An Coimisiún um Rialáil Fóntais

Commission for Regulation of Utilities

Gas Transmission Tariff Methodology – Tariff Network Code Article 28 Consultation

Gas year 2021/22

Consultation Paper

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CRU Mission Statement

The CRU's mission is to protect the public interest in Water, Energy and Energy Safety. The CRU is guided by four strategic priorities that sit alongside the core activities we undertake to deliver in the public interest. These are:

- Deliver sustainable low-carbon solutions with well-regulated markets and networks
- Ensure compliance and accountability through best regulatory practice
- Develop effective communications to support customers and the regulatory process
- Foster and maintain a high-performance culture and organisation to achieve our vision

Executive Summary

Gas Networks Ireland (GNI) owns and operates the gas transmission network. Regulated tariffs apply for the use of this system. The CRU sets the methodology for how these tariffs are calculated. These tariffs allow GNI, as the network operator, to recover the annual revenue set by the CRU to operate the network in a safe and efficient manner.

As part of the annual tariff setting process, the CRU is required under Article 28 of the European Tariff Network Code to consult on the following:

- Levels of multipliers and seasonal factors;
- Levels of discounts (e.g. discount for Virtual Reverse Flow).

The role of these items in the tariff setting process are as follows:

- **multipliers and seasonal factors are applied to calculate the tariffs for non-annual products**: The CRU's transmission tariff methodology sets the tariffs for annual capacity at the transmission entry and exit points. In order to calculate the tariffs for non-annual capacity products (i.e. quarterly, monthly, daily) the annual tariffs are combined with multipliers[1] and seasonal factors[2]. Therefore, the levels of these factors determine the tariffs for the non-annual capacity products. The multipliers & seasonal factors are set to incentivise certain behaviour among gas system users.

[1] Multipliers determine the multiple of the annual capacity product tariff, which is applied to a non-annual capacity product to calculate its tariff. For example, the monthly multiplier is 1.5, which means that buying monthly capacity for each month in the year will cost 1.5 times more than buying the annual capacity product.
[2] Seasonal factors are used to create a profile for the non-annual capacity products across the year. This leads to different prices for a non-annual capacity product at different times of year. For example, the monthly product is more expensive in the winter but is cheaper in the summer.

- **Setting the cost of virtual reverse flow**: The Tariff Network Code allows for adjustments/ discounts. Currently a discount is only applicable for Virtual Reverse Flow (VRF).[3] VRF is a 'reverse flow' service offered on a virtual interruptible basis, at the Interconnection Points, to enable Shippers to virtually flow gas from Ireland via Moffat and into Ireland via Gormanston.[4] VRF is a day-ahead interruptible product. As it is an interruptible product it receives a discount. Therefore, the level of the discount (referred to as the A-factor), amongst other things, determines the level of the VRF tariff.

Last year, the CRU examined the multipliers and seasonal factors and VRF and decided to not make any changes (CRU/20/057). This was decided in order to allow for additional analysis[5] and a more holistic approach[6] to reviewing these factors. This resulted in the VRF discount and the multipliers and seasonal factors being maintained at the same levels for gas year 2020/21. In accordance with the approach set out in last year's paper (CRU/20/057), the CRU has built on the previous work and is now consulting on the proposed multipliers and seasonal factors and VRF for gas year 2021/22.

Multipliers and seasonal factors

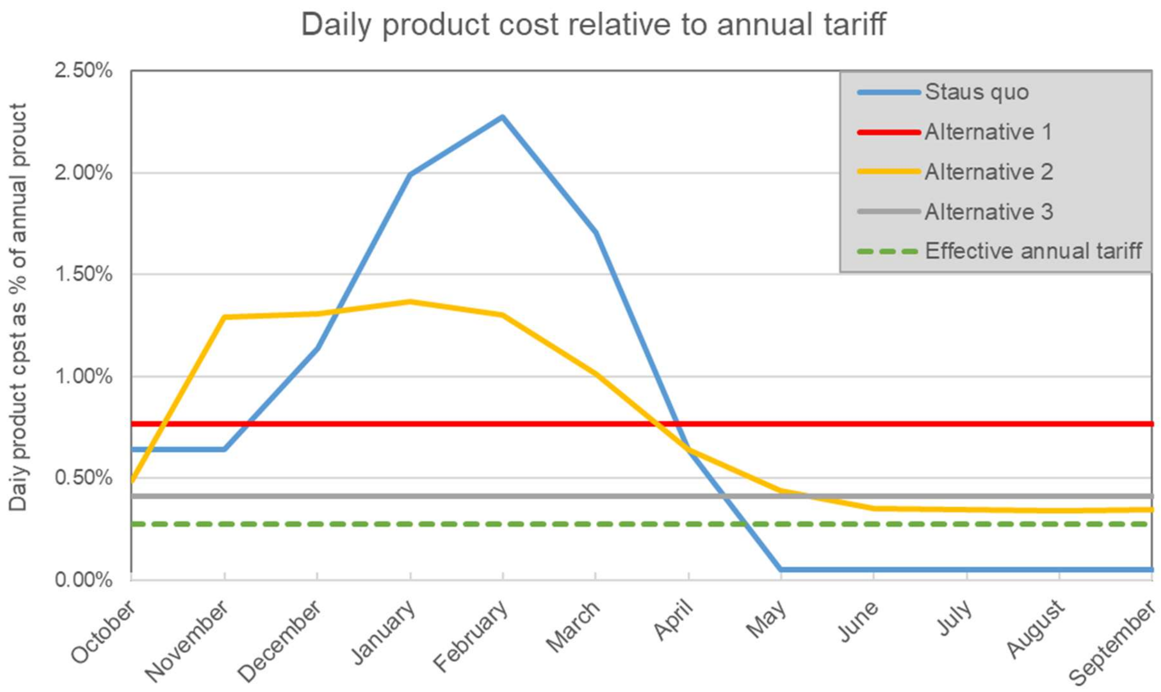
The CRU has engaged with GNI to further review the multipliers & seasonal factors. The CRU has examined four options submitted by GNI and the additional information provided on their potential impacts. The four options reviewed by the CRU are as follows:

- Status quo: Current multipliers and current seasonal factors
- Alternative 1: Current multipliers and no seasonal factors
- Alternative 2: Current multipliers and adjusted seasonal factors
- Alternative 3: Daily multipliers reduced to 1.5 limit and no seasonal factors

[3] The tariff network code requires that discounts are provided for storage facilities and that they may be applied for LNG facilities, however these do not currently exist on the Irish network.
[4] 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.
[5] The factors and a new tariffing approach for VRF came into force on 01 October 2019. Last year they had not yet been in place for a full gas year. As the dynamics in the gas market change over the course of the year (e.g. demand levels vary from Winter to Summer due to differences in heating requirements), the CRU considered that it was important to collect a full year's worth of data before making any changes, particularly in the case of VRF as it underwent a significant change in tariffing approach. In addition, the seasonal factors change the cost of the VRF product throughout the year and the CRU has yet to see the impact of the full range of these costs on VRF use.
[6] For multipliers and seasonal factors, the CRU noted that it was important to further consider wider market changes, such as the changing role for gas in power generation

The difference in these approaches is best highlighted by illustrating the costs of the daily product, as per the figure below. This is because it is the most expensive short term product, thereby emphasising the maximum difference in costs and any seasonal trends. The daily capacity costs for each profile relative to the annual tariff are presented in the figure below, see the footnote for further explanation.[7]

Figure 1.1: Daily capacity cost in each option



The CRU has assessed these options against the criteria set out in the network code and in the context of the Irish gas market. Although the multipliers and seasonal factors have been examined separately in order to allow for separate consideration against their associated Art. 28 criteria, it is also important to consider their overall impact on a joint basis. In addition, it is important to note that there is complexity and uncertainty surrounding this topic due to the potential impacts on a wide-range of elements of the gas market. In coming to this initial opinion, the CRU has considered the relative importance of each criteria, as some of these are more relevant than others in the context of the Irish gas market. In addition, the CRU is keen to hear the views of stakeholders because it is the users of the network who would be directly affected

[7] For example, the blue line, which represents the status quo illustrates that the daily capacity cost is effectively zero in Summer (0.05%) but much more expensive in the Winter, peaking in February (2.28%). This graph, specifically the dashed green line, also highlights the current effective cost of daily capacity if a user were to buy the annual product (i.e. 1/365 = 0.27%). Therefore, in February, it is currently over eight times ((2.28%/0.27%)=8.4) more expensive to purchase daily capacity than the annual product equivalent, while in the summer it is over five times ((0.27%/0.05%)=5.4) less expensive.

by changes to the multipliers and seasonal factors. Finally, it is important to note that the CRU is cognisant of the complexity and uncertainty involved and therefore if a decision is made to change the multipliers and seasonal factors, it would be appropriate for there to be ongoing monitoring of impacts.

Firstly, with regard to multipliers and their possible reduction, the CRU's assessment under each criteria is summarised[8] in the table below. The CRU has not identified negative outcomes resulting from the application of the current multipliers. For this reason, the CRU is of the view that a reduction in the daily multiplier limit to 1.5 (alternative 3) may not be warranted, particularly as it may lead to an increase in the potential for undue costs being placed on the Residential & SME customer sector. **As a result, the CRU is consulting on a proposal to maintain the current daily multiplier at 2.79.**

Table 1.1: Multiplier review - summary table

	Balancing short-term trade & long-term signals for investment	Impact on revenue and its recovery	Avoid cross-subsidisation and enhance cost-reflectivity	Physical and contractual congestion	Cross-border flows
Current (Daily 2.79)	–	–	✔	–	n/a
Alternative 3 (Daily 1.5)	–	✕	✕	–	n/a

Secondly, with regard to seasonal factors, the CRU's assessment under each criteria is summarised in the table below. The CRU's view is that the current seasonal factor profile may no longer provide an effective incentive for current or future network users to utilise the gas infrastructure more efficiently.[9] In addition, it may be leading to a reduction in cost-reflectivity as a result of changing market dynamics since the factors were last adjusted in 2012. For example, there was an adjustment to support, amongst other things, seasonal gas storage, however gas storage ceased in 2017. Given the current uncertainty surrounding the effectiveness of the incentives that seasonal factors are meant to provide networks users and considering the potential for these signals to have unintended effects, the CRU is of the view that their removal may be warranted. However, the CRU is of the view that although the removal of seasonal factors may be justifiable, the CRU is cognisant of, amongst other things, the importance of tariff stability and certainty for the market (i.e. not just the Art. 28 criteria), particularly as there could be effects for individual network users. Therefore, any change from the current seasonal factors

[8] The CRU elaborates further in section 2.3 and additional analysis is provided in Appendix A.
[9] This is due to the effect of wind generation on gas demand and the decreased likelihood of significant additional gas demand due to decarbonisation policy.

should be incremental in nature. Therefore, the CRU is of the view that the complete removal of seasonal factors under Alternative 1 would not be in the best interests of gas consumers at this time and instead **the CRU is consulting on a proposal to implement Alternative 2 as it provides for an incremental change.**

Table 1.2: Seasonal factor review - summary table

	Efficient utilisation of gas infrastructure	Improving cost-reflectivity
Status quo	-	×
Alternative 1 (no seasonality)	-	-
Alternative 2 (reduced seasonality)	-	-

As this change alters the cost of booking non-annual capacity over the course of the year, there may be an effect on how non-annual capacity users (e.g. Power sector) book capacity to match their demand requirements, and subsequently, how GNI recovers its allowed revenue. GNI's analysis indicates that the change in bookings may lead to upward pressure in the cost of annual capacity. In terms of quantifying the impact, there is considerable uncertainty, however GNI estimates that Alternative 2 could result in a 4% increase in the cost of transporting gas from the Moffat entry point[10], which could equate to an increase of up to €2.8 or 0.3% on a residential customer's annual bill. This is because residential customers are required to book annual capacity for security of supply reasons. However, it is important to note that not all network users would see an increase in cost and, on balance, the CRU is of the view that this change should positively impact the gas market, by making charges more cost-reflective and reducing the potential for cost volatility. The CRU is keen to hear the views of stakeholders on this proposal and will consider these as part of any decision on whether to change the levels of seasonal factors for the gas year 2021/22.

Virtual Reverse Flow

As part of last year's Art. 28 call for evidence paper (CRU/20/057) the CRU presented data on the use of VRF. It highlighted that since the new tariffing approach for VRF came into force on 01 October 2019 there was a significant decrease in the use of the VRF product. However, at the time this tariff had not yet been in place for a full gas year and the cost and dynamics in the gas market change over the course of the year (e.g. demand levels vary from winter to summer due to differences in heating requirements). The CRU therefore took the view that it was important to

[10] Annual Moffat entry capacity tariff + annual domestic exit capacity tariff. The transportation cost of gas from Moffat (a.k.a. GB gas) is important because Irish wholesale gas prices are generally 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.

collect a full year's worth of data before considering any changes as "*the CRU will then have been able to monitor the use of VRF under a wide range of different cost levels.*"

The CRU has now received data covering the full gas year since the new VRF tariff was introduced and has updated its analysis with the new data. The goal of this analysis was to assess whether the VRF discount is appropriate, by examining the trends over time, comparing VRF use before and after the new tariff was introduced and the factors that might affect the use of VRF. However, this data does not point to any definitive factor or trigger point, which determines the use of VRF, which continued to be very low throughout gas year 2020/21.

The CRU noted this possibility last year, "*a continued lack of use of VRF in these coming* [summer] *months may indicate that issues regarding its use cannot be solved by changes to the VRF tariff given that the tariff may be as low as can possibly be achieved.*" It appears from the timing of the change that the limited use of VRF is in some part driven by the new tariffing approach. However, the numerous push and pull factors in play at any one time, continues make it difficult to have full sight of what is driving the use of VRF. This makes it challenging to set a discount (referred to as the A factor), the purpose of which is to reflect the economic value of the VRF product.

From the evidence gathered to date, both in the form of the quantitative data provided in this and last year's paper, and in the form of qualitative data from respondents to previous consultations the CRU cannot put forward a reasoned alternative VRF discount. For reasons that are unclear to the CRU, it appears that participants currently prefer the option of commercial swaps of gas. Importantly, the CRU has not identified any obvious negative outcomes for the gas market resulting from this change. The CRU requests the views of industry on its analysis, any additional evidence and would welcome proposals (supported by data and analysis) for an alternative VRF discount (within the Art. 28 consultation scope) that could be considered as part of next year's consultation.

The CRU proposes that the level of the discount (referred to as the A-factor) will continue to be as follows for gas year 2020/21.

Table 1.3: Virtual reverse flow A-factor

Interconnection point	A-factor
Moffat	6
Gormanston	2.25

Public/ Customer Impact Statement

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 public interest. These tariffs allow GNI, as the network operator, to recover the annual revenue set by the CRU to operate the network in a safe and efficient manner.

The CRU has with this paper published a consultation on the value of multipliers, seasonal factors and levels of discounts. These items impact the price paid by companies using the gas network and the way in which these network users are incentivised to use the network. These costs may be passed on to the final customer. As such, it is important to keep the value of multipliers, seasonal factors and levels of discounts under review to ensure that they are set appropriately. In this paper the CRU has provided a detailed analysis of the multipliers, seasonal factors and levels of discounts ahead of next gas year, which runs from 01 October 2020 to 30 September 2021.

The CRU's examination of the multipliers has not identified any reasons that justify a change in approach, however the CRU has identified that the seasonal factors may need to be altered. This is because there is uncertainty surrounding the effectiveness of the incentive that seasonal factors are meant to provide network users and considering the potential for these signals to have unintended effects. As a result, the CRU is of the view that their removal may be warranted. The CRU is consulting on a proposal to make an incremental change to the seasonal factors, rather than fully remove them. This is partly because of the importance of tariff stability and certainty for the market.

As this change alters the cost of some types of capacity, there may be an effect on how network users book capacity, and subsequently, how GNI recovers its allowed revenue. GNI's analysis indicates that the change in bookings may lead to upward pressure in the cost of the annual capacity product. The CRU estimates that the impact of this change would equate to an increase of €2.8 or 0.3% on a residential customer's annual bill but could lead to a reduction in cost of other network users and should provide an overall benefit to the gas market by making charges more cost-reflective and reducing the potential for cost volatility.

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Glossary of Terms and Abbreviations

Abbreviation	Definition or Meaning
ACER	Agency for the Cooperation of Energy Regulators
Art.	Article
EU	European Union
GB	Great Britain
GNI	Gas Networks Ireland
I&C	Industrial/Commercial
IBP	Irish Balancing Point
IP	Interconnection Point
SEM	Single Electricity Market
LNG	Liquefied Natural Gas
NBP	National Balancing Point
PC4	Price Control 4
RPM	Reference Price Methodology
SAP	System average price
TAR NC	Commission Regulation (EU) 2017/460 of 16 March 2017 establishing a network code on harmonised transmission tariff structures for gas
TSO	Transmission System Operator

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 originally established as the Commission for Energy Regulation (CER) in 1999. The CER changed its name to the CRU in 2017 to better reflect the expanded powers and functions of the organisation. The CRU has a wide range of economic, customer protection and safety responsibilities in energy and water.

Under the Gas (Interim) (Regulation) Act, 2002, the CRU is responsible for regulating charges in the natural gas market. Under Section 14 of that 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 customers. Our goal is to ensure that gas is safely and securely supplied and that the charges are fair and reasonable. This paper relates to factors impacting on gas transmission tariffs.

1.2 Background

Each year tariffs are set for GNI to recover revenue that it needs to operate and invest in the gas network. As part of the annual tariff setting process,[11] the CRU analyses any additional revenue requests from GNI, over/under recoveries of revenue in the previous years and updated demand projections in order to calculate tariffs for the forthcoming gas year. As part of that process, the CRU is required to consult annually on certain elements feeding into the tariff setting process. This annual consultation is a requirement that stems from European requirements set out in the Tariff Network Code. The aspects that are consulted upon relate to transmission tariffs only and are:

- Levels of multipliers;
- Levels of seasonal factors;
- Levels of discounts for storage and LNG; and,
- Levels of discounts for interruptible capacity products (i.e. Virtual Reverse Flow).

This paper is seeking comment on those factors excluding LNG and storage facilities, the rationale being, there are currently no LNG or storage operators using the system and therefore

[11] More detail as to the overall tariff setting process is available in (CRU/20/097).

no discount is applicable. An LNG operator can apply to the CRU for such a discount and the CRU will consult on its application.

Gas capacity charges are known as references prices and are calculated on the basis of shippers booking a fixed capacity across the entire year (i.e. annual capacity). However, it is possible to book capacity over shorter periods (e.g. book for a month or a day). To set the prices of these non-annual products, so called multipliers and seasonal factors are applied.

