Consultation on Short Term Exit Capacity for Gas Transmission in Northern Ireland

Consultation

31 March 2023

About the Utility Regulator

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We are not a policy-making department of government, but we make sure that the energy and water utility industries in Northern Ireland are regulated and developed within ministerial policy as set out in our statutory duties.

We are governed by a Board of Directors and are accountable to the Northern Ireland Assembly through financial and annual reporting obligations.

We are based at Queens House in the centre of Belfast. The Chief Executive leads a management team of directors representing each of the key functional areas in the organisation: Corporate Affairs, Markets and Networks. The staff team includes economists, engineers, accountants, utility specialists, legal advisors and administration professionals.

Our mission

To protect the short- and long-term interests of consumers of electricity, gas and water.

Our vision

To ensure value and sustainability in energy and water.

Our values

- Be a best practice regulator: transparent, consistent, proportionate, accountable and targeted.
- Be professional – listening, explaining and acting with integrity.
- Be a collaborative, co-operative and learning team.
- Be motivated and empowered to make a difference.

Abstract

This paper consults on whether to introduce short term exit products into the Northern Ireland postalised gas transmission system.

This consultation follows on from the initial 2016 “Exit Review” which concluded that any change would be considered after the implementation of the Integrated Single Electricity Market (ISEM) in Northern Ireland in 2018.

Audience

This document is likely to be of interest to regulated companies in the energy industry, government and other statutory bodies and consumer groups with an interest in the energy industry.

Consumer impact

The consumer impact of the introduction of short term exit capacity products is a key question in the review. Before we take any decisions on new products, we will need to assess, for example, the impact on electricity prices in the SEM and the impact on gas bills including the potential for transfer of transmission cost recovery from power stations to domestic and industrial gas consumers. An illustrative impact on the transmission tariff is set out in section 7.

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Executive Summary

Background to the review

Short term (non-annual) gas capacity products have been available at entry points to the Northern Ireland (NI) gas transmission system since 2015 as required by the EU Network Code on Capacity Allocation Mechanism (CAM) (which has been subsequently transposed into UK legislation following EU exit, see paragraph 1.1a). Suppliers in the power generation sector have called for the availability of short-term capacity products at transmission exit points in NI. There is no legal requirement to implement such products therefore the Utility Regulator (UR) is consulting on whether their introduction would be in the interest of gas and electricity consumers. The project is included in our Forward Work Plan for 2022/23[1].

In 2016 the Utility Regulator (UR) carried out a review to ascertain whether short term products should be introduced at gas transmission exit points – called the "Exit Review"[2]. The review covered a range of issues which had been raised by generators and considered whether short term products at exit may address these. Based on responses to our Call for Evidence[3], we concluded[4] that no change was appropriate at that time. We anticipated that the issues raised might be addressed within the development of ISEM and stated that if not, it would be appropriate for us to reconsider short term exit products at a later date.

Since then the electricity System Operator for Northern Ireland (SONI)'s Ten Year Transmission Forecast Statement 2021[5] (TYTFS) indicates a requirement for peaking plants to both back up intermittent non-synchronous renewable generation and to meet peak demand periods. The move to a peakier generation profile is also highlighted in the Northern Ireland Gas Capacity Statement[6] (NIGCS) with a new Open Cycle Gas Turbine (OCGT) peaking plant power station at Kilroot expected to commission in Gas Year 23-24, following awarded capacity in the SEM Capacity Auctions.

Introducing short term exit products may benefit the gas-fired power generators in Northern Ireland (NI) who may be better able to match their capacity bookings on the gas network with their expected dispatch in the SEM (and so reduce their costs).

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[1] Forward Work Plan 22/23
[2]https://www.uregni.gov.uk/files/uregni/media-files/2016-04-15_Exit_Capacity_Review_Call_for_Evidence_v10.pdf
[3] https://www.uregni.gov.uk/publications/exit-review-call-evidence-responses
[4] https://www.uregni.gov.uk/publications/exit-review-call-evidence-conclusions
[5] https://www.soni.ltd.uk/media/All-Island-Ten-Year-Transmission-Forecast-Statement-TYTFS-2021.pdf
[6] https://gmo-ni.com/assets/documents/NIGCS-2022-23-to-2031-32-FINAL.pdf

However, the introduction of short term exit products could have a number of the potential implications and risks particularly for non-power generation gas users and electricity consumers.

Therefore, the impact that these new products could have on other gas users in NI needs to be carefully considered, for example the consequences of any possible redistribution of costs from the power to the distribution sector and increased volatility in the end of year reconciliation. Inaccurate forecasting could potentially exacerbate these consequences.

Structure of this paper

We have modeled the potential impact of introducing short term exit products into the gas transmission system in a number of worked scenarios and these are set out in chapter 3.

The assumptions underpinning the scenarios are explained at paragraph 3.2. For example, a key assumption is that the Distribution Network Operators (DNOs) continue to book exit capacity on 1 in 20 basis in NI (see from paragraph 5.49). This would make it less likely that the distribution sector will avail of short term exit products compared to the power sector.

All scenarios are compared against an enhanced Base Case, which includes an additional capacity forecast on the gas transmission system in Gas Year 2024/25 as per the NIGCS[7].

The information underlying the forecasts used for the modelling is almost a year old and work is underway to publish the next transmission tariff by 31 May and the next NIGCS by the end of September. In the interim as the new power station at Kilroot is due to start generating during 23/24, we have engaged with the owner of the new power station and with SONI to refine our understanding of the likely profile of capacity booking for the new power station from 2024 onwards. This has been used in the scenario analysis and reflects the best information available at this point in time.

However, we acknowledge that there is currently a level of uncertainty about the potential profile of capacity bookings by the NI power sector once the new station is available. We would welcome further information from respondents in the power sector which would assist us to refine the scenarios and assess the case for change so that our final decisions are based on the most robust evidence available.

[7] https://gmo-ni.com/assets/documents/NIGCS-2022-23-to-2031-32-FINAL.pdf

The key findings from the gas scenario analysis are:

- The additional capacity in itself, if booked, should lead to reduction in gas transmission tariffs, other things remaining equal, regardless of whether the additional capacity is an annual or a short term product.
- inaccurate short term exit capacity forecasting would have an impact on the year end reconciliations.
- The proportion of the revenue recovery from DNOs' capacity bookings may increase and that of the power sector consequently decrease as a result of the power sector optimising their capacity booking as a result of additional flexibility.
- Smoothing Seasonal Multipliers may blunt the impact on suppliers from inaccurate forecasts.

The potential impact on the price of traded electricity in the SEM is considered in chapter 4. Given the impact the ratchet may have in the electricity market we consider it would be appropriate to discontinue the ratchet mechanism and introduce an exit capacity overrun mechanism to mirror the mechanism which operates for entry capacity. We consider that the removal of the ratchet could have a beneficial impact on market efficiency. However, the two mechanisms are not interdependent i.e., the ratchet could be removed without introducing short term products at exit and be replaced with an overrun penalty. It is more difficult to be certain about the impact of short term capacity at exit on SEM.

In chapter 5 we set out in more detail a number of potential consequences/risks to gas consumers that need to be considered ahead of any decision on whether to introduce short term exit capacity products. For example, redistribution of capacity costs between shippers, increased volatility in the gas year end reconciliation. We include some examples of possible proposals to mitigate some of these risks and would encourage respondents to consider whether there are other mitigations which we should consider. We would welcome views on whether we have identified all the appropriate risks and consequences. We also welcome any view on potential upsides to the introduction of short term capacity at exit that we have not considered.

Chapter 7 set out the potential impact on the gas transmission annual capacity charges if short term exit capacity products are introduced.

The consultation questions are set out in chapter 8.

Next steps

The next steps in the project are set out in chapter 6. We envisage a decision making phase (steps a-d below) and a subsequent implementation phase (step e) if required.

a) Development of a policy position on whether to implement short term exit capacity products and changes to the ratchet.

b) If required development and consultation on any licence modification required to implement the policy position

c) If required final licence decisions once we have considered the responses to any consultation on proposed licence modifications.

d) If required Single NI Code[8] modification consultation and decisions

e) If required implementation of any regulatory changes

Separately but parallel to this process, a consultation to meet requirements of the Tariff Network Code (see paragraph 5.7), will propose to maintain current seasonal multiplier factors from October 2023 and smooth the factors from October 2024.

These steps will take some time to work through. Therefore we consider that the earliest date that short term exit products could be introduced would be 1st October 2024, the tariff process for which begins in January 2024.

[8] NI Network Gas Transmission Code | GMO Northern Ireland (gmo-ni.com)

Acronyms and Glossary

CCGT	Combined Cycle Gas Turbine
CRU	Commission for Regulation of Utilities, which regulates gas in the Republic of Ireland
DM	Daily Metered
DNO	Gas Distribution Network Operators
GDN	Gas Distribution Network (GB)
GMO NI	Gas Market Operator Northern Ireland
LDM	Large Daily Metered
NIGCS	Northern Ireland Gas Capacity Statement
NTS	National Transmission System
OCGT	Open Cycle Gas Turbine
Ofgem	Office for Gas and Electricity Markets in Great Britain, which regulates gas in Great Britain
RoI	Republic of Ireland
SEM	Single Electricity Market
SONI	System Operator Northern Ireland
Tariff Network Code	EU Network Code on Harmonised Transmission Tariff Structures for Gas, transposed into UK legislation following EU Exit
TSO	Transmission System Operator
TYTFS	(SONI)'s Ten Year Transmission Forecast Statement
UNC	Uniform Network Code in GB
UR	Utility Regulator NI

1. Introduction

Subject of this Consultation

1.1 In this consultation we are seeking views on the subject of short term capacity products at exit points in the gas transmission regime in Northern Ireland (NI), in particular:

a) Whether to introduce short term capacity options at exit and to what extent these products would mirror the products currently available at entry. Under the European Network Code on Capacity Allocation Mechanisms (CAM) [9], which was transposed after EU exit into UK legislation in the Gas (Security of Supply and Network Codes) (Amendment) (EU Exit) Regulations 201910, Operators must offer quarterly, monthly, daily and within day daily entry capacity products. We wish to consider if the same suite of products should be available at exit.

b) Ratchet mechanism. If short term exit capacity products become available as a result of this review, we consider it would also be appropriate to discontinue the ratchet mechanism and introduce an exit capacity overrun mechanism. This could mirror the mechanism which operates for entry capacity. See from paragraph 5.43.

c) 1 in 20 obligation. The obligation to book entry capacity falls to the gas suppliers who are bringing gas into the NI transmission network to facilitate power generation and to supply the gas distribution networks. However, at exit, the responsibilities are different. For the power generators, the end user books capacity, but for gas consumers, the DNO books and holds their capacity based on a 1 in 20 year demand. See from paragraph 5.49.

d) Secondary transfers. The NI Network Gas Transmission Code sets out the circumstances[11] under which a shipper can transfer all or part of its exit capacity. Shippers may transfer exit capacity for whole months to a shipper at the same exit point at least ten days in advance of the transfer period. The approach to secondary transfers differs between GB and RoI, as outlined in paragraph 10.8, 10.28 and 10.29. Therefore, should short term exit products become available in NI, it may be worthwhile considering if the current arrangements for secondary transfer of exit capacity should be reviewed.

[9] Commission Regulation (EU) No 984/2013 Network Code
[10] https://www.legislation.gov.uk/uksi/2019/531/made
[11] Paragraph 3.9 of NI Network Gas Transmission Code

1.2 The introduction of short term exit products could have a number of the potential implications and risks particularly for non-power generation gas users and electricity consumers.

1.3 Therefore, we have analysed the potential impact of short-term exit products on the gas capacity tariff, on shipper reconciliations and on cost allocation between Power Generation and DNOs. We have also considered smoothing the seasonal multipliers as a mitigating factor. We have provided a summary of this analysis and our assumptions as part of this consultation document in chapter 3.

1.4 We have also considered how we might expect short term gas exit capacity products to impact on wholesale electricity prices in the SEM[12].

Legal and Regulatory Framework

1.5 There is no legal requirement to introduce short term capacity products at gas transmission exit points. Therefore, any decision to do so must further our statutory duties so as to protect the interests of consumers.

UR Statutory Duties

1.6 Due to the inter-dependencies between the gas and electricity sectors, we consider that the interests of both gas and electricity consumers are relevant when considering the potential changes to the gas exit regime set out in this paper. The UR has separate duties for electricity and gas and we will need to consider whether both sets of duties are engaged before any decisions are taken on whether to change the gas exit regime. The relevant duties are set out separately below. In making this assessment we will give due consideration to any responses received to this consultation.

1.7 If only UR's gas duties are engaged, the interests of electricity consumers can be considered under Article 14(4) of the Gas Order.

Statutory Duties with Respect to Gas

1.8 Our statutory duties with respect to gas are set out in article 14 of the Energy Order.

1.9 More specifically, pursuant to article 14 (1) of the Energy Order, they include the principal objective to "*promote the development and maintenance of an efficient, economic and co-ordinated gas industry in Northern Ireland, and to do so in a way that is consistent with the fulfilment by the Authority, of the*

[12] UR analysis is based on publicly available information available at the time of publication of this document.

designated regulatory gas objectives."[13]

1.10 Article 14 (2) of the Energy Order provides that the Authority shall carry out those functions in the manner which it considers is best calculated to further the principal objective, having regard, amongst other things, to

- the need to ensure a high level of protection of the interests of consumers of gas;
- the need to secure that licence holders are able to finance [their] activities ;
- the need to protect the interests of gas licence holders in respect of the prices at which, and the other terms on which, any services are provided by one gas licence holder to another.

1.11 Subject to this, the Authority shall, pursuant to Article 14 (5), carry out its functions in the manner which it considers is best calculated to, amongst other things:

- promote the efficient use of gas and efficiency and economy in the conveyance, storage or supply of gas;
- secure a diverse, viable and environmentally sustainable long-term energy supply; and
- facilitate competition between persons whose activities consist of or include storing, supplying or participating in the conveyance of gas.

1.12 Based on Article 14(3) of the Energy Order, the Authority shall have regard to the interests of individuals who are disabled or chronically sick, individuals of pensionable age and individuals with low incomes. However, this is not to be taken as implying that regard may not be had to the interests of other description of consumers.

1.13 Based on Article 14(4) of the Energy Order, the Authority may, in carrying out any gas functions, have regard to the interests of consumers in relation to electricity.

Statutory Duties with Respect to Electricity

1.14 Our statutory duties with respect to electricity are set out in article 12 of the Energy (Northern Ireland) Order 2003[14] as amended (Energy Order). In addition, article 9 of the Electricity (Single Wholesale Market) Northern

[13] For a definition if designated regulatory gas objectives, see Electricity and Gas etc. (Amendment etc.) (EU Exit) Regulations 2019, Article 128.
[14] Energy (Northern Ireland) Order 2002 (as amended).

Ireland Order 2007[15] as amended sets out principal objectives and duties in relation to the Single Electricity Market.

1.15 More specifically, pursuant to article 12 (1) of the Energy Order, our statutory duties include the principal objective to "*protect the interests of consumers of electricity supplied by authorised suppliers, wherever appropriate by promoting effective competition between persons engaged in, or in commercial activities connected with, the generation, transmission, distribution or supply of electricity*."

1.16 Article 12 (2) of the Energy Order clarifies that the Authority shall carry out those functions in the manner which it considers is best calculated to further the principal objective, having regard, amongst other things, to the need to secure that all reasonable demands in Northern Ireland or Ireland for electricity are met.

1.17 Subject to this, the Authority shall, pursuant to Article 12 (5), carry out its functions in the manner which it considers is best calculated to, amongst other things, promote the efficient use of electricity and efficiency and economy in the generation, distribution, transmission and supply of electricity.

1.18 Based on Article 12 (4) of the Energy Order, the Authority may, in carrying out any electricity functions, have regard to the interests of consumers in relation to gas.

Common tariff/ postalisation requirement

1.19 The principle of postalisation was approved by the NI Executive and Assembly in September 2001 and was implemented in NI on 1 October 2004. Postalisation means that the charge for transporting gas along designated pipelines will be the same irrespective of where the gas is offtaken for final use.

