Northern Ireland

Gas Capacity Statement

2013/14 – 2022/23

February 2014



About the Utility Regulator

The Utility Regulator is the independent non-ministerial government department responsible for regulating Northern Ireland's electricity, gas, water and sewerage industries, to promote the short and long-term interests of consumers.

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

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

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

Our Mission	Value and sustainability in energy and water.
Our Vision	We will make a difference for consumers by listening, innovating and leading.

Our Values

Be a best practice regulator: transparent, consistent, proportional, accountable, and targeted.

Be a united team.

Be collaborative and co-operative.

Be professional.

Listen and explain.

Make a difference.

Act with integrity.

Abstract

This capacity statement provides an assessment of the Northern Ireland transmission network's ability to meet future demands on the network over a ten year period.

The system is assessed by using network modelling on days of different demands over a number of different scenarios.

The modelling results for each of the scenarios and demand days are presented and discussed.

Audience

The paper is intended primarily for the gas and electricity power sectors. However we expect that there is a wider interest in terms of the security of gas supplies to Northern Ireland.

Consumer impact

The paper provides an assessment of the ability of the transmission network to flow gas over a number of potential future scenarios.

Contents

Executive Summary

The Northern Ireland Capacity Statement (NICS) provides an assessment of the ability of the Northern Ireland (NI) gas transmission network to deliver gas over a number of potential scenarios within the next ten years.

The NI Transmission System Operators[1] carried out the assessment using modelling software to test the network's ability to meet three types of demand days (minimum summer demand, average winter demand and severe winter demand) for the following scenarios:

i. Base Case scenario which assumes the existing infrastructure for all years;
ii. Base Case scenario plus the proposed 'Gas to the West' network extension;
iii. Introduction of a compressor on the Scotland to Northern Ireland Pipeline (SNIP);
iv. Use of a compressor at Coolkeeragh;
v. Introduction of a gas storage facility at Larne, Co. Antrim.

The modelling also considered the firm and interruptible demands for the severe winter demand day. The demand data was provided by the Northern Ireland power stations and distribution companies.

A key assumption in the modelling was a 56 barg pressure level at Twynholm. Twynholm is the point where the NI transmission network connects to the upstream BGE(UK) network. The pressure level adopted at this point is a key factor in the pressures available to the downstream NI network. The reasons for this assumption are explained in section 4.1. A pressure level of 56 barg is considered a conservative modelling assumption.

The modelling results show that the existing NI transmission infrastructure can meet the average winter peak and minimum summer demands for the Base Case scenario. However there are potential low pressure issues on the severe winter peak day for both the Base Case and additional Gas to the West demands which may create network issues in such extreme circumstances.

Should these circumstances occur, arrangements are in place to enable shippers to utilise the SNP and the modelling has shown that use of the SNP will provide the necessary pressures to meet full demand. There are also arrangements in place to address low pressures on the network such as power stations switching

1 BGE (UK), Belfast Gas Transmission Limited, Premier Transmission Limited

to secondary fuels.

Modelling has shown that including additional compression facilities at Twynholm would also address the low pressure issues.

The modelling has also shown that there are limited benefits of using the compression facilities at Coolkeeragh because the pressure levels are below the operating conditions of the compressor.

For the storage scenario pressures and flows on the NI system remain within acceptable pressures for all years.

1. Introduction

1.1 Background information

The Northern Ireland Transmission System Operators (TSOs) are obliged in their respective network codes and licences to produce a capacity report based upon network analysis of relevant supply and demand scenarios. The publication of the NICS meets these requirements.

In recent years the Utility Regulator and the CER produced a Joint Gas Capacity Statement (JGCS) which assessed the ability of the all-island transmission network to meet the future requirements on the system.

This year Gaslink have published a Network Development Plan (NDP) in line with Article 22 of Directive 2009/73/EC. Subsequently the CER have decided not to develop an all-island JGCS as there will be areas of duplication with the NDP.

The Utility Regulator has also consulted on changes to the TSO licences which would require the TSOs to provide the Utility Regulator with coordinated network forecast statements by the tenth working day in June in each calendar year. We will discuss with the TSOs the process for developing the NICS going forward.

1.2 Report Structure

This paper is set out as follows:

Section 2 provides an overview of the existing Northern Ireland transmission network and also future infrastructure projects that are currently being considered.

Section 3 provides information on historic and forecast gas demand for NI.

Section 4 sets out the scenarios that have been modelled in this year's NICS.

Section 5 sets out the modelling results.

Section 6 provides commentary on the results.

Appendix 1: Demand Forecasts

Appendix 2: Summary of System Modelling Assumptions

2. Transmission Network Overview

2.1 Scottish Onshore system and subsea system

The Moffat Entry Point connects the Northern Ireland and Ireland gas networks to National Grid's National Transmission System (NTS) in GB. This connection allows for the importation of GB gas to Ireland and Northern Ireland. From the connection with the National Grid system at Moffat, the Scottish onshore system consists of a compressor station at Beattock, which is connected to Brighouse Bay by two pipelines from Beattock to Cluden and a single pipeline from Cluden to Brighouse Bay, all capable of operating at 85 barg.

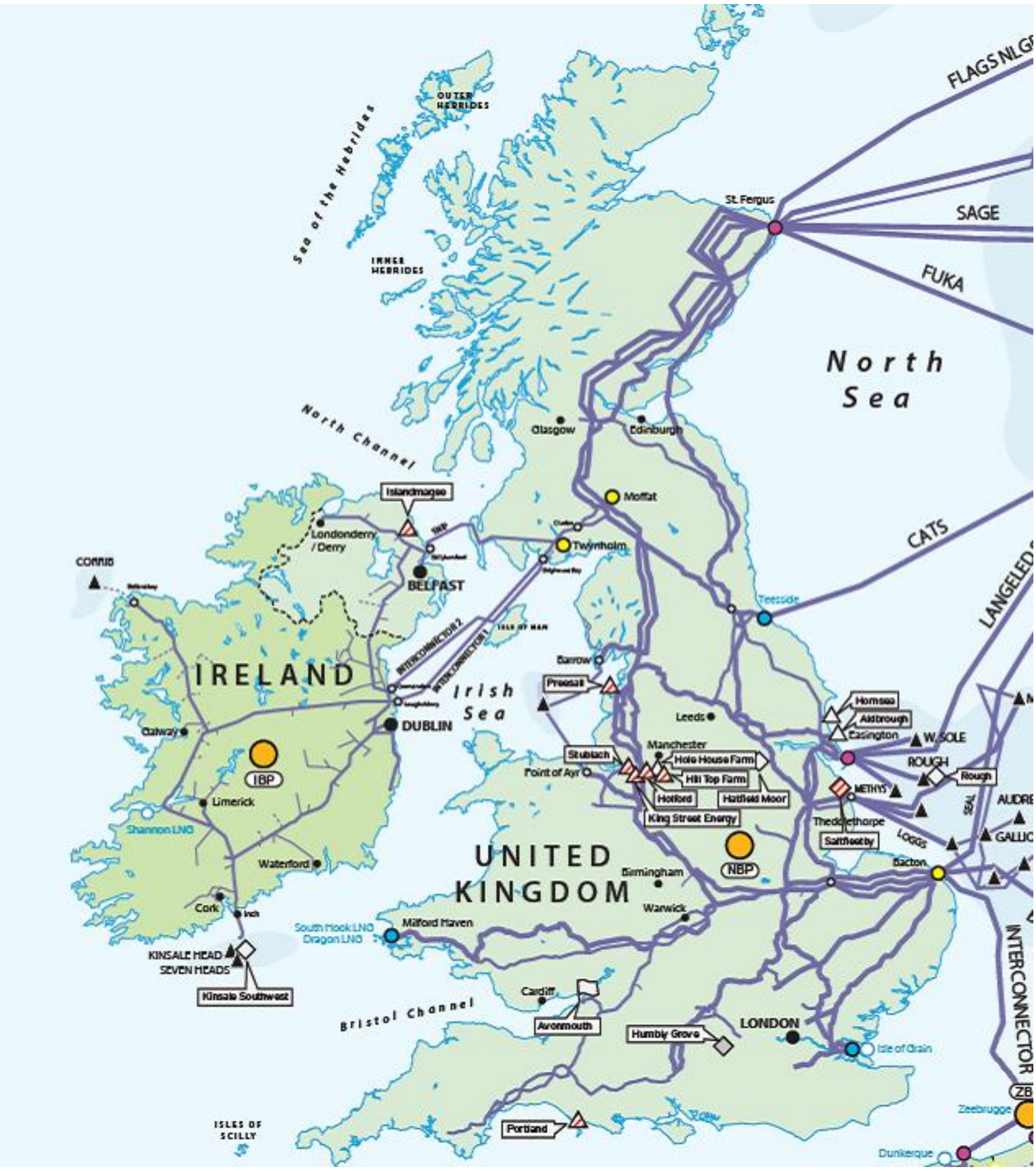
A second compressor station at Brighouse Bay compresses the imported gas into the two sub-sea interconnectors to Ireland which can operate at pressures in excess of 140barg if required. Before reaching the Brighouse compressor station, an offtake station at Twynholm supplies gas to Northern Ireland via the SNIP. The SNIP pipeline has a maximum operating pressure of 75barg, although there is a minimum guaranteed supply pressure into this system which is currently 56barg.

A map of the UK/Ireland transmission network is presented in Figure 1.

2.2 Northern Ireland transmission system

The Scotland to Northern Ireland 600mm pipeline (SNIP) connects to the BGÉ(UK) system at Twynholm in Scotland and has a maximum operating pressure of 75 barg. The pipeline is 135 km long and runs towards the coast near Stranraer and crosses the Irish Sea to terminate at Ballylumford Power Station, Islandmagee. The SNIP is owned and operated by PTL.

Figure 1: UK/Ireland transmission network map



The Belfast Gas Transmission Pipeline (BGTP) comprises a further 35kms of

600mm pipeline with a maximum operating pressure of 75 Barg and runs from Ballylumford via Carrickfergus to Belfast, where it supplies the Greater Belfast demand. The North-West Pipeline (NWP), extends a further 112km of 450mm pipeline from Carrickfergus to supply the power station at Coolkeeragh. The NWP, is owned and operated by BGÉ (UK) Ltd. The firmus energy distribution network also connects several towns to the NWP.

