An Coimisiún um Rialáil Fóntas

Commission for Regulation of Utilities

National Preventive Action Plan

Gas

2018 – 2022

Ireland

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

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Glossary of Terms and Abbreviations

Abbreviation or Term	Definition or Meaning
CRU	Commission for Regulation of Utilities
DCCAE	Department of Communications, Climate Action and Environment
BEIS	Department of Business Energy and Industrial Strategy
DfE	Department for the Economy
DCS	Distribution Control System
EU	European Union
ENTSOG	European Network of Transmission System Operators for Gas
GB	Great Britain
GCG	Gas Co-ordination Group
GEEP	Gas Electricity Emergency Planning
GNI	Gas Networks Ireland
IC	Interconnector
JPAP	Joint Preventive Action Plan
LNG	Liquefied Natural Gas
NBP	National Balancing Point
NDP	Network Development Plan
NGEM	National Gas Emergency Manger
NGEP	Natural Gas Emergency Plan
NI	Northern Ireland
NGU	Natural Gas Undertaking
NRA	National Regulatory Authority
NTS	National Transmission System
PAP	Preventive Action Plan
PCI	Project of Common Interest
SI	Statutory Instrument
SNP	South North Pipeline
SWSOS	South West Scotland Onshore System
TSO	Transmission System Operator
UK	United Kingdom

Related Documents

i. Ireland’s 2018 National Risk Assessment;

ii. Regulation (EU) 2017 / 1938 concerning measures to safeguard the security of gas supply;

iii. Ireland's 2016 National Preventive Action Plan - Gas (CER/16/340);

iv. Ireland's 2016 National Gas Supply Emergency Plan (CER/16/338);

v. Norway Risk Group Assessment 2018; and

vi. United Kingdom Risk Group Assessment 2018.

Executive Summary

This CRU document has been developed in line with the previous National Preventive Action Plan, existing European Regulation's, and bi-lateral arrangements. This document has not been developed to consider the potential implications of Brexit on the Irish Gas System.

The Security of Gas Supply Regulation

EU Regulation 2017/1938 ("The Regulation") mandates that EU Member States are required to implement measures to safeguard gas security of supply. To assess Member State's ability to supply gas, under predefined Standards (i.e. Infrastructure Standard and Gas Supply Standard), Regulation 2017/1938 requires each Member State to prepare a National Risk Assessment. The National Risk Assessment identifies possible risks and hazards to Member States security of gas supply. In addition, Member States are required to prepare a Preventive Action Plan which outlines measures to either remove or mitigate the risks and hazards identified in the Risk Assessment.

Preventive Action Plan

Pursuant to EU Regulation 2017/1938 ("the Regulation"), Member States are required to implement measures to safeguard security of gas supply including, inter-alia, the development of a Preventive Action Plan.

There is a requirement to update the action plan every four years. In fulfilment of this requirement, the CRU has prepared this document, which is the Preventative Action Plan for 2018 – 2022.

The primary tenet of the Preventive Action Plan is risk management, as the Regulation requires that Member States develop preventive measures, to reduce the risk to gas supplies, and to safeguard supplies to protected customers. Consequently, the preventive measures identified within this Preventive Action Plan for 2018 to 2022, are in response to the risks identified within Ireland's latest Risk Assessment document. The latest Risk Assessment was submitted to the European Commission in October 2018.

Ireland's Risk Assessment

The Infrastructure Standard: is assessed by performing the N-1 calculation. The N-1 calculation removes the technical capacity of the single largest piece of gas infrastructure on a peak day with a view to determining whether the remaining gas infrastructure can meet 100% of peak day gas demand. To pass, the calculation must equate to 100% or more. Ireland failed the Infrastructure Standard meaning that after losing the single largest gas infrastructure the technical capacity of the remaining infrastructure cannot meet demand. To pass the Infrastructure Standard, Ireland requested the United Kingdom (UK) to adopt a regional approach, which takes the island of Ireland and Great Britain as one region for the assessment. Further details on the regional approach can be found in the UK's Regional Risk Assessment.

The Gas Supply Standard: is based on ensuring gas supply to protected customers and Ireland currently meets this requirement on a national basis. To ensure gas supply to protected customers (e.g. residential customer, small to medium enterprises and special categories such as hospitals etc.), the following obligations have been placed on Natural Gas Undertakings:

- the gas transmission system operator to build network for a 1-in-50 winter;
- suppliers to book capacity for protected customers for a 1-in-50 winter, and;
- gas producers and storage operators to comply with instructions of the National Gas Emergency Manager (NGEM) in an emergency, which may include injecting into the system during an emergency.

Ireland complies with the Supply Standard and can ensure gas supply to protected customers. An examination of internal system hazards reveal that gas supplies to protected customers would only be jeopardised in the event of a mixed failure event (e.g. loss of Beattock compressor station and Cappagh South AGI and Kinsale production).

Loss of Gas Supply from Great Britain (GB): during 2016 the energy regulator for Great Britain (Ofgem) sharpened incentives on gas shippers to enhance security of supply in Britain. Shippers in Britain who are short during a gas deficit emergency would be required to compensate firm customers whose load is interrupted. As a result, GB shippers will have greater financial incentives to ensure continuation of gas supplies in GB. These incentives in GB could have a positive impact for the Irish gas market. However, there could be a negative impact depending on commercial incentives in Ireland, and the behaviour of shippers in response to those incentives.

Loss of Gas Supply Outside of EU: An EU Commission analysis in 2009 indicated that a disruption of gas supplies from a country outside the EU does not pose any significant risk to gas supplies to the UK or Ireland. The likely impact on Ireland could be an increase in wholesale gas prices.

Furthermore, ENTSOG was required under Article 7 of Regulation (EU) 1938 / 2017 to carry out a Union-wide simulation of gas supply and infrastructure disruption scenarios.[1] As part of this analysis Ireland was assessed as part of

[1]https://www.entsog.eu/public/uploads/files/publications/sos/ENTSOG%20Union%20wide%20SoS%20simulation%20report_INV0262-171121.pdf

the North Sea Gas supply group across a number of regional disruption scenarios. The analysis showed that there was no impact on Ireland in any of the relevant risk scenarios.

Potential Risks and Hazards: Ireland's Risk Assessment considered failure modes at entry points and various system components (e.g. above ground installations). External hazards, such as natural and manmade hazards were also considered. The Preventive Action Plan, through preventive measures, aims to eliminate, or reduce the impact of these risks on gas customers in Ireland.

<u>Preventive Measures</u>

Market-based measures rely on supply and demand dynamics, in particular given Ireland's connection to the highly liquid National Balancing Point (NBP) in Great Britain. In a gas supply shortage, the wholesale market should react, and a rise in wholesale prices should reduce demand. Non-market-based measures are to be used when market-based measures alone cannot ensure gas supplies to protected customers.

Market-based Supply Side Measures in Ireland: Ireland has indigenous production capacity at the Corrib gas field and some limited production capacity in the depleting Kinsale gas field.

Measures such as reverse flow, coordinated dispatching, long term contracts, and short-term contracts have no additional benefits to gas security of supply in Ireland. The market signals from the UK's NBP should result in pricing signals resulting in industrial customers opting not to consume gas (i.e. reducing demand).

Market-based Demand Side Measures in Ireland: The majority of gas demand in Ireland can be attributed to power generation consumption, which averaged 58% of annual gas demand in 2016/17. Due to operational limitations on the electricity system, it is too risky to have an uncontrolled fuel switch from gas fired generators to secondary fuel (i.e. oil). As such, a controlled fuel switch over a more prolonged period may occur.

Non-Market-based Supply Side Measures in Ireland: measures including increased indigenous production is provided for in Ireland's National Emergency Plan. In 2018, the Corrib gas field is expected to meet up to 64% of Ireland's annual system demand, with the Inch and Moffat Entry Points providing the remaining 7% and 29%, respectively. By 2020/21 Corrib gas supplies are expected to account for around 44% of gas demand in Ireland, with Inch expected to cease production in 2020.

Market-based Supply Demand Measures in Ireland: Fuel switching is a non-market-based measure that could be used to ensure gas security of supply.

The electricity TSO (EirGrid) has indicated that there are electricity network operational limitations e.g. risk of tripping that require a controlled switch over to secondary fuel EirGrid have indicated that the electricity system would require 30 hours to switch the 12 gas fired plants (12 gas fired plants would be expected to be operating on a peak gas day) to their secondary fuel. This ramping down would require gas consumption equivalent to 60% of the overall peak day gas demand. In addition, daily metered customer's e.g. industrial users could also provide demand side response to a potential emergency.

Public/Customer Impact Statement

There are approximately 687,000 natural gas customers in Ireland, who contribute to the operation of the gas network through their gas bills. In the event of a gas shortage, Ireland's Preventive Action Plan endeavours to ensure gas continues to flow to Protected Customers. Protected Customers in Ireland are defined in the table below:

Ireland's Definition of Protected Customer
All NDM sector customers (residential and some small business) and, in addition, priority customers in the DM sector which are of the following categories: • Hospitals and Nursing Homes including retirement homes; • High Security Prisons; and • District Heating Schemes and further categories of essential social services as determined by the CRU from time to time.

1 Introduction

1.1 Competent Authority

The Commission for Regulation of Utilities (CRU) is the competent authority under Regulation 2017/1938. The primary obligations of the CRU as designated Competent Authority under the Regulation include:

- the completion of a Risk Assessment,
- the establishment of a Preventive Action Plan and Emergency Plan[2] in order to mitigate the risks identified in the Risk Assessment,
- the monitoring of security of gas supply at national level,
- cooperating with other Competent Authorities to prevent a supply disruption and to limit damages in such an event; and
- establishing the roles and responsibilities of relevant market participants.

In addition to the security of supply functions, the CRU also has explicit safety functions relating to the safe storage, transmission, distribution and utilisation of natural gas.

1.2 Risk Groups

Ireland is a member of the UK Risk Group and the Norway Risk Group. The members are as follows:

- **UK Risk Group**: UK, Belgium, Germany, Ireland, Luxembourg and the Netherlands
- **Norway Risk Group**: UK, Belgium, Denmark, Germany, Ireland, Spain, France, Italy, Luxembourg, the Netherlands, Portugal, and Sweden

1.3 Development of the Preventative Action Plan

The Preventative Action Plan for 2018 – 2022 has been prepared in accordance with Article 8 and 9 of Regulation 2017/1938. Article 8 relates to the establishment of an action plan, while Article 9 sets out the required content of the plan. In compliance with Article 9, the Preventive Action Plan 2018 – 2022 includes:

- the results of Ireland's national Risk Assessment,
- the measures, volumes, capacities and the timing needed to fulfil the infrastructure and supply standards,

- the obligations on Natural Gas Undertakings (NGUs) and other relevant bodies,
- other preventive measures to address the risks identified in order to maintain gas supply (where possible) to all customers,
- the mechanisms to be used for cooperation with other Member States for preparing and implementing joint Preventive Action Plans,
- information on existing and future interconnections, and;
- information on Public Service Obligations (PSOs) regarding security of gas supply.

In terms of preparing Ireland's Preventive Action Plan, cognisance was given to the Regulation's requirements that the Preventative Action Plan take account of 10-year network development plan for Europe, as developed by the European Network of Transmission System Operators for Gas (ENTSOG), and the emphasis attached to the utilisation of market-based security of gas supply measures.

2 Description of the System

The objective of this section is to provide an overview of the Irish gas market. In particular, this section focuses on the structure of the Irish gas market, the gas network, and the supply and demand for gas, thus providing the foundations for interpreting Ireland's Risk Assessment. Ireland is part of the UK Risk Group and the Norway Risk Group.

2.1 Description of the system (Regional gas system for each risk group)

2.1.1 UK Risk Group

The natural gas systems of the members of the United Kingdom Risk Group are characterised by significant levels of interconnection, liquid markets and sufficient infrastructure that more than meets the region's needs. The United Kingdom Risk Group is comprised of the natural gas systems of the UK Belgium, Germany, Ireland, Luxembourg and the Netherlands.

With the exception of Belgium and Luxembourg, all Member States of the United Kingdom Risk Group have some level of domestic production, underpinning the resilience of the north-west European gas system. The United Kingdom and the Netherlands are the two largest natural gas producers in the European Union, producing approximately 416TWh (38 bcm) and 430TWh (44 bcm) respectively in 2017.

Although production from the United Kingdom Continental Shelf (UKCS) has, since 2014, increased year-on-year due to the development of new fields and increased production at some of the existing fields, production from the UKCS has generally been falling since the turn of the century, with production declining by around 8% a year between 2000 and 2013. Production is forecast to return to a pattern of decline.

Natural gas production in the Netherlands will decline rapidly over the next decade, due to the decision taken in 2018 to terminate production from the Groningen gas field by 2030. The shutdown in Groningen production is expected to reduce national Dutch production by an average of 19% per year in the period 2018-2021.

2.1.2 Norway Risk Group

Norway is a major oil and gas producer and, since 2012, natural gas is the largest energy source produced in the country. In 2015, it accounted for half of the total energy produced in Norway. Total gas production reached a record in 2017 with 124 bcm. After growing steadily from the mid-1990s, natural gas production has stabilized in recent years at a high level. All the natural gas is produced from combined oil and gas extraction.

The Norwegian Petroleum Directorate's (NPD) production forecast currently foresees a relatively stable for the next few years and a decrease from the early 2020s. Production from new fields that come on stream will partly compensate for the decline in production from some ageing fields. In the longer term, the level of production will depend on new discoveries being made, the development of discoveries, and the implementation of improved recovery projects on existing fields. Gas supplies from Norway are therefore not expected to contribute beyond what has been delivered so far.

In Norway only 5% of the produced gas is consumed in the country. The vast majority of the gas is exported, mainly to neighbouring consuming countries in the North Sea area. Most of the gas is exported via subsea pipelines to destinations in Western Europe. Germany is the main importer, accounting for 42% of Norwegian gas exports in 2015, followed by the United Kingdom (25%), France (15%), and Belgium (12%). Exports from Norway cover more than 20% of the European gas demand and are a major contributor to the European gas supply security.

2.2 Description of the system (National level)

2.2.1 Market Structure

Prior to market liberalisation, the Irish gas market was controlled by state-owned company Bord Gáis Éireann (BGÉ), which operated as a monopoly. Under the 1976 Gas Act, BGÉ was given sole responsibility for the purchasing, transmission, distribution and supply of natural gas in Ireland, and therefore operated as a Vertically Integrated Utility (VIU) company.

Following the EU's decision in 1988 to create an internal energy market, the structure of the Irish gas market has gradually evolved in accordance with the provisions contained within the EU energy packages. Consequently, by 2007 all Irish gas consumers were permitted to choose alternative gas suppliers, and gas shippers were granted third party access to BGÉ's gas transmission and distribution system.

In order to facilitate third party access to the gas network, Gaslink (an independent subsidiary of BGÉ) was established in 2008 as an Independent System Operator (ISO). Specifically, Gaslink had responsibility for the operation, maintenance and development of the gas transmission and distribution system, while BGÉ remained as owner of the gas transmission and distribution system.[3]

[3] BGÉ through its division Bord Gais Networks (BGN) continued to carry out work and provided services at the direction of Gaslink in respect of the development, maintenance and operation of BGÉ's network.

With reference to market size, there are over 687,000 natural gas customers in Ireland, who can obtain gas supply from various gas suppliers.[4] In relation to customer classification, Irish gas customers are categorised into the following demand categories:

- Large Daily Metered (LDM);[5]
- Daily Metered (DM),[6] and;
- Non-Daily Metered (NDM).[7]

In 2012, the Irish Government announced its intention to sell BGÉ's non-networks energy business ("Bord Gáis Energy"), as part of the State asset disposal programme. In 2013, the Irish government confirmed that a preferred bidder was selected for the sale of Bord Gáis Energy. In order to facilitate the sale of Bord Gáis Energy, the Irish Government introduced the Gas Regulation Act 2013, which provided the legislative framework for the legal separation and sale of BGÉ's energy business and the re-organisation of the networks business into a single entity.

