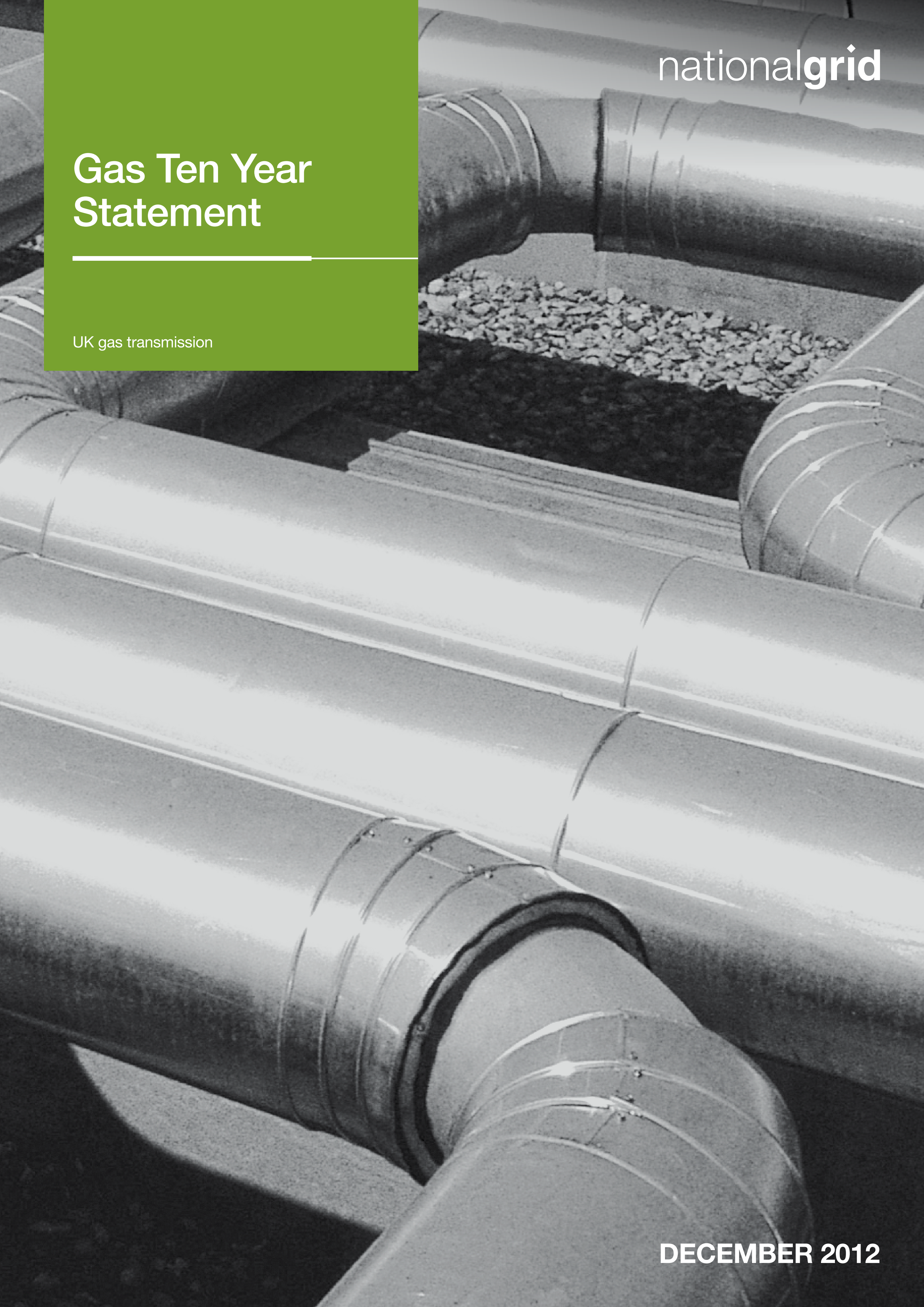
nationalgrid

Gas Ten Year Statement

UK gas transmission



DECEMBER 2012

Welcome to the 2012 edition of the Gas Ten Year Statement. I hope that you find it an informative and useful document. The purpose of this document is to set out our assessment of the future demand and supply position for natural gas in the United Kingdom, the consequences for operation of the gas transmission network and subsequent investment requirements.

The production of the Gas Ten Year Statement is the conclusion to the planning process for the current cycle. It follows the publication of our UK Future Energy Scenarios[1] document in September 2012. Some of the detail behind our scenarios sits within the Future Energy Scenarios document, allowing the Gas Ten Year Statement to focus on the implications of the scenarios for the development of the gas network.

This Gas Ten Year Statement sits alongside our new Electricity Ten Year Statement (E-TYS). The first Electricity Ten Year Statement was published in November 2012 following an extensive consultation, and it replaces the former Seven Year Statement (SYS) and Offshore Development Information Statement (ODIS).

In order to continually improve our Gas Ten Year Statement and ensure that we continue to add value to the information that we provide, I encourage you to tell us what you think by writing to us at SystemOperator.GTYS@nationalgrid.com.

I hope that you find this an informative and useful document and look forward to receiving your feedback.

Mike Calviou
Director of Transmission Network Service
National Grid
SystemOperator.GTYS@nationalgrid.com

1 www.nationalgrid.com/uk/Gas/OperationalInfo/TBE/

Please Note:
This document does not take into account Ofgem's final proposals for the 8 year RIIO-T1 period starting in April 2013.

Contents

Executive summary

Supply and demand outlook

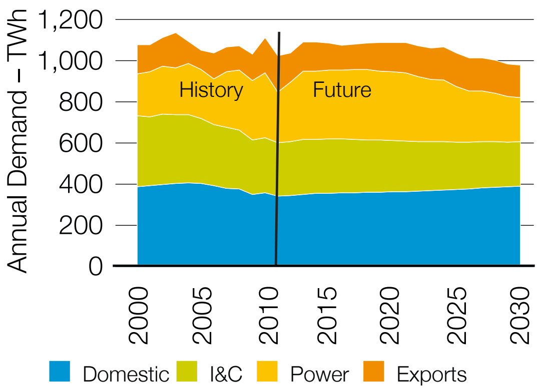
In 2011 National Grid replaced a single 'best view' forecast of gas supply and demand with scenarios representing three different views of the future. For 2012 we have developed this approach further based on feedback from our stakeholders. The three scenarios are described fully in our Future Energy Scenarios document[2].