1.20 Pipelines subject to the common (i.e. the postalised) tariff are designated by DfE under article 59 of the Energy Order and include all the high pressure pipelines in NI.

1.21 The objectives of the UR, in relation to the common tariff, are set out in Article 14(1) and Article 14(2)(c) of the Energy Order and these provide that UR shall carry out its functions in the manner which it considers is best calculated to further the principal objective, having regard to:

14(2)(c) the need to secure that the prices charged in connection with the conveyance of gas through designated pipe-lines (within the meaning of

[15] Electricity (Single Wholesale Market) Northern Ireland Order 2007 (as amended).

Article 59) are in accordance with a common tariff which does not distinguish (whether directly or indirectly) between different parts of Northern Ireland or the extent of use of any pipe-line;".

1.22 Currently, the transmission tariff methodology results in the same reference price[16] at all entry points and the same reference price at all exit points. It is therefore compatible with the common tariff requirement. The reference price is then used to calculate the tariffs for each non- annual entry product by applying the relevant product multiplier.

1.23 If a decision is made to introduce short term exit capacity products, it will be implemented by way of licence modifications which reflect and be informed by the decision and the provisions relating to common tariff requirements.

Regulatory framework

1.24 The broader regulatory context in which exit regime reform is to be considered includes licence provisions on postalisation and recovery of TSO allowed revenues. These provide:

a) That Gas Transmission System Operator (TSO) allowed revenue recovery is assured; and

b) That revenue recovery is delivered in a timely manner and consistent with the mutualised approach that delivers low overall costs to NI energy consumers.

1.25 If short term exit products are introduced following the present review, we consider that any revenue derived from these products should be treated as postalised system payments. Revenue derived from non-annual products at transmission entry points are treated as postalised system payments. See chapter 2 for an overview of the postalised transmission charging regime.

Structure of this document

1.26 The structure of this document is as follows:

- Chapter 2 contains background information, including an overview of the postalised transmission charging regime and the drivers for the current review;
- Chapter 3 sets out the results of the gas scenario analysis we have undertaken. Each scenario calculates the year-end tariff for different

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[16] The reference price refers to the price for the annual capacity product for applicable for entry and exit points derived in accordance with the methodology which determines cost allocation between different points in the transmission network. UR has adopted a 'postage stamp' methodology.

assumptions and models the impact this could have on cost allocation between gas users in NI (i.e. between the power and distribution sectors) and the impact on the end of year gas transmission reconciliation;

- Chapter 4 explores whether the introduction of short term exit capacity products in NI may impact the SEM and examines the impact of the gas ratchet mechanism in the SEM and the potential impact of short term gas exit capacity costs in price formation in the SEM;

- In Chapter 5 we consider the potential impact of short term exit products on the year-end reconciliation, cost recovery between the power generation and distribution sectors and considerations around the 1 in 20 capacity booking obligation and the seasonal multiplier factors, We also consider implications for capacity booking responsibilities, capacity booking platform and capacity overrun mechanisms. This chapter also considers the importance of good forecasting;

- Chapter 6 outlines the steps required if there was a decision to introduce short term exit capacity products. It considers the steps to implement any changes to the transmission charging regime;

- Chapter 7 uses the scenario analysis to illustrate the potential impact on the transmission tariff of introducing short term exit products;

- Chapter 8 contains the consultation questions;

- Chapter 9 explains how to respond to the consultation;

- The Annex, numbered as chapter 10, provides an overview of the regulatory arrangements in Great Britain (GB) and the Republic of Ireland (RoI) with respect to those aspects that are of particular relevance for this consultation.

2. Background

Postalised Transmission Charging Regime

2.1 The four transmission pipelines in NI are owned independently by four TSOs (GNI (UK), PTL, BGTL and WTL[17])However they are operated as a single system, in a single zone with a single transmission tariff. The Gas Market Operator for Northern Ireland ("GMO NI") operates the natural gas transmission market in NI on their behalf.

2.2 The postalised charging regime calculates charges at entry and exit points and suppliers pay entry and exit capacity charges and commodity charges based on their booked entry and exit capacity and volumes transported. A supplier pays the same tariff, regardless of how far the gas has travelled through the system from any one point to any other point on the system.

2.3 The transmission services revenue, which is used to determine the tariff, is the sum of the TSOs' required revenues. Tariff payments are made into a joint bank account (the PoT) which are distributed to TSOs following licence formulae to equalise the payments they receive with their revenue requirement.

2.4 The postalised regime is designed to ensure that the TSOs receive all of their required revenue and in particular that MEL's actual required revenue is recovered from all gas consumers in a timely way. Therefore all NI gas users pay for MEL pipelines in all circumstances, including, the cost of other users' non payment of tariffs/bad debt. Also any under recovery of PTL/BGTL/WTL actual required revenues will also be recovered from all gas consumers.

2.5 Consequently, the TSOs are not exposed to either capacity or volume risk as suppliers pay their proportion of the required revenues based on their actual volumes/capacity at the end of the year. The inability of one group of consumers to contribute to cost recovery would therefore result in a transfer of costs onto the remaining consumer groups based on their actual volumes/capacity at the end of the year.

2.6 The four TSOs have implemented a contractual joint venture arrangement to jointly operate the market facing commercial arrangements, known as the Gas Market Operator for Northern Ireland or GMO NI.

2.7 The postalised charging regime is managed on an annual cycle. Forecast Postalised Charges are set, ahead of the Gas Year, based on estimated TSO costs and the forecast capacity and commodity quantities for the

[17] WTL is not a TSO as defined by the European Commission but it is referred to as a TSO in this document for simplicity

forthcoming Gas Year. These Forecast Postalised Charges are applied in invoices during the Gas Year. Following the Gas Year, once the TSO actual costs along with the actual quantities of capacity booked and commodity flowed are known, a reconciliation calculation is carried out in order to determine the 'actual' unit price for the Gas Year and deal with any under or over recovery of revenue. The reconciliation process generates a single ('bullet') payment each year to/from shippers based on their actual volumes/capacity at the end of the year. This ensures that the TSOs' total required revenue is recovered from consumers who use the network in that year.

Drivers for a review of the current exit regime in NI

2.8 Short term, i.e. Non-annual, gas capacity products have been available at entry points to the NI gas transmission system since 2015, see paragraph 1.1(a). Since then, power generators have called for the availability of short-term capacity products at transmission exit points in NI. There is no legal requirement to introduce short term exit products.

2.9 The power generation industry contends that additional flexibility in the form of short term exit capacity is required by gas fired power generators is required following increased electricity generation from renewable sources.

2.10 Short term exit products may have beneficial impacts on aspects of the SEM. In RoI, shippers have the flexibility to book their exit capacity on a daily, monthly, quarterly, or annual basis. By introducing short term exit products in NI, we would be able to offer terms for investment in NI generation that are more closely aligned with those in ROI.

2.11 The focus of this consultation is therefore to explore whether there is a case for moving to short term (non-annual) products at exit and additionally a case for smoothing Seasonal Multipliers as outlined in worked scenarios in Chapter 3.

2.12 In this consultation we consider the impact of any changes to the current exit capacity regime on shipper cost allocations, end of year reconciliation and consumer bills in NI.

Previous Review of Exit Capacity Arrangements

2.13 UR has previously considered whether non-annual capacity should be available at exit points. In 2016 the UR published an "Exit Capacity Review[18]" call for evidence.

[18] 2016-04-15_Exit_Capacity_Review_Call_for_Evidence_v10.pdf (uregni.gov.uk)

2.14 The objective of the call for evidence was to elicit feedback from industry as to whether exit reform was appropriate and if so, what arrangements might have been preferred.

2.15 The outcome of the call for evidence was informed by eleven responses received[3]. Seven of the responses, received from a range of industry players, indicated that reform to introduce gas transmission exit short-term capacity products was unnecessary.

2.16 These responses typically referenced the complexity that would be introduced by short term products at exit and expressed that this was unwarranted and disproportionate given the size of the NI market. They also suggested that reform would create uncertain benefits for power generators versus certain costs for others, and therefore reform was not justified.

2.17 The remaining four responses came from the generation sector and contended that reform of the exit capacity scheme in NI was essential. The responses noted that the current annual capacity regime in NI was not fit for purpose, and that specifically it may:

a) Impact negatively on the financial viability of existing NI generators.

b) Limit potential for investment in new NI generation; and

c) Place existing NI generation at a competitive disadvantage compared with RoI generation.

2.18 UR concluded[4] that the evidence gathered did not justify amending the existing gas transmission regime at that stage and that developments in the SEM may address the concerns of power generators.

NI Energy Strategy

2.19 The NI Energy Strategy "The Path to Net Zero"[19] set out a target of at least 70% of electricity consumed to come from renewable sources by 2030, this was further increased to 80% in the Climate Change Act (Northern Ireland) 2022[20].

2.20 However, gas-fired generation is expected to play a role in the energy transition, replacing retiring conventional plant and providing the multi-day capacity, during extended spells of low wind and solar output. Furthermore, it will ensure security of supply during periods of high demand, and low

.pdf"The Path to Net Zero Energy. Safe. Affordable. Clean. (economy-ni.gov.uk)
my/Energy-Strategy-for-Northern-Ireland-path-to-net-zero.pdf"The Path to Net Zero Energy. Safe. Affordable. Clean. (economy-ni.gov.uk)
[20] Climate Change Act (Northern Ireland) 2022 (legislation.gov.uk)

renewable output.

2.21 In this context, SONI's 2021 TYTFS[21] indicated a requirement for peaking plants to both support renewable generation and to meet peak demand periods. In NI two new OCGTs at Kilroot were successful in capacity auctions and are due to begin generating in the 23/24 year.

[21] https://www.soni.ltd.uk/media/All-Island-Ten-Year-Transmission-Forecast-Statement-TYTFS-2021.pdf

3. Gas Scenario Analysis

Outline of scenarios

3.1 We have explored a number of scenarios to inform our considerations. We are interested in Respondents' views on the results of our scenarios. The table below summarises the scenarios and they are explained in more detail in the following paragraphs.

Scenario Number	Key Points
Base Case	Current tariff
Base Case Enhanced	Current tariff with additional capacity for GY 24/25
Scenario 1	Introducing short term exit products plus the additional capacity forecast in NIGCS GY 24/25. Actual is equal to forecast.
Scenario 2	Introducing short term exit products plus the additional capacity as forecast in NIGCS GY 24/25. Actual is lower than forecast at exit for daily products only, assuming only a proportion of the daily capacity forecast is actually booked.
Scenario 3	Introducing short term exit products plus the additional capacity as forecast in NIGCS GY 24/25. Actual is zero at exit for all daily capacity.
Scenario 1b	Same as Scenario 1 but with smoothed Seasonal Multipliers at both entry and exit.
Scenario 2b	Same as Scenario 2 but with smoothed Seasonal Multipliers at both entry and exit.
Scenario 3b	Same as Scenario 3 but with smoothed Seasonal Multipliers at both entry and exit.

Figure 1 – Summary of Exit Capacity Scenarios.

Assumptions in the Scenarios

3.2 The key assumptions used in the scenarios are outlined below.

a) The scenario analysis is based on GY 24/25 only – see paragraph 3.33 regarding future years.

b) The forecasts are based on publicly available information. The forecast exit capacity requirement in the Base Case is the exit capacity forecast for 24/25 as shown in the 22/23 postalised tariff publication[22], which is 94GWh.

c) The additional capacity in the Base Case Enhanced is the difference between the 24/25 exit capacity forecasts for the two existing power stations (Ballylumford and Coolkeeragh) in the 22/23 postalised tariff publication (42.8GWh) and the Average Winter Peak Day[23] for power generation in 24/25 in the NI Gas Capacity Statement[24] (51.7GWh), which is 8.9GWh. We used the Average Winter Peak Day because experience has shown it to be a good indication of the actual annual peak, see Figure 4 in Chapter 5. We assume that this "additional" capacity is due to additional gas fired generation following the closure of the coal-fired units at Kilroot. Only annual exit capacity is assumed to be available in Base Case Enhanced.

d) From scenario 1 onwards, the current short-term entry capacity regime is assumed to be largely replicated at exit. This would mean the introduction of quarterly, monthly and daily products. For scenarios 1, 2 and 3, the short term products would have the current seasonal multiplier factors applied to provide an incentive to book annual capacity.

e) For the scenarios with short term exit products, we used the entry capacity forecast for the two existing power stations (Balllylumford and Coolkeeragh) in 24/25 as shown in the 22/23 forecast tariff to estimate the seasonal profile of forecast daily capacity at exit.

f) The extent to which the new OCGT gas-fired power station at Kilroot will require gas exit capacity is a key assumption. As explained in paragraph 2.21, SONI has indicated a need for more peaking plants, so this new plant may have a more variable need for capacity than other users. We discussed our assumptions with the owner of the new power station at Kilroot as part of our checking process and it provided data showing recent dispatch patterns of other peaking plants. Those peaking plants, in aggregate, tended to be dispatched for 170 days a year and the average dispatch per unit is around 25% of their individual peak day. For the scenarios with short term exit products, we assumed "additional" capacity of 8.9GWh would be booked for 170 days and we checked that this is significantly less than Kilroot's forecast Average Winter Peak for 24/25 in the NIGCS. We were therefore broadly content that it is appropriate to use our

[22] https://gmo-ni.com/assets/documents/Tariffs/2022-23/GY2022-2023-Postalised-Tariff-Explanatory-Note.pdf
[23] See also Table 1
[24] https://gmo-ni.com/assets/documents/NIGCS-2022-23-to-2031-32-FINAL.pdf

assumptions.

g) The DNOs are assumed to continue to book exit capacity in a 1 in 20 basis. This is discussed from paragraph 5.49. For the purposes of these scenarios, the DNOs are assumed to continue to make these capacity bookings on an annual basis.

h) In scenarios 1b, 2b and 3b, the smoothed seasonal multiplier factors are assumed to have no seasonal fluctuation but have a flat multiplier applied. The multiplier chosen for modelling purposes is 1.5 for monthly products and 2.7844 for daily products. The smoothed seasonal multiplier factors are assumed to be applied at both entry and exit.

i) In all scenarios, actual capacity bookings at entry are assumed to be equal to forecast. This allows the impact of changes at exit to be viewed in isolation.

j) Only daily capacity products have been assumed to be used in addition to annual capacity. For present purposes modelling has not been undertaken with regard to monthly and quarterly.

k) The required revenue is the forecast from 24/25 from the postalised tariff publication, expressed in March 2022 monies and remains constant in each scenario.

3.3 The forecasts used in the scenarios for annual and non-annual gas capacity use by the power stations in NI plant in 24/25 are critical to the utility of the scenarios. Our assumptions regarding the new Kilroot plant are explained above. For Coolkeeragh and Ballylumford power stations there are two changes in prospect which could affect their gas capacity use in 24/25 and which we cannot account for at this stage:

a) The ship-or-pay agreement at **Coolkeeragh power station** is coming to an end in 2024. This may afford Coolkeeragh more flexibility to optimise its gas capacity bookings between annual capacity and non-annual capacity.

b) The long-term contract[25] between **Ballylumford** and Power NI's Power Procurement Business (PPB) ends in 2024. This may alter Ballylumford capacity forecasts from 24/25 onwards compared to historical figures but we cannot say how now with any accuracy.

[25] Power Purchase Agreements (PPAs) were introduced at the privatisation of NIE in 1992 https://www.uregni.gov.uk/files/uregni/media-files/FEMO_Draft_Decision_Paper_Dec_03.pdf.

3.4 **Base Case "As is"**

a) The Base Case is the current tariff with the shipper forecasts as they are now and annual only exit products.

b) In the base case actual is equal to forecast.

3.5 **Base Case Enhanced**

a) The Base Case Enhanced is the current tariff model adjusted to include the additional annual Power Generation capacity forecasted in the NIGCS for Gas Year 24/25 at entry and exit. For clarity there are no short-term products at exit in this scenario.

b) In the Base Case Enhanced scenario, actual is equal to forecast.

c) In order to isolate the impact of short term exit products, we have considered that the scenarios should be compared against a base which includes the additional forecasted capacity. Therefore, the following scenarios are compared against the Base Case Enhanced.