During a period of significant company restructuring within BGÉ, the following events occurred:

- **July 2013:** Following an Irish Government decision, BGÉ was designated with responsibility for the provision of water and waste water services in Ireland, which resulted in the establishment of Irish Water as a subsidiary within the BGÉ Group.
- **June 2014:** In accordance with Section 8(1) of the ESB (Electronic Communications Networks) Act 2014, the Irish Minister for Communication, Energy and Natural Resources (MCENR) renamed BGÉ as Ervia.
- **June 2014:** Bord Gáis Energy sale was completed.
- **December 2014:** Bord Gáis Networks (BGN) business rebranded as Gas Networks Ireland (GNI).
- **January 2015:** GNI was incorporated as a wholly owned subsidiary of Ervia.
- **April 2015:** BGÉ (UK) changed its name to GNI (UK) Ltd.

[4] Appendix 1 provides a list of gas suppliers operating in the Irish gas market, and a list of Irish gas shippers who are registered at Ireland's gas entry points (i.e. Moffat, Inch and Corrib).

[5] LDM sites are sites with an annual demand of 57 GWh or greater, and includes all gas fired power stations and large industrial/commercial sites. There is approximately 37 LDM industrial/commercial customers connected at transmission level and 15 on the distribution network.

[6] DM sites are sites with an annual demand greater than 5.55 GWh and less than 57 GWh (e.g. medium industrial/commercial customers, hospitals). There is approximately 17 industrial/commercial customers on the transmission network and 202 at distribution level.

[7] NDM sites are sites with an annual demand of 5.55 GWh or less (e.g. small industrial/commercial customers, and residential customers. There is approximately 645,269 residential gas customers in Ireland and 25,304 NDM industrial commercial customers.

- **August 2015:** To complete the company restructuring, as part of their Network Transfer Plan, Ervia and Gaslink transferred assets, licences, rights, liabilities and staff to GNI.

On the 29th January 2016, the CRU received an opinion from the EU Commission regarding its preliminary decision to certify GNI. The EU Commission's opinion requested that the CRU:

- Require GNI to notify the CRU if additional generation units of Irish Water start exporting electricity to the grid;
- Specify in its final decision whether Ervia's non-trading companies are engaged in activities of generation or supply of gas or electricity, and;
- Assess in its final decision the degree of independence, which the Minister for Environment, Community and Local Government (MECLG) enjoys in the exercise of their function in relation to Ervia and GNI.

The CRU's final certification decision was amended to include an obligation on GNI to notify the CRU if additional generation units of Irish Water start exporting electricity to the grid. Additionally, the CRU confirmed that Ervia's non-trading companies are not engaged in the activities of generation or supply of gas or electricity. Finally, the CRU deemed the MECLG and MCENR both independent and not under common influence of another public entity. Consequently, on the 29 March 2016, in accordance with Article 10 of the Directive, Article 3 of Regulation (EC) 715/2009 and S.I. No. 16 of 2015, the CRU certified GNI as FOU compliant[8].

2.2.2 Gas Network

Gas supply in Ireland is delivered via a network of approximately 14,172 km of pipelines. The integrated supply network is sub-divided into 2,427 km of high-pressure sub-sea and cross-country transmission pipe, and approximately 11,745 km of lower pressure distribution pipe (see Figure 1 for further details).

Ireland's onshore gas system consists of a ring-main system between Dublin, Galway and Limerick, with cross-country pipelines running from the ring-main system to Cork, Limerick, Waterford, Dundalk and numerous regional towns.

In terms of obtaining gas supplies, the Irish gas system conveys gas from three entry points, namely:

- Moffat (Western Scotland);
- Inch (Southern Ireland), and
- Bellanaboy (Western Ireland)

The Moffat entry point connects the Irish natural gas system to National Grid Gas's (NGG) gas system in Great Britain (GB), and allows for the importation

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[8] For further details please see CRU's Final Certification Decision - GNI's Gas FOU Certification Application

of GB gas to Ireland, via two sub-sea Interconnectors and an onshore transmission network in Scotland (i.e. South West Scotland Onshore System (SWSOS)). From the connection with the NGG's system at Moffat, the Scotland based onshore system consists of:

- a compressor station at Beattock, which is connected to Brighouse Bay by two pipelines from Beattock to Cluden;
- 80km of pipeline including a 50km single pipeline from Cluden to Brighouse Bay, (construction on twinning of the 50km of pipeline is on-going), and;
- a compressor station at Brighouse Bay, which compresses the imported gas into the two sub-sea Interconnectors.

From Brighouse Bay there are two pipelines connecting Ireland to the GB gas network (i.e. Interconnector 1 (IC1) & Interconnector 2 (IC2). IC1 and IC2 are connected to the onshore Irish system north of Dublin at Loughshinny and Gormanston, respectively.

The Inch entry point connects the Kinsale and Seven Heads gas fields and the Kinsale storage facility to the onshore network. There is also a compressor station at Midleton, Co. Cork that compresses the gas from Inch to facilitate transmission throughout the system. The Kinsale storage facility is operated by PSE Kinsale Energy Limited (KEL) using the depleted Southwest Kinsale gas field. KEL ceased full storage operations in 2017 and commenced blowdown of Southwest Kinsale. Currently production is expected to cease in 2020.

The Bellanaboy entry point connects the Corrib gas field to the onshore network The Bellanaboy entry point is connected to the onshore ring main via the Mayo-Galway pipeline, this facilitates the flow of gas from the Corrib Field into GNI's system.

Figure 1: Overview of Ireland's Gas Network. Source: ENTSOG

With reference to gas connections to the UK, the Irish gas system connects to the UK gas system at three points. There is one physical entry from GB at Moffat, and two exits to Northern Ireland at Twynholm and Gormanston:

- Moffat: Moffat is Ireland's primary gas entry point and is an Interconnection Point which connects the National Transmission System (NTS) in GB and GNI's transmission system in Ireland. This entry point between GB and Ireland is unidirectional, as gas can only flow physically from Scotland to the three markets downstream (i.e. Ireland, Northern Ireland, and the Isle of Man). There is also a facility to virtually reverse flow gas from Ireland to GB at this point.
- Twynholm: Gas is delivered from Moffat to the Northern Ireland gas system at Tywnholm, where the gas is delivered to Northern Ireland customers via the Scotland to Northern Ireland Pipeline (SNIP). The SNIP is owned and operated by PTL, which is a subsidiary of Mutual Energy Limited.

- Gormanston: The SNP is a gas transmission pipeline (which forms part of Northern Ireland's transmission system) that spans both the Irish and Northern Irish jurisdictions, and facilitates physical gas flows from GB (from Moffat), along IC2 into the SNP for delivery to Northern Ireland (NI) at the Interconnection Point at Gormanston. However, the SNP does not physically facilitate gas flows from the Irish onshore network to NI (and vice versa). The SNP is commercially operational and includes a virtual reverse flow facility where gas can be virtually reversed flowed from NI through the Irish subsea system to Moffat.[9]

2.2.3 Technical Capacity of Gas Transmission Network

Maximum Technical Capacity of the Moffat Entry Point[10]

The maximum technical capacity of the Moffat entry point is determined by the maximum technical capacity of SWSOS transmission system, consisting of the compressor stations at Beattock and Brighouse Bay and the inter-station pipeline network. The current maximum theoretical technical capacity of SWSOS transmission system is 31.0 mscmd. It is anticipated that this will increase to 35.0 mscmd following completion of the SWSOS twinning project. The maximum capacity is limited by the technical capacity of the compressor stations, and is based on the following assumptions:

i. Completion of the SWSOS twinning project
ii. A station inlet pressure of 47.0 barg, based on the NGG's Anticipated Normal Off-take Pressure (ANOP) of 47.0 barg for the Moffat Entry Point.
iii. Beattock station discharge pressure optimised to share the compression duty optimally between Beattock and Brighouse Bay;
iv. A gas temperature of 10^0C and molecular weight of 18.3 g/mol, and;
v. Three compressors operating in 'parallel mode' configuration at Beattock, with the fourth compressor operating in stand-by mode.
vi. Five compressors operating in 'series mode' configuration at Brighouse Bay, with the sixth compressor operating in stand-by mode.

[9] A Virtual Reverse Flow service can be implemented at an interconnection point where gas nominated to flow backwards is less than that nominated to flow in the opposite direction. In this case, the TSO can offer capacity as a 'counter flow' or "backhaul" on a 'virtual' basis in the other direction. The gas is not actually moving in the opposite direction, but the gas flow requested in the counter flow direction is subtracted from the gas flowing in the forward direction. This is referred to as "netting". Counter flow transport can be offered up to the maximum of the physical forward flow. VRF products are offered on an interruptible basis, as a TSO cannot guarantee the shipment of the counter flow gas under all circumstances.

[10] Further information regarding GNI's Transmission Network and its technical capacities is available on the following link.

Maximum Technical Capacity of the Inch Entry Point

The technical capacity of the Inch entry point is determined by the capacity of the Midleton compressor station. The Midleton compressor station currently has a maximum technical capacity of **6.0 mscmd**, based on the following assumptions:

i. A station inlet pressure of 29.5 barg;
ii. A station discharge pressure of 65.0 barg;
iii. A gas temperature of $15^{0}C$ and molecular weight of 18.3 g/mol, and;
Two compressors running with a third compressor operating in stand-by mode.

Maximum Technical Capacity at Bellanaboy Entry Point (Corrib)

The technical capacity of the Bellanaboy Entry Point is based exclusively on the physical characteristics of the system:

i. The capacity of the 650mm Mayo Galway transmission pipeline
ii. The capacity of Cappagh South AGI
iii. The inlet pressure at Bellanaboy AGI
iv. The operating pressure on the ROI ring main transmission system

The technical capacity at Bellanaboy Entry Point has been determined as 9.9 mscmd, based on the capacity of the pipeline, capacity of Cappagh South AGI, an inlet pressure of 85barg at Bellanaboy, and a maximum operating pressure of 70 barg on the ROI ring main transmission system.

	Max daily Production (mscmd)	Current Production (mscmd)	% of Annual Production
Bellanaboy (Corrib)	9.9	9.91	62%
Inch (Kinsale)	6.0	NA	7%

Table 1: Domestic production

2.2.4 Network Operations

Grid Control

The management of gas flow through the GNI Transmission System is controlled by GNI's Grid Control Centre in Cork. A Supervisory Control and Data Acquisition (SCADA) system is used to monitor and control the network through the use of Remote Terminal Units (RTUs). Additionally, Grid Control develop and implement procedures to ensure gas supply and demand are balanced.

Gas Flow

Currently the majority (62%) of Ireland's gas demand is obtained from the Corrib Gas field, with some production form Inch also. The balance is supplied from gas flows via Scotland[11]. Specifically, gas is withdrawn from NGG's NTS system at Moffat in Scotland. While gas pressures at Moffat have an ANOP of 47 barg, the gas pressures can exhibit significant variations. Figure 2 highlights Moffat gas pressures during 2017, which ranged from a minimum pressure of about 50 barg to a maximum pressure of about 73 barg.

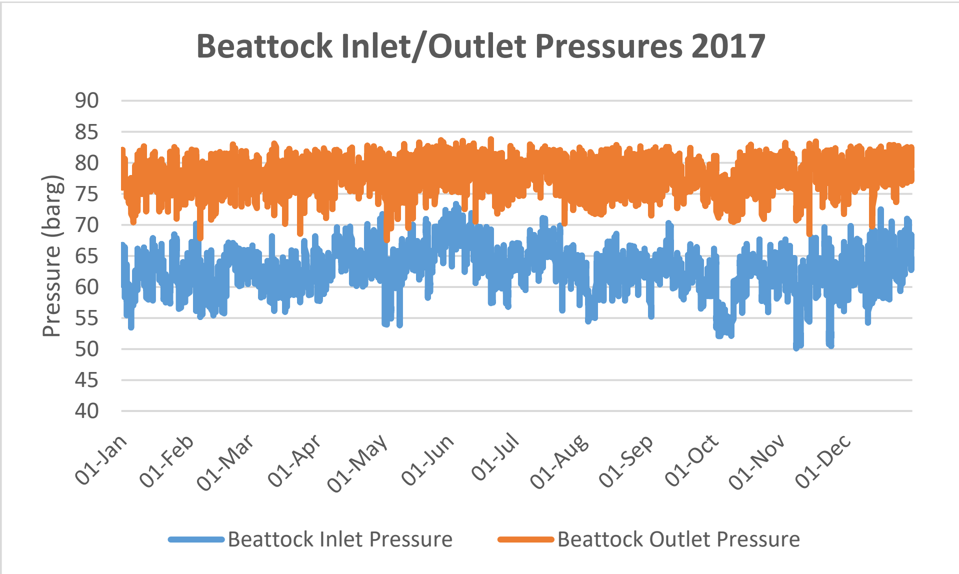

Figure 2: Moffat Pressures (barg) 2017

Once gas enters GNI's system from Moffat, gas is then discharged from Beattock compressor station up to a maximum pressure of 85 barg (the maximum operating pressure of the SWSOS pipeline). Gas then flows along the South West Scotland Onshore System (SWSOS), with supplies to Northern Ireland exiting the SWSOS at Twynholm, and gas supplies for Ireland and IOM flowing to Brighouse Bay, where the gas can be compressed/pressurised up to 148 barg and transported to Ireland via the subsea ICs.

Gas enters Ireland's onshore transmission system at reception terminals at Loughshinny (from IC1), Gormanston (from IC2), at Inch (from Kinsale Storage) and at Bellanaboy (from the Corrib gas field). At each reception terminal it is the responsibility of GNI to monitor gas quality[12], control gas flows and

[11] Moffat is expected to be re-established as Irelands majority source of supply gas by 2018/19

[12] Each Shipper shall use all reasonable endeavours to procure that the appropriate contractual arrangements are in place and to procure implementation of any quality control measures requested by

pressures, receive metering information and provide emergency shut-off facilities. Following the entry of gas at the reception terminals, the gas is transported along the transmission system (at a potential maximum of 85 barg).[13] The gas on the transmission system is then decreased through reducing pressure tiers (i.e. 40, 37.5 and 19 barg), where the gas is then supplied into the distribution system or to customers directly (e.g. generating stations).

The distribution system is supplied gas from the transmission system via a system of Above Ground Installations (AGIs). Within the distribution system, there are two pressure categories, namely medium pressure (i.e. operating between 1 and 4 barg) and low pressure (i.e. operating between 18 and 100 mbarg). The final pressure for gas delivery is restricted to 20mbarg for domestic users and is between 20 mbarg and 75 mbarg for industrial/commercial users.

Gas Odourisation

For safety reasons, gas is odourised to enable the detection by smell of any potential gas leakage. Odourisation in Ireland is at transmission level, which is in contrast to GB where it is odourised at distribution level. However, Ireland's gas odourisation practices do not hamper cross-border trade, as Ireland is dependent on Great Britain for its gas supply. The issue of gas odourisation may require review in the future, if Ireland exports gas to GB.

Safety Compliance

A gas safety case, supported by a risk assessment, is required to be produced by GNI for the gas transmission and distribution system. The purpose of this safety case is to demonstrate that the risks associated with the gas transmission and distribution systems are As Low As Reasonably Practicable (ALARP). GNI's safety cases are reviewed by the CRU in accordance with Natural Gas Safety Regulatory Framework – Safety Case Guidelines.

