gas Networks Ireland Transmission Tariffs and Allowed Revenue 2019/20 – Information note CRU19061
- Gas Networks Ireland Distribution Tariffs and Allowed Revenue 2019/20 – Information note CRU19062
- Decision on Harmonised Transmission Tariff Methodology for Gas CRU/19/060
- Establishing a Network Code on Harmonised Transmission Tariff Structures for Gas (Commission Regulation (EU) 2017/460)

1.4 Structure of the Paper

This information paper is structured as follows:

- Section 1 provides background as to the Irish transmission system and how transmission tariffs are calculated;
- Section 2 outlines the way by which tariffs are updated and how the CRU updates allowed revenues on an annual basis;
- Section 3 provides specific information required by Article 30 of the TAR NC; and
- Section 4 sets out the transmission tariffs for 2019/20 as published in CRU/19/061.

2 Irish Transmission Network

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 summary of the key economic and technical characteristics of the Irish gas transmission system, an outline of the reference price methodology[3] (RPM) (Matrix methodology) and the parameters used within the Matrix methodology.

2.2 Irish Transmission Network

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 1 for a map of the Republic of Ireland (ROI) transmission system. The offshore portion of the network consists of the two gas interconnectors (IC1 and IC2) that connect Ireland to Brighouse Bay, Scotland. There is a sub-sea offtake point from IC2 that supplies the Isle of Man depicted in Figure 1.

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 the Corrib gas field enters the Irish transmission system. The addition of the Corrib entry point at the end of 2015, brought 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 gas transmission system at Gormanston. However, no commercial gas currently flows to NI from the ROI system and this pipe is used for emergency support only. In the event that commercial flows to

[3] Reference Price Methodology (RPM) is 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.

Northern Ireland (NI) did occur the Gormanston IP could also become an entry point for virtual reverse flow (VRF) from the NI system to the ROI system.

Figure 1 Gas Network Ireland's transmission system

2.3 Transmission Tariff Methodology for Gas

Last year, in line the European network code on harmonised transmission tariff structures for gas (TAR NC)[4], the CRU commenced a reviewed of the methodology for calculating transmission tariffs for gas. The aim of the TAR NC was to overcome

[4] Establishing a network code on harmonised transmission tariff structures for gas (Commission Regulation (EU) 2017/460).

issues relating to Member States using different approaches to tariff setting for gas transmission services which could add to the complexity of using the various transmission systems. As part of the tariff methodology review process, the CRU held a number of industry stakeholder workshops and published a consultation paper which set out key proposals and invited comments from interested parties. In June 2019, the CRU set out its decision in CRU/19/060. A key component of that paper was the CRU's decision to continue to calculate transmission tariffs using a forward-looking Matrix RPM, also referred to as the Matrix model. This Matrix model was used to set the tariffs for the 2019/20 gas year. In accordance with Article 30 a simplified version of this Transmission Tariff Model is available alongside this information paper, at the following link. Some of the key inputs to this methodology are highlighted in Table 4.1.

2.4 Parameters used in the Matrix Methodology

In accordance with Art. 30 (1)(a)(i) of the TAR NC, this section includes information on parameters used in the Matrix RPM that relate to the technical characteristics of the transmission system.

The Matrix RPM is a forward-looking methodology based on long run marginal costs (LRMC). 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. The same approach is applied at exit.

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 €/GigaWatt hour/day/kilometre (€/G/h/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.

The wet expansion constant is €8,783 per GigaWatt/day/kilometre, and the dry is €7,810 per Gigawatt/day/kilometre. See CRU/18/247 sections 4.7 & 4.8 for further information on expansion constants and annuitisation factors. Table 2.1 below outlines further details required under Article 30 of the TAR NC relating to the parameters used with the Matrix model.

