Transmission Development Statement

2009/10 to 2018/19

gaslink
Gas System Operator

Contents

1. Introduction

This is the third publication of the Transmission Development Statement (TDS), which covers the 10 year period from 2009/10 to 2018/19. It has been prepared by Gaslink (the independent Gas System Operator), with assistance from Bord Gáis Networks (BGN).

Gaslink is required to produce a Long-term Development Plan under Condition 11 of its Transmission System Operator Licence. The publication of the TDS is designed to meet this obligation and also serves as the Gaslink input into the Gas Capacity Statement (GCS) consultation process.

Natural gas continues to play a very important role in the Republic of Ireland (ROI) energy mix. It brings considerable economic and environmental benefits such as being cheaper than oil, having the lowest CO_2 emissions of any fossil fuel and providing the most efficient form of thermal power generation.

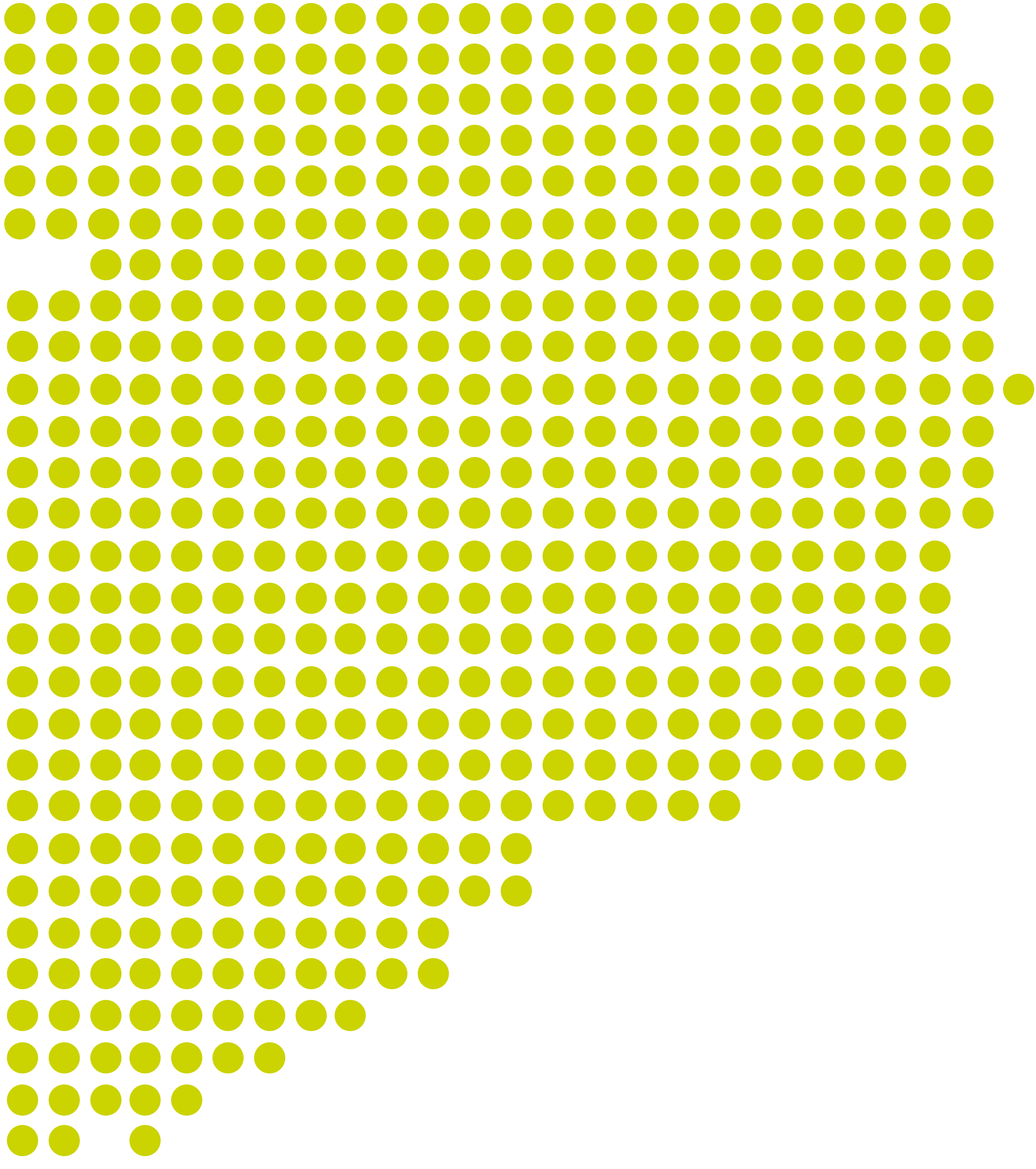
It is hoped that the TDS will assist users to optimise their gas usage and thereby maximise the resulting economic and environmental benefits to the ROI economy. It is intended to provide existing and potential users of the ROI transmission system with an overview of future demand, likely sources of supply and the capacity of the existing transmission system.

The main focus of the TDS is the ROI transmission system, which for the purposes of the TDS is defined to include both the onshore ROI transmission system and the Bord Gáis Interconnector (IC) system, which includes:

- The two subsea interconnectors from Loughshinny and Gormanston in Ireland to Brighouse Bay in Scotland; *and*
- The Brighouse and Beattock compressor stations and connecting transmission Pipeline, which connect the two subsea interconnectors to the Great Britain (GB) National Transmission System (NTS) at Moffat in Scotland.

The Northern Ireland (NI) and Isle of Man (IOM) peak-day and annual demands are also included in the TDS demand forecasts for completeness, as they have a material impact on the capacity of the IC system. These forecasts are based on information provided by Premier Transmission LTD (PTL) in NI and the Manx Electricity Authority (MEA) on the IOM.

Quarter 2, 2010



2. Executive Summary

2.1 ROI GAS DEMAND

Peak-day gas demand grew by +5.5% in 2008/09, due to favourable fuel-prices and colder weather. Annual gas demand fell by -3.1% in 2008/09, with the largest reduction taking place in the power sector -4.6%.

The reduction in annual gas demand is being attributed to the economic recession, which led to reduced electricity demand and, therefore, to reduced annual gas demand from the power sector. It also led to a -0.9% reduction in the annual I/C gas demand, which was partially offset by a +0.9% increase in residential demand (due to colder weather).

The I/C annual gas demand is forecast to grow by 6.1% over the forecast period due to the recovery in the economy; however, this will be offset by increasing energy efficiency from 2016 onwards. The annual gas demand of the power sector is expected to grow by +10.2% by 2018/19; however, it is expected to initially decline due to higher gas prices, rising renewable production and additional interconnection with GB. It is forecast to recover from 2014/15 onwards due to the assumption of higher carbon prices.

The I/C annual gas demand is forecast to grow by 6.1% over the forecast period due to the recovery in the economy; however, this will be offset by increasing energy efficiency from 2016 onwards. The residential annual gas demand is forecast to decline by -9.1% over the same period due to increasing energy efficiency and the slowdown in new housing construction.

Overall ROI peak-day gas demand is forecast to grow by +1.0% p.a., and annual gas demand by +0.7% p.a. (with most of the growth coming from the power sector). These forecasts are lower than those published in the previous TDS due to the impact of the economic recession.

2.2 GAS SUPPLY SCENARIOS

The majority of the ROI gas demand requirements will be sourced from GB imports in the short-term, and the purchase of Marathon's Celtic Sea assets by PSE Kinsale Energy will hopefully ensure that the remainder continues to be met from Inch production and storage gas.

The outlook will change in 2012, when Corrib is assumed to commence production. There are also other proposed supply projects, including additional gas storage in NI and the Celtic Sea, and the Shannon Liquefied Natural Gas (LNG) terminal. There is uncertainty about the timing of new supplies, which has been managed using the following scenario approach:

- **Base Supply**: Assumes the retention of the existing Kinsale production and storage facilities, plus Corrib gas production from April 2011, with any remaining supply shortfall being met from GB imports through Moffat,
- **High Supply**: Assumes the above Base Supply scenario, plus Shannon LNG imports and gas storage in NI from October 2014; *and*
- **Celtic Sea Supply** Assumes the above Base Supply scenario plus additional gas storage in the Celtic Sea.

In order to complete the detailed analysis and modelling required to produce this document, the demand and supply scenarios were defined in Q4 2009 based on the most up to date data. During this period (and up until recently), Corrib production was anticipated to commence in April *2011.*

The Corrib partners recently announced the Corrib project will be delayed until 2012-13. This recent change is represented in the Base Supply scenario, by the inclusion of a sensitivity examining the impact of a 1 year delay to Corrib production.

2.3 TRANSMISSION INFRASTRUCTURE

2.3.1 Base Supply Scenario

The existing transmission system has sufficient capacity to meet the gas flows arising from the forecast peak-day demand and the Base Supply scenario over the forecast period from 2009/10 to 2018/19, even if the start date for Corrib gas production is delayed by 1-year to 2012.

2.3.2 High Supply Scenario

The existing transmission system has sufficient capacity to meet the forecast peak-day demand, but may not be able to accommodate the maximum flows from all of the proposed new supply projects.

The combined maximum exports from the proposed Shannon LNG and Larne gas storage projects will exceed the forecast peak-day demand of the ROI and NI. One solution would be to physically export gas to GB; however, this presents a number of technical challenges:

- Any gas exported from the ROI and NI transmission system would be odorised, whereas the GB NTS currently only transports non-odorised gas and, therefore, it may potentially be necessary to deodorise parts of the ROI and NI transmission systems;
- The ROI transmission system would need reinforcement to facilitate the export of gas, particularly from Shannon LNG (which would require a new compressor station north of Dublin); *and*
- If it is assumed that the above gas quality and system reinforcement issues can be satisfactorily addressed, then the high-level conceptual studies indicate that it may be possible to export up to 103GWh/d (9.3 mscm/d) from Larne, and 89 GWh/d (7.9 mscm/d) from Shannon LNG in certain scenarios.

There is also a physical constraint on the maximum quantity of Corrib and Shannon LNG gas that can be transported from the West Coast to the main markets along the East Coast, while still maintaining the minimum specified operating pressure at the Dublin City Gates:

- The maximum West Coast flows that can be accommodated on the existing transmission system while maintaining 55 barg at Dublin, is approximately 192 GWh/d (17.0 mscm/d);
- This is approximately -6.9% lower than indicated in the previous TDS, due to the current assumption that Kinsale gas production and storage facilities remain in service;
- It may be possible to accommodate Shannon LNG (Phase I) without reinforcement, provided its exports are ramped-up to coincide with declining Corrib production; *and*
- The existing transmission system would need reinforcement to accommodate the Shannon LNG (Phase II) exports.

The maximum withdrawal rate of any gas storage facility in NI will be limited to the NI peak-day demand plus what can be exported to the ROI through the South/North (S/N) Pipeline and Scotland to NI Pipeline (SNIP).

The network analysis modelling indicates that the maximum export potential to the ROI is approximately 126 GWh/d (11.4 mscm/d), based on exporting 44 GWh/d (4.0 mscm/d) through the S/N and reverse-flowing 82 GWh/d (7.4 mscm/d) through the SNIP Pipeline.

2.3.3 Celtic Sea Scenario

The ability of the existing ROI transmission system to accommodate additional production or storage gas from the Celtic Sea will be determined by the capacity of the Inch Entry Point, which will be largely determined by the capacity of the Midleton compressor station, once the reconfiguration of the Cork area transmission system is completed in early 2010.

The Midleton compressor station currently has a capacity of approximately 63 GWh/d (6.0 mscm/d). Inch gas flows in excess of this limit are possible, but are limited to the gas demand of the old Aghada power station.

While it is possible to technically increase the capacity of the Midleton compressor station, this would require obtaining an Integrated Pollution Prevention Control (IPPC) licence from the Environmental Protection Agency (EPA). This may prove challenging given the age and technological vintage of the existing compressor units.

3. Demand Outlook

3.1 HISTORIC ROI DEMAND

3.1.1 Overall ROI demand

The historic ROI daily gas demand is shown in Fig. 3.1, together with the corresponding peak-day and annual demand statistics in Table 3.1. The peak-day and annual demand has grown by +3.9% p.a. and +2.9% p.a. respectively, between 2002/03 and 2008/09

Figure 3.1: Historical daily ROI gas demand summarised by sector

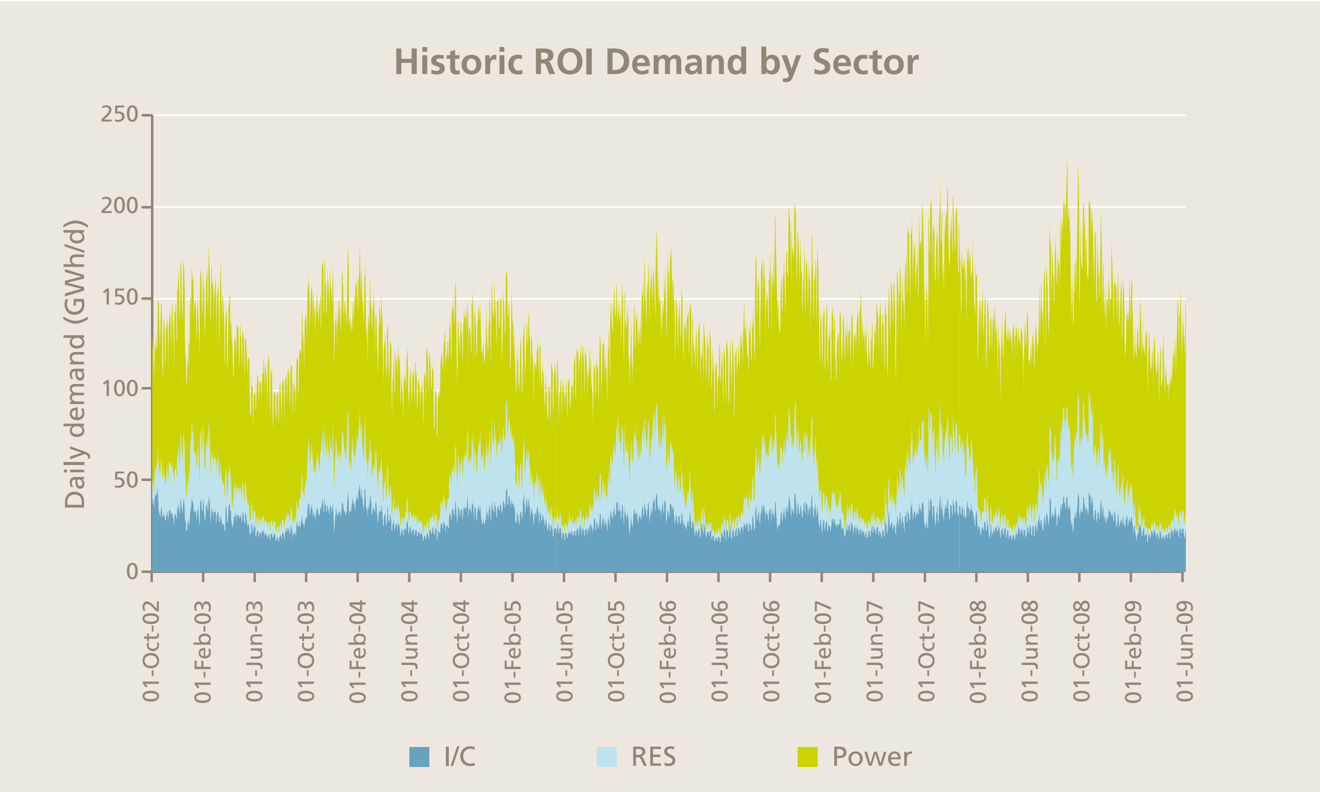


Table 3.1: Historic ROI Peak-Day and annual gas demand (actual demands)[1]

	2002/03 (GWh)	2003/04 (GWh)	2004/05 (GWh)	2005/06 (GWh)	2006/07 (GWh)	2007/08 (GWh)	2008/09 (GWh)
Peak-day							
Power[2]	97.0	91.8	73.6	96.8	111.2	119.7	126.4
I/C	42.8	43.9	45.5	43.4	43.1	43.4	44.4
RES1	41.5	45.2	47.0	49.4	50.4	52.5	56.7
Total	181.3	180.9	166.1	189.6	204.7	215.7	227.5
Annual							
Power	28,775	28,845	25,630	29,775	34,688	37,758	36,007
I/C	10,538	11,154	11,127	10,352	10,486	10,507	10,415
RES	6,701	7,434	7,757	8,149	7,716	8,239	8,312
Total	46,013	47,433	44,514	48,276	52,890	56,504	54,734

[1]*Actual demands shown (no weather correction), with RES estimated as % of NDM demand*

[2]*Power sector demand includes Aughinish gas demand*

The ROI gas demand is very seasonal in nature (see Fig. 3.1), rising in the winter months and falling in the summer months, due to the weather sensitive nature of the residential and small I/C gas demand (which primarily use gas for space heating purposes).

The power generation sector is the largest user of natural gas and accounted for 65.8% of total ROI annual gas demand in 2008/09, followed by the I/C sector which accounted for 19.0% and the residential sector which accounted for 15.2%.

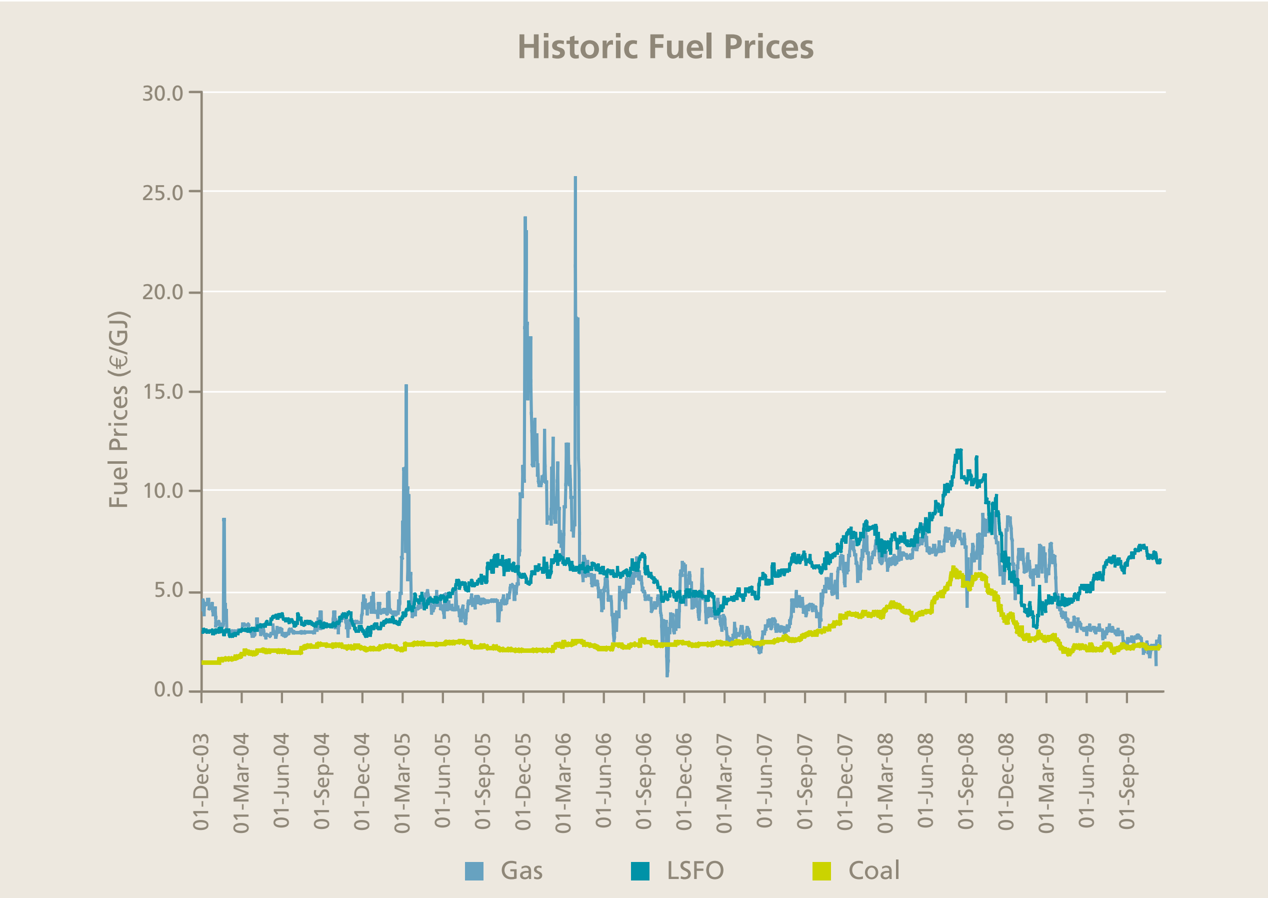
The weather sensitive nature of the residential demand means that it makes a bigger contribution to peak-day demand (24.9% in 2008/09). The corresponding contributions of the power and I/C sectors on the peak-day demand were 55.6% and 19.5% respectively.