2.2.5 Gas Demand

In 2016, natural gas accounted for 29% of Ireland's Total Primary Energy Requirement (TPER),[14] with approximately 50% of natural gas used for

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GNI to ensure that the quality of all Natural Gas tendered for delivery by a Shipper to the Transportation System.

[13] Ireland's gas transmission system consists primarily of the high pressure (70 barg) ring main linking Dublin, Galway and Limerick, a pipeline connecting Bellanaboy to the ring main (85 barg), and a number of spur lines linking to Cork and Waterford, and lower pressure transmission pipelines (40 barg and 19 barg) within urban centres in regional networks.

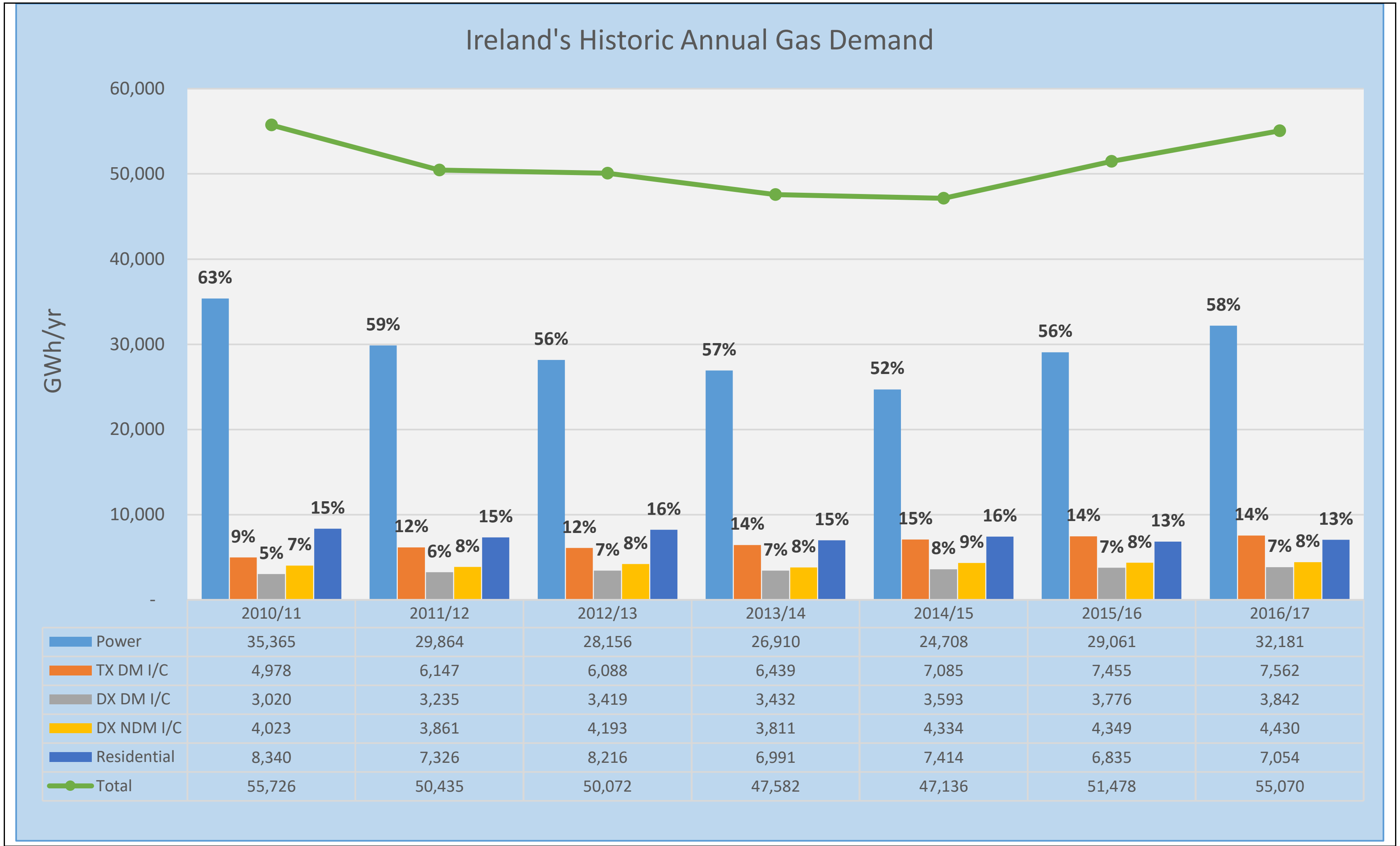
[14] TPER is the total requirement for all uses of energy, including energy used to transform one energy form to another, and energy used the final consumer. Oil accounts for Ireland's largest source of energy, and accounted for approximately 48% of Ireland's TPER in 2016. https://www.seai.ie/resources/publications/Energy-in-Ireland-1990-2016-Full-report.pdf

electricity generation.[15] Following energy transformations, natural gas accounted for approximately 15% of Ireland’s Total Final Energy Consumption (TFEC) in 2016.[16]

With reference to historical annual gas consumption, Ireland has experienced an increase in gas demand over the last two years following on from several years of decline. This is due to a number of factors including, strong economic growth leading to growth gas demand in the industrial and commercial sector. Electricity demand is also up leading to an increase in gas demand in the power generation sector. Furthermore, the introduction of a carbon price floor in GB has led to increased electricity exports from Ireland to GB fuelling further growth in gas demand in the power generation sector.

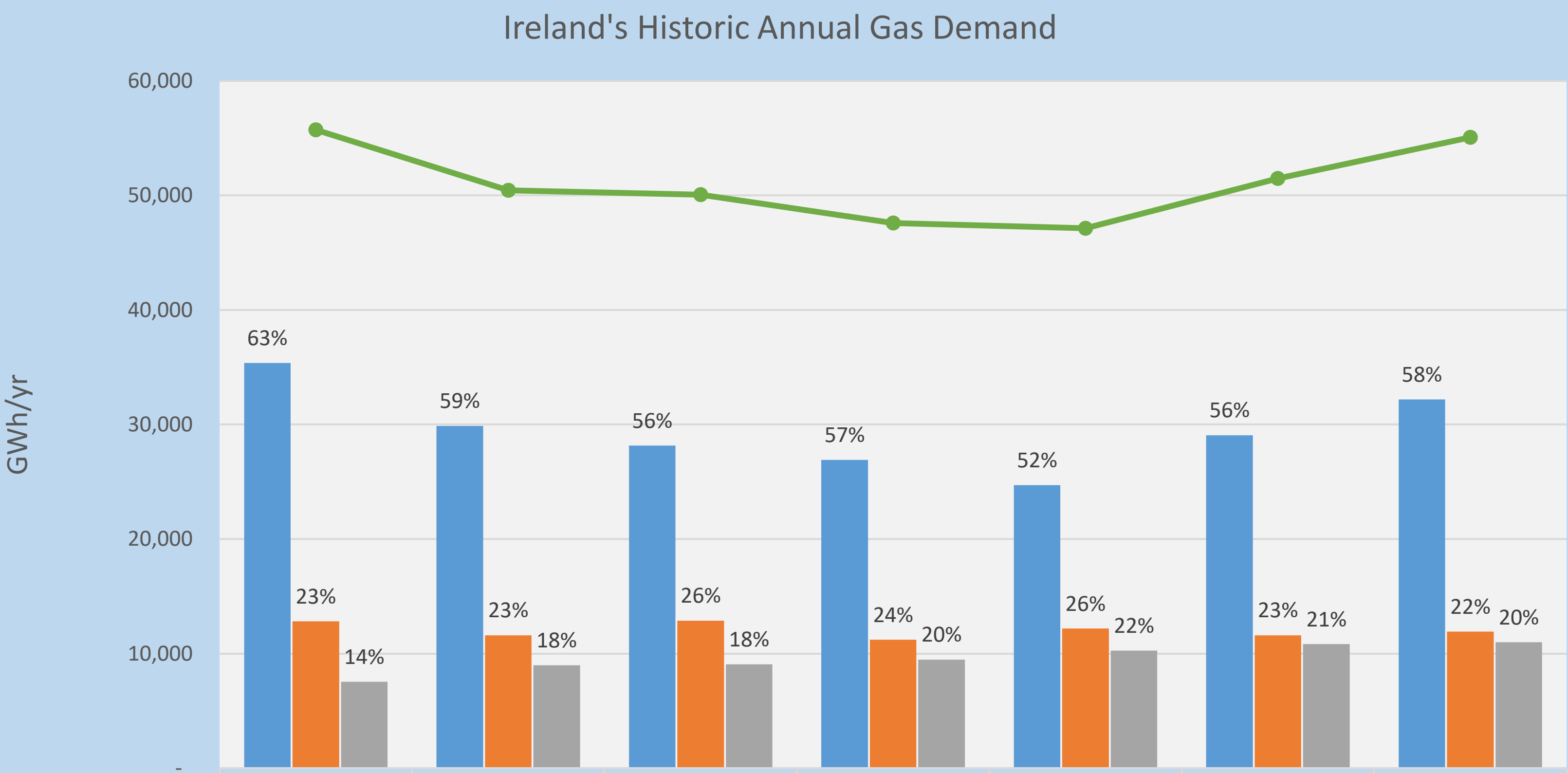
[15] Appendix 3 of the National Risk Assessment provides a list of all gas powered electricity generation stations in Ireland, and appendix four provides a breakdown of the All-Island electricity fuel mix for 2017, and the share of gas used for electricity generation.

[16] TFEC is the energy used by the final consuming sectors of industry, transport, residential, agriculture and services. It excludes the energy sector, such as electricity generation and oil refinery.



	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Power	35,365	29,864	28,156	26,910	24,708	29,061	32,181
TX DM I/C	4,978	6,147	6,088	6,439	7,085	7,455	7,562
DX DM I/C	3,020	3,235	3,419	3,432	3,593	3,776	3,842
DX NDM I/C	4,023	3,861	4,193	3,811	4,334	4,349	4,430
Residential	8,340	7,326	8,216	6,991	7,414	6,835	7,054
Total	55,726	50,435	50,072	47,582	47,136	51,478	55,070

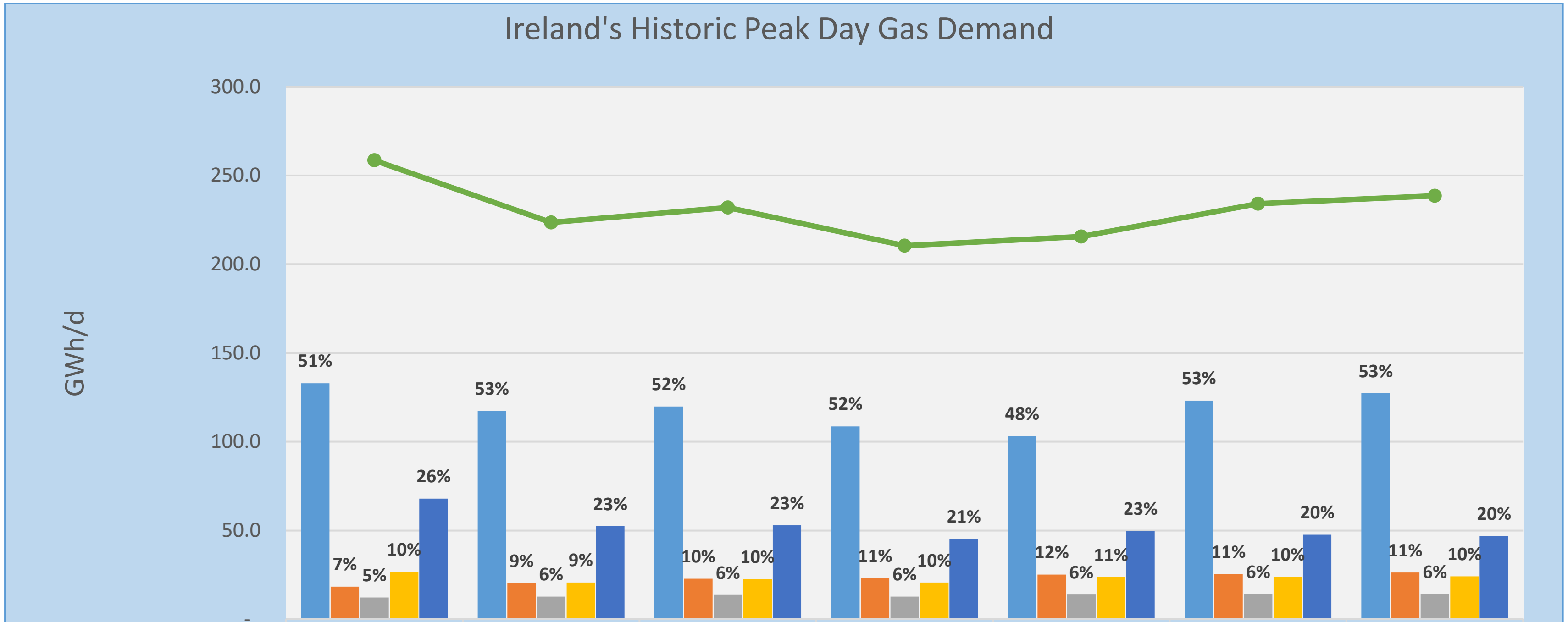
Figure 3: Ireland's Historic Annual Gas Demand



	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Power	35,365	29,864	28,156	26,910	24,708	29,061	32,181
Non-Protected	12,818	11,600	12,866	11,200	12,182	11,596	11,907
Protected	7,542	8,970	9,050	9,473	10,246	10,821	10,982
Total	55,726	50,435	50,072	47,582	47,136	51,478	55,070

Figure 4: Ireland's Historic Annual Gas Demand for Protected and Non-Protected Customers

Ireland's historic peak day gas demand is recorded in two instances namely, coincident peak day and non-coincident peak day. The coincident peak day is the actual recorded peak day and the breakdown of each sector on this day. The non-coincident peak day pertains to the peak day for each individual sector at different times of the year (i.e. power sector, residential sector and I/C sector). Simply, the non-coincident peak day is all of the peaks from different sectors added together to illustrate, if all peaks occurred simultaneously, a maximum system peak. For the purposes of the National Risk Assessment the non-coincident peak ('peak') demand shall be utilised (i.e. the worst-case scenario).