Table 2.1 Parameters used in the reference price methodology

TAR NC Article	Description	Detail
Art. 30(a)(i)	Technical capacity at entry and exit points	The technical capacity at the entry points to the transmission network is available on GNI's transparency dashboard, available at the following link. However, it should be noted that the technical capacity at entry and exit points of the transmission network is not a relevant variable for the purpose of the methodology of calculation of the transmission tariffs.
Art. 30(a)(ii)	Forecasted contracted capacity at entry and exit points	The forecasted contracted capacity at the entry points and at exit [1] is available in Table 2.2. The assumptions underlying the calculation of forecasted contracted capacity are detailed in Table 3.2.
Art. 30(a)(iii)	Quantity and direction of the gas flow for entry and exit points	Demand is assumed to be met first by domestic production (i.e. Bellanaboy and Inch), with Moffat providing the marginal source of gas. The direction of gas flow from entry to exit is not a variable in the Matrix RPM that effects the calculation of the transmission tariffs. However, a representation of how gas flows around the network is available on GNI's transparency dashboard, available at the following link.

TAR NC Article	Description	Detail
Art. 30(a)(iv)	Structural representation of the transmission network	The structural representation of the GNI's transmission system is provided in Figure 1.
Art. 30(a)(v)	Additional technical information related to the transmission system, such as length and diameter of pipelines	The information involved in the calculation of the expansion constants and annuitisation factor has been provided in CRU/18/247. The files which detail the calculation of these parameters are available for download at the following link.

3 Tariff Setting Process

3.1 Introduction

This section outlines how the CRU sets GNI's allowed transmission revenue every 5 years through a process known as a Price Control. It also details the process followed by the CRU in setting the transmission tariffs on an annual basis. By charging these tariffs GNI recovers its allowed revenue, as approved by the CRU.

3.2 Price Control

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 and which is carried out every 5-years. The current 5-year period started on 01 October 2017 (PC4). A Price Control sets out the allowed revenue for the 5 year period to ensure that GNI can operate, maintain and invest in the network effectively.

The transmission business's allowed revenue is made up of three parts:

i. Revenue to cover the transmission business's operational costs;

ii. A return on capital on the transmission business's assets; and,

iii. Revenue to cover depreciation of the transmission business's assets.

In August 2017, the CRU published its decision paper (CER/17/260) on the allowed revenue that GNI's transmission business may recover over the Price Control period from 01 October 2017 to 30 September 2022. That decision allowed €924m to be recovered for transmission over the 5-year period.

GNI as the transmission network operator, then recovers this allowed revenue on an annual basis through network tariffs which are set by the CRU. Network tariffs are charged to gas suppliers who may choose to pass them on to their customers.

3.3 Annual tariff setting process

As part of the annual tariff setting process, the CRU analyses any additional revenue requests from GNI (pass-through costs and extra-over items), over/under recoveries in the previous years and updated demand projections. These items are now discussed.

3.3.1 Pass-through costs

Each year GNI send a tariff submission to the CRU. This submission includes requests for additional revenues which are considered either pass-through costs or extra-over items. Pass-through costs are costs which GNI has no control over (e.g. CO_2) or has limited control over (e.g. local authority rates). For the gas year 2019/20 the CRU decided (refer to CRU19061) to allow GNI an allowance of c.€0.2m for CO_2 and c.€1.39m for rates as transmission pass-through costs.

3.3.2 Extra-Over Items

Extra-over items are items that were not foreseen at the time of the Price Control – in this instance as part of Price Control 4 (CER/17/260) which was published in 2017. The CRU carries out a through review of these costs. GNI did not seek any transmission extra-over items for 2019/20.

3.3.3 Correction Factor (or K-Factor)

As transmission tariffs are calculated in advance, we must use forecast data i.e. forecast inflation, revenues and pass-through costs. However, once actuals are available, we carry out an adjustment to take those into account. This is called a Correction Factor or K-Factor adjustment. The K-Factor is for 2 years previous as that is when the actual data is available i.e. when setting the tariffs for 2019/20 the CRU closes out the year 2017/18. The formula for the K-Factor is set out in CER/03/170.