- Multipliers determine the multiple of the annual capacity product tariff, which is applied to a non-annual capacity product to calculate its tariff. For example, the monthly multiplier is 1.5, which means that buying monthly capacity for each month in the year will cost 1.5 times more than buying the annual capacity product. It is more expensive to book these non-annual products, as these products provide more flexibility and can potentially increase system costs (see section 2 for further information).
- Seasonal factors are used to create a profile for the non-annual capacity products across the year. This leads to different prices for a non-annual capacity product at different times of the year. For example, the monthly product is more expensive in the winter but is cheaper in the summer. The cost is more expensive in winter as there is more demand on the system and this high demand can lead to increased system costs (e.g. building additional capacity), while the cost is less in the summer to incentivise increased utilisation of the network, which increases system efficiency.

The tariffs for the non-annual capacity products are calculated by multiplying the reference prices/ annual capacity tariffs by the above multipliers and seasonal factors. They lead to capacity prices that vary depending on the length of the product chosen and the time of the year in which it is booked. In contrast to capacity charges, commodity charges are the same regardless of the time of year or duration of gas flow.

There is a requirement (Art. 28 of TAR NC) to consult on multipliers and seasonal factors annually. This is discussed more in the next section. There is also a requirement to consult on any discounts that may be applied to the reference prices. This is discussed more in section 3.

1.2.1 Gas transmission tariff methodology reviews

In June 2019 the CRU, following a public consultation, published a decision (CRU/19/060), setting out the current gas transmission tariff methodology. The CRU undertook that review to fulfil EU tariff network code requirements (more specifically, European Commission Regulation (EU) 2017/460 of 16 March 2017 establishing a network code on harmonised transmission tariff structures for gas[12]). The EU Tariff Network Code, referred to as TAR NC, was developed with the objective of contributing to market integration, enhancing security of supply and promoting the interconnection between gas networks.[13]

The June 2019 decision was the first time the CRU completed a TAR NC Article 26 and Article 28 review. Article (Art.) 26 of TAR NC requires the CRU to review and to consult on the RPM being applied in Ireland at least every five years. Art. 28 requires the CRU to review and to consult annually on aspects of the tariff setting methodology such as those relating to discounts, multipliers and seasonal factors.

The 2019 review resulted in some minor adjustments to the tariff setting methodology, which is referred to as the Matrix Reference Price Methodology or Matrix RPM.

The minor adjustments were conducted not only to achieve compliance with TAR NC but also to improve the methodology to the benefit of the gas industry in Ireland. ACER individually assessed each NRA's consultation and provided recommendations for consideration in each NRA decision.[14]

On 06 April 2020 ACER published a report[15], which summarised its overall findings and included individual country sheets which detailed, amongst other things, how the CRU and other NRAs implemented ACER's recommendations. Table 1 in the Ireland country sheet included in ACER's report highlights that the CRU's decision achieved full compliance with the network code.

On 19 May 2020 the CRU published its annual Art. 28 paper (CRU/20/057) ahead of gas year 2020/21. In that paper the CRU set out its view as to why it was not appropriate to change the multipliers, seasonal factors and discounts for gas year 2020/21 and requested the views of respondents. The CRU thanks those respondents for their views, which have been considered in the development of this paper. With this paper the CRU is now carrying out its third annual Art. 28 review ahead of gas year 2021/22.

[12] Commission Regulation (EU) 2017/460 of 16 March 2017 establishing a network code on harmonised transmission tariff structures for gas

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

[14] ACER's analysis of the CRU consultation is available at this clickable link.

[15] ACER's implementation monitoring report is available at this clickable link.

1.3 Purpose of this paper

In accordance with the approach set out in last year's call for evidence paper (CRU/20/057) the CRU has built on the previous work and is now consulting on the following aspects of the tariff methodology as required by Art. 28 of TAR NC, these are summarised below:

- Levels of multipliers;
- Levels of seasonal factors; and,
- Levels of discounts for interruptible capacity products (i.e. Virtual Reverse Flow).

1.4 Related documents

The documents published alongside this paper are as follows:

- GNI Alternative 2 calculation spreadsheet (CRU/21/14a);
- GNI multiples & seasonal factor options – impact assessment spreadsheet (CRU/21/14b);

Some documents related to this publication are provided below:

- CRU Call for Evidence Paper on Tariff Network Code Article 28 (CRU/20/057);
- CRU Decision Paper on Harmonised Transmission Tariff Methodology for Gas (CRU/19/060);
- CRU Consultation Paper on Harmonised Transmission Tariff Methodology for Gas (CRU/18/247);
- ACER's analysis of the CRU consultation is available at this clickable link;
- ACER's implementation monitoring report is available at this clickable link
- Regulation (EC) No 715/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the natural gas transmission networks and repealing Regulation (EC) No 1775/2005;
- 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 Matrix model and simplified 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.**

1.5 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 examines the levels of multipliers and seasonal factors used to derive tariffs for non-yearly capacity products and provides a summary of the CRU's analysis.
- Section 3 examines the levels of discounts.
- Section 4 provides a summary and next steps.
- Appendix A provides the CRU's more detailed analysis on the levels of multipliers and seasonal factors.

1.6 Responding to this paper

The CRU invites responses to the questions set out in this paper by 10 March 2021, 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.

The responses will be assessed and may be used to support proposed changes to the multipliers and seasonal factors and discounts, which will be decided upon in time for the tariff year 2021/2022. 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.[16]

[16] https://www.cru.ie/privacy-statement/

2 Multipliers & Seasonal Factors

Multipliers determine the multiple of the annual capacity product tariff, which is applied to a non-annual[17] capacity product (also known as shorter-term products) to calculate its tariff. It is more expensive to book these non-annual products, as they provide more flexibility to network users. This flexibility can potentially increase system costs as longer-term capacity bookings make it easier for GNI to identify periods of peak demand and plan for additional system investment where required. Also, shorter-term bookings can lead to increased revenue recovery volatility.

Seasonal factors are used to create a profile for the non-annual capacity products across the year. The profile sets different prices for a non-annual capacity product at different times of year. For example, the monthly product is set to be more expensive in the winter and cheaper in the summer. The cost is more expensive in winter as there is more demand on the system and this high demand can lead to increased system costs (e.g. building additional capacity), while the cost is less in the summer to incentivise increased utilisation of the network, which increases system efficiency.

In the interests of simplicity, the CRU has to date presented the multipliers and seasonal factors on a combined basis. See Table 2.1, which sets out the current combined multiplier & seasonal factor profile. This table presents the profile as a percentage of the reference price.

To understand how this works, consider the following example: The reference price for Moffat entry is €315/MWh. If you wanted to book monthly capacity for December, you could calculate the cost by referring to Table 1 and applying the relevant combined multiplier & seasonal factor; in this case 17.08%. That would result in the following – €315/MWh * 17.08% = €54/MWh.

Table 2.1: Combined multiplier & seasonal factor profile as a % of annual product

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%

[17] In Ireland the non-annual products are quarterly, monthly, daily and within-day. 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.

Month	Quarterly %	Monthly %	Daily %
August		0.97%	0.05%
September		0.97%	0.05%
Total	*135.0%*	*150.0%*	*279.44%*

The existing multiplier & seasonal factor methodology has been developed over a number of years by GNI and the CRU. They are based on, amongst other things, the principle of cost-reflectivity – i.e. that requirements for capacity during periods of high utilisation (peak demand days) are more likely to lead to additional network costs by potentially leading to requirements for additional infrastructure investment through reinforcing the network and building additional capacity.

The methodology adopted 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 those periods. There were a small number of adjustments over time in consideration of things such as supporting seasonal gas storage and incentivising uptake of short term products. However, in general, the multipliers and seasonal factors have been stable for the last decade.

In accordance with Art. 28 of TAR NC the CRU is carrying out its annual consultation on multipliers and seasonal factors. Last year, the CRU has decided not to change the multipliers and seasonal factors. This was decided in order to allow for additional analysis and a more holistic approach to reviewing these factors.

2.1 Review approach

2.1.1 Background

In accordance with the approach set out in last year's call for evidence paper (CRU/20/057), the CRU has engaged with GNI to further review the multipliers & seasonal factors. In undertaking this review the CRU is cognisant of the potential for changes to multiplier & seasonal factors to have several wide-ranging redistributive effects. For example, a change to short-term multipliers would affect those who can avail of non-annual products (e.g. Power sector) differently from those you can't (Residential & SME sector who must book annual capacity in line with their 1 in

50 peak day[18].). In addition, reducing the seasonal profile range will result in seasonal network users being affected differently from those who use the network yearly.[19]

A change to the multiplier & seasonal factor profile could also have effects on GNI and how it operates the network. For example, there could be changes to capacity booking profiles, revenue recovery and network demand patterns.[20]

It is clear that changes to multiplier & seasonal factors have the potential to have wide reaching impacts. With this review of multipliers and seasonal factors, the CRU is not only aiming to ensure compliance with EU regulations and network codes, the CRU is also aiming 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.

Last year, the CRU requested feedback from network users and end customers on what they considered to be the context of the review. In the paper the CRU touched on some of the following as important context:

- gas plant being used more and more as a flexible source of electricity generation;
- changing demand and patterns of use by different network user types;
- possible effects on the price of electricity;
- alignment of multipliers and seasonal factors between the Irish and Northern Irish gas markets given the single electricity market (SEM);
- potential decarbonisation of natural gas;
- potential for ACER to issue a recommendation for multipliers for daily and within-day products to be limited to 1.5 (currently, 3).

Respondents agreed with the CRU's description of the context of the review. As such the CRU has mainly considered the multipliers and seasonal factors in this context. Some of these considerations are discussed within the body of the document and others are elaborated on in Appendix A.3.

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[18] A 1-in-50 peak day is the requirement to fulfil gas demand during a 1-in-50 year severe weather scenario. This is to ensure that security of supply is maintained and that the gas continues to flow to customers even when demand is at its maximum.
[19] As those who use the system all year round will have a greater proportion of annual capacity bookings, which aren't directly affected by multipliers and seasonal factors.
[20] See Appendix A for further discussion.

2.1.2 Criteria for review

In 2020, the CRU stated that the review of multipliers and seasonal factors should be based on a consideration of the criteria highlighted in Art. 28, with any proposed amendments cross-checked against the overall requirements of Art. 13 of Regulation (EC) No 715/2009.

Art. 28 of TAR NC states that the NRA shall take into account the views of respondents and the following aspects:

(a) for multipliers:

(i) the balance between facilitating short-term gas trade and providing long-term signals for efficient investment in the transmission system

(ii) the impact on the transmission services revenue and its recovery

(iii) the need to avoid cross-subsidisation between network users and to enhance cost-reflectivity of reserve prices

(iv) situations of physical and contractual congestion

(v) the impact on cross-border flows

(b) for seasonal factors:

(i) the impact on facilitating the economic and efficient utilisation of the infrastructure

(ii) the need to improve the cost-reflectivity of reserve prices.

Regulation (EC) No 715/2009 sets 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. In summary, Art. 13 of Regulation (EC) No 715/2009 requires that tariffs, or the methodologies used to calculate them shall:

- be transparent
- take account the need for system integrity and its improvement
- reflect efficient costs
- include appropriate return on investment
- be applied in a non-discriminatory manner
- facilitate efficient gas trade and competition
- avoid cross-subsidies between network users
- provide incentives for investment and maintaining or creating interoperability for transmission networks

Last year, the CRU requested feedback from network users and end customers on what criteria they considered essential as part of this year's review. Respondents noted some of the following:

- Economic viability of gas generators;
- Alignment of the factors between the gas markets in Ireland and Northern Ireland;
- Impact that tariff changes and the timings of such may have on gas consumers; and,
- Incentivise use of low carbon gas units.

The CRU thanks the respondents for their feedback and has considered these additional criteria/ issues in its review. However, the CRU notes that although it has considered the power sector as a whole, the economic viability of gas generators and the incentivisation of low carbon gas units is not within the scope of a review of multipliers and seasonal factors.

2.2 Options for review

2.2.1 Introduction

Following the publication of last year's call for evidence paper the CRU engaged with GNI and developed a terms of reference for this year's Art. 28 review. In discussions with GNI, the CRU shared the view that it was most appropriate for GNI to put forward options for review. This is because the multipliers and seasonal factors impact on gas shipper behaviour and therefore GNI is best placed to assess the impact on capacity bookings, tariffs and revenue recovery. In addition, GNI may want to consider the signals it wants to send to its network users and how they want to incentivise use of the network. The CRU would then consult on these options as part of its Art. 28 consultation. The terms of reference provided guidance to GNI on how it should go about developing these options and the accompanying information the CRU required in order to assess the impact of these options. In addition, the CRU requested that GNI present its initial findings to industry. GNI presented this information at the Code Modification Forum on 16 December 2020, the minutes of which are available on GNI's website.[21] The CRU requested initial comments from participants on GNI's presentation so that they could be taken into account for the consultation. The CRU has taken these into account where relevant, for example, following respondents' suggestions the CRU has ensured the publication of excel sheets alongside the consultation paper so that stakeholders can review the calculations, thereby ensuring transparency.

[21] https://www.gasnetworks.ie/corporate/gas-regulation/service-for-suppliers/code-of-operations/code-modifications/code-modification-forum-meetings/2020_cmf_meetings/index.xml

GNI have provided the CRU four multiplier and seasonal factor profiles for the review. These are as follows and examined further in the subsequent sections:

- **Status quo: Current multipliers and current seasonal factors**
- **Alternative 1: Current multipliers and no seasonal factors**
- **Alternative 2: Current multipliers and adjusted seasonal factors**
- **Alternative 3: Daily multipliers reduced to 1.5 limit and no seasonal factors**

In order to keep references to each profile concise within the text the paper sometimes refers to the current approach as status quo or SQ, and the other profiles as alternative 1 or A1, alternative 2 or A2 and alternative 3 or A3.

2.2.2 Options

This section sets out the different multiplier and seasonal factor profiles, and where required, explains how they were derived. The table below provides full detail, however their differences are best illustrated by examining the figure in section 2.2.2.5.

Table 2.2: Non-annual capacity costs as % of annual product

Month	Quarterly %				Monthly %				Daily %			
	SQ	A1	A2	A3	SQ	A1	A2	A3	SQ	A1	A2	A3
Oct	38.43	33.75	45.16	30.0	12.81	12.5	7.91	10.83	0.64	0.77	0.49	0.41
Nov					12.81	12.5	21.01	10.83	0.64	0.77	1.29	0.41
Dec					17.08	12.5	21.26	10.83	1.14	0.77	1.31	0.41
Jan	80.69	33.75	53.83	30.0	29.89	12.5	22.19	10.83	1.99	0.77	1.36	0.41
Feb					34.16	12.5	21.17	10.83	2.28	0.77	1.30	0.41
Mar					25.62	12.5	16.45	10.83	1.71	0.77	1.01	0.41
Apr	13.27	33.75	20.89	30.0	12.81	12.5	10.38	10.83	0.64	0.77	0.64	0.41
May					0.97	12.5	7.15	10.83	0.05	0.77	0.44	0.41
June					0.97	12.5	5.68	10.83	0.05	0.77	0.35	0.41
July	2.61	33.75	15.12	30.0	0.97	12.5	5.61	10.83	0.05	0.77	0.35	0.41
Aug					0.97	12.5	5.56	10.83	0.05	0.77	0.34	0.41
Sept					0.97	12.5	5.64	10.83	0.05	0.77	0.35	0.41
Total	*135.0*	*135.0*	*135.0*	120.0	150.0	150.0	150.0	135.0	279.4	279.4	279.4	150.0

2.2.2.1 Status quo - current multipliers and current seasonal factors

This approach is based on maintaining the current profile and provides the base case against which the impacts of alternatives can be examined.

2.2.2.2 Alternative 1 - current multipliers and no seasonal factors

This approach is based on maintaining the current multipliers but removing the seasonal factors. This results in the non-annual capacity products costing the same regardless of time of year for which they are booked. Therefore, comparing the expected impacts of this proposal against the base case should give an insight into the impact that the current seasonal factors have.

2.2.2.3 Alternative 2 - current multipliers and adjusted seasonal factors

This approach maintains the current multipliers but adjusts the seasonal factors. As highlighted earlier, the status quo seasonal factor approach is mainly based on 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.[22] This alternative involves an update to the probability of a peak day analysis and combines it with a profile that reflects the peak demand in each month. It involves a number of steps, which are summarised below, see GNI website[23] and spreadsheet (CRU/21/14a) supplied alongside this paper for full detail.

1. An updated profile of the probability of a peak day occurring is developed by examining the occurrence of top 25 peak days in the each of the last five years. As expected, this results with a probability of zero in summer and a higher probability in winter months.[24] January is the month with the highest probability, with 20.4% of the peak days occurring in that month.

2. A second peak demand profile is derived by examining the size of the peak day demand in each month. This can be explained best by considering the following example: The peak day for October in each of the last five years (169.5 GWh, 169.0 GWh, 175.0 GWh, 210.1 GWh, 206.9 GWh) is averaged, resulting in a figure of 186.1 GWh. This is done for each of the twelve months of the year. A percentage for October is then derived by dividing the October average (186.1 GWh) by the sum of the averages for each month (2,249.9 GWh), resulting in 8.27%. The resulting profile still results in higher percentages in winter and lower in summer, but the percentages are much more evenly distributed than the profile in point 1 above. February is the month with the highest percentage, with 9.17%; while the lowest is August, with 7.41%.

[22] First published here (https://www.cru.ie/wp-content/uploads/2007/07/cer07082.pdf), however there have been subsequent adjustments.
[23] https://www.gasnetworks.ie/corporate/gas-regulation/service-for-suppliers/code-of-operations/code-modifications/code-modification-forum-meetings/2020_cmf_meetings/index.xml
[24] An adjustment is made to account for holidays, which this mostly affects the month of December.

3. The percentages for each month calculated under point 1 and 2 are then averaged, resulting in a single percentage for each month.