	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Power	133.0	117.4	119.9	108.7	103.2	123.2	127.3
TX DM I/C	18.4	20.4	22.9	23.1	25.1	25.4	26.3
DX DM I/C	12.3	12.7	13.7	12.8	13.8	14.1	14.0
DX NDM I/C	26.8	20.7	22.6	20.6	23.8	23.9	24.1
Residential	68.0	52.4	52.9	45.2	49.7	47.6	47.0
Total	258.5	223.5	231.9	210.4	215.6	234.1	238.6

Figure 5: Ireland's Historic Peak Day Gas Demand[17]

[17] Source: Gas Networks Ireland NDP

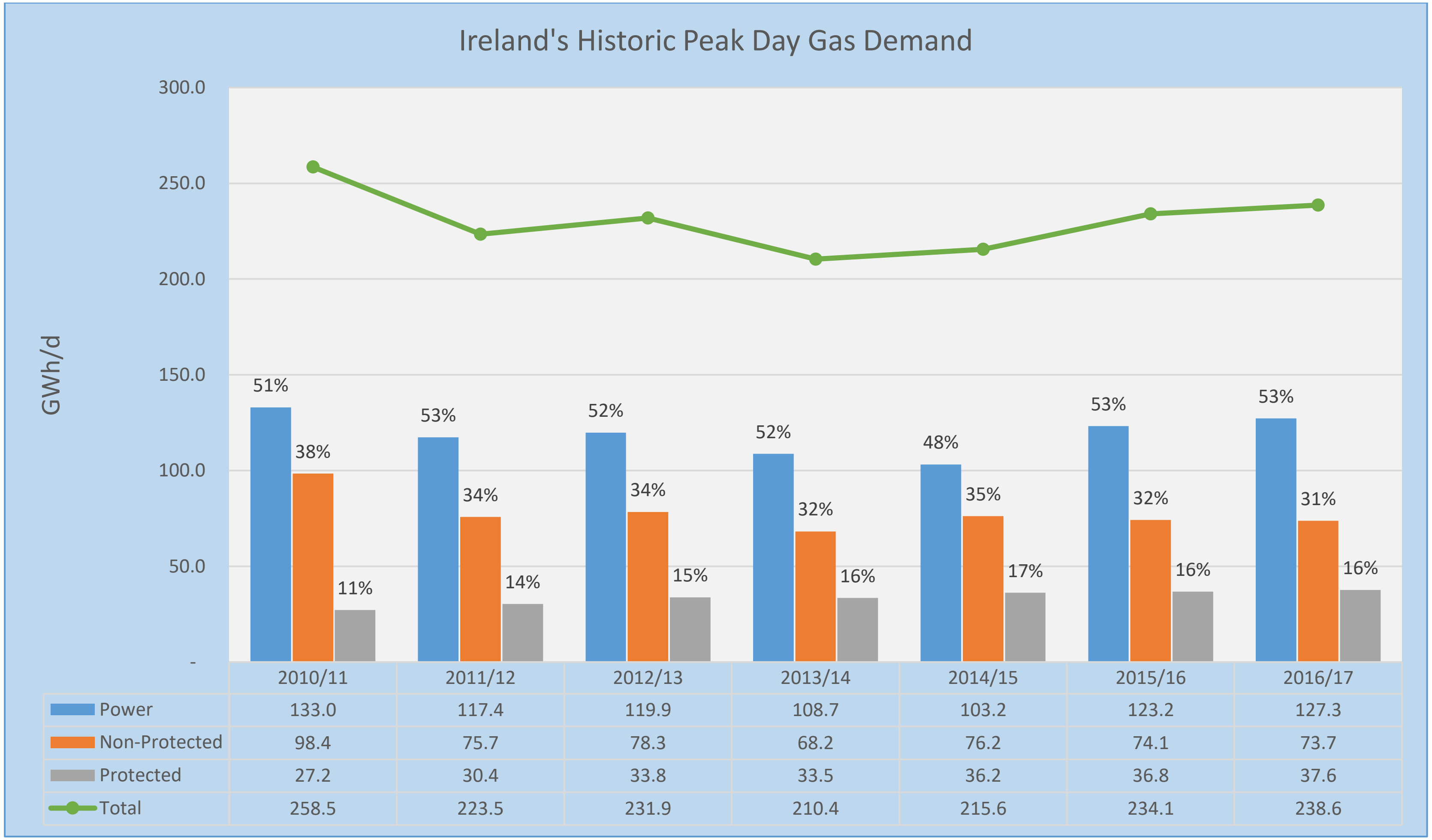
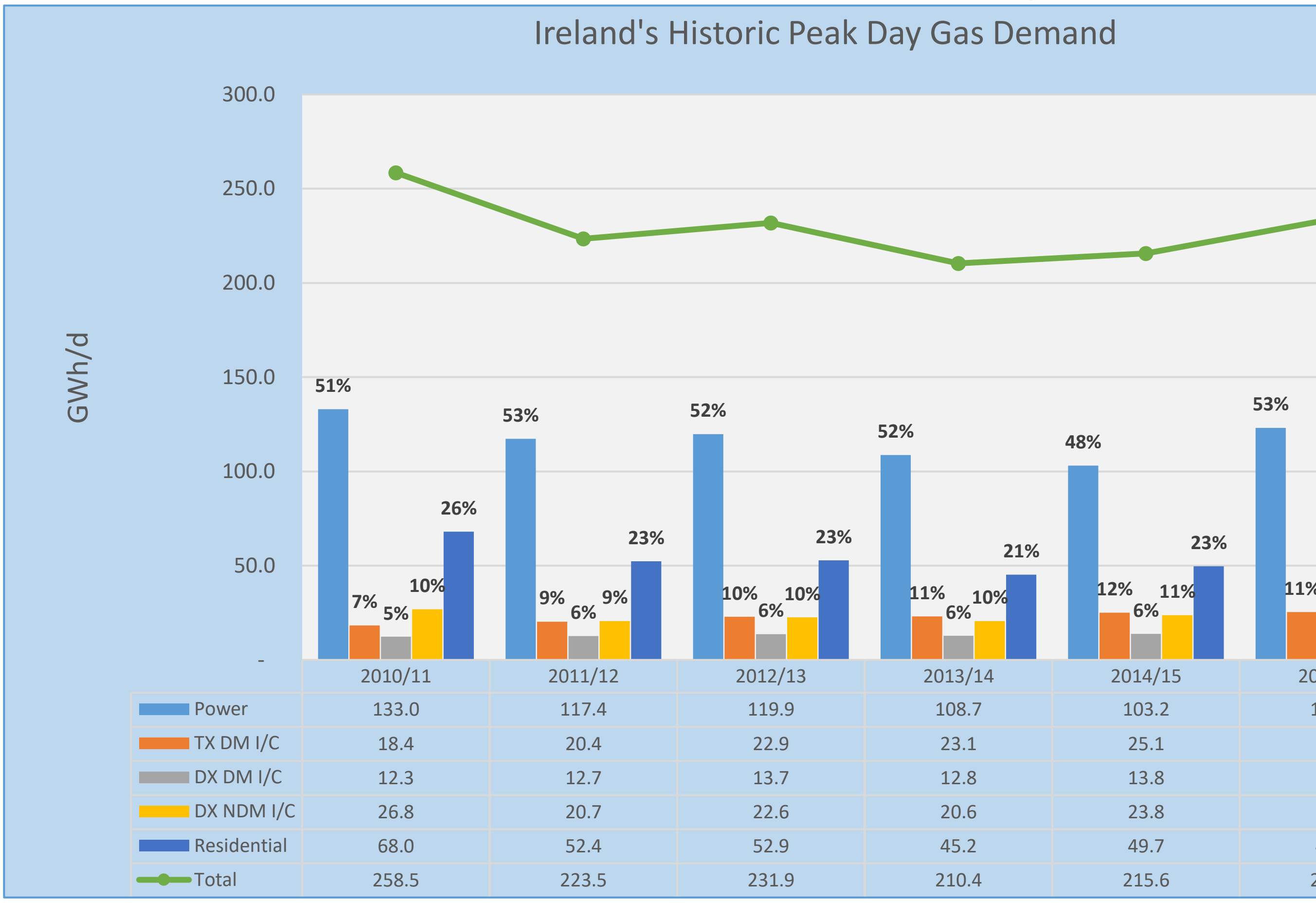


Figure 6: Ireland's Historic Peak Day Gas Demand for Protected and Non-Protected Customers

In general, Ireland’s peak has declined relative to its all-time peak of 258.5 GWh/d in 2010/11 (see



	2010/11	2011/12	2012/13	2013/14	2014/15
Power	133.0	117.4	119.9	108.7	103.2
TX DM I/C	18.4	20.4	22.9	23.1	25.1
DX DM I/C	12.3	12.7	13.7	12.8	13.8
DX NDM I/C	26.8	20.7	22.6	20.6	23.8
Residential	68.0	52.4	52.9	45.2	49.7
Total	258.5	223.5	231.9	210.4	215.6

Figure 5). The decline in peak day gas demand can be attributed to 1-in-50 weather events in 2010/11, which resulted in Ireland experiencing record peak day gas demands. However peak day gas demand has increased in recent years following on from a number of consecutive warm winters and in general gas demand is growing in all demand sectors.

It should be noted that the Irish daily metered Industrial and Commercial sectors are not weather corrected, as their daily demands are driven by other factors such as, relative fuel-prices and economic growth. In contrast to the Industrial and Commercial sector, the residential sector is particularly weather sensitive, as the gas is primarily used for space heating purposes.

With reference to forecast gas demands, annual gas demands are forecasted to increase by 24% by 2026/27, with peak day gas demands increasing by 14%. Figure 7 illustrates forecasted growth rates in annual and peak day gas demand up to 2026/27.

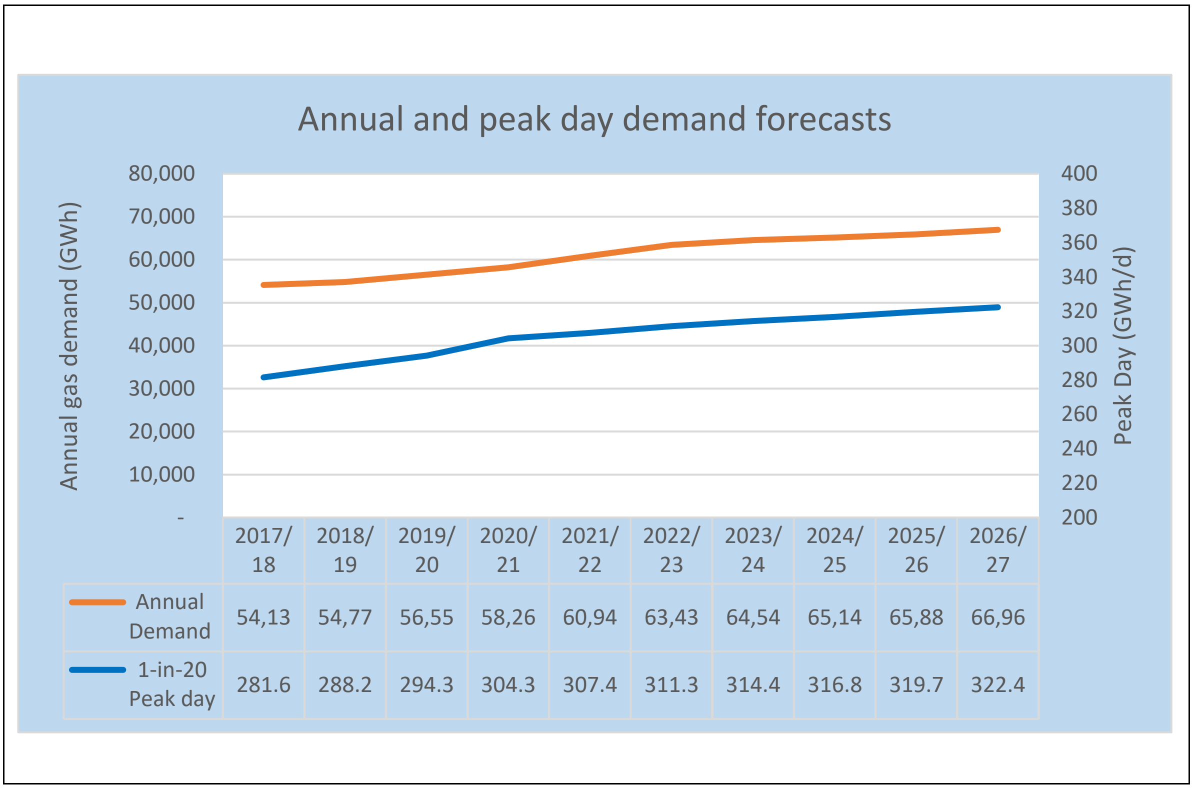


Figure 7: Ireland's Annual & Peak Day Forecast Gas Demands

2.2.6 Gas Supply

The majority of gas demand in Ireland can be attributed to power generation consumption, which averaged 58% of annual ROI gas demand in 2016/17. The industrial/commercial sectors make up, on average, 29% of annual gas demand. The residential sector accounts for approximately 13% of annual gas demand.

In 2016/17, the majority of the gas demand (62%) in Ireland was supplied from the Corrib gas field. The Moffat Entry Point accounted for 31% of the overall requirement with the remaining 5% supplied from production gas from an off-shore gas field at the Inch entry point.

In 2017/18, the Corrib gas field is expected to meet up to 64% of annual ROI gas demand, with the Inch and Moffat Entry Points providing the remaining 7% and 29%, respectively.

By 2020/21 Corrib gas supplies are expected to account for around 44% of gas demand in Ireland, with Inch expected to cease production in 2020. The anticipated reduction in Corrib and Inch gas supplies will re-establish the Moffat Entry Point as the dominant supply point. By 2020/21 Moffat will account for approximately 56% of Ireland's annual system demand

Gas Source	% of annual supply		
	2016/17	2017/18	2020/21 (projected)
Moffat	62%	29%	56%
Corrib	31%	64%	44%
Kinsale	5%	7%	0%

Table 2: Annual Gas Supply by Source

Country of origin source of imported gas via the Moffat Entry Point is 100% from the UK.

2.2.7 Gas Transportation Arrangements & Gas Flows at Entry/Exit Point

Corrib

The Corrib gas field came online on the 31 of December 2015. Following on from the successful completion of commissioning on the 29 of June 2016, Corrib commenced operation at full capacity. Table 3 below shows forecast maximum daily supplies from Corrib[18]. Analysis of historical Corrib entry flows has shown a slight reduction in maximum daily output commencing in January 2018. This reduction is in line with projected daily supply profile shown in the table below.

[18] Source: Gas Networks Ireland

	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
Daily Supply (mscm/d)	9.91	8.13	7.7	7.44	6.01	4.91	4.25	3.65	3.28	2.86
Daily Supply (GWh/d)	103.8	85.1	80.6	77.9	62.9	51.4	44.5	38.2	34.3	30.0

Table 3: Projected Daily Supply Profile

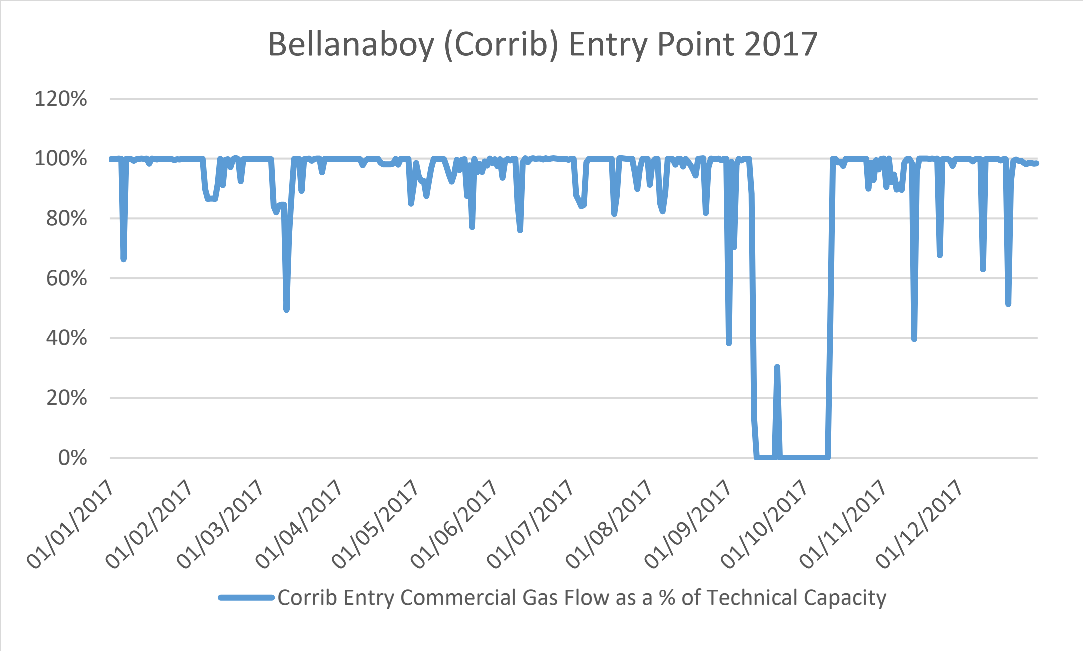


Figure 8: Bellanaboy (Corrib) Entry Point Commercial Flows

Gas Transportation Arrangements at Moffat

Gas is transported to Ireland from GB, via shipper to shipper arrangements (i.e. an Irish registered shipper contracts with a GB National Transmission System (NTS) registered shipper to move contracted volumes of gas across the flange at Moffat (Scotland).