3.6 **Scenario 1**

a) This scenario provides a view on how the tariff may be impacted by the introduction of short term exit products. It is based on the Base Case Enhanced with the introduction of short-term products as exit.

b) The existing power generation exit capacity forecasts have been divided into annual and daily capacity products at the same proportion as their 22/23 entry capacity forecast used for the postalised tariff calculation. Then, the daily capacity is given a seasonal profile to meet the capacity forecast for 24/25 from the 22/23 forecast tariff.

c) The additional capacity forecast for Power Generation for GY 24-25 as forecast in the NIGCS is added to the model at entry and exit as a daily only product and is assumed to follow the same seasonal profile of daily capacity usage as the 24/25 forecast of daily entry capacity for the existing power generators.

d) In Scenario 1, actual is equal to forecast.

3.7 **Scenario 2**

a) This scenario considers the year-end reconciliation, and recalculated final tariff, if none of the daily exit capacity which was forecast for the additional capacity is actually booked, while the capacity forecast by the existing power generators is assumed to be booked as forecast.

b) The forecasts used are the same as in Scenario 1 above.

c) Actual is equal to forecast except that none of the additional daily exit capacity which had been forecast for new power generation is actually booked. No adjustment is made to entry capacity.

3.8 **Scenario 3**

a) This scenario goes further than scenario 2 to assess what might happen in the extreme circumstance that none of the daily exit capacity forecast is actually booked. It considers what the year-end reconciliation might be and therefore the final tariff.

b) The forecasts used are the same as Scenario 1 and 2 above. The actual daily capacity at exit is assumed to be zero, which would mean that none of the power generators actually book any of the daily exit capacity they had forecast. No adjustment is made at entry.

3.9 **Scenario 1B**

a) This scenario is based on scenario 1 and considers how the tariff might be affected if the seasonal multipliers were smoothed, at both entry and exit, through the reduction of the seasonal element leaving the multiplier to be applied on a flat basis throughout the year.

b) The other assumptions in scenario 1 are unchanged.

3.10 **Scenario 2B**

a) This scenario makes the same adjustment to the seasonal multipliers as scenario 1B but applies it to scenario 2. This assesses the impact on the year-end reconciliation and the final tariff.

b) The other assumptions in scenario 2 are unchanged.

3.11 **Scenario 3B**

a) This scenario makes the same adjustment to the seasonal multipliers as scenario 1B but applies it to scenario 3. This assesses the impact on the year-end reconciliation and the final tariff in this extreme circumstance.

b) The other assumptions in scenario 3 are unchanged.

Scenario Model

3.12 To provide greater insight on the scenarios, we have prepared a scenario model which will be published alongside this consultation. It is an amended version of the Appendix 1 – Forecast Tariff Spreadsheet which is published each year on the GMO NI website[26] to meet transparency requirements in the Tariff Network Code. The scenario model has a separate sheet which sets out the key inputs of each of the scenarios and allows the user to pick any scenario and see the calculated forecast and year-end tariff as well as any reconciliation amount.

3.13 The cells with the spreadsheet are not locked, so users may amend the input data to model their own scenarios.

Outcomes – Indicative Impact on Tariff

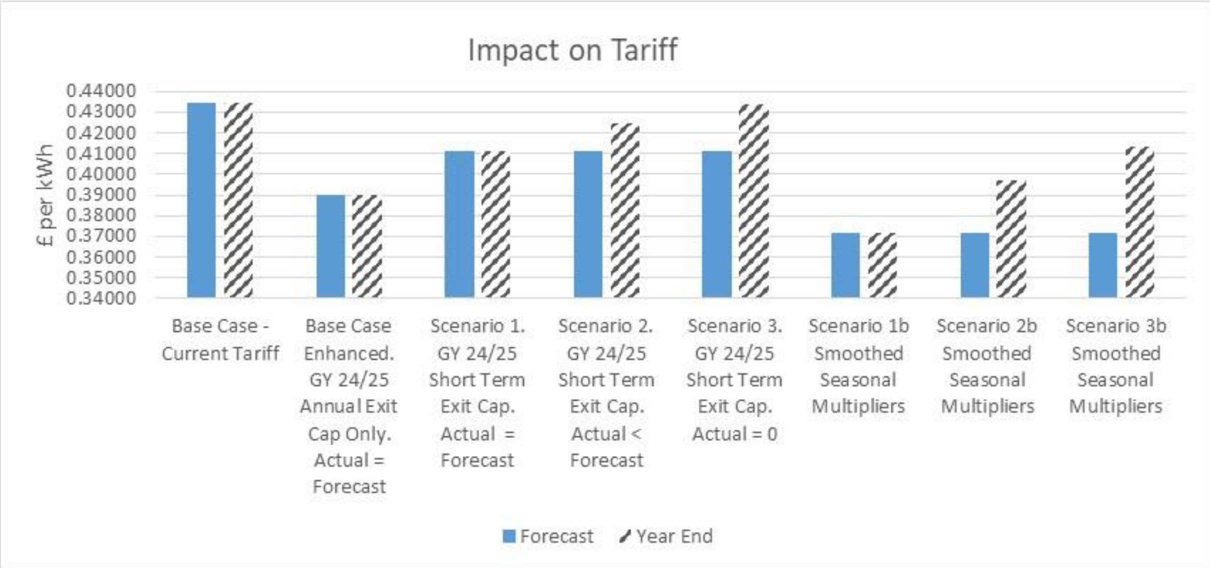

Figure 1 – Indicative Impact on Postalised Gas Transmission Capacity Tariff.

3.14 As outlined previously the Base Case Enhanced Scenario is where we retain the current exit regime and add additional capacity forecasted for Power Generation for GY 24/25. This is added as an annual capacity product at entry and exit.

3.15 The tariff in the Base Case Enhanced scenario is 10% lower than the tariff in the Base Case.

3.16 We can compare Scenario 1 to the Base Case Enhanced Scenario to consider the impact on the tariff price with the introduction of short term exit products and when actual is equal to forecast.

3.17 In that context we can see a 5% increase in the tariff as a result of the

[26] https://gmo-ni.com/tariffs

introduction of short-term products at exit in Scenario 1.

3.18 For scenarios 2 and 3, although the forecast tariff is the same, it gets adjusted at year-end to reflect the assumed difference between actual and forecast capacity bookings. For scenario 2, the actual additional daily capacity is assumed to be zero, while in scenario 3, all actual daily capacity is assumed to be zero.

3.19 Compared to Base Case Enhanced, the year-end tariff for Scenario 2 is 9% higher and the year-end tariff for Scenario 3 is 11% higher.

3.20 However, by smoothing the seasonal multipliers in Scenarios 1b-3b, there is a lower impact on the year-end tariff in each comparative scenario. For scenario 1b, the tariff would reduce by 5% compared to base case enhanced; for scenario 2b, the tariff would increase by 2% and for scenario 3b, the tariff would increase by 5%. We have not taken into account any potential change in booking behaviour by the power generators as a result of any change in seasonal multipliers.

Outcomes – Indicative Impact on Cost Allocation

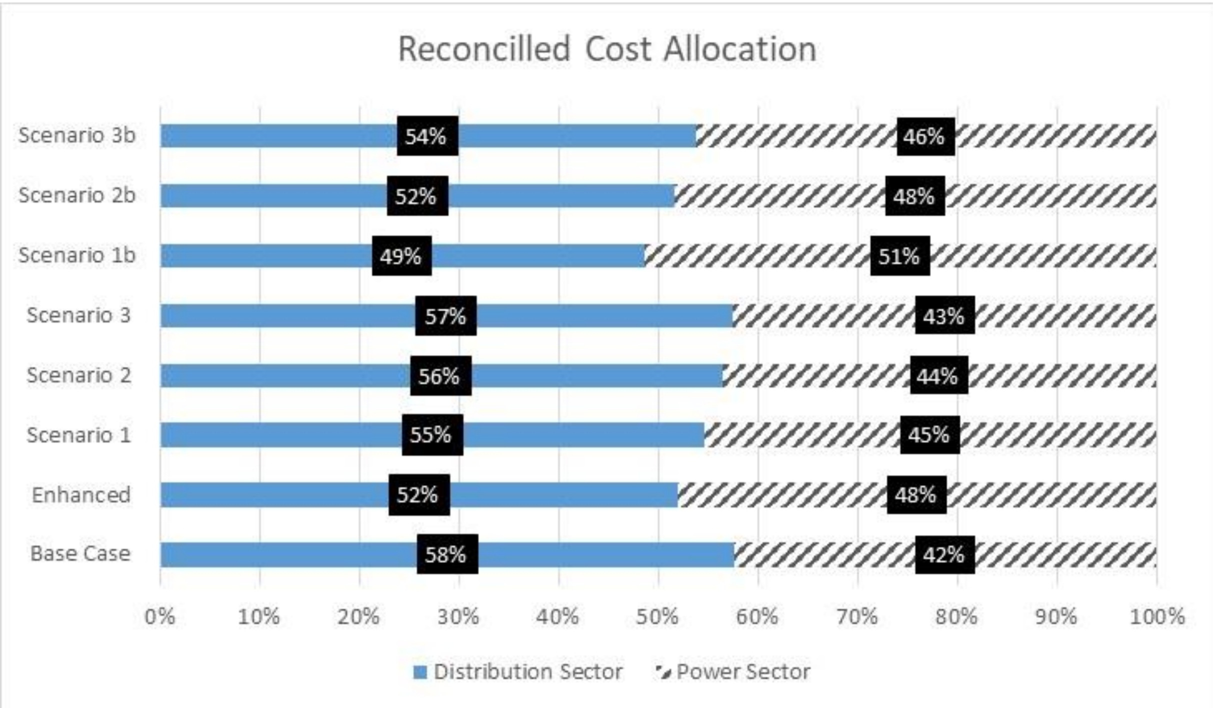

Figure 2 – Indicative Reconciled Cost Allocation

3.21 The graph above outlines the year-end reconciled cost allocation between the gas distribution sector and Power Generation for each scenario. The revenue to be recovered is the same in each scenario.

3.22 In the Base Case Enhanced we can see that the postalised payments between distribution and power generation sector have a ratio of 52:48%. In the Base Case which is the 22/23 tariff, before the additional capacity forecast are added, the ratio is 58:42.

3.23 With the introduction of short-term exit products, in Scenarios 1-3, the postalised payments expected to be made by the power generation sector are seen to reduce and as a result the distribution payments will increase, up to a proportion of 57% in scenario 3.

3.24 In Scenarios 1b-3b, the proportion of costs due to be paid by the distribution sector reduces as a result of smoothed Seasonal multipliers. Scenario 1b shows the distribution sector paying 49% of the required revenue, reduced from 55% in scenario 1.

Outcomes – Indicative Impact on Year End Reconciliation

3.25 The graph below illustrates the year-end reconciliation amounts in the scenarios and shows that Smoother Seasonal Multipliers can be seen to potentially increase the year-end reconciliation amount in Scenarios 2b & 3b. This is explored in the next section.

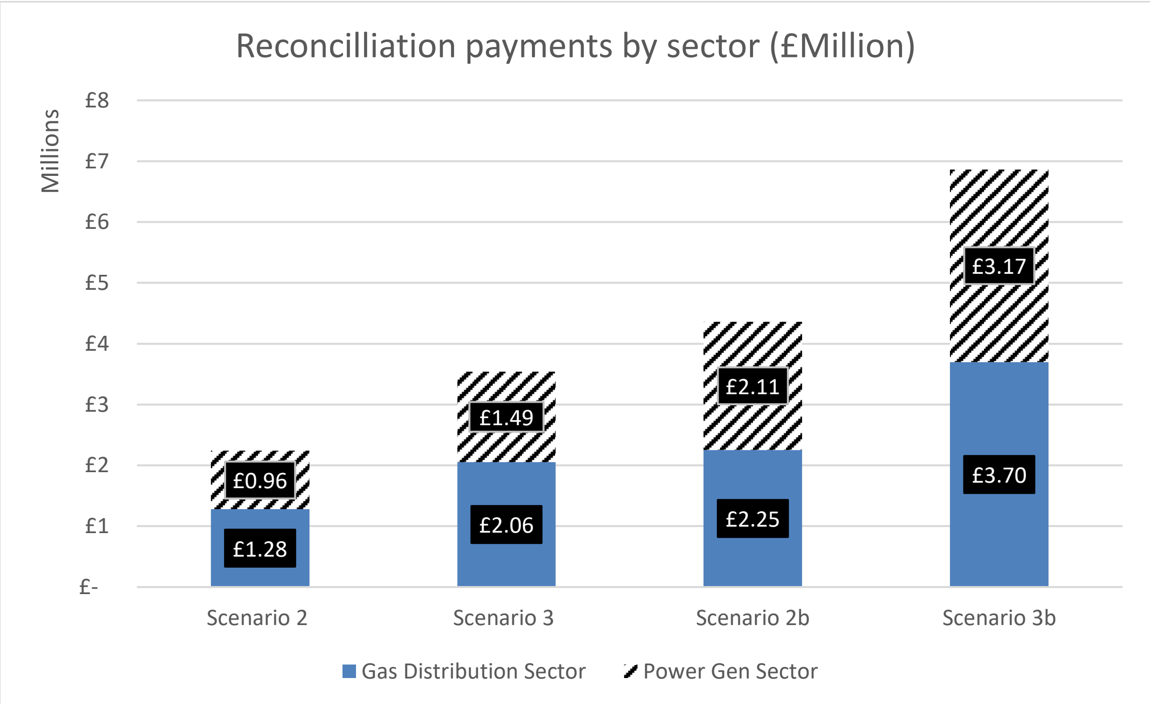

Figure 3 – Indicative Reconciliation payments by sector

Impact of Smoothed Seasonal Multipliers

3.26 The smoothed seasonal multiplier factors appear to help counteract the transfer of cost recovery from power generation sector to the gas distribution sector.

3.27 This is occurring because the daily capacity forecasts peak in the summer months, due to lower reliability of wind-powered generation meaning that more gas-fired generation is required. The current seasonal multiplier factors are designed to encourage shippers to book in the summer instead of the winter, when the traditional peak requirement was expected.

3.28 Also power generation have peaks throughout the year, including much higher peaks in the summer. In summer, the power generation sector can access low daily capacity charges at entry and scenario 1 assumes that would be replicated at exit. When the actual is assumed to be lower than forecast in scenarios 2 and 3, the current seasonal profile (with peaks in summer and winter) dampens the impact on the year-end reconciliation.

3.29 However, in scenarios 2b and 3b, with smoothed seasonal multiplier factors, the financial impact of unbooked capacity in the summer is much greater and is showed to result in a higher year-end reconciliation. We recognise that the assumption of much reduced actual daily capacity bookings in scenarios 2 and 3, and therefore 2b and 3b, are extreme, but we wished to model these extreme scenarios in order to inform the discussion.

3.30 Although the smoothed seasonal multiplier factors in scenarios 2b and 3b result in a much higher year-end reconciliation amount, it should be noted that there is a less pronounced transfer to cost recovery from the power generation sector to the gas distribution sector in scenarios 1b, 2b and 3b compared to Base Case Enhanced than scenarios 1, 2 and 3, as illustrated in Figure 2.

3.31 However, we recognise that shippers will choose the optimum booking pattern for their forecast. The considerations around whether to book annual capacity or short term capacity will be different for different seasonal multiplier factors. The seasonal profile of daily capacity bookings which we have extracted from the forecast tariff may not apply in a situation of smoothed seasonal multipliers. Nevertheless, we consider these scenarios still illustrate how the tariff and the year-end reconciliation might look in different circumstances.

3.32 In summary, by smoothing seasonal multipliers the gas distribution sector would appear to be less adversely affected in terms of cost allocation shift.

Future Years

3.33 The scenario analysis is based on GY 24/25 only. We consider that it is difficult at this stage to model future years beyond this due to changes which are anticipated in the subsequent years. For example:

a) The **North South Interconnector** is planned to become operational by 2026[27]. Currently, one electricity interconnector links the NI and RoI electricity transmission networks. As this restricts the amount of electricity that can flow across the island, this creates a bottleneck that prevents the electricity transmission network from operating efficiently on an all-island basis. It can result in NI gas-fired power generators running when they may not otherwise be required because electricity from potentially more efficient ROI plants could not be imported to a sufficient extent into NI. Conversely, it also limits the potential for NI power generators to meet all-island needs.