2 www.nationalgrid.com/uk/Gas/OperationalInfo/TBE/Future+Energy+Scenarios/

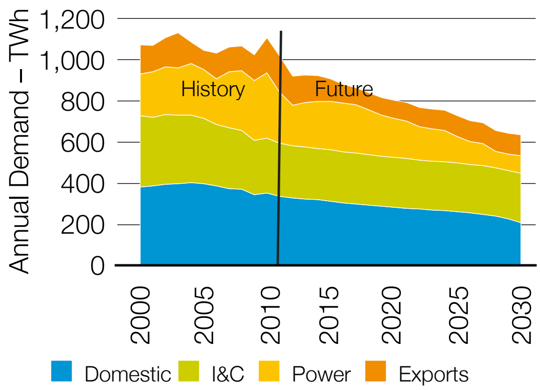
Demand

- Total gas demand under our Slow Progression scenario remains relatively flat in the period to 2030. Slight increases in domestic demand from an increase in household temperatures are offset by small reductions in industrial and commercial (I&C) demand.
- In Gone Green, there is a general reduction in demand over the scenario period. This is mainly due to consistent reductions in the domestic sector and reductions from power generation demand beyond 2016 as renewable energy increases its share of the power generation mix.
- Accelerated Growth shows a similar but more pronounced demand trend compared to Gone Green. This again is attributable to further reductions in gas demand from the domestic sector and reductions in power generation demand.
- Peak gas in all scenarios broadly reflects changes in annual demand, with allowances made for changes in the utilisation of gas-fired power generation at times of low renewable generation.

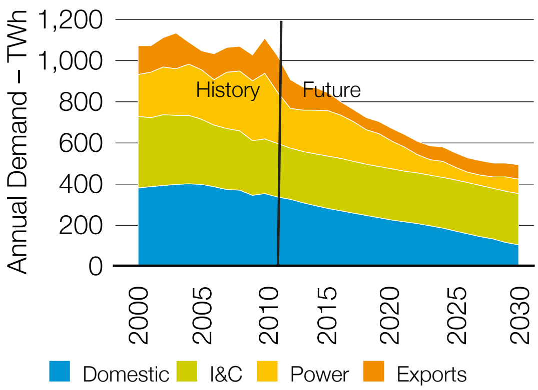
Annual gas demand slow progression



Annual gas demand gone green



Annual gas demand accelerated growth

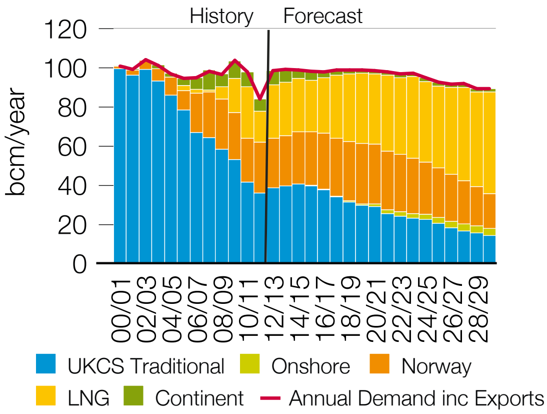


Executive summary

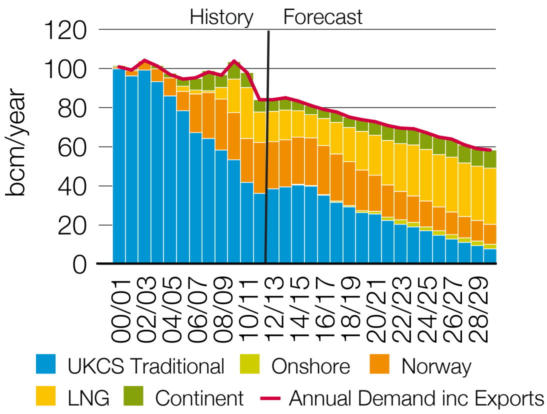
Supply

- UK Continental Shelf (UKCS) and Norwegian supplies are highest under Slow Progression due to confidence in future gas demand and a stable regime, which drives increased upstream investment. An increase in global liquefied natural gas (LNG) liquefaction leads to a significant increase in LNG imports. The high level of imports drives investment in seasonal storage and sees the UK continue to be a net exporter to the Continent.
- Compared with Slow Progression, lower demand under Gone Green is met with lower levels of supply particularly from Norway and LNG. Under Gone Green, global LNG supplies are less plentiful, but more gas is imported from the Continent. In terms of gas storage, Gone Green assumes further development of more flexible gas storage.
- In Accelerated Growth, the global LNG market remains tight throughout the scenario period. In addition UKCS and Norwegian supplies are lower due to lower gas demands and a higher carbon price which sees lower upstream investment. Peak demands are met by utilising flexibility at LNG terminals combined with imports from the Continent along with existing storage facilities.