A 450mm pipeline connecting the Interconnector System to the NWP was built in 2006. This pipeline, called the South-North Pipeline (SNP), is 156kms long and extends from the IC2 landfall at Gormanston, Co. Meath in Ireland to Ballyalbanagh on the NWP, approximately 12km west of the Carrickfergus AGI. This pipeline facilitates supplies to towns and industries in the corridor from Newry to Belfast (also being developed by firmus energy) and in the longer term will be able to support the SNIP pipeline in meeting increased demand levels in Northern Ireland.

2.3 Northern Ireland distribution system

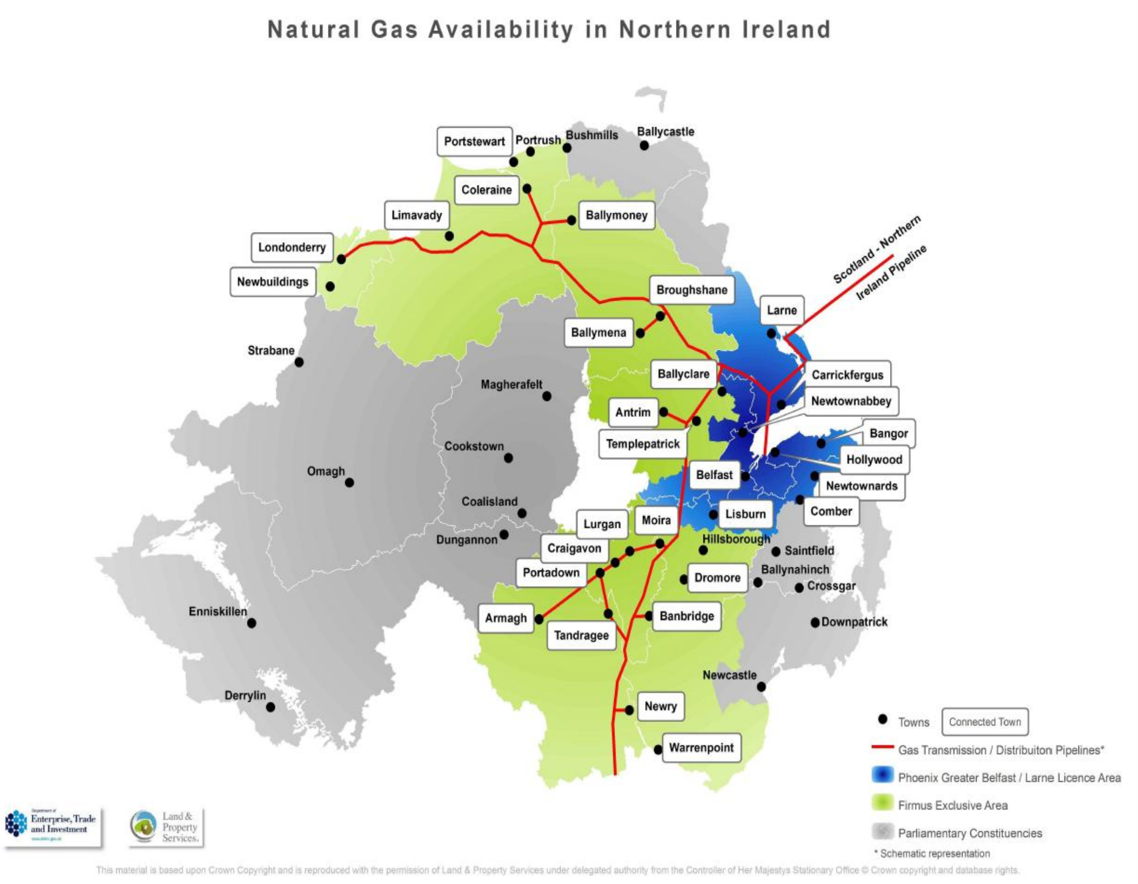
Northern Ireland has two gas distribution network companies: Phoenix Natural Gas Limited (PNGL) and firmus energy (distribution) Limited (firmus). PNGL own and operate the distribution network in the Greater Belfast and Larne areas. PNGL was awarded their conveyance licence in September 1996. Presently they have over 150,000 customers connected within the Greater Belfast and Larne licence area.

firmus own and operate the distribution network within the ten towns licence. This area covers a greater geographical area including Londonderry, Limavady, Coleraine (inc. Portstewart, and Bushmills), Ballymoney, Ballymena (Broughshane), Antrim (inc. Ballyclare and Templepatrick), Craigavon (inc. Portadown and Lurgan), Banbridge, Newry (Warrenpoint) and Armagh (Tandragee).

firmus was awarded their conveyance licence in March 2005 and have around 20,000 customers connected within the ten towns licence area.

A map outlining the PNGL and firmus distribution licence areas is shown in Figure 2.

Figure 2: Northern Ireland Distribution Network



2.4 Network extension – 'Gas to the West'

The Department of Enterprise, Trade and Investment (DETI) and the Utility Regulator have been progressing work on bringing natural gas to additional towns in the West and North-West of Northern Ireland since 2009.

A number of technical assessments, economic evaluations and consultations have been carried out and are available on the DETI and Utility Regulator websites for further information.

In January 2013, the Northern Ireland Executive agreed in principle to provide financial assistance up to £32.5 million towards the cost of constructing new gas networks to the West and North-West.

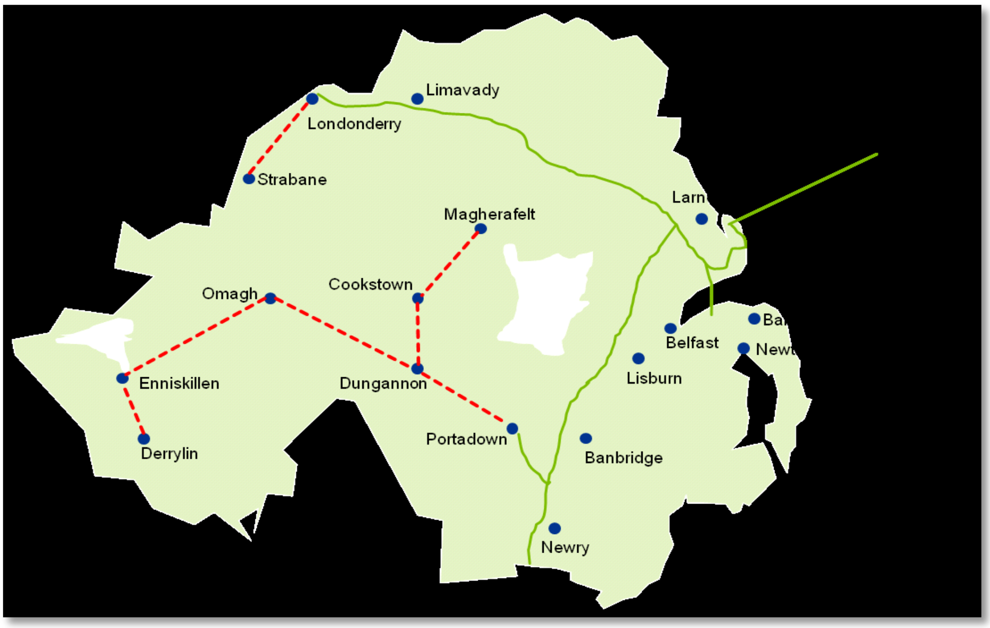
A map of the proposed network extension has been included in Figure 3. It is estimated that this project would connect some 34,000 new business and domestic consumers to natural gas in the West and North-West.

On the 6th February the Utility Regulator published a Notice calling for applications for the available licences[2].

After the award of new gas licence(s), the new licensee(s) will have to complete detailed design work on the new gas infrastructure, consider any environmental issues, and obtain the necessary wayleaves and planning consent in advance of any construction works commencing.

As such, it is difficult to determine when the first connections to the pipeline extensions will be in place, however in order to determine the impact of the extensions to the network, the modelling has assumed that the network will be available in gas year 2016-2017.

Figure 3: Proposed Network Extensions under the 'Gas to the West' project



2 http://www.uregni.gov.uk/news/ur_launches_gas_to_the_west_licence_application_process

2.5 Gas Storage

Islandmagee Storage Limited is progressing plans to develop an underground natural gas storage facility which will have its above-ground facilities near Ballylumford, in County Antrim, Northern Ireland. Seven caverns with a total gas storage capacity of approximately 500 million cubic metres are planned within a layer of bedded salt greater than 200 metres thick located approximately 1,500 metres beneath Larne Lough.

The project has been granted planning permission, a gas storage licence from the Utility Regulator, and a Mineral Licence from DETI.

Applications have been submitted for three marine licences to the Department of Environment and Northern Ireland Environment Agency. Further consents will also be needed before the project can proceed to full construction and operation.

The network modelling has assumed that the Islandmagee storage project commences operations in gas year 2018-2019.

3. Northern Ireland Gas Demand

3.1 Historic NI Annual Demand

The historic NI gas demand is summarised by sector in Table 1 and shown graphically in Figure 4 below. The distribution category includes the gas demand of Phoenix Natural Gas and firmus energy, while the power sector includes the Ballylumford and Coolkeeragh power stations. The total NI annual demand has grown by 9.3% over the period 2003/04 – 2011/12 (or 1% p.a.).

Gas demand in NI reached a peak in 2006/07, however since this time gas demand has lowered to its current levels. This overall decrease in demand from 2006/2007 until 2011/12 is driven by lower demand from the power sector which has decreased markedly over these years. On its own the power sector demand has reduced by 42% between 2006/07 and 2011/12.

Lower demand from the power sector is due to a number of factors. Lower coal prices has lowered the demand from gas fired power stations and more efficient gas plant operating in the Republic of Ireland (RoI) has reduced Northern Ireland power stations position in the SEM merit order. Consequently there is less electricity demand from the NI gas fired power stations and therefore lower gas flows. Increasing wind powered generation and the general economic downturn have also contributed to a decrease in demand.

There was a slight increase in annual gas demand between 2009/10 and 2010/11. Demand increased by 2.98% from 15,921 GWh/y in 2009/10 to 16,396 GWh/y in 2010/11, which was largely attributed to an increase in power sector demand by 1.85%. The increase in power sector demand was caused by the unavailability of the Moyle interconnector which resulted in lower electricity imports and therefore increased use of gas fired power stations in Northern Ireland.