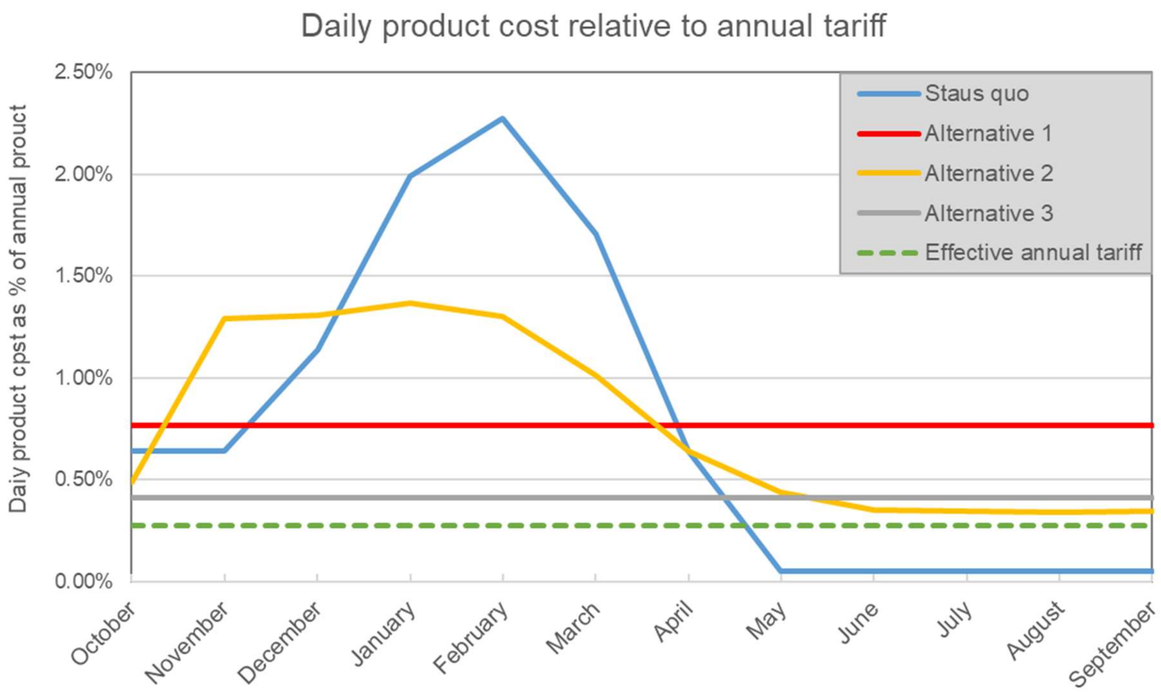
2.2.2.4 Alternative 3 - daily multipliers reduced to 1.5 limit and no seasonal factors

This approach examines the effect of a significant reduction in the cost of short-term capacity in addition to removal of the seasonal factors. It was included by GNI to reflect the fact that TAR NC includes a possible requirement for multipliers for daily products to be limited to 1.5 (currently, 3) of the annual product by 1 April 2023 in the case that ACER makes such a recommendation by 1 April 2021. However, the CRU and other national regulatory authorities have been informed by ACER that it will not be making this recommendation. Regardless, the CRU is of the view that this approach warrants analysis and consideration.

2.2.2.5 Summary

The difference in these approaches is best highlighted by examining the costs of the daily product as it is the most expensive short term product, thereby emphasising the maximum difference in costs and seasonal trend. The daily capacity costs for each profile are presented in the figure below.

Figure 2.1: Daily capacity cost in each option



The dashed green line represents the current effective cost of daily capacity if a user were to buy the annual product (i.e. 1/365 = 0.27%).

The blue line represents the status quo. It is clear that this approach leads to the greatest variability in the seasonal profile. The daily capacity cost is effectively zero in Summer (0.05%) making it cheaper than the annual product equivalent (0.27%), but much more expensive in the Winter, peaking in February (2.28%) when it is over eight times more expensive than the annual product equivalent.

The red line (alternative 1) reflects the approach of current multipliers but with no seasonal factors. The cost is therefore equal throughout the year and at 0.77%, 2.79 times more expensive than the annual product equivalent.

The orange line (alternative 2) reflects the approach of current multipliers and adjusted seasonal factors. This approach produces seasonal variability but has a more muted profile than the current approach. The daily capacity cost is slightly more expensive (0.35%) than the annual product equivalent in summer (0.27%), with a greater difference in Winter, peaking in January (1.36%) when it is over five times more expensive than the annual product equivalent.

Finally, the grey line (alternative 3) represents the approach of daily multipliers reduced to 1.5 limit and no seasonal factors. The cost is therefore equal throughout the year and at 0.41%, 1.5 times more expensive than the annual product equivalent.

2.3 Review of options

2.3.1 Introduction

In section 2.1.2 the CRU set out the criteria it would use to review the four options set out in section 2.2. In order to further examine the multiplier and seasonal factor options the CRU have separated these two components where possible. This is because there are different Art. 28 criteria that need to be considered when setting each. In this section the CRU has provided a summary of its review, for further detail on the CRU's review, particularly the data used to analyse these options, please see appendix A and the spreadsheet (CRU/21/14b) published alongside this paper.

2.3.2 Multipliers

The options are now assessed against the following criteria as set out in section 2.1.2.

(i) the balance between facilitating short-term gas trade and providing long-term signals for efficient investment in the transmission system;

(ii) the impact on the transmission services revenue and its recovery;

(iii) the need to avoid cross-subsidisation between network users and to enhance cost-reflectivity of reserve prices;

(iv) situations of physical and contractual congestion;

(v) the impact on cross-border flows.

As highlighted by the table below, Alternative 3 is the only option that would result in a change to the multipliers. As such, the differences between this option and the base case (status quo) is the focus of the analysis in this section. However, as the other alternatives may also lead to changes in user behaviour (e.g. capacity bookings), this information is also included here for reference and because it is important to consider their overall impact on a joint basis.

Table 2.3: Multipliers for capacity products

Capacity Product	**Status quo**	Alternative 1	Alternative 2	**Alternative3**
Annual	**1**	1	1	**1**
Quarterly	**1.35**	1.35	1.35	**1.2**
Monthly	**1.5**	1.5	1.5	**1.3**
Daily	**2.794383812**	2.794383812	2.794383812	**1.5**
Within day	**2.794383812**	2.794383812	2.794383812	**1.5**

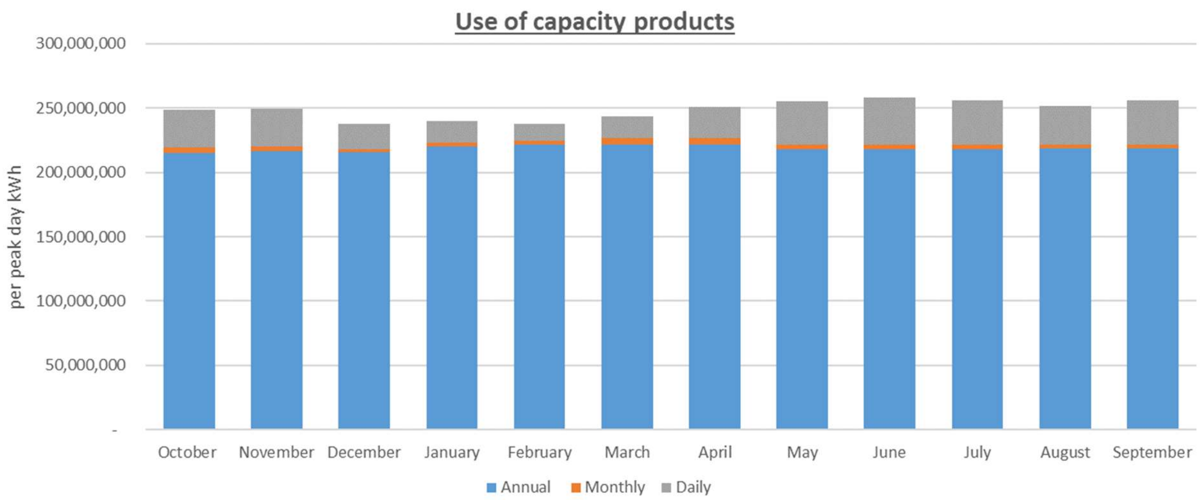
The balance between facilitating short-term gas trade and providing long-term signals for efficient investment in the transmission system

As highlighted earlier, multipliers are applied to the non-yearly costs in order to increase the relative attractiveness of the annual product versus the non-annual products. It is important to strike the correct balance in this regard; however, it presents a challenge. On the one hand if the price of non-annual products is at a too high level, it would reduce the ability of gas traders to participate in short-term trade; on the other hand, if it is too low, there could be reduced long-term bookings, resulting in reduced long-term signals for investments.[25] However, the importance of this signal is reducing as gas demand is expected to reduce in the longer term, reflecting decarbonisation policy, leading to spare capacity on the network. The non-annual capacity multipliers should therefore be set at a level that encourages annual capacity booking, where the end user requires capacity on an annual basis.

[25] This is because gas network operators look at changes in forecasted capacity booking profiles for signals on changes in demand as they plan the future development of their networks. It is argued that the presence of longer-term stable capacity bookings can provide a better indication of future demand.

In order to assess this criteria, the CRU has examined the levels of bookings for each of the various capacity products and benchmarked the multiplier options against those in other member states. This analysis, which is detailed further in Appendix A, essentially provides an initial 'health' check for the reasons discussed in the appendix, with more detailed analysis provided in the review of the other criteria.

Figure 2.2: Use of capacity products at exit per peak day kWh (average of last five years)



The examination of the current levels of bookings in the figure above shows that annual capacity makes up the majority of bookings at exit, with daily and the monthly making up the rest.[26] This indicates that the status quo application of multipliers encourages annual capacity bookings, where the end user requires capacity on an annual basis and does not appear to make short-term capacity products economically unviable. As the vast majority of network users use natural gas all year round, it is not surprising that annual capacity bookings are by far the most prevalent.

The benchmarking analysis (Appendix A) against other member states indicates that the status quo multipliers are comparable and that Ireland is not an outlier in this regard. In addition, a reduction to multipliers under Alternative 3 would not cause Ireland to become an outlier.

Therefore, the initial analysis provided under this criteria indicates that both the status quo and alternative 3 options do not fail to meet this criteria. However, this analysis is best described as providing an initial 'health' check only.

[26] Quarterly is not included in the figure as there were no quarterly capacity bookings at exit.

The impact on the transmission services revenue and its recovery

Tariffs are paid by network users so that GNI can recover its transmission services revenue. As multipliers effect the levels of the tariffs, they can also have an effect on the recovery of the transmission services revenue. For example, large daily multipliers can significantly increase the cost of daily capacity products. The cost differential created between the annual capacity product and the daily capacity product will send signals/ incentives to network users, which can affect what capacity products they decide to purchase. This can have a significant effect on the recovery of transmission services revenue and the level of the annual tariffs.[27]

As the cost of the capacity bookings differs under the options put forward by GNI, network users would be expected to respond to the various cost signals sent under each option and book capacity in different ways to suit their needs. By forecasting the expected bookings under each option, GNI estimates the impacts of these options on revenue recovery. These forecasted bookings are developed by GNI. GNI's optimisation software package estimates the lowest cost way in which shippers in each market segment can meet assumed booking requirements throughout the year given the different capacity product costs.

This analysis, which is detailed further in Appendix A, indicates that a reduction in the daily multiplier to 1.5 under Alternative 3 will lead to a significant increase in daily capacity bookings when compared to the status quo. A large majority of the increase in daily bookings is attributable to the Power sector, with a minor increase in the Large Industrial and Commercial (Large I&C) sector. There is no change in the Residential & SME sector as these users are required to book annual capacity.

[27] For example, if GNI's capacity forecasts indicated that demand for the more expensive shorter-term capacity products was going to increase, there would be a reduction in the annual capacity tariff to offset the additional revenue that would be recovered through the use of these more expensive products. However, in the event that a significant increase in daily capacity booking patterns was not foreseen and tariffs weren't adjusted, it could lead to significant over recoveries of revenue. This revenue would need to be returned to customers in future years through a decrease in the tariffs. Therefore, having large multipliers for the non-annual capacity products can also lead to increased revenue and tariff volatility.
On the other hand, having very low non-annual multipliers reduces the incentive to book annual capacity. Annual capacity bookings are associated with more stable cost-recovery as capacity is booked for the entire year and paid for over the course of the entire year regardless of whether the network user flows gas or not. Having very low non-annual multipliers could lead to a sort of commoditisation of capacity bookings, whereby capacity is only booked (by those who can avail of these products) on a daily basis for the amount of gas that needs to be flowed. Therefore, on a day where expected gas flows are not realised, capacity will not be booked and GNI recovers less revenue. Therefore, low multipliers for the non-annual capacity products can also lead to increased revenue and tariff volatility.

The increase in daily bookings for the Power sector under Alternative 3 appears to be a result of the reduction in daily multiplier as it allows for more efficient (cheaper) portfolio optimisation, i.e. capacity bookings that more closely match the variable gas demand associated with this sector.

The forecast capacity bookings under Alternative 3, would at current tariff levels, reduce GNI's transmission revenue by approximately €28m. The level of the annual tariff would therefore need to increase to recover this revenue. The CRU estimates that the transportation cost of GB gas[28] (annual Moffat entry capacity tariff + annual domestic exit capacity tariff) would increase by 18% under this option. To give further context to this effect, this tariff increase would lead to an approximate increase in a residential customer's bill of €11.7 (1.4%). However, it is important to note that not all customers would see an increase in cost, some users of non-annual capacity products may see a reduction cost. These redistributive effects are examined further under the next criteria.

A key tenet of the CRU's tariff methodology is tariff stability. There is the potential for reduced multipliers to effect tariff volatility in different ways. It is therefore is difficult to determine whether Alternative 3 would lead to more or less stable tariffs in the longer-term. However, it is clear that in the short-term this would likely lead to increased tariff volatility.[29]

The need to avoid cross-subsidisation between network users and to enhance cost-reflectivity of reserve prices

A key element of the CRU's 2019 review of the Matrix RPM centred around the cost-reflectively of reference prices in order to send appropriate signals to attract new investment where it can be shown to be efficient. While the continued application of the Matrix RPM ensures that the reference prices (i.e. annual capacity tariff) are cost-reflective, it is important to consider if the multipliers derive prices for the non-annual products that are also cost reflective. As highlighted earlier in Figure 2.1, the status quo multiplier and seasonal factor profile can lead to daily

[28] The transportation cost of GB gas is important because Irish wholesale gas prices are generally 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.

[29] As part of the analysis in Appendix A the CRU also examined the expected impact on capacity bookings and costs under Alternative 1 (no seasonal factors) and Alternative 2 (adjusted seasonal factors). Although these options do not change the multipliers, they change the cost of the non-annual products during the year and therefore would also be expected to lead to a change, albeit smaller, in capacity bookings. The analysis indicates that under Alternative 1 and Alternative 2, there would also be an increase in non-annual capacity products, however in the monthly rather than daily product. It is estimated that this would lead to a 6% and 4% increase in the cost of transportation of GB gas under Alternative 1 and Alternative 2, respectively. This tariff increase would lead to an approximate increase in a residential customer's bill of €3.7 (0.4%) and €2.8 (0.3%) under Alternative 1 and Alternative 2, respectively. However, costs would not be expected to increase for users who can avail of non-annual capacity.

capacity costs that are many times (up to 8x) more expensive than the equivalent daily cost of an annual capacity product.

TAR NC requires that the transmission services revenue is recovered through capacity-based charges. This is because capacity is one of the main network cost drivers along with pipeline distance. It is argued that the presence of longer-term stable capacity bookings may provide a better indication of future demand and may allow GNI to reduce network costs through better planning. Therefore, there is an argument that shorter-term products should be priced at a premium as they could potentially increase network costs.

With regard to cross-subsidisation, this 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.[30]

The analysis, which is detailed further in Appendix A, indicates that a reduction in the multipliers under Alternative 3 provides a benefit to users of non-annual capacity products at the expense of those who cannot avail of these products. This redistribution of revenue is not necessarily negative, particularly, if it leads to greater cost-reflectivity. However, identifying the costs associated with different network user types is challenging, due to the differing timings and physical locations of the customers. In order to generate a high-level estimate of the costs associated with each sector the CRU has, as a proxy, examined the relative peak demand of each sector as it is peak demand that drives network costs. The CRU has then compared the estimated relative cost per sector (as reflected by the proportionate peak demand of that sector) with the relative costs recovered from each sector (as estimated from the forecasted booking profiles). Although it is subject to significant uncertainty, this analysis indicates that it would lead to a reduction in cost-reflectivity. Under the status quo it appears that the proportion of revenue recovered per sector, generally reflects the proportional peak demand per sector.

However, the analysis highlights a potential redistribution of revenue under Alternative 3. As highlighted earlier there is a reduction in transmission revenue due to the reduction in multipliers and increase in daily capacity bookings by the Power sector. This reduction in transmission revenue would lead to an increase in the annual tariff to ensure cost recovery. This reduces the

[30] Cross-subsidies could arise between network users with rather flat transmission patterns and those with highly variable ones, since a very significant reduction in non-annual multipliers would result in a shift from longer-term to shorter-term capacity bookings and an increase in tariffs for those with flat transmission patterns due to reduced revenue recovery, as highlighted under the previous criteria.

proportion of costs recovered from the users of non-annual capacity products at the expense of those who can not avail of these products. This creates a greater differential between the proportion of revenue recovered per sector and the proportional peak demand per sector. As this redistribution of revenue does not appear to be cost-reflective it therefore may increase the potential for undue cross-subsidisation under Alternative 3.[31]

Situations of physical and contractual congestion

Currently, there are no issues of physical or contractual congestion on the Irish gas network. GNI keeps the gas network under review for both contractual and physical congestion on an ongoing basis. GNI's annual Network Development Plan assesses adequacy of the gas transportation system and security of supply. As part of its submission GNI stated that it "does not anticipate that proposed changes to the multipliers will impact the overall power demand on the natural gas network, which is determined by overall electricity demand and renewables."

There are currently no situations of physical and contractual congestion on the network. As GNI does not foresee these issues arising due to changes in the multipliers the CRU has not considered this criteria in more detail, however it will continue to be considered as part of the annual Art. 28 consultations in the event that there is a change in the situation.

The impact on cross-border flows

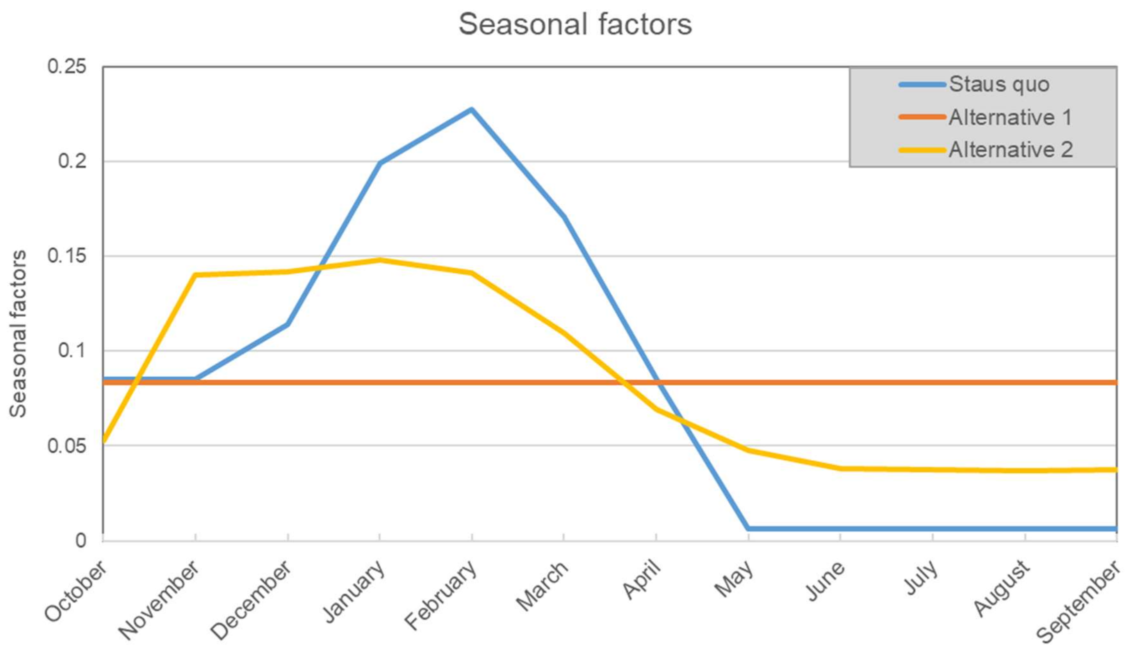
The Moffat interconnection point (IP), allows for gas flows into Ireland from GB. Domestic production is first in the merit order in terms of supply to Irish customers, with flows from GB via Moffat providing the marginal source. There is also an IP with the Northern Irish gas transmission system at Gormanston. The Gormanston IP is unidirectional, only allowing for gas flow from Ireland into the Northern Irish gas transmission system. However, no commercial gas currently flows in that direction; it is used for emergency support only. Therefore, gas flows into Ireland are a result of gas demand from Irish customers only, as there are no cross-system flows. As proposed in the call for evidence paper the CRU has excluded this Art. 28 criteria from the review due to its lack of applicability. The CRU notes that the facilitation of short-term trade with GB (which doesn't necessitate cross border flows due to the Virtual Reverse Flow (see section 3)) is considered to some degree under the criteria, which examines the balance between facilitating short-term gas trade and providing long-term signals for efficient investment in the transmission.