The second North South Interconnector will remove this constraint and allow the all-island network to operate more efficiently. This is expected to have a positive impact on electricity prices. It is also anticipated – on balance – to entail a reduction in NI power sector demand due to the potential for newer, more efficient power generation plant, including in ROI.

b) The owners of the new power station at Kilroot have indicated that they plan to convert the **gas-fired OCGT units** to a Combined Cycle Gas Turbine (CCGT) unit from GY26/27[28]. Robust forecasts for annual and non-annual gas capacity use by the new station at Kilroot in CCGT mode are difficult to judge at this stage due to the high forecast rollout of renewable generation.

c) Changes in the way that electricity is needed – both through increased renewable generation and increased demand for electricity through Electric Vehicles and domestic heat pumps to meet the aims of the Northern Ireland Energy Strategy[29].

3.34 We have not modelled the impact of these factors but we recognise they will affect future capacity bookings, particularly after 24/25.

[27] https://www.soni.ltd.uk/the-grid/projects/tyrone-cavan/the-project/

[28] "The latest capacity offered at the Kilroot site cleared in the recent T-4 25/26 was classified as part of a Combined Cycle Gas Turbine (CCGT) arrangement" page 13 of https://www.soni.ltd.uk/media/documents/EirGrid_SONI_2022_Generation_Capacity_Statement_2022-2031.pdf

[29] https://www.economy-ni.gov.uk/sites/default/files/publications/economy/Energy-Strategy-for-Northern-Ireland-path-to-net-zero.pdf

4. Electricity price impact

Interaction between gas and electricity markets

4.1 The Single Electricity Market (SEM) is a marketplace where market participants (i.e., Power Generators, Suppliers and Demand Side Units) based in Ireland and Northern Ireland are subject to a common set of market rules. In particular, market participants in both jurisdictions compete in the same capacity, energy and ancillary services markets.

4.2 The cost associated with gas-fired power generation can be impacted by different regulatory regimes and cost base in both jurisdictions.

4.3 For example, the availability of short term exit capacity in Northern Ireland will change the nature of the gas capacity booked by the local power stations as they seek to optimise their gas capacity bookings to reduce costs. [30] As a consequence, Power Generators may adjust their bidding methodologies in the SEM to cater for the availability of short term exit capacity products.

4.4 This section explores two issues:

a) The impact of the gas ratchet mechanisms on price formation in the SEM

b) The impact of short term gas exit capacity costs in price formation in the SEM

Ratchet Mechanism

4.5 The current ratchet mechanism only applies in Northern Ireland and was introduced in 2015. The mechanism operates automatically such that if a shipper makes a nomination on a day which exceeds their booked exit capacity, the additional capacity needed to meet their nomination is added to the level of annual exit capacity already booked by that shipper. This increases their capacity booking for the rest of the Gas Year with the effect that the shipper will pay for the additional exit capacity as if it had been booked for the entire year. No additional charge is applied for the overrun capacity.

4.6 This ensures that there is no incentive to knowingly under-book gas exit capacity. However, it also means there is no penalty for under-forecasting use of exit capacity.

4.7 From a gas perspective we consider that the ratchet mechanism should be

[30] Entry arrangements are already largely aligned in consequence of EU law.

reviewed if short term exit capacity products become available, as the need for it will become redundant in Northern Ireland. In that case suppliers will make choices about what duration capacity to book and proper incentives to ensure good forecasting will be increasingly important. The ratchet mechanism does not provide this incentive.

4.8 If the ratchet is removed a capacity over run mechanism will be needed which incentivises suppliers to forecast their gas capacity needs as accurately as possible. This is discussed from paragraph 5.43 where we discuss an exit capacity overrun mechanism to mirror the mechanism which operates for entry capacity.

4.9 Within the SEM energy market arrangements, the absence of short term exit capacity products in NI produces a discontinuity in the bidding pattern of generators as the ratchet costs are reflected in their bids. This discontinuity reduces market efficiency in some trading periods as it creates an asymmetry of cost components between generators based in Ireland and Northern Ireland.

4.10 Consequently, we consider that the removal of the ratchet could help level the playing field between both jurisdictions of the SEM.

4.11 See chapter 5 where we discuss the potential introduction of an exit capacity overrun mechanism to replace the ratchet mechanism. If we decide to introduce short term exit capacity products then we envisage that any changes to the ratchet mechanisms could be made at the same time as any new short term products are introduced (which would be no earlier than October 2024).

4.12 However, we will keep this timing under review pending the responses to the consultation and reflecting the fact that the ratchet mechanism could be replaced or amended without the introduction of short term exit products.

4.13 We note that in the SEM, penalty charges, such as capacity overrun charges, must not be included in energy market bids. The excerpt below is taken from the prevailing BCOP:

Unreasonable Exposure to Certain Charges 12D.

A Licensee's COD should reflect an expectation that it will act so as to avoid unreasonable exposure to the following:

a) *charges (known as overrun charges in Ireland and unauthorised flow charges in Northern Ireland) associated with the movement of gas on the relevant system without capacity; and*

b) *any other penalties or charges of a similar nature.*

Electricity Price Impact

4.14 As explained above we consider that the removal of the ratchet could help level the playing field between both jurisdictions of the SEM. In regard to the potential impact of short term capacity at exit on SEM, we note the following:

a) The introduction of short term capacity bookings will change the basis for the bidding formation in all SEM energy markets. This should produce a slightly different price curve, in some trading periods the prices, under the new regime could produce higher prices, in other period the new regime should produce lower prices when compared to the status quo. Overall market efficiency should increase on the basis that the market will clear bids submitted by Irish and Northern Irish generators under a common set of rules related to gas transportation costs.

b) It is also worth noting that given the smaller share of the market taken by generator from Northern Ireland, any potential price differential produced by the new regime should have relatively low impact in the all island market.

c) The market effects (i.e. SEM Balancing Market and Constraints Costs) of the new regime will also be driven by how SONI will ultimately schedule the gas fired generators in Northern Ireland, in particular the new units at Kilroot and when the new units are scheduled to run (summer/winter).

4.15 In order to refine our analysis we would welcome the view of respondents on the potential impact that short term exit capacity products would, or could, have on prices in the SEM.

5. Consequences

5.1 This chapter considers a number of consequences and examples of possible mitigations of introducing short term exit capacity products and includes the following:

a) Cost Recovery Between Power and Distribution Sectors

5.2 Under-recovery causes a delay in TSOs receiving their full revenue. The quantum of a delayed reconciliation amount may cause financing problems for the TSOs. For example, the reconciliation amount in scenario 3B, which is the most extreme scenario modelled, at £6.8m is almost one-tenth of the required revenue for that year, see Figure 3.

a) Volatility of end of year reconciliation

b) Overrun mechanism to Replace the Ratchet mechanism

c) 1 in 20 capacity booking Obligation

d) Capacity Booking Responsibilities

e) Seasonal Multiplier Factors

f) Improving Accuracy of Forecasts

5.3 We would welcome any further mitigations that we should consider and we have asked a question on this topic, see paragraph 8.5.

Cost Recovery Between Power and Distribution Sectors

5.4 Gas networks are capital intensive, long term investments. They therefore require sufficient revenue streams over the lifetime of the asset to enable adequate returns on investment and recovery of capital. Thus, in regulated networks, assurances about allowed revenue streams are provided to take account of the recovery of capital costs (return and depreciation) and operating costs. This review concerns the cost of NI gas transmission networks.

5.5 These costs are recovered from the users of the network. Broadly speaking, these users can be categorised into two groups: the power sector and the distribution sector. The power sector uses the NI gas network to bring in the gas required for electricity generation in gas-fired power stations. Due to their specific operational requirements, gas-fired power stations have been connected directly to the gas transmission network which operates at high-pressure. The distribution sector uses the NI gas transmission network to bring gas to their distribution zones and onward to domestic, industrial and commercial end consumers. Such consumers are typically[31] connected to the gas distribution networks (which is operated at intermediate and low pressures).

5.6 As both the power and distribution sectors avail of the high pressure network, they both contribute to the associated costs. This section analyses the implications which may arise due to changes to the exit regime relating to the share of the cost of the NI gas transmission system that is borne by the power and distribution sectors.

5.7 The main driver for the overall cost for the provision, ongoing operation and maintenance of the high pressure gas network is capacity. This is reflected in the capacity: commodity split.[32] To ensure compliance with the Tariff Network Code (Network Code on Harmonised Transmission Tariff Structures for Gas)[33], which was transposed into UK legislation after EU exit in The Gas (Security of Supply and Network Codes) (Amendment) (EU Exit) Regulations 2019[34], UR made the decision[35], following a public consultation[36], to set the capacity: commodity split to 95:5. This means that 95% of the required revenue will be recovered from capacity-charges, and 5% from flow-based commodity charges. Capacity charges are paid for capacity levels booked before gas flows; they allow for an option to flow gas up to the booked level. Commodity charges are levied on actual energy flows.

5.8 The capacity of the NI gas network was originally sized to meet peak demand and capacity booking requirements. The capacity charging regime should therefore be designed in a way that ensures users contribute to the capacity cost according to their respective share in peak capacity requirements.

Sectoral Comparison based on Winter Peak Day Demand

5.9 Experience over the last few years has shown average winter peak day forecast demand to be relatively closely aligned with actual peak. Figure 4 below has been extracted from the NI Gas Capacity Statement 2022/23 to 2031/32[37] to illustrate this. It demonstrates that the forecast Average Winter

[31] Utility Regulator states, in its Gas Regulatory Letter No. 1, amended as per 18 May 2015: "*Other than in exceptional cases, we expect that all final customers seeking a connection to the gas system should be connected to a low pressure network.*" Any such exceptional cases will be subject to regulatory consent.
[32] See Utility Regulator: Consultation on Harmonised Transmission Tariffs for Gas, 21 June 2018.
[33] Commission Regulation (EU) 2017/460 of 16 March 2017 establishing a network code on harmonised transmission tariff structures for gas.
[34] https://www.legislation.gov.uk/uksi/2019/531/made
[35] See Utility Regulator: Decision on Harmonised Transmission Tariffs for Gas, 17 December 2018.
[36] 2018-06-21 - Consultation on harmonised transmission tariff structure for gas FINAL.pdf (uregni.gov.uk)
[37] See GNI (UK)/MEL: Northern Ireland Gas Capacity Statement 2022/23 – 2031/32.

Peak has been a good indication of actual peak.

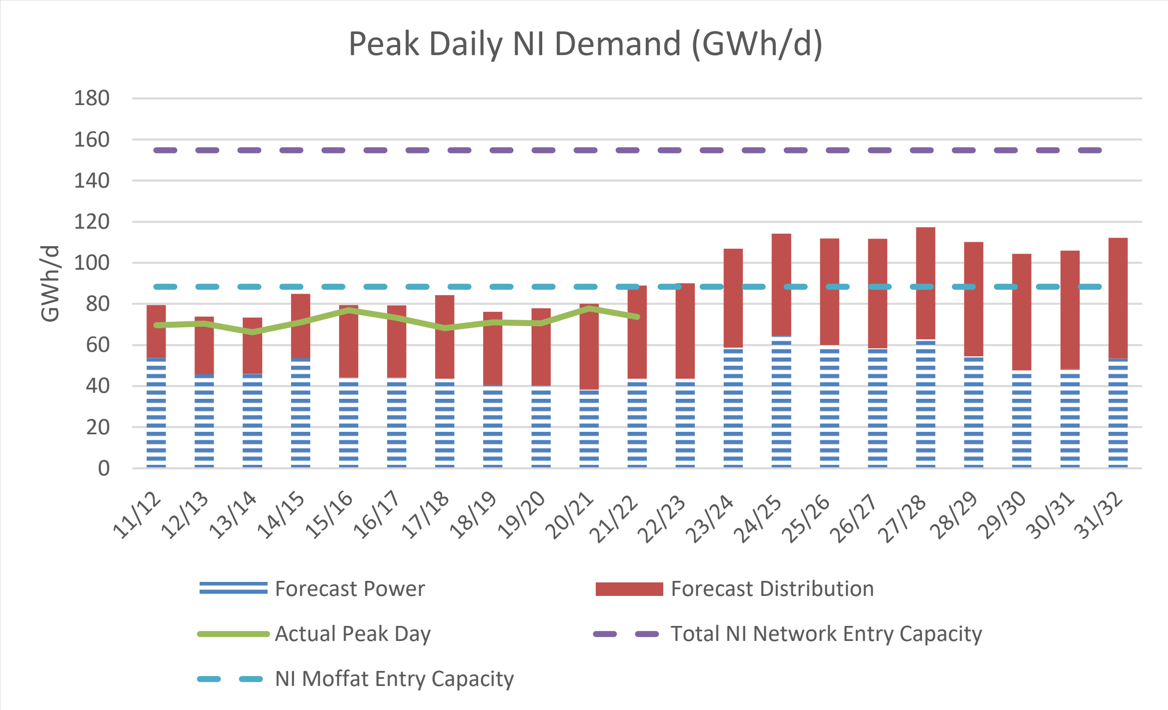

Figure 4 – Historic vs Actual Peak Demand Days

5.10 We can then use the forecast for the Average Winter Peak by sector to compare against the cost recovery by sector in the scenario analysis in chapter 3.

	Average Winter Peak Demand (Firm & Int) Forecast Demands (GWh/day)			% of Total NI Demand	
Year	Power	Distribution	Total NI Demand	Power	Distribution
2022/23	29.4	47.2	76.6	38.4%	61.6%
2023/24	53.4	48.9	102.3	52.2%	47.8%
2024/25	51.7	50.3	102.0	50.7%	49.3%
2025/26	47.1	51.5	98.6	47.8%	52.2%
2026/27	45.5	52.8	98.4	46.3%	53.7%
2027/28	50.0	54.0	103.9	48.1%	52.0%
2028/29	41.7	54.9	96.7	43.1%	56.8%
2029/30	34.9	55.8	90.0	38.5%	61.5%
2030/31	35.4	56.7	92.1	38.4%	61.6%
2031/32	40.6	57.8	98.4	41.3%	58.7%

Table 1: Share of power and distribution sector demand of total firm and interruptible Average Winter Peak Day

(Figures may not sum due to rounding)

5.11 This table uses data from the NI Gas Capacity Statement 2022/23[37] to show the forecast Average Winter Peak Day for ten years. It forecasts that the power sector is expected to comprise between 38-52% of the total peak with the distribution sector comprising 48 -62%. The differences from year to year may arise due to:

- Commissioning of the second North-South Interconnector envisaged for 2025/26, which is anticipated to lead to a reduction in power sector demand from then onwards due to the potential for newer, more efficient plant (including those located in RoI) to meet NI electricity demand, even though on peak days there might be larger exports from NI to RoI (see paragraph 3.33)
- Continued displacement of fossil fuel generation
- Increase in gas demand from the growing distribution Network.

5.12 The split in GY 24/25 is 51:49 between power sector and distribution.

5.13 Our Base Case Enhanced scenario found a split of 48:52 between power sector and distribution. See Figure 2 and paragraph 3.22.

5.14 This does appear to indicate that the distribution sector pays a higher percentage of revenue than their share in Average Winter Peak Day demand would suggest.

Sectoral Comparison based on Anticipated Capacity Bookings

5.15 Due to the 1-in-20 obligation (for further details see from paragraph 5.49), DNOs are required to book exit capacity that is at least enough to convey sufficient gas to meet daily firm demand from network consumers which is likely to be exceeded only in 1 year out of 20 years.[38]

5.16 Based on the demand data from the NI Gas Capacity Statement (Table A1-4 and Table A1-5), interruptible demand is relatively small, with ca. 4.1 GWh/day on an average winter peak day. [37], which is around 4% of peak capacity. As a 1-in-20 winter is a relatively rare event, this means that in many years (except in the case of a 1-in-20 or worse winter) DNOs are likely booking capacity that exceeds the capacity demand, to ensure they hold sufficient capacity to satisfy firm demand should a particularly cold winter occur; the associated cost could be seen as constituting the cost of ensuring

[38] See:
FEDL: Licence for the Conveyance of Gas in Northern Ireland, 29 January 2019, Condition 2.12
PNGL: Licence for the Conveyance of Gas in Northern Ireland, 29 January 2019, Condition 2.13
SGN NG: Licence for the Conveyance of Gas in Northern Ireland, 29 January 2019, Condition 2.19

security of supply for firm demand.