3.1.2 Power sector gas demand

The annual gas demand of the power sector reduced by -4.6% during 2008/09 and this accounted for practically all of the overall reduction in the total ROI annual gas demand over the same period. This reduction in power sector gas demand was attributed to:

- A reduction to the underlying demand for electricity following the economic recession, with EirGrid reporting a -4.3% reduction in electricity sales during the 12-month period from October 2008 to September 2009 (inclusive);
- Increased electricity imports through the Moyle Interconnector in NI, due to lower prices in the GB electricity market (also due to the impact of the recession on GB electricity demand);
- Major outages at a number of gas-fired power stations during 2008/09; *and*
- Adverse fuel-price movements during the first half of 2008/09 (see Fig. 3.2), when gas was considerably more expensive than either Low Sulphur Fuel Oil (LSFO) or coal.

Figure 3.2: Historic fuel-prices



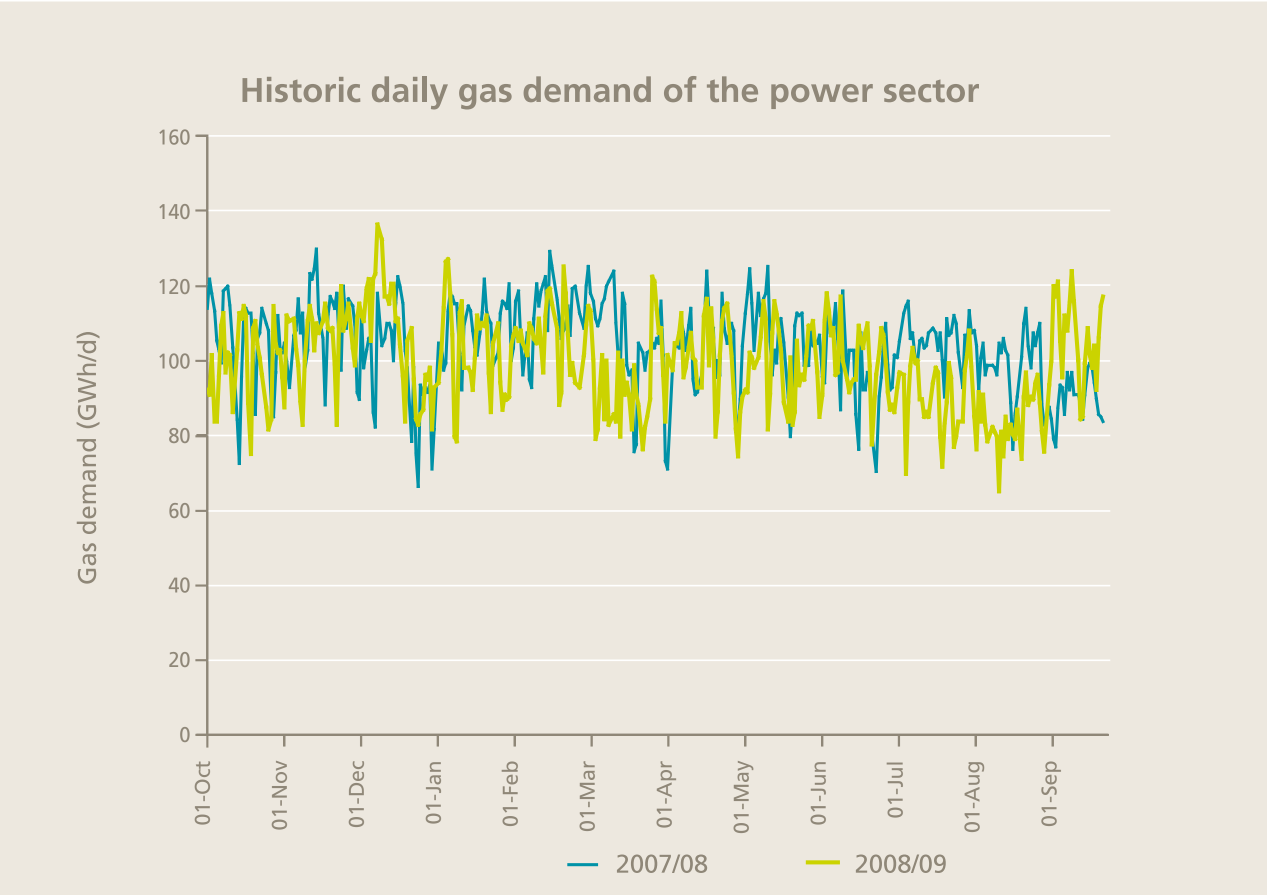
**LSFO = Low Sulphur Fuel Oil, i.e. the main fuel burned by oil-fired power stations*

The reduction in power sector gas demand could have been even larger were it not for the favourable movements in fuel-prices during the second half of 2008/09 (see Fig. 3.2), when gas was considerably cheaper than LSFO and almost as cheap as coal.

The gas demand of the power sector on the ROI peak-day increased by +5.6% to 126.4 GWh/d on 7th January 2009. The divergence between peak-day and annual demand trends is attributed to timing, with the monthly electricity statistics data published by EirGrid showing the monthly growth rate trend only beginning to go negative during January 2009.

The daily gas demand of the power sector is shown in Fig 3.3 for both 2007/08 and 2008/09. It can be seen that the gas demand of the power sector was noticeably lower in the months of March (-12.5%), May (-8.5%), July (-12.5%) and August (-15.6%);

Figure 3.3: Historic daily gas demand of the power sector



3.1.3 I/C gas demand

The annual gas demand of the I/C sector fell by -0.9% during 2008/09; however, there were significant differences between the trends for transmission and distribution connected sites (which respectively accounted for 33.8% and 66.2% of total I/C gas demand in 2008/09);

- Annual gas demand of the larger transmission connected I/C sites fell by -7.3%; *and*
- Annual gas demand of the smaller distribution connected I/C sites rose by +2.7%.

The transmission connected I/C sector includes the larger manufacturing, pharmaceutical and dairy co-op sites, which primarily use natural gas to provide heat for manufacturing and processing purposes. The reduction in the transmission connected I/C gas demand, therefore, primarily reflects the impact of the wider economic recession.

The distribution connected I/C sector includes the small I/C sector, offices, retail units, hospitals and schools etc, which would primarily use gas for space-heating purposes and, therefore, their gas demand would be much more weather sensitive.

The increased annual gas demand of the distribution connected I/C sector can be attributed to colder weather during 2008/09 (compared to 2007/08), which more than offset any reduction in their gas demand due to the economic recession.

3.1.4 Historic residential gas demand

Total residential gas demand grew by +0.9% during 2008/09; however, the annual gas demand per residential customer reduced by -2.1%. It can be seen from Table 3.2 that this is a continuation of recent trends, whereby the growth in annual gas demand has lagged the corresponding growth in customer numbers:

- The average number of residential customers for each gas year increased from 418,439 in 2002/03 to 602,387 in 2008/09, an increase of +44.0%; *however*
- The total residential gas demand only grew by +24.0% over the same period, i.e. from 6,700.6 GWh/y in 2002/03 to 8,311.8 GWh/y in 2008/09.

The downward trend in annual residential gas demand per customer is being attributed to enhanced building regulations for new houses, increasing energy efficiency initiatives for existing houses and a response to rising gas prices.

Table 3.2: Residential gas demand per customer

	2002/03 (GWh)	2003/04 (GWh)	2004/05 (GWh)	2005/06 (GWh)	2006/07 (GWh)	2007/08 (GWh)	2008/09 (GWh)
No. of customers							
On 1st October	401,094	435,784	456,339	500,837	538,822	571,485	595,740
On 30th September	435,784	456,339	500,837	538,822	571,485	595,740	609,034
Customer growth	34,690	20,555	44,498	37,985	32,663	24,255	13,294
Average for Gas Yr[1]	418,439	446,062	478,588	519,830	555,154	583,613	602,387
RES Demand							
Total RES demand	6,700.6	7,433.6	7,756.7	8,148.9	7,716.1	8,238.5	8,311.8
Demand per customer[2]	0.0160	0.0167	0.0162	0.0157	0.0139	0.0141	0.0138

[1] Average for Gas Yr = Average number of residential customers connected to the distribution system over the course of the gas year (i.e. the average number of customers at the start and end of gas year)

[2] Per customer = Average residential annual gas demand per customer (before weather adjustment)

The slowdown in the construction sector can also be seen in the new connection number. The total number of new residential connections dropped from approximately 24,255 in 2007/08 to 13,294 in 2008/09, a reduction of -45.2%.

3.1.5 ROI annual energy demand

Natural gas continues to make an important contribution to the overall ROI energy-mix and accounting for approximately 30% of the ROI Total Primary Energy Requirements (TPER) in 2009 (see Figure 3.4 & 3.5).

The TPER includes the use of fuel for electricity generation and natural gas is also an important fuel for electricity generation, accounting for 56.1% of all fuels used for electricity generation in 2009.

Natural gas accounted for 12.7% of Total Final Consumption (TFC). Its lower share of TFC compared to TPER can be explained by the fact that the TFC excludes the use of energy for electricity generation for 19.72% of the residential TFC, 23.7% of the commercial TFC and 24.6% of the industrial TFC.

Figure 3.4: Analysis of historic ROI TPER

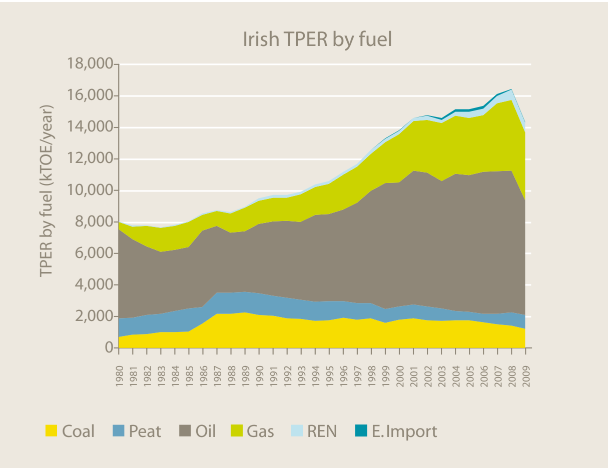
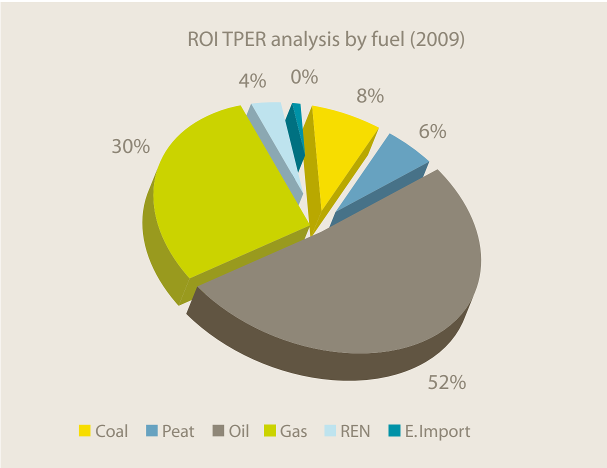


Figure 3.5: Breakdown of ROI TPER



3.1.6 Bord Gáis system demand

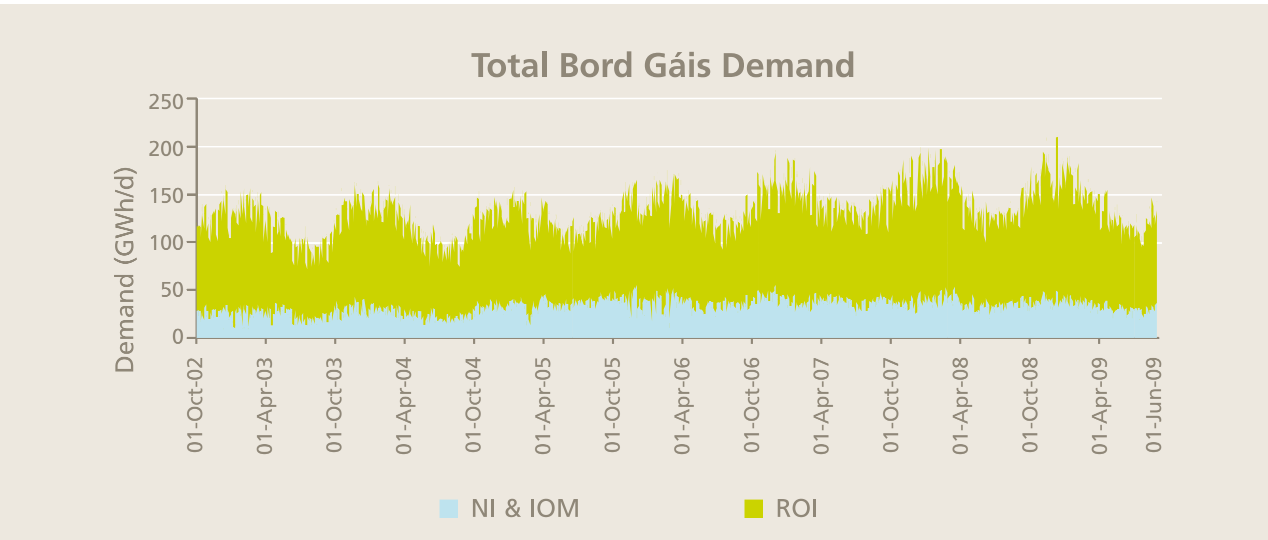
The historic peak-day and annual demand of the overall Bord Gáis system is shown in Table 3.3 and includes the aggregated demands of the ROI, NI and the IOM.

The historic daily demand of the Bord Gáis system is shown in Fig. 3.6.

Table 3.3: Historic Bord Gáis Peak-Day and annual gas demand (actual demands)

	2002/03 (GWh)	2003/04 (GWh)	2004/05 (GWh)	2005/06 (GWh)	2006/07 (GWh)	2007/08 (GWh)	2008/09 (GWh)
Peak-day							
ROI	172.1	176.6	164.6	165.7	196.7	205.9	227.5
NI + IOM	52.0	53.4	57.5	79.8	79.0	74.8	67.7
Total	224.1	230.0	222.0	245.5	275.7	280.7	295.2
Annual							
ROI	46,013	47,433	44,514	48,276	52,890	56,504	54,734
NI+IOM	12,837	13,683	17,975	19,353	20,216	19,294	18,022
Total	58,850	61,116	62,489	67,629	73,106	75,798	72,756

Figure 3.6: Historic daily demand on the Bord Gáis transmission system



The overall Bord Gáis system peak-day demand increased +5.2% during 2008/09, but the annual demand reduced by -4.0%. The ROI peak-day coincided with the Bord Gáis system peak-day during 2008/09, whereas this was not always the case in previous gas years.

The main driver of the growth in the Bord Gáis system peak-day demand was the increased contribution of the ROI peak-day demand, which increased by 10.5% during 2008/09. This more than offset the reduced contribution from NI and IOM peak-days, which fell by -9.5% during 2008/09.

The annual demand on the Bord Gáis system reduced by -4.0% during 2008/09. This simply reflected the -3.1% reduction in the annual demand of the ROI and -6.7% reduction in the combined annual demand of NI and the IOM.

3.2 FORECAST ROI GAS DEMAND

3.2.1 ROI power sector forecast

The outlook for the future gas demand of the power sector is very challenging, despite the planned construction of new gas-fired stations. The gas demand of the ROI power sector will be determined by a number of factors including:

- The overall demand for electricity and the order in which power stations are dispatched to meet that demand (i.e. the "merit-order", which is very sensitive to fuel-prices); *and*
- National and international policies in relation to targets for renewable electricity production, electrical interconnection and global warming (including carbon prices).

The outlook for the future gas demand of the power sector is being squeezed by lower forecasts for electricity demand, continuing investment in renewable electricity production, increased electricity interconnection with GB and rising gas prices:

- The forecasts published by EirGrid in its latest Generation Adequacy Report (GAR) assume that electricity peak-demand will increase from 4,665 MW in 2009 to 5,233 MW by 2016 in its median forecast (i.e. an increase of + 568 MW);
- The forward price curve for winter gas indicates that prices will increase from circa 30p/therm in 2009/10 to 61p/therm in 2013/14 (an increase of +103.0%); *and*
- EirGrid forecasts the installed wind-capacity will increase from 1.396 MW in 2009 to 4,121 MW by 2016 (an increase of +2,725MW) and confirmed that it is on schedule to complete the 500 MW East/West electricity interconnector to GB in 2012.

The global drive to reduce greenhouse gases may provide some upside for gas demand however, by displacing coal for electricity generation. The carbon price is assumed to reach €25/tCO2 by 2018/19, during Phase III of the Emission Trading Scheme (ETS). This should lead to a recovery in power sector gas demand, towards the end of the forecast period.

The TDS planning assumptions in relation to the construction and retirement of power stations in both the ROI and NI are tabulated in Table 3.4 and may be briefly summarised as follows:

- The Aghada and Whitegate Combined Cycle Gas Turbine (CCGTs) in Cork which are currently commissioning, together with an Open Cycle Gas Turbine (OCGT) in Edenderry (which will use gas/oil);
- Endesa will retire their oil-fired plants by 2012/13, and replace them with a 440 MW CCGT at Great Island, and initially a 300 MW OCGT at Tarbert (and later a CCGT);
- A number of additional gas-fired stations have also been included in the TDS for planning purposes, including two new CCGTs in Louth and Belfast, and two small OCGTs in the Midlands; *and*
- The Poolbeg Steam station will be retired, and the Marina station converted from a CCGT to OCGT by February 2010.