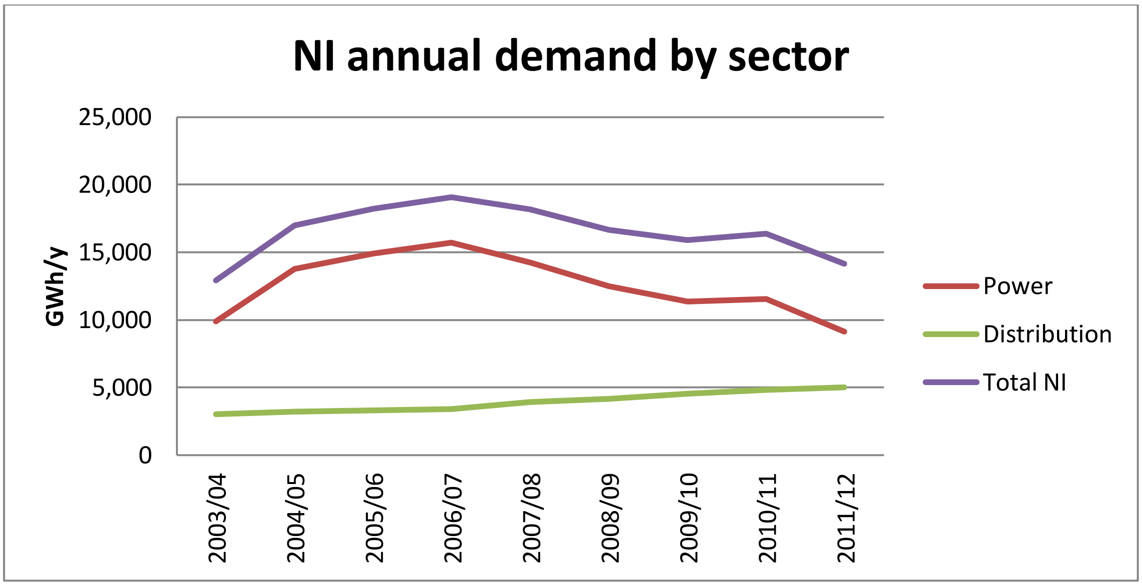
Although overall power sector gas demand has fallen, Table 1 shows a steady year-on-year increase in demand from the distribution sector reflecting the growth in domestic and industrial/commercial sectors within Northern Ireland. However since demand from the power sector accounts for a high percentage of overall total demand in Northern Ireland and due to the reduction in demand from the power sector as noted above, the total annual gas demand has decreased between 2006/2007 until 2011/12.

Table 1: Historic NI Annual Demand Summarised by Sector

	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
ENERGY (GWh/y)									
Power	9,903	13,770	14,922	15,696	14,249	12,489	11,352	11,562	9,137
Distribution	3,040	3,209	3,327	3,394	3,923	4,161	4,569	4,834	5,008
Total NI	**12,943**	**16,978**	**18,249**	**19,089**	**18,172**	**16,650**	**15,921**	**16,396**	**14,145**
VOLUME (mscm/y)									
Power	891	1,239	1,343	1,413	1,292	1,128	1,026	1,075	827
Distribution	274	289	299	305	356	376	413	450	453
Total NI	**1,165**	**1,528**	**1,642**	**1,718**	**1,648**	**1,504**	**1,439**	**1,525**	**1,280**

[1]Volumes have been derived from the energy values by assuming a Moffat GCV of 40 MJ/m^3 for 2003/04 to 2006/07, 39.7 MJ/m^3 for 2007/08, 39.8 MJ/m^3 for 2008/09 and 2009/10, 39.8 MJ/M^3 for 2010/11 and 39.77 MJ/M^{3}for 2011/12.

Figure 4: Historic NI Annual Demand by sector



3.2 Forecast NI demand

The power stations and distribution companies have provided 10 year forecast demand figures to the Utility Regulator as inputs into the modelling for the NICS. The figures are summarised in Table 2 and presented in Figure 5 below.

Overall demand is forecast to grow at an average of 1% per annum over the period modelled. However the underlying figures for each sector demonstrate continuing year-on-year growth in the distribution sector and a reduction in volumes to the power stations. The following sections provide some further details on each of the sectors. Notably the annual demand for distribution sector is forecast to be greater than the power sector in 2019/20.

Table 2: Forecast NI Annual Demand Summarised by Sector

Year	1	2	3	4	5	6	7	8	9	10
(mscm)	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23
Power	622	656	657	665	649	574	449	452	523	523
Distribution	501	519	532	544	556	569	582	595	606	609
TOTAL	1123	1175	1089	1209	1205	1143	1031	1046	1130	1133

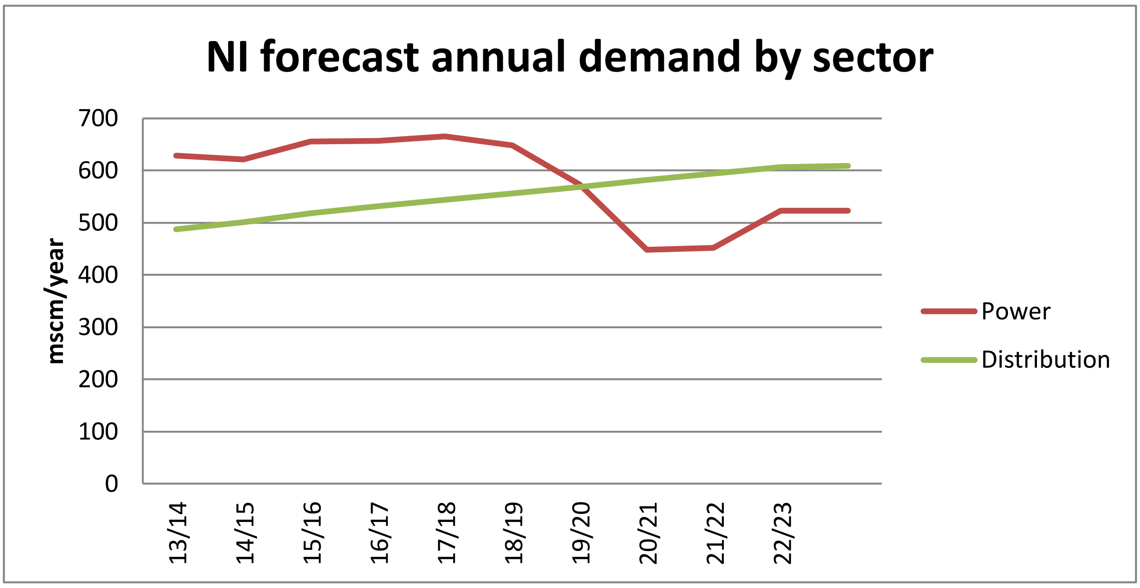
Power Generation

Forecast figures were provided by the two gas fired power stations, Ballylumford and Coolkeeragh. The total power generation figures provided in Table 2 are the aggregated demand for the two sites. Figures provided were from the generators own demand modelling forecasts based on a number of assumptions: including the power stations' expected growth rates in electricity demand, the impact of planned generator units and the expected dispatch order under SEM. Forward commodity prices and the influence of other fuel sources were also included in the modelling inputs.

The power sector is forecast to contract by 16% from 2013/14 to 2022/23. This is due to the continuing impact of the coal-gas price differential where coal prices are expected to displace gas powered generation until 2018 at least. Further more efficient generating plant in the Republic of Ireland and the impact of renewable wind generation is also expected to reduce annual NI power station gas demand.

A further impact is the expected increased capacity of North/South electrical transmission tie-line in 2018 which is expected to further erode dispatch of NI power stations. The power stations noted that it is difficult to provide a high degree of accuracy due to the number of factors affecting the forecast demands. The figures should be viewed with this in mind.

Figure 5: NI Forecast Distribution Demand



Distribution

Forecast figures were provided by the two gas distribution companies, PNGL and firmus. The total distribution figures provided in Table 2 are the aggregated demand forecasts for both distribution companies. Again figures provided for the purposes of the NI capacity statement were based on the distribution companies own modelling forecasts which incorporated the expected growth rates within the domestic and I/C sectors over the 10 years modelled.

The distribution sector is forecast to grow by 22% over the next ten years (or 2.2% per year). The year-on-year increase reflects the distribution companies' expected growth rates within the domestic and industrial/commercial sectors. Forecast growth rates have also been revised to take into account prevailing economic conditions as well as the effect of energy efficiency measures across the sector.

NI Winter Peak-day gas demand

In order to assess the system on days of different demand patterns, three sample demand days are analysed for each scenario over the 10 year period modelled: 1-in-20 year winter peak day, average year winter peak day and average year summer minimum.

All of the data used for the modelling is presented in Appendix 1.

Since the network is designed to meet firm winter peak demand there is particular interest in assessing the ability of the network to meet the demands on the two winter peak days i.e. the severe winter peak day demand representing the demands expected in 1 out of 20 years and an average year peak day representing an average winter peak day demand.

Last year's JGCS highlighted that the NI total demands for the winter peak demands included both firm and interruptible load. The data for this year's capacity statement provided a breakdown between the firm and interruptible demands so that these demands could be modelled separately.

The figures for firm demand for the two winter peak demands are presented in the Tables 4 and 5 below.

Table 4: 1-in-20 Winter Peak Day Demand (Firm)

1-in20 peak day demand (firm)										
	1	2	3	4	5	6	7	8	9	10
(mscm/day)	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23
Power	4.36	4.36	4.36	4.36	4.36	4.36	4.36	4.36	4.36	4.36
Distribution	2.94	3.04	3.15	3.26	3.35	3.46	3.56	3.65	3.74	3.83
Total	7.30	7.40	7.51	7.62	7.71	7.82	7.92	8.01	8.10	8.19

1-in-20 Winter Peak Demand (Firm)

The 1-in-20 winter peak demand (firm) figures in table 4 above represent the combined total of the individual 1-in-20 peak demands for each of the power stations and distribution companies. These figures therefore represent a simultaneous firm demand for both sectors.

It can be seen that the power stations peak 1-in-20 demand remains unchanged while there is a year-on-year growth for the distribution sector. This trend reflects previous forecasts and actual growth for the distribution sector.

At their lower end these figures compare to the firm capacity booking on the PTL system for 2013/14 winter, which is 7.4 mscm/d. However, they are higher than actual winter peak demands. For example, the highest peak daily demand was 6.7 mscm/day on 7th January 2010. This was considered a severe winter although it should be noted that Coolkeeragh powerstation was temporarily off line for a short period that day so peak flows could have been higher. In the severe winter of 2010/2011 the peak was 6.6 mscm/day on the 8th, 21st, 22nd and 23rd December 2010. In the 2012/13 winter the peak recorded was 6.54 mscm/day.

In light of the actual figures, the modelling is taking a conservative approach but the figures modelled are in line with the capacity booked on the system. It is also noted that there are circumstances that could lead to a higher record peak day demand occurring and that overall demand is set to increase due to growth in the distribution sector over the period modelled.