5.17 The table below compares the Severe Winter Peak forecast for firm and interruptible for NI demand in the NIGCS for 24/25 year with the Average Winter Peak forecast. As the Average Winter Peak gives a good indication of the actual peak, this table helps to illustrate the extent of overbooking which must be made by DNOs.

GY 2024/25	Firm & Int Forecast Demands (GWh/day)			% of Total NI Demand	
Year	Power	Distribution	Total NI Demand	Power	Distribution
Average Winter Peak	51.7	50.3	102.0	50.7%	49.3%
Severe Winter Peak	64.5	61.5	126.0	51.2%	48.8%

Table 2 – Average Winter and Severe Winter Peak Forecast

5.18 As detailed from paragraph 5.49, there may be some limited potential for DNOs, within their existing licence obligations, to cover some of their exit capacity needs with short term products rather than annual exit capacity holdings.

Cost Allocation: Entry: Exit Split

5.19 In the NI postalised regime, the entry-exit split is an output of the reconciliation process rather than being set ex-ante.[39] This means that the tariff calculation does not seek to direct the recovery of cost from either entry or exit capacity. Thus, if:

- with the availability of short term products for entry, entry capacity bookings are more closely aligned with anticipated demand;
- with the availability of short term products for exit, the power sector aligns the capacity held more closely to the anticipated dispatch profile;
- the distribution sector – subject to the 1-in-20 obligation –continues to book annual exit capacity that (except in the case of a 1-in-20 or worse winter) exceeds the capacity demand from distribution,

this means that the distribution sector is not just contributing over-proportionally (compared to its share in winter peak day demand) to the exit

[39] For further details see:
Utility Regulator: Consultation on the introduction of entry charges into the Northern Ireland postalised regime for gas, 16 October 2014; paragraphs 5.28 onwards;
Utility Regulator: Decision on Harmonised Transmission Tariffs for Gas, 17 December 2018,

capacity bookings, but to capacity bookings overall.

5.20 As outlined later in this chapter, from paragraph 5.49, the effect could be softened if GDNs, similar to what has been assumed for the power sector, were in a position to achieve exit capacity booking efficiencies through the potential changes in the exit regime. To what extent such efficiencies could be achieved may depend on a variety of factors, including the portfolio individual to each GDN.

5.21 We note that a potential introduction of an ex-ante entry: exit split, which may seek to recover a higher proportion of cost from entry capacity, could reduce the impact of the 1 in 20 obligation. We are seeking views on this and have included a question in chapter 8.

Implications from Impact on Capacity Reference Price

5.22 If the power sector reduces its holding of annual exit capacity and satisfies part or all of its exit capacity needs through shorter term products[40], , this constitutes a decrease in capacity bookings which will, other things being equal, lead to an increase of the capacity reference charge which is applicable for capacity bookings from both the power and distribution sectors.

TSO revenue recovery arising from volatility in end of year reconciliation

5.23 Under-recovery causes a delay in TSOs receiving their full revenue. The quantum of a delayed reconciliation amount may cause financing problems for the TSOs. For example, the reconciliation amount in scenario 3B, which is the most extreme scenario modelled, at £6.8m is almost one-tenth of the required revenue for that year, see Figure 3.

Volatility of end of year reconciliation

5.24 The postalised regime requires full reconciliation at the end of each gas year. This is a key feature of postalisation (see from paragraph 2.1) and ensures that PTL's, BGTL's, and WTL's actual required revenues are recovered from all gas consumers[41]. In practice this means that all NI gas users pay for the mutualised pipelines in all circumstances, including, the cost of other users' non payment of tariffs, if any. Any reconciliation payments are included in the invoice issued to suppliers in December of the next gas year. In the event of

[40] To better align capacity held with the anticipated dispatch profile.

[41] PTL, BGTL and WTL are part of Mutual Energy Limited (MEL). These companies are subject to a 'mutualised' model in which Northern Ireland gas consumers absorb deviations between forecast and actual operating costs in return for an absence of equity funding / returns from the business. The other TSO, GNI (UK), is subject to a traditional 'revenue cap' incentive framework;

an over recovery a reconciliation payment will be due to gas suppliers. Conversely an under recovery will trigger a payment from gas suppliers. There is no provision to roll forward an over- or under-recovery into the following year.

5.25 The reconciliation amount can arise for two reasons: the forecast revenue is different than expected due to actual capacity bookings or commodity flows differing from forecast[42], and/or the actual required revenue of the MEL companies varies from forecast.

5.26 The reconciliation payment is calculated by reference to actual bookings and throughput, which means that the shippers who meet their forecast must pay for under-recovery resulting from shippers who do not meet their forecast.

5.27 It could be argued that through the year-end reconciliation payment the effect of any under-or over-recovery that had occurred during the course of the Gas Year is neutralised for the TSOs.

5.28 However, conveyance charges are typically passed through to end consumers and, in case of an end-of-year bullet payment to Shippers to compensate for a previous over-recovery (or from Shippers to compensate for a previous under-recovery), there is a potential that not every end consumer is compensated exactly for the amount they had overpaid (charged exactly with the amount they ought to contribute based on the capacity required to satisfy their demand). This could e.g. be due to:

- changes in the customer base over time, with customers moving in and out of premises connected to the gas network, and new connections being made over time;
- decisions by individual parties on the processing of end-of-year reconciliation payments.

5.29 It also needs to be borne in mind that being out of pocket due to the over-recovery, even if only temporarily, potentially can put a financial strain on shippers, especially in difficult economic times. Similarly, a need to make an end-of-year bullet payment to compensate for an under-recovery, without having recovered the associated funds upfront from downstream users, can put a financial strain on shippers, all the more so in difficult economic times and if they did not anticipate the payment.

5.30 Prior to the introduction of shorter term capacity products and the ratchet mechanism, there was typically no variation between the forecast and actual capacity booked. For example, in each gas year from October 2011 to the

[42] Commodity volumes comprise 5% of the charges, so a variance in throughput has limited impact on the reconciliation amount. For that reason our analysis focusses on capacity.

end of gas year 2015 there was no variance between capacity forecast and capacity booked. In this time period only annual capacity was available, and only at the exit points.

5.31 The ratchet mechanism at exit points and short term entry products were both introduced in October 2015. Since then we have seen variation between forecast and actual capacity booked in each year. Analysis of reconciliation amounts since 2015 has shown that variance from forecast in non-annual entry capacity bookings has had a significant impact on the actual revenue recovered from capacity charges in a number of years.

5.32 This is demonstrated by Table 3, which shows the variance in revenue recovery which can be attributed to each capacity product. These variances then feed into the year-end reconciliation calculation. This table does not include any variance arising from the required revenues of the mutualised companies.

Variance	2015/16 Variance £m	2016/17 Variance £m	2017/18 Variance £m	2018/19 Variance £m	2019/20 Variance £m	2020/21 Variance £m	2021/22 Variance £m
Annual Exit Capacity	5.4	1.7	2.1	0.2	0.1	0.4	0.8
Annual Entry Capacity	0.0	0.0	0.0	0.1	0.2	-0.6	2.1
Quarterly Entry	0.0	0.0	-0.1	0.3	0.0	-0.2	0.6
Monthly Entry	0.0	0.2	-0.2	-0.1	0.0	1.5	0.4
Daily Entry	1.4	0.9	-3.7	-2.8	2.0	0.1	-1.9
Commodity	2.5	2.5	0.5	0.1	0.0	0.2	0.1
Total Variance	**9.2**	**5.3**	**-1.5**	**-2.3**	**2.3**	**1.3**	**2.2**

Table 3 – Capacity product revenue variances

(totals may not agree due to rounding)

5.33 The variance in actual non-annual entry capacity booking from forecast has comprised a significant proportion of the variance. This is explored further in the following table, which illustrates that, although daily capacity bookings have comprised a small percentage of forecast capacity revenue, variances between forecast and actual daily capacity bookings have comprised a high proportion of the total revenue variance.

Daily capacity as % of capacity revenue	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
Forecast Revenue	0%	2%	12%	2%	4%	12%	7%
Actual Revenue	3%	4%	3%	7%	8%	12%	6%
Reconciliation	15%	18%	247%	124%	87%	11%	-86%

Table 4 - Daily Capacity as a Percentage of Capacity Revenue

5.34 The increased flexibility offered by short term exit capacity products is likely to further increase the variance between actual and forecast capacity figures and therefore increase the volatility of the year-end reconciliation. If the experience with entry products demonstrated in Table 3 is any guide, this volatility may be more acute in the years immediately following the introduction of new exit products. However, this does not mean that volatility will be experienced in the short term only. It is likely that changes in gas capacity use by the power sector will occur in the coming years as a consequence of:

5.35 In chapter 3, we have attempted to model the future use of gas capacity by the power sector and the impact this could have on cost allocation between the power and distribution sectors and on the reconciliation. See related consultation questions in chapter 8.

5.36 Although the year-end reconciliations in recent years have generally been an over-recovery with payments back to suppliers, we wish to consider how to prepare for any increased risk of under-recovery and ensure that the impact of any volatility on consumers remains low.

5.37 We can also look to experience in Ireland as a guide to the level of future volatility. GNI reported in 2020 that it had experienced significant over-recoveries of revenue, which has been driven in part by increased daily capacity bookings, such that its variance had the third highest proportion in the EU at that time[43].

5.38 CRU in the Republic of Ireland uses a correction factor to adjust for a under- or over-recovery in gas transmission revenue in the following years (see from paragraph 10.41 for further details). CRU states[44] that this adjustment ensures that tariffs are stable, and volatility is avoided.

5.39 In light of the potential for increasing volatility, we wish to:

[43] https://www.cru.ie/wp-content/uploads/2020/05/CRU20057-Tariff-Network-Code-Article-28-Call-for-Evidence-Gas-Year-202021.pdf
[44] https://www.cru.ie/wp-content/uploads/2022/06/CRU202247-Gas-Transmission-Tariffs-22_23-Decision-Paper.pdf

a) understand from gas suppliers what impact reconciliation payments has on their business. For example, the year-end reconciliations in recent years have been an over-recovery with payments back to suppliers, but we assume that the consequences of an under recovery may be more difficult for suppliers to manage. We have included a question on this in chapter 8;

b) understand the impact of reconciliation payments, i.e. how an over-recovery back to shippers is reflected in future prices;

c) consider whether to mitigate the impact of any increased risk of under-recovery, and how, with the aim of ensuring that the impact of any volatility on consumers remains low. Any measures to mitigate the risk of volatility in the reconciliation should be proportionate to the impact on suppliers. Note it is not possible to eliminate the need for reconciliations as, for example, MEL revenue forecasts may differ from actual.

5.40 Examples of potential mechanisms to mitigate the risk of volatility in the reconciliation might include any of the following:

a) Reviewing the seasonal multiplier factors. The seasonal element of these factors increases the price of daily capacity in the winter, so a variance in the daily forecast at that time has a disproportionate effect on variances. We wish to consider if a smoothing of these factors would mitigate the extent of such variances. This is further discussed from paragraph 5.64 and will form a separate consultation, planned for spring of 2023.

b) Due to the nature of the mutual model, it is not feasible to roll-forward any under or over recoveries into the next years tariffs as a traditional K-factor would do. However, in order to prepare for any bullet payment Shippers are provided with information from GMO NI on actual capacity booked and the forecast reconciliation at a number of points during the year. The aim is to assist Shippers to make provision for a bullet payment if required.

c) In addition, we consider that it should be possible to create an account – separate from the PoT account – with monies on deposit which could be used as needed to reduce any under-recovery to be made up by suppliers via reconciliation payments. Our thinking on this is at an early stage but it is likely that the operation and maintenance of a 'buffer account' would give rise to a number of issues, for example:

- How to calculate the amount to be retained as the buffer. We consider this should be related to the potential variance between forecast and actual capacity bookings and the revenue impact of this;

- The source of the initial deposit for the buffer. We ask MEL to consider whether there are monies currently held for the benefit of NI gas consumers which could be used for this purpose;

- the rules governing the management of the ‘buffer account’;

- the trigger for the buffer to be used and what is can be used for;

- how the buffer amount would be replenished if used. Our current thinking is that it would be recovered from tariffs in the following gas year.

- Whether a new account would need to be established for this purpose or whether the ‘buffer’ could be held within an existing account such as the disbursements account;

- Whether the buffer should apply only to the distribution sector and not to the power sector on the basis that the distribution sector may contribute proportionately less to the problem of volatility;

- the buffer account option would have an ongoing cost to administer whereas the option of shippers using information from GMO to manage the consequences of the reconciliation themselves would not.

d) Consider if there should be incentives or penalties to shippers for inaccurate forecasting. This would require careful consideration, as outlined from paragraph 5.71.

e) Make provision for a mid-year tariff review in specified circumstances.

5.41 We have included a number of consultation questions related to the concept of a ‘buffer account’ in chapter 8. We would also welcome views on whether any other mitigations could be considered, including any that respondents may suggest from experience in GB and RoI.

5.42 In light of potential risks surrounding the impact of short term exit products, should the cost allocation swing significantly to a particular market sector, there may be a need to consider reviewing the tariff methodology in future years.

Overrun mechanism to replace the Ratchet mechanism

5.43 Given the impact the ratchet can have in the electricity market, discussed in chapter 4, we consider it would be appropriate to discontinue the ratchet mechanism and introduce an exit capacity overrun mechanism to mirror the mechanism which operates for entry capacity. It may be appropriate to replace the ratchet mechanism regardless of any decision to introduce short term exit products.

5.44 In the NI single network code, if a shipper has not booked sufficient entry capacity, it will be charged for the overrun quantity on the basis of the daily capacity charge they should have paid multiplied by a factor of eight:

Overrun charge = 8 X relevant NI Reserve Price for Daily IP Entry Capacity X Overrun Quantity[45]

5.45 In GB and RoI, there are similar overrun mechanisms at both entry and exit. Gas Networks Ireland, in the Republic of Ireland, uses a multiplier to 1.546 for exit capacity overruns and National Grid47 uses a multiplier of 6 for exit capacity overruns (see also Annex at Chapter 10)

5.46 GMO NI was asked by shippers to consider reducing the entry capacity overrun multiplier in light of the reductions in neighbouring jurisdictions. Having considered the forecasted growth in Moffat entry capacity bookings in the upcoming years and the possible interaction between any lower overrun multiplier and the requirement for Shippers booking and flowing gas at an alternative entry point, GMO NI stated in September 2022 that it intended to pause the proposal at the time and consider it alongside further work aimed at congestion management at Moffat.

5.47 From paragraph 5.72, we highlight the importance of forecasting accuracy, including with respect to exit capacity.

5.48 We therefore intend to discuss with GMO NI how the ratchet mechanism might be replaced with an exit capacity overrun mechanism.

1 in 20 capacity booking Obligation

5.49 The licence obligation on DNOs to book exit capacity for gas consumers requires them book exit capacity that is at least enough to convey sufficient gas to meet daily firm demand from network consumers which is likely to be

[45] Extracted from NI Single Network Code
[46] Code Mod proposal from GNI code mod forum
[47] Gas Transportation Code – Section B System Use and Capacity and Decision on Mod to multiplier

exceeded only in 1 year out of 20 years[48]. This condition is intended to ensure there is sufficient capacity to meet a period of extremely high gas demand and preserve supply to firm distribution network consumers.

5.50 This obligation aligns with the requirements of the EU Regulation on Measures to Safeguard the Security of Gas Supply (2017/1938)[49], which was transposed into UK legislation after EU exit in The Gas (Security of Supply and Network Codes) (Amendment) (EU Exit) Regulations 2019)[50], which states in Article 6:

"*The Secretary of State shall require the natural gas undertakings to take measures to ensure the gas supply to the protected customers in each of the following cases:*

"(a) extreme temperatures during a 7-day peak period occurring with a statistical probability of once in 20 years;

"(b) any period of 30 days of exceptionally high gas demand, occurring with a statistical probability of once in 20 years"

(c)for a period of 30 days in the case of disruption of the single largest gas infrastructure under average winter conditions.