Figure 9 illustrates the percentage of daily contracted capacity[19] bookings at Moffat entry point in 2017 (relative to the technical capacity that is available)[20]. During 2017, the maximum daily contracted capacity at the Moffat entry point equated to 82%, while the minimum and average contracted capacity equated to 45% and 55%, respectively. Additionally, Figure 8 shows that daily commercial gas flows[21] in 2017 were on average 29% of the technical capacity

[19] Contracted Capacity = Total capacity (long term and short term) booked at the point for the gas day.

[20] Technical Capacity is the max capacity that can be made available to Shippers at the Moffat entry point for the gas day.

[21] Commercial Gas Flow equates to the Total Quantity of Gas allocated at the Moffat entry point on the Previous Gas Day.

available at Moffat entry, while there was a minimum and maximum commercial gas flow rate of 10% and 64% (relative to technical capacity).

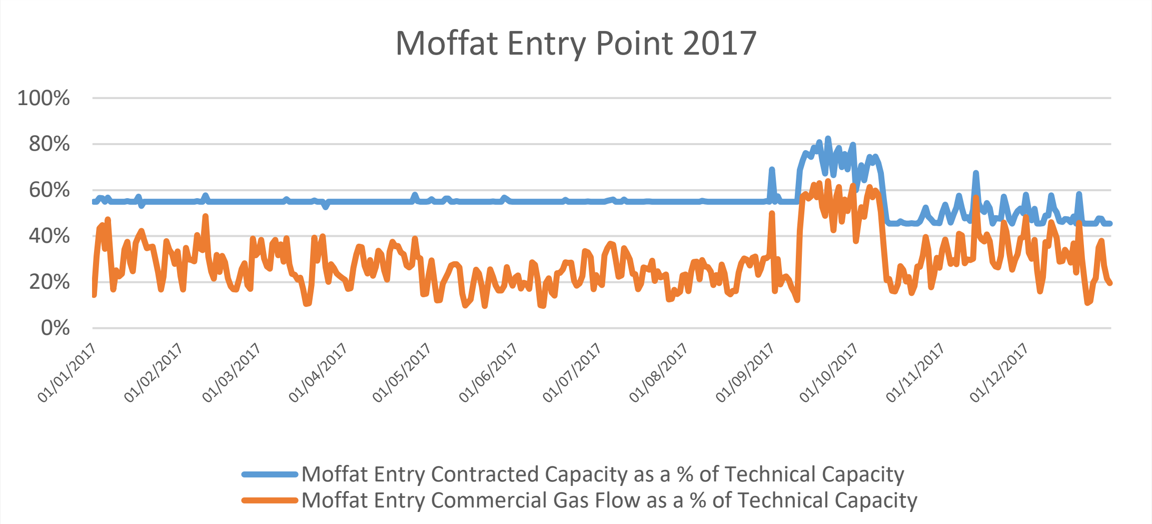


Figure 9: Moffat Entry Point Contracted Capacity & Commercial Gas Flows

Gas Transportation Arrangements at Inch

Figure 10 illustrates the percentage of daily contracted capacity bookings at Inch Entry Point in 2017 (relative to the technical capacity that is available). During 2017, the maximum daily contracted capacity at the Inch Entry Point equated to 54%, while the minimum and average contracted capacity equated to 7% and 27%, respectively. Additionally, Figure 10 reveals that daily commercial gas flows were on average 20% of the technical capacity available at Inch entry, while there was a minimum and maximum commercial gas flow rate of 0% and 38% (relative to technical capacity available).

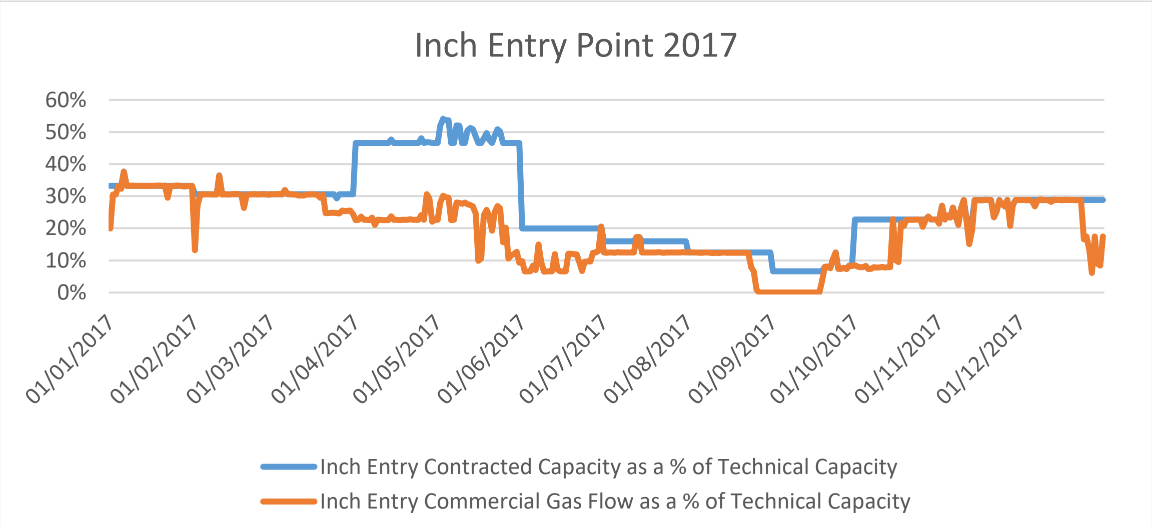


Figure 10: Inch Entry Point Contracted Capacity & Commercial Gas Flows

The Kinsale storage facility is operated by PSE Kinsale Energy Limited (KEL) using the depleted Southwest Kinsale gas field. KEL advised the CRU in 2015 that it planned to cease full storage operations and commence blowdown of Southwest Kinsale. Blowdown is where the gas used for pressure support in Southwest Kinsale is produced and sold into the market. There were no injections into Southwest Kinsale in 2017 and the storage gas has now been fully withdrawn. Only production gas is now being supplied from the Inch Entry Point. Production is expected to cease in 2020.

Gas Transportation Arrangements at Twynholm

Twynholm exit point has an exit capacity of 89,778,000 kWh. Figure 2.9 illustrates the percentage of daily commercial gas flows at Twynholm entry point in 2017 (relative to the technical capacity that is available). During 2017, the maximum daily commercial gas flows at the Twynholm exit point equated to 76%, while the minimum and average commercial gas flows equated to 27% and 51%, respectively.

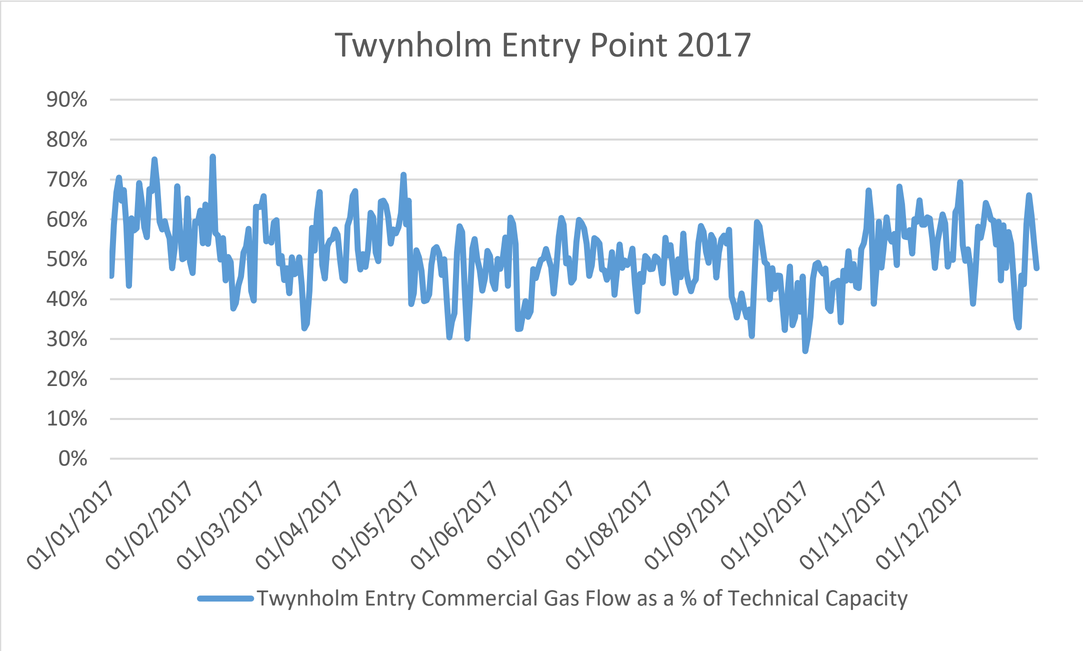


Figure 11: Twynholm Exit Point Commercial Gas Flow

Gas Transportation Arrangements at SNP Exit

With reference to the SNP exit point there is a technical capacity of 66,275,000 kWh. However, during 2017 there was no capacity booked at the SNP exit point, and all gas to Northern Ireland was flowed through the SNIP.

2.2.8 Gas & Electricity Interactions

The majority of gas demand in Ireland can be attributed to power generation consumption, which averaged 58% of annual ROI gas demand in 2016/17. Gas fired generation accounted for approximately 50% of Ireland's electricity generation in 2016/17.

The strong relationship between gas and electricity has already proven to be very beneficial to Ireland; providing and maintaining competitive energy prices and a secure and reliable supply of energy.

Typically, there is a decoupling of peak day and annual gas demand in the power generation sector as a result of wind generation's impact on the operation of gas fired plant in the SEM[22]. Annual power generation gas demand tends to be impacted by increasing wind generation capacity, which displaces gas fired generation or at least offsets growth in demand.

However, wind generation typically has little impact on the winter peak day. There is often limited wind generation available during cold weather peak demand periods. Consequently, there is a high dependency on thermal generation, particularly gas fired generation, to meet the high levels of electricity demand which occur during such cold weather periods.

As well as seasonal intermittency, within-day intermittency is a feature of wind generation. Given its flexibility, gas is the optimal complementary energy source for wind generation as gas turbines can be adjusted upward and downward fairly rapidly according to load changes.

In 2017, out of 7914 MW of total dispatchable electricity generation in Ireland, gas fired generation capacity accounted for 4200 MW. In 2017, installed wind generation in Ireland was 3310 MW. [23]

2.2.8.1 Gas and Electricity Interactions: Preventative Measures

The infrastructure standard considers demand response measures, but the supply standard does not. Under the supply standard, only the demand of protected customers' is taken into account and all other demand is excluded from the calculation. The length of time required to reduce the demand of others is not considered. In reality it will take time to reduce gas demand; for example, in the power generation sector.

Analysis of GNI power demand models determined that there would be approximately 12 gas plants in merit on a peak day. This would require 30 hours in all to switch to secondary fuels at all gas plants. Therefore, to safely switch to back up fuel in a controlled manner, a large volume of gas is required. This volume of gas is not considered in the supply standard. Further information on this is provided in Section 6.2.

[22] Single Electricity Market
[23] Source: EirGrid Generation Capacity Statement 2018

3 Summary of the Risk Assessments

3.1 Regional Risk Assessments

A list of types of risk that may have negative impact on the security of gas supply is included in the Annex V of the Regulation. These include Political risk, Technological risks, Commercial/financial risk, Social and Natural risks and Long-term production.

3.1.1 UK Risk Group

UK Continental Shelf offshore production infrastructure is directly connected to the United Kingdom and Netherlands transmission networks. The Netherlands' production infrastructure is directly connected to the Netherlands transmission network. There are, therefore, no third countries with a transit role.

In terms of potential impacts on security of supply, political risk is not considered to be a significant factor in the UK Risk Group.

The key technological risk is the potential for infrastructure to suffer technical failure. Whilst significant levels of resilience are built into the region's infrastructure, instances of technical failure do still occur. On these rare occasions, there is sufficient spare capacity within the network to ensure that no security of supply issues arise.

Studies published on behalf of the United Kingdom Health and Safety Executive and the Norwegian Seismic Array[24], as well as by the British Geological Survey[25] conclude the North Sea continental shelf to be an area of moderate seismic activity. Although risks are generally low, offshore infrastructure is designed accordingly. Gas production from the Groningen gas field located North-East of Netherlands has reduced due to the significant number of earthquakes caused by gas extraction. Gas extraction permitted was reduced from 54 bcm in 2013 to 23.98 bcm in 2017. The Dutch Government has committed to reducing production at Groningen as quickly as possible to 12bcm and then to reduce this to 0bcm by 2030.

[24] Seismic Hazard: UK Continental Shelf, EQE International Ltd, 2002
[25] North Sea Geology, British Geological Survey, 2002

3.1.2 Scenario example

ENTSOG's modelled scenario used a simulation model which builds on expertise from the TSOs to study the potential impacts of a supply disruption at the Forties pipeline system under three high demand scenarios[26]:

- A historical high demand winter based on winter 2009/10
- A period of 2 weeks of exceptionally high demand, occurring with a statistical probability of once in 20 years
- One day (peak day) of exceptionally high demand, occurring with a statistical probability of once in 20 years.

The results of the simulations show that increased gas flows from Norway and LNG as well as higher storage withdrawal rates would compensate for the supply shortfall due to the disruption, resulting in no demand curtailments in the region under any of the scenarios considered.

3.2 National Risk Assessment

Pursuant to the implementation of EU Regulation 2017/1938 ("the Regulation"), Member States are required to developa a national Risk Assessment.[27] TheCRU, as Competent Authority for Ireland, prepared the 2018 National Risk Assessment, in accordance with Article 7 (Risk Assessment) of the Regulation. The Regulation requires the Competent Authority to run various scenarios of supply disruptions and assess the likely consequences of these scenarios. This section identifies hazards that have the potential to cause disruption to Ireland's gas supplies, and then screens the hazards identified based on relevance (i.e. likelihood of occurrence) and impact (i.e. consequence of occurrence).

The Risk Assessment categorises the identified risks into four categories which are listed below.

3.2.1 Internal Systems Hazards

GNI produced a technical risk analysis report in order to screen internal system hazards (i.e. failure of Ireland's gas system components). The purpose of GNI's report is to assess the relevance of these hazards and the impact that they have on gas demand (having regard to the infrastructure and supply standards).

[26] For more information on the modelling assumptions and methodology used by ENTSOG, please refer to: https://entsog.eu/publications/security-of-gas-supply#UNION-WIDE-SIMULATION-OF-SUPPLY-AND-INFRASTRUCTURE-DISRUPTION-SCENARIOS-

[27] Article 7(7) states that "By 1 October 2018 Member States shall notify to the Commission the first common risk assessment once agreed by all Member States in the risk group and the national risk assessments. The risk assessments shall be updated every four years thereafter".