Average Winter Peak Demand (Firm)

Table 5: Average Winter Peak day Demand (Firm)

average winter peak day demand (firm)										
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
(mscm/day)	**13/14**	**14/15**	**15/16**	**16/17**	**17/18**	**18/19**	**19/20**	**20/21**	**21/22**	**22/23**
Power	3.10	3.10	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
Distribution	1.90	1.97	2.04	2.10	2.16	2.23	2.29	2.34	2.40	2.44
total	5.00	5.07	5.04	5.10	5.16	5.23	5.29	5.34	5.40	5.44

Again, the average winter peak demand figures represent the combined total of the individual average winter peak demands for each of the power stations and distribution companies, i.e. a simultaneous demand for both sectors.

It is difficult to pinpoint an ‘average’ year, however the forecast figures that have been provided are largely in line with the range of actual figures that have been recorded.

4. Modelling Scenarios

4.1 Modelling overview and assumptions

Modelling Approach

A hydraulic model of the NI transmission system was constructed using Pipeline Studio® software. Pipeline Studio® pipeline modelling software allows the user to configure and analyse the demand on the network for a number of scenarios.

The model was run for the ten years of the capacity statement from 2013/14 – 2022/23 inclusive, to determine if the existing Northern Ireland transmission system has the capacity to meet forecasted flow requirements.

As noted in the previous section, in order to assess the system on days of different demand patterns, three sample demand days were analysed for each scenario over the 10 year period: 1-in-20 year ("severe") winter peak day, average year winter peak day and average year summer minimum. Also, where it was appropriate, the analysis also modelled firm plus interruptible demand and firm demand only. Differentiating between the firm and firm plus interruptible demand was a recommendation from the JGCS 2012.

The modelling considers the ability of the system to meet the peak or minimum daily demand within that day. It does not consider the ability of the system to respond to within day demand changes.

Additionally for storage, these demand type days represent the best case scenario regarding maximum possible withdrawal rates on peak days and maximum possible injection rates on summer minimum days. This assumes that the proposed storage facility included in the analysis operate on a seasonal basis, i.e. injecting gas during the summer months and withdrawing gas during the winter months.

The scenarios that have been modelled are presented in section 4.2.

Modelling Assumptions

The general assumptions that have been taken for the modelling have been included in Appendix 2. The specific modelling assumptions for the key pieces of infrastructure on the NI transmission system and the reasoning for adopting these assumptions are set out below.

Twynholm

The assumptions taken at Beattock and Moffat are a key factor in the pressure available at Moffat.

The 2012 JGCS indicated that the theoretical technical capacity of the Moffat Entry Point, 32 mscmd, was subject to the capacity of Beattock Compressor Station, based on a number of operating assumptions;

- Station inlet pressure of 47 barg (from the National Grid NTS)
- Station discharge pressure of 85 barg
- Gas inlet temperature of 15°C
- Three compressor units operating in "series mode" (with a fourth unit on standby)

This led to an assumed pressure level at Twynholm of 67.8 barg.

However as set out in JGCS 2012, the technical capacity at the Moffat Entry Point was revised in response to studies that were carried out by BGE(UK) in 2011 following the severe winter period in December 2010. These studies analysed the Southwest Scotland Onshore System (SWSOS) during the peak demand events experienced in December 2010 and BGE(UK) consequently revised the assumptions associated with Beattock compressor station and the station's overall technical capacity. A key refinement in the assumptions was the mode of operation for the compressor units in Beattock compressor station.

BGE(UK) analysis prior to the 2011 study assumed that Beattock's compressor units could operate in 'series mode' on peak days and deliver a high discharge pressure up to the maximum operating pressure of the SWSOS, i.e. 85 barg. On this basis, network analysis of the SWSOS system had determined the technical capacity of the Moffat Entry Point as 32 mscmd.

However, the BGE(UK) 2011 study indicated that the optimal operating mode for Beattock's compressor units is parallel as this mode enables Beattock, to accommodate the high flows and the high flow variability seen on severe winter peak days. Operating Beattock's compressors in series mode has the advantage of a higher pressure lift than that of parallel mode. However, the capacity of the compressors in series mode is less than that of parallel mode and the compressors have a narrower operating envelope i.e. not as able to accommodate significant re-nomination changes. Since power generation accounts for the majority of RoI and NI gas demand and is experiencing increasing gas demand volatility due to increasing renewable generation on the electricity system; this increasing demand volatility requires a high level of flow flexibility to accommodate shipper re-nominations.

BGE(UK) has therefore concluded that operating the station's compressors in parallel mode provides the wide operating envelope required to provide the high level of flow flexibility required at the Moffat Entry Point. In any case the units operate (and have operated) in parallel mode since they were commissioned in 2000. The assumption of parallel mode therefore reflects the current operating arrangements.

A further change resulting from the BGE(UK) 2011 study is a change to the calculated discharge pressures at Beattock of 76.6 barg (as above, this was previously 85 barg).

Following the 2011 analysis, BGE(UK) declared the capacity of Beattock Compressor and the Moffat Entry Point as 31 mscmd (previously 32 mscm/d) based on;

- Station inlet pressure of 47 barg (from the National Grid (GB) NTS), known as Anticipated Normal Operating Pressure (ANOP)
- A discharge pressure of 76.6 barg,
- A gas inlet temperature of 10°C
- Three compressor units operating in 'parallel mode' (with one on standby).

The revision to these assumptions combined with advancements in network analysis resulted in a change to the calculated discharge pressures at Beattock.

Previously 85 barg was taken as the discharge pressure in all cases, whereas Beattock's discharge pressure is now determined by desktop analysis based on the compressor performance characteristics, inlet pressure and temperature conditions and forecasted Moffat flows, for parallel mode of operation.

This revision has an impact on the pressure available at Twynholm. Previously, 32 mscmd/85 barg at Moffat resulted in pressure at Twynholm (inlet) of 67.8 barg. Under the revised (and current) technical capacity (31 mscmd/76.6 barg), network analysis has determined the Twynholm (inlet) pressure to be equal to 57.5 barg.

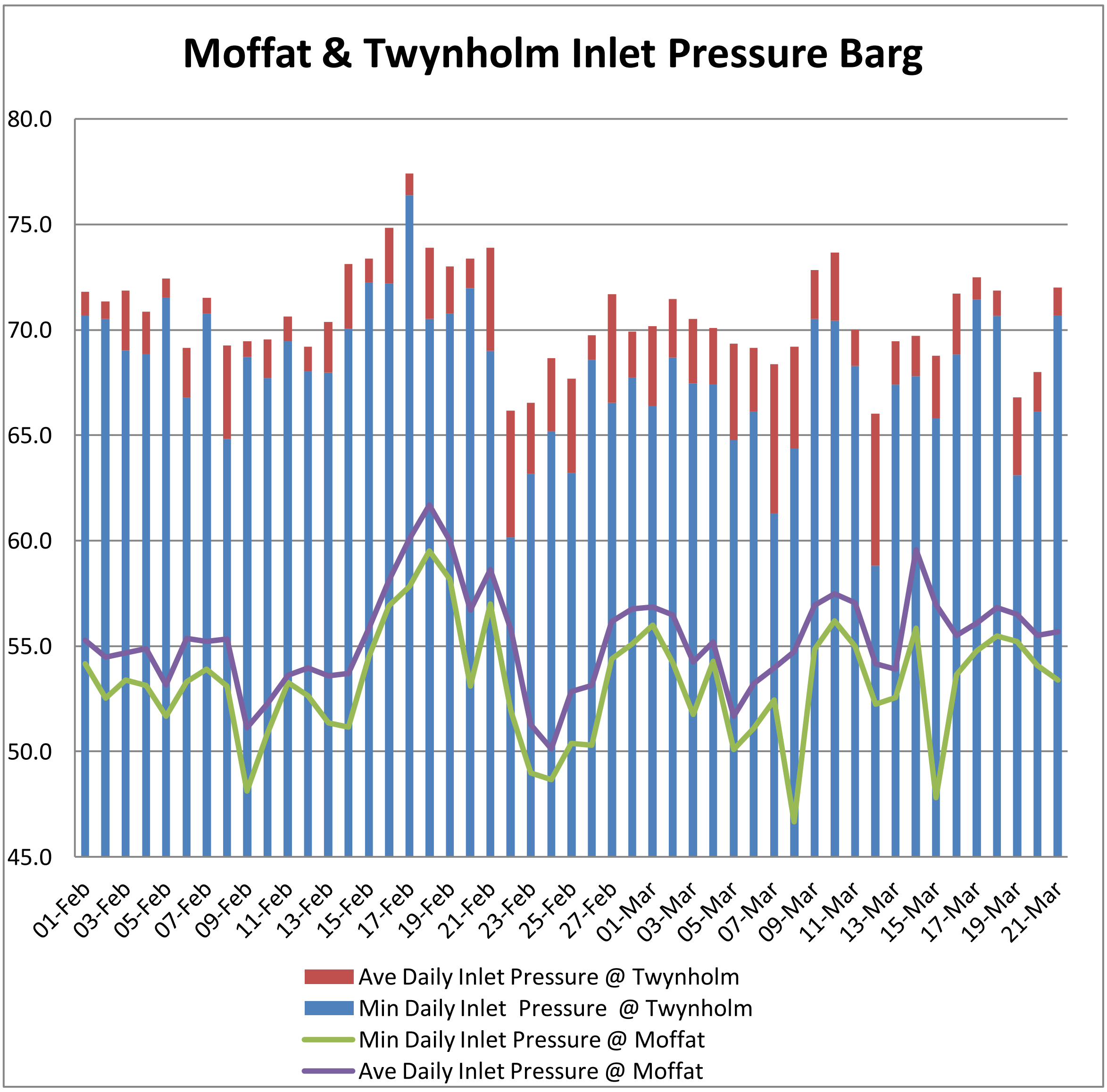
The minimum pressure at Twynholm that BGE(UK) are contractually required to provide to PTLis 56 barg although this level has never been reached.

Further information on actual pressures at Twynholm is presented below. The lowest recorded pressure (from recent records)[3] at Twynholm (inlet) is 59 barg and this was recorded during the December 2010 peak flow event.

More recent figures from 2012/13 are presented in Figure 6. Figure 6 presents the average and minimum pressure levels at Twynholm and Moffat for the prolonged winter period leading up to the peak day on the 20th March 2013 of 6.54 mscm when pressure levels were recorded at 66.1 barg at Twynholm. The minimum pressure level recorded for this period was 58.8 barg at Twynholm which occurred on the 12th March 2013.