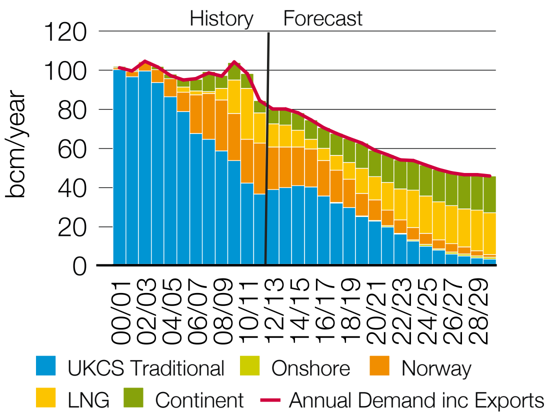
annual gas supply slow progression



annual gas supply gone green

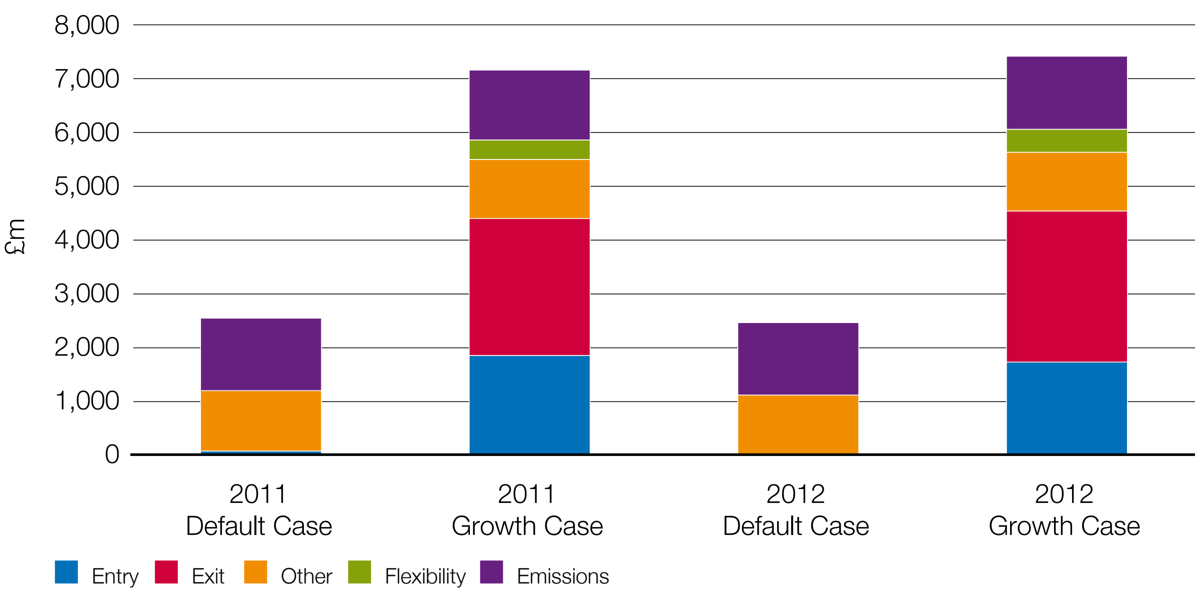


annual gas supply accelerated growth



Investment Implications

- Uncertainties in the future supply mix are affecting future investment on the National Transmission System (NTS). St Fergus supplies are decreasing, however, rising demands in Scotland (including the Moffat offtake) are expected to continue. This is compensated by supplies arriving at southern Aggregate System Entry Points (ASEPs). To maintain supplies in Scotland it will, therefore, be increasingly necessary to route gas 'South to North' within the network.
- No further investments have been triggered through long-term entry auction signals, but it is possible that reinforcement will be required to support new storage projects and large new power stations, should signals be received from users. There exists a significant uncertainty relating to entry, exit and storage projects (and associated investment requirements) in the latter half of the 10-year period considered.
- As user requirements from the network evolve, it is increasingly necessary to consider the ability of the system to switch between different flow scenarios, explicitly considering 'transient' (changing) flows on the network.
- Forecast 'Emissions' investment is driven by the need to comply with environmental legislation. The Industrial Emissions Directive (IED) will drive the need for investment to address our non-compliant gas generators, although the full impact of the legislation still remains uncertain until it has been transposed into UK law in January 2013.
- The chart below shows our view of the investment required over the ten-year forecast period, compared to the same forecast from 2011. The 'Default Case' represents the potential investment on the network if no user signals for incremental capacity are received, whereas the 'Growth Case' sensitivities represent views of potential investment required as a result of receiving user signals for incremental capacity. The 2012 cases are consistent with our RIIO-T1 business plans, although financial totals will not align precisely due to the different time frames considered.



Chapter one
Document scope

1.1
Overview of Future Energy Scenarios consultation process

The production of the Gas Ten Year Statement is the conclusion to the planning process for the current planning cycle. This document uses energy scenarios detailed within our 2012 UK Future Energy Scenarios publication. Our "Future Energy Scenarios" (FES) consultation will initiate the planning process for 2013.

Our stakeholder engagement will continue to include a mixture of questionnaires, meetings, workshops and seminars. We will continue to develop our stakeholder engagement to ensure our scenarios are based upon as broad a range of stakeholders views as possible. The feedback will inform the development of the 2013 scenario analysis and feed into the resultant network investment options.

Shortly after the publication of the Gas Ten Year Statement, targeted questionnaires will be circulated to a range of industry stakeholders (producers, importers, shippers, storage operators, terminal operators, transporters and consumers) requesting demand and supply forecast data and inviting views on our underlying assumptions.

The proposed programme for the next year is as follows:

- Publish 2012 Gas Ten Year Statement – December 2012
- Hold consultation meetings and workshops – December / January 2013
- Circulate 2013 consultation questionnaires – January 2013
- Receive responses to questionnaires – February 2013
- Provide feedback on responses received – February 2013
- Publish 2013 UK Future Energy Scenarios, highlighting our latest view of energy scenarios for both gas and electricity, released at an industry seminar – July 2013
- Publish 2013 Electricity Ten Year Statement – November 2013
- Publish 2013 Gas Ten Year Statement – December 2013

1.2 Structure of document

In 2011 the structure of the document changed to reflect the publication of our UK Future Energy Scenarios document. The 2012 Future Energy Scenarios document was published in September, and contains more detail on our three scenarios used here. This document is, therefore, able to concentrate on the implications of the scenarios for the development of the gas network.

The appendices provide details of the methodologies used to produce the demand and supply scenarios, the latest demand and supply scenarios themselves, actual gas flow data, system maps and connection specifications (including gas quality). The final sections of the document contain a section on industry terminology and a conversion matrix.

The key demand and supply data shown in this year's document can be found in an Excel spreadsheet file on our website[3], published as part of the 2012 Future Energy Scenarios consultation.

3 http://www.nationalgrid.com/uk/Gas/TYS/

4 www.nationalgrid.com/uk/Gas/TYS/LTDP/index.htm
5 www.northerngasnetworks.co.uk/cms/54.html
6 http://www.sgn.co.uk/index.aspx?id=54&rightColHeader=95&rightColContent=15&rightColFooter=237&TierSlicer1_TSMenuTargetID=114&TierSlicer1_TSMenuTargetType=4&TierSlicer1_TSMenuID=6
7 www.wwutilities.co.uk/long-term-development-statement.aspx?GroupKeyPos=02,06,

1.2.1 Distribution Network Long-Term Development Statements

The Gas Ten Year Statement concentrates solely on the gas transmission network. Information relating to the Distribution Networks can be found in the Long-Term Development Statements / Plans which can be accessed via the links on the right:

National Grid UK Distribution Long-Term Development Plan[4]

Northern Gas Networks Long-Term Development Statement[5]

Scotia Gas Networks Long-Term Development Statement[6]

Wales & the West Utilities Long-Term Development Statement[7]

1.3
Other publications

This document details the implications of gas investment from our demand and supply scenarios. We have a suite of other documents relating to scenarios and energy investment. These include:

1.3.1
Stakeholder Feedback document[8]

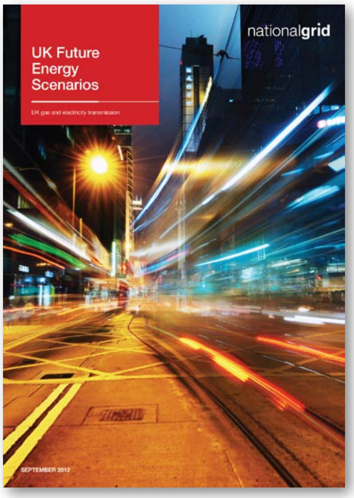
In November 2011 we published our UK Future Energy Scenarios document which presented the assumptions behind our main scenarios used in the analysis and development of future energy scenarios.

Early in 2012 we sought feedback on our scenarios from our stakeholders in an annual consultation process.

The Stakeholder Feedback document was published in July 2012 and provided a summary of the views that were expressed during the 2012 consultation process.

1.3.2
Future Energy Scenarios document[9]

The second edition of our Future Energy Scenarios document was released in September 2012. Here we describe in detail the scenarios finalised in the first half of 2012 and presented to the industry at the Future Energy Scenarios event held in September. Early in 2013 we will be seeking feedback on our scenarios in the next stage of our annual consultation process. This Future Energy Scenarios document provides detail on our latest scenarios, while the Gas and Electricity Ten Year Statements cover the investment implications on the gas and electricity networks.



