



Commission for Energy Regulation

An Coimisiún um Rialáil Fuinnimh

## Gas Entry/Exit Tariff Methodology

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## List of Abbreviations

<b>ACER</b>	Agency for Cooperation of Energy Regulators
<b>BGE</b>	Bord Gáis Energy
<b>CAM</b>	Capacity Allocation Mechanisms
<b>CAPEX</b>	Capital Expenditure
<b>CWDA</b>	Capacity Weighted Distance Approach
<b>GNI</b>	Gas Networks Ireland
<b>EAI</b>	Electricity Association of Ireland
<b>ENTSOG</b>	European Network of Transmission System Operators for Gas
<b>EU-ETS</b>	European Union Emissions Trading Scheme
<b>ESB GWM</b>	Electricity Supply Board Generation and Wholesale Markets
<b>FG TAR</b>	Framework Guidelines on Harmonised Transmission Tariff Structures
<b>IBP</b>	Irish Balancing Point
<b>IOOA</b>	Irish Offshore Operators Association
<b>I.S.</b>	International Standard
<b>I-SEM</b>	Integrated Single Electricity Market
<b>LRMC</b>	Long Run Marginal Cost
<b>NBP</b>	National Balancing Point
<b>NC TAR</b>	Network Code on Harmonised Transmission Tariff Structures for Gas
<b>NGG</b>	National Grid Gas
<b>NRA</b>	National Regulatory Authority
<b>NTLG</b>	Network Tariffs Liaison Group
<b>MEC</b>	Matrix Expansion Constants
<b>NEC</b>	Negative Expansion Constant
<b>Ofgem</b>	Office for Gas and Electricity Markets
<b>OPEX</b>	Operating Expenditure
<b>PC3</b>	Price Control 3
<b>SEM</b>	Single Electricity Market

<b>SRMC</b>	Short Run Marginal Cost
<b>SSE</b>	Scottish and Southern Energy
<b>TSO</b>	Transmission System Operator
<b>VPA</b>	Virtual Point approach
<b>WACC</b>	Weighted Average Cost of Capital

## Glossary

<b>Adjusted tariffs</b>	An Entry or Exit tariff after a secondary adjustment has been applied.
<b>Required Revenue</b>	The sum of revenues that the TSO is entitled to obtain in a given period, as approved by the CER.
<b>Domestic Exits</b>	Exit Points that are within Ireland, excluding Interconnection Points.
<b>Equalisation</b>	A secondary adjustment applied to tariffs across a certain category of network users for the purposes of tariff stability. The result of equalisation is that the same tariff is charged at all the relevant (equalised) points
<b>Interconnection Point</b>	A point connecting one entry-exit system to another entry/exit system.
<b>Non-equalised tariff</b>	An adjusted tariff for a point that is not included in the Equalisation Secondary Adjustment.
<b>Primary Tariff</b>	An Entry or Exit tariff calculated based on the Long Run Marginal Cost associated with that Entry or Exit point. Also known as a pre-adjusted tariff.
<b>Rescaling</b>	A secondary adjustment to primary tariffs calculated under the Matrix methodology to obtain the required revenues of the TSO.
<b>Secondary Adjustment</b>	An adjustment that can be applied to primary or adjusted tariffs for the purposes of revenue recovery or tariff stability.

## **Related documents**

[Future of Gas Entry Regime Draft Decision Paper](#) (CER/15/057) (2015)

[Future of Gas Entry Tariff Regime Initial Modelling Evidence](#) (CER/14/455) (2015)

[Future of Gas Entry Regime Information Note](#) (CER/14/127) (2014)

[The Regulatory Treatment of the BGÉ Interconnectors and Future Gas Transmission Tariff Regime](#) (2012)

[ACER Framework Guidelines on Harmonised Transmission Tariff Structure for Gas](#) (2014)

[ENTSOG Network Code on Harmonised Transmission Tariff Structures for Gas](#) (2013)

**Abstract:**

This Decision Paper outlines the CER's final decision on the methodology that will be used to set transmission network charges for remuneration of the Gas Networks Ireland Required Revenues, from 1<sup>st</sup> October 2015. This methodology was the subject of a draft Decision Paper published on 27<sup>th</sup> March 2015.

The CER's final decision on these matters is outlined in this Decision Paper and in line with the CER's statutory duties, constitutes a direction to Gas Networks Ireland.

## 1.0 Introduction

### 1.1 The Commission for Energy Regulation

The Commission for Energy Regulation (CER) is the independent body responsible for overseeing the regulation of Ireland's electricity and gas sectors. The CER was established and granted regulatory powers over the electricity market under the *Electricity Regulation Act 1999*. The *Gas (Interim) (Regulation) Act 2002* expanded the CER's jurisdiction to include regulation of the natural gas market. The CER is working to ensure that consumers benefit from regulation and the introduction of competition in the energy sectors.

### 1.2 Purpose of this Decision Paper

The purpose of this Decision Paper is to set out the directions to Gas Networks Ireland (GNI) on the methodology to be used to set gas transmission network tariffs from 1<sup>st</sup> October 2015.

### 1.3 Structure of this paper

This paper is structured as follows.

**Section 1** outlines the background to the Decision Paper.

**Section 2** outlines the directions to Gas Networks Ireland on the choice of gas entry/exit tariff methodology to be employed and the inputs to be applied. This includes directions to GNI regarding certain policy matters relating to the application of the methodology.

**Section 3** outlines the results of an Impact Assessment undertaken by the CER that takes account of the decisions taken in the previous section.

In addition, **Appendix A** outlines the responses received to the issues that were included in the Draft Decision Paper (CER/15/057) as well as the CER's response to the issues raised. **Appendix B** outlines other issues that were raised by stakeholders to the Draft Decision Paper and the CER's response to those issues. **Appendix C** outlines additional details on the Commodity element of charges and the Load Factors used as part of the Impact Assessment.

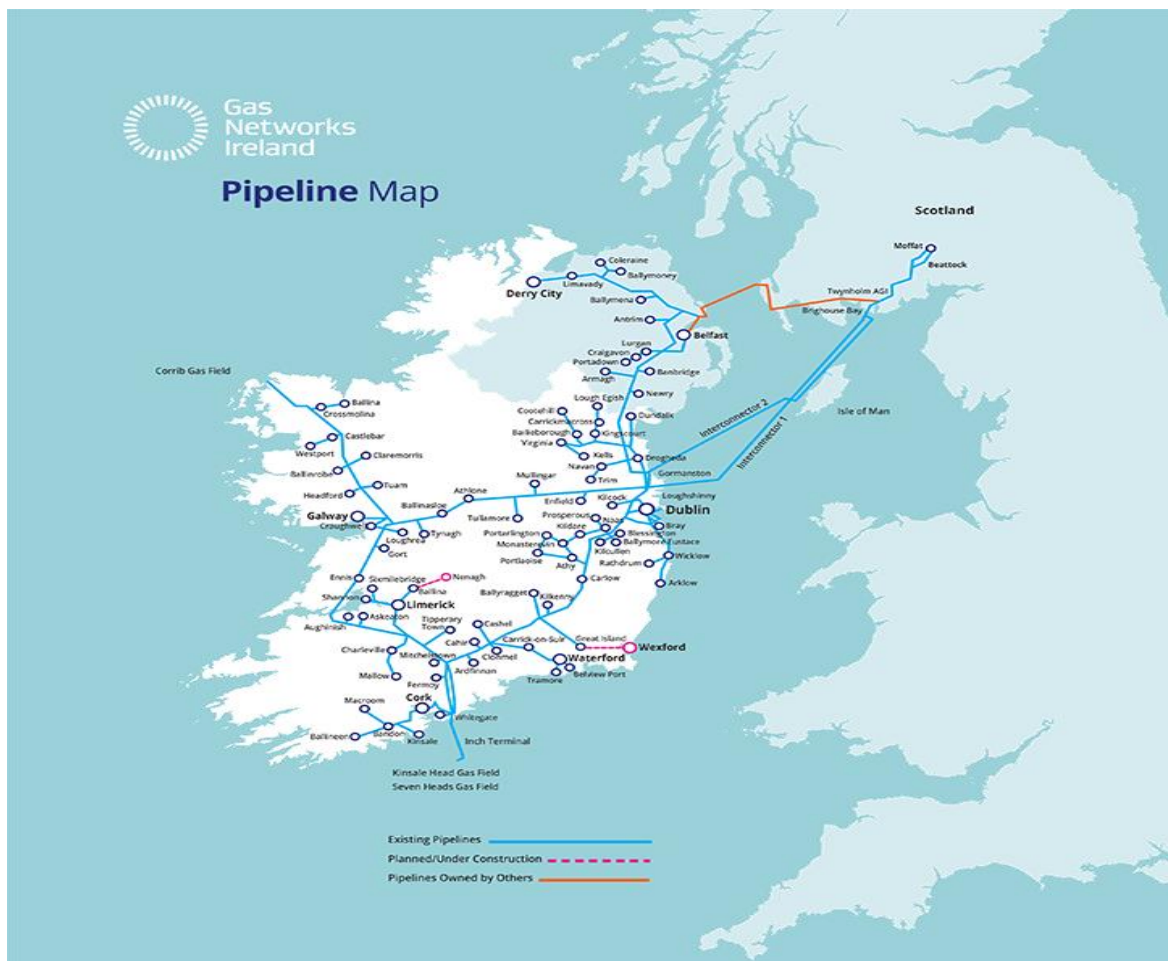
## 2.0 Background

### 2.1 The regulatory treatment of Gas Networks Ireland

As part of the economic regulatory remit of the CER, 5 yearly price control reviews are carried out which sets out certain Required Revenues for the period. These Required Revenues cover Capital Expenditure (Capex), Operating Expenditure (Opex) and a return (WACC) to GNI for building, maintaining and operating the gas transmission system. This is known as the Regulated Asset Base (RAB).

The revenues required over a price control are remunerated via transmission network tariffs which are set annually and apply from 1<sup>st</sup> October to 30<sup>th</sup> September of each year. As the regime is based on Required Revenues, in the event that there is an over or under recovery of revenues then these are corrected in subsequent years.

Therefore, the purpose of this Decision Paper is to outline the methodology that will be used as the means of distributing these required revenues amongst Entry Points onto the transmission system and Exits from the transmission system. An overview of the system is set out in the figure below.



## **2.2 Context**

In the next number of months a significant change to Irish gas supplies will arise with the coming on stream of gas flows from the Corrib gas fields. This is a significant change to supply sources in Ireland and will be the first new indigenous source of gas in over 30 years.

As a result of this change, the gas Interconnectors that connect Ireland to Great Britain will no longer be the primary supply source of gas, at least in the medium term until flows from Corrib decline. In addition, there is the potential of a LNG facility at Ballylongford, Co. Kerry in the coming years.

## **2.3 Existing regime and the need to reform**

The current transmission entry tariffing regime needs reform. Without reform the reduced Moffat throughput (due to new sources of gas coming on stream) will increase the unit Moffat entry tariff, potentially significantly so. This higher Moffat entry tariff would, in turn, push up the wholesale price for gas in Ireland, as other entry points supplying gas would be free to price up to, or just under the now significantly higher wholesale cost of gas. Therefore, whilst Ireland would enjoy more diverse sources this would be negative for Ireland's energy competitiveness and consumer welfare as it would come at a significantly higher price to consumers.