By way of explanation there are two rules to the formula:

1. Any over-recovery in excess of 105% of allowed revenues is returned in the following gas year e.g. any 2017/18 k-factor >105% is returned in gas year 2020/21 not gas year 2019/20. This is to ensure that the tariffs are stable and that volatility is avoided.

2. Any over- or under-recovery of revenue attracts an interest rate of Euribor (interbank lending rate) +2%. Any over-recovery in excess of 103% of revenue attracts an interest rate of Euribor +4%. This is to incentivise GNI to make accurate forecasts of demand and new customer connections.

The transmission K-Factor for 2019/20 tariffs is a **c**.€21m give-back. This over-recovery relates to a 2017/18 allowed revenue variance (c.€15.51m), pass-through costs (c.€3.38m), inflation (c.€0.81m) and interest costs (c.€1.01m). As noted above, any over-recovery in excess of 105% of allowed revenues is returned in the following gas year. As the amount of money to be given back through the k-factor exceeds the 105% rule, €9.2m will be returned in 2019/20 and the remainder will be returned in 2020/21.

In addition to the 2017/18 k-factor, c.€4m is being accrued to customers this year as part of the CRU's decision to spread out the 2016/17 over-recovery over the remainder of PC4.

3.3.4 Demand Projections

In addition to information relating to expenditure, demand projections are also estimated through the Price Control process for each of the five years of the Price Control period. As part of the annual tariff setting process GNI submits updated demand figures which take into consideration the latest forecasts. These are reviewed and are used in setting the transmission tariffs.

3.3.4.1 Assumptions

The forecast demands for 2019/20 are based on the assumptions outlined in Table 3.1. These assumptions influence the demands forecasted at the Entry Points to the transmission system and at the Exit from the transmission system.

Table 3.1: Demand assumptions

Assumption	Description
Weighted Annualised Capacity Bookings	It is anticipated that shippers will continue to optimise their capacity bookings via a mixture of annual and short-term capacity products. This applies to the Large Daily Metered (LDM) and Daily Metered (DM) sectors[5]. Short-term capacity forecasts are weighted depending on the month when the booking is expected to arise. For example, if you buy a short-term capacity product in August it is cheaper than buying a short-term capacity product February. This is due to a lower multiplier being applied. These multipliers are set out in Section 5.1. The value of these capacity products is converted into an annual value. In this way the forecast bookings are "annualised".[6]
Power generation	GNI's demand assumptions are based on Eirgrid's 2018-2027 Generation Capacity Statement (GCS) published in October, 2018. Power demand is based on Eirgrid's Median Electricity Demand scenario. The Power sector is expected to increase capacity bookings relative to the 2018/19 tariff demands due to overall growth in the electricity sector. In addition, overall electricity demand can be expected to be higher in 2019/20 due to forecasted increased economic activity.
Daily Metered (DM) Industrial & Commercial (I/C)	The LDM & DM sector is expected to increase capacity bookings relative to the 2018/19 tariff demands in part due to forecasted increased economic activity.
Non-Daily Metered (NDM)	The NDM sector capacity booking is derived by the Annual Quantity (AQ) and Supply Point Capacity (SPC) setting process in GNI, and there is a requirement on this sector to book a peak day (1 in 50) requirement at the Exit. The 1 in 50 has decreased in 2019/20 relative to the 2018/19 tariff demands.
Entry Points	Updated production profiles provided by the producers at Inch and Corrib have been utilised. Inch Production is forecast to decrease as the blowdown of cushion gas continues. Corrib Production has now come off peak and as a result capacity booking have decreased at Bellanaboy, resulting in increased capacity bookings at Moffat, which provides the marginal source of gas.

[5] The customer category classifications for LDM, DM and NDM are set out in the GNI Code of Operations under Part F, Section 2 Classification.
[6] An example of how capacity forecasts were annualised is shown in the 2014/15 Transmission Tariffs decision paper (CER/14/140).