5.51 A similar requirement exists in GB (see paragraph 10.9) and, albeit with somewhat different rules, in ROI, (see paragraph 10.32).

5.52 This means that the DNOs must book more capacity than they expect to need in a normal year. Meanwhile, power generators can book just the capacity they require. While gas consumers pay disproportionately for exit capacity, this recognises the security of supply benefit that supply to firm distribution network consumers would be prioritised if gas supply was constrained.

5.53 We note that this matter is not new. The fact that the distribution sector is contributing over-proportionally (compared to its share in Average Winter Peak Day demand) to capacity bookings overall, and to associated recovery of revenue requirements has been implicit in the current postalised charging regime. However, the potential change in exit capacity booking behaviour by the power sector as a result of the introduction of short term exit capacity products could make the extent to which this happens more pronounced.

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48 See:
FEDL: Licence for the Conveyance of Gas in Northern Ireland, 29 January 2019, Condition 2.12
PNGL: Licence for the Conveyance of Gas in Northern Ireland, 29 January 2019, Condition 2.13
SGN NG: Licence for the Conveyance of Gas in Northern Ireland, 29 January 2019, Condition 2.19

49 https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32017R1938&from=EN

50 https://www.legislation.gov.uk/uksi/2019/531/made

5.54 In the absence of (anticipated) congestion in the exit capacity market, DNOs could potentially fulfil some of their exit capacity needs through short term products, as long as they can be sure that such products are available when needed. This could be of relevance e.g. in cases where, based on the information available, the daily firm demand during winter (which typically is the period of peak demand for Gas Distribution Networks) has been lower than summer for power generator in recent years.

5.55 Also, for growing networks (as is currently still the case for SGN NG), where firm daily demand continues to increase as the network develops, increasing exit capacity bookings gradually throughout the year might make sense. Short term exit products could present an opportunity to do so in a more cost efficient way than having to book annual exit capacity.

5.56 However, DNOs may nonetheless opt to continue to book exit capacity long term, as an annual product, e.g. to minimise the risk of non-compliance with their respective licence obligation[48] and/or for reasons of cost efficiency. Managing exit capacity bookings more dynamically, using short term products, might increase the administrative burden and associated cost for the DNOs. Also, if shorter term products need to be held consistently for longer periods of time, with the application of seasonal multiplier factors (see from paragraph 5.64), the saving potential may be limited. This is why we have based our scenario analysis (see chapter 3) on the assumption that DNOs will continue to fulfil their 1 in 20 obligation by using annual capacity bookings.

5.57 Further details on the findings of our analysis specifically with respect to the implications of the introduction of short term exit capacity on the proportion of exit capacity cost borne by the Distribution and power sectors are set out from paragraph 5.4.

5.58 The effect could be softened if DNOs, similar to what has been assumed for the power sector, were in a position to achieve exit capacity booking efficiencies through the potential changes in the exit regime. To what extent such efficiencies could be achieved may depend on a variety of factors, including the portfolio individual to each DNO. We have included a question on this in section 8.

5.59 We are conscious of the potential that, in the context of energy transition, the quantities of indigenous renewable gases in the NI network might increase and could, dependent on their suitability to address security of supply requirements, possibly reduce the need to reliance on transmission exit capacity to some extent. However, for the moment the requirements noted above in 5.50 prevail. We consider the licence requirement may be reviewed in the future if there is significant volumes of renewable gases injected into the network with proven reliability.

Capacity Booking Responsibilities

5.60 The obligation to book entry capacity falls to the suppliers who are bringing gas into the NI gas transmission network for both power generation and to supply the gas distribution networks. However, at exit, the responsibilities are different. the DNOs book and holds capacity for the distribution networks.

5.61 Gas suppliers in Northern Ireland have a condition in their licence, to accurately forecast their total capacity bookings and gas flows for future gas years, see footnote 57 for more information.

5.62 At the time of Exit Review[51] in 2016, we concluded that it was more efficient for the DNOs to book the required exit capacity to meet the 1 in 20 obligation and recover the costs as part of the distribution service. This is likely to be more efficient and prevents double booking of capacity due to customers changing supplier.

5.63 We are seeking views on capacity booking responsibilities at chapter 8.

Seasonal Multiplier Factors

5.64 Following the introduction of entry charges to the postalised regime in 2015, and in anticipation of the requirements of the Tariff Network Code (see paragraph 5.7), we established multipliers and seasonal factors to apply to short term entry capacity products[52]. These factors were set to incentivise suppliers to make more use of the network in the summer and shift demand away from the winter peak. They were set to provide a balance between facilitating short-term gas trade and providing long-term signals for efficient investment in the transmission system. These have been included in the transmission charging regime since 1 October 2015.

5.65 The Tariff Network Code defines “multiplier” as the factor applied to the respective proportion of the reference price in order to calculate the reserve price for a non-annual standard capacity product. It further defines “seasonal factor” as the factor that reflects the variation of demand within the year which may be applied in combination with the relevant multiplier.

5.66 These factors are multiplied by the annual tariff for entry capacity to determine the tariff for a non-annual entry capacity product, for example monthly capacity or daily capacity.

5.67 Since their inception in 2015, we have aligned the seasonal multiplier factors

[51] Exit Capacity Review Conclusions
[52] https://www.uregni.gov.uk/publications/seasonalfactors-final-determination

with those offered in the Republic of Ireland. We consider that this alignment is beneficial to ensure there is no perverse pricing signal which affects the decisions of all-island electricity generators.

5.68 The seasonal factors have been set to incentivise suppliers to make more use of the network in the summer and shift demand away from the winter peak. They were set to provide a balance between facilitating short-term gas trade and providing long-term signals for efficient investment in the transmission system.

5.69 The seasonal factor makes daily entry capacity in the winter period up to eight times the annual rate, which means that, since their introduction in 2015, the variances in daily capacity bookings have been a key component of the year-end reconciliation amount. We recognise that forecasting of short term products is intrinsically difficult for suppliers, but the impact of volatility in reconciliation payments is felt across all suppliers.

5.70 We indicated in our Decision on Seasonal Multiplier Factors 2022[53], that a full and comprehensive review of the factors should take place ahead of Gas Year 23/24. As mentioned in paragraph 6.18, respondents to previous consultations have requested sufficient notice of any changes to seasonal multipliers.

5.71 We intend to hold our consultation on seasonal multiplier factors in spring 2023.

Improving Accuracy of Forecasts

5.72 Capacity and demand forecasting plays in important role in operating the gas network in an efficient and economic way.

5.73 Ahead of each Gas Year, forecast revenue requirements, annual quantities and capacity requirements feed into the calculation of the Forecast Postalised Commodity and Capacity Charges which will inform the conveyance charges for the Gas Year. Deviations between forecast and actual figures will lead to under or over-recoveries that need to be reconciled at the end of the Gas Year.

5.74 The difference between forecast and year end Postalised charges will (in combination with other factors, such as differences between forecast and actual revenue requirements) determine the size of the reconciliation payment, which is either paid to, or due from, Shippers under the NI Network Gas Transmission Code at the end of the Gas Year.

5.75 Whilst the financial strain on shippers in case of an end-of-year bullet

[53] Decision on Seasonal Multiplier Factors for Gas Transmission, May 2022

payment to compensate for an under-recovery might be alleviated to some extent by the potential solution to address volatility of year-end reconciliation discussed from paragraph 5.40, the solution could also mean that end consumers are left out of pocket for longer in case of an over-recovery.

5.76 Minimising any under- and over-recoveries, and the associated volatility of conveyance charges therefore is important. This is all the more the case because such volatility may, dependent on price elasticity of demand, impact negatively on the accuracy of demand forecasting when, conversely, such accuracy of capacity demand forecasting is an important factor in minimising under-and over-recoveries.

5.77 The current regulatory framework therefore contains a number of mechanisms designed to further forecasting accuracy. Those of specific relevance for forecasting of exit capacity include:

- Licence Obligation on DNOs to consult on, and book exit capacity that is at least enough to convey sufficient gas to meet daily firm demand from network consumers which is likely to be exceeded only in 1 year out of 20 years (1-in-20 obligation)[54].

- Licence Condition 2A.2.3.1(b) of the gas high pressure licences[55] which requires the Licensee to ensure that the forecast Capacity Figures are as accurate as possible having regard to the information and forecasts available to the Licensee. This is supplemented by clause 16.2 of the NI Network Gas Transmission Code[56] which requires the Transporter to issue a Shipper Forecast Information Request covering the forecast information, and the Shippers to complete and return that request.

5.78 In addition, the current regulatory framework also contains a number of mechanisms to facilitate, during the course of a Gas Year, early detection of significant discrepancies between capacity forecasts and actuals; so that related interventions (where relevant and appropriate) and/or the resulting impact on end-of-year reconciliation payments can be planned for. For example, licence condition 2A.2.3.3 of the gas high pressure licences [55] requires the Licensee to provide quarterly information on actual capacity and

[54] See:
FEDL: Licence for the Conveyance of Gas in Northern Ireland, 29 January 2019, Condition 2.12
PNGL: Licence for the Conveyance of Gas in Northern Ireland, 29 January 2019, Condition 2.13
SGN NG: Licence for the Conveyance of Gas in Northern Ireland, 29 January 2019, Condition 2.19
[55] The gas high-pressure licences are:
BGTL: Licence for the Conveyance of Gas in Northern Ireland, 21 July 2022
PTL: Licence for the Conveyance of Gas in Northern Ireland, 21 July, 2022
WTL: Licence for the Conveyance of Gas in Northern Ireland, 21 July 2022
GNI (UK): Licence for the Conveyance of Gas in Northern Ireland, 21 July 2022
[56] GMO NI: NI Network Gas Transmission Code,.

any likely inaccuracy in the tariff process.

5.79 In addition to these reporting requirements, GMO NI also provides to all shippers a quarterly update on Forecast Annual Reconciliation Payments.

5.80 In addition to relying on these existing mechanisms, consideration could be given to enhancing the robustness of the requirements for good forecasting by modifying licence condition 3A.2.2.1 of the gas supply licences[57] to extend the requirement in paragraph (b) to cover breakdown of Capacity Products at exit points as well as entry points.

5.81 We are interested in views on ways to improve forecasting and have included a question at chapter 8.

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[57] Condition 3A.2.2.1 (b) of the gas supply licences reads:
"*The Licensee shall, each Gas Year, provide the following forecasts and information to each of its Primary DPO (in respect of each such Primary DPO Network only), in each case no later than the tenth Business Day in June in respect of the next Gas Year (GY) and each of the following four Gas Years (GY+1 to GY+4):*
[…]
(b) a breakdown of the Annual Capacity Products and Non-Annual Capacity Products which the Licensee is forecast to use at each Entry Point in GY to GY+4. […]"

6. Next Steps

6.1 Following publication of this consultation we envisage a decision making phase (steps a-d below) and a subsequent implementation phase (step e) as required.

a) Development of a policy position on whether to implement short term exit capacity products and changes to the ratchet

b) Development and consultation on any licence modification required to implement the policy position

c) Final licence decisions once we have considered the responses to any consultation on proposed licence modifications.

d) Single NI Code[58] modification consultation and decisions, to reflect the policy decision

e) Implementation of any regulatory changes

Separately but parallel to this process, a consultation will propose maintaining current seasonal multiplier factors from October 2023 and smooth the factors from October 2024, to meet requirements of the Tariff Network Code.

6.2 If the decision is made not to introduce short term exit capacity products, we will need to consider whether changes are required to the ratchet, when, and what should replace it.

6.3 If the decision is to introduce short term exit capacity products, we consider that they could potentially be implemented for 1 October 2024. For the reasons explained below, it is not possible to complete the steps any sooner.

6.4 Also, if any new products are introduced, we consider that they should only be introduced at the start of a gas year as this is most efficient and less resource intensive. Implementation of short term exit products at any other point in the year would require transitional arrangements to be put in place, applicable only for a few months, but would be resource intensive to design and implement in their own right.[59] Doing so would likely detract effort from implementation of any enduring arrangements.

[58] NI Network Gas Transmission Code | GMO Northern Ireland (gmo-ni.com)

[59] There are a number of reasons this would be a significant project in its own right, including the need to consider systemisation on Delphi, how to deal with exit capacity booked that a supplier may have booked for GY 23/24, ensuring the reconciliation process is robust, assess the impact on TSO cash flows and on DNOs, changes needed to the tariff model and supplier credit arrangements. Furthermore, the licence has no provisions detailing how a mid-year transmission tariff should be recalculated and reconciled.

Process step	Indicative timing if UR decides to implement short term exit products
Decision on seasonal multiplier factors for GY23 to meet Tariff Network Code timescales	May 2023
Policy decision on whether to introduce short term exit products and whether to smooth seasonal multipliers for GY24	September 2023
If needed, decision on any licence modifications needed to implement the policy decision	December 2023
If needed, implementation phase, including any required system changes and code modifications - allsubject to policy decision	Up to end September 2024
Earliest implementation date for any policy decision to introduce short term exit capacity products, smooth seasonal multipliers and/or remove the ratchet mechanism.	1 October 2024

Policy development and decision making

6.5 Information about how to respond to this consultation is in chapter 9.

6.6 We will consider responses following the consultation period in order to make a policy decision on whether to introduce short term exit products. We anticipate a policy position will be adopted by September2023.

6.7 Final decisions on the policy around short term exit capacity will be taken following this consultation.

6.8 If a policy decision is taken to introduce short term exit products or any other changes to the regulatory regime, **licence modifications** would be required. We would need to assess what modifications would be required but this would be expected to include the following:

a) Changes to the standard conditions in part 2A of the conveyance licences,

b) In the supply licences, we would need to consider what amendments are required at the standard conditions at 3A.

c) We would need to review if any amendments are required to the DNO licences.

6.9 Article 14 of the Gas (Northern Ireland) Order 1996[60] outlines the licence modification requirements:

a) We must hold a consultation on any proposed modifications for at least 28 days.

b) We must consider any representations made during the consultation to inform the board's decision.

c) There must be a notice period of at least 56 days between the publication of the decision and the effective date of the modifications.

6.10 If licence modifications are needed following a policy decision, it is also likely that there will need to be **modifications to the gas transmission network code**. This process will be managed by GMO NI, as the NI gas transmission system operator. The changes could include changes to capacity booking requirements, financial arrangements and the exit capacity overrun mechanism. The code modification rules[61] require a consultation period of at least 20 business days, followed by consideration of the responses and submission of the Final Modification Report to UR for a decision. The implementation date can be any time after the licence modification decision depending on the specifics of the modification.

6.11 The code modification development and implementation process can overlap, to some extent, with the licence modification process.

Implementation of any regulatory changes

6.12 Any implementation phase will need to be scoped out if required, and a plan put in place to implement any decisions made. It would need to factor in the following:

a) Time to alter the gas transmission tariff model so that any new capacity charges can be calculated and the revenue from them

[60] https://www.legislation.gov.uk/nisi/1996/275/article/14
[61] https://gmo-ni.com/assets/documents/NI-Network-Gas-Transmission-Code-Modification-Rules-Version-2.0-31st-December-2020.pdf

reconciled robustly

b) Requirements for systemisation changes to the relevant capacity booking platform

c) Alignment with the gas transmission tariff setting process

d) Sufficient notice of any changes to seasonal multipliers

6.13 The **gas transmission tariff model** does not currently have the functionality that would be required to calculate forecast and actual short term capacity charges at transmission exit points. This functionality would need to be added and the model altered to account for any decisions made in respect of the ratchet and capacity overruns. Our experience with the introduction of short term products at entry suggests this will take a number of months. All parties (UR, TSOs, DNOs and all gas suppliers on the postalised system) will need assurance that any future model is fit for purpose.

6.14 To implement the regulatory changes, **systemisation changes to the relevant capacity booking platform** could be needed. GMO NI operates a single IT gas transmission management system, known as Delphi. This allows GMO NI to manage the market operations such as exit capacity booking, nominations and allocations. At present, shipper book exit capacity at an annual auction.

6.15 Shippers use PRISMA to book entry capacity as that meets the requirement for an integrated European gas market set out in the European network codes. Shippers have access to book the short term entry capacity products when they are required.