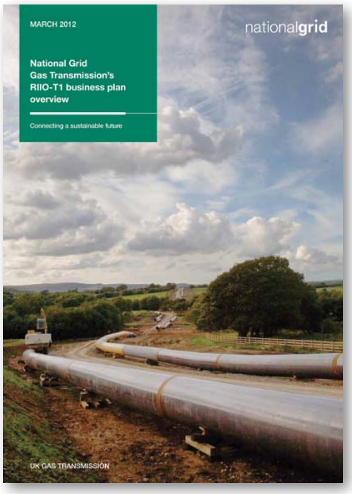
8 www.nationalgrid.com/NR/rdonlyres/2450AADD-FBA3-49C1-8D63-7160A081C1F2/54699/UKFESStakeholderFeedback2012.pdf

9 www.nationalgrid.com/uk/Gas/OperationalInfo/TBE/Future+Energy+Scenarios/

10 www.talkingnetworkstx.com/gastransmissionplan/our-business-plan.aspx
11 http://www.nationalgrid.com/uk/Electricity/ten-year-statement/

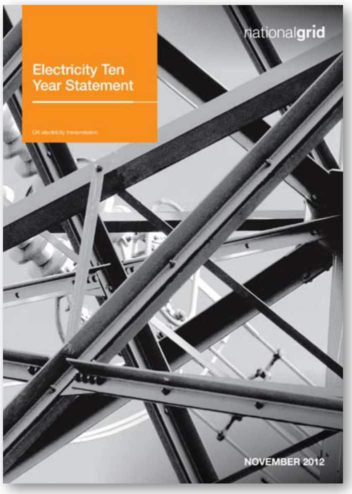
1.3.3
RIIO-T1 Overview

RIIO-T1 is the first Transmission price control under Ofgem's new model of regulation and will run from April 2013 to March 2021. This updated document summarises our Gas Transmission business plan for this period. Further information on National Grid's business plans[10] can be found at Talking networks – Business plans.



1.3.4
Electricity Ten Year Statement[11]

The new Electricity Ten Year Statement (E-TYS) replaces the Seven Year Statement (SYS) and the Offshore Development Information Statement (ODIS), harmonising their outputs and ensuring consistency in their assumptions with those in our Future Energy Scenarios. The aims of the Electricity Ten Year Statement publication are to illustrate the potential future development of the GB Transmission System and to help existing and future customers to identify connection opportunities on both the onshore and offshore transmission system.



Chapter two
Scenarios

2.1 Overview

12 An axiom is a premise or starting point of reasoning.
13 www.nationalgrid.com/uk/Gas/OperationalInfo/TBE/Future+Energy+Scenarios/
14 This list is not exhaustive; other axioms in the Future Energy Scenarios document are also relevant to gas supply and demand.

This document details three scenarios. These are:

- **Slow Progression** – developments in renewable and low carbon energy are relatively slow in comparison to Gone Green and Accelerated Growth and the renewable energy target for 2020 is not met until some time between 2020 and 2025. The carbon reduction target for 2020 is achieved but not the indicative target for 2030.
- **Gone Green** – Gone Green sees the renewable target for 2020 and the emissions targets for 2020, 2030 and 2050 all met.
- **Accelerated Growth** – this scenario has more low carbon generation, including renewables, nuclear and Carbon Capture and Storage (CCS), coupled with greater energy efficiency measures and electrification of heat and transport. Renewable and carbon reduction targets are all met ahead of schedule.

Our 2012 scenarios make extensive use of axioms[12] to intentionally create scenarios which encompass a wide range of possible future developments.

Appendix 1 of our Future Energy Scenarios document[13] contains the full set of axioms used in creating our 2012 scenarios; Table 2.1A shows some of those most relevant to gas supply and demand.

Table 2.1A:
Gas supply and demand axioms[14]
Source: National Grid

	Slow Progression	Gone Green	Accelerated Growth
Targets	Pressure for EU 2020 renewable targets and UK 2050 carbon targets to be abandoned grows.	Targets met. Scenario based on meeting targets. Balanced approach across all market sectors, no trading. No change to EU and UK policies.	2020 targets met early.
CCGT	Significant new build over period.	New build predominantly in period to mid-2020s. Some CCGT capacity with CCS after 2025.	New build predominantly in period to 2020. Some CCGT capacity with Carbon Capture and Storage after 2020.
Domestic Gas Demand	Overall increases in demand with higher comfort levels and new house build exceeding reductions from low levels of energy efficiency.	Demand reduces due to energy efficiency improvements followed later by the high penetration of heat pumps. Comfort levels assumed to remain the same as today. New build houses have low energy use and high use of heat pumps.	Significant demand reduction due to energy efficiency improvements and lower comfort levels followed by very high penetration of heat pumps. New build houses have very low energy use and very high use of heat pumps.
NTS Industrial Gas Demand	High gas case. Low gas prices discourage significant demand reductions in this sector.	Low gas case. Mid-case gas prices and economic view encourage some demand reductions in this sector.	Low gas case. Higher gas prices than GG have less effect than stronger economy leading to demands that are very slightly higher in the long term.

Table 2.1A continued:
Gas supply and demand axioms
Source: National Grid

Gas Supply (UKCS)	Higher UKCS supply due to confidence in market. Though gas prices are lower in SP, they are still attractive for UKCS in a stable regime.	Balanced / mid position.	Lower UKCS due to lower gas demand, high carbon price and limited export opportunity.
Gas Supply (Norway)	Higher Norwegian production and higher exports to UK due to demand certainty and possibly more contracts.	Balanced / mid position.	Lower Norwegian production and lower exports to UK due to a 'green' world.
Gas Supply (LNG)	Plentiful world LNG from existing and new production. UK LNG terminals are base load, new LNG facilities needed.	Balanced / mid position.	Tight LNG market due to lack of new production facilities. UK LNG terminals provide flexible supplies.
Gas Supply (Continent)	UK exports more due to supply availability and low prices, but potential imports at peak.	Balanced / mid position.	UK imports more, particularly at high demands, use of Continental storage rather than new UK storage developments.
Shale Gas, Coal Bed Methane, Biogas	More shale and CBM, reduced biogas compared to GG.	Some shale, CBM and biogas.	No shale or CBM. More biogas compared to GG.
Gas Storage	New seasonal development(s) to accommodate market needs (high imports).	No seasonal developments but new flexible storage Market led – greater flexibility, GG provides increased opportunities.	Existing (and currently under construction) levels of gas storage. Continent (storage) and LNG terminals provide flexible supplies as an alternative to new storage.

There are three key drivers for investment in gas transportation infrastructure:

- The forecast level of 1-in-20 peak day gas demand
- Entry requirements for supplies including imports and storage
- Network flexibility requirements

This chapter covers our assessment of annual and peak demand and the key drivers associated with these demands.