3.3.4.2 Demand forecasts

Table 3.2 below presents GNI's updated forecast capacity and commodity bookings for the upcoming gas year 2019/20 and highlights the trend in comparison to the forecast capacity bookings for the gas year 2018/19 and the original PC4 forecast.

Table 3.2: Forecast capacity bookings for 2018/19 (MWh)

Entry/Exit	**PC4 forecast 18/19**	**PC4 forecast 19/20**	**Updated forecast 19/20**	**19/20 update vs PC4**	**19/20 vs 18/19**
Exit	265,753	258,942	289,729	*11.89%*	*9.02%*
Inch Production	7,472	4,916	5,173	*5.23%*	*-30.77%*
Biogas	-	-	114	-	-
Bellanaboy	88,103	81,861	68,785	*-15.97%*	*-21.93%*
Moffat	111,416	125,119	145,120	*15.99%*	*30.25%*
Total Entry	206,992	211,896	219,191	*3.44%*	*5.89%*

Note: The Entry Capacity is lower than the Exit Commodity as NDM customers are required to book for 1 in 50 at Exit.

Table 3.3: Forecast commodity bookings for 2018/19 (MWh)

Entry/Exit	**PC4 forecast 18/19**	**PC4 forecast 19/20**	**Updated forecast 19/20**	**19/20 update vs PC4**	**19/20 vs 18/19**
Exit	49,441,145	50,296,175	54,908,497	*9.17%*	*11.06%*
Entry	50,678,812	51,535,930	56,390,521	*9.42%*	*11.27%*

Note: The Exit Commodity total is lower than the Entry Commodity total primarily due to the Isle of Man offtake, which is not included in the Exit total.

4 TAR NC Article 30 information

Article 30 of the TAR NC requires certain tariff information to be published ahead of the upcoming tariff period (i.e. gas year 01 October 2019 – 30 September 2020). This includes detail on elements of the CRU's allowed revenue methodology, GNI's Matrix Model, and other additional information all of which is used either directly or indirectly to calculate GNI's allowed revenue and the transmission tariffs for the 2019/20 gas year. Table 4.1 sets out this information. For further details, please refer to Article 30 of the TAR NC.

Table 4.1: Information on TSO Revenue - Revenue level (15/16 monies)

<table>
<tr><th>TAR NC Article</th><th>Description</th><th>Period</th><th colspan="2">Detail</th></tr>
<tr><td>Art. 30 (1)(a)</td><td>Information on parameters used in the reference price methodology that are related to the technical characteristics of the transmission systems</td><td>2019/20</td><td colspan="2">See Section 2.4.

A simplified version of the transmission tariff model is available on GNI's website at the following link. A full version of the tariff model is available from GNI following the signing of a licence. Please contact tom.oconnor@gasnetworks.ie for further detail.</td></tr>
<tr><td>Art. 30 (1)(b)(i)</td><td>Allowed revenue</td><td>2019/20</td><td colspan="2">€176.65m</td></tr>
<tr><td>Art. 30 (1)(b)(ii)</td><td>Changes in allowed revenue</td><td>2018/19 – 2019/20</td><td colspan="2">Decrease in allowed revenue of 2% from gas year 2018/19 to 2019/20. This decrease is primarily due to the correction factor that has been applied to the 19/20 allowed revenue, as a result of the close out of the 2017/18 gas year. In addition to the 2017/18 correction factor, c.€4m is being accrued to customers this year as part of the CRU's decision to spread out the 2016/17 over-recovery over the remainder of PC4.</td></tr>
<tr><td rowspan="7">Art. 30 (1)(b)(iii)(1)</td><td rowspan="7">Asset types and their aggregated value</td><td rowspan="7">At start of current regulatory period – 01.10.2017</td><td>Asset type</td><td>Net book value (15/16 monies)</td></tr>
<tr><td>Pipelines/AGIs (incl. GTTW)</td><td>€1246.4</td></tr>
<tr><td>Land</td><td>€1.9m</td></tr>
<tr><td>Equipment</td><td>€19.2m</td></tr>
<tr><td>Compressors</td><td>€62.9m</td></tr>
<tr><td>Buildings</td><td>€17.6m</td></tr>
<tr><td>Total</td><td>€1348</td></tr>
<tr><td>Art. 30 (1)(b)(iii)(2)</td><td>Cost of capital and calculation methodology</td><td>2017/18-2021/22</td><td colspan="2">4.63% WACC – cost of debt is calculated using the estimated yield on government bonds plus a debt premium, while the cost of equity is calculated using the CAPM model.</td></tr>
<tr><td>Art. 30 (1)(b)(iii)(3)(a)</td><td>Initial asset valuation methodology</td><td>n/a</td><td colspan="2">Acquisition cost</td></tr>
</table>