In order to complete their technical risk analysis, GNI employed data from their 2018[28] Network Development Plan and the following methodology was applied:

i. Identify various failure modes, which threaten Ireland's gas security of supply.
ii. Assign a likelihood of occurrence to each failure mode by using empirical evidence and published statistical data.[29]
iii. Analyse the consequence of each failure mode on the ability to meet demand for both 1-in-20 peak day demand and over a 30-day average winter period – incorporating simulation of N-1 disruption using hydraulic modelling
iv. Generate a risk chart corresponding to both the infrastructure & supply standards and plot each failure mode using the corresponding likelihood of occurrence and consequence on demand
v. Summarise each failure mode and the respective result on a risk register

In conducting the technical risk analysis, GNI adopted a quantitative approach taking into consideration the JRC Institute for Energy's methodological guidelines for best practice in conducting gas security of supply risk assessments. Potential hazards which have been identified and analysed in the technical risk analysis report. The results of the technical risk analysis for 2020/21 are presented in a risk register along with an assessment of the impact of the failure.

Ref	2018 Failure Modes	Likelihood Peak year	Likelihood Avg. year	Peak year % impact	30 day, avg. year % impact (Protected Customers)
		National Risk Assessment			
A1	Partial loss of SWSOS (IC2 due to compressor station valve failure)	-	-	-%	-%

Table 4: Illustration of the Risk Register as per the National Risk Assessment 2018

28 In maintaining the standards specified in Articles 5 and 6, Severe Winter Peak Day demands in the Risk Assessment have been based on the 1-in-20 year peak day, as opposed to the 1-in-50 year considered in the NDP

29 The likelihood of a particular scenario event occurring has been expressed in probability terms, e.g. 1 x 10-6 per annum. These have been based on an average of the UK industry failure rates (UKOPA) and the European failure rates (EGIG) or on specific data in relation to GNI equipment where this data exists.

For confidentiality purposes, we can’t list down the failure modes.

The consequence of an event happening (as indicated in the columns labelled *“% impact*”) is assessed using the infrastructure standards set out in Article 5 & 6 (c) of the Regulation. A higher percentage indicates that a higher percentage of gas demand can be met if the event occurs.

3.2.2 Cyber Security

As cyber security threats are constantly evolving, GNI continue to engage with industry stakeholders with a view to mitigating the cyber security threat. In addition, GNI conduct various internal audits and benchmark against other European Critical Infrastructure. These included the following audits:

- 2017 audit of the GNI SCADA[30] Level 0 + 1 systems (Engineering Technology) to determine network alignment with the IEC 62443 Security Level 3 (SL 3) [31] cyber security standards for industrial automation and control systems.
- 2014 audit and 2017 re-audit of the GNI SCADA Level 2 + 3 systems (Operations Technology) to determine alignment with the IEC 62443 (SL 3) cyber security standards.

The outcomes of the audits formed the basis of ongoing remediation projects.

Ervia IT Security are continuing to stand up an Ervia wide CMS (Central Monitoring Station) with the view that it will monitor all of GNI networking levels (Engineering Technology, Operations Technology and Information Technology). Ervia are also contributing to a consultation on the NIS Directive Security Measures and Incident Reporting for Operators of Essential Services.

3.2.3 External Hazards

In accordance with the EU’s JRC’s “Development of an evaluation tool to assess correlated risks and regional vulnerabilities” document, this Risk Assessment group’s external hazards into natural and man-made events. These external hazards are then screened based on:

- **Relevance/ likelihood of occurrence:** The purpose of this task is to screen out those potential external events, which are not relevant to the selected infrastructure. This means that they cannot occur in its surrounding or their frequency of occurrence is below a predefined threshold or that their strength is too low (can be expressed quantitatively or qualitatively).

[30] Supervisory Control and Data Acquisition

[31] SL3 is defined in standard IEC 62443 as Protection against intentional violation using sophisticated means with moderate resources, IACS specific skills and moderate motivation

- **Impact Screening & Evaluation:** The impact screening is essentially a consequence-based screening, selecting only those hazards that are posing significant threat to Ireland's gas infrastructure. By evaluating impacts, potential mitigation measures are taken into account.

3.2.4 Disruption of Imports from GB and Outside of EU

This section considers importation risks that may impact gas supplies to Ireland, namely:

- Disruption of gas imports from GB, and;
- Disruption of gas supplies from Russia to the EU.

In October 2017 BEIS published Gas Security of Supply – A strategic assessment of Great Britain's gas security of supply. The report provides a detailed evaluation of the long-term security of gas supply in GB. In assessing the current levels of gas security, the GB system was found to have high levels of security:

- the range of supply diversity available to the UK markets (including storage) can deliver 130 million cubic metres per day above the maximum daily demand expected once in every 20 years of 472 million cubic metres per day

- even for a higher daily demand (expected once in 50 years) combined with an infrastructure loss, the market could adequately deal with this shock with an effective demand side response from large users

- if the UK were to lose its single largest piece of gas infrastructure, the wide range of supply sources available mean that it would still have 27% more capacity than it needs to deliver maximum daily demand seen once in 20 years

- Between 60% and 70% of supply capacity would have to be lost before supplies to domestic consumers would be interrupted. A 60% loss in supply capacity would represent losing all LNG supply, all imports from Belgium and Netherlands, and a loss of fifty per cent of current UK production

- at average demand levels, there is sufficient capability for the GB gas system to meet all required demand, both domestic and expected exports to continental Europe and Ireland, for all disruption scenarios relating to the Russia-Ukraine dispute.

Incorporating future levels of gas security, the conclusion is that the gas system is resilient to all but the most extreme, unlikely shocks:

- "It is clear that we are secure in the short term, and that the gas system is well placed to respond to a wide range of demand and supply scenarios well into the future. While there are possibilities of exploiting new domestic resources, the reality is that an increasing proportion of gas consumption will need to be met through imports. Modelling shows that while we need to be vigilant to the world market, the GB gas market is able to withstand all but the most extreme shocks and still maintain supplies to protected (non-daily metered) customers."

Given Ireland's reliance on the GB market for gas supplies, it can be concluded from the BEIS security of supply assessment that there is no significant risk to gas supplies to Ireland from GB or from outside the EU via GB.

Furthermore, ENTSOG was required under Article 7 of Regulation (EU) 1938 / 2017 to carry out a Union-wide simulation of gas supply and infrastructure disruption scenarios.[32] As part of this analysis Ireland was assessed as part of the North Sea Gas supply group across a number of regional disruption scenarios. The analysis showed that there was no impact on Ireland in any of the relevant risk scenarios.

[32] https://www.entsog.eu/public/uploads/files/publications/sos/ENTSOG%20Union%20wide%20SoS%20simulation%20report_INV0262-171121.pdf

4 Infrastructure Standard (Article 5)

4.1 N-1 Formula

Under Article 5 of the Regulation, Member States are required to ensure that necessary measures are taken so that, in the event of a disruption of the single largest gas infrastructure, the capacity of the remaining infrastructure is able to satisfy total gas demand during a day of exceptionally high gas demand occurring with a statistical probability of once in 20 years. The assessment is required to be carried out using the N-1 formula set out in Annex II of the Regulation. An N-1 value of 100% or greater indicates that the technical capacity of the remaining gas infrastructure is sufficient to satisfy total gas demand if the largest gas infrastructure fails on a day of exceptionally high gas demand occurring with a statistical probability of once in 20 years.

It should be noted that the GNI Ten Year Network Development Plan[33] assesses gas demands under a 1-in-50 year peak-weather event[34], which is higher than the 1-in-20 peak-weather event that is required under the Regulation. The GNI methodology[35] for calculating the 1-in-20 peak day is consistent with that used in calculating the 1-in-50 peak day demand projection, with the main difference arising in the weather corrected element i.e. the non-daily metered (NDM) sector. This results in the 1-in-50 year NDM demands being approximately 6% higher than the NDM demands for a 1-in-20 year event. The total 1-in-50 year demand (incorporating the Power Generation and Industrial & Commercial sectors) is approximately 2% higher than the 1-in-20 year demand.

In carrying out the N-1 calculations and this risk assessment generally, the figures from GNI's latest 1-in-20 year demand forecast were used. Consequently, the application of the N-1 formula will differ from the 1-in-50 peak day demand forecasts presented in the GNI 2018 Network Development Plan. However, the difference in demand calculations are not so material that they undermine the

[33] GNI's 2018 Network Develop Plan examines forecasts of customer demand for natural gas, the relevant sources of supply and the capacity of the gas transmission system up to 2026/27. It is produced following wide consultation with industry players and includes one-to-one interviews with gas undertakings and potential new entrants. Note: The assumptions which underlie the Network Development Plan are subject to change (e.g. economic growth rates).

[34] Due to Ireland's relatively low level of interconnection to neighbouring gas markets, and low diversification of gas supply sources, reinforcements on the GNI system are triggered by requirement to meet 1-in-50 peak day demand requirements (as opposed to 1-in-20 peak day)

[35] Appendix 6 of the National Risk Assessment outlines the methodology for calculating the 1-in-20 peak-day.

calculations in this report. The results of the N-1 calculation which apply are shown in Figure 4.1.

4.1.1 N-1 Calculations

Article 5 Infrastructure Standard - N-1 Calculations					
N -1 Formula					
N -1 [%] (EPm + Pm + Sm + LNGm - Im) / (Dmax - Deff)					
					Ramp Down Gas Power Stations
Projected Supply and Demand for Calculated Area for 2020/21					
			Facility	**mscm/d**	**mscm/d**
EPm	**E**	Technical Capacity of Entry Points	**Moffat**	26.92	26.92
Pm	**P**	Maximum Technical Production Capability	**Inch**	0	0
			Corrib	7	7
Sm	**S**	Maximum Technical Storage Deliverability			
LNGm	**L**	Maximum Technical LNG Facility Capacity			
Im	**I**	Technical Capacity of largest Gas Infrastructure	**Moffat**	9.92	9.92
D max		Total Daily Demand of the Calculated Area		28.38	28.38
		During a day of exceptionally High Gas Demand (1 in 20)			
Deff		The Portion of Dmax that can be addressed via Demand side measures			6.14
N-1%	-			85%	108%

Table 5: Infrastructure Standard & Ireland's N-1 2020/21

The median supply and demand scenarios assumptions as set out in GNI's 2018 Network Development Plan have been used to project the 1-in-20 peak day projections for the N-1 formula. The analysis is based on the year 2020/21. The median scenario includes a projection that by 2020/21, operations at Inch storage facility will have ceased, and therefore no storage or production from Inch is assumed in the risk assessment. Additionally, in 2020/21 the Corrib gas field is further into its operating life and the volumes forecast are reduced in line with the latest estimates.

In previous risk assessments, total disruption to the gas supply from the Moffat entry point constituted the largest gas infrastructure in relation to gas supply to Ireland. Projects are currently underway at Beattock and Brighouse Bay compressor stations to eliminate the single point of failure which drove the existing failure mode i.e. total disruption to the gas supply from the Moffat entry point.

These mitigation works are scheduled for completion prior to gas year 2020/21 and will allow splitting of the entire SWSOS. This will result in a revision to the treatment of the N-1 calculation in that the loss of the largest piece of gas infrastructure will now constitute a partial disruption to the gas supply from the Moffat entry point. It can be seen that the result of the N-1 calculation is 85%[36] and that Ireland fails to meet the criteria (i.e. if the supply of gas via Moffat is partially disrupted Ireland will be unable to deliver sufficient gas from other entry points to meet total demand on a 1 in 20 year peak-day).

In the event that an EU Member State cannot fulfil the N-1 infrastructure standard on a national basis, the Regulation permits the adoption of a regional approach in order to meet the Standard. Following a request from the CRU, BEIS agreed to adopt a regional approach between the UK and Ireland. The initial analysis indicates that the joint N-1 position for the UK and Ireland is 112%. Further information on this is provided in Section 8 'Regional Approach'.

4.1.2 Bi-directional capacity

Physical Reverse Flow Capacity on Ireland's Gas Network

Article 5(4) of the Regulation stipulates that Transmission System Operators (TSOs) shall enable permanent physical capacity to transport gas in both directions ('bi-directional capacity') on all interconnections between Member States, except:

- In the case of connections to production facilities, to LNG facilities and to distribution networks; or
- Where an exemption from that obligation has been granted, after detailed assessment and after consulting other Member States and with the Commission in accordance with Annex III.

In terms of enabling physical reverse flow at Moffat, the CRU notified BEIS and the EU Commission in 2012 of the request for an exemption under Article 7 of the Regulation. The rationale for this decision was based on findings by Gaslink (the former TSO on the Irish side of the flange) and NGG (the TSO on the GB side of the flange), which suggest that:

[36] In comparison to Ireland's 2016 Risk Assessment, Ireland's N-1 has increased from 28% to 85% in 2018. This can be attributed to the mitigation works taking place to allow the SWSOS to be operated fully split.

- In the short term the majority of gas demand for Ireland will be met via gas from Corrib, but it is expected that in the medium term there will be a return to dependency on the Moffat Entry Point for the majority of gas supplies.
- Previous market demand assessments (undertaken between August – September 2011) have not indicated a need for enabling physical reverse flow at Moffat.
- There would be no additional security of supply benefit for the Member States of the UK or Ireland from enabling bi-directional capacity at the Moffat Interconnection Point, in the short term.

Over the longer term, with increased infrastructure and supply development on the island of Ireland, combined with declining indigenous GB gas production, there could potentially be market-based and security of supply reasons for implementing physical reverse flow at Moffat.

The assessment for enabling bi-directional capacity is facilitated through Irelands' national Risk Assessment. Ireland's 2016 National Risk Assessment did not express a need to enable bi-directional capacity at the Moffat Interconnection Point. At the same time the 2016 risk assessment noted that developments regarding the potential for physical reverse flow would be continued to be monitored by the competent authorities. It highlighted that the exemption would be considered again in 2018; when the next National Risk Assessment would be conducted.

Gas Networks Ireland is in receipt of funding from the Connecting Europe Facility in order to conduct feasibility regarding Physical Revers Flow at Moffat. These studies as well as incorporating technical feasibility will also involve a detailed Cost Benefit Analysis (CBA) to determine whether there is a business case for Physical Reverse Flow at Moffat. In light of these studies, Gas Networks Ireland has requested a further extension of the current exemption, from the competent authorities (CRU & BEIS – UK) until after the conclusion of these studies in November 2018. The output of the studies will then be used to inform a market consultation on Physical Reverse Flow at Moffat in 2019.

GNI has also undertaken an assessment of the market demand and security of supply benefits of enabling bi-directional capacity on the South North Pipeline (SNP). The market assessment does not foresee supply in NI exceeding demand within the next 5 years. As a result, it is unlikely that physical reverse flow on the SNP is required by the market at this time. Gas Networks has written to the competent authorities requesting a continuation of the current exemption.

As part of the Risk Assessment reviews, which are carried out every four years, developments regarding the potential for physical reverse flow will be continued to be monitored by the Competent Authorities.

5 Supply Standard

Under Article 6 (Supply Standard) of the Regulation, the CRU in its role as Competent Authority shall require that the natural gas undertakings[37] that it identifies, to take measures to ensure gas supply to the protected customers in the following cases:

> (a) Extreme temperatures during a 7-day peak period occurring with a statistical probability of once in 20 years;
>
> (b) Any period of at least 30 days of exceptionally high gas demand, occurring with a statistical probability of once in 20 years, and;
>
> (c) For a period of at least 30 days in case of the disruption of the single largest gas infrastructure under average winter conditions.