It is on this basis that the CER has decided to reform the gas entry/exit tariff methodology to ensure its replacement is fit for purpose.

The reforms decided in this paper are the outcome of a 5 year tariff reform process begun by CER as far back as 2011. In 2012 CER published a Decision Paper *The Regulatory Treatment of the BGÉ Interconnectors and Future Gas Transmission Tariff Regime* (CER/12/087) setting out the rationale and principles for the future methodology that would endure after reform had taken place. The key principles included a decision to base future reform on a forward looking cost concept (the cost of expansion of the system) rather than the current methodology which recovers the historical revenues of Gas Networks Ireland.

## 2.4 European developments

In undertaking the tariff reform process, the CER has been guided by developments at an EU level specifically the publication of the ACER Framework Guidelines on Tariffs (FG TAR)<sup>1</sup> and at the end of 2014, the publication of ENTSOG's Draft Network Code on Tariffs (NC TAR)<sup>2</sup>. As the CER considers that the tariff regime requires reform now rather than when the Network Code is binding, it is preferable to implement changes now that are, where possible, in line with EU guidance.

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<sup>1</sup> [ACER Framework Guidelines on Harmonised Transmission Tariff Structure for Gas](#)

<sup>2</sup> [ENTSOG Network Code on Harmonised Transmission Tariff Structures for Gas](#)

## 3.0 The Tariff Reform process

### 3.1 The process of reform

This Decision Paper is the outcome of a multi-stage consultation process led by the CER to reform the gas entry/exit tariff methodology. This consultation process has been ongoing with shippers, suppliers, producers, the TSO and others since early 2014. This included convening a Networks Tariff Liaison Group (NTLG) of industry stakeholders which has met 9 times since February 2014, 2 Public Workshops and presentations at the Code Mod forum. In terms of publications, an Information Note (June 2014), a Consultation Paper (September 2014) and a Draft Decision (March 2015) have been published to encourage engagement with the process of reform. In addition, 2 models have been published; one with the Consultation Paper and an updated version of that model with the Draft Decision, which took account of further work done on inputs to the model.

The June Information Note (CER/14/127) detailed the methodologies that were available and the circumstances in which they could apply, as well as whether they could, in theory at least apply to Ireland.

At the same time the CER developed an excel model based on three of the methodologies. Therefore the Information Note was followed up with a Consultation Paper (CER/14/455) in September 2014 which indicated initial modelling evidence for three methodologies as well as the actual model itself which allowed stakeholders to interact with the model and test the inputs and parameters. Feedback from this Consultation Paper and subsequent NTLG meetings guided the CER on refining further inputs.

In March 2015 the CER published its Draft Decision Paper (CER/15/057) which outlined the CER proposed methodology that would apply from October 2015, as evaluated against a set of criteria. In addition, that Draft Decision Paper requested feedback on other matters which have an impact on network users. The full range of issues outlined in that Draft Decision Paper are indicated below.

	<b>Issue</b>
<b>Choice of methodology and inputs</b>	Choice of Methodology
	Expansion Constants
	Application of Negative Expansion Constant
	Annuitisation Factor
<b>Policy directions that impact Network Users</b>	Capacity/ Commodity split
	Entry/Exit split
	Postalisation of Exit Tariffs
	Storage
	Isle of Man

Table 3.1 Issues from Draft Decision

### 3.2 Responses received to Draft Decision

In total the CER received 18 responses to the Draft Decision as set out in the table below. In addition to individual responses a number of respondents stated that they were supportive of the response issued by IOOA. A summary of the issues raised is included in Appendix A and B. In addition, all non-confidential responses received are published alongside this Decision Paper.

<b>Respondent</b>	<b>Organisation</b>
Aughinish Alumina	End gas user
Bord Gáis Energy (BGE)	Shipper/Supplier/Power generation
Diageo	End gas user
Gas Networks Ireland (GNI)	Transmission System Operator
Electricity Association of Ireland (EAI)	Trade association
ESB Generation and Wholesale ( ESB GWM)	Shipper/Power generation
Flogas	Shipper/Supplier
Irish Offshore Operators Association (IOOA)	Trade association
Kinsale Energy	Producer/Storage operator
Manx Utilities	Shipper
Paul Hunt	Independent consultant
Shannon LNG	Producer
Shell	Producer
SSE	Shipper/Supplier/Power generation
Tynagh Energy	End gas user
Vayu	Shipper/Supplier
Vermilion	Producer

Table 3.2 Respondents to Draft Decision

The CER thanks all respondents for their feedback, and would like, in particular to thank the active members of the NTLG who have contributed to a productive consultation process ongoing since February 2014.

### **3.3 Legal basis for direction to Gas Networks Ireland**

This Decision Paper sets out a number of directions to GNI on the choice of gas entry/exit tariff methodology, its inputs and related policy matters.

As the National Regulatory Authority (NRA) for Ireland, the CER is obligated under Article 41(6) of Directive 2009/73/EC concerning common rules for the internal market in gas, as a minimum to approve a methodology that is used for network tariffs for connections onto the system. This is in addition to the requirements of Article 13 of Regulation (EC) No 715/2009 on conditions for access to the natural gas transmission system and Section 14 of the Gas (Interim) (Regulation) Act, 2002 (as amended).

## **4.0 Directions to Gas Networks Ireland on Gas Entry/Exit tariff Methodology**

This section outlines the CER's directions to GNI on the matters relating to the gas Entry/Exit tariff methodology and associated matters.

Section 4.1 outlines the directions to GNI on the gas Entry/Exit tariff methodology and inputs. This includes:

- The choice of methodology;
- Expansion Constant values;
- Annuitisation Factor;
- Rescaling of Tariffs, and
- Treatment of K-Factors.

Section 4.2 outlines the directions to GNI on policy matters related to the implementation of the Gas Entry/Exit tariff methodology. This includes;

- Capacity/Commodity split;
- Direction on Commodity calculation;
- Postalisation of Exit tariffs; and,
- Treatment of Storage.

### **4.1 Choice of methodology and inputs**

#### **4.1.1 Choice of methodology**

In the Draft Decision, the CER indicated that it was minded to apply the Matrix methodology as it was best suited to the criteria included in the Draft Decision. Taking account of feedback received, the CER is still of the view that the forward looking Matrix methodology is most suited to Ireland. Therefore, the CER is directing GNI to implement the Matrix methodology. In line with the requirements of this methodology, GNI must use a forward looking unit cost matrix that is reflective of the unit costs for each path between each entry point<sup>3</sup> and all exit points. The unit costs applied will be as directed in Decision 2 below.

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<sup>3</sup> The methodology will include Entry & Exit Points that are considered active within a reasonable period of time as determined by GNI.

**Decision 1: The CER directs Gas Networks Ireland to apply the forward looking Matrix methodology for the calculation of Capacity transmission tariffs from 1<sup>st</sup> October 2015.**

#### **4.1.2 Expansion Constants**

One of the inputs into the Matrix methodology are Expansion Constants (unit costs) which calculate a numerical value for the cost of expanding the system to allow unit (GWh) of gas to flow a certain distance (km) i.e. the Long Run Marginal Cost. The CER stated in the Draft Decision that it was minded to apply two distinct values; one where there was wet expansion of the system (i.e. subsea) and a value for dry expansion of the system (i.e. onshore). After considering the feedback received as part of the consultation process, the CER considers that the values established in the Draft Decision are appropriate.

**Decision 2: The CER directs Gas Networks Ireland to apply €7, 874/GWh km as the value of the Dry Expansion Constant and €8,757/GWh km for the Wet Expansion Constant as the unit cost inputs to the Matrix methodology from 1<sup>st</sup> October 2015.**

#### **4.1.3 Application of the Negative Expansion Constant**

A flexible input into the Matrix methodology is the Negative Expansion Constant. In the Draft Decision Paper the CER stated that the application of the Negative Expansion Constant did not “*contribute positively to the overall stability of tariffs nor the differentials established between Entry Points*” and was therefore minded not to apply this input.

**Decision 3: The CER directs Gas Networks Ireland to not apply the Negative Expansion Constant as an input into the Matrix methodology from 1<sup>st</sup> October 2015.**

#### **4.1.4 Annuitisation Factor**

In the Draft Decision the CER included an Annuitisation Factor of 10.5%. The Annuitisation Factor is the annual payment made to remunerate the return of and on capital as well as associated operating costs of delivering gas to the system, whilst taking into account a depreciation profile of an asset<sup>4</sup>.

**Decision 4: The CER directs Gas Networks Ireland to apply an Annuitisation Factor of 10.5% as an input into the Matrix methodology from 1<sup>st</sup> October 2015.**

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<sup>4</sup> There was considerable debate on this input into the Matrix methodology which is outlined in some detail in Appendix A.

#### **4.1.5 Rescaling of Primary tariffs**

Where the primary tariffs calculated do not recover or over recover the Required Revenue to be obtained from Entry Points or from Exit Points then tariffs will be rescaled upwards or downwards as necessary via the application of a secondary adjustment known as additive or subtractive rescaling with the purpose of achieving recovery of the Required Revenue.

**Decision 5: The CER directs Gas Networks Ireland to apply additive or subtractive rescaling as a secondary adjustment, where necessary to obtain the Required Revenues based on a specified Entry/Exit and Capacity/Commodity split from 1<sup>st</sup> October 2015.**

#### **4.1.6 Treatment of K-Factors**

It is expected that there would be under/over recoveries at the existing Entry (Inch/Moffat) and Exit points that will require correcting in the coming years. In the Draft Decision Paper the CER considered retaining separate K-Factors for the current Entry Points and Exit with the aim of moving towards a single K-Factor across the system after a transition phase. The aim of this was to allow the over/under recoveries that had arisen in the gas years 13/14 and 14/15 to be attributed to the relevant entry and exit tariffs.

Examination of the expected under/over recoveries for the gas years 13/14 and 14/15 suggest that the overall size of the over/under recoveries is so small that it doesn't warrant such a transition phase.

**Decision 6: The CER directs Gas Networks Ireland to apply a single Required Revenue K-Factor from 1<sup>st</sup> October 2015, this single K-Factor to be divided in accordance with the Entry/Exit split.**

## 4.2 Decision on related policy matters

In addition to the directions to GNI on the gas entry/exit tariff methodology and inputs, set out in section 4.1, there are further policy decisions which the CER now directs GNI to implement that have an impact on the tariffs that network users will see as outlined below.

In determining these directions to GNI the CER has attempted to ensure that the status quo for network users is maintained as much as possible.

### 4.2.1 Entry/Exit split

In Decision Paper CER/12/087 as part of the principles underpinning tariff reform, the CER indicated that in line with the remuneration of a single system, that it would move to a 50:50 Entry/Exit split. At the time, the rationale behind this proposed split was based on the fact that every molecule that enters must exit. Hence, the 50:50 split seemed appropriate in the Irish gas market context. In addition, the Draft Network Code on Tariffs suggests a 50:50 split as a default unless other splits can be justified. However, the CER did note at the time that it was *open to arguments on different splits and these will be teased out in the Networks Tariff Liaison Group*. The Entry/Exit split issue received most responses which are detailed in Appendix A. On the basis of responses received to the Draft Decision, the CER has decided the following split.