3 59 barg (58.8 barg) was also recorded on 12th March 2013. See reference on page 21.

Figure 6: Twynholm Inlet Pressure Winter 2013 Average and Minimum Daily pressure (barg)



The figures presented in the Figure 6 demonstrate that the pressure levels at Twynholm and Moffat fluctuate on a daily and within day basis. Over the period considered the pressures at Twynholm ranged from a peak average of 76.4 barg (17th February 2013) to a minimum of 58.8 barg (12th March 2013). The corresponding pressures at Moffat for these days were 60.1 barg and 52.2 barg. (Notably these are peak average figures; the maximum figures on the day would be higher). The lowest pressure level recorded at Moffat for the period was 46.7 barg on 8th March, which is beneath the 47 barg ANOP at Moffat; the pressure at Twynholm on this day was 64.4 barg. The pressures at Twynholm are higher than those at Moffat due to the pressure uplift from the Beattock compressors.

For a 56 barg pressure level at Twynholm to occur, upstream pressures in the National Grid system need to be approaching the ANOP of 47 barg and high demands need to be flowing through Moffat (~31mscm). These two contributing factors have never occurred simultaneously. That is not to say they will not occur (the record within-day flows observed at Moffat in December 2010 were equivalent to approximately 34.5 mscm/d for example) but the analysis has shown that the probability of them occurring together is considered to be low.

Adopting a 56 bar inlet pressure at Twynholm is therefore a conservative approach and should be kept in mind when assessing the results that are provided in section 5.

<u>Offtake pressure</u>

A technical minimum system pressure limit of 27 barg is assumed for all off-takes on the NI system, based on the technical limits associated with the AGIs on the NI system[4]. It should be noted that the minimum contractual pressures set out in the NI TSOs' network codes are 12 barg.

Unless otherwise specified in a scenario, the minimum inlet pressure at Coolkeeragh AGI is the AGI minimum design pressure of 27 barg, with an assumed pressure drop/loss across the AGI of 3 barg due to losses at AGI components[5]. Pressure losses occur within an AGI, due to the gas having to pass through several processes; filters, meters, heaters, regulators and the pipe work features located between each of the processes.

The technical minimum system pressure limit of 27 barg also applies to the Carrickfergus AGI.

BGE(UK) have noted that the Carrickfergus Entry point capacity is subject to a number of factors;

- The infrastructure which transports the gas, i.e. Carrickfergus AGI and the BGÉ (UK)system, i.e. the SNP and NWP.

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4 PTL and BGTL AGIs have been designed to operate with a minimum design pressure of 15 barg.

5 A specific scenario considers a lower Coolkeeragh AGI pressure of 25 bar. This is discussed in section 4.2.3.

- The pressure at the Entry Point, i.e. at Carrickfergus AGI which is dependent on the upstream pressures, i.e. pressures in the SNIP.

- The downstream pressure requirements, i.e. minimum pressure (technical) limits of the various AGIs located on the SNP and NWP, supplying the Northern Ireland towns and Coolkeeragh power station.

The modelling has recorded the pressures available at the Carrickfergus AGI which are a result of these factors. These are set out in the relevant tables of section 5.

Additionally, Carrickfergus AGI is modelled as currently operated in flow control mode, whereby the hourly flow through Carrickfergus AGI equals the sum of the hourly downstream demands on the BGÉ (UK) system.

The outlet pressure at Carrickfergus is determined by the inlet pressure at the AGI less an assumed pressure drop across the AGI of 3 barg due to losses at AGI components.

This differs from previous JGCS, which under Common Arrangements for Gas, had assumed a 'CAG open' arrangement, whereby Carrickfergus AGI operated in a "free flow" mode, effectively ceasing to operate in its current form, and had an assumed pressure drop of 0.5 barg to account for pressure losses across the AGI pipework

4.2 Modelling Scenario Overview

Four scenarios were modelled for this year's NICS. The Base Case (Scenario 1) assumes the existing infrastructure for all years, with the exception of the extension of the network for the Gas to the West scenarios.

Last year's JGCS indicated a potential capacity constraint[6] for the Northern Ireland system on a severe winter peak day. This constraint was identified from the results of network analysis which indicated pressures at peripheral points on the system were less than the minimum technical limits. With that in mind, scenarios 2 and 3 in this capacity statement, consider the mitigation measures of increased system inlet pressure via SNIP compression (Scenario 2), and using on-site

6 A capacity constraint indicates that the network does not have the capacity to deliver the forecasted flow to end users under the assumed conditions. i.e. pressures observed in the network model are less than the minimum pressure limits at one (or more) of the exit points.

compression at ESB Coolkeeragh which may facilitate a lower technical pressure limit at Coolkeeragh AGI (Scenario 3).

Scenario 4 examines the implications of the introduction of a gas storage facility at Larne, Co. Antrim

Each of the scenarios is discussed further below.

4.2.1 Scenario 1 – Base Case

The Base scenario represents the existing network infrastructure and is run for all demand days for all years. An additional Gas to the West scenario has been added to the base case to model the planned network extension.

Base Case modelling assumptions are equivalent to the base modelling assumptions described in section 4.1

4.2.2 Scenario 2– SNIP Compression

The SNIP compression scenario assumes a compression facility at the entry to SNIP from 2016/17 onwards, allowing approximately three years for planning, construction and commissioning of such a facility.

The network analysis model for the SNIP Compression Case assumes a compressor facility located at Twynholm AGI which is capable of raising the pressure to 85 barg, i.e. assumed fixed supply pressure of 85 barg at the inlet to SNIP. No assumptions were made regarding the power, sizing, or operating limits of such a compressor, which was modelled on a “black box” basis.

In line with the increased system pressures from compression, the maximum operating pressure of the NI system is assumed to be increased to 85 barg.

All other modelling assumptions are equivalent to the base modelling assumptions described in section 4.1

4.2.3 Scenario 3– Coolkeeragh Compression

In response to the results of previous JGCS, which indicated low pressures on the Northern Ireland transmission system, utilising on-site compression at ESB Coolkeeragh was considered as a solution to pressures outside (below) technical limits.

The network analysis model for the Coolkeeragh compression scenario assumes a lower technical limit of 25 barg at the inlet to Coolkeeragh AGI, following consultation with ESB Coolkeeragh. However, it should be noted that such a pressure is less that the current minimum design limit of the BGÉ NI system.

Following further analysis, ESB Coolkeeragh have updated the NI TSOs to note that the station could continue to operate with 25 barg at the inlet to Coolkeeragh AGI, however this would be subject to the station running at a reduced load.

All other modelling assumptions are equivalent to the base modelling assumptions described in section 4.1

4.2.4 Scenario 4– Larne Storage

In Scenario 4, a gas storage facility is modelled connecting to the NI system at Larne, Co. Antrim with an assumed peak injection rate of 12 mscmd, an assumed peak withdrawal rate of 22 mscmd, an assumed delivery pressure of 85 barg and a minimum inlet pressure of 27 barg. The facility has been assumed to be operational from 2018/19 onwards.

In order to meet full injection capacity, gas is supplied via the Gormanston entry point into the system at pressures up to 85 barg. In this case, flows across Carrickfergus AGI are flow-controlled from West to East, with a pressure drop of 3 barg due to pipework/equipment.

In line with the increased operating pressures of the storage facility, the maximum operating pressure of the NI system is assumed to be increased to 85 barg.

Larne is utilised as the primary supply point in modelled peak day withdrawal cases.

Surplus supply from Larne, i.e. max withdrawal rate less NI demand, may be available for export to the ROI and/or GB markets subject to the appropriate infrastructural modifications, and contractual and commercial arrangements being in place. The export of such excess supply is not modelled.

5. Modelling Results

Based on the demand figures supplied, and the modelling assumptions outlined in section 4, the network analysis demonstrates that:

- The Northern Ireland transmission network has sufficient capacity to meet summer minimum day and average winter peak day demands on a firm, and firm and interruptible basis.

- The Northern Ireland transmission network does not have the capacity to meet the full demand on a severe winter peak day (firm or firm & interruptible) based on minimum technical pressure limits and upstream pressure assumptions. The use of capacity short fall measures or the use of the South-North pipeline to rebalance the system would be required under such conditions to meet system demands.

- The use of on-site compression at ESB Coolkeeragh, as per scenario 3, will not provide the capacity required to meet NI severe winter peak day requirements. Due to the upstream pressure assumptions, the pressures available at Coolkeeragh are too low for the compressor to operate.

- SNIP compression results in pressures within acceptable limits on all severe winter peak day cases.

- The full injection and withdrawal rates for the modelled Larne gas storage facility can be achieved, while maintaining system minimum pressures for the summer minimum and severe winter peak days modelled.

The following table summarises the suite of network modelling completed for the NI GCS 2013 (Note: ‘F’ – Firm, ‘F & I’ – Firm and Interruptible)

	Base	SNIP Compression	Coolkeeragh Comppression	Larne Storage
Day	1	2	3	4
Severe Winter Peak Day (F)	✓	✓	✓	
Severe Winter Peak Day (F & I)	✓	✓	✓	
Severe Winter Peak Day & Gas to West (F)	✓	✓	✓	
Severe Winter Peak Day & Gas to West (F & I)	✓	✓	✓	✓ Withdrawal
Average Winter Peak Day (F)	✓		✓	
Average Winter Peak Day (F & I)	✓		✓	
Summer Minimum Day (F)	✓		✓	
Summer Minimum Day (F & I)	✓		✓	✓ Injection

The following sections outline the results of the Network Analysis. The summary results are colour-coded as follows:

: All Pressures within acceptable technical limits

: Some/All Pressures outside acceptable technical limits

: Results unobtainable due to infeasible conditions in the model

: Year not modelled

Where appropriate i.e. when a yellow or red is flagged in the summary results tables, a further table detailing the pressures on the network and explanation are also presented. The term ‘infeasible conditions’ in the pressure tables refers to pressure levels reaching zero on parts of the network and the model not being able to provide outputs as a result.

Figures are coloured red in the pressure tables, where they are below 27 bar which is the assumed minimum operating design pressure of the AGIs. The minimum contractual pressures set out in the NI TSOs network codes are 12 barg. Therefore where a figure is flagged as red, the pressure is below the operational limits, not the contractual limits.

5.1 Scenario 1 – Base Case

Average Winter Peak Day

Base Case analysis demonstrates that the Northern Ireland transmission network has sufficient pressure to meet average winter peak day demands on a firm, and firm and interruptible basis.