[31] As part of the analysis in Appendix A the CRU also examined the expected impact on capacity bookings and costs under Alternative 1 (no seasonal factors) and Alternative 2 (adjusted seasonal factors). As these options have a smaller effect on capacity bookings and revenue recovery, they do not lead to the same levels of redistribution of revenue as Alternative 3 and therefore have less impact on cost-reflectivity and the potential for undue cross-subsidisation.

2.3.3 Seasonal factors

The seasonal factor is multiplied by the relevant multiplier and the result is combined with the reference price to derive the tariff for each non-annual capacity product. The figure below highlights the seasonal factors applied for each month under the status quo, Alternative 1 and Alternative 2. Alternative 3 is not considered here as the seasonal factors are the same as Alternative 1, i.e. removal of seasonal profile.

Figure 2.3: Seasonal factors



The seasonal factors are now assessed against the following criteria as detailed in section 2.1.2:

(i) the impact on facilitating the economic and efficient utilisation of the infrastructure;

(ii) the need to improve the cost-reflectivity of reserve prices.

<u>The impact on facilitating the economic and efficient utilisation of the infrastructure</u>

It is important that the gas network is used in an efficient way. The network is built to provide enough capacity for a 1 in 50 peak day[32]. Historically, these peak days have occurred in the winter months. As highlighted earlier, the status quo seasonal profile is derived from the probability of a peak day. This is because incremental peak demand is a trigger of network

[32] A 1-in-50 peak day is the requirement to fulfil gas demand during a 1-in-50 year severe weather scenario.

investment. The result is increased winter capacity costs and reduced summer capacity costs. This cost profile promotes efficient utilisation of the network by making in cheaper to use the network at times where there is spare capacity and more expensive to use the network at times of peak capacity to avoid additional investment costs.

From the analysis, which is detailed further in Appendix A, it appears that the network is currently being used in a relatively efficient way. However, the CRU is of the view that the status quo profile (i.e. current seasonal factors) may no longer be significantly affecting how networks users physically use the network, as evidenced by the effect of wind generation on gas generation. In addition, the importance of sending signals to potential future gas demand is reduced given the Government's decarbonisation policy. As a result, it is questionable whether the status quo seasonal factor profile is actually facilitating the economic and efficient utilisation of the infrastructure and this raises the question as to whether a seasonal factor profile of reduced magnitude (Alternative 2) or no seasonality (Alternative 1) may be warranted.

The need to improve the cost-reflectivity of reserve prices

As highlighted earlier in the discussion on the cost-reflectivity of multipliers, the Matrix RPM ensures that the reference prices are cost-reflective. Therefore, in this regard, it is important to consider if the seasonal factors derive reserve prices for the non-annual products that are also cost reflective.

Figure 2.1 illustrated the significant effect that the combined daily multiplier and seasonal factor profile can have on daily capacity costs, which are up to 8x more expensive in winter and significantly cheaper than then annual capacity cost in summer. As discussed further in Appendix A, the status quo seasonal factors are a result of a small number of adjustments over time, which have altered the profile from its original format[33]. These adjustments, which were made to reflect certain attributes of the gas market, may no longer be warranted given that these attributes have changed (i.e. cessation of seasonal storage and changing role of gas plants). This raises a question as to the cost-reflectivity of the status quo profile, particularly as it results in daily capacity costs during the summer that are less than the cost of the annual product on a daily basis (1/365), which is a direct output of the cost-reflective Matrix tariff methodology.

As discussed in more detail in Appendix A, the CRU is of the view that both Alternative 1 (a removal of seasonal factors) and Alternative 2 (a reduction in the seasonal variation) may be more cost-reflective than the status quo.

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[33] CER/07/115

2.3.4 Conclusions

The CRU have considered the options submitted by GNI and has analysed the data provided alongside these options. Although the multipliers and seasonal factors have been examined separately in order to allow for separate consideration against their associated Art. 28 criteria, it is also important to consider their overall impact on a joint basis. In addition, it is important to note that there is complexity and uncertainty surrounding this topic due to the potential impacts on a wide-range of elements of the gas market, such as those highlighted in section 2.1.1. In coming to its initial opinion, the CRU has considered the relative importance of each criteria/ element, as some of these are more relevant than others in the context of the Irish gas market. In addition, the CRU is keen to hear the views of stakeholders because it is the users of the network who would be directly affected by changes to the multipliers and seasonal factors. Finally, it is important to note that the CRU is cognisant of the complexity and uncertainty involved and therefore if a decision is made to change the multipliers and seasonal factors, it would be appropriate for there to be ongoing monitoring of impacts.

Firstly, with regard to multipliers, the CRU's assessment under each criteria is summarised in the table below. The CRU has not identified negative outcomes resulting from the application of the current multipliers. For this reason, the CRU is of the view that a reduction in the daily multiplier limit to 1.5 (alternative 3) may not be warranted, particularly as it may lead to an increase in the potential for undue costs being placed on the Residential & SME customer sector. **As a result, the CRU is consulting on a proposal to maintain the current daily multiplier at 2.79.**

Table 2.4: Multiplier review - summary table

	Balancing short-term trade & long-term signals for investment	Impact on revenue and its recovery	Avoid cross-subsidisation and enhance cost-reflectivity	Physical and contractual congestion	Cross-border flows
Status quo (Daily 2.79)	-	-	✔	-	n/a
Alternative 3 (Daily 1.5)	-	✗	✗	-	n/a

Secondly, with regard to seasonal factors, the CRU's assessment under each criteria is summarised in the table below. The CRU's view is that the status quo seasonal factor profile may no longer provide an effective incentive for current or future network users to utilise the gas infrastructure more efficiently. This is due to the effect of wind generation on gas demand and the decreased likelihood of significant additional gas demand due to decarbonisation policy. The alternative options may not also create this incentive but may be preferable to the status quo as they alter the price of non-annual products to a lesser degree and are therefore less likely to have unintended impacts elsewhere. In the context of cost-reflectivity the CRU is also of the view that both Alternative 1 (a removal of seasonal factors) and Alternative 2 (a reduction in the seasonal variation) may be preferable to the status quo, which may be leading to a reduction in cost-reflectivity as a result of a change to market dynamics since they were last adjusted.

Table 2.5: Seasonal factor review - summary table

	Efficient utilisation of gas infrastructure	Improving cost-reflectivity
Status quo	-	×
Alternative 1 (no seasonality)	-	-
Alternative 2 (reduced seasonality)	-	-

Given the current uncertainty surrounding the effectiveness of the incentive that seasonal factors may provide networks users and considering the potential for the signal to have unintended effects, the CRU is of the view that their removal may be warranted. Although the CRU is of the initial view that the removal of seasonal factors may be justifiable, the CRU is cognisant of, amongst other things, the importance of tariff stability and certainty for the market, particularly as there could potentially be significant effects for individual network users. Therefore, any change from the status quo should be incremental in nature. As a result, the CRU is of the initial view that the complete removal of seasonal factors under Alternative 1 would not be in the best interests of gas consumers at this time and instead **the CRU is consulting on a proposal to implement Alternative 2 as it provides for an incremental change.**

As this change alters the cost of booking non-annual capacity over the course of the year, there may be an effect on how non-annual capacity users (e.g. Power sector) book capacity to match their demand requirements, and subsequently, how GNI recovers its allowed revenue. GNI's analysis indicates that the change in bookings may lead to upward pressure in the cost of annual capacity. In terms of quantifying the impact, there is considerable uncertainty, however GNI estimates that Alternative 2 could result in a 4% increase in the cost of transporting gas from the Moffat entry point[34], which could equate to an increase of up to €2.8 or 0.3% on a residential customer's annual bill. This is because residential customers are required to book annual capacity for security of supply reasons. However, it is important to note that not all network users would see an increase in cost and, on balance, the CRU is of the view that this change should positively impact the gas market, by making charges more cost-reflective charges and reducing the potential for cost volatility. The CRU is keen to hear the views of stakeholders on this

[34] Annual Moffat entry capacity tariff + annual domestic exit capacity tariff. The transportation cost of gas from Moffat (a.k.a. GB gas) is important because Irish wholesale gas prices are generally 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.

proposal and will consider these as part of any decision on whether to change the levels of seasonal factors for the gas year 2021/22.

2.4 Summary and request for comment

In accordance with the approach set out in last year's call for evidence paper (CRU/20/057), the CRU has engaged with GNI to further review the multipliers & seasonal factors. In undertaking this review the CRU is cognisant of the potential for changes to multiplier & seasonal factors to have several wide-ranging redistributive effects. The CRU has examined four options submitted by GNI and the additional information provided on their potential impacts. The CRU has assessed these options against the criteria set out in the network code and in the context of the Irish gas market.

The CRU has come to the initial view that the multipliers should remain at their current levels but that the variation in the seasonal factor profile should be reduced. This is represented by the option called 'Alternative 2'. This option, if implemented may lead to some redistributive effects for network users, potentially leading to a slight increase in costs for residential customers. However, on balance, the CRU is of the view that it will benefit the gas market as it reduces the possibility of the seasonal factors sending unintended signals to network users and negatively impacting cost-reflectivity.

The CRU is keen to hear the views of stakeholders and will consider these as part of any decision. If, as part of its decision, the CRU decides to change the seasonal factors, there will be ongoing monitoring in this area to identify impacts.

CRU Questions

1. Do you agree with the CRU's proposal to apply alternative 2? Please provide a rationale for your answer.

2. Should this change be implemented for gas year 2021/22? Please provide a rationale for your answer.

3 Level of discounts

3.1 LNG

TAR NC[35] allows for the adjustment (i.e. discount) of tariffs at entry points from LNG facilities. Unlike storage[36], TAR NC allows for, but does not require, the application of discounts to LNG 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.

In CRU/19/060 the CRU stated that it was of the view that it is in the public interest to continue to consider the case for LNG discounts as new information becomes available. To this end the CRU decided that proposed LNG projects can apply for a potential discount. The CRU set out non-binding criteria[37], against which applications for discounts would be assessed and timelines for submissions (the CRU must be notified of an application 18 months before the start of the gas year in which discounts are sought, with a formal application 12 months before tariffs are set for that year).

The CRU continues to be of the view that this approach is appropriate. As the CRU has not yet set a discount, it cannot consult on the level of any LNG discount. The CRU will consult prior to setting an LNG discount in the future and will consult annually on the level of that discount as required by Art 28.

3.2 Interruptible discounts – Virtual Reverse Flow

3.2.1 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 Ireland via Moffat and into Ireland via Gormanston.[38] VRF is a day-ahead interruptible[39] product and the only interruptible product.

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[35] 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.
[36] There are currently no storage facilities in operation in Ireland since the Kinsale gas fields began the blowdown of cushion gas. However, as stated in CRU/19/060, in the event that a storage facility began operation the CRU would apply at least a 50% discount in accordance with Art. 9. 1.
[37] See Section 3.8.3. of CRU/19/060 for further information.
[38] For example, if there is a total nomination of 100 units of gas for delivery from GB to Ireland and a gas shipper in Ireland wishes to virtually transport 10 units of gas from Ireland to GB, these 10 units are netted off the 100 units, resulting in the delivery of 90 units into the Irish gas network.

In accordance with the CRU's TAR NC decision paper, for gas year 2019/20 a new tariff was introduced for VRF, which replaced the previous registration fee approach. The calculation of the VRF tariffs at Moffat and Gormanston are now based on the TAR NC principles and requirements for standard interruptible capacity products.

Art. 16 of TAR NC 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 formula for calculating the adjustment which should be applied is set out in TAR NC and is as follows:

$$Di_{ex-an} \quad = Pro \times A \times 100\%$$

Where:

$Di_{ex\text{-}ante}$ is the level of the ex-ante (forecast) adjustment;

Pro Factor is the probability of interruption;

A Factor 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).

Full details on how the CRU sets the VRF tariffs for Moffat and Gormanston and the reasoning for its approach, can be found in section 3.11 of the CRU's TAR NC decision paper (CRU/19/060), in summary:

- The VRF tariffs are based on the Moffat exit point and Gormanston entry point reference prices, as calculated by the Matrix RPM.
- A Pro Factor of 8% is applied to the Moffat and Gormanston VRF products.
- A risk premium of 10% is applied to both the Moffat and Gormanston VRF products.
- A market interaction factor of 30% applies to the Moffat VRF product only to bring the price below that of the equivalent forward flow tariff for reasons of cross-border trade.

These inputs result in an A-factor of 6 for Moffat VRF and an A-factor of 2.25 for the Gormanston VRF.

[39] 'Interruptible' capacity means gas transmission capacity that may be interrupted by the network operator. As this capacity is not guaranteed to be available it is often discounted. VRF is interruptible as flows from GB to Ireland are required to enable VRF as highlighted by the example in footnote 38.

For the gas year 2020/21 this resulted in a Gormanston VRF reference price of €76/MWh and a Moffat VRF reference price of €271/MWh. By comparison the Gormanston exit reference price is €385/MWh and the Moffat Entry reference price is €315/MWh. Daily multipliers are not applied to the VRF product as it can only be booked on a daily basis (there is no annual VRF product). However, seasonal factors are applied to the VRF product. So, for example, the cost to book daily VRF capacity at Moffat in February is €57/MWh[40], while the cost in June is €1/MWh. Therefore, if the CRU implemented a change to the seasonal factors, as is proposed in section 2.4, it would have an impact on the cost of VRF during the year and make it less variable.

In accordance with Art.4 of TAR NC, commodity charges apply to use of the VRF product.

It should be noted that in moving from the previous registration fee to the above tariff saw a large increase in the cost of using VRF. The CRU was cognisant of this and took measures to ensure that the tariff reflected the nature of the VRF product while also ensuring that the VRF tariffs were lower than their forward flow equivalents to help avoid cross-border flow distortions. Setting the tariff in this way was a pragmatic approach based on the balance of information available and is aimed at ensuring utilisation of the VRF service. More about the challenges of setting an appropriate VRF tariff are now discussed.

3.2.2 Purpose of VRF and challenge in setting the tariff

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 notional location for trading 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.

As there are currently no flows through the Gormanston IP, VRF is not bookable at this IP, and has not been used. However, it is bookable and has been used at the Moffat IP, i.e. to export gas from the IBP to the NBP. The data shows that it has typically been used by shippers who are active at the Bellanaboy entry point (i.e. those shipping gas from the Corrib gas field).

[40] (€250*2.28%)/2.79

As the IBP price should in theory be above the NBP price, one expects that the majority of gas from the Corrib gas field will be sold to Irish customers, with VRF enabling any surplus to demand at the IBP to be sold at the NBP.[41]

These trades at the IBP and the use of VRF must be assessed in the round with market dynamics that can at times be complex. Gas markets can often be simultaneously importing and exporting, as is currently the case in GB (exporting gas via interconnectors and importing gas via LNG tankers). There are also numerous confidential contracts between gas undertakings (e.g. producers, shippers, and suppliers), which the CRU does not have sight of. The numerous push and pull factors at play at any one time, make it difficult to have full sight of what is driving the price of gas and the use of VRF. This makes it challenging to set a “correct” economic value or A factor for the VRF product.

In setting the VRF tariffs, the CRU acknowledged these challenges and stated that it is difficult to predict all impacts of the new tariff. Given this, the CRU considered it important to assess, to the extent possible, the impacts of the new VRF tariff. The CRU receives data from GNI in this regard.

As part of last year’s Art. 28 call for evidence paper (CRU/20/057) the CRU presented the data it had received at that time and decided to not make any changes to the VRF discount. This was decided in order to allow for additional analysis as at the time of last year’s paper the new tariffing approach for VRF not yet been in place for a full gas year, having come into force on 01 October 2019. As the dynamics in the gas market change over the course of the year and the seasonal factors change the cost of the VRF product throughout the year, the CRU had yet to see the full impact of the new tariffing approach. The CRU asked respondents for their views on the CRU’s analysis and if they had any further information to share on the economic value of tariff. With regard to the former the CRU received useful feedback on its analysis and for the latter the CRU did not receive the type of information which can assist in estimating its value.

The CRU has now received data covering the full year since the new VRF tariff was introduced. The CRU has updated its analysis with this new information and where relevant has incorporated the feedback on the analysis presented in last year’s call for evidence paper. The goal of this analysis is to assess whether the VRF discount is appropriate, by examining the trends over time, comparing VRF use before and after the new tariff was introduced and the factors that might affect the use of VRF.

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[41] Please note that not all gas is sold at the IBP and shippers can trade gas bilaterally to or from other balancing points; sourcing gas for example across the interconnector from GB. So, this surplus only reflects that Corrib was trying to sell more gas at the IBP then purchasers were willing to buy.

3.2.3 Analysis

3.2.3.1 Use of VRF

The dataset consists of daily information on the system average price (SAP) at the IBP and NBP, VRF use, and IBP to NBP transportation costs. As there are currently no flows through the Gormanston IP, VRF is not available, and therefore only data from the Moffat IP is analysed here. The main period of analysis ranges from 01 April 2019[42] to 30 September 2020[43]. The CRU has split the data into two periods and compared them. The first period, from 01 April to 30 September 2019, is when the registration charge applied (i.e. the capacity and commodity tariffs were zero) and the second period, from 01 October 2019 to 30 September 2020, is when the new tariff has applied.

The first step was to look at the use of VRF over the two periods. This is presented in Table 3.1.

Table 3.1: Use of VRF

metric	April '19 – September '19	October '19 – September '20
No. of days in period	183	363
VRF used (no. of days)	121	10
VRF used (% of days)	66.12%	2.75%

It is clear from the above table that the use of VRF has significantly decreased since the new tariff was introduced. This may indicate that the price of the new VRF tariff is at a level that makes the VRF product an unattractive option to shippers, i.e. it is not commercially viable to export gas from the IBP to the NBP. Recall that the A Factor aims to reflect the estimated economic value of the interruptible capacity product and that commercial considerations are part of the VRF tariff setting process.