6.16 GMO NI need to consider which platform to use if short term exit products are introduced. Whichever platform is preferred, work will need to be undertaken to specify the changes and implement them.

6.17 GMO NI has indicated that the IT specification would need prepared once the changes are known followed by the scheduling of the work. This is likely to take several months overall.

6.18 The gas transmission (postalised) **tariff setting process** is outlined in the gas conveyance licences and the Transmission Network Code. The annual process begins in January, when shippers are asked to provide forecasts to GMO NI. Any changes to the licence and Code would need to be effective in advance of the publication of the NI Gas Capacity Tariff on 31st May 2024. The tariff is published at the end of May and becomes effective in October. Shippers have previously requested **sufficient notice of any changes to seasonal multipliers** on the tariff regime. This extract from our Decision on

Seasonal Multiplier Factors for Gas Transmission, 21 May 2021[62] summarises the responses on this matter:

"*3.4 Some respondents asked that the notice of any changes should be longer than indicated in the consultation, and for the review to involve the gas industry.*

a) *EAI[63] requests at least one year, ideally two years, notice of changes to factors to allow for amendments to commercial arrangements and longer-term user contracts. It states that full industry engagement in the review process would increase transparency and "contribute to enhancing investor certainty of cost estimates"*

b) *EP Ballylumford and EP Kilroot urges UR to take account of the efficient operation of the SEM. They request that any changes are introduced incrementally, with full industry engagement and at least one year's notice of the change, in order to allow suppliers to make adjustments.*

c) *PPB[64] urges that any review to change the factors be undertaken as soon as possible so that gas users have time to reflect and adjust their gas capacity booking strategy to meet their needs."*

6.19 We further stated in paragraph 4.11 of the Decision on Seasonal Multiplier Factors for Gas Transmission, 21 May 2021 that:

"We intend to give one year's notice of any change to seasonal multiplier factors".

6.20 We will publish our annual consultation on seasonal multipliers to meet the requirements of the Tariff Network Code[65] in spring 2023.

6.21 This timescale should allow UR to make any decisions on the seasonal multipliers that would apply from GY 24/25 alongside its policy decisions on short term exit capacity products. It would also afford suppliers sufficient notice to factor in any changes to the gas exit regime and any new multipliers when preparing their capacity forecasts for gas year 2024/25.

[62] Decision on Seasonal Multiplier Factors for Gas Transmission, 21 May 2021
[63] Electricity Association of Ireland
[64] Power NI Energy Limited Power Procurement Business
[65] Commission Regulation (EU) 2017/460 of 16 March 2017 establishing a network code on harmonised transmission tariff structures for gas, now incorporated in UK law by the European Union (Withdrawal) Act 2018 and the European Union (Withdrawal Agreement) Act 2020, as amended by Schedule 5 of the Gas (Security of Supply and Network Codes) (Amendment) (EU Exit) Regulations SI 2019/531.

7. Consumer Impact

7.1 In this section we assess the potential impact on the gas transmission annual capacity charges if short term exit capacity products are introduced.

7.2 In the table immediately below we have set out:

a) The forecast gas transmission annual capacity tariff for 2022/23 as published by GMO NI.

b) the forecast gas transmission annual capacity tariff for the following four gas years as published by GMO NI. The year we have modelled in the scenario analysis is 24/25.

	2022/23	2023/24	2024/25	2025/26	2026/27
Entry Capacity Charge (£ per kWh/d booked)	0.43436	0.40372	0.38554	0.40992	0.41046
Exit Capacity Charge (£ per kWh/d booked)	0.43436	0.40372	0.38554	0.40992	0.41046
Commodity Charge (£ per kWh)	0.0002170	0.0001939	0.0001915	0.0002118	0.0002093

Table 5 - Forecast Gas Transmission Tariffs 2022/23 and GY+1 - GY+4[66]

7.3 The year-end tariffs for 24/25 across each of the scenarios modelled in section 3 are set out in the table below.

[66] Source: Published NI Forecast Postalised System Transmission Tariffs (NI Forecast Tariff Publication GY2223 - All 5 Years.xls.xlsx (gmo-ni.com))

Modelled actual charges for GY 24/25							
	Base case enhanced	Scenario 1	Scenario 2	Scenario 3	Scenario 1b	Scenario 2b	Scenario 3b
Entry Capacity Charge (£ per kWh/d booked)	0.38999	0.41095	0.42496	0.43349	0.37158	0.39686	0.41308
Exit Capacity Charge (£ per kWh/d booked)	0.38999	0.41095	0.42496	0.43349	0.37158	0.39686	0.41308

Table 6 - Modelled Gas Transmission Tariffs GY 24/25

7.4 The transmission tariff makes up a small percentage of the tariff that end users pay. In the UR briefing paper[67] which accompanied the firmus energy tariff review announced on 6 December 2022, we illustrated that network costs, which include the costs to use both the transmission and distribution networks, comprise around 18% of the maximum average price from 1st January 2023. We estimate that transmission charges are less than one-quarter of that, which is 4.5%. In the UR briefing paper mentioned above, the typical annual bill (excluding the Energy Price Guarantee) from January 2023 was calculated at £1,817. The transmission charge element of that, at 4.5%, would be £ 81.

7.5 But, in the scenarios analysis, all of the scenarios resulted in a tariff which is below the current tariff for 22/23. This is because the assumed additional capacity booking by the new power station at Kilroot is expected to offset any increase due to optimisation of capacity booking due to the additional flexibility of short term products.

7.6 Therefore, in the scenarios modelled, the impact of short term exit capacity on end users tariffs appears as a small decrease.

7.7 We will keep the impact on gas consumer prices under review as we progress towards any decision. We are very aware that in the current climate of high prices, any potential price increase is unwelcome.

[67] https://www.uregni.gov.uk/publications/firmus-tariff-review-briefing-paper-6-december-2022

8. Consultation Questions

Merits of introducing short term exist capacity products.

8.1 Do Respondents consider that short term exit capacity products should be introduced? Please explain the reasons for your view and provide supporting evidence.

8.2 We are interested in views on which exit capacity products should be available at exit. Do you agree that these options should mirror those currently available at transmission entry points with the exception of quarterly products? Please explain the reasons for your view

8.3 Are quarterly products required at the exit point? If so, why?

8.4 Are there any further risks or consequences that may arise as a result of introducing short term exit capacity products that we should consider? Please identify whether these consequences impact the gas or electricity market/consumers and provide supporting evidence.

8.5 Are there any further mitigations which could be considered, including any that respondents may suggest from experience in GB and RoI? Please outline how these might be implemented.

Gas Scenario analysis

8.6 We would welcome views on the assumptions underpinning the scenario analysis set out in chapter 3.

8.7 Do respondents consider there are other scenarios which should usefully be modelled at this time?

8.8 In chapter 3 we have attempted to model the future use of gas capacity by the power sector and the impact this could have on cost allocation between the power and distribution sectors and on the reconciliation. We would welcome:

a) Commentary from respondents in the power sector on whether our assumptions on future use of gas capacity by the power sector are robust;

b) Further information from respondents in the power sector which would assist us to refine these scenarios in chapter 3 for the 24/25 gas year

c) information from respondents in the power sector which would assist us to model a scenario for the 26/27 gas year.

Impact on prices in the SEM

8.9 Do respondents have any views on the impact that short term exit capacity products would have on prices in the SEM?

Ratchet mechanism

8.10 Irrespective of whether short term exit capacity products are introduced do you consider that the ratchet mechanism needs to be reviewed? If so why?

8.11 Do you agree with our proposal to replace the ratchet mechanism with a capacity overrun mechanism? If not are there any other alternatives to capacity overrun mechanism you can suggest?

8.12 Are there any circumstances which would warrant the retention of the ratchet mechanism?

Cost recovery between power and distribution sectors

8.13 Do Respondents have any views on our assessment of the impact that the introduction of short term exit capacity products may have on how gas transmission required revenues are allocated between the power and distribution sectors?

Volatility risks

8.14 Do Respondents have any views on whether the introduction of short term exit capacity products will increase the risk of delayed payments to TSOs and what issues the TSOs may face as a result?

8.15 If so, how should any increased risk of volatility in required shipper payments be managed following the introduction of short term exit capacity products?

8.16 Do Respondents have any views on whether the introduction of short term exit capacity products will increase the risk of volatility in the reconciliation payment?

8.17 Does the current level, or potential future level, of volatility in the end of year reconciliation pose issues for gas suppliers? If so, in what way?

8.18 We would welcome views on the potential mechanisms to mitigate this risk of volatility set out in paragraph 5.40.

8.19 Do you consider that the concept of a 'buffer account' should be explored further and do you have any additional thoughts on how this should operate?

8.20 We would welcome a view from MEL as to whether there are monies currently held for the benefit of NI gas consumers which could be used as the initial deposit for the buffer.

1 in 20 obligation and capacity booking

8.21 If short term exit products capacity were introduced, would DNOs avail of these products in order to meet the 1 in 20 obligation? Please provide reasoning for your view.

8.22 If short term exit capacity products were available who should have responsibility for booking these - the DNOs or gas suppliers? Please explain the reasons for your view

8.23 What would be the implications of changing the booking responsibility?

Other:

8.24 The NI Network Gas Transmission Code includes arrangement for secondary transfer of exit capacity. Do Respondents consider that these arrangements would need to be reviewed if short term exit capacity products were available? If so, in what way?

8.25 We note that a potential introduction of an ex-ante entry:exit split, which would recover a higher proportion of cost from entry capacity, could reduce the impact of the 1 in 20 obligation. Do Respondents have any views on this?

8.26 We are interested in views on how forecasting of gas capacity bookings could be improved at entry and exit points.

8.27 Are there any further matters that should be considered?

9. Responding to the Consultation

9.1 We will hold a virtual stakeholder engagement event on Thursday 4th May 2023 at 10am to provide an opportunity for stakeholders to seek clarification on any part of this consultation ahead of submitting a response. Anyone who is interested is asked to register at the email below.

9.2 We invite respondents to express a view on the options we have outlined and any aspect of the paper. Responses should be received on or before 12 noon on 9th June 2023, addressed to:

Emma Todd
Networks Directorate
Utility Regulator
Queens House
14 Queens Street
Belfast BT1 6ER

9.3 Gas_networks_response@uregni.gov.uk with cc to emma.todd@uregni.gov.uk

9.4 Our preference would be for responses to be submitted by e-mail.

9.5 Your response may be made public by the Utility Regulator. If you do not want all or part of your response or name made public, please state this clearly in the response by marking your response as 'CONFIDENTIAL'

9.6 If you want other information that you provide to be treated as confidential, please be aware that, under the FOIA, there is a statutory Code of Practice with which public authorities must comply and which deals, amongst other things, with obligations of confidence. In view of this, it would be helpful if you could explain to us why you regard the information you have provided as confidential.

9.7 Information provided in response to this consultation, including personal information, may be subject to publication or disclosure in accordance with the access to information regimes (these are primarily the Freedom of Information Act 2000 (FOIA) and the Data Protection Act 2018 (DPA)).

9.8 As stated in the GDPR Privacy Statement[68] for consumers and stakeholders, any personal data contained within your response will be deleted once the matter being consulted on has been concluded though the substance of the response may be retained.

[68] https://www.uregni.gov.uk/privacy-notice

9.9 This document is available in other accessible formats, such as large print, Braille, audio cassette and a variety of relevant minority languages if required. To request this, please contact Emma Todd, either 028 9031 1575 or email to Gas_networks_responses@uregni.gov.uk.

10. Annex – Comparison to Other Jurisdictions

Overview

10.1 This annex provides an overview over the regulatory arrangements in Great Britain (GB) and the Republic of Ireland (RoI) with respect to those aspects that are of particular relevance for this consultation, namely:

- Exit products and secondary exit capacity transfers
- Exit capacity booking obligations
- Exit Capacity Overrun
- Multipliers and seasonal factors
- Year-end reconciliation

10.2 Considering regulatory practice and associated lessons learned from other jurisdiction can be a helpful exercise when designing, considering and assessing the potential implications of related aspects of the NI regulatory arrangements.

10.3 Furthermore, alignment of certain regulatory arrangements with those in ROI is of particular importance due to the SEM as further detailed in from paragraph 10.26.

GB

<u>Exit Products and Secondary Exit Capacity Transfer</u>

10.4 In Great Britain (GB), exit capacity products are currently available for:[69]

- Long-term applications
    - ♦ Enduring annual exit (flat) capacity increase for capacity covering the period Y+4 to Y+6; this capacity can be increased or decreased later, subject to user commitment
    - ♦ Enduring annual exit (flat) capacity decrease, allowing a user to decrease their enduring capacity holdings from Year Y+1
    - ♦ Annual NTS (National Transmission System) (flat) exit capacity for the period Y+1 to Y+3; this capacity is not enduring and

[69] See Exit capacity | National Grid Gas:

therefore cannot be increased or decreased.

- Short-term applications
    - ♦ Day-ahead daily NTS exit (flat) capacity
    - ♦ Within-day daily NTS exit (flat) capacity
    - ♦ Off-peak daily NTS exit (flat) capacity[70], depending on the prevailing forecast total system demand of the gas day being less than 80% of the 1-in-20 peak demand.

10.5 Exit capacity is not available on a monthly basis71.

10.6 Daily NTS exit (flat) capacity is off-peak where it is subject to curtailment and otherwise firm.[72]

10.7 Traditionally, Exit within-day Firm products have been allocated 5 times throughout the Gas Day, at 8:00, 14:00, 18:00, 22:00 and 01:00. With gas fired power stations increasingly acting as a back-up to renewable electricity generation, a need was identified to access NTS Exit Capacity in a more reactive manner. In response to these developments, within-day hourly allocations for NTS Exit Firm Capacity have now been enabled from 06:00 until 02:00. [73, 74]

10.8 Shippers can assign all or some of their capacity rights at an NTS Exit Point to another shipper at the same location. The shipper must notify National Grid no later than 5 days prior to the assignment and both Users must match the assignment.[71]

Exit Capacity Booking Obligations

10.9 In GB, GDNs (Gas Distribution Network Operators) have an obligation to book capacity to meet 1-in-20 peak demand for conveying gas to

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[70] The amount of off-peak daily NTS exit (flat) capacity that will be made available comprises:
- combined unused firm NTS exit (flat) capacity
- over the preceding 30 days maximum NTS exit point offtake rate value
- multiplied by 24
- minus any firm capacity held by users
- plus any discretionary amount National Grid may decide to release.

See National Grid: Gas Transmission Capacity Guidelines, June 2022. For further details see UNC, Transportation principal Document, Part B, paragraph 3.6.
[71] See NTS Capacity Team: Gas Transmission NTS Entry and Exit Capacity Frequently Asked Questions.
[72] See UNC, Transportation principal Document, Part B, paragraph 3.1.5(d).
[73] See: Joint Office of Gas Transporters, UNC 0759S: Enhancements to NTS Within-Day Firm Entry and Exit Capacity Allocations, Final Modification Report, 18 June 2021.
[74] See UNC, Transportation principal Document, Part B, paragraph 3.5.1.

consumers.[75]

10.10 When a user, including a GDN, books Enduring Annual NTS Exit (Flat) Capacity, they will generally be subject to a User Commitment. This User Commitment applies to the increase plus any existing capacity allocation.[76]

10.11 The amount of user commitment for Baseline Exit Capacity is calculated as charges for a given period, using the indicative capacity price and the increased amount of capacity. Users cannot reduce this capacity booking until the full user commitment amount has been paid. [77]The relevant time period used to be four years, but it has now been reduced to 2 years for Baseline Exit Capacity.[76, 78]

10.12 It has been noted that these provisions are particularly pertinent to GDNs; they need to comply with the 1-in-20 demand obligation are the predominant users of Enduring Capacity.[78] More specifically, GDNs book exit capacity wholly on behalf of end consumers, at 1-in-20 peak demand levels, but do not have the flexibility to revise bookings downwards where demand forecasts are reduced due to user commitment locking them into capacity charges. This can lead to "sterilised" capacity which cannot be accessed by other users, and to the increased cost being passed through to end consumers.[77]

10.13 In May 2021, Ofgem has informally consulted on removing user commitment on NTS Enduring (Flat) Exit capacity bookings up to baseline obligated levels[79] for GDNs. [77] UR has not been aware of any publication of conclusions from this consultation.