Table 3.4: New and retired power station assumptions

Name	Type	Status	Export (MW)	Start Date	Location
New					
Aghada	CCGT	Committed	430	May-10	Cork
Whitegate	CCGT	Committed	445	Jul-10	Cork
Edenderry OCGT	OCGT	Committed	111	Sep-10	Offaly
Great I. CCGT	CCGT	Assumed	440	Oct-13	Wexford
Tarbert OCGT*	CCGT	Assumed	300	Oct-12	Kerry
New CCGT1	CCGT	Assumed	440	Oct-13	Louth
New CCGT2	CCGT	Assumed	430	Oct-13	Belfast
New OCGT1	OCGT	Assumed	100	Oct-11	Midlands
New OCGT2	OCGT	Assumed	100	Oct-13	Midlands
Total 2,796					
Retired					
Tarbert	Oil	Assumed	590	Mar-13	Kerry
G. Island	Oil	Assumed	216	Mar-13	Wexford
Poolbeg	Dual	Committed	461	Mar-10	Dublin
Total 1,267					

**Assumed to be converted into CCGT by 2016/17*

The TDS forecast assumes that peak-day electricity demand will increase from 4,665 MW in 2009/10 to 5,319 MW by 2018/19, an increase of +726 MW. This level of growth in electricity demand will be insufficient to fully utilise all of the proposed new generation:

- The combined export capacity of all the gas-fired power stations is assumed to increase from 3,525 MW to 5,285 MW by 2018/19 (an increase of +1,762 MW);
- The installed wind-capacity is assumed to increase from approximately 1,396 MW to 4,831 MW by 2018/19 (an increase of +3,435 MW); *and*
- The level of electrical interconnection is assumed to increase from 450 MW to 950 MW by 2012/13 (an increase of +500 MW).

The most likely outcome from the above assumption is that the potential increase in gas demand from the assumed new gas-fired power stations will be largely offset by reduced gas demand from the older and less efficient gas-fired stations (which will be forced further-up the merit-order and dispatched less frequently).

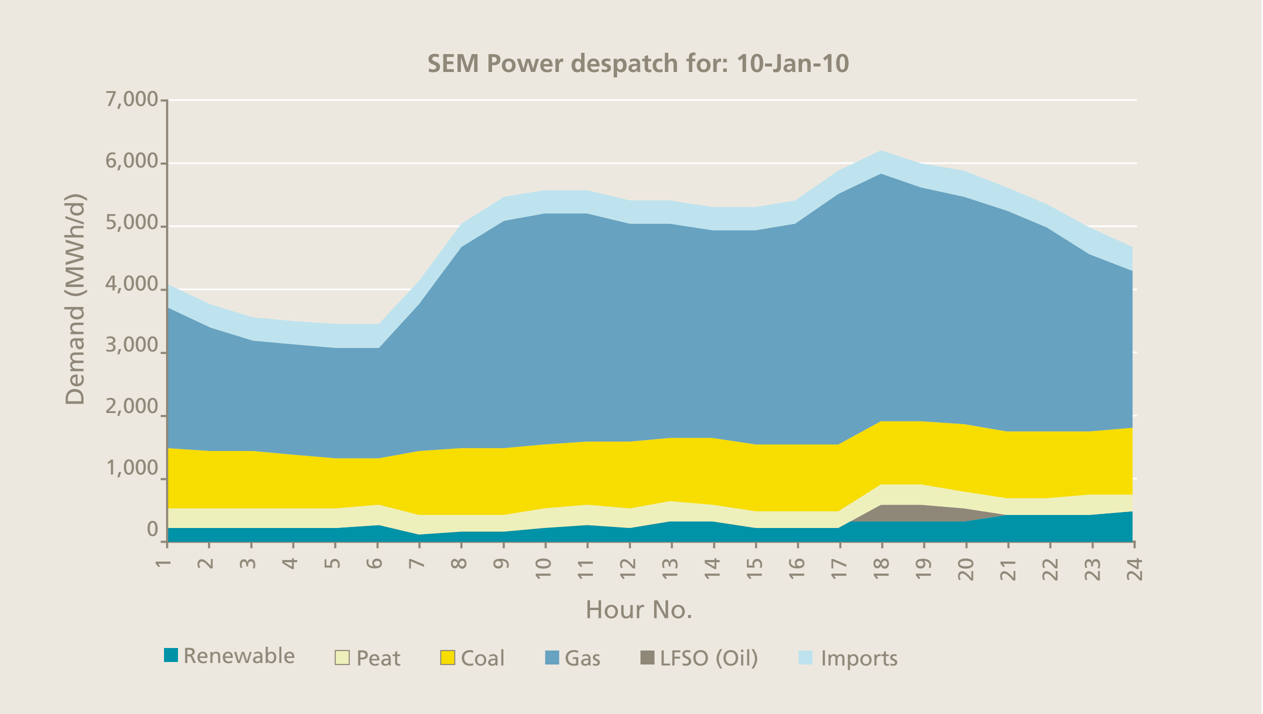
This can also be seen in Fig. 3.7, which shows the TDS forecast of hourly power generation by fuel for the 2009/10 peak-day. There is already insufficient baseload electricity demand for the existing coal, peat and gas-fired stations, and the gas-fired stations will need to be curtailed at night-time. The forecast trend for power sector annual demand are as follows:

- It will recover during 2009/10 due to the construction of two new CCGTs and a favourable gas price relative to other fuels;
- It will then decline until 2015/16 due to the combination of rising gas prices, rising renewable energy and increased electrical interconnection with GB; *and*
- It will begin to recover from 2015/16 onwards due to the assumptions of rising carbon prices and a phasing out of the Public Service Obligation (PSO) levy for peat stations.

The annual gas demand of the power sector is expected to increase by +10.2% over the forecast period (or by +1.1% p.a.). The peak-day gas demand of the power sector will follow a broadly similar trend, which may be summarised as follows:

- It is forecast to grow at a higher rate of +21.4% over the forecast period or +2.2% p.a., primarily due to the assumption that wind-power will have a lesser impact on the peak-day demand of the sector (since the system peak-day is assumed to occur on a calm day, which is the worst-case scenario for gas system planning purposes);
- It is expected to decline during the middle of the forecast period due to the impact of the East/West electricity interconnector to GB in 2012/13, and the assumption that a new CCGT will be commissioned in the Belfast area in 2013/14; *and*
- Finally, it is expected to recover from 2014/15 onwards due to the assumptions of rising carbon prices and a phasing out of the peat PSO levy.

Figure 3.7: Forecast despatch of SEM power sector by fuel-type on 2009/10 gas Peak-Day



3.2.2 Forecast I/C gas demand

The future growth in annual I/C gas demand will primarily be driven by the recovery in the ROI economy and the demand for economic goods and services, which will drive the demand for the associated primary inputs such as natural gas.

The TDS forecast uses the economic forecasts published in the ESRI Quarterly Economic Commentary (QEC) for autumn 2009, which forecast that Gross Domestic Product (GDP) will reduce by -7.2% during 2009 and -1.1% during 2010. A pragmatic view has been taken for economic growth post 2010, following consultation with the ESRI:

- The economy will come out of recession by 2010/11, and will initially grow above its estimated long-term trend potential of +3.5% during 2011/12; *and*
- Economic growth will then revert back to its long-term trend potential of between 3.0% and 3.5% p.a. post 2011/12.

The TDS forecast assumes that the annual I/C gas demand will grow at 80% of the GDP growth rate, but this will be offset by both rising gas prices and increasing energy efficiency (particularly post 2016). The forecast trends in the annual I/C gas demand may be summarised as follows:

- I/C gas demand will continue to decline until 2011/12 due to weak economic growth, increasing energy efficiency and the assumption of rising gas prices in 2010/11;
- It will recover from 2011/12 onwards due to rising economic growth; however, this will be increasingly offset by rising energy efficiency (particularly post 2016); *and*
- Overall I/C annual gas demand is assumed to grow by 6.1% (or +0.7% p.a.) over the forecast period, with the peak-day gas demand following a similar trend.

Most of the I/C energy efficiency savings identified in the National Energy Efficiency Action Plan (NEEAP) for Ireland are assumed to take place post 2016. The TDS forecast assumes annual energy efficiency savings of 65 GW/y up to 2015/16, and 266 GWh/y from 2015/16 onwards (equivalent to 0.6% and 2.6% respectively of the I/C annual gas demand in 2008/09).

The forecast peak-day and annual gas demand of the I/C sector are summarised in Appendix 1, and the assumptions in relation to the I/C energy efficiency savings are explained in more detail in Appendix 3.

3.2.3 Forecast residential gas demand

The future gas demand of the residential sector will be driven by both the number of new connections, and the impact of the various proposed energy efficiency measures. The assumptions in relation to new connections are summarised in Table 3.5.

The total number of connections from new housing is forecast to increase from 5,335 p.a. in 2009/10 to 15,000 p.a. in 2018/19, and the number of one-off housing connections from 3,925 p.a. to 5,000 p.a. in 2018/19 (i.e. existing houses that convert to gas from other fuels).

The total number of residential customers is forecast to grow from 609,034 at the start of 2009/10 to 749,844 by the end of 2018/19, an increase of +23.1% over the forecast period (+2.3% p.a.). Residential annual gas demand is forecast to reduce by -9.1% over the forecast period (-1.1 % p.a.) for a number of reasons:

- The incremental gas demand of new residential customers has been falling due to tighter building regulations (with further tightening expected in 2010);
- The average gas demand of existing residential customers has also been falling due to increasing energy efficiency, greater vacancy rates and in response to rising gas prices in recent years; *and*
- Further initiatives are planned for improving the energy efficiency of existing houses in the NEEAP, including retrofitting insulation to older houses, smart metering and setting a new standard for more efficient boilers.

Table 3.5: New residential connecting assumption by gas year

	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19
New	5,335	4,500	4,500	6,000	7,750	10,000	12,250	14,000	15,000	15,000
One-off	3,925	3,900	3,900	4,750	5,000	5,000	5,000	5,000	5,000	5,000
Total	9,260	8,400	8,400	10,750	12,750	15,000	17,250	19,000	20,000	20,000

All of these trends are expected to intensify over the forecast period. The proposed amendments to the building regulations in 2010 will further reduce the energy consumption of new housing. The average incremental annual gas demand of a new customer in 2005 was approximately 12.3 MWh/y and this is expected to reduce by 60% to 4.9 MWh/y by 2012.

The proposed standard for more efficient boilers, smart metering and the Low Carbon Homes, Warmer Homes and Home Energy Savings schemes are designed to improve the energy efficiency of the existing housing stock. It is estimated that these measures could lead to an annual reduction of -1.8% p.a. to the existing residential gas demand.

It should be emphasised that there is still considerable uncertainty surrounding the rollout and implementation of the energy efficiency initiatives for existing housing. The energy efficiency assumptions made in the TDS forecast are described in more detail in Appendix 3. The peak-day and annual residential gas demand forecasts are tabulated in Appendix 1.

3.3 RECORD PEAK DEMAND IN JANUARY 2010

The all time record peak demand for both the Bord Gáis Transmission system and the onshore Republic of Ireland (ROI) system occurred on 7th January 2010, as a result of the exceptionally cold weather conditions experienced during this period.

The Bord Gáis system peak of 332.9 GWh/d (30.2 mscm/d) that occurred on 7th January is the sum of the ROI, NI and Isle of Man (IOM) demands, which were 252.9 GWh/d (23.0 mscm/d), 75.2 GWh/d (6.8 mscm/d) and 4.8 GWh/d (0.4 mscm/d) respectively.

The ROI system peak of 252.9 GWh/d (23.0 mscm/d) coincided with a 20.7 Degree Day (DD) at Dublin Airport, slightly short of the 1-in-50 DD of 21.0. The actual ROI peak demand on 7th January slightly exceeded the forecast for 1-in-50 peak day demand, of 245.7 GWh/d (22.4 mscm/d).

The ROI electricity system also recorded its highest ever system demand peak of 4950 MW on 7th January. This high demand coincided with low levels of wind generation (83 MW at the time of the system peak), and resulted in record power generation gas demand of 134.8 GWh/d (12.3 mscm/d).

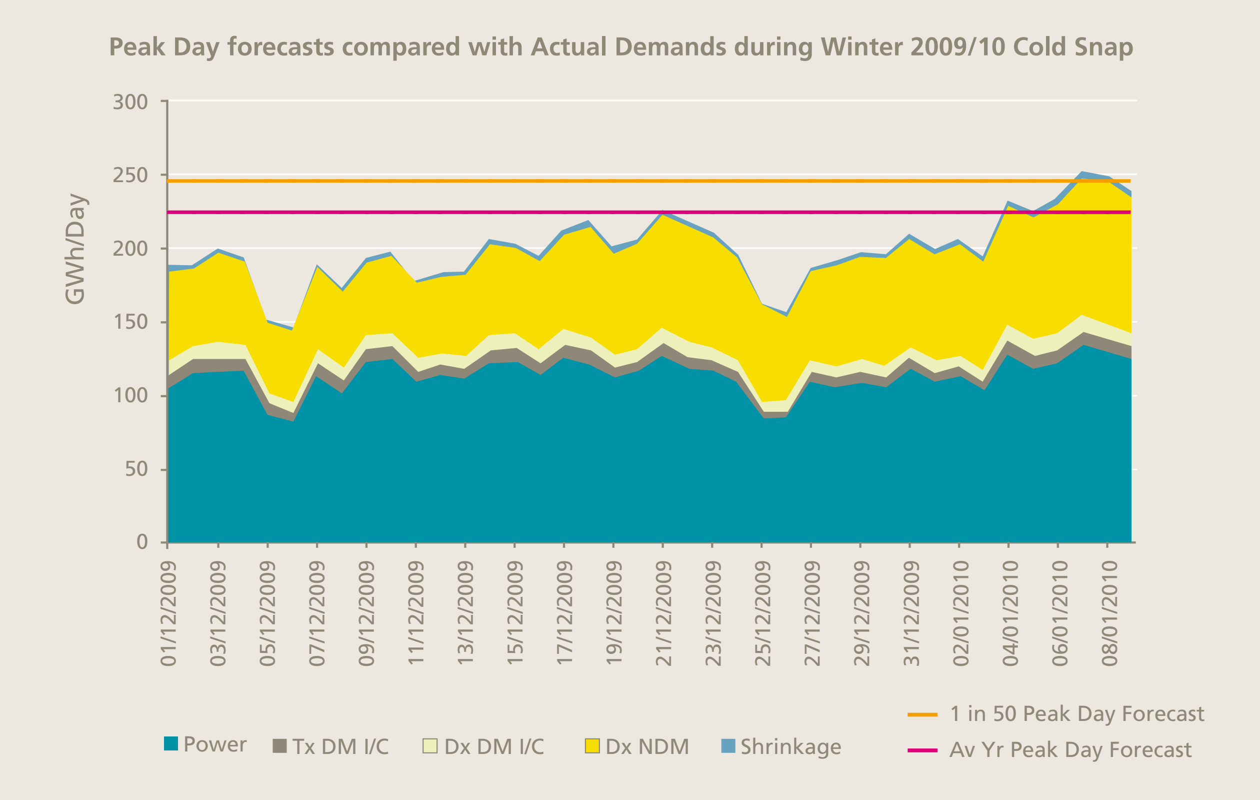
Daily Metered (DM) I/C demand, of 20.8 GWh/d (1.9 mscm/d), was not as high as peak days from previous years, due to the current economic recession.

Non Daily Metered (NDM) recorded its highest peak to date on 7th January, 92.4 GWh/d (8.4 mscm/d). However, this NDM demand record was exceeded the following day, 8th January, at 95.2 GWh/d (8.7 mscm/d). This slightly exceeded the forecast 1-in-50 peak day NDM demand of 94.7 GWh/d (8.6 mscm/d).

Gas flows through the subsea Inter-connector (IC) system on 7th January, of 218.1 GWh/d (19.7 mscm/d), exceeded the IC1 design capacity of 188.2 GWh/d (17.0 mscm/d).

Both gas supplies and the Bord Gáis transmission system were sufficient in meeting the peak demand requirement on 7th January.

Figure 3.8: Actual Demand by Sector for mid-winter 2009/10 and Peak-Day Forecasts



4. Gas Supply Outlook

4.1 HISTORIC GAS SUPPLIES

The majority of the ROI gas demand continues to be supplied from GB gas imports through Moffat, with the remainder coming from production and storage gas through the Inch Entry point. Total Inch deliveries in 2008/09 were equivalent to 7.7% of the ROI annual demand.

GB imports from Moffat were also supplied through the Inch Entry point to help refill the Kinsale Storage facility during the summer (supplementing the offshore production). The historical indigenous gas production is shown in Fig. 4.1, together with GB imports.

The peak-day and annual entry supplies through Moffat and Inch are shown in Table 4.1. It can be seen that gas supplies through the Inch Entry point make a bigger contribution to the peak-day demand compared to annual demand (supplying 15.6% of the ROI peak-day in 2008/09 compared to 7.7% of annual demand), due to the operation of Kinsale storage.

Figure 4.1: Historic annual indigenous gas production and GB imports

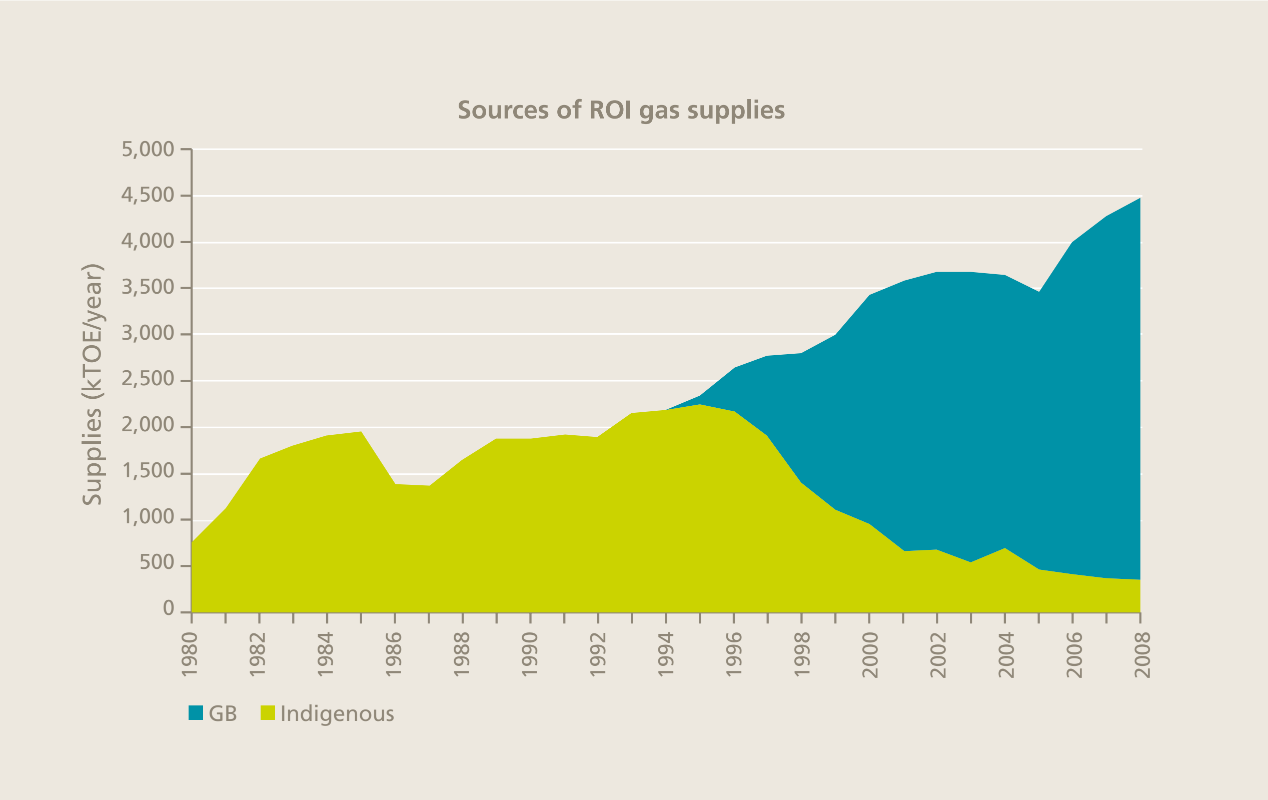


Table 4.1: Historic Peak-Day and Annual Supplies through Moffat and Inch

	2002/03 (GWh)	2003/04 (GWh)	2004/05 (GWh)	2005/06 (GWh)	2006/07 (GWh)	2007/08 (GWh)	2008/09 (GWh)
Peak-day							
Moffat	190.2	169.5	175.8	197.7	234.5	245.6	251.4
Inch	41.1	60.9	46.8	40.6	43.6	40.0	35.6
Total	231.2	230.4	222.6	238.3	278.1	285.6	287.0
Annual							
Moffat [3]	53,221	51,982	56,890	64,023	69,236	72,645	70,446
Inch	6,637	9,705	6,397	5,451	4,976	4,772	4,259
Total	59,858	61,687	63,287	69,474	74,212	77,417	74,705

[1]*Daily supply data taken from Gas Transportation Management System (GTMS)*
[2]*Table shows total Moffat supplies including supplies to ROI, NI and IOM*
[3]*There is a very minor revision to Moffat data (<0.3%) for 2007/08 compared to previous TDS*

4.2 FUTURE GAS SUPPLY OUTLOOK

4.2.1 General overview

In the short-term, the majority of the ROI gas demand will continue to be met from GB imports through the Moffat Entry Point. It is likely to change significantly from 2012/13 onwards, with a number of new gas supply projects at various stages of their project lifecycle:

- The Corrib gas field off the Mayo Coast is expected to commence commercial production in 2012-13;
- Shannon LNG has received planning permission to develop a LNG terminal on the river Shannon, near Ballylongford in Co. Kerry;
- Islandmagee Storage and North East Storage are separately looking into the commercial feasibility of developing salt-cavity storage near Larne in NI; *and*
- PSE Kinsale Energy and Island Oil & Gas are separately investigating the commercial feasibility of developing further gas storage capacity in the Celtic Sea

4.2.2 Corrib Gas

The Corrib gas field is being developed by the Corrib owners, who include Shell, Statoil and Vermillion. The project is at an advanced stage with construction work completed on the subsea infrastructure and the gas processing terminal at Bellanaboy.