<table>
<tr><th><u>TAR NC Article</u></th><th><u>Description</u></th><th><u>Period</u></th><th colspan="3"><u>Detail</u></th></tr>
<tr><td>Art. 30 (1)(b)(iii)(3)(b)</td><td>Asset revaluation methodology</td><td>n/a</td><td colspan="3">Acquisition cost, indexed with inflation (HICP), as a proxy for current replacement cost</td></tr>
<tr><td>Art. 30 (1)(b)(iii)(3)(c)</td><td>Evolution of the value of the assets</td><td>n/a</td><td colspan="3">Assets are added to the Regulated Asset Base (RAB) at their acquisition cost (historic cost). The assets are indexed with inflation (HICP) in order to calculate the value of an asset at the required point in time. The assets are then depreciated, using straight line depreciation, the rate of depreciation is set by the asset life. Assets are removed from the RAB when they are fully depreciated or disposed of.</td></tr>
<tr><td rowspan="6">Art. 30 (1)(b)(iii)(3)(d)</td><td rowspan="6">Depreciation periods and amount per asset type</td><td rowspan="6">At start of current regulatory period – 01.10.2017</td><td>Asset Type</td><td>Depreciation Period (Asset life)</td><td>Annual Depreciation Amount (15/16 monies)</td></tr>
<tr><td>Pipelines/AGIs/GTTW</td><td>50 years</td><td>€40.6m</td></tr>
<tr><td>Land</td><td>40 years</td><td>€0.1m</td></tr>
<tr><td>Equipment</td><td>5 years</td><td>€5.7m</td></tr>
<tr><td>Compressors</td><td>25 years</td><td>€5.1m</td></tr>
<tr><td>Buildings</td><td>40 years</td><td>€0.8m</td></tr>
<tr><td>Art. 30 (1)(b)(iii)(4)</td><td>Operational expenditures</td><td>2019/20</td><td colspan="3">€80.7m</td></tr>
<tr><td>Art. 30 (1)(b)(iii)(5)</td><td>Incentive mechanisms and efficiency targets</td><td>2017/18-2021/22</td><td colspan="3">Capex and opex incentives[7], with an ongoing controllable opex efficiency challenge of 1%.</td></tr>
<tr><td>Art. 30 (1)(b)(iii)(6)</td><td>Inflation indices</td><td>2017/18-2021/22</td><td colspan="3">Harmonised Index of Consumer Prices[8]</td></tr>
<tr><td>Art. 30 (1)(b)(iv)</td><td>Transmission services revenue</td><td>2019/20</td><td colspan="3">€176.65m (19/20 monies)</td></tr>
<tr><td>Art. 30 (1)(b)(v)(1)</td><td>Capacity-commodity split</td><td>2019/20</td><td colspan="3">90:10</td></tr>
<tr><td>Art. 30 (1)(b)(v)(2)</td><td>Entry-exit split</td><td>2019/20</td><td colspan="3">33:67</td></tr>
</table>

[7] See Section 7 of CER/17/260 for further detail regarding the incentives applied to the TSO.
[8] See 'Inflation' and 'Indexation' tab of CRU/19/061a Transmission revenue model 2019/20 for further detail.