However, the solution to this issue may not be a simple reduction in the VRF tariff as there are likely a number of factors that shippers consider, when deciding to use or not use VRF. An example of such factors are as follows: the cost of transporting gas from Ireland to GB, the price of gas at the IBP and NBP, and the level of Corrib production versus domestic demand. There are also other factors at play, but these are the most obvious and likely to be the most significant. The CRU has further explored data related to these factors below.

3.2.3.2 Cost of exporting gas from the IBP to the NBP

Table 1 highlighted that the use of VRF has effectively ceased since the new tariff was implemented. In order to understand the effect pre- and post- tariff consider the below example, which shows how the cost of VRF has changed. Two dates are used in this example, 01 January

[42] Date from which IBP activity set cashout prices.
[43] End of most recent gas year.

2019 and 01 July2019. As stated earlier, seasonal factors now apply to the use of VRF, resulting in different costs across the year. Starting with an IBP SAP of 30p/therm, two export cost scenarios are examined. The first scenario is represented by the columns with 'No tariff' in the header. This scenario is essentially the previous registration fee regime, where the cost of getting gas to the NBP was just the UK entry commodity charge. The second scenario is represented by the columns with 'New tariff' in the header. This scenario illustrates the cost of exporting gas to the NBP under the new tariff methodology that has applied since the beginning of gas year 19/20.[44]

Table 3.2: Cost of export

p/therm	01-Jan		01-Jul	
	No tariff	New tariff	No tariff	New tariff
IBP SAP	30	30	30	30
+				
RoI VRF exit capacity	0	1.66	0	0.04
+				
RoI VRF exit commodity	0	0.56	0	0.56
+				
UK entry commodity	1.67	1.67	1.67	1.67
=				
Total	31.67	33.89	31.67	32.27

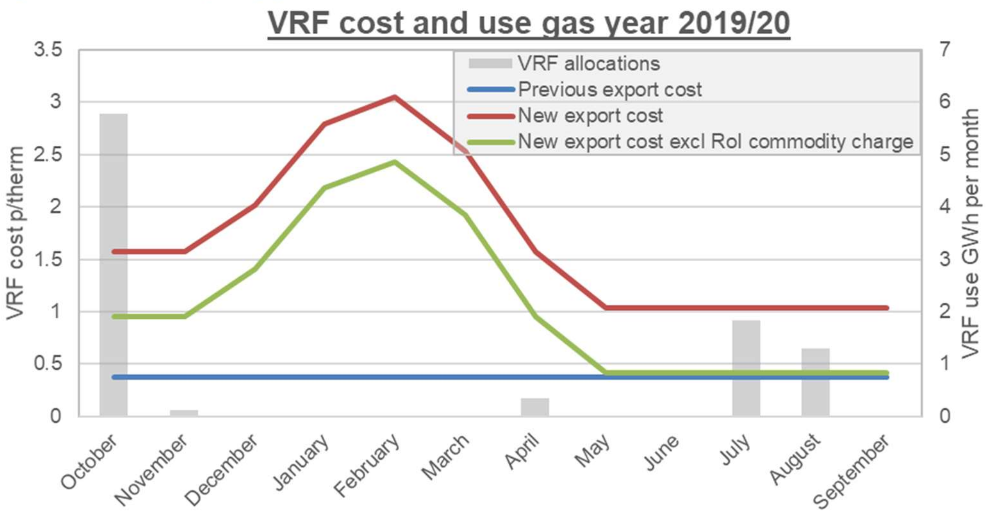
From the table, assuming an IBP SAP of 30p/therm, the cost of exporting gas to GB has increased by approximately 7% in the January example and 2% in the July example. This highlights the significant effect that the seasonal multipliers have on the cost of exportation.

The effect of seasonal multipliers is further examined in the table below, which examines the cost of VRF over the course of the year (GNI VRF Moffat daily exit capacity tariff + GNI exit commodity tariff + National Grid entry commodity charge). This graph also contains data on the use of VRF in gas year 19/20. The aim of this analysis is to identify whether there is an apparent relationship between the cost of VRF during the year and its use, with the expectation being that as the cost of VRF decreases the cost should increase.

[44] Note that the cost of VRF into the UK network has subsequently changed since a new tariff methodology was introduced from 01 October 2020, however this was outside the period examined in this paper and so we have not included it here.

The red line, which is plotted against the left axis, highlights how the export cost of VRF[45] changes during the year. The blue line, also plotted against the left axis, illustrates the previous export cost (i.e. National Grid entry commodity charge only), while the bars highlight the use of VRF in the period, plotted against the right axis. As already highlighted in table 3.1 there has been a significant decrease in the use of VRF during gas year 2019/20, with only ten instances of use. From the figure below it doesn't appear that there is any clear seasonal trend, for example there is no significant increase in use during the cheapest months of May to September. However, identifying trends is challenging due to the small sample size.

Figure 3.1: Cost of exporting gas from Ireland to GB via VRF



Therefore, this data fails to identify a trigger point in terms of cost for the use of VRF. One might argue, as a respondent did in their response to the call for evidence paper, that at the current cost VRF is not commercially viable and that it therefore needs to be lower for it to be utilised. However, when considering the range of the VRF cost, it is important to note that there is an effective floor on the cost of the VRF tariff. The CRU's VRF charge is made up of two main parts, the capacity charge and the commodity charge. The capacity charge varies throughout the year, resulting in the profile seen in Figure 3.1 above, while the commodity charge is flat. The capacity charge significantly increases the cost in winter; however, the capacity charge is effectively zero in summer. The green line in the figure above, illustrates this by graphing the new export cost[45] (red line) minus the GNI exit commodity tariff. Note that in the months May – September the green line (where commodity charges are removed) is nearly equal to the blue line (previous registration fee). This highlights that the difference between the new export cost and the previous arrangement (blue line) in the months May – September is made up almost entirely of the commodity charge.

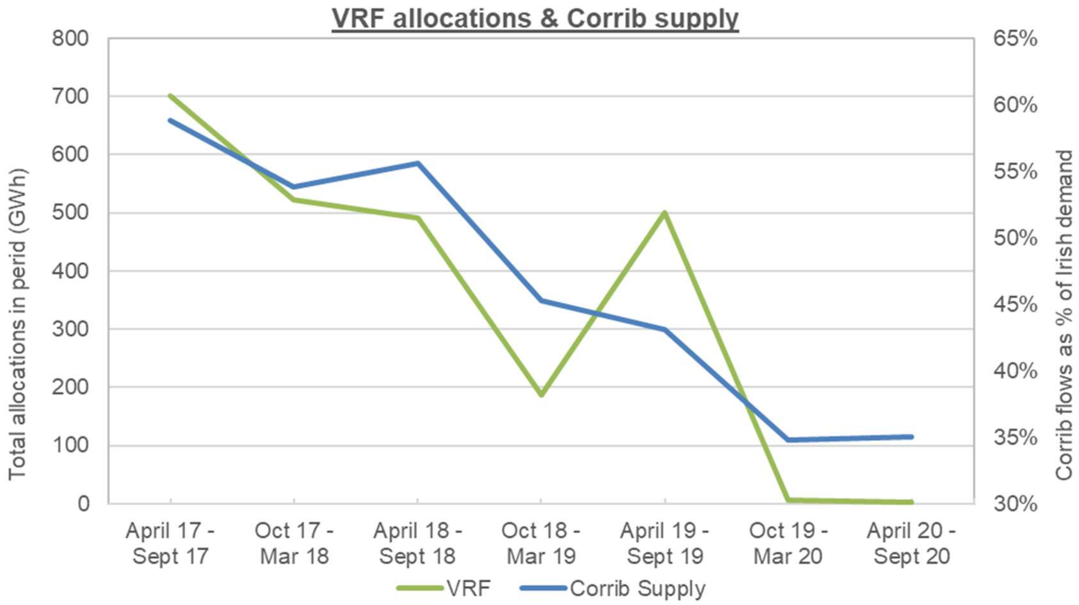
[45] GNI VRF Moffat daily exit capacity tariff + GNI exit commodity tariff + National Grid entry commodity charge

If the CRU was to reduce the VRF capacity charge through an increase in the A factor (which is the scope of the Art. 28 consultation), commodity charges would still apply. This is in accordance with Art. 4 of TAR NC which clearly states that the commodity charge shall be “the same at all entry points and the same at all exit points”. As Art. 4 of TAR NC is quite clear that commodity charges must apply at all points, the CRU’s scope to reduce the cost any further in the months May – September is constrained. The evidence i.e. continued lack of use of VRF in the summer months while the VRF tariff is at its floor, indicates that changes to the A factor may not increase the use of the VRF product. Instead it appears that there are other factors that also determine the use of this product, which are examined further in the subsequent sections.

3.2.3.3 Corrib production and Irish gas demand

Commercial gas flows at the Corrib entry point began in 2016 with maximum flows reached shortly thereafter, the field is now in decline. Therefore, the volume of gas shipped by individual shippers at the Bellanaboy entry point is in decline. In theory, as Corrib production reduces, the remaining portion (gas in excess of that needed by Irish customers supplied via Bellanaboy shippers) to be sold onto the NBP reduces and therefore the utilisation of VRF reduces. Figure 3.2 below highlights the relationship between VRF allocations and Corrib supply since Corrib reached maximum production.[46]

Figure 3.2: Relationship between VRF allocations and Corrib supply since peak production



[46] As highlighted in last year’s paper the relationship is disjointed prior to peak supply, where use of VRF was very high. The CRU stated that this was possibly due to reduced liquidity at the IBP and that it took time to develop the necessary commercial arrangements to supply Irish customers. A respondent to the CRU’s call for evidence paper agreed that the initial high level of VRF usage could in part be attributed to a lack of liquidity at the IBP, which has improved over time as the number of IBP counterparty relationships increased.

From the graph it is clear that as Corrib supply has declined, from approximately 60% of Irish demand to just above 35% of demand. The use of VRF has significantly dropped in the same period, particularly since October 2019, when the new tariff was introduced. The graph also highlights that there may also be some effect of the seasonal variation of Irish gas demand on the use of VRF. Irish demand is higher during the Oct – March periods, which when combined with a decrease in Corrib production, potentially results in less gas being available for export to GB and a significant reduction in the use of VRF as seen in Oct 18 – Mar 19, Oct 19 – Mar 20. The reduced Summer demand in the periods April 18 – Sept 18, April 19 – Sept 19 appear to slow the decline in the use of VRF. However, it appears that despite the tendency for VRF to be used to a greater degree in the summer and for the current tariffing arrangement to provide for the lowest cost for VRF at the same time, it was not a preferred option for gas shippers.

3.2.3.4 Commercials of exporting gas from Ireland

Gas shippers will naturally try to sell their gas at the highest price and therefore, on days where the NBP SAP is at a premium to (greater than) the IBP SAP, it could be expected that there would be a higher use of the VRF product, as it allows access to the GB market. As stated earlier, the IBP price is typically NBP plus transportation. In theory for it to make commercial sense to transport gas from Ireland to GB, the NBP premium has to be greater than the cost of transportation to GB, otherwise it would be more lucrative to sell the gas in Ireland. The relevant gas transportation charges in this case are the Moffat VRF capacity and commodity tariff and the GB entry commodity tariff (the GB entry capacity tariff at Moffat is negligible).

Last year the CRU compared the published IBP SAP[47] and NBP SAP spreads to identify the days where the use of VRF appeared to be profitable and whether there was an increase in the use of VRF on those days. However, the CRU could not identify a relationship between IBP and NBP spreads and the use of VRF. Given that there not has been significant use of VRF since the last year's analysis the CRU has not presented the updated analysis here as the trends are very similar and the same conclusion is reached, i.e. from the data there is no apparent relationship between the IBP and NBP spreads and the use of VRF in Ireland, indicating that there are other factors that have a more significant impact on its use.[48]

[47] The average price is published every day and is known as the system average price (SAP). The best estimate of the IBP SAP is the average price of visible trades, which are made on the IBP trading platform. However, the volume of gas traded on this platform is a small portion of the total gas demand in Ireland on a given day, and therefore there may be significant differences between the actual average wholesale gas price in Ireland and the IBP trading platform SAP.
[48] This view was shared by two respondents to the CRU's call for evidence paper.

3.2.3.5 Effects on trading platform

Last year the CRU has also examined the available data to see if the new tariff has had an impact on liquidity at the IBP. In order to estimate liquidity at the IBP the CRU examined the monthly volume of gas traded on the trading platform, however the CRU found that there were no obvious impacts on liquidity due to the new tariff. It is important to highlight that the trading platform is a small portion of the total gas demand in Ireland on a given day and that measures of liquidity on the trading platform are the best available estimate of overall IBP liquidity. Regardless, identifying the effect of VRF use on IBP liquidity would be a very complex exercise as there are a lot of variables which can influence the number and volume of gas trades on the IBP trading platform, such as; the level of Corrib production against demand at that time, commercial strategies, wind and temperature.

3.2.3.6 Effects on balancing

A couple of respondents to the CRU's call for evidence paper noted that VRF was an important balancing tool for gas shippers and that the new cost of VRF may make it more difficult for shippers to manage their portfolios, which could have a negative impact on the system due to it being left 'long' i.e. excess gas on the system. While one respondent noted that VRF not being used can be viewed as indicative that the IBP is increasingly efficient as a source of local balancing.

There are a number of factors (imbalance charges, etc.) that can affect how shippers behave with regard to their balancing obligations. The issue of the system being left long is something that has been discussed at the Code Modification Forums. The issue pre-dates any changes to the VRF tariff and is something that the CRU and GNI continue to monitor. The table below presents the number of days where GNI have taken balancing actions and the average size of these actions. If the system was being left long more often, the expectation would be that GNI would have to undertake more balancing sell actions. From the data in the table below it appears that there has been an increase in the number of actions, while the average volume sold has decreased. However, this trend is more than likely attributable to GNI's recent shift from the use of balancing contracts to the trading platform, which has seen a shift from larger balancing actions to more frequent, smaller actions, in line with their policy to steer the cumulative shipper imbalance back towards zero everyday rather than allowing it to drift.

Table 3.3: Balancing sell actions by GNI

metric	April '19 – September '19	October '19 – September '20
No. of days in period	183	363
Balancing sell days	24%	31%
Average volume of balancing sell actions	5,898,720 kWh	4,875,519 kWh

This concern was raised during when the CRU proposed the new tariffing arrangement for VRF. In the CRU's decision (CRU/19/060), it stated that "*The CRU acknowledges that the introduction of a VRF tariff may increase the costs of balancing and lead to greater use of alternative balancing products, such as the IBP platform, which may be more expensive than the status quo. Nevertheless, the CRU considers that the status quo VRF product (based on the registration fee) is under-priced and has signalled a move away from this for a number of years.*"

3.2.3.7 Summary

As highlighted in the previous sections, there are a number of factors which appear to affect the use of VRF. Last year, the CRU stated that "*The effect of significant increases in tariffs during the colder months, combined with the increased seasonal demand and reduced Corrib production could likely go some way to explaining the lack of use of VRF since October 2019*." However, the CRU wanted to collect more data on the VRF product, noting that the new tariff had not yet been in place for a full gas year and that "*The data that will be collected over the summer months will be particularly valuable as the CRU will then have been able to monitor the use of VRF under a wide range of different cost levels."*

The CRU has now collected this additional data and as highlighted in the sections above the use of VRF did not increase in the summer, when the tariff is effectively at its floor, and despite increased VRF use also typically being associated with the summer period. The CRU noted this possibility last year, "*a continued lack of us of VRF in these coming* [summer] *months may indicate that issues regarding its use cannot be solved by changes to the VRF tariff given that the tariff may be as low as can possibly be achieved."*

In the CRU's decision (CRU/19/060), it stated that "*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*." It therefore appears from the analysis that despite the very low cost of VRF in the summer, at a time when use has typically been at its highest, means that participants currently prefer the option of commercial swaps of gas. From the evidence gathered to date, both in the form of the quantitative data provided here and in the form of qualitative data from respondents to previous consultations, the CRU cannot put forward a reasoned alternative VRF discount. Importantly, the CRU has not identified any obvious negative outcomes for the gas market resulting from this change. Prior to the introduction of VRF, network users undertook swaps, these users also now have the ability to use the IBP trading platform which wasn't in place when the VRF product was first introduced.

3.2.4 Summary

There has been very limited use of the VRF product since the new tariff came into effect in October 2019. The CRU noted the possibility that by gathering additional information over a full gas year, particularly at a period where the tariff was at its lowest, it may be able to identify the point at which it becomes an attractive option for shippers. This could potentially give an indication of its economic value. The economic value is a key component in the VRF tariff formula and is meant to be reflect by the A factor, which is the scope of the Art. 28 consultation. In addition, the CRU has examined IBP – NBP spreads, the cost of exporting gas to GB and the relationship between Corrib production and domestic demand.

However, the numerous push and pull factors in play at any one time, continues make it difficult to have full sight of what is driving the use of VRF. The data does not point to any definitive factor or trigger point, which determines the use of VRF. It appears from the timing of the change that the limited use of VRF is in some part driven by the new tariffs. However, from the evidence gathered to date, both in the form of the quantitative data provided here and in the form of qualitative data from respondents to previous consultations the CRU cannot put forward a reasoned alternative VRF discount. For reasons that are unclear to the CRU, it appears that participants currently prefer the option of commercial swaps of gas. Importantly, the CRU has not identified any obvious negative outcomes for the gas market resulting from this change.

The CRU requests the views of industry on its analysis and would welcome proposals (supported by data and analysis) for an alternative VRF discount (within the Art. 28 consultation scope) that could be considered as part of next year's consultation.

The CRU proposes that the level of the discount (referred to as the A-factor) will continue to be as follows for gas year 2020/21.

Table 3.4: Virtual reverse flow A-factor

Interconnection point	A-factor
Moffat	6
Gormanston	2.25

Finally, the CRU notes that if the change to the seasonal factors, as is proposed in section 2.4, is implemented, it would have an impact on the cost of VRF during the year and make it less variable.

CRU Questions

3. Do you have any views on the CRU's analysis of VRF use? Please provide a rationale for your answer.

4. Do you have any proposals (supported by data and analysis) for an alternative VRF discount (within the context of the Art. 28 consultation scope) that could be considered as part of next year's consultation?

4 Conclusion & next steps

The CRU has with this paper carried out its annual tariff network code Art. 28 review, in advance of gas year 2021/22.

Within Section 2 of this paper the CRU has proposed to maintain the multipliers but adjust the seasonal factors. This adjustment, Alternative 2, would have the effect of reducing the variation in the current seasonal factors. The CRU has requested comment from stakeholders on this proposal. The CRU has also presented additional analysis in Appendix A, which respondents should consider in their submissions.

Within section 3 of this paper the CRU provided an assessment of the impacts of the new VRF tariff. It examines the trends in use over time (comparing VRF use before and after the new tariff was introduced) and the factors that might affect the use of VRF. There has been very limited use of the VRF product since the new tariff came into effect in October 2019. However, the CRU has not identified any obvious negative outcomes for the gas market resulting from this change.

To aid respondents, Table 4.1 provides a list of all questions posed throughout the paper.