**Decision 7: The CER directs Gas Networks Ireland to implement a 33% Entry and 67% Exit split, this split to be applied to the Required Revenue.**

### 4.2.2 Capacity/Commodity split

In the Draft Decision, the CER indicated that there was no firm view on the appropriate Capacity/Commodity split to apply from October 2015. This was because although the Draft Network Code envisaged 100% Capacity charges, this requirement is not expected to be binding until the Network Code is in force. The CER received substantial feedback on this issue and the decision below has been informed by this.

**Decision 8: The CER directs Gas Networks Ireland to maintain the currently prevailing 90:10 Capacity/Commodity split, to be applied to the Required Revenue from 1<sup>st</sup> October 2015. The CER will review this split in light of any future Network Code requirements.**

### 4.2.3 Commodity charges

Under the existing methodology, Commodity forecasts are calculated separately for each Entry Point and for Exit. The Commodity charge is calculated by dividing 10% of the revenues associated with an Entry Point or 10% of the Exit revenues by the forecast Commodity bookings at each.

From 2015/16 onwards applying an Entry/Exit split of 33/67 for revenues, a single Commodity charge will be charged at all Entry Points based on the sum of Commodity forecasts at all Entry Points. Similarly a single Commodity charge will be charged at all Exits based on the Commodity forecasts at Exit<sup>5</sup>.

**Decision 9: The CER directs Gas Networks Ireland to calculate a single Commodity charge applicable at all Entry Points and a single Commodity charge applicable at all Exit Points from 1<sup>st</sup> October 2015.**

### 4.2.4 Postalisation of Exit tariffs

The CER indicated in the Draft Decision that it would continue to postalise the domestic Exit tariffs via the application of the Equalisation secondary adjustment. This does not include Interconnection Points from the GNI system such as the Gormanston Exit Point.

**Decision 10: The CER directs Gas Networks Ireland to continue to apply the principle of postalised domestic tariffs from 1<sup>st</sup> October 2015, via the Equalisation secondary adjustment. For Exit points that are not domestic exit points, Gas Networks Ireland is directed to apply the non-equalised exit tariff applicable to that point.**

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<sup>5</sup> Additional details on the calculation of Commodity charges are included in Appendix C.

#### 4.2.5 Treatment of Storage

As part of the Draft Decision, the CER included an assessment of a 100% discount for storage gas where it re-enters the GNI system, the results of which were based on a 50:50 Entry/Exit split.

As the CER has now decided to apply a 33:67 Entry/Exit split, this has a downward effect on the revenues that require redistribution amongst other Entry Points<sup>6</sup>. In addition, the 90:10 Capacity/Commodity split decision removes a portion of revenues that would otherwise need to be recovered from other Entry Points where Storage receives a discount.

The CER considers that the retention of a storage facility on the island is positive and sees economic rationale in applying the incremental cost to the Storage Entry Point which was suggested by one respondent to the Draft Decision.

Therefore, the CER has decided that there will be no change to the current Exit policy for Storage, as was outlined in the Draft Decision<sup>7</sup>. In addition, the CER has decided that where storage gas re-enters the GNI system from the Inch Entry Point it will pay the primary (pre-adjusted) entry tariff as calculated by the Matrix methodology. Rescaling will not apply to the primary tariff for Storage gas from the Inch Entry Point. For clarity, production gas from the Inch Entry Point will pay the rescaled (adjusted) Entry tariff.

**Decision 11: The CER directs Gas Networks Ireland to apply the primary (pre-adjusted tariff) Inch Entry Point tariff where storage gas re-enters the GNI system from the Inch Entry Point from 1<sup>st</sup> October 2015.**

#### 4.2.6 Isle of Man

The Isle of Man books Entry capacity at Moffat only and does not book exit capacity. Therefore, the Entry tariff at Moffat and the split of overall revenue to be obtained from Entry has a direct effect on the price paid by the Isle of Man. A move to 50:50 Entry/Exit split would have negatively impacted the Isle of Man, as it would not have seen the reduced Exit tariff that Irish users would have seen. In the Draft Decision, the CER requested feedback on the suitable treatment of the Isle of Man.

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<sup>6</sup> The effect of this described in CER/15/057 was also based on revenues of €200m and 100% Capacity

<sup>7</sup> The original decision on this matter is in CER/06/154

<http://www.cer.ie/docs/000149/cer06154.pdf>

Under Price Control 3(PC3) total Required Revenue of c. €1 billion was allowed for GNI. Of this total c. €319m (32%) was for the recovery of the Interconnector part of the system and €12m for recovery from Inch, therefore, of the total €331m was to be recovered from Entry. If the methodology were to continue unchanged except for a move to 50:50 Entry/Exit then this would increase the total revenue from Entry from €331m (33%) to €500m. However, the CER has now decided to implement an Entry/Exit that is more closely aligned to the current split. This maintains the proportion of revenues that are to be recovered from Entry broadly in line with the position today. In the CER's view the chosen Entry/Exit split also has the effect of ensuring that the tariff position of the Isle of Man is not unduly affected.

**Therefore, no direction is required on the Isle of Man to Gas Networks Ireland.**

## 5.0 Impact Assessment of the new gas Entry/Exit tariff methodology

This section addresses a request from a number of respondents that an Impact Assessment should be conducted to assess the impact of Network Tariffs at each Entry and Exit across the different customer categories at the existing Entry Points. The CER has been minded to ensure that on certain matters the status quo was broadly maintained to ensure minimal impact or redistributive effects across network users.

A number of respondents to the Draft Decision requested that some of the issues considered in the Decision Paper (such as the entry exit split) should be an ex-post outcome of an Impact Assessment. Therefore, the decision on the Capacity/Commodity split and the Entry/Exit split set out in Section 4.2.1 and 4.2.2 were influenced by an analysis of the effects across different network users. The scenarios presented below compare a “do-nothing” scenario and the chosen Matrix methodology with the 14/15 tariffs<sup>8</sup>.

This section sets out the Impact Assessment based on certain assumptions and inputs.

### 5.1 Impact Assessment assumptions

The CER has conducted an updated Impact Assessment to take account of the decisions outlined in this paper. It should be noted that the assumptions below relating to revenues and forecasts are based on information available at the time when the Impact Assessment was conducted. These forecasts may change when actual tariffs are set in August.

1. A Capacity/Commodity split of 90:10 across all scenarios.
2. An Entry/Exit split of 33:67 for the chosen Matrix methodology.
3. Updated Required Revenue of €190m. These are the forecast revenues anticipated as of June 2015<sup>9</sup>.
4. For 14/15 the forecast bookings at Exit were 267.8 GWh and the forecast bookings at Entry were 201.8 GWh. This results in an Entry to Exit booking ratio of 0.75 i.e. for every unit of Exit booked 0.75 of corresponding Entry is booked.
5. For the 15/16 do nothing and Matrix methodology the forecast bookings are 283.9 GWh for Exit and 186.4 GWh at Entry. This results in an Entry to Exit booking ratio of 0.66.

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<sup>8</sup> Additional scenarios including the CWDA & Matrix under different Entry/Exit splits are included in the Excel file published alongside this paper (CER/15/140a).

<sup>9</sup> This does not include any assessment of any additional pass through or extra over items that are included in the annual tariff updates. The actual revenues will be published as part of the setting of 15/16 tariffs in August.

6. The impact on different users has been modelled using Moffat Entry+ Exit as well as Inch Entry+ Exit. Corrib has not been modelled as there are no users currently associated with this Entry.
7. A range of network users have been assumed with differing Load Factors<sup>10</sup>.
8. Storage gas from the Inch Entry Point paying the primary tariff for re-entry onto the GNI system.

## 5.2 Network Tariffs across scenarios

The table below illustrates the currently prevailing tariffs and the 15/16 tariffs based on not changing the existing methodology (Do Nothing) and the Matrix methodology using a 33:67 Entry/Exit split.

	14/15 Tariffs	15/16 tariffs "Do Nothing"	Estimated 15/16 tariffs Matrix (33:67 split)
<b>Exit</b>			
Capacity	€443	€406	€403
Commodity	€0.28	€0.27	€0.27
<b>Gormanston Exit</b>			
Capacity	€0	€0	€108
Commodity	€0	€0	€0.27
<b>Moffat</b>			
Capacity	€359	€925	€448
Commodity	€0.16	€0.41	€0.12
<b>Inch</b>			
Capacity	€54	€50	€311
Commodity	€0.03	€0.04	€0.12
<b>Corrib</b>			
Capacity	€0 <sup>11</sup>	€0	€294 (see note below)
Commodity	€0	€0	€0.12

Table 5.1 Illustrative tariffs

<sup>10</sup> As detailed in the Draft Decision Paper, a Load Factor illustrates peak day usage over the average usage. For example, a domestic user's peak day usage is assumed as 3 times the average. See Appendix C.

<sup>11</sup> There is a nominal tariff for the Linkline originally set in 2009 of €100 per peak day/MWh & €0.10 per MWh Commodity.

Note: It should be noted that this figure is one of two elements to comprise the Bellanaboy Entry Tariff. The methodology for the calculation of the Corrib Linkline element is outlined in tandem with this Decision Paper (CER/15/141).

	Bellanaboy	Moffat	Inch
Required Revenue element	€294	€448	€311
Linkline element	€441	N/A	N/A
Entry Tariff	€735	€448	€311

In the Draft Decision, the Entry tariffs indicated were on the basis of a 100% discount for Storage. Therefore the tariffs indicated were €460 per peak day MWh (Moffat), €323 per peak day MWh (Inch production) and €307 per peak day MWh (Corrib). Appendix A includes additional details on the redistribution of revenues based on the Entry/Exit split and the application of a primary tariff for storage gas from the Inch Entry Point.

### 5.3 Tariff impacts across Moffat network users

Below illustrates the tariffs for Moffat users (paying Moffat entry and exit).

Network User	14/15 tariffs	Do nothing	Matrix 33:67
Base Load Industrial	€960	€1578	€992
Base Load Power	€1085	€1569	€1050
Hospital	€1228	€1772	€1189
Hotel	€1406	€2026	€1364
Food	€1584	€2280	€1538
Mid-merit	€1798	€2585	€1748
Resi + Peaker	€2298	€3297	€2237

Table 5.2 Network user tariff (Moffat)

The table below indicates the percentage change across network users versus the current network tariffs using the existing methodology. This illustrates that the effects

of the Matrix methodology across network users are broadly neutral with no significant distributive effects between Moffat network users. This is with the exception of baseload industrial customers (who see a rise of 3%). However, if the reforms outlined in this decision were not in place this user would face an upward rise in tariffs of c. 64% compared to 14/15 tariffs.

<b>Network User</b>	<b>14/15 tariffs</b>	<b>Do nothing</b>	<b>Matrix 33:67</b>
<b>Base Load Industrial</b>	100%	164%	103%
<b>Base Load Power</b>	100%	145%	97%
<b>Hospital</b>	100%	144%	97%
<b>Hotel</b>	100%	144%	97%
<b>Food</b>	100%	143%	97%
<b>Mid-merit</b>	100%	143%	97%
<b>Resi + Peaker</b>	100%	143%	97%

Table 5.3 Network user impact (Moffat)

#### 5.4 Tariff impacts across Inch network users (production)

Below indicates the tariff change that network users at **the Inch Entry Point** would see versus the current network tariffs (paying Inch Entry and Exit). These indicate that unlike Moffat customers, there is a significant rise for Inch customers versus the currently prevailing tariffs across all network users. It should be noted that this applies to gas from Inch production.