The last remaining piece of major infrastructure is the construction of the onshore pipeline between land-fall and the gas processing terminal at Bellanaboy. The planning permission process for this pipeline is currently ongoing.

The TDS forecast assumes that the first commercial production of Corrib gas will take place in 2011 in all of the supply scenarios. The impact of a 1-year delay to Corrib gas is also analysed, in the event that the construction of the pipeline between the Corrib land-fall and gas processing terminal takes longer than assumed.

4.2.3 Shannon LNG

Shannon LNG has received planning permission for both its proposed LNG terminal near Ballylongford in Co. Kerry, and for the associated transmission pipeline that will deliver the gas into the ROI transmission system. It is proposed to develop the LNG terminal on a phased basis:

- Phase I will involve the construction of one or two LNG storage tanks and re-gasification facilities with a maximum export capacity of up to 191.1 GWh/d (17.0 mscm/d); *and*

- Phase II will involve the construction of up to four LNG storage tanks and additional re-gasification facilities with a maximum export capacity of up to 314.7 GWh/d (28.0 mscm/d).

The TDS forecast assumes that Phase I of the proposed LNG project will proceed as planned in the High Supply scenario and be available for first commercial operation from October 2014 onwards.

4.2.4 Larne Storage

There are currently two separate salt-cavity gas storage projects being proposed for the Larne area in NI, by Islandmagee Storage and North East Storage respectively. Both projects are looking into the commercial feasibility of developing gas storage in the salt layers that run underneath the Larne area:

- Islandmagee Storage is a consortium of Portland Gas Northern Ireland and Moyle Energy Investment Holdings, and is looking to develop a 5,514 GWh (500 mscm) salt cavity gas storage facility underneath Larne Lough, with a maximum withdrawal rate of 265 GWh/d (24.0 mscm/d) and injection rate of 132 GWh/d (12.0 mscm/d); *and*

- North East Storage is a consortium of Bord Gáis and Storengy (a GDF-Suez company), which based on the available data is looking to develop a 3,308 GWh (300 mscm) storage facility near Larne, with maximum withdrawal and injection rates of 165-221 GWh/d (15-20 mscm/d) and 66-88 GWh/d (6-8 mscm/d) respectively.

Islandmagee Storage has completed seismic testing and is currently preparing a planning application for its project. North East Storage is due to complete seismic testing and drill a borehole during 2010, and plans to submit a planning application for their project in 2011.

The relatively small size of the gas market in both the ROI and NI means that it is unlikely that both of the proposed salt cavity gas storage projects will proceed as planned. The TDS forecast assumes one generic salt cavity gas storage in the Larne area from October 2014 in the High Supply scenario.

4.2.5 Celtic gas storage

PSE Kinsale Energy concluded the purchase of the Marathon Celtic Sea assets during the course of 2009, which should secure the longer-term future of the existing Kinsale gas production and storage facilities. PSE Kinsale Energy is also investigating the commercial feasibility of redeveloping the depleted Ballycotton gas field into a gas storage facility.

Island Oil & Gas have discovered proven gas reserves in their Schull and Old Head of Kinsale prospects. They are currently investigating the commercial feasibility of either developing these prospects for gas production or gas storage purposes.

The TDS forecast assumes that the current Kinsale product and storage facilities remain in operation for all the supply scenarios (with declining production from the main Kinsale gas field).

There is currently no firm data available in relation to the development of future gas storage facilities. The Celtic Sea Supply scenario is designed to highlight the maximum additional gas deliveries that can be accommodated by the existing transmission system at the Inch Entry Point.

4.3 GAS SUPPLY SCENARIOS

While there is clearly a significant number of potential supply projects in the pipeline, there remains uncertainty about their timing. The following supply scenarios have been constructed to try and manage this uncertainty.

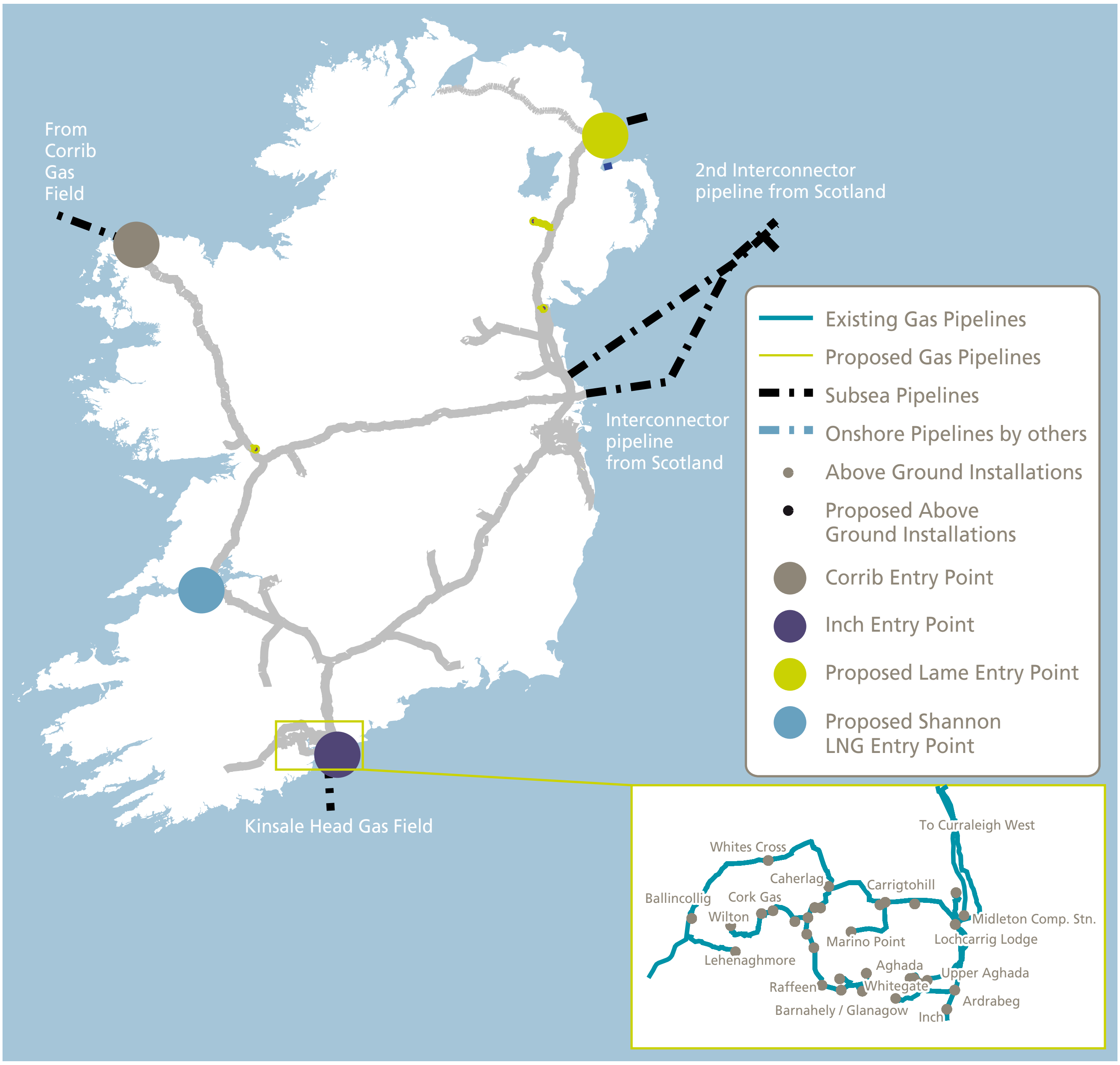
- The **Base Supply** scenario includes all of the existing sources of supply, plus any new supply project that has been declared commercially viable. It assumes that:
  - » The current Kinsale gas production and storage facilities remain in operation;
  - » First commercial Corrib gas production from April 2011, based on the profile provided by the Corrib Operator in Q4 2009; *and*
  - » Any remaining supply shortfall is assumed to be gas imports through the Moffat Entry Point.
- The **High Supply** scenario is based on the Base Supply scenario plus the Shannon LNG and Larne gas storage (see Fig. 4.2). It is designed to test the ability of the existing transmission system to accommodate these new sources of supply and to investigate the technical feasibility of physically exporting gas to GB through Moffat. It assumes:
  - » The current Kinsale gas production and storage facilities remain in operation;
  - » First commercial Corrib gas production from April 2011;
  - » A gradual ramp-up of Shannon LNG (Phase I) exports from October 2014, with exports assumed to rise from an initial 99.7 GWh/d (8.9 mscm/d) to 191.1 GWh/d (or 17.0 mscm/d) by 2017/18;
  - » A phased commissioning of a salt cavity gas storage facility in Larne, with the maximum withdrawal rate increasing from 66.2 GWh/d (6.0 mscm/d) in 2014/15 to 2645 GWh/d (24.0 mscm/d) by 2017/18; *and*
  - » Any remaining supply shortfall is assumed to be met from GB imports through the Moffat Entry Point.
- The **Celtic Sea** scenario is based on the Base Supply scenario plus additional gas storage in the Celtic Sea and is designed to test the maximum capacity of the Inch Entry Point (particularly in relation to the Midleton compressor station). It assumes:
  - » The current Kinsale gas production and storage facilities remain in operation;
  - » First commercial Corrib gas production from April 2011;
  - » Additional gas storage in the Celtic Sea; however, in the absence of firm data this has been modelled from the perspective of what is the maximum additional Inch delivery that can be accommodated by the existing Inch Entry Point infrastructure.

In some of the supply scenarios the maximum combined supply from all of the Entry Points exceeded the daily demands of ROI, NI and IOM, particularly in the case of the High Supply scenario. The following assumptions were made in relation to the order in which supplies would be called by the market for planning purposes only:

- Indigenous gas production would flow first;
- Followed by depleted field and salt cavity storage;
- Followed by Shannon LNG; *and*
- Finally, GB gas imports through Moffat and the subsea IC system.

It should be emphasised that the above assumptions are for planning purposes only and the actual order in which supplies are called will be determined by the market participants and the contractual arrangements between shippers, producers, storage and LNG terminal operators.

Figure 4.2: Existing and potential future sources of ROI supply



5. The ROI Transmission System

5.1 OVERVIEW OF THE EXISTING ROI TRANSMISSION SYSTEM

The ROI transmission system consists of approximately 2,150 km of high-pressure steel pipeline, Above Ground Installations (AGIs) and compressor stations in the ROI and Scotland. The high-level system statistics are summarised in Tables 5.1 and 5.2 and shown in Figure 5.1.

Table 5.1: ROI Transmission pipeline summary statistics

Location	Current MOP Pressure (bar-g)	Total Length (km)	Max Nominal Pipe Diameter (mm)
Onshore ROI	85.0	130.0	650
Onshore ROI	70.0	1,146.7	900
Onshore ROI	40.0	91.0	500
Onshore ROI	37.5	99.9	600
Onshore ROI	19.0	155.9	600
Onshore ROI	7.0/4.0	7.2	600
Subtotal	N/A	1,630.7	900
Scotland	85.0	110.5	900
Subsea	148.0	409.0	750
Total	N/A	2,150.2	900

Table 5.2: Bord Gáis installation summary

Location	No. of AGI[1] Installations	No. of Compressor Stations	Compressor Power[2] (MW)
Total ROI	160	1	8.8
Total Scotland	7	2	61.6
Total	167	3	70.4

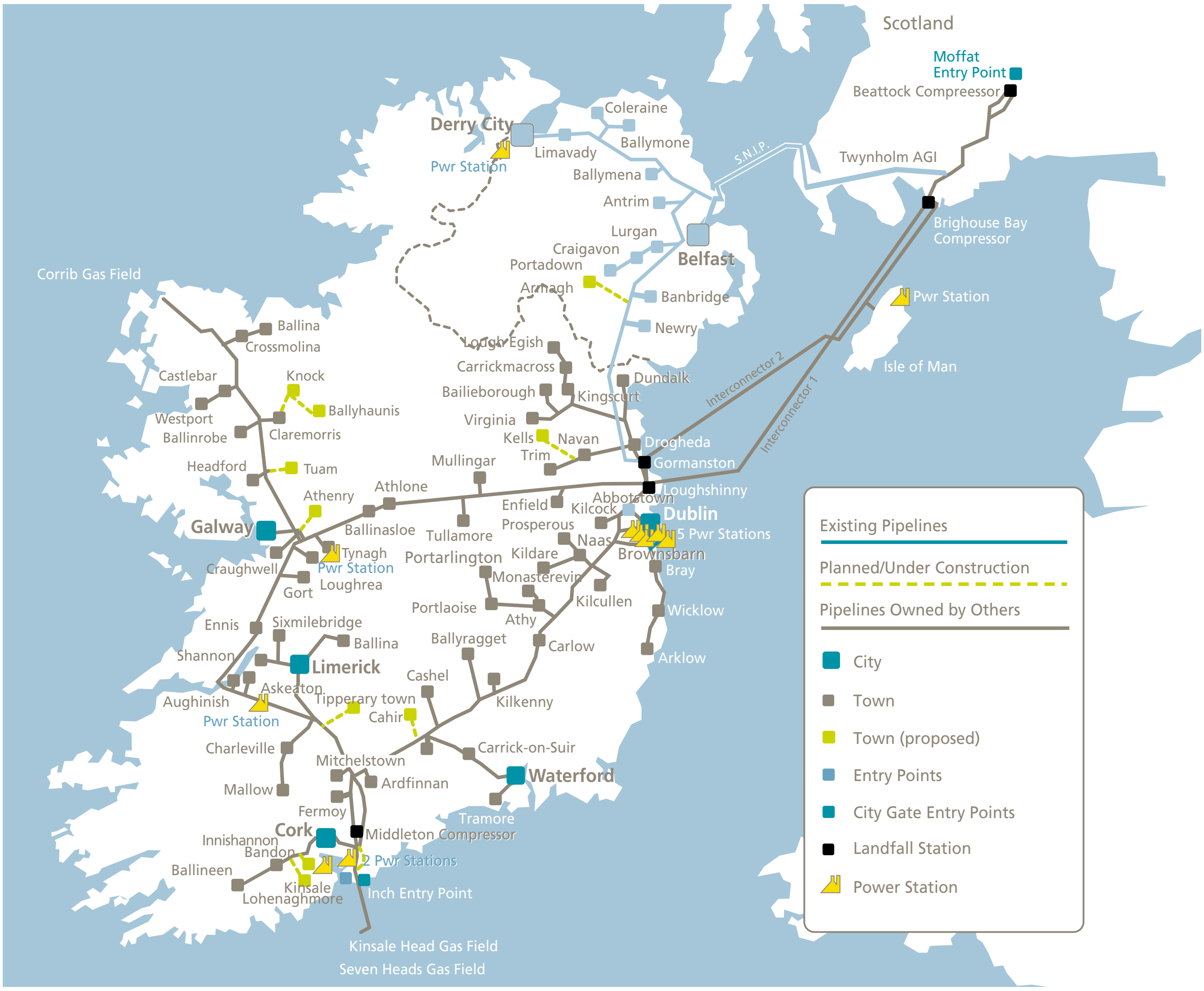
[1] *AGIs include pressure regulating, metering and block valve stations*
[2] *Refers to duty power of station and excludes standby compressors*

The ROI transmission system includes the IC system and the onshore ROI system. The IC system includes two subsea interconnectors to Scotland, two compressor stations at Beattock and Brighouse Bay, and the 110 km of onshore pipeline between Brighouse and Moffat in Scotland (see Fig. 5.1).

The IC system connects the onshore ROI system to the GB National Transmission System (NTS) at Moffat in Scotland. It also supplies gas to the NI market from Twynholm and to the IOM market from IC2. The IC system is also used to provide a gas inventory service to ROI shippers.

The onshore ROI 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 the Corrib Bellanaboy terminal in Mayo. It also includes a compressor station at Midleton.

Figure 5.1: Overview of the ROI transmission system



5.2 NEW CONNECTIONS AND NEW TOWNS

Various new connection projects were completed during the course of 2008/09, which will facilitate the connection of various large I/C sites and new towns to the gas transmission and distribution systems. The list of projects completed during 2008/09 includes:

- The connection of the Aghada CCGT, which is currently taking gas for commissioning purposes;
- The transmission pipeline and AGI to the Whitegate CCGT;
- The connection of the following towns from the New Towns Review (Phase I): Ballina, Castlebar, Claremorris, Craughwell, Crossmolina, Headford, Tuam and Westport (with Athenry, Ballyhaunis and Knock under review);
- The connection of the following towns from the New Towns Review (Phase II): Ballinrobe, Cashel and Monasterevin (with Cahir under review, and Gort and Loughrea scheduled to be connected during winter 2009/10);
- The completion of the transmission pipeline from Santry to Cloghran and associated AGI (with work ongoing on the distribution part of the connection);
- The completion of the transmission AGI for the new Merck, Sharp and Dohme facility in Carlow (and associated distribution pipeline); *and*
- The completion of the Mayo/Galway Pipeline, which was finally connected to the Corrib gas terminal in Bellanaboy during 2008/09.

A number of new connections and new town projects are planned for 2009/10 gas year, including:

- The transmission connection for a new Combined Heat and Power (CHP) site at Bailieborough in Co. Cavan;
- Planning and front-end engineering works will commence on the two new pipelines to the proposed Endesa gas-fired stations at Great Island and Tarbert; *and*
- The following towns will be connected under the New Towns Review (Phase III): Kinsale, Innishannon, Kells, Tipperary Town.