2.2
Demand

2.2.1
Annual demand

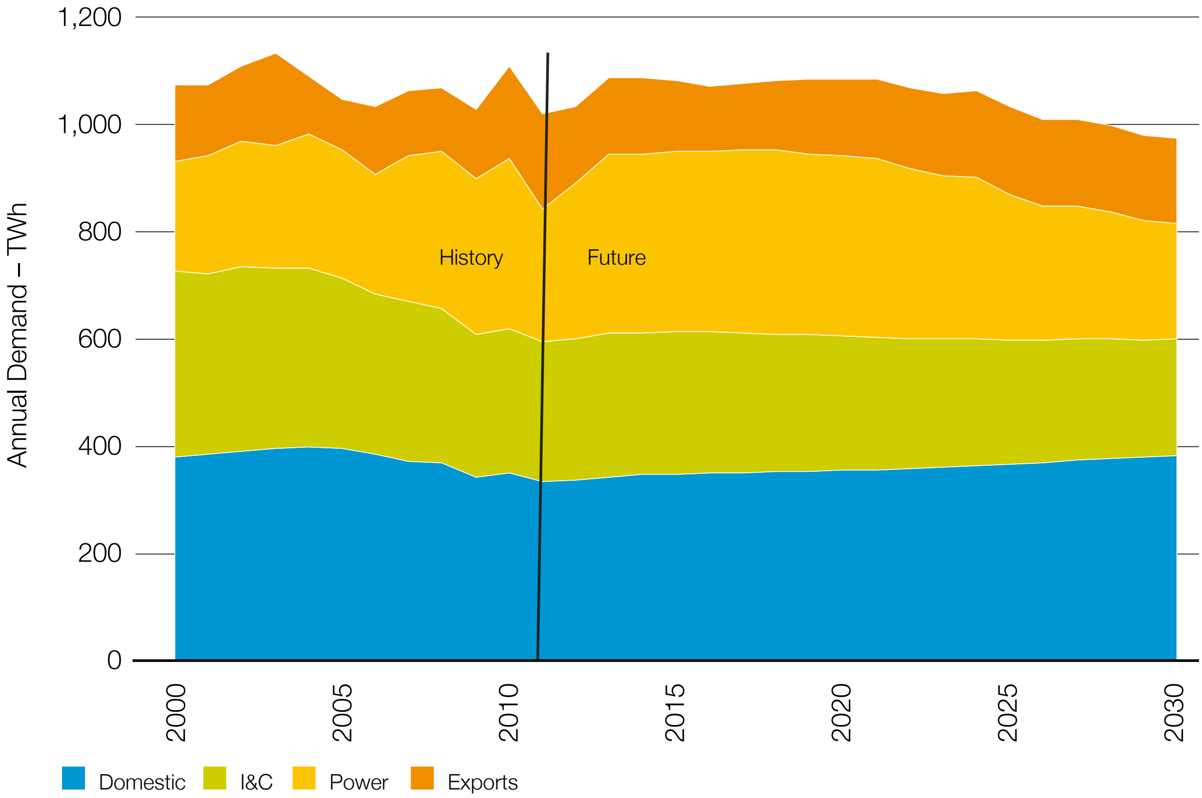
Gas demand described here is discussed in further detail in the National Grid publication Future Energy Scenarios.

The main drivers of gas demand are:
- Fuel prices
- Economy
- Energy efficiency
- Electrification of heat
- Sites opening / closing
- Power generation requirements and associated power generation mix
- Gas exports to the Continent and Ireland.

These factors vary between scenarios due to the axioms that underpin them.

The three scenarios show very different outcomes for gas demand, due predominantly to the changes in demand for power generation and domestic sectors.

Figure 2.2A:
Annual gas demand scenarios including history – Slow Progression
Source: National Grid



Our Slow Progression scenario has a fairly flat view of demand over the scenario period. Slight increases in domestic demand offset similar reductions in industrial and commercial demand, with changes in power generation causing the greatest changes in total demand. Total demand increases slightly from 2011 then remains broadly flat, until early to mid-2020s, predominantly due to the changes in power generation demand.

In the Gone Green scenario, there is a general reduction in gas demand throughout the scenario period. This is mainly due to consistent reductions in the domestic sector and reductions from power generation demand beyond 2016.

Accelerated Growth shows a similar but more pronounced trend to Gone Green. This is again mainly attributable to further reductions in the gas demand from the domestic sector and power generation sector, these decline more and earlier than Gone Green. The reduced level of exports in Accelerated Growth also has a significant effect on total demand.

Figure 2.2B:
Annual gas demand scenarios including history – Gone Green
Source: National Grid

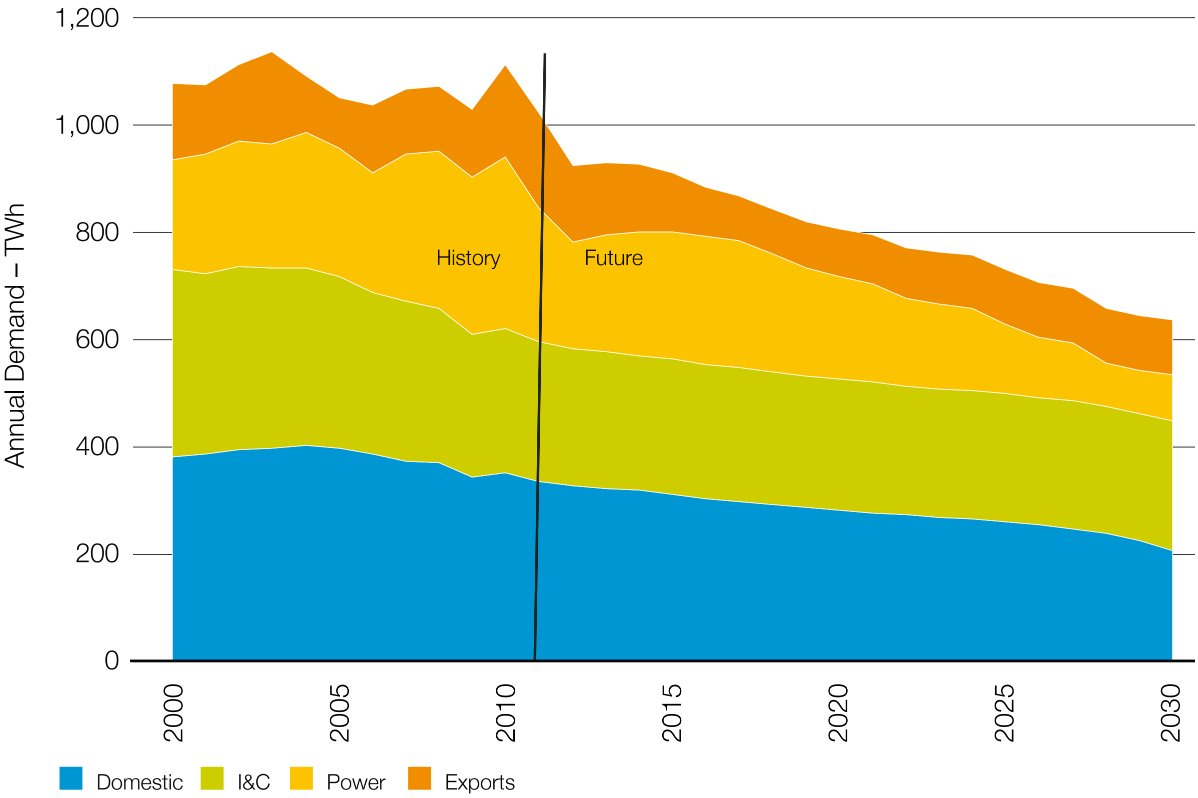
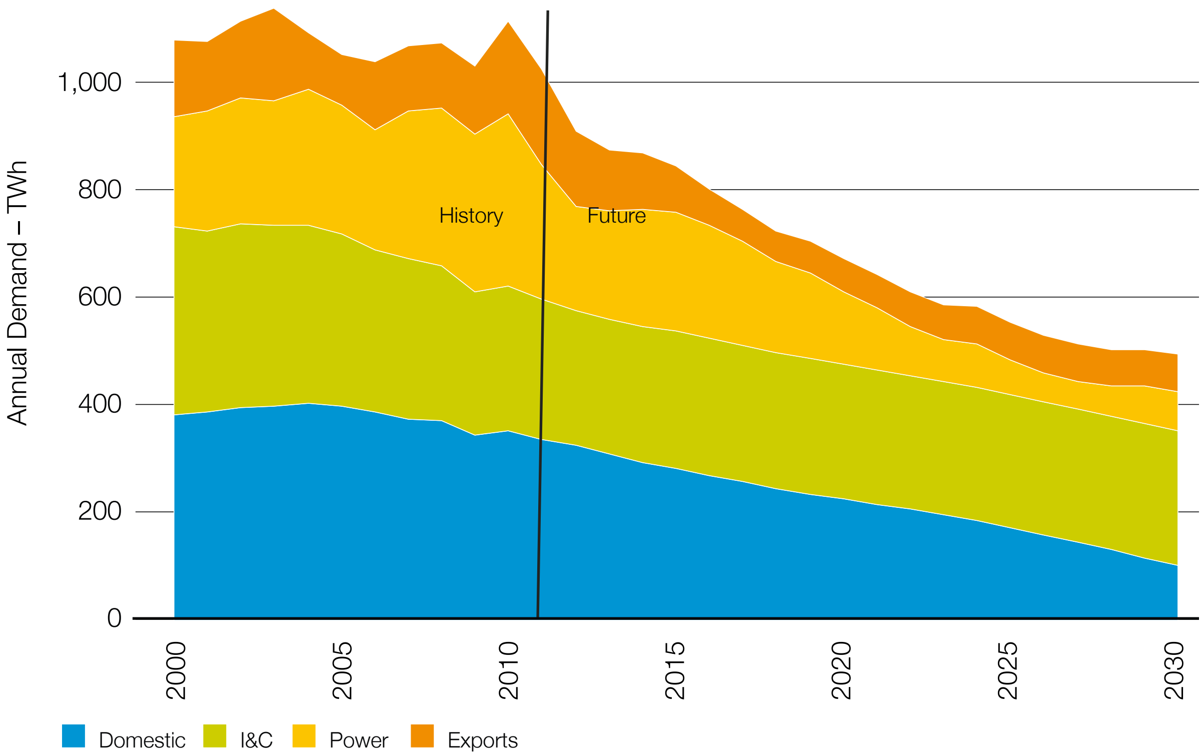