Network User	14/15 tariffs	Do nothing	Matrix 33:67
<b>Base Load Industrial</b>	€610	€567	€855
<b>Base Load Power</b>	€741	€682	€932
<b>Hospital</b>	€838	€770	€1054
<b>Hotel</b>	€959	€880	€1206
<b>Food</b>	€1080	€990	€1358
<b>Mid-merit</b>	€1225	€1122	€1540
<b>Resi + Peaker</b>	€1563	€1429	€1966

Table 5.4 Network user tariffs (Inch)

The percentage change versus the currently prevailing is indicated below, which indicate that there is a much more negative effect on Inch users than those at Moffat who are broadly neutral from tariff reform. This relates to the production element of Kinsale, which accounts for significantly less capacity than the storage element of the facility. The Storage element is c. 85% (31 GWh of a total of 36 GWh) and is also illustrated separately.

Network User	14/15 tariffs	Do nothing	Matrix 33:6 7
Base Load Industrial	100%	93%	140%
Base Load Power	100%	92%	126%
Hospital	100%	92%	126%
Hotel	100%	92%	126%
Food	100%	92%	126%
Mid-merit	100%	92%	126%
Resi + Peaker	100%	91%	126%

Table 5.5 Network user impact (Inch production)

### 5.5 Tariff impacts across Inch network users (Storage)

The network user impact including 14/15, do nothing and the chosen Matrix methodology are indicated below for Storage users. Again, these illustrative tariffs are based on an Entry/Exit booking ratio of 0.75 for 14/15 and 0.66 for 15/16 and the Load Factor across different network users as indicated in Appendix C. For the Matrix below, the Inch Entry Point tariff is the primary tariff of €61 MWh as per the CER model.

Currently, there is a differential between Inch & Moffat of €304 per MWh (€358-€54) some of which would be expected to be garnered by the Storage facility and some of which could be expected to be garnered by the shipper using the facility. Under the Matrix methodology, applying the primary tariff the differential as per the CER model is €387 per MWh. However, it should be noted that this differential is not garnered for production gas from the Inch Entry Point, whereas to date there was no differentiation between production or storage gas from that Entry Point.

Network User	14/15 tariffs	Do nothing	Matrix 33:67
Base Load Industrial	€610	€567	€605
Base Load Power	€741	€682	€717
Hospital	€838	€770	€806
Hotel	€959	€880	€917
Food	€1080	€989	€1028
Mid-merit	€1225	€1122	€1160
Resi + Peaker	€1563	€1429	€1471

Table 5. 6 Network user tariffs (Inch Storage)

Network User	14/15 tariffs	Do nothing	Matrix 33:67
Base Load Industrial	100%	93%	99%
Base Load Power	100%	92%	97%
Hospital	100%	92%	96%
Hotel	100%	92%	96%
Food	100%	92%	95%
Mid-merit	100%	92%	95%
Resi + Peaker	100%	91%	94%

Table 5.7 Network user impact (Inch Storage)

As the Storage primary tariff is broadly in line with the current tariff the impact on network users availing of Storage at Inch should be minimal.

## 5.6 Summary

With the exception of baseload industrial users, the impact assessment across Moffat network users is broadly neutral or slightly positive using the Matrix methodology. The CER does note that Inch users paying the production entry tariff will face a significant increase in the tariff levels versus 14/15. However, the treatment of this Entry Point is consistent with that of all other Entry Points that remunerate the GNI system. In addition, the application of the primary tariff to storage gas that re-enters the GNI

system ensures that the status quo for this category of user is broadly maintained as part of the tariff reform process. As such, the CER views the Matrix methodology applying the decisions outlined in this paper as fit for purpose.

## 5.7 Entry/Exit split and Storage assumptions

In the Draft Decision, the impact of giving a 100% discount at entry to storage gas re-entering the system was a €103/MWh rise in all entry tariffs. This was based on a number of assumptions including the entry/exit split of 50:50.

One effect of the Decision set out in section 4.2.1 to use a 33:67 split is that with a 100% discount, the increase in all entry tariffs is reduced to €55/MWh. Adjusting for the application of the primary tariffs to gas re-entering the system from storage, the effect is reduced to c. €42/MWh.

The redistributed revenues per MWh and in total are indicated below<sup>12</sup>. The tariffs indicated in Table 5.1 are inclusive of a redistribution of c. €42 per MWh across all Entry Points.

	50:50 split (as per Draft Decision )	33:67 split ( 100% discount for Storage)	33:67 split ( Primary Inch Entry Point tariff for storage gas)
<b>Tariff impact on Entry Points</b>	€103 per MWh	€55 per MWh	€42 per MWh
<b>Total redistributed revenue</b>	€15.9 m	€8.5m	€6.5m

Table 5.8 Storage impacts.

<sup>12</sup> Total redistributed revenue is based on the € per MWh impact multiplied by 154,808 MWh. This is the forecast entry bookings minus the storage element.

## 6.0 Conclusions and Next Steps

The decisions outlined in the paper are the culmination of 5 years of tariff reform by the CER. Throughout this reform process the CER has actively engaged with stakeholders via an extensive consultation process to ensure that stakeholders were actively involved in the reform. The CER considered the views of stakeholders carefully and as such, on many issues, the status quo will be maintained to ensure the impact on customers is minimised as much as possible. The CER would like to thank industry for its considerable engagement and commitment to this reform process and considers the input given as invaluable in ensuring a robust regulatory framework for the future gas market.

The decisions outlined in this Decision Paper constitute a direction to GNI to finalise a tariff model based on the choice of methodology, associated inputs and policy directions in this Decision Paper. When the GNI model has been finalised to take account of these inputs, GNI will hold a workshop for stakeholders outlining the GNI model that will be used to set actual tariffs from 1st October 2015. This workshop will take place on the 10<sup>th</sup> August, in the Cork International Airport between 10.30am and 1pm.

Readers of this Decision Paper should be aware that the annual network tariffs, for both transmission and distribution will be set in late August. This will include extra-over and pass-through items as well as the correction of K-Factors to establish finalised revenue for the forthcoming year.

Finally, readers of this paper should also consider the CER Decision Paper "*Methodology for calculation of the Corrib Linkline element of the Bellanaboy Entry Tariff*" (CER/15/141) in order to familiarise themselves with the two elements of the Bellanaboy entry tariff.

## Appendix A: Responses received to Draft Decision and CER response

18 responses were received to the Draft Decision Paper (CER/15/057) as set out in Section 3.2. These responses were discussed at the NTLG and were considered by the CER as part of this Decision Paper.

The views received, as well as the CERs response to each of the issues raised in the Draft Decision, are summarised below<sup>13</sup>. It should be noted that responses were received individually from Kinsale Energy, Statoil, Shell and Vermilion which were supportive of the IOOA response.

The full range of issues consulted upon in the Draft Decision Paper are indicated below and are dealt with in this order in this Appendix.

	Issue
<b>Choice of methodology and inputs</b>	Choice of Methodology (Section A.1)
	Expansion Constants (Section A.2)
	Application of Negative Expansion Constant (Section A.5)
	Annuitisation Factor (section A.6)
<b>Policy directions that impact Network Users</b>	Capacity/ Commodity split (Section A.7)
	Entry/Exit split (Section A.8)
	Postalisation of Exit Tariffs
	Storage (Section A.10)
	Isle of Man (Section A.9)

### A.1 Choice of methodology

In total 13 responses were received on the choice of methodology with the majority in favour of the Matrix methodology. One respondent (IOOA)<sup>14</sup> was of the view that the CWDA “*was a stronger contender for the choice of methodology*”. An extract from that response is included below which compares the advantages of the CWDA with the disadvantages (in IOOA’s view) of the Matrix methodology. It should be noted that the sub-criteria (ease of understanding, adjustments needed after methodology applied etc.) on which IOOA has assessed the methodology were not a part of the CER’s three criteria against which the methodologies were examined.

<sup>13</sup> This is with the exception of the Postalisation of domestic Exit tariffs, which received only one response agreeing with the CER’s approach.

<sup>14</sup> IOOAs response represented a number of producers who were active members of the NTLG.

### IOOA comparison of CWDA and Matrix

	<b>CWDA</b>	<b>Matrix</b>
<b>Predictability and transparency</b>		
<b>-Ease of understanding</b>	Intuitive	Dependent on hypothetical costs of providing pipeline capacity.
<b>-Adjustments needed after methodology applied.</b>	No secondary adjustments- realigning the Entry/Exit split more closely with the assets used produces a better allocation.	Only applies to around 25% of the revenue.
<b>-Subjectivity</b>	Dependent on straightforward network distances and demands. Forecasts of demand form part of the normal commercial evaluation which takes place on investment.	Dependent on parameters which must be derived indirectly and over which there has been considerable debate and no consensus.
<b>-Reliability of transfer in to GNI model</b>	No problem	Unknown
<b>Stability</b>	CWDA is relatively stable across different demand changes.	The 'economic signal' element- the differential between Entry Points- is not stable to adjustments in the number of exit points, while being indifferent to changes in entry demand.

<p><b>Equity</b></p>	<p>Presents greater equity between producers and consumer as described in Appendix 4.</p>	<p>Has been managed to minimize entry differentials- halving the expected incentive to indigenous production over imports on which investments have been made and assets traded.</p>
<p><b>Promotion of effective competition</b></p>	<p>Provides clarity and security for ongoing investment in new sources of supply.</p>	<p>Biased process demonstrates the scope for regulatory interference.</p>

## A.2 CER response

In the Draft Decision Paper, the CER assessed the three modelled options against the criteria of “*stability*”, “*predictability*” and “*equity and promote effective competition*”. In the CER’s view, although both the CWDA methodology and the Matrix methodology produced relatively stable tariffs, the advantage of the Matrix methodology was that the differentials vis-à-vis Moffat remained the same across scenarios, scoring well under both stability and promote effective competition criteria (stable differentials should give a better investment signal).

In addition although there are more inputs into the Matrix methodology, this does not mean that they are necessarily unstable or subjective, rather they require in-depth analysis. The CER considers that such in-depth analysis was carried out during the consultation process through the NTLG meetings and the public workshops.

Furthermore, it should be noted that GNI has independently produced their own model for the CWDA, VPA and Matrix methodologies. As part of the response to the Draft Decision paper GNI included indicative tariffs which indicate that comparing the CER model with the GNI model “*the majority of the results are within 5% of each other*”. Therefore, whilst there will be a transition to the GNI model, GNI as TSO has acted consistently to independently verify CER inputs and assumptions to ensure the transition to the GNI model is reliable.