5.3 SYSTEM REINFORCEMENT

It is necessary from time to time to reinforce the existing gas transmission to facilitate local development etc. Reinforcement projects that were either completed during 2008/09 (or are in the final phases of commissioning) include:

- Twinning the existing Curraleigh West to Midleton Pipeline and the associated Midleton to Loughcarrig Lodge Pipeline, with the project scheduled to be completed in early 2010;
- Completion of the Ballynora to Lehenaghmore transmission pipeline and associated AGI, for the reinforcement of the Cork area; *and*
- Completion of capacity upgrade to the Ballyveelish AGI (Clonmel).

The twinning of the Curraleigh West to Midleton Pipeline and the construction of the associated Loughcarrig Lodge to Midleton Pipeline will transfer the Cork area transmission system to the discharge side of Midleton compressor station. This will bring significant benefits in terms of enhanced pressures to the customers connected to the system.

The old Aghada power station and the Whitegate and Long Point AGIs remain connected to the transmission system between Midleton compressor station and the Inch Entry Point. Any Inch gas in excess of these demands will be compressed at Midleton into the 70-bar system in the Cork area.

Further capacity upgrades to the following local AGIs are due to commence during 2009/10 gas year: Glebewest, Hollybrook, Loughshinny, Nessans Road and Loughboy.

5.4 SYSTEM REFURBISHMENT

There is a continuous programme to review and refurbish the gas transmission system to ensure that it continues to comply with all of the relevant legislation, technical standards and Codes of Practice. This refurbishment work is coordinated with reinforcement work (where possible) to minimise overall costs and to limit disturbance to local communities.

The previous construction boom resulted in very significant third-party activity in the vicinity of transmission pipelines, which required preventative measures such as the diversion of pipelines, the provision of impact protection and the installation of “heavy-wall” pipe. The following refurbishment and diversion projects were completed during 2008/09:

- Refurbishment of the Royal Oak AGI in Dublin, and upgrades to water-bath heaters at various AGI locations; *and*

- The NEP2 diversion (Gormanston), NEP3 diversion (Mullagh) and the N8 diversion (Mitchelstown).

The following transmission system refurbishment and diversion projects are planned for the 2009/10 gas year (or are currently under construction and due to be completed in 2009/10):

- The Dublin-4 pipeline replacement project; *and*

- Kilshane Block Valve refurbishment (currently underway).

6. Network Analysis & Modelling results

6.1 SYSTEM MODEL

The network analysis was carried out by constructing a single hydraulic model of the ROI and NI transmission systems, using the Pipeline Studio software. The hourly 'transient' behaviour of the system was modelled over a 3-day period on an energy basis. The ability of the system to transport the resultant gas flows was validated from the model, using the following criteria:

- Maintaining the specified minimum operating pressures at key points on the ROI transmission system, including:
  - 55 barg at the Dublin City Gates;
  - 25 barg at Ballineen (West Cork); *and*
  - 56 barg at Twynholm;
- Operating the compressor stations within their defined performance envelopes; *and*
- Ensuring where possible that the gas velocities are within the design range of 10 – 12 m/s, and do not exceed the limit of 22 m/s specified in IS 328.

6.2 ENTRY POINT ASSUMPTIONS

The gas pressure and Gross Calorific Value (GCV) assumptions for each Entry Point are summarised in Table 6.1, which shows both the contractual minimum pressure and the pressure assumed in the network analysis.

Table 6.1: Gas pressure and GCV assumptions for each Entry Point

	Unit	Moffat	Inch	Corrib	Shannon	Larne
Pressure						
Contractual	barg	42.5	30.0	up to 85.0	N/A	N/A
Assumed	barg	47.0	30.0	up to 85.0	up to MOP	up to 85.0
Other						
GCV	MJ/scm	39.7	37.6	37.5	40.5	39.7
Flow profile		Flat	Flat	Flat	Flat	Flat

[1] *MOP=Maximum Operating Pressure (MOP) of the Pipeline*

[2] *Flat flow profile assumes that the hourly delivery of the Entry Point = 1/24th of the daily delivery*

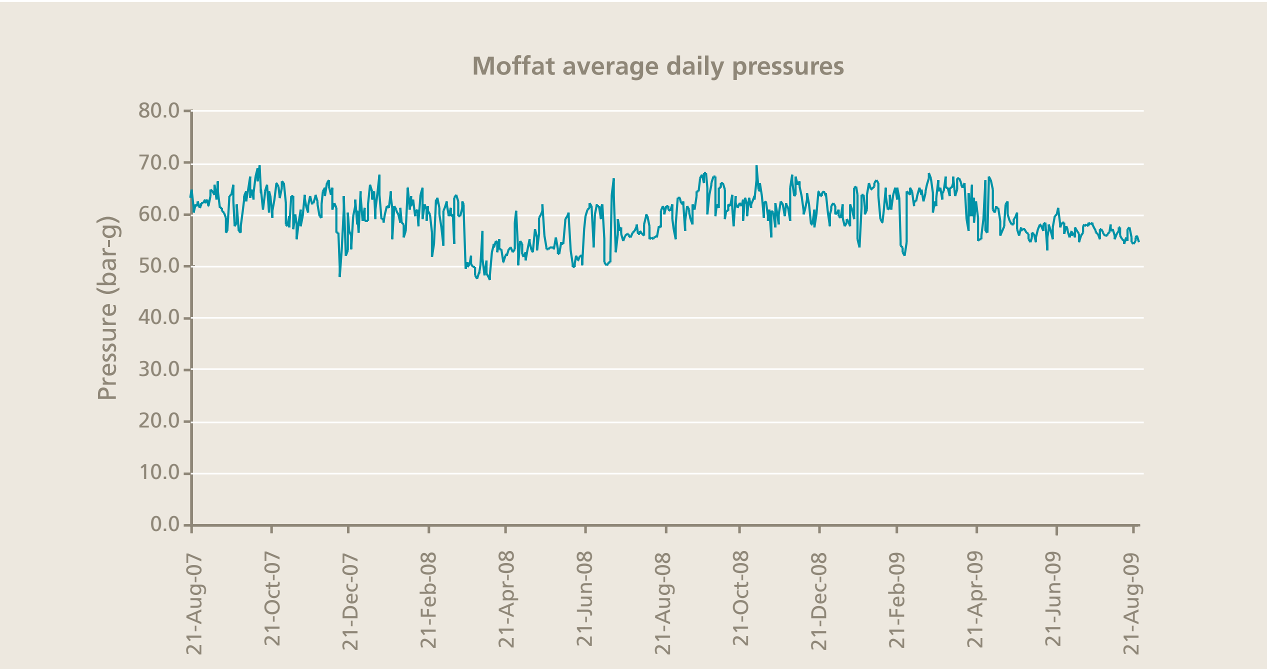
The Pressure Maintenance Agreement (PMA) requires National Grid to provide a minimum pressure of 42.5 barg at Moffat. They have also advised a higher Anticipated Normal Operating Pressure (ANOP) pressure for Moffat of 47 barg (i.e. the expected pressure under normal circumstances).

The actual average daily pressure at Moffat has been higher than this (see Figure 6.1) and varied between 69.3 and 47.1 barg during 2007/08 and 2008/09 (and averaged 59.2 barg). A peak-day pressure of 47.0 barg at Moffat has been used for network analysis modelling, based on the ANOP and the observed pressure during 2008/09.

PSE Kinsale Energy is required to provide a minimum pressure of 30 barg at Inch and the Corrib Operator is required to provide up to 85 barg at Bellanaboy. No contractual arrangements have been finalised with Shannon LNG, but it is assumed that they will be able to deliver up to the Maximum Operating Pressure (MOP) of the ring-main.

Similarly, no contractual arrangements have been agreed with either of the proposed Larne gas storage projects; however, it is assumed that they will be able to deliver gas at 85 barg. This higher pressure is considered necessary to make these storage projects viable. It also assumes that the MOP of the NI transmission system can be raised from 75 to 85 barg.

Figure. 6.1: Historic Moffat Entry Point pressures



The daily flows through each Entry Point are assumed to follow a flat profile, with the diurnal swing in the load profile being absorbed by the line-pack of the ROI onshore transmission system and the subsea IC system.

6.3 ALL ISLAND FLOWS

The ROI and NI transmission systems are essentially physically separated at Gormanston due to the current system configuration. In the High Supply scenario, it is assumed that Larne storage will be able to export gas from NI to the ROI, and that Shannon LNG will be able to export gas from the ROI to NI.

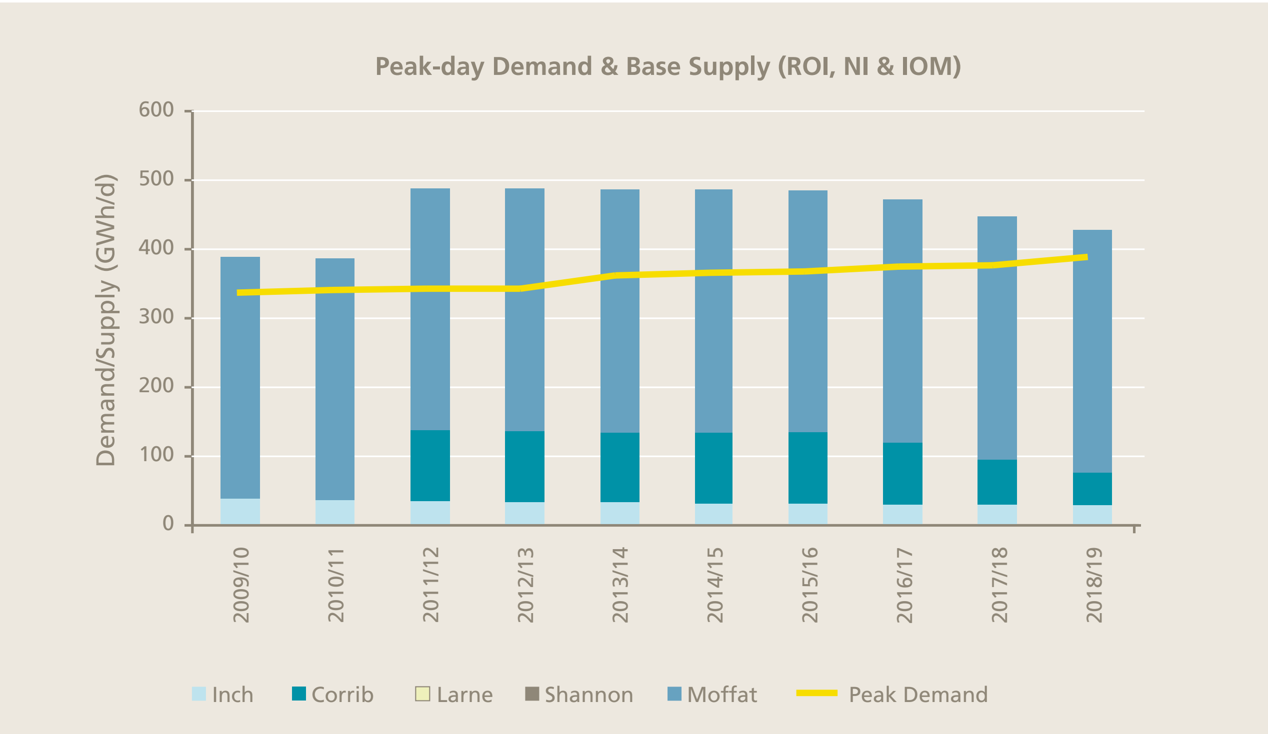
It is assumed that the necessary operational, commercial and market arrangements will be put in place as part of the Common Arrangements for Gas (CAG) project, to facilitate these cross-border flows of gas.

6.4 NETWORK ANALYSIS RESULTS FOR THE BASE SUPPLY SCENARIO

6.4.1 Overall results

The network analysis modelling results indicated that there is sufficient capacity available on the existing ROI gas transmission system to meet the forecast peak-day demand in the Base Supply scenario (see Figure 6.2) over the forecast period.

Figure 6.2: Peak-Day demand and supply for Base Supply scenario



**Peak-day includes the peak-day demand of ROI, IOM & NI under severe weather conditions*

It can be seen from Fig. 6.2 that there is more than sufficient supply capacity available at Inch, Corrib and Moffat Entry Points to meet the forecast peak-day 1 in 50 peak-day demand of the ROI, NI and the IOM over the forecast period. The Entry Capacity assumptions are based on the following assumptions:

- The existing Kinsale gas production and storage facilities continue in operation, with declining production from the Kinsale and Seven Heads gas-fields and a maximum delivery of up to 28.9 GWh/d (2.8 mscm/d) from Kinsale storage;
- Corrib production based on the latest production profile provided by the Corrib Operator and assuming first commercial production from April 2011; *and*
- The capacity of the Moffat Entry Point is assumed to be approximately 353 GWh/d (32.0 mscm/d), based on the results from the recent performance review of the Beattock and Brighouse compressor stations (see next section).

The network analysis also showed that the existing ROI transmission system still had sufficient capacity to meet the forecast 1 in 50 peak-day demand, even if the start date for the first commercial production from the Corrib gas field was delayed by 1-year to April 2012.

6.4.2 Performance review of Beattock compressor station

BGN recently completed a study to analyse the performance of its compressor stations at Beattock and Brighouse Bay in Scotland, since the capacity of these stations currently determines the overall capacity of the Moffat Entry Point.

The performance testing focussed primarily on the rotating machinery within the station, i.e. the gas turbines and compressors. The capacity of any gas compressor station is a function of various variables, including:

- The required pressure-lift or compression ratio, i.e. the ratio of the discharge pressure to the suction pressure;
- The available power of the compressor units; *and*
- The gas temperature and density (i.e. the gas molecular weight) etc.

The main driver of the station capacity is the available pressure from the National Grid NTS system at Moffat. The theoretical maximum capacity of the existing Beattock compressor station has been assessed at 353 GWh/d (32.0 mscm/d), based on the following assumptions:

- An inlet pressure of 47 barg at the compressor station, based on the National Grid ANOP of 47.0 barg for the Moffat Entry point;
- A discharge pressure of 85 barg to ensure that the contractual minimum pressure of 56 barg is maintained at Twynholm;
- A gas temperature of 15 degree C and a gas molecular weight of 18.3; *and*
- Three compressor units operating in 'series-mode' configuration, with the fourth unit operating in stand-by mode.

The performance testing study indicated that it should be possible to flow 353 GWh/d (32.0 mscm/d) without major modifications to the existing station under the above assumptions. There are a number of caveats in relation to this theoretical study:

- The above capacity is significantly higher than the original design capacity of the station, namely 287 GWh/d (26.0 mscm/d), and a more detailed analysis of the subsystems would be required to verify that they were capable of meeting these flows (i.e. station pipe-work, meters, filters and after-coolers etc); *and*

- Minor modifications would be required to the station pipe-work to mitigate the flow-related vibrations that arise at these higher flow-rates (above the original design-flow).

The capacity of the station is sensitive to the assumed station inlet pressure. If the minimum contractual pressure under the PMA of 42.5 barg is assumed, then the theoretical maximum capacity of the station in series mode reduces to 302 GWh/d (27.4 mscm/d). The capacity is also sensitive to the gas temperature assumptions.

6.4.3 Performance testing of Brighouse Bay compressor station

The main driver of the Brighouse Bay capacity is the available pressure at the station inlet. If it is assumed that Beattock is discharging at 85 barg, then the available pressure at the Brighouse Bay inlet will be 60 barg or higher.

The maximum theoretical capacity of Brighouse Bay has been assessed at 298 GWh/d (27 mscm/d) based on a station inlet pressure of 60 barg and a discharge pressure of 120 barg (to give a compression ratio of 2.0).

6.4.4 Local system reinforcement requirements

The network analysis indicated that the local transmission systems had sufficient capacity to meet the forecast 1 in 50 peak-day demand. Pipeline velocities in excess of the 10-12 m/s design range were observed in certain areas; however, they were all within the maximum range of 22 m/s specified in IS 328 (and no further action is considered necessary).

It is worth noting that there are currently a number of large connection enquiries at various locations around the transmission system, which may necessitate the requirement for system reinforcement if they came to fruition, e.g. Limerick.

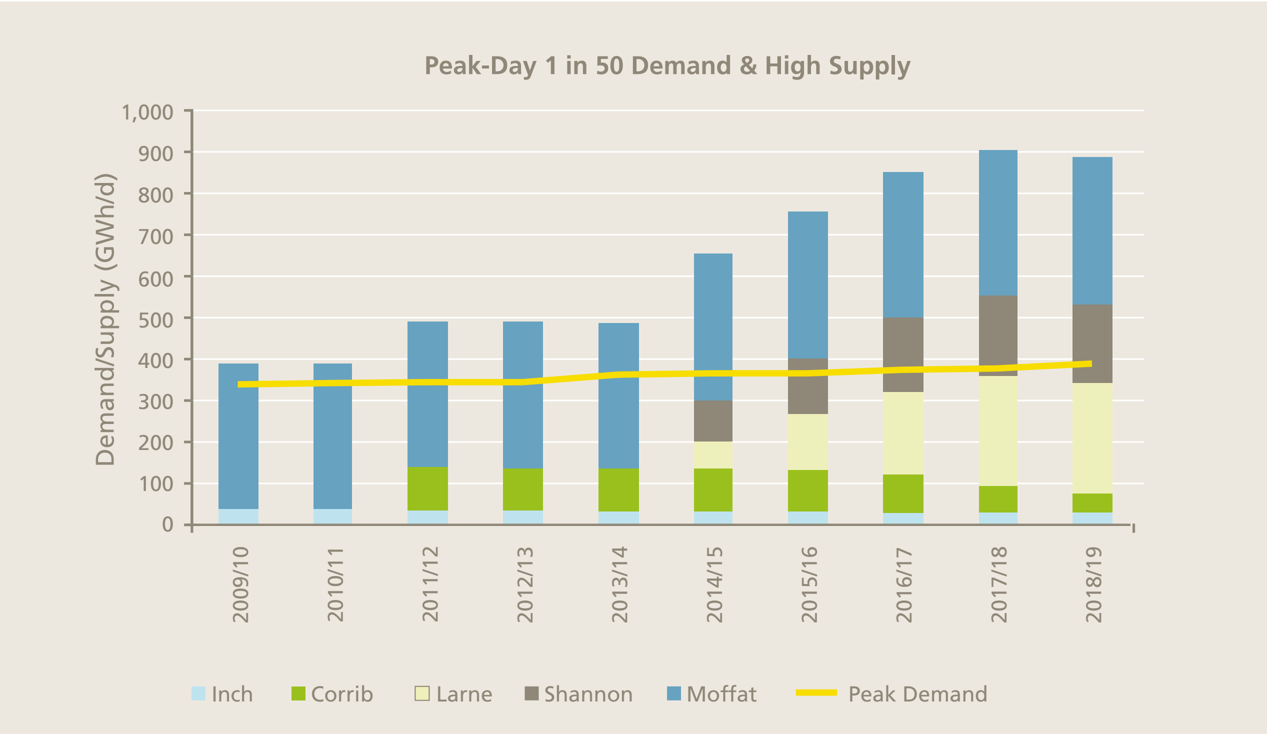
6.5 NETWORK ANALYSIS RESULTS FOR THE HIGH SUPPLY SCENARIO

6.5.1 Overall result

The existing ROI transmission system has sufficient capacity to meet the forecast 1 in 50 peak-day demand; however, it may not be able to accommodate the maximum flows from all of the supply sources assumed in this scenario for a number of reasons:

- The combined maximum flow from all of the supply sources assumed in this scenario exceeds the forecast peak-day of the ROI and NI markets, i.e. there is insufficient demand on the island to absorb all of the assumed supply (see Fig. 6.3);
- There are a number of physical constraints on the existing transmission system that are specific to the High Supply scenario:
    - There is a physical limit to the quantity of Corrib and Shannon LNG gas that can be transported from the West Coast to the main gas markets along the East Coast, while ensuring adequate system pressures at the Dublin City gates; *and*
    - The maximum withdrawal rate of the proposed Larne salt cavity gas storage project is potentially limited by the NI peak-day demand and the ability of the existing transmission systems to physically export gas to the ROI market.