<table>
<tr><th><u>TAR NC Article</u></th><th><u>Description</u></th><th><u>Period</u></th><th colspan="5"><u>Detail</u></th></tr>
<tr><td>Art. 30 (1)(b)(v)(3)</td><td>Intra-system/cross-system split</td><td>2019/20</td><td colspan="5">100% intra-system as there are currently no cross-system flows.</td></tr>
<tr><td>Art. 30 (1)(b)(vi)(1)</td><td>Actual revenue recovered in kt-2 (i.e. 17/18)</td><td>2017/18</td><td colspan="5">Actual revenue recovered was €192.6m in nominal monies.</td></tr>
<tr><td>Art. 30 (1)(b)(vi)(2)</td><td>(i) Correction factor for the year Kt-2, (ii) its effect on revenues in year Kt (19/20) and (iii) incentives.</td><td>2017/18</td><td colspan="5">(i) €21m, (ii) Reduced allowed revenue by €9.2m[9], (iii) Refer to Section 3.3.3</td></tr>
<tr><td>Art. 30 (1)(b)(vii)</td><td>Intended use of auction premium</td><td>2019/20</td><td colspan="5">N/A - no auction premium applied</td></tr>
<tr><td>Art. 30 (1)(c)(i)</td><td>Commodity-based tariffs</td><td>2019/20</td><td colspan="5">See Table 5.1</td></tr>
<tr><td>Art. 30 (1)(c)(ii)</td><td>Non-transmission tariffs</td><td>2019/20</td><td colspan="5">The Corrib Linkline Element of the Bellanaboy tariff is considered a non-transmission tariff[10] under TAR NC</td></tr>
<tr><td>Art. 30 (1)(c)(iii)</td><td>Reference prices for other points than interconnection points</td><td>2019/20</td><td colspan="5">See Table 5.1</td></tr>
<tr><td>Art. 30 (2)(a)(i)</td><td>Information about tariff changes and trends</td><td>2017/18 - 2018/19</td><td colspan="5">See Appendix A for the difference in tariffs and Section 3 for an explanation of this difference.</td></tr>
<tr><td>Art. 30 (2)(a)(ii)</td><td>Information about tariff changes and trends</td><td>2017/18 - 2021/22</td><td colspan="5">A simplified model is available on GNI's website at the following link. This allows the calculation of the possible evolution of tariffs.</td></tr>
<tr><td>Art. 30 (2)(b)</td><td>A simplified tariff model</td><td>2019/20</td><td colspan="5">A simplified model is available on GNI's website link.</td></tr>
<tr><td rowspan="5">Art. 30 (3)</td><td rowspan="5">Information on the amount of forecasted contracted capacity and the forecasted quantity of the gas flow on non-relevant points</td><td rowspan="5">2019/20</td><td>Market Segment</td><td>Unit</td><td>Forecasted Contracted Capacity</td><td>Unit</td><td>Forecasted Gas Flow</td></tr>
<tr><td>Power gen</td><td>MWh/d</td><td>142,349</td><td>GWh/y</td><td>30,330</td></tr>
<tr><td>DM</td><td>MWh/d</td><td>44,869</td><td>GWh/y</td><td>12,124</td></tr>
<tr><td>NDM</td><td>MWh/d</td><td>96,756</td><td>GWh/y</td><td>12,436</td></tr>
<tr><td>CNG</td><td>MWh/d</td><td>133</td><td>GWh/y</td><td>18</td></tr>
</table>

[9] As the correction factor is in excess of the 105% rule €9.2m will be returned in 2019/20 and the remainder will be returned in 2020/2.

[10] Non-transmission services are "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".