In terms of the “*equity and promote effective competition criterion*”, the CER reiterates that the Matrix methodology scores higher on both these issues as the cost concept is based on sending a forward based signal, i.e. costs associated with gas transportation (i.e. an efficient combination of pipelines, compressors, opex and fuel costs), whereas the CWDA is a revenue (historic) based signal that includes items that are not necessarily associated with incremental entry capacity (e.g. the actual mix of pipelines and compressors, IT infrastructure costs). The CER considers that the Matrix methodology sends the appropriate, cost-reflective signal to the market, and is based on carefully chosen inputs. In addition, the CER considers that the equity effect between producers and consumers is balanced and stable in the Matrix methodology as measured by the Diversity Premium<sup>15</sup> which remains static regardless of changes to Entry/Exit splits. The Diversity Premium under the CWDA on the other hand is not stable where the Entry/Exit split is altered. This affirms that the signal being sent by CWDA is revenue based whereas the signal being sent by the Matrix methodology is cost based which is stable regardless of the Entry/Exit split chosen.

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<sup>15</sup> The Diversity Premium is the differential (in MWh) between an Entry Point tariff as an outcome of the Entry/Exit tariff methodology and the Moffat Entry Point which is intended to reward efficient entry.

### A.3 The value of the Expansion Constants

In total 8 responses were received regarding the value of the Expansion Constants. An Expansion Constant is a numerical value of the cost of expanding the system to allow one unit (GWh) of gas to flow a certain distance (km).

Three respondents agreed with the CER approach and hence the values of the Expansion Constants (GNI, ESB GWM and SSE). IOOA and its members did not agree with the values on the basis that the calculations should include other inputs.

ESB GWM stated that although they were supportive of the Matrix methodology, it was important that a “framework for ongoing stability” of the methodology was considered by the CER for inputs such as the Expansion Constants.

Another respondent (SSE) who agreed with the CER approach stated that an additional margin should not be built into the calculations i.e. the values were at the appropriate level. In other words, the system is built to ensure capacity is available in extreme conditions, it would not stand to reason to include a future margin to the calculation.

Conversely, those that disagreed with the CER’s approach stated that a flow margin should be built into the calculation, as the CER approach assumed that the pipelines were being utilised at 100% of capacity. IOOA suggested that this was inconsistent with what a TSO should include in system planning. The respondent referred to Great Britain where National Grid Gas (NGG) includes a 5% flow margin in the Expansion Constant applied there.

In addition, this respondent stated that similar to a flow margin, there would normally be redundancy built into the compressor stations on the system e.g. if 4 compressors would supply the peak flow, a fifth compressor would be installed. The respondent considered that if redundancy was built into the compressor element of the Expansion Constant this would increase the required compressor costs, and hence the values of the Expansion Constants.

Other issues raised on the Expansion Constants include the efficiency of pipeline flows, the inlet pressure assumption used for the onshore calculation and the use of technical capacity for the wet pipelines which is much larger than the 1-in-50 demand in Ireland.

## **A. 4 CER response**

### **A.4.1. Future review and transparency of inputs**

This consultation process has been focused on the choice of methodology and developing appropriate and enduring inputs to the Matrix methodology. It should be noted that the Draft Decision stated that the signals sent via the Expansion Constants should be enduring<sup>16</sup> and that the majority of inputs would be fixed. Any future review of inputs to the methodology should only occur where a significant change in material costs or technology would necessitate such a review.

### **A.4.2 Inclusion of a margin in the Expansion Constant**

The CER referred a number of detailed technical questions to GNI for their input and the responses below have been informed by GNI's assistance in answering these questions.

On the basis of analysis conducted in 1986 the National Grid model includes a flow margin of 5%<sup>17</sup>. A review in 2000 undertaken by National Grid indicated that although the transient components of the margin had increased (due to changes in the gas market in the UK between 1986 and 2000) there was no requirement for a change in the flow margin.

A further review in 2008 indicated that some elements of the flow margin could be reduced, thereby reducing the flow margin figure. Despite this, the flow margin of 5% was not changed. GNI stated that their understanding of the NGG system indicated that the flow margin in GB was actually closer to 2%.

The gas flows on the GNI system are validated in two ways. Firstly, Grid Control metering and telemetry data is constantly being returned to Grid Control which indicates the actual flows on the system. This data is independently verified every two years to ensure its accuracy. This data is used as part of desktop system planning using a software programme called Studio Pipeline. Therefore, whilst the GB methodology does use a margin, it was not considered necessary to include a margin in the Expansion Constants for Ireland as the flow data is highly accurate.

Therefore, it is not considered necessary to include a flow margin in the Expansion Constants.

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<sup>16</sup> Page 36 of the draft decision

<sup>17</sup> The Expansion Constant excel file published alongside the Draft Decision includes the NGG calculation on the Pipeline Flow Equation tab which references 5%.

In addition, the calculation of the Expansion Constants for the wet and dry sections of the system are based on average values across the 4 largest pipelines for dry and the diameters of the two subsea interconnectors for the wet. As such, the signal that is being created by these values is for a technical capacity of the largest pipelines on the network. It does not stand to reason that a supply margin above the technical capacity should be included in the calculation.

#### **A.4.3 Redundancy of compressors**

The calculation of the Expansion Constants is based on two elements. First, the capex required for a given length and diameter of pipeline and secondly the cost of compression. It is compression that provides the motive power to flow the gas. The cost of the compressors that has been included in the calculations matches the gas flow through the pipelines modelled.

Similar to the pipeline capacity above (the flow margin), it is possible for redundancy to be built into the calculation. This could be done by either increasing the compression required to match a flow margin (of say 5%) or by increasing the compression required to incorporate compressor redundancy. The Expansion Constants that the CER is applying already have equipment redundancy implicitly already built into the calculations. This is because the calculations are based on the cost of compressors at Beattock and further on at Brighthouse Bay. At Beattock there are 3 compressors required with 1 additional compressor providing backup (133%) and at Brighthouse Bay there are four compressors with one providing additional compression (125%). As the compressor costs are based on these observed costs which include redundancy there is no requirement to include further redundancy.

#### **A.4.4 Flow Efficiency Factor**

IOOA stated that a flow efficiency factor of 95% should be considered as part of the Expansion Constants. However, in the case of the GNI system the assumptions made using the transmission network model (Pipeline Studio ®) are validated against actual metered data that is sent back to Grid Control. The cross-checking of the modelling against the actual metering on the system indicates that the modelled values used are highly accurate. It is on this basis that a flow efficiency factor has not been included.

In tandem with the flow efficiency factor it was suggested that a pipeline roughness of 1,750 micro inches could be included in the calculations.

The pipeline roughness assumed in the Expansion Constants applied is 15 micron which is equivalent to 600 micro inches. This reflects the roughness factor of pipelines constructed more recently by GNI. The roughness factor of these newer pipelines is lower than older pipeline (40 micron or 1,600 micro inches) because they are lined internally. As it is likely that any future pipelines constructed would be lined, it stands to reason that the lower roughness of 600 micro inches is applied.

#### **A.4.5 Inlet pressure assumptions**

In the Draft Decision, the CER explained the rationale for the choice of the inlet pressure for the dry and wet Expansion Constants. For the dry, an inlet pressure of 86 bara was chosen as this reflects the actual pressures seen on the GNI system. In their response IOOA states that standard I.S.328 allows for an inlet pressure of 98 bara which if used as an input into the dry expansion constant would reduce the dry Expansion Constant values.

The CER understands that I.S.328 does not specify an upper pressure limit. As the inlet pressure assumption of 86 bara is observable on the GNI system the CER is of the view that it stands to reason that it should be applied as an input to the calculation. Similarly the inlet pressure of 131 bara is that which is observed on the wet pipelines<sup>18</sup>.

#### **A.4.6 Pipeline capacity assumptions**

The wet and dry expansion constant were calculated using the weighted average of the 4 largest pipelines for the dry and the weighted average of the two interconnectors for the wet. IOOA suggest that as the technical capacity of the weighted wet expansion constant is in excess of the 1-in-50 peak day demand the use of the larger capacity has a downward effect on the wet expansion constant.

However, whilst the technical combined capacity is indeed 490 GWh/d<sup>19</sup> it is the weighted average of the two subsea pipelines that is used for the calculation of the wet expansion constant. This gives an average technical capacity of 245 GWh/d, which is below the peak day demand forecast for Ireland.

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<sup>18</sup> For example the interconnector between the Netherlands and the UK ( BBL) has a pressure of 135 bara and so could, in theory be used as it does reflect a wet pipeline pressure. Similarly, the offshore section of the Nordstream pipeline is 200 bara. However, neither of these reflects what is observed on the Irish gas system.

<sup>19</sup> The combined technical capacity of 174 GWh + 316 GWh.

#### A.4.7 Merchant test interconnector GB-Ireland

A concern raised by IOOA is the importance of including a merchant test to “*verify whether the economic signals as provided by MEC<sup>20</sup>, according to the Draft Decision, are appropriate. The parameters of such a project are included below which was based on a merchant Interconnector from Chester in the North of England to Dublin*”.

	<b>IOOA project example</b>	<b>CER Matrix parameters</b>
<b>Project period</b>	25 years	50 years for pipelines
<b>Real WACC</b>	7.0% <sup>21</sup>	5.2% <sup>22</sup>
<b>Pipeline diameter</b>	600mm	Average of 750mm & 600mm
<b>Pipeline length</b>	200km	200km
<b>Compression</b>	150% of requirement and 7000 running hours	Compression based on observable data from Beattock and Brighthouse Bay
<b>Pressure levels</b>	43.5 bara in GB to 71 bara in Ireland	43.5 bara in GB to 71 in Ireland
<b>Capex</b>	50/50 spread over two years before the start date of gas flow	Capex not captured before flow date

In summary, the concern raised by IOOA was that the signals created by the current Expansion Constant values do not reflect the tariff that a merchant interconnector would require to transport gas from Great Britain to Ireland.

#### A.4.7 CER response

The Expansion Constants and Annuitisation Factor as applied to the Matrix methodology are used to calculate Entry and Exit tariffs for the GNI system, not for a merchant provider. The remuneration of a merchant interconnector may be based on inputs proposed by IOOA, however this would be a matter for a merchant provider, not a matter that should be captured in the tariffs for entry onto the GNI system.

<sup>20</sup> Matrix Expansion Constants. Where Matrix methodology or MEC are used in this paper the terms are interchangeable.

<sup>21</sup> Which was the WACC consulted on in the Corrib Linkline Consultation Paper

<sup>22</sup> The WACC applicable to GNI. See CER/14/140

## **A.5 Negative Expansion Constant**

Four responses were received on this issue with three in agreement (BGE, ESB GWM and GNI) that the application of the negative expansion constant did not facilitate tariff stability. One respondent (BGE) stated that the application could require greater ex-ante forecasting to be carried out, which in itself could result in more uncertainty and tariff volatility. Another respondent (ESB GWM) stated that the ring main nature of the Irish system does not appear to justify the application of NEC, especially in comparison with the CERs example of Italy where the NEC is applied.

One respondent (Vermilion) raised the matter in the context of its view that CWDA was preferred over the Matrix, stating that the Negative Expansion Constant was “*another issue which builds uncertainty into the MEC methodology*”.

## **A.6 CER Response**

The CER is of the view that rather than being an issue which builds uncertainty into the Matrix methodology, this input (and any resulting uncertainty) can be removed from the Matrix methodology, if the application results in increased instability.