Figure 6.3: Peak-Day demand and supply for the High Supply scenario



The nature of the physical constraints on the existing ROI gas transmission system are described in more detail in the following sections for the West Coast gas supplies and Larne gas storage project, together with the potential system reinforcement solutions.

6.5.2 Shannon LNG

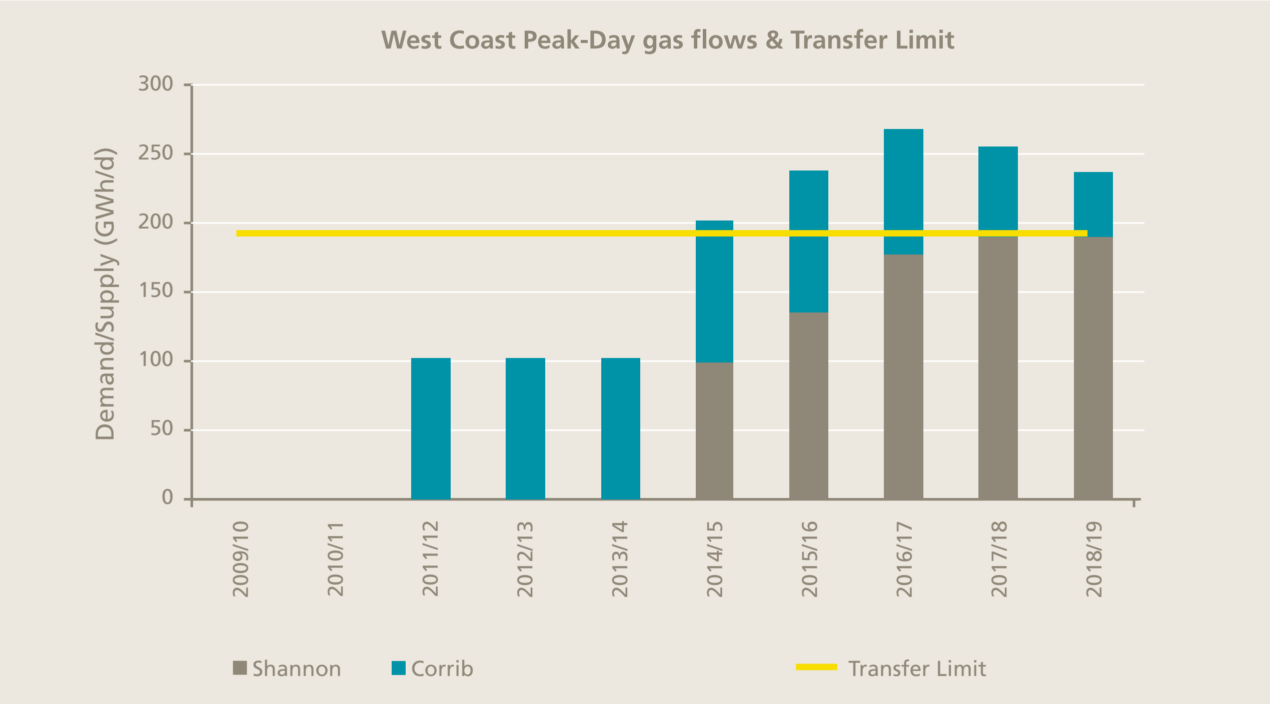
If the Corrib gas field and Shannon LNG facility proceed as planned, then there will be large flows of gas from the West Coast to the main markets in the East Coast. These large flows will result in significant pressure drops along the existing ROI transmission system.

There is a physical limit to the quantity of gas that can be transferred from the West Coast to the East Coast while still meeting the operational requirement to maintain a minimum pressure of 55 barg at the Dublin City gates.

The network analysis modelling indicates that the maximum quantity of West Coast gas flows that can be accommodated by the existing ROI gas transmission system while maintaining a minimum operating pressure of 55 barg at the Dublin City Gates is 192 GWh/d (17.0 mscm/d).

This West to East transfer limit is -6.8% lower than published in the previous TDS, due to the assumption that the existing Kinsale gas production and storage facilities continue in operation for the forecast period. The previous TDS assumed that Kinsale gas production and storage activities would cease by 2013/14.

Figure 6.4: Peak-Day West Coast gas flows & West to East Transfer Limit



The peak-day Corrib gas production and Shannon LNG export flows are shown in Fig. 6.4, together with the corresponding West to East transfer limit. It can be seen that the combined Corrib and Shannon LNG flows exceed the West to East transfer limit from 2015/16 onwards.

In the absence of any reinforcement to the existing ROI transmission system it may potentially be necessary to restrict either the Shannon LNG or Corrib flows. The maximum West Coast gas flows can be increased by reinforcing the system. The following reinforcement options have been identified:

- Twinning the existing Goat Island to Curraleigh West Pipeline with a 24-inch pipeline, would increase the West to East transfer limit to 203 GWh/d (18.1 mscm/d);
- Raising the MOP of the western section of the onshore ring-main from 70 to 85 barg (MOP Review required to confirm if this is possible) would increase the West to East transfer limit to 210 GWh/d (18.7 mscm/d); *and*
- Twinning the Goat Island to Curraleigh West Pipeline and raising the MOP of the western section of the onshore ring-main to 85 barg would increase the West to East transfer limit to approximately 220 GWh/d (19.6 mscm/d) with Corrib production and 250 GWh/d (22.2 mscm/d) if there was no Corrib production.

The western section of the ring-main refers to the Pipeline To The West (PTTW). This was originally designed to operate at 85 barg, and it should be possible to raise its MOP. Pressure reduction would be required, however, to the ensure that the older pre-PTTW sections of the ring-main didn't exceed 70 barg. It may be possible to further increase transfer limit:

- If the minimum operation requirements at the Dublin City Gates could be reduced below 55 barg; *or*
- If there is reduced or no gas deliveries to the Inch Entry Point, e.g. if there is no storage gas being withdrawn on a winter day or during the summer months (when Inch deliveries are likely to be zero, while refilling the offshore storage).

In summary, the existing transmission system can accommodate the proposed Shannon LNG (Phase I) exports, provided that the ramp-up in exports is timed to coincide with the decline in Corrib production.

System reinforcement would be required to accommodate the maximum Shannon LNG (Phase II) export level, even with no Corrib gas production. In addition to the above reinforcements, a new compressor station on the PTTW near Ballough (north of Dublin) to accommodate maximum Shannon LNG (Phase II) flow of 315 GWh/d (28.0 mscm/d).

The above reinforcements are indicative only, and are based on high-level conceptual studies. These results are also very scenario dependent, i.e. they depend on what is assumed to be flowing from other sources of supply. A more detailed engineering study would be required to identify the optimum reinforcement solution.

6.5.3 Larne Storage

A generic salt cavity gas storage facility at Larne was modelled in the High Supply scenario, with an assumed maximum withdrawal rate of 265 GWh/d (24.0 mscm/d). This withdrawal rate is considerably higher than the forecast peak-day demand for NI, which is forecast to reach 110 GWh/d (10.1 mscm/d) by 2018/19.

In order to fully utilise the proposed maximum withdrawal rate, it will be necessary to physically export the storage gas to the ROI market through the S/N and SNIP Pipelines. The network analysis results indicated that it should be possible to export approximately:

- 44 GWh/d (4.0 mscm/d) through the S/N Pipeline, based on the requirement to maintain a minimum operational pressure of 55 bar-g at the Dublin City Gates; *and*
- Reverse flowing an additional 82 GWh/d (7.4 mscm/d) through the SNIP to Twynholm and then back to the ROI market via Brighouse Bay and the subsea IC system (based on maintaining a minimum pressure of 59 barg at the inlet to Brighouse).

The above analysis assumes that the MOP of the NI transmission system can be increased from 75 to 85 barg. A formal MOP review study will be required to confirm whether this is possible in practice.

It may be possible to achieve higher flows than 82 GWh/d (7.4 mscm/d) through Brighouse Bay compressor station, with a lower inlet pressure than 59 barg. However, further studies would need to be undertaken to determine the feasibility of this.

From the above analysis, it should be possible to fully utilise the proposed maximum withdrawal rate of the assumed Larne salt cavity storage facility on the NI peak-day. It may not be possible to fully utilise this withdrawal capacity at other times in the year, i.e. when the NI demand will be less than the forecast peak-day value.

The maximum injection into any future salt cavity storage facility will be determined by the difference between the maximum import capacity of the S/N and SNIP Pipelines during the summer months and the NI demand:

- The maximum import capacities of the S/N and SNIP Pipelines is estimated to be 22 GWh/d (2.0 mscm/d) and 137 GWh/d (12.4 mscm/d) respectively, to give a total import capacity for NI of 159 GWh/d (14.4 mscm/d);

- The average NI daily demand during the summer months in 2018/19 is estimated to be approximate 63 GWh/d (5.7 mscm/d); *and*

- The average gas storage injection rate during the summer months, therefore, may be limited to approximately 96 GWh/d (8.7 mscm/d).

The assumed import capacity of the S/N Pipeline is lower than its assumed export capacity. This is primarily because of the assumption that the proposed Louth CCGT will be supplied off the S/N Pipeline.

The maximum import capacity of the SNIP is dependent on the pressure available at Twynholm, which is in turn a function of the gas flow through the Moffat Entry Point. The maximum import capacity would be lower in higher-demand periods (e.g. during the winter months) or in different supply scenarios where there are higher flows assumed from Moffat.

This limitation on storage injection rate may not be as onerous as it might first appear, given that it should still be possible to fill a storage facility with a 5,514 GWh (500 mscm) working volume within 62 days. There should be no difficulty, therefore, in filling the larger of the proposed gas storage projects during the summer months.

6.6 PHYSICAL EXPORT OF GAS TO GREAT BRITAIN

6.6.1 General overview of issues

In the high supply scenario, the combined maximum flows from all the assumed sources of supply exceeds the forecast peak-day demand of the ROI, NI and the IOM, i.e. there is insufficient demand on the Island to absorb all of the proposed supplies (even in severe weather conditions).

A number of project developers have enquired about the technical feasibility of physically exporting gas to GB in the event that all of the assumed new sources of supply actually materialise.

The ability to physically export gas from both the proposed Shannon LNG terminal and Larne salt cavity storage facilities was investigated as part of the network analysis modelling for this TDS. The modelling focussed on two particular issues:

- The gas quality issues that may arise in any export scenario, particularly in relation to gas odorant; *and*

- The physical capacity of the existing ROI and NI gas transmission systems to export gas to the GB NTS system through Moffat.

The commercial negotiation and market operation issues associated with the physical export of gas to the GB market through Moffat were considered to be outside of the scope of the TDS study.

6.6.2 Gas Quality issues and National Grid (NG) requirements

Moffat is currently classified as an Exit Point from the National Grid NTS. In order to get Moffat also classified as an Entry Point into the NTS, it will be necessary to reach agreement with NG on both the physical connection arrangements and the gas composition.

NG publish an indicative gas quality specification in Appendix 5 'Connections to the National Grid National Transmission System (NTS)' of their annual Ten Year Statement publication. Gaslink and BGN have reviewed this indicative specification with NG, and have identified the following issue:

- Gas is not odorised when it enters the GB NTS and is instead odorised by the Distribution Network (DN) companies at the off-takes from the NTS;

- All gas entering the ROI transmission system is odorised at Moffat and Inch, i.e. the gas is odorised when entering into the ROI transmission system (versus being odorised when exiting from the GB NTS);

- Any gas that is physically exported to GB from either the proposed Shannon LNG terminal or Larne gas storage facilities will be odorised, which may potentially conflict with the requirement outlined in the indicative gas quality specification;

- NG is of the opinion that the export of odorised gas would be a material change to both the indicative gas quality specification and the Gas Safety Management Regulations (GSMR) requirements, and would require consultation and agreement with the affected users of the NTS including:

  » DN companies may be concerned about their ability to odorise the gas in accordance with the GSMR requirements, since it is difficult to monitor the level of odorant in the gas in real-time, and could potentially lead to scenarios where the gas is either over or under-odorised;

  » Power generation stations may be concerned about the impact of odorant on their emissions, since odorant contains sulphur based compounds;

  » Petrochemical facilities may be concerned about the impact of odorant on their manufacturing processes; *and*

  » NG would also have to carry out a risk assessment to determine the impact (if any), of odorised gas on the operation of the NTS itself.

The alternative to physically exporting odorised gas into the NTS system at Moffat would be to deodorise parts of the ROI and NI transmission system, i.e. to move the odour injection points from the Entry Points to the relevant City Gates and distribution off-takes:

- In the case of the proposed Larne gas storage projects, this would involve deodorising the IC system, the SNIP and S/N Pipelines; *and*

- In the case of the proposed Shannon LNG, terminal it would be necessary to deodorise the IC system, the ROI onshore 70 barg ring-main and the SNIP and S/N Pipelines.

More detailed studies would need to be carried out by both Gaslink and National Grid to establish the impact and cost associated with each of the above options, and to identify the optimum solution to accommodate the physical export of gas to GB.

6.6.3 Infrastructure requirements for Larne Storage

In order to physically export gas to GB from the proposed Larne gas storage projects, it would be necessary to reverse-flow the gas through the SNIP Pipeline to Twynholm and then on to the Beattock compressor station, which would compress the gas into the National Grid NTS system at Moffat (at pressures up to 85 barg).

Engineering modifications to Beattock would be required to physically 'turn-around' the compressor unit configuration, so that they could compress gas into the NTS at Moffat. These would include:

- Modifications to the existing pipe-work, valve arrangements and control systems, so that gas was delivered to the suction side of station and discharged into the NTS at Moffat;

- Modification to the existing after-coolers to meet the National Grid requirements to provide a delivery pressure of up to 85 barg and a gas temperature in the range from 1 to 38 degree C; *and*

- Modifications to the Twynholm AGI to facilitate potential export flows over and above the current capacity of the AGI.

The existing after-coolers at the Beattock compressor station are designed to cool the discharged gas to

45 degree C, after being compressed from 42.5 to 85 barg. They would not be able to cool the gas below 38 degree C while discharging into the NTS at 85 barg and, therefore, would also require modification.

If it is assumed that all of the above modifications can be satisfactorily completed, then the network analysis indicates that it should be possible to physically export approximately 103GWh/d (9.3 mscm/d) from Larne to Moffat (and maintain 42.5 barg at the inlet to Beattock). No flows through Brighouse Bay and the ROI subsea IC system are assumed in this scenario.

It should be emphasised that the above preliminary conclusions are based on a high-level conceptual studies and that further detailed engineering studies would be required to confirm the feasibility of physically exporting Larne gas.

These high-level studies focused primarily on the physical capacity of NI SNIP and ROI IC systems. Further network analysis and detailed engineering studies would be required from both National Grid and PTL to determine:

- What capacity was available at the NTS side of Moffat and what physical modifications (if any) would be required to the National Grid system at Moffat (or beyond); *and*

- What modifications would be required to the SNIP Pipeline and the NI transmission system to allow the MOP to be raised from 75 to 85 barg and to accommodate the maximum physical export flow identified above.

Although it is outside the scope of the TDS (which is primarily intended to focus on the technical), there would also be contractual issues associated with the reverse-flow of gas through Twynholm. The current contractual arrangements with PTL only allow for gas to be off-taken from Twynholm to NI.

6.6.4 Infrastructure requirements for Shannon LNG

The physical export of gas from the Shannon LNG terminal would involve delivering the gas to the Dublin area, compressing the gas into the subsea IC system, flowing the gas from Brighouse Bay in Scotland to Beattock, and compressing the gas into the GB NTS at Moffat.

The physical export of gas from Shannon LNG would require significant additional infrastructure to get the gas to Scotland, including the construction of a new compressor station north of Dublin.

High-level conceptual studies indicate that a compressor station would be required on the PTTW near Ballough. Once the Shannon LNG gas reached Scotland, it could be reverse flowed through the existing transmission system to the NTS at Moffat (similar to Larne gas). The high-level study assumed that:

- Inch storage gas withdrawals but no Corrib gas production (it was assumed that the construction of Phase II would coincide with the decline of Corrib production);

- The Shannon LNG terminal was exporting the maximum Phase II flow of 315 GWh/d (28.0 mscm/d); *and*

- In this scenario Shannon LNG gas was delivered to the proposed compressor station at the end of the PTTW at pressure of c. 27 barg, and 89 GWh/d (7.9 mscm/d) was compressed into the IC subsea system and exported by reverse-flow to Beattock, where the gas was compressed into the GB NTS at Moffat.

The compressed gas will then essentially by-pass the Brighouse Bay compressor station and be delivered to the inlet to Beattock, where it will be compressed into the GB NTS at Moffat. It will obviously be necessary to carry out the same modifications to Beattock as described previously for the export of Larne gas.

Again it must be emphasised that the above results are based on very high-level conceptual studies and that much more detailed engineering studies would be required to identify the optimum overall reinforcement required to accommodate the Shannon LNG (Phase II) exports.

6.7 NETWORK ANALYSIS RESULTS FOR THE CELTIC SEA SCENARIO

6.7.1 Potential developments in the Celtic Sea

Both PSE Kinsale Energy and Island Oil & Gas are currently evaluating the commercial feasibility of developing potential gas storage and gas production projects in the Celtic Sea area:

- PSE Kinsale Energy has taken over the ownership and operation of the existing Kinsale gas production and storage facilities, and it is also understood that they are evaluating the commercial feasibility of converting the depleted Ballycotton gas field into a gas storage facility; and

- Island Oil & Gas has confirmed proven gas reserves in both the Schull and Old Head of Kinsale prospects, and is currently evaluating the commercial feasibility of developing these prospects as either gas production or storage facilities.

There is currently no firm data available on the potential maximum withdrawal and production rates of these projects, given that they are still at a relatively early stage of development (and have yet to be declared commercially feasible).

An indication of the capability of the existing transmission system to accommodate additional deliveries of gas to the Inch Entry Point can, nevertheless, be provided to project developers by reference to the capacity of the Midleton compressor station.

6.7.2 Maximum capacity of the Inch Entry Point

Once the Midleton to Lochcarraig Lodge and Curraleigh West to Lochcarraig Lodge reinforcements are completed, the maximum Inch deliveries into the existing transmission system will be determined by the capacity of the Midleton compressor station and the gas demand of the old Aghada power station.

The Midleton compressor station was returned to service during 2003, by refurbishing three of the original four compressor units at the station. It currently has a capacity of 63 GWh/d (6.0 mscm/d), based on two compressors being available for duty with the third being operated in stand-by mode.

It is technically possible to increase the capacity of Midleton to approximately 94 GWh/d (9.0 mscm) by returning the fourth original compressor unit to service; however, this would lead to environmental and emission related challenges.

The station is currently classified as a 'combustion installation with a rated thermal input exceeding 20 MW', under the terms of its Greenhouse Gases Emissions Permit. This Permit also stipulates that advance notification and approval would be required from the Environmental Protection Authority (EPA) for any material change to the station, including any increase to the capacity of the station.

If the fourth compressor unit was returned to service, then the total thermal input to the station would exceed the 50 MW threshold and the site would have to comply with the requirements of the Large Combustion Plant (LCP) Directive. It would then be necessary to obtain an Integrated Pollution Prevention Control (IPPC) licence for the site from the EPA.