Gas Year	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23
Firm										
Firm & Interruptible										

The table below summarises the pressure conditions on the network for an average winter peak day (firm and interruptible).

Year	Twynholm (SNIP)		Carrickfergus	C'keeragh	B'lumford
	Flow	Pressure (1)	Pressure (2)	Pressure (3)	Pressure (4)
	(mscmd)	(barg)	(barg)	(barg)	(barg)
Limits	**8.08 / 8.64**			**27 (Min)**	**27 (Min)**
2013/14	5.54	53.2 / 49.5	40.8 / 35.2	37.8 / 32.2	44.6 / 39.0
2014/15	5.62	53.4 / 49.7	40.8 / 35.0	37.7 / 32.0	44.6 / 39.0
2015/16	5.59	53.4 / 49.7	40.8 / 35.1	37.7 / 32.1	44.6 / 39.0
2016/17	5.64	53.1 / 49.3	40.2 / 34.4	37.0 / 31.3	44.0 / 38.3
2017/18	5.70	53.2 / 49.5	40.1 / 34.3	36.9 / 31.1	44.0 / 38.2
2018/19	5.76	53.4 / 49.6	40.1 / 34.2	36.8 / 31.0	44.0 / 38.1
2019/20	5.83	53.1 / 49.3	39.5 / 33.4	36.1 / 30.1	43.4 / 37.4
2020/21	5.88	53.3 / 49.5	39.4 / 33.3	36.0 / 30.0	43.4 / 37.3
2021/22	5.94	53.5 / 49.6	39.4 / 33.2	36.0 / 29.9	43.4 / 37.3
2022/23	5.95	53.5 / 49.6	39.4 / 33.2	36.0 / 29.8	43.4 / 37.3

Notes:

1. Pressures at Twynholm (SNIP) are the maximum and minimum in the diurnal cycle at the outlet of Twynholm AGI.
2. Pressures at the Carrickfergus AGI are the maximum and minimum in the diurnal cycle, and are those downstream of the AGI in the North West pipeline.
3. Pressures at Coolkeeragh are the maximum and minimum in the diurnal cycle and are those in the pipeline upstream of the AGI.
4. Pressures at Ballylumford are the maximum and minimum in the diurnal cycle and are those in the pipeline.

As presented in the summary table the pressures at the key points on the NI transmission network are within the operating pressure limits off the system and can provide the pressure to deliver the gas flows demanded for all years modelled.

Severe Winter Peak Day

Base Case analysis demonstrates that the Northern Ireland transmission network does not have sufficient pressure to meet severe winter peak day demands on a firm, and firm and interruptible basis.

Technical minimum pressure design limits cannot be met for all points on the NI Transmission system for severe winter peak day demands on a firm or firm & interruptible basis as modeled.

Gas Year	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23
Firm								1	1	1
Firm & Interruptible	1,2	1,2	1,2	1,2	1,2	1,2	1,2	1,2	1,2	1,2

Notes:

1. The existing contractual capacity of the Twynholm Entry point (8.08 mscmd) is exceeded
2. The design capacity of Twynholm AGI (8.64 mscmd) is exceeded

a. Severe Winter Peak Day – Firm

The following table summarises conditions within Northern Ireland (SNIP, South-North and North-West Pipelines) for severe winter peak day firm demands.

System Pressures at Coolkeeragh and Ballylumford must remain above 27 barg through the diurnal cycle in order to meet technical minimum system pressures. As noted early these are the design limits of the AGIs.

Pressures below zero at the inlet to Coolkeergh AGI (the most peripheral point on the NI system), results in infeasible conditions in the model.

Year	Twynholm (SNIP)		Carrickfergus	C'keeragh	B'lumford
	Flow	Pressure [1]	Pressure [2]	Pressure [3]	Pressure [4]
	(mscmd)	(barg)	(barg)	(barg)	(barg)
Limits	**8.08 / 8.64**			**27 (Min)**	**27 (Min)**
2013/14	7.32	53.5 / 49.4	32.4 / 23.3	**25.6 / 16.0**	37.1 / 27.9
2014/15	7.42	53.5 / 49.4	31.7 / 22.3	**24.6 / 14.5**	36.5 / 27.2
2015/16	7.53	53.5 / 49.4	31.0 / 21.3	**23.5 / 12.9**	35.5 / **26.3**
2016/17	7.63	53.3 / 49.2	29.6 / 19.5	**21.4 / 9.9**	33.9 / **24.7**
2017/18	7.73	53.3 / 49.2	28.8 / 18.4	**20.2 / 7.8**	34.0 / **24.2**
2018/19	7.83	53.3 / 49.2	28.1 / 17.4	**19.0 / 5.3**	33.5 / **23.0**
2019/20	7.93	53.4 / 49.4	27.4 / 16.3	**17.5 / 0.7**	32.9 / **22.1**
2020/21	8.02	**Infeasible**	**Infeasible**	**Infeasible**	**Infeasible**
2021/22	**8.11**	**Infeasible**	**Infeasible**	**Infeasible**	**Infeasible**
2022/23	**8.20**	**Infeasible**	**Infeasible**	**Infeasible**	**Infeasible**

Notes:

1. Pressures at Twynholm (SNIP) are the maximum and minimum in the diurnal cycle at the outlet of Twynholm AGI.
2. Pressures at the Carrickfergus AGI are the maximum and minimum in the diurnal cycle, and are those downstream of the AGI in the North West pipeline.
3. Pressures at Coolkeeragh are the maximum and minimum in the diurnal cycle and are those in the pipeline upstream of the AGI.
4. Pressures at Ballylumford are the maximum and minimum in the diurnal cycle and are those in the pipeline.

The results show that pressure at the inlet to Coolkeergah falls below the minimum technical design limit of the AGI (27 bar) for all years modelled. The contractual limit of 12 bar is not breached until 2016/17.

Pressures at Ballylumford fall below minimum inlet pressure (27 barg) from 2015/16 onwards. The contractual pressure of 12 bar at Ballylumford is not breached for all years modelled.

Network analysis results cannot be obtained from 2020/21 since pressures have fallen below zero at the inlet to the Coolkeeragh AGI (the most peripheral point on the NI system). This occurs at a demand of 8.02 mscm. Notably the 8.08 contractual limit of the SNIP is surpassed in 2021/22.

Modelling the Severe Winter Peak Day (Firm and Interruptible) results in similar infeasible modelling outcomes as the demands are greater than 8.02 for all years.

Severe Winter Peak Day & Gas to the West

The addition of Gas to the West demands brings forward the years where the model outputs infeasible conditions, i.e. pressures at Coolkeeragh reach zero.

Gas Year	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23
Firm						1	1	1	1	1
Firm & Interruptible				1,2	1,2	1,2	1,2	1,2	1,2	1,2

Notes:

1. The existing contractual capacity of the Twynholm Entry point (8.08 mscmd) is exceeded
2. The design capacity of Twynholm AGI (8.64 mscmd) is exceeded

The table below provides the modelling output for the severe Winter Peak Day and Gas to the West (Firm) demands. The additional gas to the west demands are forecast to flow in 2016/17. The pressures from 2013/14 to 2015/16 are therefore unchanged from the base case scenario.

The additional Gas to the West demands lower pressures on the network for 2016/17 until the model fails in subsequent years because the pressures are too low at Coolkeeragh.

Notably for the 2016/17 year where results have been returned the minimum pressures at the Gas to the West Offtake (16.3 barg) are below the assumed minimum operating design pressures for network AGIs of 27 bar. Therefore under these circumstances the system would not be able to provide the necessary pressures to deliver the full amount of gas to the Gas to the West network segment (nor Ballylumford or Coolkeeragh as the pressures are below the minimum 27 bar assumed for these points).

Notably the 8.08 mscm contractual limit of the SNIP is surpassed in 2018/19 with the additional Gas to the West demands, whereas this limit is forecast to be exceeded in 2021/22 for severe winter peak demand forecasts without Gas to the West demands.

Year	Twynholm (SNIP)		Carrickfergus	C'keeragh	B'lumford	Gas to the West Off Take
	Flow	Pressure [1]	Pressure [2]	Pressure [3]	Pressure [4]	Pressure
	(mscmd)	(barg)	(barg)	(barg)	(barg)	(barg)
Limits	**8.08 / 8.64**			**27 (Min)**	**27 (Min)**	
2013/14	7.32	53.5 / 49.4	32.4 / 23.3	**25.6 / 16.0**	37.1 / 27.9	N/A
2014/15	7.42	53.5 / 49.4	31.7 / 22.3	**24.6 / 14.5**	36.5 / 27.2	N/A
2015/16	7.53	53.5 / 49.4	31.0 / 21.3	**23.5 / 12.9**	35.5 / **26.3**	N/A
2016/17	7.76	53.3 / 49.3	28.5 / 18.3	**18.8 / 7.3**	33.1 / **23.8**	**23.9 / 16.3**
2017/18	8.00	**Fail**	**Fail**	**Fail**	**Fail**	**Fail**
2018/19	**8.12**	**Fail**	**Fail**	**Fail**	**Fail**	**Fail**
2019/20	**8.23**	**Fail**	**Fail**	**Fail**	**Fail**	**Fail**
2020/21	**8.33**	**Fail**	**Fail**	**Fail**	**Fail**	**Fail**
2021/22	**8.43**	**Fail**	**Fail**	**Fail**	**Fail**	**Fail**
2022/23	**8.53**	**Fail**	**Fail**	**Fail**	**Fail**	**Fail**

Notes:

1. Pressures at Twynholm (SNIP) are the maximum and minimum in the diurnal cycle at the outlet of Twynholm AGI.
2. Pressures at the Carrickfergus AGI are the maximum and minimum in the diurnal cycle, and are those downstream of the AGI in the North West pipeline.
3. Pressures at Coolkeeragh are the maximum and minimum in the diurnal cycle and are those in the pipeline upstream of the AGI.
4. Pressures at Ballylumford are the maximum and minimum in the diurnal cycle and are those in the pipeline.

Summer Minimum Day

Base Case analysis demonstrates that the Northern Ireland transmission network has sufficient capacity to meet summer minimum day demands on a firm, and firm and interruptible basis.

Gas Year	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23
Firm										
Firm & Interruptible										

5.2 Scenario 2– SNIP Compression

The availability of higher pressures (85 barg) as a result of SNIP compression, results in higher pressures across the Northern Ireland transmission system in all cases modelled, as demonstrated in the results below. Pressures in all cases are within system limits.