4.1 Request for comment

Table 4.1: Request for comment

Topic	Query	Section
Multiplier & seasonal factor review	1. Do you agree with the CRU's proposal to apply alternative 2? Please provide a rationale for your answer.	2.4
Multiplier & seasonal factor review	2. Should this change be implemented for gas year 2021/22? Please provide a rationale for your answer.	2.4
Virtual reverse flow	3. Do you have any views on the CRU's analysis of VRF use? Please provide a rationale for your answer.	3.2.4
Virtual reverse flow	4. Do you have any proposals (supported by data and analysis) for an alternative VRF discount, (within the context of the Art. 28 consultation scope) that could be considered as part of next year's consultation?	3.2.4

4.2 Next steps

The CRU will consider responses from stakeholders on the above questions. These responses will be assessed and incorporated into the CRU's decision in March/ April 2021.

The following are the milestones that follow the publication of this call for evidence paper:

- Four-week response period i.e. deadline for responses is close of business 10 March 2020.

- The CRU will review responses and engage with GNI. Further analysis may be carried out to examine issues highlighted in the responses. Decision published in March/April 2021.
- CRU publication of tariffs for gas year 2021/22 – by 05 June 2021.
- New gas tariffs coming into effect – 01 October 2021.

CRU Disclosure Requirements

Unless marked confidential, all responses from companies or organisations may be fully 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 members of the public will be anonymised prior to publication on the CRU website unless the respondent explicitly requests their personal details to be published.

The CRU privacy notice sets out how we protect the privacy rights of individuals and can be found here.

A Appendix – Multipliers & Seasonal factors analysis

In section 2.3 the CRU provided its initial views on multipliers and seasonal factors. This appendix provides further detail on the CRU's analysis and elaborates on the CRU's initial views. In addition, the spreadsheet (CRU/21/14b) published alongside this paper for further information.

A.1 Multipliers

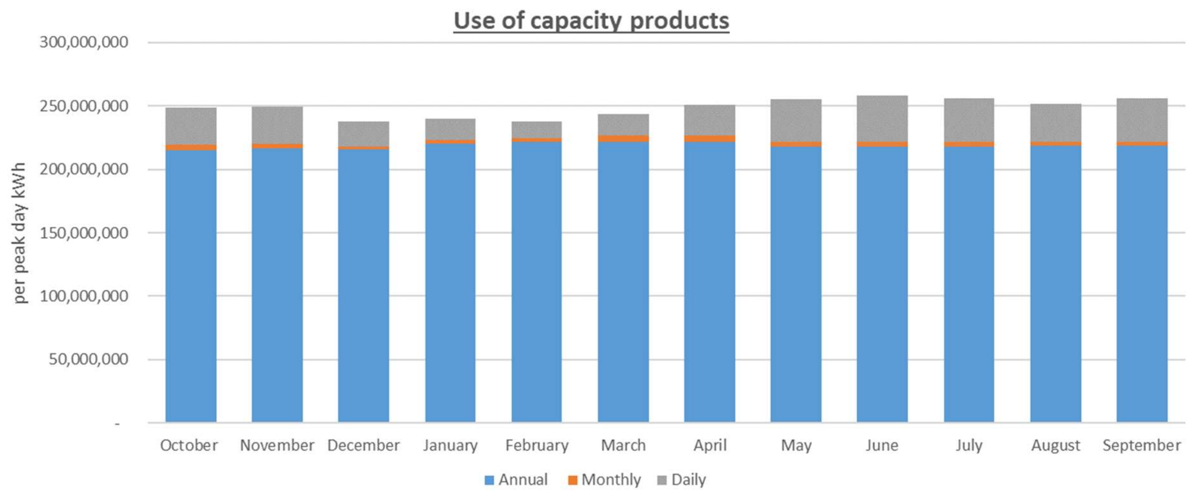
The proposals are now assessed against the following criteria as set out in section 2.1.2

The balance between facilitating short-term gas trade and providing long-term signals for efficient investment in the transmission system

In the figure below the CRU has presented data on the use of different capacity products. It shows that annual capacity makes up the majority of bookings at exit, with daily and the monthly making up the rest.[49] This indicates that the status quo application of multipliers encourages annual capacity bookings, where the end user requires capacity on an annual basis and does not appear to make short-term capacity products economically unviable. As the vast majority of network users use natural gas all year round, it is not surprising that annual capacity bookings are by far the most prevalent. It is worth noting that the uptake of monthly bookings appears relatively small when compared to the daily bookings.

[49] Quarterly is not included in the figure as there were no quarterly capacity bookings at exit.

Figure 4.1: Use of capacity products at exit per peak day kWh (average of last five years)



Although this gives an indication that all capacity products are used and therefore should be economically viable (at least to some degree) it is very difficult to say from this graph whether the correct balance is being achieved or what the ‘correct’ amount of bookings for each capacity product is. In this way this assessment provides an initial ‘health’ check and it appears that the capacity multipliers are set at a level that encourages annual capacity booking, where the end user requires capacity on an annual basis, as is the case for the vast majority of network users.

With regard to a change in the daily multiplier to 1.5 under alternative 3, the CRU expects the annual capacity bookings would decrease and shorter-term capacity bookings would increase (this is examined further in the assessment of the impact on the transmission services revenue and its recovery). However, it would not be expected to lead to a deterioration compared to the current position under this criteria.

An additional piece of evidence that can be used to identify whether the multipliers are appropriate is to benchmark their levels against other member states. This is presented in the table below, where Ireland is represented as the “IE” country code.

Table 4.2: Multipliers by member state

Multipliers by Member State

Country code	Direction	Daily	Monthly	Quarterly
AT	Entry	1.2	1.05	1.03
AT	Exit	1.3	1.15	1.05
DE	Entry & Exit	1.4	1.25	1.1
BE	Entry & Exit	1.5	1.5	1.5
CZE	Entry & Exit	1.5	1.25	1.1
FR	Entry & Exit	1.5	1.5	1.33
IT	Entry & Exit	1.5	1.3	1.2
LT	Entry & Exit	1.5	1.25	1.1
LV	Entry & Exit	1.5	1.25	1.1
DK	Entry & Exit	1.77	1.47	1.25
NL	Entry & Exit	1.84	1.5	1.25
HU	Entry & Exit	1.94	1.2	1.1
PL (Gaz-system (ISO))	Entry & Exit	1.95	1.3	1.1
BG	Entry & Exit	2	1.4	1.3
PT	Entry & Exit	2	1.5	-
PL (Gaz-system)	Entry & Exit	2.18	1.44	1.26
RO	Entry & Exit	2.72	1.36	1.29
IE	Entry & Exit	2.79	1.5	1.35
SK	Entry & Exit	2.99	2.4	1.6
GR	Entry & Exit	3	1.48	1.38
HR	Entry & Exit	3.01	1.51	1.35
ES	Entry & Exit	3.02	1.46	1.39
SI	Entry & Exit	3.04	1.48	1.43

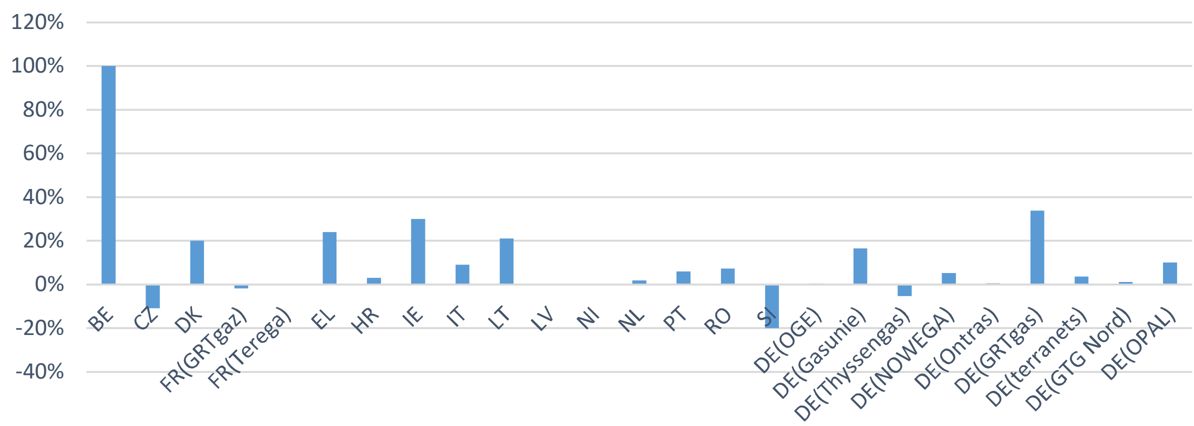
As highlighted by the table above the status quo multipliers in Ireland are not outliers, but they are towards the higher end of the range. A change to a daily multiplier limit of 1.5 would bring Ireland to the lower end of the range. However, benchmarking in this way must be done carefully and should be used in a similar way to the examination of capacity bookings, i.e. something that is best done as an initial cross-check to identify any obvious issues, or in this case significant differences between Ireland and other member states that may, for example, inhibit trade. This careful comparison is warranted as the role of the multipliers and seasonal factors on capacity bookings, cost recovery, etc. will vary significantly from one member state to the next and that market behaviours will also be affected by the unique characteristics of each member state. For example, the effect of multipliers on short-term gas trade is likely to differ significantly between, a MS (such as Ireland) which is at the "end of the pipes" where gas will flow regardless; versus another MS that is heavily interconnected, with more competition between entry points and cross border flows.

In summary, this initial analysis indicates that the status quo (2.79) application of multipliers encourages annual capacity booking, where the end user requires capacity on an annual basis and does not appear to make short-term capacity products economically unviable. In addition, the levels of the multipliers are comparable with those in other member states. The CRU also expects that a reduction in daily multipliers under Alternative 3 would not change this position. Therefore, the evidence is that both the status quo and Alternative 3 proposal do not fail to meet this criteria. However, for the reasons discussed above the analysis under this criteria is best described as providing an 'health' check. The additional analysis below and consideration of the impacts of multipliers 'in the round', allows the CRU to better identify, on balance, what levels of multipliers appear most appropriate for the Irish gas market.

The impact on the transmission services revenue and its recovery

In recent years there have been significant over-recoveries of revenue, which has been driven in part by unexpected levels of daily capacity bookings. The scale of these over-recoveries is highlighted in the figure below. Ireland (IE) ranks as the third highest. However, as highlighted in section 2.3, it is not clear whether a reduction in multipliers would lead to an improvement or exacerbation of this situation. The CRU notes that there are tools it uses when setting the tariffs to ensure that volatility is minimised and that there are a number of elements that can contribute to these over-recoveries.

Figure 4.2: Over / under recoveries as a share of the allowed/target revenue, per TSO (source: ACER report -The internal gas market in Europe: The role of transmission tariffs – April 2020)



The estimated impacts of each of the options are examined further below, by examining capacity bookings, revenue recovery and tariffs. These impacts are based on GNI's optimisation software package that estimates what the annual booking requirement need is for the gas system. This is useful as it estimates the lowest cost way in which shippers in each market segment can meet assumed booking requirements throughout the year given the different capacity product costs. This model is a means of estimating the effect of different multiplier levels against the intended outcome of efficient booking, although it cannot exactly replicate the behaviour of market participants as it assumes perfect foresight.

Effect on capacity bookings

Essentially, the software estimates the lowest cost way in which shippers in each market segment (Power, Large Industrial and Commercial (Large I&C), Residential & Small Medium Enterprises (SME)) could meet assumed booking requirements throughout the year given the different capacity product costs. The proportional levels of product bookings are presented as a percentage of total capacity booked on the system over the year. The estimated effect on the capacity bookings is highlighted in the table below.

Table 4.3: Estimated effect on capacity bookings

EXIT CAP	Capacity	**Actual 20/21 bookings**	Current multipliers & no seasonal	Adjusted seasonal factors	**1.5 limit & no seasonal**
		Status quo	Alternative 1	Alternative 2	**Alternative 3**
Power	Annual	**36.9%**	36.0%	36.6%	**26.1%**
	Monthly	**0.0%**	0.7%	1.1%	**0.6%**
	Daily	**8.6%**	8.6%	8.0%	**15.8%**
Large I&C	Annual	**16.2%**	15.3%	14.8%	**14.8%**
	Monthly	**0.1%**	0.3%	0.4%	**0.2%**
	Daily	**0.6%**	0.3%	0.6%	**1.3%**
Residential / SME	Annual	**37.7%**	38.9%	38.4%	**41.3%**

ENTRY CAP	Capacity	**Status quo**	Alternative 1	Alternative 2	**Alternative 3**
Bellanaboy	Annual	**32.6%**	36.5%	33.8%	**38.8%**
	Monthly	**0.3%**	0.3%	0.4%	**0.3%**
	Daily	**-**	-	-	**-**
Moffat	Annual	**64.7%**	51.6%	61.7%	**42.3%**
	Monthly	**0.3%**	6.5%	1.0%	**6.6%**
	Daily	**2.2%**	5.1%	3.2%	**12.0%**

Alternative 3 is the focus of this section as it is the approach that includes a change in the multipliers, while 'status quo' is the base case against which the alternative are compared. Both Alternative 1 and Alternative 2 have the same multipliers (those that are currently applied), with the former removing seasonality and the latter reducing the magnitude of seasonality.

It is clear that Alternative 3, which reduces the daily capacity limit to 1.5, leads to a very significant increase in the levels of short-term[50] capacity bookings at Exit and Entry. For Exit the impact is mainly seen in the Power sector. As highlighted earlier, the Power sector already books most of the daily capacity on the system and this is expected to increase as the cost of daily

[50] Mostly daily capacity, however there are some increases in monthly capacity bookings at Exit.

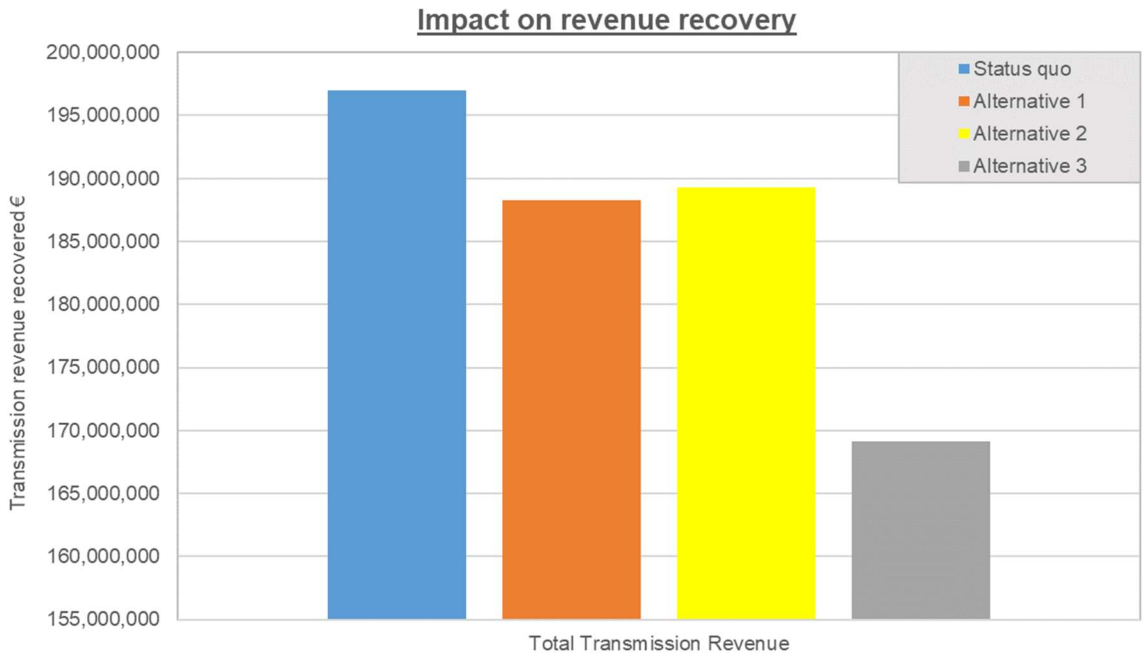
capacity reduces under Alternative 3. The reason that the most significant increase is for this sector is due to the variability in Power demand, which is due to gas generation's variable role in supporting wind generation. A reduction in short-term multipliers allows for more efficient portfolio optimisation and capacity bookings that more closely match the variable gas demand created by this sector. There is also an increase in short-term bookings for Large I&C, however it is less significant as this sector's demand tends to be more stable. There is no change in the residential & SME sector's short-term capacity bookings as this sector is required to book annual capacity in line with its 1 in 50 peak day requirement. The table shows that the annual booking percentages for this sector are increasing under the alterative scenarios, particularly Alternative 3. This is because increased portfolio optimisation by the other sectors leads to a decrease in the bookings on a per MWh basis, and therefore the share of total system bookings made by the Residential & SME sector increases.

This same explanation applies at entry where the annual percentage bookings at Bellanaboy increase, despite the amount of capacity booked at that point remaining stable, due to a lower amount of bookings at the Moffat entry point. The significant increase in daily capacity bookings at Moffat is driven by the Power sector, as is seen at Exit. The reason bookings change at Moffat and not Bellanaboy is because Moffat provides the marginal source of supply and therefore increases and decreases during the year in line with the total demand at Exit.

It is worth noting that in addition to reducing the short-term multipliers, Alternative 3 also removes seasonality. The effect of removing seasonality can be estimated by examining the bookings under the Alternative 1 proposal, which removes seasonality but does not include a change to multipliers. Alternative 1 has a much more similar booking profile to the status quo, which indicates that the majority of the impact estimated is due to the reduction in multipliers under Alternative 3, rather than any change in seasonality. Alternative 2, which adjusts the seasonal profile also has an impact, however it is even more similar to the status quo than Alternative 1.

Effect on revenue recovery

Having examined the estimated impact on the bookings, the next step is to look at the impact on cost-recovery, which is highlighted in the figure below. The transmission revenue is estimated by combining the current gas tariffs with the estimated capacity bookings under each proposal.



The blue bar (status quo) is the current (gas year 2020/21) transmission business' allowed revenue and represents the expected revenue recovered under the current multipliers & seasonal factors with the 2020/21 demands and tariff levels. It is clear that Alternative 3 (grey bar) would lead to a significant under-recovery of revenue by GNI approximately €28m when compared with the status quo.

The effect of removing seasonality can be estimated by examining the bookings under the Alternative 1 proposal (orange bar), which removes seasonality but does not include a change to multipliers. Alternative 1 also results in an under-recovery, however to a lesser degree, which indicates that the majority of the impact under Alternative 3 is due to the reduction in multipliers under Alternative 3, rather than any change in seasonality. Alternative 2 (yellow bar), which adjusts the seasonal profile also has an impact, however it is even more similar to the status quo than Alternative 1.

Therefore, it would follow that the increased uptake of short-term capacity bookings under alternative 3 does not lead to additional revenue recovery, which can sometimes be associated with short-term bookings due to their higher cost. This makes sense as GNI's model optimises the capacity bookings and therefore, in the absence of the change in end customer demand, there should not be a shift in booking patterns unless it was economically advantageous. Essentially, those that can avail of the cheaper short-term capacity would be expected to book it and be better able to optimise their booking portfolio, thereby reducing their costs, leading to reduced revenue recovery for GNI.