## A.6 Calculation of the Annuitisation Factor

In the Draft Decision, the CER outlined the components that make up the Annuitisation Factor and requested feedback on the calculation. As a reminder, the calculation was as follows:

**WACC\*Pipeline Capex Pipeline Opex+ WACC\*Compressor Capex Compressor Opex +Fuel Costs +Depreciation**

Each of these components is explained in more detail in CER/15/057 (page 38-41).

### A.6.1 Responses Received

The Annuitisation Factor was an issue that generated a large number of responses and was also the subject of significant discussion at the NTLG. A brief summary of the responses received are below.

Aughinish Alumina noted that the fuel cost is historic rather than the forward curve, and that it was not clear whether or not EU-ETS costs had been included.

IOOA noted that the Annuitisation Factor was broadly in line with that used in Great Britain. However this respondent noted that a number of the constituent parts of the National Grid Gas (NGG) Annuitisation Factor “*as far as they understand*” were different to the Annuitisation Factor used in the Draft Decision. IOOA noted that the proposed Annuitisation Factor had been based on the “wet Pipeline” calculations underpinning the Expansion Constant calculations, whereas if an Annuitisation Factor had been calculated using the “Dry Pipeline” this would yield a result of 17%.

They further noted that if the wet pipeline was used with a 50km length the Annuitisation Factor calculated would be 21.7%. This respondent also suggested that differing Annuitisation Factors could be calculated for Pipelines and Compressors.

One respondent (EAI) suggested that the inclusion of variable operating costs (OPEX) ran the risk of double counting of costs that would be captured elsewhere in the methodology.

SSE stated that compressor fuel costs should not be included in the calculation notwithstanding that the Draft Decision stated that there would be no double counting of this cost. This respondent stated that there was no justification given in the paper as

to why an imperfect approximation of (pass through) operating costs should be captured by new entrants and charged through to customers in a “diversity premium”.

GNI considered that the overall approach to the calculation in the Draft Decision was appropriate to calculate an annual cost related to the mix of Capex and Opex involved in (notionally) expanding the network. However this respondent noted that as the cost of shrinkage gas is recovered outside of the transmission tariff that fuel costs should be removed.

Finally, one respondent (ESB GWM) stated simply that they broadly agreed with the approach used in calculating the Annuity Factor.

### **A.6.2 Discussion at the NTLG**

Discussion at the NTLG centred on whether to include or exclude Opex costs and Fuel costs and also on the calculation of the Annuity Factor using some mix of pipelines and compressors or wet and dry pipelines.

### **A.6.3 The appropriateness of including Opex and Fuel costs**

- **Opex Costs**

There was some discussion of this matter at the NTLG, however there was broad agreement that at least some fixed Opex costs were inevitable once the capital assets is built. As such, there was general agreement that at least fixed operating costs should be included. There was also some discussion as to the difficulty in splitting out all the fixed costs from the variable operating costs. However, it was noted that fuel costs was easily identifiable as a variable cost.

- **The inclusion of fuel costs in the signal**

While there was broad agreement as to fixed costs being included in the Annuity Factor, there was no such broad agreement on the issue of the inclusion or otherwise of fuel costs in the calculation.

The discussion opened with the question of what signal it was that the regime was seeking to send regarding entry capacity; was the signal for the provision (but not use of) entry capacity or was the signal for the transportation of gas to the IBP. The former would exclude variable operating costs such as fuel, whereas the latter would include variable operating costs including fuel costs. As a prelude to answering this question a number of other issues were discussed.

All parties at the NTLG agreed that expected fuel costs are an important factor in deciding on incremental capacity investment. In making an investment decision CAPEX, OPEX and FUEL costs will be included in the decision. The example was given of a choice between a smaller pipeline (requiring more compression to achieve a set throughput) or a larger pipeline (requiring less compression to achieve a set

throughput). An investment decision would need to factor in the additional fuel costs that would be required in the case of the smaller pipeline with more compression.

For some parties the obvious logical conclusion was that fuel costs should be used in the Annuitisation Factor which is used to set the transmission tariffs. They argued that to leave out the expected fuel costs would distort the forward looking investment signal. A similar concern is that by leaving fuel costs out of the calculation one of the key distance related cost drivers would be attenuated<sup>23</sup>. The concern was that by removing the compressor fuel costs the true cost of moving the gas a given distance would not be fully reflected in the tariffs.

On the other hand, some parties argued that while expected fuel costs were an important part of the efficient investment decision (what mix of pipe and compressor to build), the efficient operation decision was a different matter. As fuel costs are a variable cost, the argument was that it should not be part of the entry signal. Rather fuel costs should be in the efficient operation decision on the day when the decision is made on whether or not to run.

As noted by GNI in their response, compressor fuel costs are collected through the Shrinkage charge, these costs are NOT collected through the Transmission tariffs. Therefore, for some parties the obvious logical conclusion was that fuel costs should not be used or included in the setting of transmission tariffs. On the other hand some parties argued that it was not relevant where the fuel costs were recovered, as fuel costs are a transportation cost and that if the regime is seeking to reflect the cost of moving gas to the IBP (at least an approximation of) this cost should be included in the fixed differential between entry points.

#### **A.6.4 Would fuel costs be better captured at the IBP?**

Another matter discussed was whether it was appropriate to include an “imperfect” approximation of fuel costs in the regime where recovering compressor costs as a full “pass through” in IBP sales would be much more accurate. Further consideration of this matter is contained below.

Consider a producer on the west coast with its own compression facilities. This producer consumes gas in its own compressors in order to get its gas to the market. The cost of this compressor fuel is borne by the producer; it is not added to the shrinkage bill.

An alternative supply is via Moffat. If Moffat supplies gas to IBP, the cost of compressor fuel in Moffat is added to the shrinkage bill. The shrinkage bill is levied on a per unit basis at all entry points (including at the entry point used by the western producer).

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<sup>23</sup> In simple terms compressors add the motive power to the molecules of gas; this motive power is reduced by friction in the pipeline. The longer the pipeline the more friction, the more motive power is needed to keep the gas moving along.

The producer can, in theory, attempt to pass on this fuel cost in the sales price of its molecules. In a market like Ireland, with a clear marginal entry point, which is linked to NBP prices, it is reasonable to expect that the producer would not normally succeed in passing on the compressor fuel cost.

In simple terms the system of tariffs and shrinkage would cover the cost of some molecules being moved to the IBP (from Moffat) but would not necessarily facilitate the covering of all such costs from other entry points. Therefore, if there is no recovery via IBP it would stand to reason that recovery in a network charge is the appropriate mechanism.

### **A.6.5 The calculation of different Annuitisation Factors for Wet and Dry**

One respondent suggested that two different Annuitisation Factors could apply; one for wet and one for dry. However, in the CER's view the annuity applied already includes a mixture of both as it is based on the mixture of pipelines and compressors in Scotland which are both wet and dry.

Regarding using the Wet Annuitisation Factor, once the decision is made to include fuel costs then some data for fuel consumption must be decided upon. As the fuel costs at Brighthouse Bay are observable and considering that the Moffat Entry Point has, to date, provided c. 95% of gas requirements for Ireland ( and hence 95% of the compression), the CER considered it appropriate to use the Wet Expansion Constant to determine the Annuitisation Factor for the GNI system.

As a cross check the NGG Annuitisation Factor is broadly in line with that calculated by CER.

### **A.6.6 CER Conclusion**

Considering all the arguments made, the CER considers that fuel costs should be included in the Annuitisation Factor, and that the data from wet expansion constant should be used as the input to the annuity. Fuel costs are a key cost in the investment decisions in the provision of entry capacity. Fuel costs are a key element of the cost of moving gas to IBP; as such it is a key component of the "distance" cost driver. If fuel costs were entirely removed from the calculation then this would remove a cost that is clearly associated with entry from the entry tariff differentials, which would need to be remunerated in some other manner.

Therefore, after considering the feedback received and the discussions at the NTLG, the CER considers that the calculations as outlined in the Draft Decision ensure that the Annuitisation Factor captures the appropriate ranges of costs that are associated with entry. This is reflected in Decision 4 (Section 4.1.4).

## **A.7.Capacity/Commodity split**

### **A.7.1 Responses received**

Of those that responded (10) the majority (8) were in favour of maintaining the current capacity/commodity split with two respondents suggesting a move to 100% capacity. There were various reasons given for maintaining the current 90:10 split, which included:

- From a generator perspective, a movement to 100% capacity would restrict a Short-Run Marginal Cost (SRMC) that can currently be bid into SEM.
- Suppliers indicated that the Commodity charge had an element of risk sharing, whereas a move to 100% capacity would place the entire burden on suppliers as it would entail no risk at all placed on volumes actually used by customers.
- A move to 100% capacity would disproportionately impact low volume customers, which can currently offset some of their costs via a Commodity element.
- It was acknowledged that whilst the final Network Code may require 100% Capacity in time, in light of changes as a result of CAM and I-SEM it would be beneficial to retain the 90:10 split for the time being.
- It was also suggested that the Draft Network Code may not be as prescriptive on this element and that any changes should be considered in light of the final Network Code.

Of those that were in favour of moving to 100% capacity, it was stated that as the final Network Code would require the move to capacity only charging in time there was no reason to delay it. Another respondent stated that a 100% Capacity would reward those customers with a low load factor and predictable demand.

### **A.7.2 CER response**

At this time, the CER considers that it is appropriate to retain the current 90:10 split and to review this requirement in line with the finalisation of the Network Code. It is now expected that the Network Code will not be binding until 2019.

In the CER's view there are a number of benefits to retaining the current split.

1. It maintains the status quo on this issue at a time when there are significant changes occurring in both the gas and electricity markets. Of significance is the fact that Commodity can currently be bid into SEM and the removal of this element would have a detrimental effect on the recovery of costs for gas-fired generators. It is prudent to maintain the status quo pending the I-SEM changes that will effect c. 60% (by volume) of gas network users i.e. power plants.
2. The impact of the move to 100% Capacity would have a larger effect on those with a Load Factor of 1.50 or above. This includes mid-merit and peaker plants as well as

Residential customers. Conversely a move to 100% Capacity would benefit base load plants. In the CER's view, on balance, it is preferable to retain the current Capacity/Commodity split as this avoids such distributive effects.

3. The Network Code is not yet binding, and as such there may be certain services provided by the TSO that would more accurately be captured by a Commodity "flow based charge", as envisaged by the Draft Code. The CER has not examined what services could be more appropriately captured by a Commodity charge as part of this tariff reform. As such, it is preferable to maintain the status quo for now pending further detailed analysis by GNI and CER on this matter.

## **A.8 Entry/Exit split**

The Entry/Exit split received the most responses from stakeholders (11) with three splits being suggested. In addition, one respondent stated that the decision on the outcome should be an outcome of an Impact Assessment.

### **20:80**

One respondent stated that an Entry/Exit split of 20:80 would recognise uncertainty around shipper optimisation and would recognise the benefits that the Isle of Man brings in terms of bookings.

### **50:50**

This split was favoured by all suppliers, the TSO and all powergen respondents on the basis that the CER had already come a decision on this matter in 2012, that it would increase flexibility for shippers and that there would be benefits for NDM customers from a move to a 50:50 split. This was because it would lower the peak day booking requirements for the NDM sector from the current c. 67% Exit split.