Average Winter Peak Day

Gas Year	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23
Firm										
Firm & Interruptible										

Severe Winter Peak Day

Gas Year	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23
Firm								[1]	[1]	[1]
Firm & Interruptible				[1,2]	[1,2]	[1,2]	[1,2]	[1,2]	[1,2]	[1,2]

Notes:

1. The existing contractual capacity of the Twynholm Entry point (8.08 mscmd) is exceeded
2. The design capacity of Twynholm AGI (8.64 mscmd) is exceeded

The severe winter peak day results for the years 2013/14 to 15/16 are highlighted as outside technical limits since the modelling has assumed that the compressor is only available in 2016/17.

Severe Winter Peak Day & Gas to the West

Gas Year	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23
Firm						[1]	[1]	[1]	[1]	[1]
Firm & Interruptible				[1,2]	[1,2]	[1,2]	[1,2]	[1,2]	[1,2]	[1,2]

Notes:

1. The existing contractual capacity of the Twynholm Entry point (8.08 mscmd) is exceeded
2. The design capacity of Twynholm AGI (8.64 mscmd) is exceeded

Summer Minimum Day

Gas Year	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23
Firm										
Firm & Interruptible										

5.3 Scenario 3– Coolkeeragh Compression

The modelling for the base case has indicated low pressure issues for the 1-in-20 winter peak day (firm and interruptible) of the base case demand and also for the Gas to the West Demands.

Modelling was carried out for these demands utilising on-site compression at ESB Coolkeeragh as a potential solution to pressures below technical limits. As noted in section 4.2.3, the analysis assumed a lower technical limit of 25 barg at the inlet to Coolkeeragh AGI. However the reduction of the minimum inlet pressure at Coolkeeragh AGI to 25 barg results in no significant benefit to the severe winter day results over the base case, as demonstrated in the tables below.

For all severe winter peak days (firm & interruptible) the pressure levels at Coolkeeragh AGI are lower than 25 barg and the compressor cannot be used.

The results are therefore the same as the results for the base case severe winter peak day and severe winter peak day including Gas to the West.

Severe Winter Peak Day

As noted above, the analysis demonstrates that the Northern Ireland transmission network does not have sufficient capacity to meet severe winter peak day demands on a firm, and firm and interruptible basis.

Technical minimum pressure design limits cannot be met for all points on the NI Transmission system for severe winter peak day demands on a firm or firm & interruptible basis as modelled.

Gas Year	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23
Firm								1	1	1
Firm & Interruptible	1,2	1,2	1,2	1,2	1,2	1,2	1,2	1,2	1,2	1,2

Notes:

1. The existing contractual capacity of the Twynholm Entry point (8.08 mscmd) is exceeded
2. The design capacity of Twynholm AGI (8.64 mscmd) is exceeded

Severe Winter Peak Day & Gas to the West

The addition of Gas to the West demands brings forward the lower system pressures outlined in the severe winter peak day cases previously modelled for the base case.

Gas Year	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23
Firm						1	1	1	1	1
Firm & Interruptible				1,2	1,2	1,2	1,2	1,2	1,2	1,2

Notes:

1. The existing contractual capacity of the Twynholm Entry point (8.08 mscmd) is exceeded
2. The design capacity of Twynholm AGI (8.64 mscmd) is exceeded

5.4 Scenario 4– Larne Storage

Severe Winter Peak Day & Gas to the West – Withdrawal from Storage

Over the modelled period, demands in the NI system utilise 8.9 – 9.3 mscmd of the 22 mscmd assumed maximum daily withdrawal capacity of the gas storage facility, leaving 12.7 - 13.1 mscmd excess withdrawal capacity available.

Gas Year	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23
Firm										
Firm & Interruptible										

Summer Minimum Day – Injection into Storage

The Gormanston entry point to the NI system is utilised to meet the full injection capacity of the storage facility.

Gas Year	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23
Firm										
Firm & Interruptible						3	3	3	3	3

Notes:

3. The design capacity of Gormanston AGI (6.0 mscmd) is exceeded

5.5 Additional Modelling

Maximum flows with 56 bar assumption at Twynholm

For the scenarios and demands modelled, the results have shown that the highest flows through the system which can retain the minimum operating pressures at Coolkeeragh of 27 bar and the 56 barg assumption at Twynholm is 5.95 mscm/day (Year 2022/23 for the Average Winter Peak Day (page 28). The higher demands modelled in the severe winter result in either pressures below 27 bar at Coolkeeragh or the model providing 'infeasible' conditions.

The TSOs carried out further modelling to determine what the highest demands that could be met whilst maintaining pressure levels of 27 bar at Coolkeeragh and 56 bar at Twynholm. The additional modelling indicated that demands of 6.35 mscmd flow could be met whilst retaining these pressures. Demands of 6.54 mscm/day could be flowed if pressures of 25 barg were feasible at the inlet to Coolkeeragh AGI.

Additional modelling was also carried out to consider profiling of supplies through Twynholm using the maximum NI recorded demand of 6.7mscm/day and retaining 56 bar at Twynholm and a range of pressure levels at Coolkeeragh. The modelling for the previous runs adopted flat flow profiles through Twynholm i.e. maximum demand for the day divided by 24 hours. The TSOs amended this flow profile to two 12 hours periods which facilitated 12 hours at 108% (7.24 mscm) of flat flow rate and 12 hours of 92% (6.16 mscm/day) of flat flow rate whilst retaining 26 barg at Coolkeeragh.

The results of the additional modelling are summarised in table 6 below:

Table 6: Maximum flows with 56 bar assumption at Twynholm

Twynholm Pressure	Coolkeeragh Pressure	Profiling assumption	Maximum Flows
56 barg	27 barg	Flat	6.35 mscm/day
56 barg	25 barg	Flat	6.54 mscm/day
56 barg	26 barg	Profiled	7.24 mscm/day for 12 hours 6.16 mscm/day for 12 hours

These maximum flow figures demonstrate that the network is operating at its limits when delivering flows assuming the 56 barg pressure at Twynholm. The highest (theoretical) flow is recorded as 7.24 mscm/day and this assumes a split 12 hour profile.

The 7.24 mscm maximum theoretical flow at 56 bar is slightly lower than the maximum forecast 1-in-20 demands for the forthcoming years 2013/2014 (7.32 mscm) and 2014/15 (7.42 mscm). However the 56 bar assumption is conservative and it is expected that the system pressures would be higher.

Maximum flows with higher pressures available at Twynholm

The TSOs also considered what pressures are required at Twynholm in order to deliver higher flows assuming Coolkeeragh pressure was fixed at 25 barg and flat profiles were adopted. The results are presented in Table 7:

Table 7: Maximum flows with higher pressures available at Twynholm

Flows	Coolkeeragh Pressure	Profiling assumption	Twynholm Pressure
7.32 mscm/day*	25 barg	Flat	61.5 barg
8.00 mscm/day	25 barg	Flat	63.5 barg

*Severe Winter Peak Day Firm 2013/14

Following further analysis, ESB Coolkeeragh have updated the NI TSOs to note that the station could continue to operate with 25 barg at the inlet to Coolkeeragh AGI, however this would be subject to the station running at a reduced load. A minimum of 26 barg pressure would be required at the inlet to the compressor if the station was running at normal base-load.

Therefore the results in the above table need to be taken with this in mind. A 26 barg pressure at Coolkeeragh would imply slightly higher pressures than the 61.5 barg noted in the table above.

Notably the pressures required to deliver the firm peak winter demand of 7.32mscm for the current gas year 2013/14 are 61.5 barg for a flat demand assumption. If we review this pressure against the figures presented in the Twyholm inlet pressure figures presented in Figure 6, pressures of 61.5 bar were breached on two occasions only (61.3 barg on 7th March 2013 and 58.8 barg on 12th March 2013).

6. Commentary

The issues identified in this year year's modelling are pressure related. Also in later years the results indicate a capacity issue on the SNIP when demands exceed 8.08 mscm.

Pressure issues occur at the Coolkeeragh and Ballylumford exit points and arise where 27 barg minimum pressures need to be maintained at these exit points. As stated previously the minimum contractual pressure in the NI TSO network codes are 12 barg. The practice of the TSOs has been to provide pressure in excess of this where it is available but it is not guaranteed.

Power stations currently have the right to request and pay for enhanced pressure under their relevant network codes. This option has not been exercised by both stations but could lead to reinforcement in the network and additional compressor facilities being built, as considered in the modelling.

In the absence of reinforcements/additional compression arrangements are in place to deal with low pressure issues should they occur and these are explained below. These arrangements facilitate the power stations continuing to generate electricity and for gas flows to the distribution sector to be maintained.

Should pressure levels reduce so that firm flows cannot be delivered to Coolkeeragh then the TSOs can invoke the 'flip-flop' arrangements which would reduce power station demand on the system. Given that power station demand is of the order of 60% of total NI demand, taking one power station off the network should provide sufficient flexibility to deliver the remaining gas flows.

The South North pipeline can also be used to provide balancing gas flows into Northern Ireland via Gormanston at times when pressures are low and in the future when demands are forecast to be greater than SNIP capacity. The use of the South North pipeline has been modelled in previous JGCSs which demonstrated that the use of this entry point can meet future demands. The TSOs carried out additional modelling to determine the minimum system pressures for the severe winter peak (firm) 2013/14 figure of 7.32 mscm/day. Approximately 1.35 mscm/day could be flowed through Gormanston on a flat flow basis to maintain pressure levels of 27 barg at the Coolkeeragh AGI.

In the base case NI demand exceeds 8.08 in 2021/22 but when Gas to the West demand is included 8.08 is exceeded in 2018/19. As set out approximately 1.35 mscm/day could be flowed through Gormanston on a flat flow basis while maintaining pressure levels of 27 barg at the Coolkeeragh AGI.

Commercial arrangements are in place to accommodate flows from the Gormanston Entry point. However, we consider that the tariff imposed by the CER at Gormanston is high. The Utility Regulator and CER are continuing to progress this issue with the intention of finding a resolution to determine an appropriate tariff level for this entry point.

6.1 Considerations for 2014 modelling

The pressure assumption for the AGIs needed to accommodate Gas to the West is the same as the other AGIs, i.e. 27bar. However, since the demand on the Gas to the West network extensions will comprise domestic and industrial/commercial customers only, the exit points would not require the higher pressures that are required at a power station. The operating assumptions for the AGIs to accommodate Gas to the West should be refined in future gas capacity statements.