The application for any IPPC licence would have to demonstrate how the compressor station would comply with the Best Available Technology (BAT) requirements. It may be difficult to demonstrate how the existing compressor units would comply with the BAT low-emission requirements, given the age and technological vintage of the units.

If the capacity of Midleton compressor station was to be increased to 94 GWh/d (9.0 mscm/d) then it would also be necessary to reinforce the Midleton to Lochcarraig Lodge Pipeline to avoid excess pipeline velocity issues.

6.7.3 Minimum flows through Midleton compressor station

The level of Kinsale production gas has been declining in recent years and may fall below the minimum design-flow criteria of the Midleton compressor units in certain scenarios, e.g. if there is no gas withdrawals from Kinsale storage. PSE Kinsale Energy and Gaslink are currently investigating potential solutions, including operating the station in recycle-mode.

6.8 NI CAPACITY REQUEST

NI currently has a contractual entitlement of off-take up to 89.1 GWh/d (8.08 mscm/d) of gas at Twynholm, under the terms of the first intergovernmental Agreement "Relating to the Transmission of Natural Gas by Pipeline between the United Kingdom of Great Britain to Northern Ireland and Ireland" (1993).

NI is also entitled to request a further 44 GWh/d (4.0 mscm/d) of capacity on fair commercial terms, under the terms of the intergovernmental Agreement "Relating to the Transmission of Natural Gas through a Second Pipeline between the United Kingdom of Great Britain and Northern Ireland and Ireland and through a Connection to the Isle of Man" (2005).

PTL has written to Gaslink requesting clarification of the fair commercial terms on which the additional 44 GWh/d (4.0 mscm/d) would be provided (and also specifying that this additional capacity should be made available at Twynholm at 56 barg). Gaslink is currently considering the PTL request and will send a formal response in due course.

7. Security of supply

7.1 OVERVIEW OF LEGAL FRAMEWORK

The Commission for Energy Regulation (CER) has overall responsibility for monitoring and protecting the security of ROI natural gas supplies under SI No. 697 "European Communities (Security of Natural Gas) regulations".

This Statutory Instrument transposed the EU Security of Supply Directive (2004/67/EC) "Concerning measures to safeguard the security of gas supplies" into Irish law. This Directive requires:

- Each member state to clearly define the roles and responsibility of all market participants when responding to a natural gas emergency, including the publication of their national emergency plans;
- Each member state to protect at least the gas supplies to its residential sector from certain eventualities, including the partial loss of supplies for a defined period and certain extreme weather events; *and*
- Calls for the establishment of an EU Gas Coordination Group to coordinate security of gas supplies at the EU level and allows each member state to call a meeting of the group in an emergency.

As well as monitoring the security of ROI gas supplies, the CER is also empowered by SI 697 to direct natural gas undertakings to take any additional measures it deems necessary to enhance the security of gas supplies.

7.2 OPERATIONAL ARRANGEMENTS

The CER has designated Gaslink to act as the National Gas Emergency Manager (NGEM) under Section 19(B) of SI 697. Gaslink has produced a Natural Gas Emergency Plan (NGEP), which has been approved by the CER and details the roles and responsibilities of all natural gas undertakings in the event of a potential or actual gas supply emergency.

The NGEM will be responsible for managing any potential or actual gas supply emergency, in accordance with the provisions of the NGEP. The NGEM will act as the incident controller and will be responsible for declaring an emergency.

BGN would support the NGEM by acting as the interface with other natural gas undertakings, producers, storage operators and any connected system operators, and by implementing the NGEM instructions.

BGN has put in place emergency arrangements with other connected systems operators, e.g. PSE Kinsale Energy, PTL, the MEA and NG in GB. BGN has also clarified with the Network Emergency Coordinator (NEC) in GB the arrangements that will apply in the event of a gas supply emergency in GB.

7.3 PLANNING ARRANGEMENTS

The CER chairs the Task Force on Emergency Procedures (TFEP), which also includes representatives from the Department of Communications, Energy and Natural Resources (DCENR), Gaslink, BGN, EirGrid and ESB Networks.

The TFEP is responsible for ensuring that coordinated procedures are in place to manage a supply emergency on the gas and electricity systems, and that an emergency on one system does not lead to an emergency on the other. The first TFEP report was published in 2007 and included recommendations to enhance the existing arrangements and procedures, including:

- Giving EirGrid a role in the curtailment of gas supplies to power stations during a natural gas supply emergency, in order to mitigate as far as possible the impact on electricity supplies; *and*
- Requiring power stations to hold adequate stocks of secondary fuels and testing their ability to switchover to these secondary fuels in an emergency.

The CER has since issued a decision on secondary fuelling obligations for power stations, which requires all baseload gas-fired power stations to hold 5 days of secondary back-up fuel and non-baseload gas-fired stations to hold 3 days of secondary back-up fuel.

The decision also gives EirGrid the power to regularly test the ability of gas-fired power stations to switch-over to their secondary back-up fuel, and to inspect the level of secondary back-up fuel held on site.

BGN also attends the meetings of the Gas Advisory Task Group (GATG) in GB, which is responsible for monitoring the adequacy of emergency arrangements across the gas industry in GB.

8. Commercial Market Developments

8.1 GASLINK: INDEPENDENT SYSTEM OPERATOR

In accordance with the licences granted by the CER, Gaslink, as the Independent System Operator operates, maintains and develops the ROI transportation system. Bord Gáis as System Owner, holds a licence relating to its ownership of the transportation system.

The key role and responsibilities of Gaslink are as follows:

- To operate, maintain and develop, under economic conditions secure, reliable and efficient transmission and distribution systems with due regard to the environment;
- To provide any natural gas undertaking with sufficient information to ensure that transport of natural gas on the transmission system may take place in a manner compatible with the safe, secure and efficient operation of the network;
- To provide users of the transmission system with the information they need for efficient access to the transmission and distribution systems;
- To procure the energy it uses for the carrying out of its functions according to a transparent, non-discriminatory and market based procedure subject to CER approval;
- To adopt rules for the purposes of balancing the gas system which are objective, transparent and non-discriminatory; *and*
- To report to the CER, as outlined in the Gas (Interim) (Regulation) Act, 2002, and in respect of any other matters as the CER may specify.

Gaslink is independent of Bord Gáis in terms of its organisation and decision making processes when executing its responsibility for the operation of the transmission and distribution systems.

Gaslink identifies all work necessary for the operation, maintenance and development of the transportation system, and instructs Bord Gáis to carry the works in accordance with the Operating Agreement (specified in the legislation and approved by the CER). Gaslink holds two Licences from the CER for the operation of the ROI transmission and distribution systems, which *inter alia* cover the following areas:

- Connection to the transmission and distribution systems;
- Transmission and distribution system standards;
- Operating security standards;
- Provision of metering and data Services; *and*
- Provision of services pursuant to the Code of Operation (the Code).

8.2 EUROPEAN DEVELOPMENTS

The passing into law of the *Third Energy* package in September 2009 represented a key milestone for the development of the gas markets within each EU member state. In addition, the implementation of the new legislative requirements will serve as a major step towards a single European gas market. The package prescribes extensive changes to the legislative and regulatory frameworks covering gas transportation and will also result in considerable redefinition of the transportation arrangements themselves, particularly at interconnection points across Europe such as Moffat, The *Third Energy* package consists of the following key elements:

- Directive 2009/73/EC which from March 2011 will supersede Directive 2003/55;
- Regulation (EC) No. 713/2009 which from March 2011 mandates a new Agency for the Co-operation of

Energy Regulators (ACER); and

- Regulation (EC) No. 715/2009 which from March 2011 requires the setting up of European Network Transmission System Operators in gas (ENTSOG).

The European Transmission System Operators (TSO) have already put in place the organisation which will ultimately, once approved by the Commission in 2011, constitute the ENTSOG. All European TSOs will be legally obliged to co-operate with this group once the Directive comes into effect. Gaslink, as the Irish TSO, is a founding member of this organisation and is already participating actively in the work of ENTSOG. The ENTSOG foundation meeting took place on the 1st of December 2009 in Brussels.

At the heart of the Third Energy package legislation is the development of EU-wide network codes for 12 areas, aiding the integration of European gas markets and to facilitate effective cross-border trade and competition to develop across the EU member states. Framework Guidelines will be developed by the Agency for the Cooperation of Energy Regulators (ACER) and will form the basis for the Network Codes.

ACER will have a role in reviewing, based on matters of fact, draft network codes, including their compliance with the framework guidelines, and it will be enabled to recommend them for adoption by the European Commission. ACER will assess proposed amendments to the network codes and it will be enabled to recommend them for adoption by the Commission. Transmission system operators should operate their networks in accordance with those network codes. This process, which will include a mandatory public consultation, is set out in Article 6 of EC/715/2009.

The ENSTOG is responsible for developing the 12 binding Network Codes based on the framework guidelines. Once adopted by the Commission the application of the network codes will become mandatory in all member states

The network codes referred to Article 6 of the Regulation shall cover the following areas and, where appropriate, those rules will evolve over time, taking into account the special characteristics of national and regional markets with a view to ensuring the proper functioning of the internal market in gas;

(a) network security and reliability rules;

(b) network connection rules;

(c) third-party access rules;

(d) data exchange and settlement rules;

(e) interoperability rules;

(f) operational procedures in an emergency;

(g) capacity-allocation and congestion-management rules;

(h) rules for trading related to technical and operational provision of network access services and system balancing;

(i) transparency rules;

(j) balancing rules including network-related rules on nominations procedure, rules for imbalance charges and rules for operational balancing between transmission system operators' systems;

(k) rules regarding harmonised transmission tariff structures; *and*

(l) energy efficiency regarding gas networks.

The European Commission published a guidance note in October 2009 which sets priorities to be addressed in 2010. These guidelines suggest that the further development across Europe of arrangements relating to the definition and management of capacity products together with enhanced balancing and transparency requirements should be given priority by the various stakeholders. The work in 2010 will also serve as a trial of the development process itself and will inform the legally binding process to be undertaken in 2011. Gaslink will continue to participate in these various initiatives and will work with other Irish stakeholders in advancing the new arrangements.

8.3 NEW CONNECTIONS

Gaslink continues to engage with parties looking to connect to the Transmission and Distribution networks. In accordance with the Operating Agreement, Gaslink undertakes all the large connections agreements to the transmission system and manages the provision of all other connections agreements undertaken by BGN on Gaslink's behalf.

All new connections are managed in compliance with the CER approved Connections Policy. This Policy sets out the criteria for connecting new customers to the gas network. In 2010, Gaslink and BGN, in conjunction with the CER, will review various elements of the current policy.

As there has been an increase in interest in connecting 'biogas generating facilities' to the gas network, Gaslink has been engaging with the CER on this matter – it is our intention to consider the inclusion of specific requirements in the Policy that governs the terms for connection of such entry points to the gas network. In conjunction with the CER, Gaslink will review an appropriate mechanism for renewable gas entry points and together develop proposals as appropriate. These proposals will endeavour to bring clear and transparent arrangements, which will clarify the approach for these facilities which should assist the wider use of renewable gas ensuring non discriminatory access to the gas network.

Another area that requires review under the current policy is the increased need for peaking power generation plants to compensate the intermittent nature of wind. Gaslink has been approached by various developers requesting gas connections to fuel such peaking plants. The CER published a consultation paper on the treatment of new large gas connection with an expected low load factor under the Connections Policy at the end of 2009 and a decision is intended to be made in 2010.

8.4 MOFFAT

8.4.1 Selling Gas at the NBP

In response to requests from the market for the facility to sell gas into GB at the NBP from the Irish market, Gaslink is in the process of developing a virtual reverse flow product at the Moffat Entry Point. Physically, the flow is unidirectional but, through virtual reverse flow, contractual reverse flow of the gas is possible.

Moffat is currently designated as an Exit Point from the GB Transmission System. It will be necessary for Moffat to also be designated as an Entry Point in order to allow ROI Shippers to sell their gas in GB.

8.4.2 NTS Exit Reform

92.3 % of the Irish gas requirements and 100% of Northern Ireland and Isle of Man gas is supplied via the Moffat interconnection point with the GB system operated by National Grid. The current arrangement for booking capacity to ship gas through the inter-connector pipelines is a 'Ticket to Ride' Process. This means that GB parties can only book capacity at Moffat if they were nominated to do so by a counter party downstream of Moffat.

As part of what is commonly termed NTS Exit Reform, the Office of Gas and Electricity Markets (OFGEM), approved a modification (UNC 195AV) to the GB code on the 19th January 2009 which puts in place a user commitment model at Moffat where, ultimately, parties will be required to book exit capacity several years in advance in order to ensure access to such capacity. The new arrangements come into full effect on 30th

September 2012 and will result in substantial changes to the allocation of NTS exit capacity at Moffat. One key impact is the abolition of the Downstream Capacity Register which facilitated the ticket to ride required by upstream shippers in order to procure exit capacity.

Stakeholders in the GB gas market will continue throughout 2010 to develop further initiatives pursuant to NTS Exit Reform. One key focus will be the development of a capacity substitution regime at exit where unused capacity may be transferred to another NTS exit point at which additional capacity is required. Gaslink, at the request of the CER, will monitor developments in this area to the extent they impact on Moffat and will inform Irish stakeholders of the relevant proposals.

8.5 CAG SUMMARY

Background

"The All-island Energy Market Development Framework" paper (agreed by Irish and Northern Irish Ministers in November 2004) set the scene for the review of Energy markets on an All-Island basis. The Single Electricity Market (SEM) was the first phase in this development. In establishing Common Arrangements for Gas (CAG), the CER and the Northern Ireland Authority for Utility Regulation (NIAUR) plan, subject to the approval of the relevant authorities, to progress phase two of this energy management harmonisation work through the facilitation of the operation of the natural gas market in Ireland and Northern Ireland on an all-island basis.

Potential benefits of CAG include:

- Enhanced interconnectivity of gas networks on the island;
- Enhanced competition;
- More optimised investment; *and*
- Increased Security of Supply.

The first Joint Capacity Statement (JCS) was produced in 2009, as part of the CAG project. The JCS examines forecasts of customer demand for natural gas, the relevant sources of supply and the capacity of the gas transmission system on the island for the period 2008/9 to 2015/16. It constitutes an important step in developing a harmonised approach to security of supply on the island under the CAG project. This work will be central to the CAG project and the systems operations function going forward.

Current Status

- The Regulatory Authorities has initiated a number of preliminary CAG work streams;
- Gaslink has worked closely, throughout 2009, with the CER and NIAUR to advance the approach to development of a Single Network Code for CAG. Work in this area is continuing in 2010; *and*
- **Work on the 2010 Joint Capacity Statement (JCS) is being currently progressed, with an expected publication date of** July **2010. The 2010 JCS has been expanded to cover a 10 year period, from 2009/10 to 2018/19.**

The CAG work plan is aimed to be aligned with legislative timetables with respect to CAG Governance Structure if and when it is finalised.

Appendix 1: Demand Forecasts

The demand and supply forecasts are summarised in Tables A1.1 – A1.3 for the Base Case Supply scenario. The ROI demand is broken down by sector, while the total demand is given for NI and the IOM. The forecasts are based on the following weather scenarios:

- Table A1.1: Peak-day gas demand under severe 1 in 50 weather conditions, i.e. weather so severe that it only occurs once every 50 years;
- Table A1.2: Peak-day gas demand under 'average year' weather conditions, i.e. the weather conditions that typically occur each year; *and*
- Table A1.3: Annual gas demand in average year weather conditions.

The NI peak-day demand used for both the 1 in 50 and average year weather forecast is based on the latest available NI Postalised tariff data (extrapolated forward), plus provision for a new CCGT at Kilroot. The IOM peak-day is based on information provided by the MEA.

The weather correction is only applied to the distribution connected load, i.e. primarily to the residential and small I/C sectors. There is no weather correction applied to the power sector gas demand forecast and, therefore, its peak-day demand is the same for both the 1 in 50 and average year weather conditions.

Table A1.1: Peak-Day demand (1 in 50 weather) & Base Supply by gas year (in GWh/d)

	09/10 GWh	10/11 GWh	11/12 GWh	12/13 GWh	13/14 GWh	14/15 GWh	15/16 GWh	16/17 GWh	17/18 GWh	18/19 GWh
Demand										
Power	126.7	131.2	133.0	131.4	130.2	132.4	134.3	140.6	142.4	153.8
I/C	47.3	46.7	47.0	47.3	47.7	48.0	47.8	47.6	47.4	47.2
RES	67.2	66.3	66.2	66.1	66.0	66.0	65.6	65.3	65.1	64.9
Own use	4.6	4.7	3.2	3.2	3.5	3.5	3.6	3.9	4.3	4.8
Sub total	245.8	248.8	249.5	248.0	247.4	249.9	251.3	257.4	259.2	270.7
Injection	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IOM	5.7	5.8	6.2	6.3	6.4	6.5	6.6	6.6	6.7	6.8
NI	84.2	85.1	86.2	87.3	107.0	107.7	108.3	109.0	109.6	110.3
Total	335.7	339.7	341.9	341.5	360.8	364.0	366.1	373.0	375.6	387.8
Supply										
Inch	38.4	37.3	35.6	34.3	33.2	32.3	31.7	31.1	30.7	30.3
Corrib	0.0	0.0	103.3	103.3	103.3	103.3	103.3	91.2	66.0	47.1
Larne	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Shannon	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Moffat	297.2	302.4	203.0	204.0	224.3	228.4	231.2	250.7	278.9	310.4
Total	335.7	339.7	341.9	341.5	360.8	364.0	366.1	373.0	375.6	387.8

Notes

[1]Injection refers to storage injections from the transmission system into Kinsale and Larne Storage

[2]Own-use refers to fuel-gas used by the transmission system to transport the gas, e.g. fuel-gas used the compressor stations and heat exchangers at Above Ground Installations (AGIs)

Table A1.2: Peak-day demand (average year weather) & Base Supply by gas year (GWh/d)

	09/10 GWh	10/11 GWh	11/12 GWh	12/13 GWh	13/14 GWh	14/15 GWh	15/16 GWh	16/17 GWh	17/18 GWh	18/19 GWh
Demand										
Power	126.7	131.2	133.0	131.4	130.2	132.4	134.3	140.6	142.4	153.8
I/C	40.5	39.9	40.3	40.5	40.9	41.2	41.0	40.8	40.7	40.6
RES	53.5	52.9	52.8	52.7	52.6	52.6	52.3	52.1	51.9	51.7
Own use	3.1	3.2	2.2	2.2	2.4	2.4	2.4	2.6	2.9	3.2
Sub total	223.8	227.1	228.3	226.8	226.1	228.6	230.1	236.1	237.9	249.3
Injection	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IOM	4.9	5.0	5.2	5.3	5.3	5.4	5.5	5.5	5.6	5.7
NI	84.2	85.1	86.2	87.3	107.0	107.7	108.3	109.0	109.6	110.3
Total	313.0	317.2	319.8	319.4	338.5	341.7	343.8	350.7	353.2	365.3
Supply										
Inch	38.4	37.3	35.6	34.3	33.2	32.3	31.7	31.1	30.7	30.3
Corrib	0.0	0.0	103.3	103.3	103.3	103.3	103.3	91.2	66.0	47.1
Larne	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Shannon	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Moffat	274.6	279.9	180.8	181.8	202.0	206.0	208.9	228.4	256.5	287.9
Total	313.0	317.2	319.8	319.4	338.5	341.7	343.8	350.7	353.2	365.3

Table A1.3: Annual demand (average year) & Base Supply scenario by gas year (TWh/y)

	09/10 TWh	10/11 TWh	11/12 TWh	12/13 TWh	13/14 TWh	14/15 TWh	15/16 TWh	16/17 TWh	17/18 TWh	18/19 TWh
Demand										
Power	37.44	37.21	35.38	33.52	33.13	35.74	35.86	37.77	38.26	41.27
I/C	10.24	10.08	10.30	10.49	10.69	10.88	10.88	10.87	10.87	10.86
RES	7.92	7.83	7.73	7.62	7.53	7.45	7.37	7.31	7.26	7.20
Own use	0.78	0.59	0.40	0.38	0.38	0.42	0.44	0.53	0.61	0.70
Sub total	56.38	55.72	53.81	52.02	51.73	54.48	54.56	56.48	56.99	60.03
Injection	1.21	1.39	1.64	1.84	2.01	2.14	2.24	2.32	2.39	2.44
IOM	1.33	1.34	1.41	1.42	1.44	1.46	1.47	1.50	1.52	1.54
NI	16.36	17.11	17.66	18.70	24.44	24.54	24.65	24.76	24.87	24.98
Total	75.28	75.56	74.52	73.98	79.62	82.62	82.92	85.06	85.77	88.99
Supply										
Inch	4.50	4.26	3.90	3.62	3.39	3.21	3.06	2.95	2.85	2.78
Corrib	0.00	18.80	37.71	37.71	37.71	37.71	35.50	28.71	20.66	15.67
Larne	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Shannon	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Moffat	70.78	52.50	32.91	32.65	38.52	41.70	44.36	53.41	62.26	70.54
Total	75.28	75.56	74.52	73.98	79.62	82.62	82.92	85.06	85.77	88.99

The forecast assumes that the peak-day gas demand of the power sector is coincident with that of the residential and I/C sectors, as this gives the worst case scenario for gas system planning purposes.