### **36:64**

This split was initially proposed as part of the NTLG process as an alternative split for the CWDA. Those respondents in favour of a RAB split indicated that replacing the 50:50 split with something more aligned to the actual assets on the system would address the issue of what were described as redundant assets being included in the signal. In addition, some respondents stated that a split based on RAB value would facilitate the booking of backup capacity between Entry Points for insurance purposes. It was also stated that maintaining a more cost-reflective split would alleviate discrimination concerns faced by the Isle of Man.

### A.8.1 CER response

In the 2012 Decision Paper (CER/12/087) along with the move to a single system the CER indicated that a move to 50:50 remuneration for Entry and Exit would also be considered in the new regime but that this was not a settled matter and would be discussed at the NTLG. The 2012 Decision Paper, along with the Network Code guidance, provided the rationale for the proposal to base the reform on an Entry/Exit split of 50:50 as outlined in the Draft Decision Paper.

As with the Capacity/Commodity split, CER sees merit in maintaining the status quo. To do so reduces the potential for distributive effects between network users and it reduces the likelihood of having unintended consequences. However, unlike the Capacity/Commodity split, it is not immediately clear what split best represents the status quo.

The CER has identified three splits that broadly represent the status quo.

Entry	Exit	Split based on
38	62	Net book value of Entry assets and Exit assets at end of current Price Control
34	66	NPV of Required Revenues in current Price Control
33	67	Required Revenues in Current Price Control

Below summarises the redistribution effects that would arise under the 50:50 and 33:67 Entry/Exit split.

Split	Rationale	Who benefits versus today?	Distributive effects?
<b>50:50</b>	Reflects the principles decided in 2012.  Reflects the suggested split included in the Draft Network Code.	NDM  Powergen	Baseload plants  Isle of Man.
<b>33:67</b>	Broadly reflects the revenue split that is in the current tariffs	Status quo maintained for network users.	Status quo maintained for network users.

### A.8.2 Decision

Having considered the impacts between a 50:50 split and a 33:67 split, the CER is of the view that a 33:67 split is appropriate because it minimises the redistributive effects across network users. In addition, an Entry/Exit split based on revenue would seem logical given that the subject matter at hand is tariffs.

It is important to note that although the CER has chosen a 33:67 split to apply from October 2015, broadly based on Price Control revenues, it is the objective of CER that in the interests of stability, this one third/two thirds split is retained, at least until such time as a review may be needed in line with the entry into force of the final Network Code on Tariffs.

## A.9 Impact of Entry/Exit split on the Isle of Man

### A.9.1 Responses received

Of those that responded to this question (8), a number stated that a discount for the Isle of Man would affect customers in Ireland, and that therefore no specific treatment should be given. On the other hand, several respondents recognised that the tariff<sup>24</sup> paid by the Isle of Man should be addressed through alternative mechanisms. This included a suggestion for a “user commitment” mechanism. A somewhat similar suggestion was made by Manx Utilities who referenced the provisions of the Draft Network Code on “*Dedicated Services*” which could take the form of a point-to-point tariff for capacity between Moffat and the Isle of Man.

Finally, one respondent stated that the Entry tariff reform process was not the correct forum in which to decide any specific treatment for the Isle of Man, and that this was better suited to intergovernmental relations.

### A.9.2 A Dedicated Service mechanism

The Draft Network Code on Tariffs indicates that for certain categories of users, a *dedicated service* may be used. Although, the exact provisions of the Network Code regarding Dedicated Services are still being finalised, the use of this provision is intended to be limited to certain network users, specific entry or exit points or for specific infrastructure<sup>25</sup>.

Where a dedicated service (or a user commitment mechanism) was used then it would apply outside the parameters of the cost allocation methodology. If applied to the Isle of Man, network users on the island would no longer pay the standard Moffat Entry tariff, but rather would pay a specific tariff to recover a revenue stream associated with the service.

Applying a dedicated service for the provision of capacity for the Isle of Man would result in different treatment of users at the Moffat Entry Point.

**As outlined in Section 4, as the CER has decided to apply an Entry/Exit split that is broadly in line with the split currently prevailing there is no requirement to direct GNI on this matter.**

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<sup>24</sup> Based on the Matrix methodology using a 50:50 Entry/Exit split.

<sup>25</sup> As per the Draft Network Code submitted by ENTSOG on 26<sup>th</sup> December 2014 for ACER’s Reasoned Opinion.

## **A.10 Treatment of Storage**

### **A.10.1. Responses received**

Of those that responded there were mixed views on whether Storage should receive a discount. Three respondents were in favour of Storage receiving a discount, whereas five respondents were not in favour of storage receiving a discount.

Of those **in favour** of storage receiving a discount the rationale included;

1. The benefits that storage brings in terms of Security of Supply
2. That a discount for Storage in Ireland would allow storage in Ireland compete with storage facilities in Great Britain; and
3. That a discount for Storage may be appropriate but that Storage should pay an estimate of the incremental costs it causes.

Of those that **did not agree** with a proposed discount for Storage the reasons included;

1. That the Storage facility in Kinsale was not strategic and therefore the facility is operated on a fully commercial basis.
2. As a result of its status as commercial storage the argument that the facility provided Security of Supply benefits was weakened. Some respondents stated that back up fuel obligations, peaker plants and linepack all provide security of supply.
3. The 100% discount being proposed was not in line with any other North-West European country.
4. That the pricing strategy for a storage operator is based on the pricing of the next alternative product. In the case of Ireland this would be the Moffat Entry Point. Therefore, where a discount is given, the alternative has become more expensive, and therefore a discount for Storage would constitute an intervention in the flexibility market.
5. Some respondents stated that the benefits of storage accrue to one market participant which was confirmed by CER waiving the 75% capacity limit that may be held by one market participant.
6. A decision to extend discounts would have an impact on cross-border trade and that this had not been considered in the Draft Decision Paper.

### **A.10.2 CER response on Security of Supply benefits**

In the Draft Decision Paper, the CER stated that the Inch Entry Point has proved valuable in ensuring that Ireland has been able to meet winter peak demand. Whilst the CER considers that other sources also contribute to Security of Supply (linepack, secondary fuels etc., there is a benefit to retaining storage facilities on the island. Security of Supply is enhanced when there is diversity of supply, which includes multiple Entry Points.

One respondent stated that the security of supply argument was weakened, as the facility was entirely commercial. However, whilst the facility is operated on an entirely commercial basis, it is required to cooperate with the National Gas Emergency

Manager (NGEM) in the event of a supply issue. As such, it can be called upon in the event of an emergency as necessary. In addition, the presence of Storage brings regional benefits in avoiding other investment in the Southern region. This in itself is a benefit to all gas users, in the form of avoided investments.

On the issue of Secondary Fuel obligations the CER will be issuing a Consultation Paper on the matter shortly.

### **A.10.3 Effect of Entry/Exit split on Storage discount impact**

In the Draft Decision Paper, the CER modelled a discount of 100% for Storage gas re-entering the GNI system based on a 50:50 Entry/Exit split. As, the CER has now decided to apply a 33:67 Entry/Exit split, this has a downward effect on the revenues that require redistribution amongst all Entry Points<sup>26</sup>. In addition, the 90:10 Capacity/Commodity split removes a portion of revenues that would otherwise need to be recovered from all Entry Points if Storage receives a discount.

The discount modelled would be in addition to the Exit discount for Storage already in place<sup>27</sup>. As a reminder, the tariffs indicated in the Draft Decision Paper were based on a 50:50 Entry/Exit split, 100% Capacity and €200m revenues.

This amounted to a redistribution of €15.9m between Entry Points.

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<sup>26</sup> This was also based on revenues of €200m and 100% Capacity.

<sup>27</sup> No respondents commented directly on the removal of this.

<b>Assumptions: €200m revenues, 100% Capacity, 50:50 Entry/Exit, 100% discount</b>						
	14/15	14/15	15/16	15/16		
€/MWh	Current tariffs	No discounts	Tariffs with current policy of Exit discount	Tariffs with Entry and Exit discount	Tariff difference on all other Entry Points with Storage discount applied	
<b>Exit</b>	443	334	352	352	+€18	
<b>Moffat</b>	359	639	639	742	+€103	
<b>Inch</b>	54	502	502	605	+€103	
<b>Corrib</b>		485	485	588	+€103	

Table A.1 Storage discount impact (50:50)

Below illustrates the updated tariff impacts based on 33:67 Entry/Exit split, 90:10 Capacity/Commodity and €190m revenues. This would amount to a redistribution of €8.5m between Entry Points<sup>28</sup>.

<sup>28</sup> €54.80\*154,808 MWh. In the Draft Decision Paper the redistributed revenues were indicated as €3.3m which was incorrect. Rather, the redistributed revenues should have been €15.9m (€103\*154,808 MWh).

Assumptions: €190m revenues, 90:10 Cap/Com, 33:67 Entry/Exit split, 100% discount					
	14/15	14/15	15/16	15/16	
€/MWh	Current tariffs	No discounts	Tariffs with current policy of Exit discount	Tariffs with Entry and Exit discount	Tariff difference on all other Entry Points with Storage discount applied
Exit	€443	€334	€403	€403	+€41 <sup>29</sup>
Moffat	€359	€639	€405	€460	+€55
Inch	€54	€502	€268	€323	+€55
Corrib		€485	€252	€307	+€55

Table 4.2 Storage discount impacts (33:67)

Therefore, the decision by CER to maintain an Entry/Exit split that is broadly in line with the status quo observable today has a downward effect on the amount of revenue to be redistributed amongst other Entry Points.

#### A.10.4 Economic rationale for treatment of storage

As part of the responses on the treatment of Storage, one respondent (GNI) indicated that in their view a 100% discount for Storage could result in Storage receiving a cross-subsidy from other network users. Rather, the respondent stated that “*the use of storage can result in incremental costs to the network and storage sites should at least face these charges*”. As GNI stated, the question is whether the storage facility should share with other network user’s costs that are in excess of the incremental costs. The Matrix methodology that is being applied calculates the incremental costs of each Entry Point in the pre-adjusted tariffs. This is also what arises under the National Grid Gas methodology where Storage points pay the LRMC (i.e. primary) capacity charge calculated under the Distance to Virtual Point methodology applied in Great Britain.

Furthermore, where the efficiently incurred costs are charged to all network users *usually* will not change the usage behaviour relative to the rest of the market as a whole. However, a higher charge for storage may reduce storage utilisation. The

<sup>29</sup> Versus a reversal of the current Exit policy.

storage site would have inefficiently low utilisation. This in turn would result in customers paying for more expensive gas supplies at peak i.e. winter<sup>30</sup>.

CER has also considered what the impacts would be on the Storage facility vis-à-vis the status quo in place today. A regime where Storage paid a zero tariff would have two effects on Kinsale versus the status quo. It would reduce the costs associated with Kinsale storage entry from €54 (14/15 tariffs) per peak day MWh to zero. At the same time this reduction would increase the Moffat tariff<sup>31</sup>. Therefore, the value of what could be captured by Storage would be somewhere between zero and the Moffat tariff (€460) rather than somewhere between the current tariff of €54 and €359<sup>32</sup>.

Having considered a full discount and the rationale for a partial discount, the CER sees merit in the economic rationale underpinning applying the incremental cost of capacity from the storage point.