Exit Capacity Overrun

10.14 Under the UNC(Uniform Network Code), an exit capacity overrun charge is payable if:[80]

- The quantity of gas offtaken by a User from the NTS Exit Point on the

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[75] See Ofgem: Informal consultation on removing user commitment for Gas Distribution Networks ("GDNs") booking exit capacity up to and including baseline, 14 May 2021.
[76] For further details see National Grid: Exit Capacity Release Methodology Statement, effective from 10th June 2022, paragraphs 58 and 126.
[77] Ofgem: Informal consultation on removing user commitment for Gas Distribution Networks ("GDNs") booking exit capacity up to and including baseline, 14 May 2021.
[78] See Joint Office of Gas Transporters: UNC 0705R: NTS Capacity Review, amended 10 December 2021.
[79] Special condition 9.13 (Capacity requests, Baseline Capacity and Capacity Substitution) of the National Grid Gas plc Gas Transporter Licence lists each NTS Exit Point and its level of baseline obligated capacity (in GWh/d). Special condition 1.1. (Interpretation and definitions) of the same licence also contains a definition of the terms Obligated Exit Capacity and Licence Baseline Exit Capacity.
[80] See Joint Office of Gas Transporters, Uniform Network Code, Transportation Principal Document, 14 November 2022, Part B, Clause 3.13.

day exceeds the User's Fully Adjusted[81] Available NTS Exit (Flat) Capacity (individual flat overrun); and

- The aggregate quantity of gas offtaken by all Users at the NTS Exit Point on the Day exceeds the sum off the Users' Fully Adjusted Available NTS Exit (Flat) Capacity (aggregate flat overrun).

10.15 The NTS Exit (Flat) Overrun Charge payable by the relevant User will be the User's individual flat overrun multiplied by the greater of:[80]

- 6 times:
    - ♦ the highest bid price paid to National Grid NTS in relation to any capacity bid accepted in respect of the Day; or
    - ♦ the Applicable Daily Rate in relation to a capacity application in respect of the Gas Year in which the Day falls, at the NTS Exit Point;
- 1.1 times the highest offer price, forward price or option exercise price paid by Grid Transmission (NGT) in respect of any Exit Constraint Management Action taken in respect of the Day at the NTS Exit Point;
- 6 times the highest reserve price under any invitation for the Day or the Gas Year in which the Day falls for NTS Exit (Flat) Capacity at the NTS Exit Point;

<u>Multipliers and Seasonal Factors</u>

10.16 As a result of the introduction of the Tariff Network Code (TAR NC)[82], Regulatory Authorities, including Ofgem, are required to consult annually (amongst other things) on levels of multipliers and seasonal factors for further details on these see also paragraph 5.64).

10.17 In its lates related decision paper[83], Ofgem decided to leave the level of multipliers at 1.0, without seasonal factors.

<u>Year-End Reconciliation</u>

10.18 Transmissions Services Revenue Recovery Charges are a mechanism to manage any under or over recovery of revenues at Entry and Exit within the

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[81] This is a reference to the capacity amount reduced as relevant pursuant to the provisions for exit constraint management, curtailment of Off-peak Daily NTS Exit (Flat) Capacity and surrender of Daily NTS Exit (Flat) Capacity. For further details see Joint Office of Gas Transporters, Uniform Network Code, Transportation Principal Document, 14 November 2022, Part B, Clauses 3.8 to 3.11.
[82] Commission Regulation (EU) 2017/460 of 16 March 2017 establishing a network code on harmonised transmission tariff structures for gas.
[83] See Ofgem: Article 28(2) Tariff Network Code motivated decision, 28 April 2022.

Gas Year. These charges (which may be positive or negative) will be applied to the Fully Adjusted[81] Entry respectively Exit Capacity at all points, apart from that capacity classified as Existing Contracts.[84, 85]

10.19 Revisions to the Transmissions Services Revenue Recovery Charges, after they have been set for a Gas Year, are subject to a minimum notice period of two months.[86]

10.20 Whilst both Entry and Exit Revenue Recovery Charges have been set to 0 p/kWh/day for the period from 1 October 2022 onwards[84], the mechanism has been used in the past. For instance, NGT levied such charges from February 2021 onwards, to address a larger than anticipated under recovery that had been evident from capacity revenues across preceding months. The step aimed to reduce the size of the likely under recovery, mitigate the impact on charges in subsequent years, and minimise charging volatility.[87, 88]

10.21 An additional mechanism is in place to address an under- or over-recovery at the end for the Gas Year: The K-value, which reflects the difference between allowed and collected revenue, is calculated separately for Transmission Services and Non-Transmission Services for the formula year. Transmission Entry and Exit revenues are reconciled separately.[84]

10.22 The Transmission Services Revenue for a given year is split between revenue to collect on Entry Capacity charges and revenue to collect on Exit Capacity charges. This value is then be added to any under/over recovery (Transmission Services K value) which was calculated in y-2 (two years ago) and split for Exit (Entry), to make the applicable Exit (Entry) revenue which is used in the financial model to calculate the Entry (Exit) capacity charges. [84, 89]

10.23 The Transmission Services K value for exit for year t is:[89, 90]

- the difference between the Allowed Transmission Services Revenue for year t-1 and the Recovered Transmission Services Revenue for year t-1, multiplied with the sum of

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84 See Joint Office of Gas Transporters: UNC 0678A: Amendments to Gas Charging Regime (Postage Stamp), 15 May 2019.
85 See National Grid: Gas Transmission Transportation Charges, 30 September 2022.
86 See Joint Office of Gas Transporters, Uniform Network Code, Transportation Principal Document, 14 November 2022, Part Y, Clause 3.3.
87 See National Grid: Notification of Entry and Exit Revenue Recovery Capacity Charges from 1 February 2021. Note that the charges notified in this letter differ from those ultimately implemented through the updated Transmission Transportation Charges Statement. The difference is understood to be related to an open letter from Ofgem to NGG dated 23 December 2020.
88 See National Grid: Gas Transmission Transportation Charges, 29 January 2021.
89 See Joint Office of Gas Transporters, Uniform Network Code, Transportation Principal Document, 14 November 2022, Part Y, Clause 1.5.3.
90 See National Grid Gas Transporter Licence, Special Conditions, 28 July 2022, Part H.

- 1
- Average value of SONIA for year t-1 + 1.15%
- The product of penal rate proportion for year t-1 times penal rate adjustment for year t-1.

10.24 The penal rate proportion has the value of 1 unless the Authority is satisfied that the reasons for the over- or under-recovery are outside the control of the licensee and has directed a value between 0 and 1 to reflect this. [89, 90]

10.25 The penal rate adjustment serves to penalise the licensee if the over- or under-recovery exceeds a pre-defined threshold. It is: [89,90]

- 1.15% if the ratio between Recovered Transmission Services Revenue for year t-1 and Allowed Transmission Services Revenue for year t-1 ≥1.06;
- -1.15% if the ratio between Recovered Transmission Services Revenue for year t-1 and Allowed Transmission Services Revenue for year t-1 ≤0.94;
- 0 otherwise.

ROI

Exit Capacity Products and Secondary Exit Capacity Transfer

10.26 In the Republic of Ireland (ROI), exit capacity products are currently available on an annual, quarterly, monthly, daily and within day basis.[91]

10.27 Historically, in addition to short term exit capacity products, the ROI Code of Operations has also allowed for the transfer of exit capacity between shippers, sectors and between individual Large Daily Metered (LDM) and Daily Metered (DM) sites[92].

10.28 In 2010, CRU (Commission for Regulation of Utilities)[93] decided, following consultation[94], to limit such secondary capacity transfers to those within the customer sector for which the capacity was originally boked, i.e. secondary capacity was only allowed to pass from one LDM exit point to another LDM exit point, and similarly for DM exit points. In taking this decision, the CRU had been mindful that exit capacity sales were not economically inefficient in

[91] See Gas Networks Ireland Transmission Short Term Capacity Examples 2022/23 (1st October'22 to 30th September'23).
[92] LDM customers generally represent the power sector and a small number of the very largest industrial customers. DM customers represent the larger set of IC (Industrial and Commercial) customers. NDM customers generally represent al the residential and the smaller IC customers.
[93] CER (Commission for Regulation of Utilities) at the time.
[94] CER: Review of Transmission Exit Capacity Transfers in the Gas Market, 24 February 2010.

all cases, that secondary capacity transfers provided flexibility, and that cross-subsidisation of the NDM sector by certain industrial customers and generators should be addressed.[95]

10.29 In 2013, following further consultation[96], CRU[93] decided to fully remove secondary capacity transfer at exit and to remove within day purchases of short term capacity at exit to 9:00 at D-1. This decision was driven by the need to ensure fairness and efficiency in the allocation of the cost burden of financing the required transmission system to meet customers' peak requirements.[97] CRU[93] had considered that gas transmission revenues from certain sectors (in particular the power generation sector) should increase to a level such that the proportion of revenues from each respective sector would more closely match the level of peak day demand that was expected from that sector.[98]

10.30 In 2014, CRU[93] decided to rescind the within day capacity provision of its 2013 decision (which had been due to come into effect in March 2014). That is, within-day capacity was to remain unchanged, and this product continued to be available at the exit up to 03:00 on the gas day (Day D). In reaching this decision, CRU[93] had considered market observations which had shown that the key objective underlying the 2031 decision had been materially achieved in the absence if implementation of the within-day capacity provision. CRU[93] had also been mindful of representations from the electricity sector on the importance of continued availability of flexible gas capacity products.[98]

10.31 However, as a result of a recent code modification, daily exit capacity can now be booked up until 04:59 hours on the requested Capacity Booking Effective Date.[99] The extension of the capacity booking window for daily exit capacity until practically the end of the Gas Day it relates to was implemented as variability and unpredictability of power station operating patterns had increased SEM as a result of developments in the electricity market and had made accurate Daily Exit capacity bookings more difficult and inefficient for generators. It was considered that this trend was likely to grow with the further penetration of renewable energy.[100]

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[95] See CER: Decision on Transmission Exit Capacity Transfers in the Gas Market, 17 June 2010, section 6.1.2.
[96] See:CER: Access Tariffs and Financing the Gas Transmission System, Consultation Paper, 31 Mat 2013.
[97] See CER: Access Tariffs and Financing the Gas Transmission System, Decision Paper, 21 August 2013.
[98] See CER: Decision on Gas Access Products and Tariffs – Notification to Industry, 20 February 2014.
[99] Code Modification A101: Extension of Daily Capacity Booking Window and to amend The Multiplier for Categories of Capacity Overrun Charges.
[100] ESB: Mod Proposal A101, Amendment to Code of Operations to facilitate the Extension of the

Exit Capacity Booking Obligations

10.32 Under the ROI Code of Operations[101]:

- NDM exit capacity must be booked as advised by the transporter. Temperature sensitive customers must book capacity for a 1 in 50 year peak day adverse condition.

- DM customers have discretion on the amount of capacity they book. They are issued a transporter recommended exit capacity amount, but it is not binding.

- LDM customers book capacity in line with their own requirements subject to the transporter respecting overall system integrity.

10.33 In its 2013 consultation[96] on access tariffs and financing the Gas Transmission System, CRU had also set out considerations on changing the exit capacity booking arrangements summarised in paragraph 10.32, e.g. by introducing mandatory exit capacity bookings for customers other than NDM, or by removing the NDM mandatory booking requirement. However, CRU decided against such changes at the time[97], and we are not aware of any change to this position.

Exit Capacity Overruns

10.34 Under the ROI Code of Operations, Exit Capacity Overruns are calculated with respect to LDM and DM Exit Capacity (as well as sub-sea Interconnector Offtake Capacity). An Exit Capacity Overrun Charge applies which is calculated as the product of Exit Capacity Overrun Quantity and 1.5 times the applicable Exit Capacity Charges in respect of capacity of a Daily duration.[102]

10.35 The part of the Exit Capacity Overrun revenue which equals the Exit Capacity Charge in respect of Daily Exit Capacity on the Day on which the overrun occurred is retained by the Transporter; the remainder is apportioned to Shippers based on the proportion of Active Exit Capacity held by each Shipper over the relevant month.[103]

Multipliers and Seasonal Factors

Daily Exit Capacity Booking window.

[101] See Gas Networks Ireland: Code of Operations, Part C, Clause 7.

[102] See Gas Networks Ireland: Code of Operations, Part C. Clause 11.4.5, as modified by Code Modifications A 101 (Extension of daily capacity booking window and to amend the multiplier for categories of capacity overrun charges) and A 107 (Removal of annual caps for Non SPC Capacity Overrun Charges).

[103] See Gas Networks Ireland: Code of Operations, as modified by Code Modification A104 (Transfer of Capacity Overrun Revenue to allowed revenue).

10.36 As a result of the introduction of the Tariff Network Code(see paragraph 5.6), Regulatory Authorities, including Ofgem, are required to consult annually (amongst other things) on levels of multipliers and seasonal factors for further details on these see also paragraph 5.64).

10.37 In its lates related decision paper[104], CRU decided not to change the multipliers and seasonal factors for gas year 2022/23 and leave them at the level used previously, as shown in Table 7.

Month	**Quarterly %**	**Monthly %**	**Daily %**
October	38.43	12.81	0.64
November		12.81	0.64
December		17.08	1.14
January	80.68	29.89	1.99
February		34.16	2.28
March		25.62	1.71
April	13.27	12.81	0.64
May		0.97	0.05
June		0.97	0.05
July	2.61	0.97	0.05
August		0.97	0.05
September		0.97	0.05
Total	**135**	**150**	**279.44**

Table 7: Combined multiplier & seasonal factor profile as a % of annual product
Source: CRU: Gas Transmission Tariff Methodology – Tariff Network Code Article 28 Decision, Gas year 2022/23

10.38 The multipliers and seasonal factors are applied for non-annual capacity products at entry and exit points.[104]

10.39 CRU had consulted, in 2021, on a potential adjustment to the seasonal factors. This was driven by considerations that the existing seasonal factor profile might no longer be an effective incentive for current or future network users to utilise the gas infrastructure more efficiently and could be leading to a reduction in cost-reflectivity as a result of changing market dynamics.[105]

[104] See CRU: Gas Transmission Tariff Methodology – Tariff Network Code Article 28 Decision, Gas year 2022/23.
[105] See: CRU: Gas Transmission Tariff Methodology – Tariff Network Code Article 28 Consultation,

However, following consideration of feedback received, a decision was taken not to proceed with the change. CRU noted its intention to keep the multipliers and seasonal factors under review and to consider work undertaken by neighbouring NRAs in this area.[106] In 2022, CRU confirmed its decision to continue to do so.[104]

10.40 CRU noted that policy relating to the energy transition continues to evolve rapidly on national and EU levels. CRU considered that in this context, additional time to monitor the impacts of current events upon gas policy and the gas market will help in ensuring that any changes made to multipliers and/or seasonal factors are sufficiently robust and tailored to the needs of the gas network.[104]

Year-End Reconciliation

10.41 Transmission tariffs are calculated in advance, based on forecast data for inflation, revenues and pass-through costs. Once actuals are available, an adjustment is carried out to take these actuals into account. This is called a Correction Factor or K-factor adjustment. When setting tariffs for year t+1, the K-factor for year t-1 is closed out.

10.42 There are two key rules to ensure tariffs are stable and volatility is avoided:[107]

- Rule 1: Any over-recovery up to 105% of allowed revenues is returned in the following gas year. This is to ensure tariffs are stable and volatility is avoided.

- Rule 2: Any over- or under-recovery or revenue attracts an interest rate of Euribor (interbank lending rate) +2% and any over-recovery in excess of 103% of revenue attracts and interest rate of Euribor +4%. This is to incentive forecast accuracy.

10.43 For example, when setting the tariffs year t+1, any k-factor for year t-1:

- >100% and < 103% is returned at Euribor +2%;

- >103% and <105% is returned at Euribor +4%;

- >105% is credited the following year (as per rule 1), with Euribor +4% applied for both years.

Gas Year 2021/22, 10 February 2021.

[106] See: CRU: Gas Transmission Tariff Methodology – Tariff Network Code Article 28 Decision, Gas Year 2021/22, 23 April 2021.