Definition of Protected Customers

Article 2 (5) of the Regulation defines "Protected Customer *as "a household customer who is connected to a gas distribution network and, in addition, where the Member State concerned so decides, may also mean one or more of the following, provided that enterprises or services as referred to in points (a) and (b) do not, jointly, represent more than 20 % of the total annual final gas consumption in that Member State:*

> *(a) a small or medium-sized enterprise, provided that it is connected to a gas distribution network;*
>
> *(b) an essential social service, provided that it is connected to a gas distribution or transmission network;*
>
> *(c) a district heating installation to the extent that it delivers heating to household customers, small or medium-sized enterprises, or essential social services, provided that such installation is not able to switch to other fuels than gas;"*

In relation to items (a) and (b), the CRU has considered if small and medium-sized enterprises and if "essential social services" should be included in the definition of protected customers. Whilst it might be prudent to restrict the definition to residential customers only, who account for 13% of annual gas demand and 20% of peak day gas demand (as illustrated in Fig 2.3 & Fig 2.4), it is not feasible in an

[37] Natural Gas Undertaking defined in Directive 2009/73/EC means: "a natural or legal person carrying out at least one of the following functions: production, transmission, distribution, supply, purchase or storage of natural gas, including LNG, which is responsible for the commercial, technical and/or maintenance tasks related to those functions, but shall not include final customers."

emergency situation to separately isolate small and medium sized industry (i.e. NDM IC sector). Thus, it is reasonable that small business and industrial customers, which account for about 8% annual gas demand and 10% of peak day gas demand should fall under the definition of "protected customers" also.

In relation to item (c) there are very few district heating schemes in Ireland and the demand is not significant in the context of this Risk Assessment. Customers connected to district heating schemes supplied from an NDM supply point would automatically be protected. District heating schemes supplied from a DM supply point will be considered on a case-by-case basis.

Additionally, the CRU has a category of customers defined in the Code of Operations called Priority Customers. This group is defined as a customer that meets the following criteria:

- Hospitals and Nursing Homes including retirement homes;
- High Security Prisons, and;
- further categories as determined by the CRU from time to time

These customers are given the same status as domestic customers in an emergency (i.e. they are the last customers to have their load curtailed). The CRU has not included any additional category of customers into this category other than those defined in the first two categories. The current priority customers make up only a small percentage of final consumption. In addition to the priority customers in the NDM sector all of the hospitals and prisons in the DM sector account for an additional 1.1% of final demand. The priority customers may be regarded as being equivalent to the essential social services referred to in the Regulation.

Accordingly, as required by the Regulation the CRU, as Competent Authority, defines protected customers as follows:

"protected customers"[38] means all NDM sector customers and, in addition, priority customers in the DM sector which are of the following categories:

- Hospitals and Nursing Homes including retirement homes;
- High Security Prisons, and;
- District Heating Schemes and further categories of essential social services as determined by the CRU from time to time.

[38] The procedure for ensuring gas supplies to protected customers is outlined in Appendix 7.

This definition is in line with the Regulation, which permits inclusion of all domestic customers and some additional distribution and priority customers who do not represent more than 20 % of the final use of gas. The CRU intends to retain discretion, in its Code of Operations, to add other categories of customers to this definition. This might be necessary for example if it came to light during an emergency event that it was desirable or essential to ensure supply to some other category of customer for health and safety reasons. The CRU will ensure that the addition of any new categories of essential service will not lead to the 20% threshold being exceeded.

Gas Volumes Required by Protected Customers

Figure 3.1 provides a breakdown of the volumes of gas required by Protected Customers (as defined by the CRU) under 1-in-20 Peak Day and Average Year Peak Day conditions. Due to potential delays in curtailing the demand of non-protected customers during an emergency (other than demand of power stations), the volumes of gas required have been extended to also include the time taken for the ramping down of non-protected customer gas demand.

Consumption Volume Data	Ireland's Protected Customer Demand during 1-20 Peak Day				Ireland's Protected Customer Demand during Average Year Peak Day			
	2018	2019	2020	2021	2018	2019	2020	2021
1 Day Load (mscm/d)	8.60	8.61	8.60	8.62	6.76	6.77	6.84	6.85
7 Day Load (mscm/d)	60.17	60.24	60.23	60.31	47.33	47.38	47.85	47.94
30 Day Load (mscm/d)	257.85	258.17	258.15	258.46	202.84	203.04	205.09	205.45

Table 6: Protected Customer Gas Demands

Definition of Solidarity Protected Customers

Pursuant to EU Regulation 2017/1938, the CRU would propose to align the definition of Solidarity Protected Customers to the existing definition of Protected Customers. The CRU would propose the following definition of Solidarity Protected Customers,

All NDM sector customers and, in addition, priority customers in the DM sector which are of the following categories:

• Hospitals and Nursing Homes including retirement homes;

• High Security Prisons; and

• District Heating Schemes and further categories of essential social services as determined by the CRU from time to time.

5.1 Ireland's Compliance with the Supply Standard

Notwithstanding imposing any obligations on NGUs, Ireland meets the supply standards set out in Article 6 of the Regulation, as illustrated in figure 3.2:

Article 6 (Supply) - Regulation 1938/2017	Part A (mscmd - 7days)	Part B (mscmd - 30days)	Part C (mscmd - 30days)
Demand/Volume	62	266	218
Supply Capacity Required[1]	62	266	218
Supply Capacity Available	243	1,040	719
Meets Requirement	Yes	Yes	Yes

Table 7: Supply Standard Calculation Results

It should be noted that Ireland can satisfy the first two criteria (i.e. a & b) of the Supply Standard in 2020/21, on the basis of:

- Ireland's access to GB's liquid gas market, and;
- the ability of Corrib to meet approximately 25% of peak day gas demand in 2020/21.

Consequently, Ireland has sufficient access to gas commodity to supply protected customers under items (a) and (b).

With reference to item (c) of the Supply Standard, analysis by GNI confirms that Ireland can meet the gas demand of protected customers for a period of 30 days in the event of the disruption of the single largest gas infrastructure, on the basis of:

- Protected customers accounting for 30% demand for an average year peak, and;
- the ability of indigenous production to meet 28% demand of the average year peak.

Additionally, it has been demonstrated through two 1-in-50 winter events of 2010/11 that gas suppliers are able to meet protected customers' demands.

The results of the N-1 calculation for the supply standard are shown in Table 8.

Article 6 Supply Standard - N-1 Calculations				
N -1 Formula				
N -1 [%] (EPm + Pm + Sm + LNGm - Im) / (Dmax - Deff)				
Projected Supply and Demand for Calculated Area for 2020/21				
			Facility	**mscm/d**
EPm	**E**	Technical Capacity of Entry Points	**Moffat**	27.71
Pm	**P**	Maximum Technical Production Capability	**Inch**	0
			Corrib	7
Sm	**S**	Maximum Technical Storage Deliverability (incl. Linepack)		0.99
LNGm	**L**	Maximum Technical LNG Facility Capacity		
Im	**I**	Technical Capacity of largest Gas Infrastructure	**Moffat**	10.71
D max		Total Daily Demand of the Calculated Area (Protected Customers)		7.28
		During a day of exceptionally High Gas Demand (1 in 20)		
Deff		The Portion of Dmax that can be addressed via Demand side measures		
N-1%	**-**			343%

Table 8: Supply Standard & Ireland's N-1 2020/21

5.2 Economic Impact of Gas Supply Interruptions

In 2010, Ireland's Economic Social Research Institute (ESRI) examined the potential economic impact of natural gas disruptions on the Irish economy for the years 2008 & 2020 (based on projected market conditions). The potential cost of gas interruptions was calculated for three time periods (i.e. one day, three weeks and three months).

In order to take account of different market scenarios, the ESRI report provided separate costs projections of gas supply interruption based on winter and summer months, midweek and weekend days, power-plant availability[39], level of wind generation; and method of gas rationing (i.e. proportional rationing[40], preferential rationing[41]).

Additionally, when quantifying the costs associated with a natural gas outage, the ESRI report considered:

- Cost of electricity outage for residential, industrial and commercial sectors;
- Lost consumer surplus (i.e. cost of no gas to residential users);
- Lost producer surplus (i.e. cost of no gas for local suppliers of gas);
- Lost VAT on the sale of gas and electricity, and;
- Total cost of natural gas and electricity outages.

At a high level, the ESRI report found that disruption to electricity supply (as a result of a gas outage) accounts for on average 86% of the total costs of natural gas disruption in Ireland. With reference to electricity costs, Figure 12 highlights that losing gas-fired electricity generation could cost between 0.1 - 1.0 billion euro per day (based on a gas supply disruption in 2008). Additionally, the costs associated with an electricity supply interruption tend to be higher if the residential sector is subject to a rationing of load.

Section 6.4 provides further information on the impact of preventative measures.

[39] Moneypoint (MP) power station running on either full or partial availability.

[40] Each sector could lose electricity in proportion to its share of overall electricity consumption.

[41] Electricity could be preferentially rationed in the sector with the lowest gross value added per unit of electricity (i.e. industry), or electricity could be rationed in the sector with the highest GVA per unit of electricity (i.e. residential).

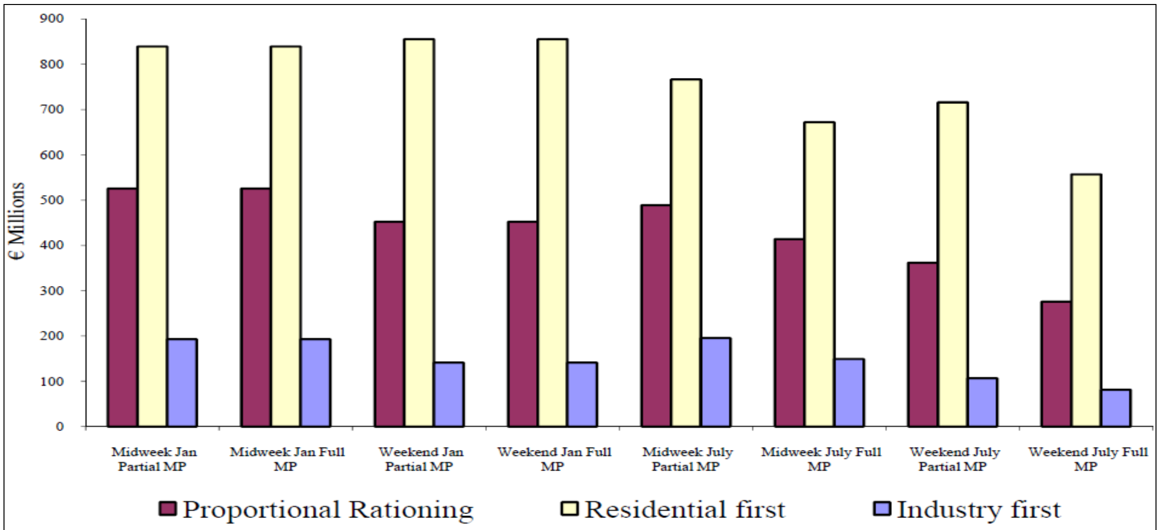


Figure 12: Cost of 1-day Electricity Shortage in 2008

Figure 13 highlights the costs of electricity shortages (due to gas supply interruption) for three weeks and three months. The results vary depending on season, method of electricity rationing, and whether Moneypoint power station is on full or partial availability.

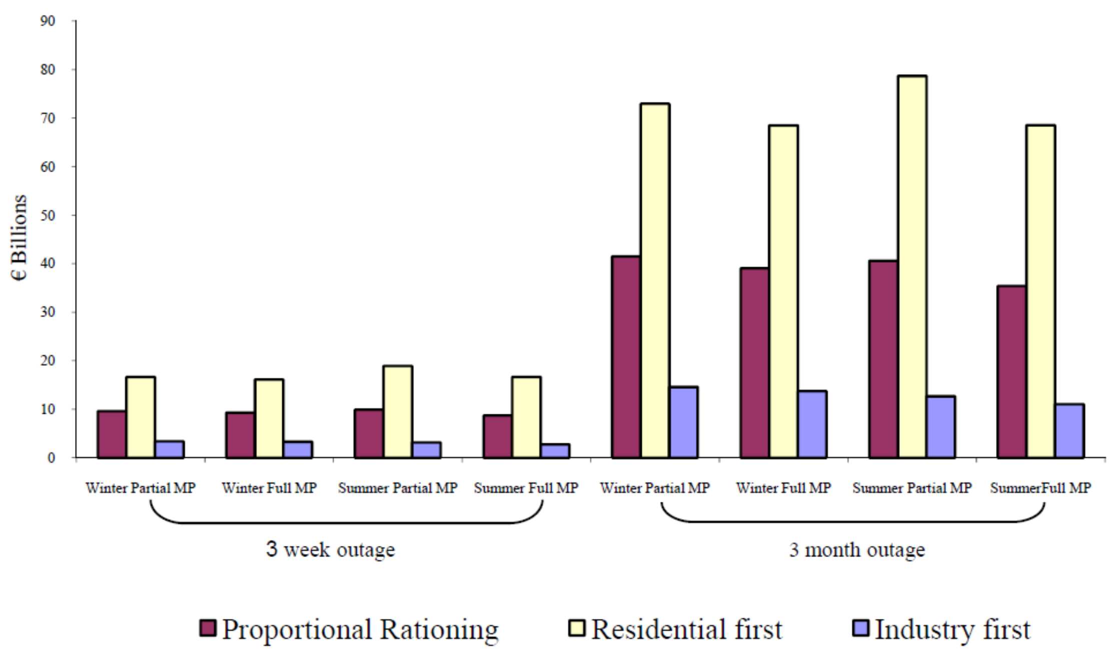


Figure 13: Cost of Three Week and Three-Month Electricity Shortages in 2008

6 Preventative Measures

6.1 Market-based Supply Side

Article 9 (3) specifies that "the preventive action plan shall be based primarily on market-based measures and shall not put an undue burden on natural gas undertakings, or negatively impact on the functioning of the internal market in gas." A non-exhaustive list of market-based supply side and demand side measures is presented in Table 9, which the Competent Authority takes into account in order to improve security of gas supplies.

Supply Side Measures	Demand Side Measures
Increased production flexibility	Fuel switching
Facilitating the integration of gas from renewable energy sources	Use of interruptible contracts
Commercial gas storage	Voluntary firm load shedding
LNG terminal capacity	Increased efficiency
Diversification of gas supplies	Increased use of renewable energy sources
Reverse flows	
Coordinated dispatching by TSO	
Use of long-term and short-term contracts	
Investment in infrastructure	
Contractual arrangements to ensure gas supply	

Table 9: Market-based Supply and Demand side Measures

6.1.1 Market-based Supply Side Measures

With reference to market-based supply side measures, Ireland has some limited production capacity in Kinsale that can be drawn on to increase supply. In the cold periods of January and December 2010 a combination of production and storage gas from the Kinsale storage facility contributed 16% of Ireland total demand. However, this facility is now in blowdown mode and is due to close in 2020. While this facility remains operational, there may be some limited flexibility available to the market to increase supply. Without this source of gas, the Moffat entry point would have been strained and unable to deliver the gas required to meet the demand. Additionally, both interconnectors from Moffat (IC1 and IC2) were required to be in operation to deliver the quantities of gas required to meet Irish demand.

Ireland now has indigenous production capacity at the Corrib gas field which was not available in 2010. In the event of such a severe weather event the presence of gas flows from Corrib would help limit any impact. It is clear from the market operation during more recent cold spells (March 2018) that suppliers react to market signals (i.e. high NBP prices), with indigenous gas production from Corrib and Kinsale operating at the maximum available output.

Given Ireland's geographical location, on the periphery of Europe, measures such as reverse flows and coordinated dispatching are not feasible supply side market-based measures. Furthermore, the use of long term and short-term contracts do not protect Ireland against low supply in the UK, or major infrastructure risks. However, it should be noted that Ireland's connection to the highly liquid NBP trading hub can result in market-based pricing signals to industrial customers at times of supply shortage.