It may also be useful to consider a range of pressures at Twynholm rather than fixing the pressure for all scenarios. Furthermore, since the average winter and summer minimum demand have not flagged any concerns it may be appropriate to concentrate on the winter peak demands only in the 2014 modelling.

Appendix 1: Northern Ireland Demand Forecast

Severe Winter Peak Day

Firm

Year	Severe Winter Peak Day Demands/Supplies (mscmd)				
	Power	Non-Power	Total	Larne	Twynholm
2013/14	4.36	2.96	7.32	-	7.32
2014/15	4.36	3.06	7.42	-	7.42
2015/16	4.36	3.17	7.53	-	7.53
2016/17	4.36	3.27	7.63	-	7.63
2017/18	4.36	3.37	7.73	-	7.73
2018/19	4.36	3.47	7.83	-	7.83
2019/20	4.36	3.57	7.93	-	7.93
2020/21	4.36	3.66	8.02	-	8.02
2021/22	4.36	3.75	8.11	-	8.11
2022/23	4.36	3.84	8.20	-	8.20

Firm & Interruptible

Year	Severe Winter Peak Day Demands/Supplies (mscmd)				
	Power	Non-Power	Total	Larne	Twynholm
2013/14	5.16	3.58	8.74	-	8.74
2014/15	5.16	3.70	8.86	-	8.86
2015/16	4.36	3.81	8.17	-	8.17
2016/17	4.36	3.91	8.27	-	8.27
2017/18	4.36	4.00	8.36	-	8.36
2018/19	4.36	4.10	8.46	-	8.46
2019/20	4.36	4.20	8.56	-	8.56
2020/21	4.36	4.29	8.65	-	8.65
2021/22	4.36	4.38	8.74	-	8.74
2022/23	4.36	4.40	8.76	-	8.76

Average Winter Peak Day

Firm

Year	Average Winter Peak Day Demands/Supplies (mscmd)				
	Power	Non-Power	Total	Larne	Twynholm
2013/14	3.10	1.91	5.01	-	5.01
2014/15	3.10	1.98	5.08	-	5.08
2015/16	3.00	2.05	5.05	-	5.05
2016/17	3.00	2.11	5.11	-	5.11
2017/18	3.00	2.17	5.17	-	5.17
2018/19	3.00	2.24	5.24	-	5.24
2019/20	3.00	2.30	5.30	-	5.30
2020/21	3.00	2.36	5.36	-	5.36
2021/22	3.00	2.41	5.41	-	5.41
2022/23	3.00	2.43	5.43	-	5.43

Firm & Interruptible

Year	Average Winter Peak Day Demands/Supplies (mscmd)				
	Power	Non-Power	Total	Larne	Twynholm
2013/14	3.10	2.44	5.54	-	5.54
2014/15	3.10	2.52	5.62	-	5.62
2015/16	3.00	2.59	5.59	-	5.59
2016/17	3.00	2.64	5.64	-	5.64
2017/18	3.00	2.70	5.70	-	5.70
2018/19	3.00	2.76	5.76	-	5.76
2019/20	3.00	2.83	5.83	-	5.83
2020/21	3.00	2.88	5.88	-	5.88
2021/22	3.00	2.94	5.94	-	5.94
2022/23	3.00	2.95	5.95	-	5.95

Summer Minimum Day

Firm

Year	Summer Minimum Day Demands/Supplies (mscmd)				
	Power	Non-Power	Total	Larne	Twynholm
2013/14	1.70	0.40	2.10	-	2.10
2014/15	1.70	0.42	2.12	-	2.12
2015/16	1.70	0.44	2.14	-	2.14
2016/17	1.70	0.45	2.15	-	2.15
2017/18	1.70	0.46	2.16	-	2.16
2018/19	1.40	0.48	1.88	-	1.88
2019/20	1.40	0.49	1.89	-	1.89
2020/21	1.40	0.50	1.90	-	1.90
2021/22	1.40	0.51	1.91	-	1.91
2022/23	1.40	0.52	1.92	-	1.92

Firm & Interruptible

Year	Summer Minimum Day Demands/Supplies (mscmd)				
	Power	Non-Power	Total	Larne	Twynholm
2013/14	1.70	0.53	2.23	-	2.23
2014/15	1.70	0.55	2.25	-	2.25
2015/16	1.70	0.56	2.26	-	2.26
2016/17	1.70	0.58	2.28	-	2.28
2017/18	1.70	0.59	2.29	-	2.29
2018/19	1.40	0.60	2.00	-	2.00
2019/20	1.40	0.61	2.01	-	2.02
2020/21	1.40	0.63	2.03	-	2.03
2021/22	1.40	0.64	2.04	-	2.04
2022/23	1.40	0.65	2.05	-	2.05

Severe Winter Peak Day + Gas to the West

Firm

Year	Severe Winter Peak Day Demands/Supplies (mscmd)					
	Power	Non-Power	GTW	Total	Larne	Twynholm
2013/14	4.36	2.96	0	7.32	-	7.32
2014/15	4.36	3.06	0	7.42	-	7.42
2015/16	4.36	3.17	0	7.53	-	7.53
2016/17	4.36	3.27	0.13	7.76	-	7.76
2017/18	4.36	3.37	0.27	8.00	-	8.00
2018/19	4.36	3.47	0.29	8.12	-	8.12
2019/20	4.36	3.57	0.30	8.23	-	8.23
2020/21	4.36	3.66	0.31	8.33	-	8.33
2021/22	4.36	3.75	0.32	8.43	-	8.43
2022/23	4.36	3.84	0.33	8.53	-	8.53

Firm & Interruptible

Year	Severe Winter Peak Day Demands/Supplies (mscmd)					
	Power	Non-Power	GTW	Total	Larne	Twynholm
2013/14	5.16	3.58	0	8.74	-	8.74
2014/15	5.16	3.70	0	8.86	-	8.86
2015/16	4.36	3.81	0	8.17	-	8.17
2016/17	4.36	3.91	0.21	8.48	-	8.48
2017/18	4.36	4.00	0.42	8.78	-	8.78
2018/19	4.36	4.10	0.45	8.91	-	8.91
2019/20	4.36	4.20	0.47	9.03	-	9.03
2020/21	4.36	4.29	0.48	9.13	-	9.13
2021/22	4.36	4.38	0.50	9.24	-	9.24
2022/23	4.36	4.40	0.52	9.28	-	9.28

Appendix 2: Summary of System Modelling Assumptions

General

- All entry points are modelled on a flat flow basis, unless otherwise indicated.
- The system upstream of the NI Transmission System is not considered in this analysis, notwithstanding the assumption regarding the 56 barg inlet pressure at Twynholm.
- Unless otherwise stated, Twynholm is the only source of supply utilised in the models.
- The SNIP, North-West and South-North Pipelines are assumed to have a maximum operating pressure of 75 barg.
- All scenarios simulate the 24 hour demand cycle of the NI transmission system repeated over a three day period to obtain steady consistent results.
- All demands are modelled as energy flows. Volumetric flow is determined from energy flow and local gas calorific value.
- Gas flow volumes are derived from supplied energy demand values by assuming a Moffat Gas Calorific Value of 39.77 MJ/m^3.
- A technical minimum system pressure limit of 27 barg is assumed for all off-takes on the NI system, based on the technical limits associated with the AGIs on the NI system.

Demands

- Forecasted annual and peak NI demands are taken from information provided to the Utility Regulator by system shippers in NI.
- The hourly gas demand of the NI power stations are based on historic diurnals.
- The hourly demand for all other AGI off-takes (i.e. distribution network off-takes) are derived from their historic contribution to peak-day and minimum day demands. Diurnal demand curves are taken from actual peak and minimum days.
- Gas flow volumes are derived from supplied energy demand values by assuming a Moffat Gas Calorific Value of 39.77 MJ/m^3 (historical measured value).
- NI Shippers have provided separate figures for firm and interruptible demands. Where applicable, models were run for both firm and firm & interruptible demands.
- The Gas to the West demand peak day forecasts have been derived using forecast annual volumes from the *Potential Extension of Natural Gas and Related Services in Northern Ireland* feasibility study report and applying appropriate load factors.
- In order to model the firm and interruptible split for the Gas to the West, the non-power firm to interruptible ratio for the existing NI system demand was applied.

Network Operation/Pressure Assumptions

Twynholm

- The ANOP at Twynholm AGI is assumed to be 56 barg.
- Twynholm AGI is modelled as a flow-control regulating AGI, with an assumed pressure drop across the AGI of 2.5 barg. The daily flows through the Twynholm entry point are assumed to follow a flat flow profile, with the diurnal swing in the demand profile being absorbed by the downstream system.
- The design capacity of Twynholm AGI is 8.64 mscmd; and the contractual capacity at the Twynholm exit point (on the BGÉ UK system) is 8.08 mscmd.

Carrickfergus

- Carrickfergus AGI is modelled in flow control mode, whereby the hourly flow through Carrickfergus equals the sum of the hourly downstream demands on the BGÉ NI system.
- The outlet pressure at Carrickfergus is determined by the inlet pressure at the AGI less an assumed pressure drop across the AGI of 3 barg.
- In the Larne storage scenario, when Larne is injecting into storage, flows are west to east across the AGI, when Larne is withdrawing, flows are east to west.

Coolkeeragh

- Unless otherwise specified in a scenario, the minimum inlet pressure at Coolkeeragh AGI is 27 barg, with an assumed pressure drop/loss across the AGI of 3 barg.
- Where the minimum inlet pressure is lowered, the assumed pressure drop/loss across the AGI is assumed to remain at 3 barg.

Future Network Development Assumptions

- Larne supplies are assumed to be available from winter 2018/19. The maximum injection and withdrawal rates for the modelled storage facility are assumed to be 12 mscmd and 22 mscmd respectively. Withdrawal will be modelled on winter peak days, and injection will be modelled on summer minimum days. The facility is assumed to have a working volume of 500 mscm.

- While there are currently no contractual arrangements in place with the proposed Larne gas storage project, it is assumed that it will be able to deliver gas up to 85 barg.

- In cases where compression on the SNIP is modelled, the compression facility is assumed at Twynholm, with the capacity to deliver pressures up to 85 barg into the

SNIP. The compressor facility was modelled as a black box solution, i.e. no assumptions regarding the design of the compressor are made.

- The NI system currently has a maximum operating pressure (MOP) of 75 barg, but it is assumed that the SNIP and BGÉ (NI) MOPs will be uprated to an 85 barg MOP coincident with the availability of Larne Storage and SNIP compression.

- The modelling has not considered the impact of Corrib with regards to demands on the SWSOS network and the resulting impact to pressures available to the NI network.