Figure 2.2C:
Annual gas demand scenarios including history – Accelerated Growth
Source: National Grid



2.2.2
Domestic demand

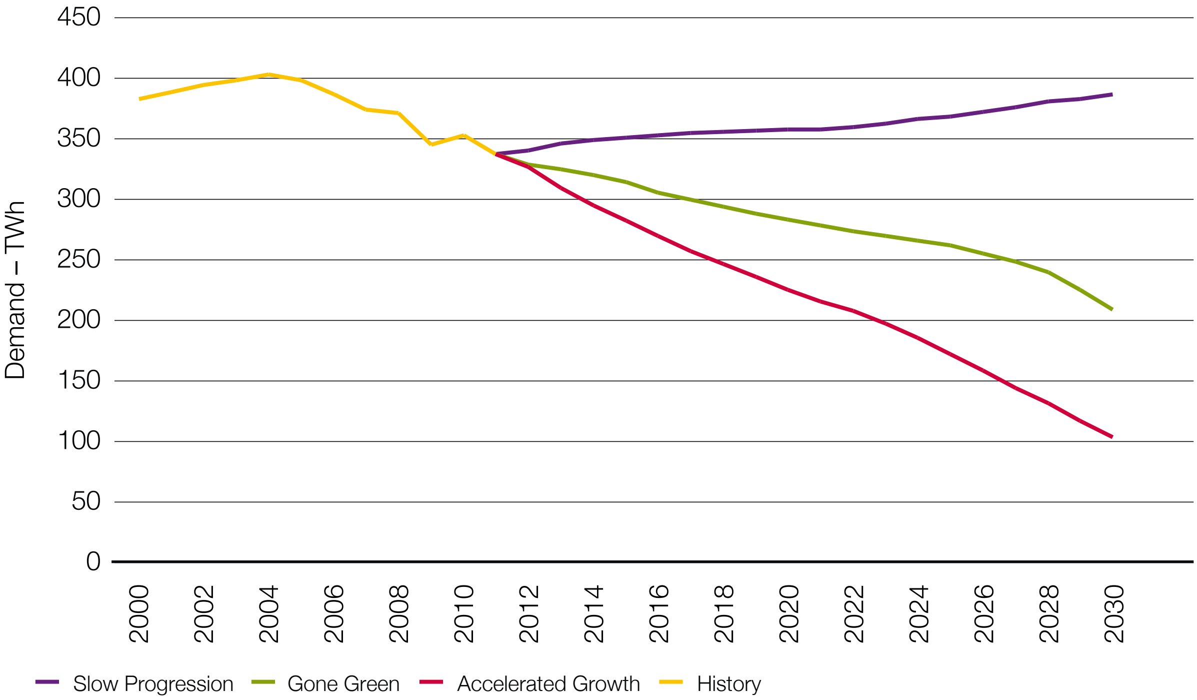
The changes in domestic gas demand are mainly due to the following:

- Behaviour change (comfort levels);
- Extra demand from new houses;
- Energy efficiency in the existing housing stock; and
- Heat pumps replacing gas boilers in the existing housing stock.

This is covered in further detail in section 3.4.2 of the Future Energy Scenarios document.

Figure 2.2D shows domestic gas demand in the context of history. After years of steady domestic gas demand growth, demand started decreasing from 2005, due to a combination of behaviour change and increasing energy efficiency in the sector. Slow Progression shows the effect of behaviour change slowly reverting to previous levels (with relatively small amounts of extra energy efficiency), whereas Accelerated Growth shows a continuation of the behaviour of lowering household temperatures combined with high levels of insulation. Gone Green lies between the other scenarios, with no behaviour change but relatively high levels of insulation. As previously mentioned, both Gone Green and Accelerated Growth have some electrification of houses currently heated by gas, with a material effect from mid / late 2020s. It is interesting to note that both Gone Green and Accelerated Growth have gas demands declining at rates similar to the historical decline of recent years.