As it is a requirement for GNI to recover their allowed revenue, the tariff levels would need to be adjusted to account for the reduced revenue recovery under the alternative approaches. The next section examines the estimated impact on tariffs.

Effect on tariffs

Having examined the estimated impact on bookings and cost-recovery, the next step is to look at the impact on tariffs, which is highlighted in the table below. The transportation cost of GB gas (Moffat entry capacity tariff + domestic exit capacity tariff) is the main cost to focus on here. The transportation cost of GB gas is important because Irish wholesale gas prices are generally 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.

Before exploring the impacts in table below it is important to note the reason for the significant differences in the percentage increases at the Entry points. This is because the gas tariff (Matrix) methodology calculates cost reflective differentials between the Moffat and other entry points.[51] In order to maintain these differentials, the tariffs are increased equally at all points to maintain cost-reflectivity while ensuring cost-recovery. For example, under Alternative 3 the tariff at Moffat entry and renewable natural gas (RNG) entry, increases by €66/MWh, which results in a 21% increase (€315/MWh to €381/MWh) for the Moffat tariff and a 62% increase (€106/MWh to €173/MWh) in the RNG tariff, however the absolute difference between that Moffat entry tariff and RNG entry tariff is maintained at €209/MWh.

Table 4.4: Tariff impacts

EXIT	Actual 20/21 bookings	Current multipliers & no seasonal		Adjusted seasonal factors		1.5 limit & no seasonal	
	Status quo	Alternative 1		Alternative 2		Alternative 3	
Domestic exit	€408	€415	2%	€426	5%	€470	15%
Gormanston	€385	€392	2%	€404	5%	€448	16%
Moffat VRF	€271	€275	1%	€281	4%	€303	12%

ENTRY	Status quo	Alternative 1		Alternative 2		Alternative 3	
Bellanaboy	€630	€664	5%	€642	2%	€696	11%
Moffat	€315	€348	11%	€327	4%	€381	21%
RNG	€106	€140	32%	€118	11%	€173	62%
Gormanston VRF	€76	€104	36%	€86	13%	€130	71%

Cost of GB gas transportation	€722	€763	6%	€753	4%	€852	18%

[51] These differentials represent the differences in marginal costs of expanding the system at different locations, see CRU/19/060 for further information

As expected, Alternative 3, which had the most significant effect on capacity bookings and reduction in revenue recovery, is associated with the biggest change in tariffs, with an increase of 18% on the transportation cost of GB gas. Both Alternative 1 and Alternative 2 had a lesser effect on capacity bookings and revenue recovery and as a result also have the lesser effect on tariffs, with a 6% and 4% increase in the cost of transportation of GB gas respectively.

A key tenet of the CRU's tariff methodology is tariff stability. There is the potential for reduced multipliers to effect tariff volatility in different way. It is therefore is difficult to determine whether Alternative 3 would lead to more or less stable tariffs in the longer-term. However, it is clear that in the short-term this would likely lead to increased tariff volatility.

From the tariffs in the table above an estimate of the potential increase on a residential customer's bill can be calculated to give an indication of the scale of effect from these tariff changes. For a residential customer Alternative 1 and Alternative 2 would lead to an increase of approximately €3.68 (0.44%) and €2.76 (0.33%), respectively, while Alternative 3 could lead to an increase of approximately €11.67 (1.39%). However, it is important to note that not all customers would see an increase in cost, some users of shorter-term capacity products such as power generators may see a reduction cost. The sectoral impacts are examined further under the next criteria.

In summary, the CRU has assessed the impact of a change in multipliers on GNI's transmission revenue and its recovery. This analysis is based on data provided by GNI's optimisation software package that estimates the lowest cost way in which shippers in each market segment can meet assumed booking requirements throughout the year given the different capacity product costs. As the multipliers change the cost of the different capacity product, the costs lead to changes in capacity bookings. This change in capacity bookings impacts GNI's revenue recovery and as a result, the levels of the tariffs are also affected. From the analysis it appears that a reduction in the daily multiplier to 1.5 under Alternative 3 would lead to a significant reduction in transmission services revenue recovery, which in turn results in a significant increase in annual capacity tariffs and a residential customer's bill. However, there may be reductions in cost for other sectors, which is examined further in the next section.

The need to avoid cross-subsidisation between network users and to enhance cost-reflectivity of reserve prices

The table below highlights the estimated revenue that would be recovered from each user category at Exit[52] from capacity bookings and commodity flows. Note that this is an estimate based on the estimated bookings made by each user category and the actual tariffs for 2020/21.

Table 4.5: Proportional revenue recovery at exit

Exit Cap & Com	20/21 estimated revenue allocation	Current multipliers & no seasonal	Adjusted seasonal factors	1.5 limit & no seasonal
	Status quo	Alternative 1	Alternative 2	Alternative 3
Power	34.3%	34.7%	33.8%	31.2%
Large I&C	10.7%	9.8%	10.2%	10.7%
Residential & SME	20.8%	21.1%	21.7%	23.7%

Under the status quo GNI estimates that it will recover 34.3% of its revenue from Power, 10.7% from Large I&C and 20.8% from Residential & SME. GNI estimates that under alternative 3 there will be a reduction in the revenue recovered from Power, reducing from 34.3% to 31.2%, with a corresponding increase from Residential & SME, increasing from 20.8% to 23.7%, while Large I&C remains stable. This occurs as the reduction in short-term multipliers under Alternative 3 allows for more efficient portfolio optimisation by the Power sector, while the Residential & SME sector cannot take advantage of these cheaper shorter-term products due to its annual booking obligation, leading to this sector bearing a greater portion of the costs on the system as GNI's revenue is recovered.

However, this is not entirely attributable to the effect of reducing multipliers, as Alternative 3 also removes seasonality. The effect of removing seasonality under Alternative 3 can be estimated by examining the revenues under the Alternative 1 proposal, which removes seasonality but does not include a change to multipliers. Alternative 1 has a much more similar booking profile to the status quo, which indicates that the majority of the impact estimated is due to the reduction in multipliers under Alternative 3, rather than any change in seasonality. Under Alternative 1 there is a slight increase in costs for Power and Residential & SME, with a decrease in costs for Large I&C.

Finally, it is worth noting that Alternative 2 has the lowest impact on changes to revenue allocation between the categories. This is not unsurprising as its multiplier and seasonal factor

[52] Note: the total percentages are approx. 66%. This is because 67% (the table doesn't include shrinkage (approx. 1%)) of GNI's revenue is recovered at Exit and 33% at Entry.

profile is the closest to the status quo. Under this option there is a slight increase in revenue recovery from Residential & SME, with some minor reductions in the revenues recovered from the other categories.

Having highlighted the estimated redistribution of revenues recovered from each category it is important to note that redistribution of revenues is not necessarily a negative impact. It is important to consider the cost-reflectivity of any proposed change and whether instances of undue cross-subsidisation may occur. The table below explores this further by examining use of the network both in terms of throughput (flows) and demand (capacity). The first column titled 'Exit total throughput 19/20' highlights the actual Exit throughput (i.e. flows not capacity) at domestic exit points (i.e. not including Isle of Man, etc.) and shows the split between the various sectors. Power accounts for 57.8% of the gas flowed, with Large I&C accounting for 21.0% and 21.1% from Residential & SME. The next column titled 'Exit throughput 19/20 33/67 adjustment', adjusts these percentages downwards pro-rata so that they are comparable with the 67% revenue allocation at Exit. The next column titled 'Exit peak day demand 19/20' highlights the peak day per sector in 19/20 to illustrate the relative peak day demand of each sector. Finally, the column titled 'Exit peak day demand 19/20 33/67 adjustment' highlights the peak day per sector in 19/20 as a % of total peak demand[53], with an adjustment downwards pro-rata so that they are comparable with the 67% revenue allocation at Exit.

Table 4.6: Sectoral demand at Exit

	Exit throughput 19/20	Exit throughput 19/20 33/67 adjustment	Exit peak day demand 19/20	Exit peak day demand 19/20 33/67 adjustment
Power	57.8%	38.7%	148.36 GWh	37.7%
Large I&C	21.0%	14.1%	40.81 GWh	10.4%
Residential & SME	21.1%	14.2%	74.83 GWh	19.0%

Comparing the adjusted throughput percentages with the demand percentages gives an indication of each sectors use of the system relative to their peak demand. For example, the Residential & SME sector has an adjusted throughput of 14.2% compared to an adjusted demand of 19.0%. This indicates that the amount of gas flowed for this sector is low relative to the amount of the network taken up by their peak demand, this is expected as residential customers' use of natural gas decreases significantly in the summer when the need for home heating is reduced. This means that the Residential & SME sector is underutilising the network in

53 Here the total peak day demand is taken to be the sum of each sector, it does not represent the actual peak demand day in 19/20. The actual peak demand day in 19/20 is lower as each sector's peak day did not fall on the same day.

the summer as it holds the same amount of capacity all year round. However, as highlighted in the CRU's decision (CRU/19/060) on the gas transmission tariff methodology, peak demand is the more important driver of network costs as the network must be built to accommodate peak demand. It is for this reason that capacity charges for use of the transmission network account for 90% and commodity charges account for 10%. To reflect this and in the interests of exploring the cost-reflectivity of charges further, the table below reiterates the revenue allocations but with the inclusion of the 'Exit peak day demand 19/20 33/67 adjustment' as a proxy for the costs incurred on the system.

Table 4.7: Sectoral demand and revenue recovery at Exit

Exit Cap & Com	Exit peak day demand 19/20 33/67 adjustment	20/21 estimated revenue allocation	Current multipliers & no seasonal	Adjusted seasonal factors	1.5 limit & no seasonal
		Status quo	Alternative 1	Alternative 2	Alternative 3
Power	37.7%	34.3%	34.7%	33.8%	31.2%
Large I&C	10.4%	10.7%	9.8%	10.2%	10.7%
Residential & SME	19.0%	20.8%	21.1%	21.7%	23.7%

From the table it appears that the costs recovered from Large I&C under the status quo (10.7%) are similar to the costs they incur on the system (10.4%) and this remains stable when the multipliers are reduced, i.e. Alternative 3.

For the Power sector it appears that the proportion of costs recovered from this sector under the status quo (34.3%) are less than the costs they incur on the system (37.7%) and the costs recovered decrease further (31.2%) when the multipliers are reduced under Alternative 3. As highlighted earlier, the Power sector is the biggest user of non-annual capacity products, which allows this sector to optimise its capacity booking portfolio in line with its often variable demand. A reduction in short-term multipliers under alternative 3 makes for more efficient portfolio optimisation and capacity bookings that more closely match the variable gas demand created by this sector, leading to a reduction in the revenue recovered from this sector.

However, in the case of Residential & SME, it appears that more revenue is recovered from this sector under the status quo (20.8%) relative to their demand (19.0%), particularly when multipliers are reduced (23.7%). The status quo difference is explained by the fact this sector must book in line with its 1 in 50 peak day demand, and therefore does not commonly reach the levels of demand it is required to book, which results in more revenue being recovered from this group relative to this sector's typical peak demand. As we highlighted earlier under Alternative 3 there is no change in the Residential & SME sector's capacity bookings as this sector is required to book annual capacity and as a result the proportion of revenue recovered from this sector increases.

Finally, it appears that as the effects of removing seasonal factors (Alternative 1) and adjusting the seasonal profile (Alternative 2) do not affect revenue recovery to the same degree as Alternative 3, they have less impact on cost-reflectivity and the potential for undue cross-subsidisation.

In summary, the reduction in the daily multiplier to 1.5 under Alternative 3 provides a benefit to those who can avail of non-annual products at the expense of those who cannot. In effect, this leads a redistribution of revenue in the form of a reduction for non-annual product users and an increase for annual only product users. As highlighted earlier the redistribution of revenue is not necessarily negative, however it appears from the table above that it would lead to a reduction in cost-reflectivity as the disparity increases between the cost each sector drive on the network (by proxy based on peak demand) and the costs recovered from each sector. As this redistribution of revenue does not appear to be cost-reflective it may therefore indicate the potential for undue cross-subsidisation under alternative 3.

Situations of physical and contractual congestion

Currently, there are no issues of physical or contractual congestion on the Irish gas network. GNI keeps the gas network under review for both contractual and physical congestion on an ongoing basis. GNI's annual Network Development Plan assesses adequacy of the gas transportation system and security of supply. As part of its submission GNI stated that it "does not anticipate that proposed changes to the multipliers will impact the overall power demand on the natural gas network, which is determined by overall electricity demand and renewables."

There are currently no situations of physical and contractual congestion on the network and as GNI does not foresee these issues arising due to changes in the multipliers the CRU has not considered this criteria in more detail, however it will continue to be considered as part of the annual Art. 28 consultations in the event that there is a change in the situation.

The impact on cross-border flows

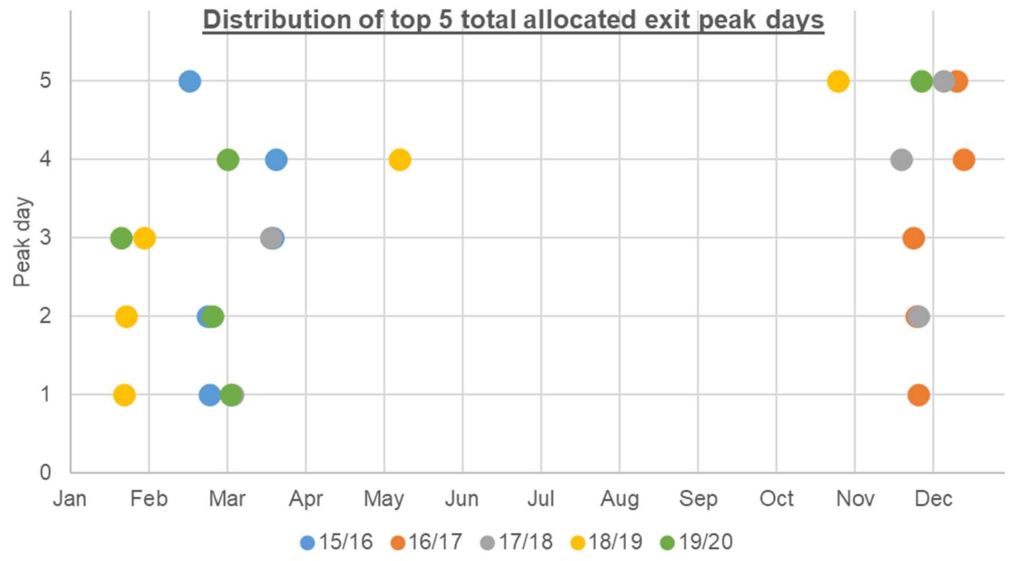
The Moffat interconnection point (IP), allows for gas flows into Ireland from GB. Domestic production is first in the merit order in terms of supply to Irish customers, with flows from GB via Moffat providing the marginal source. There is also an IP with the Northern Irish gas transmission system at Gormanston. The Gormanston IP is unidirectional, only allowing for gas flow from Ireland into the Northern Irish gas transmission system. However, no commercial gas currently flows in that direction; it is used for emergency support only. Therefore, gas flows into Ireland are a result of gas demand from Irish customers only, as there are no cross-system flows. As proposed in the call for evidence paper the CRU has excluded this Art. 28 criteria from the review due to its lack of applicability. The CRU notes that the facilitation of short-term trade with GB (which doesn't necessitate cross border flows due to the Virtual Reverse Flow (see section 3)) is considered to some degree under the criteria, which examines the balance between facilitating short-term gas trade and providing long-term signals for efficient investment in the transmission.

A.2 Seasonal factors

The impact on facilitating the economic and efficient utilisation of the infrastructure

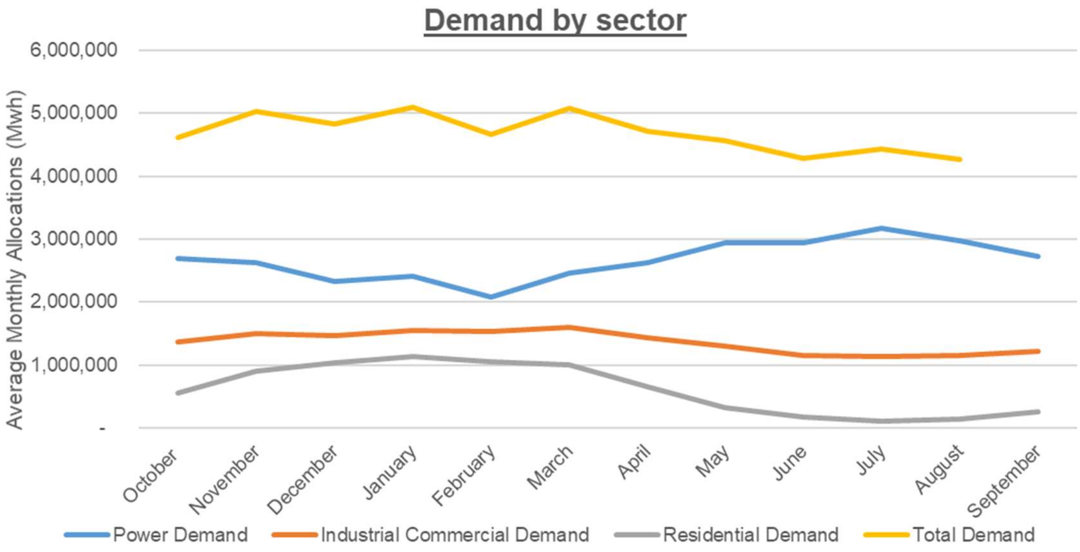
The figure below examines the occurrence of peak days by illustrating the date upon which each of the top five peak days occurred in the last five gas years. From the figure it is clear that the peak days still tend to occur in the winter months. It is worth noting that in gas year 2018/19 the fourth highest peak day occurred on 10 May 2019, which may potentially indicate that the pattern is shifting more to the summer, however this could just be an outlier.

Figure 4.3: Occurrence of top five peak demand days at exit



As outlined above, peak days have tended to occur in winter. This can be explained by the figure below which highlights the total flows on the network over the course of the year and includes the flows from each sector as well. This is based on an average of the flows over the last five gas years. Total demand is higher during the winter months and lowers in the summer months; however, the demand profile is relatively stable throughout the year, indicating that the system is being utilised relatively efficiently. The Power and Residential & SME sectors are the most seasonal (i.e. variable) users of the network; with Power using the network more in summer than winter and Residential & SME using it more in winter than summer. At an overall level Large I&C sectoral demand is relatively stable throughout the year, however it also is higher in winter.