5 Transmission Tariffs 2019/20

The previous sections outline the elements affecting the transmission tariffs such as the adjustments which occur to the allowed revenues. These adjustments then are taken together with the allowed revenue from the Price Control to calculate the allowed revenue for the forthcoming tariff year. This allowed revenue is then inputted into GNI's Transmission Matrix Model along with the updated demand forecasts and correction factor to calculate the tariffs for the upcoming gas year. The transmission tariffs which will apply from 01 October 2019 to 30 September 2020 based on an allowed revenue of €176.65m (2019/20 monies)[11] are set out below.

With these updated tariffs, the transportation cost of UK gas to RoI will decrease in nominal terms by c.**6.5%**. This is as a result of stronger demands at Exit and greater flows through Moffat. Transportation costs from Bellanaboy has fallen by c.**4%.**

Table 5.1: Transmission Tariffs 2019/20 (€)

		Bellanaboy €	Inch Production €	Moffat €	Domestic Exit €	Gormanston Exit €
Firm[12]	Capacity per peak day MWh	619.442[13]	105.557	301.345	367.658	345.341
	Commodity Per MWh	0.103			0.216	

[11] Reference for paper: CRU/19/061
[12] "Firm" means gas transmission capacity contractually guaranteed as uninterruptible by the transmission system operator.
[13] This is composed of two elements; one to remunerate the Allowed Revenue of GNI (€118.89) plus a Corrib Linkline Element (€500.55), which will remunerate the revenues relating to the Corrib Linkline (Corrib Partners).

5.1 Details of Multipliers

Multipliers and seasonal factors are applied to the reference prices to set the tariffs for non-yearly capacity products. Short-term multipliers are applied in order to, amongst other things, incentivise efficient booking and hence use of the network. The multipliers vary throughout the year with reference to the probability of severe weather.

Table 5.2 below outlines the short-term multipliers which were updated as part of the CRU's Decision on the Harmonised Tariff Methodology for Gas[14].

Table 5.2: Short term gas multipliers

Month	Quarterly %	Monthly %	Daily %
October	38.43%	12.81%	0.64%
November		12.81%	0.64%
December		17.08%	1.14%
January	80.69%	29.89%	1.99%
February		34.16%	2.28%
March		25.62%	1.71%
April	13.27%	12.81%	0.64%
May		0.97%	0.05%
June		0.97%	0.05%
July	2.61%	0.97%	0.05%
August		0.97%	0.05%
September		0.97%	0.05%
Total	*135.0%*	*150.0%*	*279.44%*

5.2 Virtual Reverse Tariff 2019/20

Virtual Reverse Flow (VRF) is a 'reverse flow' service that is offered on an interruptible basis, at the Interconnection Points. By netting off forward flows, it allows Shippers to virtually flow gas in the opposite direction to the physical flows of gas at these points. [15] This means that Shippers can virtually flow gas from the Republic of Ireland (ROI) via Moffat and into ROI via Gormanston. To date, the CRU has applied an interim charge for use of the VRF service. As part of the CRU's Decision on the Harmonised Transmission Tariff Methodology for Gas, tariffs have been set for the Moffat and Gormanstown VRF products. These tariffs are based on the principles and

[14] Reference for paper: CRU19060

[15] 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.

requirements for standard interruptible capacity products set out in the European Tariff Network Code (EU 2017/460). The Gormanston VRF Entry tariff and the Moffat VRF Exit tariff that will prevail from 01 October 2019 to 30 September 2020 are set out in Table 5.3.

Table 5.3: Virtual Reverse Flow Tariffs 2019/20

		Gormanston VRF Entry €	Moffat VRF Exit €
Interruptible	Capacity per peak day MWh	65.110	250.044
	Commodity Per MWh	0.103	0.216

5.3 Renewable Natural Gas (RNG) Transmission Entry Point Tariff

As part of the CRU's recent decision on the Harmonised Tariff Methodology for Gas (CRU/19/060), a single transmission entry tariff has been set for RNG, based on one 'notional entry point' that is derived from the average of three geographically dispersed locations in counties Cork, Galway and Meath. The RNG tariff that will prevail from 01 October 2019 to 30 September 2020 is set out in Table 5.4 below.