Figure 2.2D:
Domestic gas demand in all three scenarios
Source: National Grid



2.2 continued
Demand

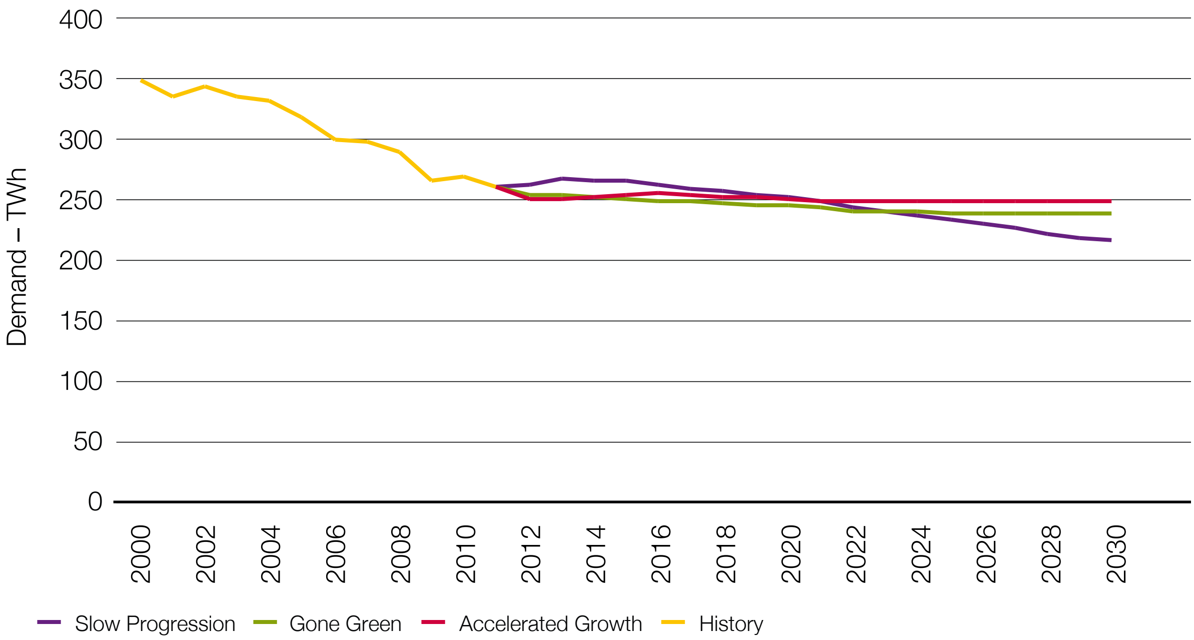
2.2.3
Industrial and commercial demand

This market sector has less variability between scenarios than other sectors for two reasons:

- Many elements of the sector have a particularly consistent gas demand – especially larger large loads; and
- The interaction of axioms pulling in opposite directions, reducing the variability between scenarios.

History shows a general steady decline in this sector. Certain large loads that reduce their demand or stop taking gas in Slow Progression do so due to lower views of the economy causing these sites to shut or reduce demand, whereas in Accelerated Growth other sites may shut due to higher fuel prices or a 'greener' economy enabling things such as gas to biomass conversion, some of which have been seen recently.

Figure 2.2E:
Industrial and commercial gas demand in all three scenarios
Source: National Grid



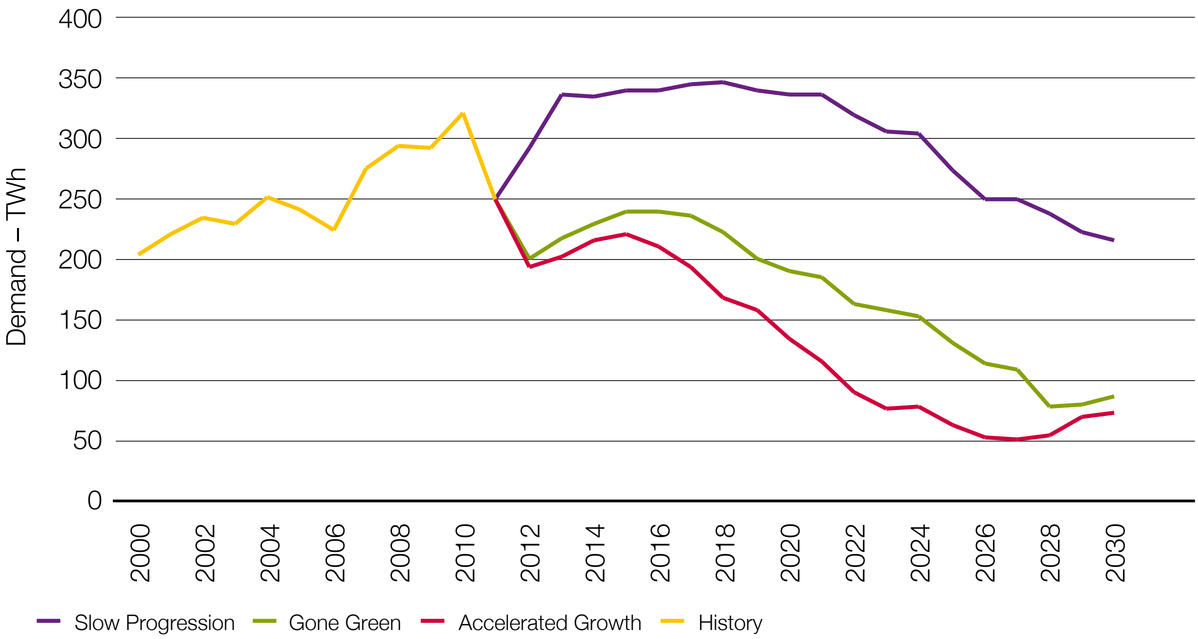
2.2.4
Power generation

In Slow Progression we expect power generation gas demand to increase strongly at first and then remain fairly flat to the early 2020s with new gas-fired power generation capacity offsetting the closure of coal and oil plants due to the Large Combustion Plant Directive. The abrupt increase in Slow Progression from current levels is due to pricing assumptions as set out in the axioms. There is less divergence between scenarios than may otherwise be expected, due to views of electrification of heat and transport in the latter part of the forecast period in Gone Green and Accelerated Growth.

From the mid-2020s, we anticipate that new nuclear capacity and gradually increasing renewable capacity and continental imports will start to reduce gas generation.

In Gone Green in the short term, we anticipate that gas demand in the power generation sector will increase slightly then remain fairly stable as new gas capacity completes commissioning while coal and oil plants close due to the Large Combustion Plant Directive. We expect that gas demand will fall steadily from around 2018 onwards in response to substantial offshore wind development and the first new nuclear station in the early 2020s, with the trend continuing out to 2030.

Figure 2.2F:
Power generation gas demand in all three scenarios
Source: National Grid



Demand

In Accelerated Growth we envisage that power generation gas demand will remain fairly stable for a few years as new gas capacity completes commissioning and thermal plant closes due to the Large Combustion Plant Directive, before declining from 2016 onwards with the closure of existing gas plants and significant increases in renewable generation, particularly offshore wind. We anticipate that the connection of new nuclear plants in the 2020s combined with further deployment of renewable generation will result in a significant decline in power station gas demand until the late 2020s when some new gas plants fitted with Carbon Capture and Storage (CCS) connect to the system.