6.1.2 Market-based Demand Side

6.1.2.1 ***Fuel Switching as a market-based demand side measure***

With an average of 50% of gas in Ireland being used for power generation in 2016, Ireland currently utilises fuel switching as a non-market-based demand-side measure for managing the gas system and protecting smaller, vulnerable and priority gas customers. In 2009, the CRU issued a Decision Paper – *Secondary Fuel Obligations on Licensed Generation Capacity in the Republic of Ireland* (CER/09/001). This paper specifies the level of primary and secondary fuel stocks electricity generators are required to maintain.

Since 2009, significant developments have taken place within Ireland's electricity and gas markets including increased renewable generation, the commissioning of the East West Interconnector (EWIC), and the first gas flows from the Corrib gas field. Given such developments, coupled with concerns regarding gas security of supply at a European level (due to a potential interruption of Russian gas supplies), discussions are ongoing between CRU and Eirgrid (Ireland's electricity TSO) to identify whether changes to the existing fuel stock obligations on electricity generators are merited. In addition, the DCCAE has engaged with CRU, GNI, and Eirgrid to help identify ways to improve market resilience.

With regard to fuel switching, CRU previously consulted on whether related market-based demand side measures could be introduced to address a gas shortage. EirGrid noted that such market measures should not be introduced to address a gas shortage in the interests of safeguarding the power system. It noted that while fuel switching provisions are in place in accordance with CER/09/001, it should only be considered as an emergency response measure due to the increased risk of electricity outages, and that the need for fuel switching must be co-ordinated by the gas and electricity system operators, as required.

6.1.2.2 Third Party Access Services as a market-based demand side measure

Article 14 of Regulation 715 of 2009 requires that transmission system operators provide both firm and interruptible third-party access services. Consequently in 2012, the CRU consulted on introducing an interruptible capacity product at entry and exit points. In respect of interruptible at exit, there was no great support for this product, from respondents to the consultation. At the time, it was considered that given that capacity congestion at the exit was unlikely, the price difference between a firm and interruptible product would be negligible, and hence market demand would be negligible.

6.2 Non-Market-based Measures

Annex VIII of the Regulation identified non-market-based supply side and demand side measures that can be utilised to enhance gas security of supply (see Table 10 below).

Supply Side Measures	Demand Side Measures
Use of strategic gas storage	Enforced fuel switching
Enforced use of stocks of alternative fuels	Enforced utilisation of interruptible contracts
Enforced use of electricity generated from sources other than gas	Enforced firm load shedding
Enforced increase of gas production levels	
Enforced storage withdrawal	

Table 10: Non-Market-based Supply and Demand side Measures

Fuel switching represents the most immediate non-market-based measures that can be utilised to ensure gas security of supply. Power stations in Ireland comprise 50% of the gas demand and can be instructed by EirGrid to run on a secondary fuel in order to prevent or respond to a gas emergency situation.

Arrangements are currently in place, which ensure that gas generators in Ireland are able to switch from their primary fuel to their secondary fuel while operating continuously and run on their secondary fuel for up to 5 days. The secondary fuel capability includes the following measures:

- Electricity generating plants whose primary fuel is gas are required to be able to run on a secondary fuel,
- Such plants must also ensure that sufficient stocks of secondary fuels are held on site,
- Electricity generating plants whose primary fuel is not gas (such as oil and coal fired plants) are required to hold additional primary fuel in storage, and;
- EirGrid monitor the capability of generators and have commenced a schedule of periodic planned tests.

In order to ramp down in a controlled manner and maintain control, EirGrid stress that only two plants could be ramped down in parallel and these plants would have to be ramped down over the course of five hours. Power demand model analysis by GNI suggests that on a peak day there would be approximately 12 gas plants in merit. When considering the operational limitations of ramping down, as raised by EirGrid, 30 hours would be required to switch these 12 plants to their secondary fuel. According to GNI's calculations, this ramping down would require gas consumption equivalent to 60% of the peak day consumption level for the power generation sector.

Daily metered customers could also provide demand side response to a potential emergency. Other non-market-based measures outlined in Table 10 including increased production and storage withdrawal are provided for in Ireland's National Emergency Plan. With reference to production, Corrib can meet approximately 28% of Ireland's peak day gas demand in 2018/19.

It should be noted also that the second interconnector from Moffat (IC2) was built for security of supply reasons. It provides 100% back up capacity and is being underwritten by the Irish customer. It has always been assumed that in the event of loss of supply at Moffat the linepack in IC1 and IC2 could supply the Irish demand on a 1 in 50 winter for five days, assuming all power stations could be fuel switched in 5 hours. This does not allow for any supply to Northern Ireland through the SNP, which is connected to IC2. However, the 2016 UK Ireland Joint Risk Assessment considered the impact of Northern Ireland having access to linepack on IC2. The adoption of this regional approach between the UK and Ireland enables Ireland to meet the N-1 Standard, as required by the Regulation, while providing access to linepack on the IC2 to NI.

It should be noted that the Gas Electricity Emergency Planning (GEEP) group is concerned with the interactions between the gas and electricity sectors, and will focus on short term issues relating to security of supply and emergencies in electricity and gas. The GEEP may also encompass some longer term and wider energy/emergency policy issues, which may emerge and be of relevance to the gas and electricity sectors. Communications between the gas and electricity sectors is also within the remit of the group.

6.3 Infrastructure Projects & Operational Improvements

With reference to the improvement of gas security of supply, the Competent Authorities in the UK and Ireland are considering initiatives such as potential security upgrades at key points within the UK's and Ireland's gas systems. Additionally, the development of Projects of Common Interest has the potential to enhance security of gas supply in the UK and Ireland.[42]

Under Regulation 347/2013 (*Guidelines for trans-European energy infrastructure*), the EU Commission is mandated with drawing up a list of infrastructure projects, referred to as Projects of Common Interest (PCIs), to further the sustainability, resilience and integration of the EU's internal energy market. The PCI list, which is developed on a biennial basis, is derived from submissions from project promoters to the EU Commission.

To date, the CRU has inputted into the EU Commission's PCI review process by providing assessments of projects' feasibility, maturity and impact where relevant to Ireland. The projects that were designated with PCI status by the EU Commission, and are of relevance to gas in Ireland include:

1. LNG Terminal located between Tarbert and Ballylongford (Ireland), which is being promoted by Shannon LNG; and
2. A clustered PCI proposal combining:
   - Underground Gas Storage (UGS) facility at Larne (Northern Ireland), which is being promoted by Islandmagee Storage.
   - Upgrade of the SNIP (Scotland to Northern Ireland) pipeline to accommodate physical reverse flow between Ballylumford and Twynholm, which is being promoted by Premier Transmission Limited.

[42] In November 2017 the European Commission published its third list of EU-wide Projects of Common Interest under Regulation (EU) 347/2013. https://ec.europa.eu/energy/sites/ener/files/documents/annex_to_pci_list_final_2017_en.pdf

- Physical reverse flow at Moffat interconnection point, which is being promoted by GNI.

The process in determining the PCI list for the two-year period 2018-2019 has commenced.

In order to support security of supply, the CRU also requires Ireland's electricity TSO (i.e. EirGrid) to engage in a programme of secondary fuel switchover testing of gas generators and monitoring of their fuel stocks. As a part of this programme, EirGrid submits an annual report to the CRU regarding generators compliance with fuel switching arrangements. Additionally, the CRU requires that Ireland's gas TSO (i.e. GNI) undertakes annual gas emergency exercises to test the effectiveness of industry response to a gas supply emergency.

6.4 Impact of Preventative Measures

The measures presented in the Preventative Action Plan sets out to limit the impacts on energy markets, the environment and on end users. However, there may be some residual impacts resulting from these measures if exercised.

In particular, with regard to the power generation load shedding arrangements set out in Section 6.2; it should be noted that there are operational risks associated with running on secondary fuels for an extended period. There will also be cost implications in terms of the wholesale price of electricity and secondary fuels (typically distillate oil) are far more carbon intensive than gas.

7 Obligations on Relevant Bodies

7.1 Natural Gas Undertaking (NGU)

7.1.1 Obligations on Gas Shippers and Gas Suppliers

In 2009, the CRU (in conjunction with UREGNI) consulted on:

- whether shippers/suppliers be required to secure supplies for an exceptionally cold winter, and;
- whether shippers/suppliers be required to book capacity for an exceptionally cold day (1 in 50 or 1 in 20 day).

In the context of almost all of Ireland's gas being sourced from Moffat and limited storage opportunities available on the island, it was decided not to require shippers to secure gas supply for an exceptionally cold winter. This would put an unfair burden on shippers and potentially result in higher gas sale prices. It was noted also that this would provide no security in the event of infrastructure failure from the Moffat interconnection point.

With reference to booking capacity for the peak day demand, the CRU requires peak day capacity be booked at exit for the NDM sector (domestic and small business sectors). This peak day requirement is for a 1-in-50 day, and is contained within Gas Networks Ireland Code of Operations.

7.1.2 Obligations on Transmission System Operator (GNI)

GNI, as the TSO, has a key role in the development of emergency arrangements for Ireland. In addition, with the approval or instruction of the NGEM, it is the responsibility of GNI to declare a national gas emergency. Further to its general obligations, GNI is required to operate a secure safe and reliable network and to develop the network to ensure long term gas demand is met. Specifically its licence obligations require it to:

- maintain the operational integrity of the gas transportation system,
- design the Transmission system to meet 1-in-50 peak day demand,
- publish 10 year network development statements on an annual basis,

- Develop and maintain the Natural Gas Emergency Plan[43], and;
- Provide Transmission and Distribution emergency response.

The CRU has designated GNI as the National Gas Emergency Manager (NGEM) to manage the operational response to gas supply interruptions in Ireland. Additionally, the CRU has designated GNI as the Crisis Manager, in accordance with the Regulation. With reference to market rules, GNI is also responsible for the Code of Operations, which sets out the market measures to maintain a supply / demand balance on the system. In this role GNI develops new products (e.g. storage) as the market dictates.

7.1.3 Obligations on Gas Producers

Gas producers are required to comply with the instructions of the NGEM. Specifically, in the case of a shortage of gas supply they may be instructed to increase production.

7.1.4 Obligations on Gas Storage Operators

With the closure of the South West Kinsale storage facility operated by PSE Kinsale Energy Ltd, there is no gas storage facility in Ireland.

7.1.5 Exception to Obligation on NGUs

Article 6(2) of the Regulation requires that the CRU identify in the Preventive Action Plan how any increased supply standard or additional obligation imposed on NGUs may be temporarily reduced in the event of a Union or regional emergency. It is considered that this requirement is not relevant to Ireland, as the CRU has not imposed such obligations on NGUs.

7.1.6 Safety Obligation on NGUs

Under the provisions of the Energy (Miscellaneous Provisions) Act 2006 (the '2006 Act'), the CRU has the responsibility to regulate the activities of NGUs with respect

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[43] In December 2008, in accordance with S.I. No. 697/2007 - European Communities (Security of Natural Gas Supply) Regulations 2007, the CRU appointed Gas Networks Ireland (the TSO) as the National Gas Emergency Manager. In accordance with the same Statutory Instrument (S.I. No. 697/2007) the CRU directed the TSO to prepare a "*Natural Gas Emergency Plan*". Thereafter, in line with our statutory powers, the CRU approved the "***Natural Gas Emergency Plan***".

to onshore gas safety, through the establishment of a natural gas safety regulatory framework (the 'Framework'). In terms of operating the Framework, the CRU requires NGUs to demonstrate that they are managing their gas safety risks to a level that is "as low as reasonably practicable" (ALARP), with an appropriate level of regulatory intervention necessary to secure compliance with the Framework and achieve the desired safety outcomes. Specifically, under the Framework document, NGUs are required, to demonstrate that they have suitable arrangements in place for responding in the event of large-scale network gas emergencies.

7.2 Other Relevant Bodies

7.2.1 Department of Communications, Climate Action, and the Environment (DCCAE)

The DCCAE has overriding responsibility for energy policy including security of supply of gas, electricity and oil, whose functions include the introduction of legislation and of Public Service Obligations (PSOs). Specifically, under section Section 21 of the Gas (Interim) (Regulation) Act 2002, the Minister for Energy may direct the CRU to impose PSOs relating to security of supply.

To date, no such direction has been given to the CRU in relation to security of gas supply. However, the DCCAE has imposed public services obligations within Ireland's electricity sector,[44] in order to support the national policy objectives of:

- security of energy supply,
- the use of indigenous fuels, and;
- the use renewable energy sources.

Currently, as regards electricity produced from gas, the electricity PSO levy support extends to biomass, including landfill gas; biomass-CHP; biomass-anaerobic digestion; and pyrolysis. This is consistent with the potential supply side measures referred to in Article 9 (3) of the Regulation for increasing gas security of supply.

[44] Section 39 of the Electricity Regulation Act 1999 (as amended) sets out the legal basis for the PSO levy in Ireland. Additionally, Statutory Instrument No. 217 of 2002 made under Section 39 requires that the CRU calculates and certifies the costs associated with the PSO and sets the associated levy for the required period.

8 Regional Approach

Regional co-operation is an underlying feature of the Regulation and is required in particular for the establishment of the Risk Assessment, the Preventive Action Plans and Emergency Plans. In addition, co-operation is important for meeting the infrastructure standard, and in the provisions for EU and regional emergency responses. This is of particular importance as Ireland is dependent on the Great Britain for its gas supply and Northern Ireland in turn is dependent on Ireland's gas import infrastructure to meet 100% of its gas supplies.

A key feature of the Regulation is the establishment of regional risk groups. A regional chapter, agreed jointly with risk group members, must now be included in the preventive action plan. Ireland is a member of two such risk groups, the Norway risk group and the UK risk group as defined in Annex I of the Regulation.

As detailed in the national Risk Assessment, Ireland cannot meet the infrastructure standard in the short-term. In the event that an EU Member State cannot fulfil the N-1 infrastructure standard on a national basis, the Regulation permits the adoption of a regional approach in order to meet that Standard. In particular "*the competent authorities of neighbouring Member States may agree to fulfil, jointly, the obligation set out in paragraph 1 of this Article. In such case the competent authorities shall provide in the risk assessment the calculation of the N-1 formula together with an explanation in the regional chapters of the preventive action plans how the agreed arrangements fulfil that obligation.*"

Following a request from the CRU (as Ireland's Competent Authority), the Department of Business Energy and Industrial Strategy (BEIS) in the UK agreed to adopt a regional approach between the UK and Ireland.

Under the previous regulation (994/2010) a UK & Ireland joint preventative action plan was required. However, under the regional group approach this requirement is now covered off in the UK group regional chapter. This chapter will be developed by the CRU and BEIS and other members of the UK risk group.

The initial analysis indicates that the joint N-1 position for the UK and Ireland is 112%.

In order to facilitate a regional approach, the UK and Ireland Competent Authorities meet through the UK and Ireland Emergency Group Forum. The forum comprises the three government departments (BEIS, DCCAE and DfE), the three regulators (OFGEM, CRU and UREGNI), and the gas and electricity TSOs (GNI, EirGrid, National Grid, National Grid Gas, SONI and PTL). Meetings take place every six months. The group is working towards a regional approach to emergencies. This involves the establishment of protocols to link emergency plans of each jurisdiction. Emergency exercises are carried out by the TSOs on an annual basis and plans are refined on the basis of the learnings from the exercises. The forum is also used to discuss the implementation of the Regulation and the plans and assessments carried out by each jurisdiction in compliance with the Regulation.

9 Summary

Ireland's Preventive Action Plan has been prepared in accordance with the Regulation. Given that the Preventive Action Plan will be required to be updated every four years, the CRU will continue to monitor market developments, and update the document to ensure consistency with the Regulation.