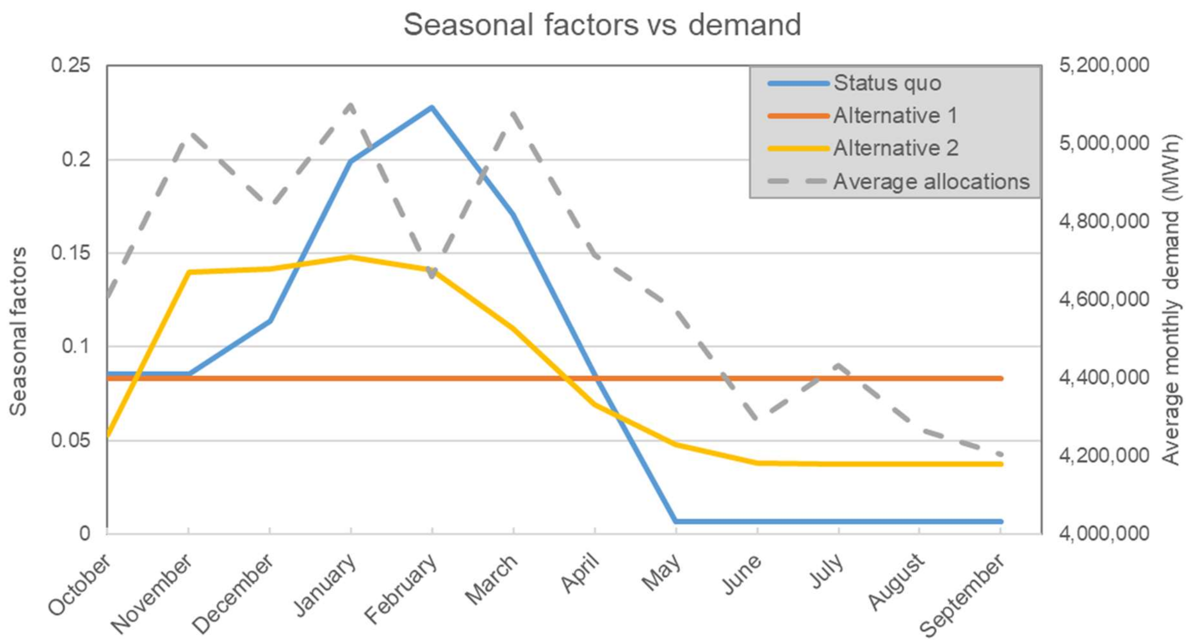
Figure 4.4: Comparison of network demand by sector (average monthly allocations last five years)



The figure below compares the seasonality of demand with the different seasonal factor profiles. As both the status quo and Alternative 2 incorporate the occurrence of peak demand days (with the latter also incorporating average monthly peak flows) the profiles generally reflect the pattern in gas demand. Alternative 1 removes seasonality completely and therefore has no relationship with network demand.

Recall that this assessment criterion relates to incentivising efficient utilisation of the network. There is no doubt that both the status quo and Alternative 2 create an incentive, however that does not mean that network users are necessarily responding to this incentive, in other words the incentive is not automatically effective.

Figure 4.5: Comparison of seasonal factors and gas demand



However, the current situation has changed. In recent years the number of new residential connections has declined and GNI do not expect there to be significant uptake in the future due to decarbonisation policy. With regard to Large I&C, there is potential for some increase in demand, particularly from data centres. However, this demand is expected to be relatively flat throughout the year due to the characteristics of that industry. Finally, the Power sector makes up close to 60% of demand and its demand both in terms of flow and peak day (see figure below) is now highest in the summer months, when historically power demand was highest in winter. However, this shift has not occurred in response to the seasonal factors, it has been driven due to the changing role of gas power generation on the electricity network. The key driver of demand for the gas power sector is the level of renewable electricity generation, particularly wind. The current role of gas power generation is providing flexible support as it can react to a reduction in wind and provide required backup generation to meet electricity demand. This is particularly clear in the figure below, which shows how the gas generation profile is effectively the opposite of the wind generation profile.

Figure 4.6: Occurrence of top five peak power demand days at exit

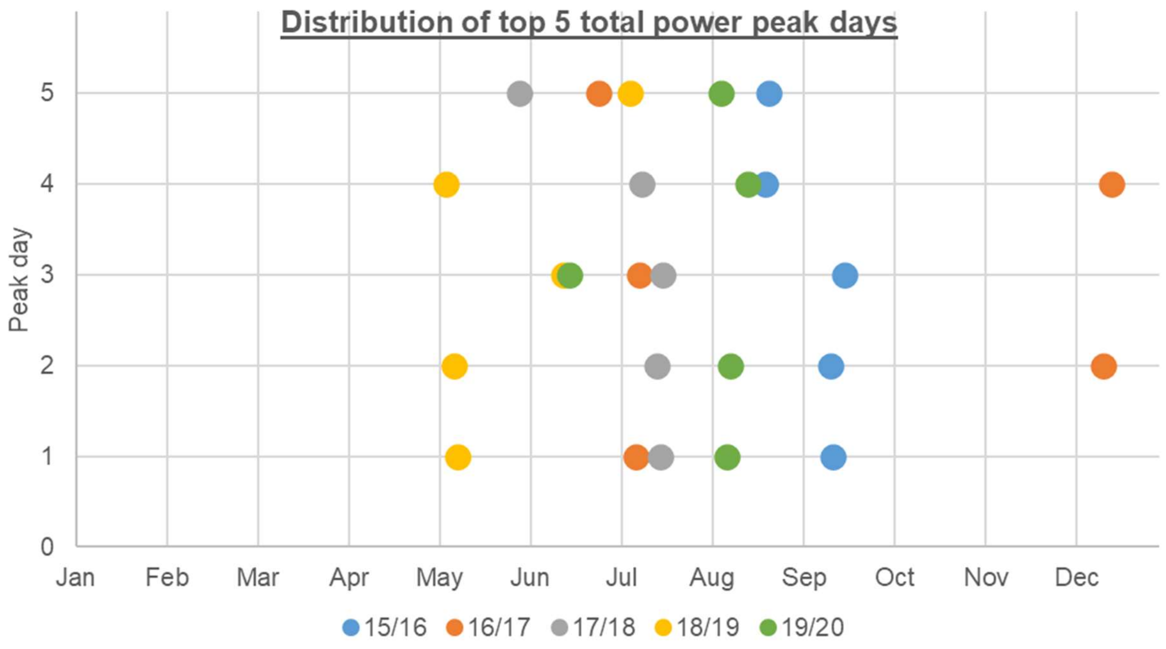
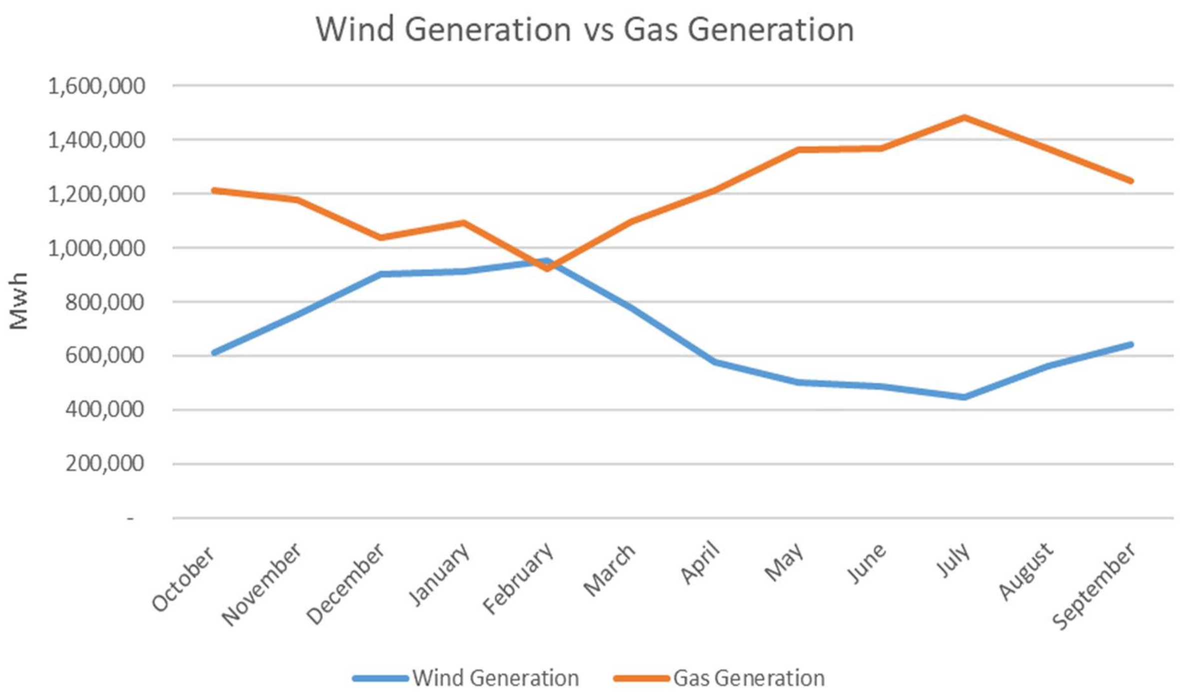
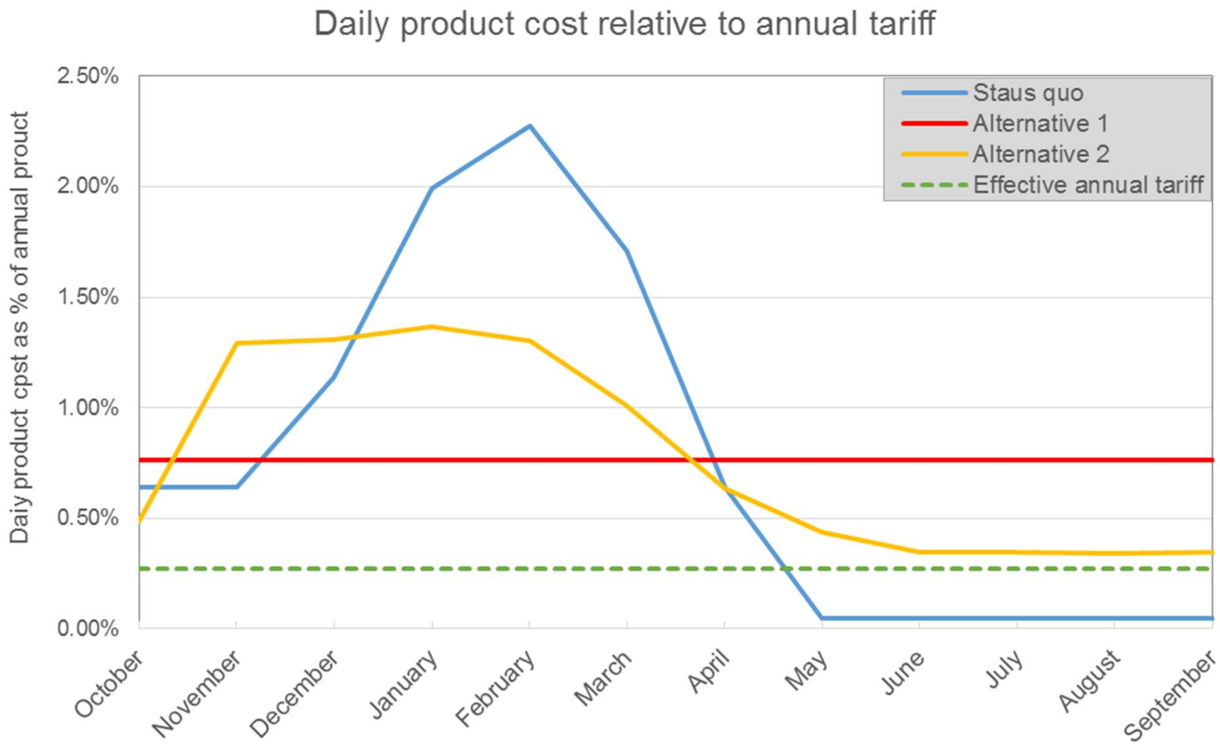


Figure 4.7: Average monthly wind and gas generation (last four years)



The need to improve the cost-reflectivity of reserve prices

The daily capacity costs under the various seasonal factor profiles are presented in the figure below. Alternative 3 is not considered here as the seasonal factors are the same as Alternative 1, i.e. removal of seasonal profile.



In the above figure the dashed green line represents the current effective cost of daily capacity if a user were to buy the annual product (i.e. 1/365 = 0.27%).

The blue line represents the status quo. It is clear that this approach leads to the greatest variability in the seasonal profile. The daily capacity cost is effectively zero in summer (0.05%) making it cheaper than the annual product equivalent (0.27%), but much more expensive in the winter, peaking in February (2.28%) when it is over eight times more expensive than the annual product equivalent.

The red line (alternative 1) reflects the approach of current multipliers but with no seasonal factors. The cost is therefore equal throughout the year and at 0.77%, 2.79 times more expensive than the annual product equivalent.

The orange line (alternative 2) reflects the approach of multipliers and adjusted seasonal factors. This approach produces seasonal variability but has a more muted profile than the current approach. The daily capacity cost is slightly more expensive (0.35%) than the annual product equivalent in summer (0.27%), with a greater difference in Winter, peaking in January (1.36%) when it is over five times more expensive than the annual product equivalent.

This example illustrates the significant effect that the combined daily multiplier and seasonal factor profile can have on daily capacity costs. As highlighted earlier, the seasonal profile of the prices for shorter-term capacity products at different times of year is 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.

When considering cost-reflectivity it is worth considering again the principles of the approaches. The status quo profile is based on the principal of cost-reflectivity as it aims to reflect 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. While, Alternative 1 removes the seasonality, it could be considered appropriate in a system with additional capacity, by way of not distorting the reserve prices. Alternative 2 is effectively a (combination of the status quo with average monthly peak flows). It is worth noting that the seasonal factor methodology in TAR NC Art 15(3) applies forecasted flows or forecasted capacity, i.e. it focuses on system use patterns rather than peak capacity. In its 2019 decision, CRU/19/060, the CRU considered that this approach was less in line with the principles of Art. 28 and was less cost-reflective than the CRU's status quo methodology, which is based on peak capacity. Therefore, Alternative 2 could be viewed as a bridge between the status quo (i.e. method based on peak day occurrence) and the TAR NC method (based on more typical network use).

As highlighted in the discussion on the previous criteria, it now appears less likely that additional demand, triggering the need for significant network investment, will occur. Therefore, the possibility of the seasonal factors (i.e. status quo and Alternative 2) causing an unnecessary impact on the outputs for the Matrix RPM appears increased and potentially a decrease in cost-reflectivity.

In a further assessment of the potential for a reduction in cost-reflectivity the CRU highlights that the status quo seasonal profile leads to daily capacity costs in the summer that are less than the cost of annual capacity on a daily basis. As highlighted earlier, there were a small number of adjustments over time, which altered the status quo profile from its original format[54]. Originally a minimum (floor) monthly percentage of 8% (1/12) was set for the months without any peak day occurrences (summer) to provide some incentive to book longer term capacity for the summer

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[54] CER/07/115

months, while also incentivising utilisation of the system. However, this was subsequently reduced to the current summer floor of near zero in consideration of things such as seasonal gas storage and incentivising uptake of short term products. This is perhaps worth reconsidering now that storage is gone and gas plant are used throughout the year.

Given the above the CRU is of the view that both Alternative 1 (a removal of seasonal factors) and Alternative 2 (a reduction in the seasonal variation) may be more appropriate from a cost-reflectivity perspective than the status quo. The increased cost of capacity in the summer, under Alternative 2 may appear to be an effective and justifiable reinstatement of the floor price[55] while still providing some seasonal incentive to network users, and one which is based on cost-reflective principles.

A.3 Additional observations

As highlighted in section 2.3.4, although the multipliers and seasonal factors have been examined separately in order to allow for separate consideration against their associated Art. 28 criteria, the CRU has also considered their overall impact on a joint basis. In this section the CRU has provided some additional observations on its proposal to implement Alternative 2.

Firstly, the CRU stated that the review of multipliers and seasonal factors should be based on a consideration of the criteria highlighted in Art. 28, with any proposed amendments cross-checked against the overall requirements of Art. 13 of Regulation (EC) No 715/2009. In summary, Art. 13 of Regulation (EC) No 715/2009 requires that tariffs, or the methodologies used to calculate them shall:

- be transparent
- take account the need for system integrity and its improvement
- reflect efficient costs
- include appropriate return on investment
- be applied in a non-discriminatory manner
- facilitate efficient gas trade and competition
- avoid cross-subsidies between network users
- provide incentives for investment and maintaining or creating interoperability for transmission networks

[55] However, the monthly product would still be cheaper than the annual product in the summer months.

The CRU has considered this and is of the view that Alternative 2 does not give rise to any issues of non-compliance with Art. 13.

Secondly, the CRU noted the complexity of multipliers and seasonal factors due to their potential impacts on a wide-range of elements of the gas market. As highlighted in section 2.1.1. the CRU is of the view that the following provide important context for the CRU's decision.

1. gas plant being used more and more as a flexible source of electricity generation;
2. changing demand and patterns of use by different network user types;
3. possible effects on the price of electricity;
4. alignment of multipliers and seasonal factors between the Irish and Northern Irish gas markets given the single electricity market (SEM);
5. potential decarbonisation of natural gas;
6. potential for ACER to issue a recommendation for multipliers for daily and within-day products to be limited to 1.5 (currently, 3).

With regard to point 1 the CRU notes that this has been considered, particularly in the sections which touched on the forecast bookings of the power sector and the relationship between the power sector demand and wind generation. The CRU has noted the potential benefits that a reduction in multipliers could have for the Power sector as a user of non-annual capacity products, but as highlighted in section 2.3.4 this change could potentially create issues of undue cross-subsidisation.

With regard to point 2 the CRU notes that this has been considered, particularly in the sections which discussed whether network users are likely to respond to the cost signals sent by seasonal factors.

With regard to point 3 the CRU has not touched on this point in detail. There are various complex elements that effect the price of electricity at any one time. However, the CRU notes that there are potentially some instances were gas has a large/significant influence on prices in the different market timeframes in the SEM. These prices may reflect their associated running costs, which could include daily capacity costs. As a reduction in seasonal variation under Alternative 2 would lead to less variable daily capacity costs, there is some potential for Alternative 2 to lead to less variable costs in the different market timeframes in the SEM. However, due to the various elements and cost drivers in effect at any one time this is subject to significant uncertainty.

With regard to point 4 the CRU notes that it has engaged with UR prior to the publication of this consultation and both NRAs have come to the view that if Alternative 2 was to be implemented it is unlikely to result in significant misalignment between the two markets. The CRU notes that there are already some differences in how gas plant in Ireland and Northern Ireland pay for and book capacity. The CRU will continue to engage and consult with UR on this issue, as it has done to date.

With regard to point 5 this has been considered, particularly in the sections which discussed whether network users are likely to respond to the cost signals sent by seasonal factors. The CRU has also considered the impact on the RNG entry tariff. As highlighted in Appendix A, the differential to Moffat i.e. the marginal point, remains consistent across all scenarios. In addition, the CRU notes that there are currently no RNG entry points on the transmission network so alternative 2, if implemented would have no direct effect on this industry. As these connections begin to occur and other RNG technologies develop, they will be considered in greater detail.

Finally, with regard to point 6 the CRU noted in section 2.2.2.4 that the CRU and other national regulatory authorities have been informed by ACER that it will not be making this recommendation.