Table 5.4 Renewable Natural Gas Tariff 2019/20

		Renewable Natural Gas Entry €
Firm	Capacity per peak day MWh	92.775
	Commodity per MWh	0.103

6 Conclusion

This information paper aims to provides a single resource for all tariff related information, ranging from; how it sets tariffs on an annual basis, the variables that cause changes in the tariffs from one year to the next, and the 2019/20 transmission tariffs. This is the second year that the CRU has published this information in one document. By making all tariff related information available to customers, in a single location, the CRU aims to make it easier for customers to understand how tariffs are set and what causes them to change from one year to the next. An important tool, also available to the public, is the simplified tariff model available on Gas Networks Ireland's website at the following link. This simplified model enables customers to further identify how transmission network tariffs are affected by demand and revenue variations, and to estimate possible evolution of tariffs.

Appendix A Transmission Tariffs 2019/20

GNI Transmission Tariffs for 2019/20			Published Tariffs				
	2019/20 Tariffs		2015/16 Tariffs	2016/17 Tariffs	2017/18 Tariffs	2018/19 Tariffs	% Change
	€	(2019/20 Monies)	€	€	€	€	Nominal
Exit							from 2018/19
capacity	**367.658**	per peak day MWh	430.882	428.352	402.080	389.884	-5.7%
commodity	**0.216**	per MWh	0.267	0.256	0.238	0.235	-8.4%
Gormanston Exit							
capacity	**345.341**	per peak day MWh	415.210	412.680	386.408	374.212	-7.7%
commodity	**0.216**	per MWh	0.267	0.256	0.238	0.235	-8.4%
Moffat Entry							
capacity	**301.345**	per peak day MWh	367.786	360.253	359.183	325.979	-7.6%
commodity	**0.103**	per MWh	0.118	0.123	0.114	0.113	-8.6%
Bellanaboy Entry							
capacity	**619.442**	per peak day MWh	617.996	610.463	658.431	630.428	-1.7%
commodity	**0.103**	per MWh	0.118	0.123	0.114	0.113	-8.6%
Inch Production Entry							
capacity	**105.557**	per peak day MWh	164.186	156.653	156.656	123.452	-14.5%
commodity	**0.103**	per MWh	0.118	0.123	0.114	0.113	-8.6%
Biogas Entry							
capacity	**92.775**	per peak day MWh					N/A
commodity	**0.103**	per MWh					N/A
Gormanston VRF Entry							
capacity	**65.110**	per peak day MWh					N/A
commodity	**0.103**	per MWh					N/A
Moffat VRF Exit							
capacity	**250.044**	per peak day MWh					N/A
commodity	**0.216**	per MWh					N/A
Illustrative Transmission Transportation Costs							
	€		€	€	€	€	
Transmission Transportation Cost of UK Gas							
capacity	**669.003**	per peak day MWh	798.668	788.605	761.263	715.864	-6.5%
commodity	**0.319**	per MWh	0.385	0.379	0.352	0.348	-8.4%
Transmission Transportation Cost of Bellanaboy Gas							
capacity	**987.099**	per peak day MWh	1048.878	1038.815	1060.511	1020.312	-3.3%
commodity	**0.319**	per MWh	0.385	0.379	0.352	0.348	-8.4%
Transmission Transportation Cost of Inch Storage Gas							
capacity		per peak day MWh	483.940	481.410	455.107	442.911	N/A
commodity		per MWh	0.385	0.379	0.352	0.348	N/A
Transmission Transportation Cost of Inch Production Gas							
capacity	**473.214**	per peak day MWh	595.068	585.006	558.736	513.337	-7.8%
commodity	**0.319**	per MWh	0.385	0.379	0.352	0.348	-8.4%
Transmission Transportation Cost of Biogas							
capacity	**460.432**	per peak day MWh					N/A
commodity	**0.319**	per MWh					N/A