The power peak-day gas demand forecast assumes that all of the non gas-fired thermal power stations are available on the day, i.e. all of the peat, coal and oil-fired power stations. If there is a forced outage at one or more of the non gas-fired thermal power stations, then the peak-day gas demand of the sector may be higher than indicated in the above forecasts.

Appendix 2: Historic Demand

HISTORIC DAILY DEMAND BY METERING TYPE

The historic demand data in Section 3 is presented by sector (i.e. residential I/C and power), as this is more useful for forecasting purposes and is also considered to be a more familiar classification for the users of this document. The actual daily demand data is collected by metering type:

- Large Daily Metered (LDM) sites with an annual demand of 57.0 GWh/y or greater and includes all the power stations and the large I/C sites;
- Daily Metered (DM) sites with an annual demand greater than 5.6 GWh/y and less than 57.0 GWh/y, and includes the medium I/C, hospitals and large colleges etc; *and*
- Non-Daily Metered (NDM) with an annual demand of 5.6 GWh/y or less and includes the small I/C and residential sectors.

The daily demands of the above categories are then recombined into the following categories for reporting and forecasting purposes, using the monthly billed residential data to split the NDM sector into its residential and I/C components:

- Power sector: The individual power stations are separated out from the LDM total;
- The I/C sector: Is comprised of the demand from the remaining LDM sites, the DM sector and the NDM I/C sector (calculated as the residual of the total NDM demand and the residential demand); *and*
- Residential sector: Calculated as a percentage of the NDM demand, using the ratio of the total billed monthly NDM and residential demand.

The historic daily demand on the transmission and distribution systems is shown in Fig. A2.1 and A2.2, with the corresponding peak-day, minimum-day and annual demands tabulated in Table A2.1. The transmission and distribution daily demands have been broken down into the following sub-categories:

- Transmission demand has been subdivided into the power sector demand, with all of the remaining LDM and DM I/C demand combined into the TX DM I/C category; *and*
- Distribution demand has been subdivided into the NDM demand, with all of the remaining LDM and DM I/C demand combined into the DX DM I/C category.

It can be seen from Fig. A2.1 that the distribution connected demand is very weather sensitive, peaking in the colder winter period and falling off in the warmer summer period. The NDM demand is particularly weather sensitive, as it includes the residential and small I/C sectors, which primarily use gas for space heating purposes.

The transmission connected demand on the other hand does not appear to be particularly weather sensitive. The gas demand of the power sector in particular is driven by relative fuel-prices rather than the weather (although the gas-price can be weather related as well).

The peak-day demands shown in Table A2.1 represent the coincident peak-day demands, i.e. the peak-day demand of each sector on the date of the overall system peak-day demands. Each sector may have had a higher demand on a different date. The non-coincident peak-day demand of each sector is shown in Table A2.2.

Figure A2.1: Historic daily demand of transmission connected sites

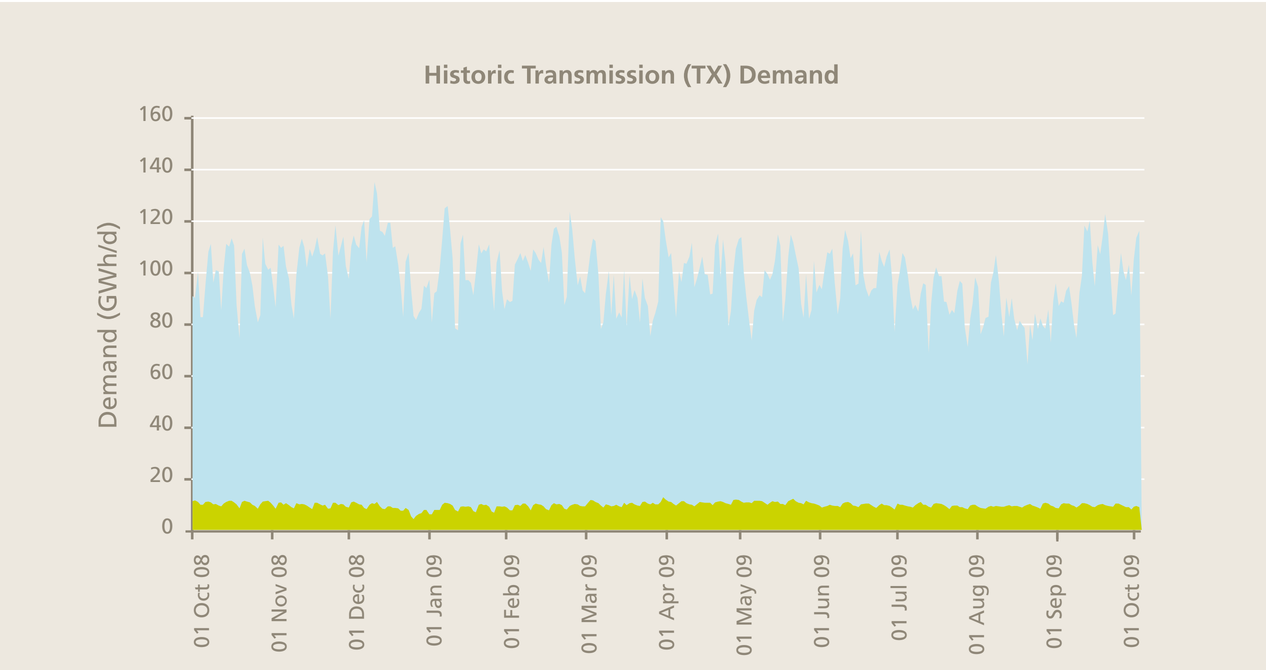


Figure A2.2: Historic daily demand of the distribution connected sites

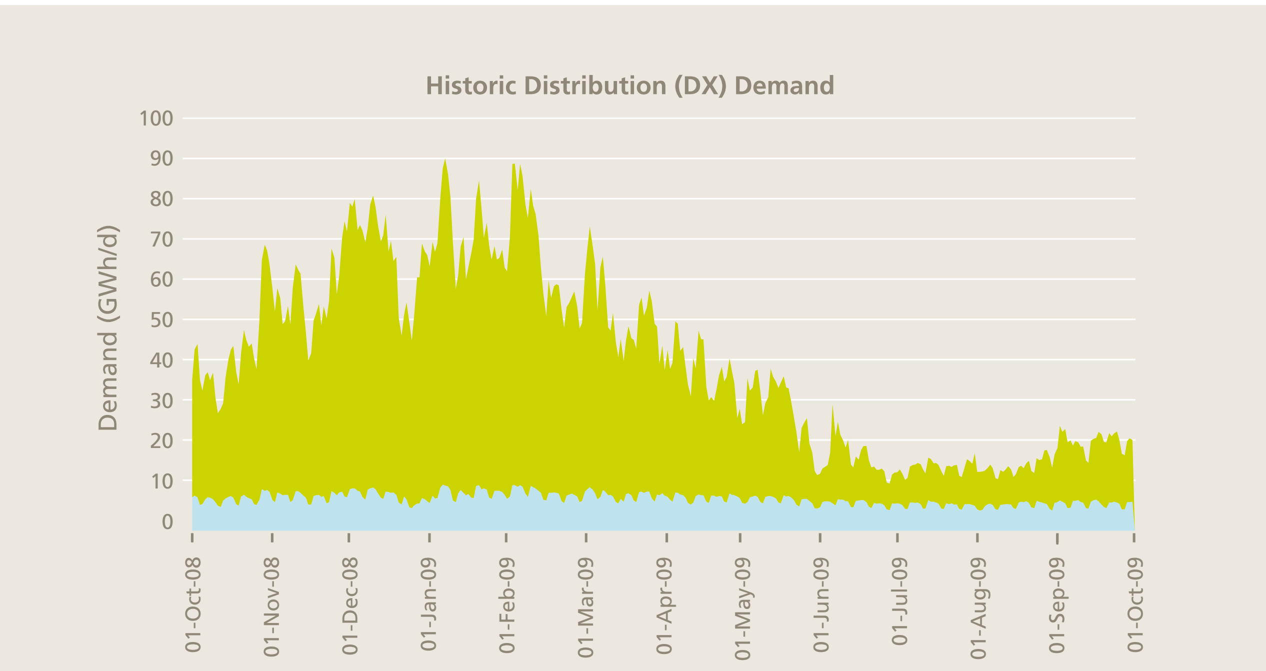


Table A2.1: Historic coincident peak-day and annual demands

	2002/03 (GWh)	2003/04 (GWh)	2004/05 (GWh)	2005/06 (GWh)	2006/07 (GWh)	2007/08 (GWh)	2008/09 (GWh)
Peak Day							
TX Power	97.0	91.8	73.6	96.8	111.2	119.7	126.4
TX DM I/C	11.9	13.0	15.5	12.3	11.2	10.7	10.4
DX DM I/C	0.0	1.6	10.0	10.8	10.8	11.2	11.0
DX NDM	72.4	74.5	67.0	69.7	71.4	74.1	79.7
Total ROI	181.3	180.9	166.1	189.6	204.7	215.7	227.5
Annual							
TX Power	28,775	28,845	25,630	29,775	34,688	37,758	36,007
TX DM I/C	4,461	4,854	4,953	4,004	4,029	3,793	3,518
DX DM I/C	107	1,682	2,468	2,597	2,827	2,828	2,835
DX NDM	12,671	12,052	11,463	11,900	11,345	12,125	12,374
Total ROI	46,013	47,433	44,514	48,276	52,890	56,505	54,734

Table A2.2: Historic Non-coincident peak-demands by sector

	2002/03 (GWh)	2003/04 (GWh)	2004/05 (GWh)	2005/06 (GWh)	2006/07 (GWh)	2007/08 (GWh)	2008/09 (GWh)
Peak Day							
TX Power	116.4	97.7	95.7	110.2	123.1	129.3	135.7
TX DM I/C	32.4	16.4	19.3	13.7	13.7	12.9	12.7
DX DM I/C	1.4	9.0	10.2	10.8	11.3	11.3	11.2
DX NDM	74.9	74.5	70.1	71.4	72.1	74.1	79.7
Total ROI	225.1	197.6	195.3	206.1	220.2	227.6	239.3
Annual							
Power	116.4	97.7	95.7	110.2	123.1	129.3	135.7
I/C	66.8	54.6	51.3	46.6	47.1	46.9	46.8
RES	41.9	45.3	48.3	49.3	50.0	51.4	56.8
Total ROI	225.1	197.6	195.3	206.1	220.2	227.6	239.3

Appendix 3: Energy Efficiency assumptions

NATIONAL ENERGY EFFICIENCY ACTION PLAN (NEEAP)

The NEEAP for Ireland sets out the Government's strategy for meeting the energy efficiency savings targets identified in the Energy White Paper (2007) and the EU Energy Services Directive (ESD). These targets include:

- The White Paper target of a 20% reduction in ROI energy demand across the whole economy by 2020, with a higher 33% target for the Public Sector; *and*
- The ESD target of a 9% reduction in energy demand by 2016;

Table A3.1: NEEAP Energy efficiency savings targets

	2010 PEE target (GWh)	2016 PEE target (GWh)	2020 PEE target (GWh)
Residential Sector			
Building Regulations 2002	1,015	1,015	1,015
Building Regulations 2008	130	1,425	2,490
Building Regulations 2010	0	570	1,100
Low Carbon Homes	0	130	395
SEAI House of Tomorrow	30	30	30
Warmer Homes Scheme	115	155	170
Home Energy Savings programme	450	600	600
Smart Metering	0	650	690
Greener Homes scheme	265	265	265
Eco-design for energy appliances (lighting)	200	1,200	1,200
More efficient Boiler Standard	400	1,600	2,400
Total residential savings	2,605	7,640	10,355
Business & Commercial sectors			
SEAI public sector retrofit programme	140	140	140.0
Building Regulations 2005	185	370	560.0
Building Regulations 2010	0	630	1,360.0
SEAI energy agreements (IS 393)	465	685	4,070.0
SEAI small business supports	160	330	565.0
Existing ESB DSM programmes	380	410	435.0
Renewable Heat Deployment programme	360	410	410.0
ACA for energy efficient equipment	100	400	800.0
Total business and commercial savings	1,790.0	3,375.0	8,340.0
Other sectors			
Transport	775	3,105	4,670
Energy Supply sector	275	300	365
Total measures identified above	5,445	14,420	23,730
White Paper target (20% reduction by 2020)			31,925
Additional measures yet to be identified			8,195

IMPACT ON RESIDENTIAL GAS DEMAND

The proposed energy efficiency measures for the residential sector will clearly have a material impact on annual gas demand of the residential sector. The TDS forecast for the residential sector includes the following assumptions:

- Incremental gas demand from new residential connections will continue to reduce due to tighter building regulations and will fall to 40% of 2005/06 levels by 2012/13; *and*
- Existing residential gas demand will also reduce due to the introduction of more efficient boiler standards (e.g. condensing boilers), smart metering and the combined impact of the Low Carbon Homes, Warmer Homes & Home Energy Saving Schemes.

The average annual gas consumption of all new residential customers connected during the 2005/06 gas year was approximately 12.3 MWh/y. The TDS forecast assumes the average gas consumption of each new customer connected by 2012/13, will reduce by 60% to 4.9 MWh/y.

The NEEAP assumes a total reduction of 4,255 GWh in residential energy demand, due to the introduction more efficient boiler standards, smart metering and the combined impact of the Low Carbon Homes, Warmer Homes and Home Energy Saving Schemes.

In addition, it also identifies the potential for a further energy efficiency reductions of 1,920 GWh from the retrofitting attic, cavity-wall and wall-lining insulation to existing houses (after adjusting for the impact of the Warmer Homes and Home Energy Savings Schemes).The TDS forecast assumes that:

- Total energy efficiency savings of 6,173 GWh in residential heat demand between 2009/10 and 2019/20 from the above measures (annual reduction of 561 GWh/y);
- Approximately 27% of this target reduction will be achieved in gas-fired residential homes, based on the gas share of residential heat in 2008, i.e. the gas share of total residential TFC after excluding the electricity and renewable components; *and*
- This would lead to a reduction of 152 GWh/y in residential annual gas demand, which is equivalent to 1.8% of the residential gas demand in 2008/09.

If all of the above energy efficiency measures are implemented as planned and achieve the assumed energy savings, then it is estimated that annual residential gas demand will reduce by approximately -7.9% over the period.

IMPACT ON I/C GAS DEMAND

The NEEAP assumes a total reduction of 3,375 GWh in I/C gas demand by 2016 and a total reduction of 8,340 GWh by 2020. Some of this reduction may have already occurred since the 2002-2005 baseline period. The TDS forecast assumes:

- That the total I/C energy demand will reduce by 3,375 GWh by 2016 and a further 4,965 GWh by 2020 (per the NEEAP), an annual reduction of 338 GWh/y up to 2016 and 1,174 GWh/y up to 2020;
- The gas share of these reductions is assumed to be 19.3% up to 2016 and 21.4% up to 2020, based on gas share of total I/C TFC in 2008 (of 23.0%) and adjustments to exclude initiatives which are specific to electricity (e.g. ESB demand reduction programmes); *and*
- This would lead to an annual reduction of 65.1 GWh/y in I/C annual gas demand up to 2014/15, and 266 GWh/y from 2015/16 onwards (which is equivalent to 0.6% and 2.6% of the 2008/09 I/C annual demand respectively).

Glossary

AGI	Above Ground Installation
ANOP	Anticipated Normal Operating Pressure
AQ	Annual Quantity
BGN	Bord Gáis Networks
CAG	Common Arrangements for Gas
CCGT	Combined Cycle Gas Turbine
CER	Commission for Energy Regulation
DCENR	Dept of Communications, Energy and Natural Resources
DD	Degree Day
DM	Daily Metered
DX	Distribution System
EPA	Environmental Protection Authority
E/W	East/West electricity interconnector
ESRI	Economic and Social Research Institute
GATG	Gas Advisory Task Group
GB	Great Britain
GCS	Gas Capacity Statement
GCV	Gross Calorific Value
GDP	Gross Domestic Product
GWh	Giga-Watt hours
GWh/d	Giga-Watt hours per day
I/C	Industrial / Commercial
IBP	Irish Balancing Point
IC	Interconnector system
IC1	Interconnector 1
IOM	Isle of Man
IPPC	Integrated Pollution Prevention Control
LF	Load Factor
LNG	Liquefied Natural Gas
LSFO	Low Sulphur Fuel Oil
MEA	Manx Electricity Authority
MOP	Maximum Operating Pressure
MTR	Medium Term Review
MW	Mega Watts
N/W	North West Pipeline
NBP	National Balancing Point
NDM	Non - Daily Metered
NEC	Network Emergency Coordinator (in GB)
NEM	Network Emergency Manager (in the ROI)
NG	National Grid
NGEM	Natural Gas Emergency Manager
NGEP	National Gas Emergency Plan
NI	Northern Ireland
NTS	National Transmission System (in GB)
OCGT	Open Cycle Gas Turbine
P.A.	Per Annum
PMA	Pressure Maintenance Agreement
PTL	Premier Transmission Ltd
PTTW	Pipeline to the West
ROI	Republic of Ireland
S/N	South / North Pipeline
SEAI	Sustainable Energy Authority of Ireland
SI	Statutory Instrument
SNIP	Scotland Northern Ireland Pipeline
SONI	System Operators Northern Ireland
SOS	Security of Supply
SRMC	Short Run Marginal Cost
SWL	South West Lobe
TDS	Transmission Development Statement
TFC	Total Final Consumption
TFEP	Task Force on Emergency Procedures
TPER	Total Primary Energy Requirement
TX	Transmission System
UK	United Kingdom

Disclaimer:
Gaslink has followed accepted industry practice in the collection and analysis of data available. However, prior to taking business decisions, interested parties are advised to seek separate and independent opinion in relation to the matters covered by the present Transmission Development Statement (TDS) and should not rely solely upon data and information contained therein. Information in this document does not purport to contain all the information that a prospective investor or participant in Ireland's gas market may need.

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