Firstly, this approach would be consistent with the *de jure* treatment of Storage facilities in Great Britain where charges for storage reflects the LRMC at each Storage Entry Point. Considering the regional nature of Storage as a flexibility service this convergence of the charging principles for Storage is considered compatible with the principles regarding cross-border trade as set out in the Third Energy Package<sup>33</sup>.

The approach to applying incremental costs is considered in tandem with the Entry/Exit split. The effect of the proposed Entry/Exit split of 33:67 and with Storage paying the incremental cost of Entry would reduce the revenues to be redistributed amongst all Entry Points.

Where the Storage tariff applied the primary Inch Entry tariff cost, then this would assume c. €67<sup>34</sup> would be paid for gas from the Kinsale Storage facility and the remaining production gas would pay the rescaled Entry tariff. The application of the primary tariff to Storage would reduce the impact on other Entry Points to c. €42 per MWh (down from €55 per MWh under a 33:67 Entry/Exit split). This would therefore require a redistribution of c. €6.5m across other Entry Points.

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<sup>30</sup> As Storage is filled in summer when gas prices are generally lower.

<sup>31</sup> The difference between Inch & Corrib is not captured today so there is no status quo applicable here.

<sup>32</sup> Assuming that a percentage of this is captured by the SSO & by the storage customer.

<sup>33</sup> Regulation 715/2009 EC, Article 13 (2).

<sup>34</sup> CER model. Matrix S2, Cell D134.

**Assumptions: €190m revenues, 90:10 Cap/Com, 33:67 Entry/Exit split, Primary Inch Entry Point tariff applied to Storage gas**

	14/15	14/15	15/16	15/16	
€/MWh	Current tariffs	No discounts	Tariffs with current policy of Exit discount	Tariffs with Entry Primary applied and Exit discount	Tariff difference on all other Entry Points with Storage discount applied
<b>Exit</b>	€443	€334	€403	€403	+€41 <sup>35</sup>
<b>Moffat</b>	€359	€639	€405	€447	+€42
<b>Inch</b>	€54	€502	€268	€310	+€42
<b>Corrib</b>		€485	€252	€294	+€42

Table 4.3. Storage discount Impacts adjusted

As outlined in Section 4 of this Decision Paper the CER has decided that in addition to no change to the policy for Storage Exit for Inch, the Inch Entry Point will pay the primary tariff for gas re-entering the GNI system from the Kinsale Storage facility.

<sup>35</sup> Versus a reversal of the current Exit policy.

## Appendix B: Other issues raised by stakeholders to the Draft Decision

. In addition to the 9 specific areas where feedback was requested in the Draft Decision, a number of respondents raised other issues as part of their response. The main issues raised are dealt with below, which includes

- The role of indigenous production as a cause for reform;
- The “do nothing” scenario is flawed;
- A request to continue with the current methodology for another year; and,
- One respondent queried whether interaction with Ofgem was required.

### B.1 The role of indigenous production as a cause for reform

An issue raised by one respondent was that, in their view, the CER was attempting to associate the need for reform with the start of flows from Corrib. In the respondents view “*there seems to be an implicit suggestion that new gas sources are the cause of problems that can more correctly be traced back to historic policy decisions*”<sup>36</sup>.

In the CER’s view, although the imminent arrival of Corrib flows certainly brings the issue of tariff reform to the forefront, the fact is that the existing methodology is not fit for purpose due to the effect of a change in supply sources, whether from Corrib or any other potential entry point. In simple terms it is the tariffing regime that is the issue as it is inflexible to change in supply.

### B.2 The “do nothing” scenario is flawed

As part of their response, IOOA stated that the reprofiling of GNI revenues in years 2 and 3 of the Price Control would have led to higher tariffs in the later years of the Price Control. Therefore, in IOOAs view, the do nothing scenario is from an artificially low basis.

The CER acknowledges that revenues were reprofiled for the Interconnectors which resulted in a back-loading of revenues to the latter years of the Price Control. However, the question of tariff reform has been indicated by CER as far back as 2011<sup>37</sup>. As such, there was recognition that although revenues would be set for the 5 year period, it was expected that the methodology that would recoup these revenues would be reformed by October 2014<sup>38</sup>. Therefore, even if the revenues had not been reprofiled the CER would still reform the methodology as it is not flexible to change, regardless of how large or indeed small the tariff impacts would be.

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<sup>36</sup> IOOA response, Appendix 1, page 1.

<sup>37</sup> Consultation Paper on *The Regulatory Treatment of the BGÉ Interconnectors in relation to Security of Gas Supply (CER/11/002)*.

<sup>38</sup> This was indicated in CER/12/087 but was delayed due to a legal challenge against that particular decision.

### **B.3 Continue with the current methodology for another year**

As part of the proposals at the NTLG, it was suggested that CER consider implementing the tariff reform in October 2016, rather than 2015. This was suggested on the basis that the Network Code could be subject to change and so a delay could allow time to determine the content of the final Network Code. In addition, changes to I-SEM were mooted as a reason to delay implementation until such time as the bidding arrangements were finalised. These points have been considered by CER in tandem with the likely tariffs that would arise if the methodology continued for another year.

The Impact Assessment included includes an analysis of the tariffs that would arise under the “do nothing” scenario, using the same inputs as the CWDA and the Matrix methodologies. These indicate that without reform, the Moffat Entry Tariff would rise from the currently prevailing €359 per peak day MWh to €925<sup>39</sup>. Although there may be some merit in awaiting a more finalised Network Code or indeed awaiting the outcomes of the I-SEM reforms, the CER maintains the view that for regulatory certainty it is prudent, and indeed necessary, to give effect to these reforms now rather than await outcomes of other work-streams.

In addition, as already outlined in this Decision Paper the CER has sought to maintain the status quo on a number of issues so as to mitigate distributional effects amongst network users. On these matters, the CER will consider the finalised Network Code before implementing any further changes that may be necessary.

### **B.4 Ofgem Interconnector Licence**

As part of the GNI system is in Scotland, GNI (UK) is subject to an Interconnector licence issued by Ofgem, as the NRA for Great Britain. Part of the standard licence conditions of an Interconnector licence issued by Ofgem requires approval of the charging methodology for access to an Interconnector. One respondent queried the status of this licence condition.

The relevant requirements for approval of the charging methodology are included in Condition 10 of the Interconnector licence issued to GNI (UK)<sup>40</sup>. However, in the case of IC1 and IC2 these particular conditions are not active. As such, the CER does not consider that there is a requirement for Ofgem approval of the tariff reforms outlined in this Decision Paper.

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<sup>39</sup> Based on the same forecast bookings at Entry & Exit that have been used as part of the consultation process.

<sup>40</sup> [https://epr.ofgem.gov.uk/Content/Documents/Gas\\_Interconnector\\_SLCs\\_Consolidated%20-%20Current%20Version.pdf](https://epr.ofgem.gov.uk/Content/Documents/Gas_Interconnector_SLCs_Consolidated%20-%20Current%20Version.pdf)

## Appendix C: Commodity calculation and Load Factors for Impact Assessment

This Appendix sets out the calculation of Commodity charges that currently arises and the calculation that will arise from 1<sup>st</sup> October 2015. In addition, this Appendix sets out the Load Factors for various network users that have been used in the Impact Assessment.

### C.1 Calculation of Commodity under current regime

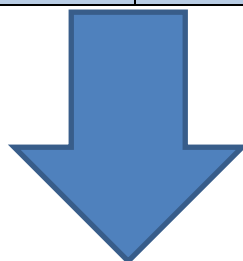
Under the current methodology, Commodity charges are calculated separately for each Entry Point (Moffat and Inch) and Exit based on 10% of the revenues associated with an Entry or Exit divided by the Commodity forecast at that Entry or Exit.

As an example, in 2014/15 the total revenues collected from the Inch Entry Point was €1.9m. Therefore, the Commodity charge was €190,000 of revenues divided by the Commodity that was forecast at Inch for 2014/15.

From 1<sup>st</sup> October, the calculation of Commodity forecasts will arise as normal at each Entry Point and the sum of the Commodity forecasts at all Entry Points will be used to generate a single Commodity charge levied at all Entry Points( i.e. one Commodity charge regardless of Entry Point).

This will be based on 10% of the total Entry revenue ( 33%) being remunerated via a single Commodity charge levied at all Entry Points and a single Commodity charge levied at Exit based on 10% of the total Exit revenue ( 67%). This is illustrated below using €200m as the illustrative revenues.

<b>Total Revenues</b>	€200m
<b>Total Entry Revenues</b>	€66m (€200m*33%)
<b>Total Exit Revenues</b>	€134m (€200m*67%)
<b>Entry Commodity Revenues</b>	€6.6m (€66m*10%)
<b>Exit Commodity Revenues</b>	€13.4m (€134m*10%)



<b>Entry 1 Commodity Forecast</b>	10 GWh
<b>Entry 2 Commodity Forecast</b>	10 GWh

<b>Entry 3 Commodity Forecast</b>	30 GWh
<b>Commodity Forecast at all Entry Points</b>	50GWh
<b>Commodity charge</b>	€0.132 (€6.6m/50GWh)
<b>Exit Commodity Forecast</b>	50 GWh
<b>Commodity Charge at Exit</b>	€0.268 (€13.4m/50GWh)

## C.2 Load Factors

The table below illustrates the Load Factors of different categories of customers which in turn influence the peak day booking requirements of that customer. For example, a hotel with a Load Factor of 1.75 would book a peak day capacity of 1.75 for Exit and would book a peak day entry capacity at a ratio of 55% to the 1.75 peak day booking requirement. A baseload industrial user on the other hand would be expected to book an Entry/Exit ratio of 1:1, as the capacity booked is closer to the network users flat use profile.

The Entry/Exit ratio for 14/15 is based on the annualised Entry and Exit bookings forecast when the annual Transmission Tariffs were set in August 2014. These were 267.8 GWh for Exit and 201.8 GWh for Entry. This results in an Entry to Exit ratio of 0.75.

For 15/16, the ratio forecast as part of the consultation process leading up to this Decision Paper were 283.9 GWh for Exit and 186.4 GWh for Entry. This results in an Entry to Exit ratio of 0.66<sup>41</sup>.

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<sup>41</sup> Where Storage received a 100% discount then no forecast bookings would be included for Storage. This would reduce the Entry/Exit ratio to 0.55. As Storage will pay the primary tariff 31 GWh of Entry capacity are assumed to arise at the storage facility.

The Load Factor and booking ratios are used as inputs into the calculation of the impacts on network users as outlined in the Impact Assessment in section 5.

Network User	Load factor	Entry to Exit ratio 14/15	Entry to Exit ratio 15/16
Base Load Industrial	1	1	1
Base Load Power	1.3	0.75	0.66
Hospital	1.5	0.75	0.66
Hotel	1.75	0.75	0.66
Food	2	0.75	0.66
Mid-merit	2.3	0.75	0.66
Resi + Peaker	3	0.75	0.66

An example of the network tariffs effect using a **Hotel** (Load Factor 1.75) is below.

$$\begin{aligned}
 & \mathbf{1.75 * Exit Capacity} \\
 & \quad + \\
 & \mathbf{+365 * Exit Commodity} \\
 & \quad + \\
 & \mathbf{1.75 * 0.66 * Entry Capacity} \\
 & \quad + \\
 & \mathbf{365 * Entry Commodity}
 \end{aligned}$$