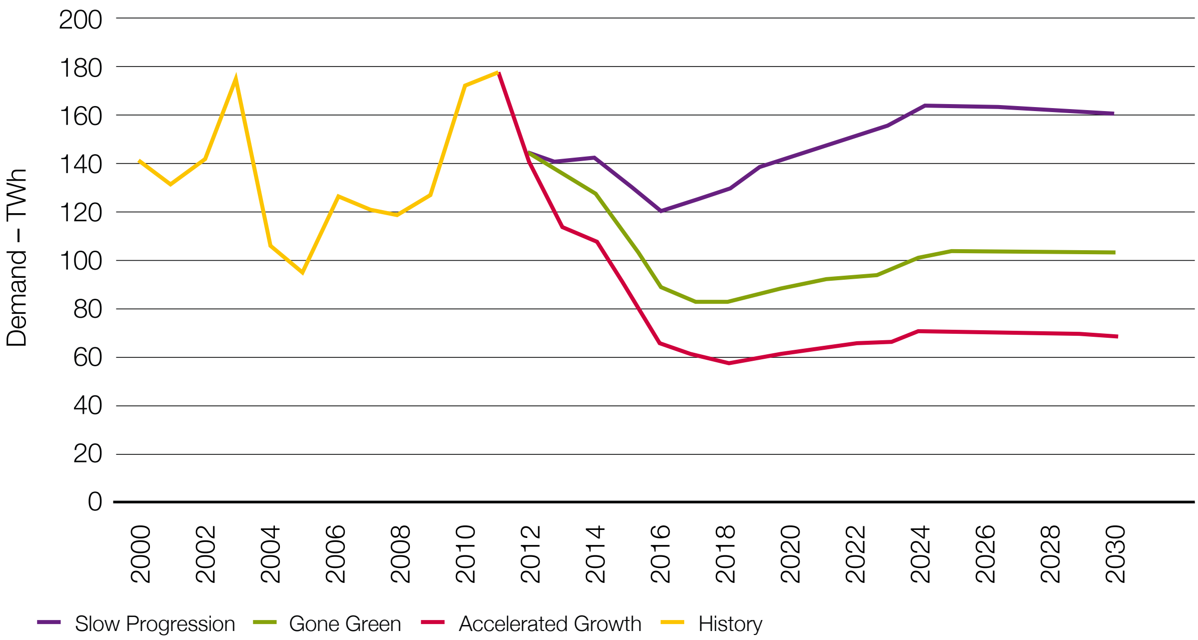
2.2.5
Exports

Gas is exported from the UK to Ireland and continental Europe.

The potential level of gas exports to Ireland is heavily influenced by the development of indigenous Irish gas supplies via the Corrib gas field, the prospects of future LNG imports and assumptions regarding Irish gas demand. For all three scenarios we assume similar Irish supplies namely gas production from Corrib post 2015/16, no development of the proposed Shannon LNG project and no new Irish storage projects. On the demand side we assume similar energy trends in Ireland to that in the UK for each scenario, hence Irish demand is essentially flat in Slow Progression, declines in Gone Green and significantly declines in Accelerated Growth.

Gas can flow in both directions between UK and the Continent through the Interconnector (IUK). IUK exports are higher in Slow Progression than in Gone Green which in turn is higher than Accelerated Growth. This is due to the assumptions regarding the overall supply availability to the UK from other supply sources. This is further described in Section 2.3.

Figure 2.2G:
Exports demand in all three scenarios
Source: National Grid



2.2.6
Peak gas demand

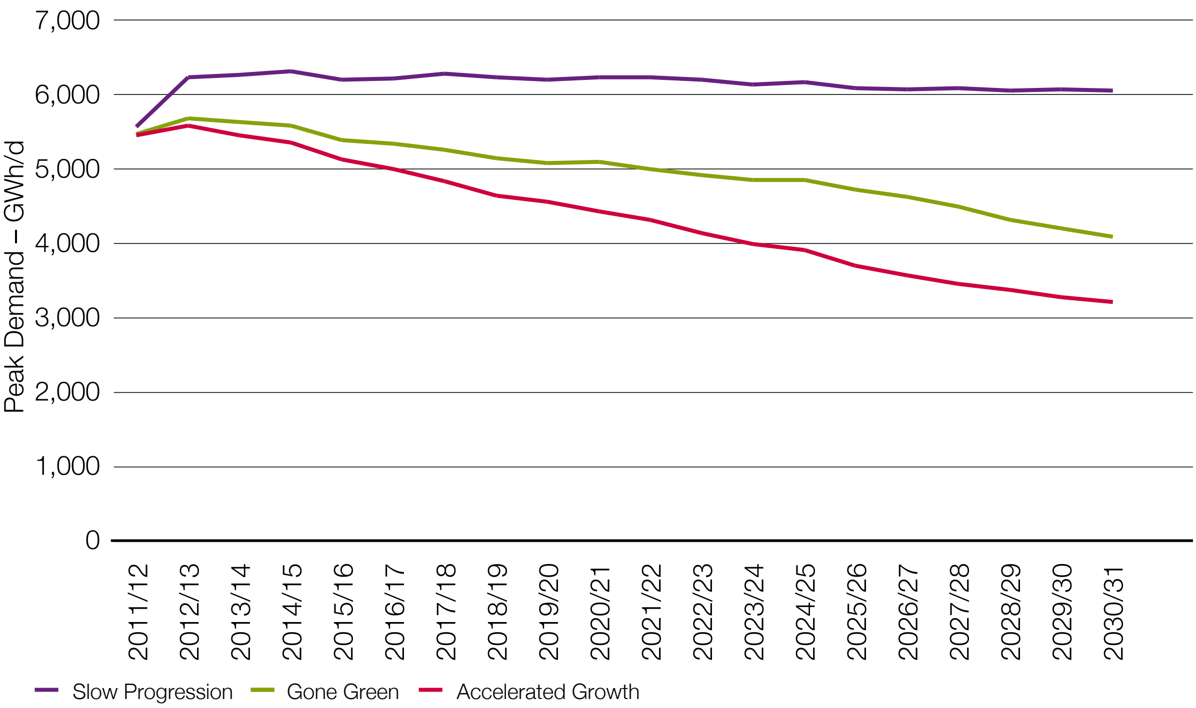
Peak gas demand is based on a historical relationship between daily demand and weather combined with the amount of gas-fired electricity generation expected on a peak day. This is via an established methodology detailed in the Gas Demand Forecasting Methodology document[15].

As a result our peak gas demand scenarios broadly align to our annual gas demand scenarios.

Figure 2.2H shows the peak demand for all three scenarios. The peak is higher in Slow Progression even in 2012/13, reflecting the axiom that states that in Slow Progression gas will be cheaper than coal, thereby favouring gas-fired power generation over coal-fired generation.

15 http://www.nationalgrid.com/uk/Gas/OperationalInfo/operationaldocuments/Gas+Demand+and+Supply+Forecasting+Methodology/

Figure 2.2H:
Peak gas demand in all three scenarios, GWh/d
Source: National Grid



The peak to annual relationship has gradually been changing over some years, with demand generally becoming more weather sensitive. This year we have made changes to the relationship in all our scenarios to reflect the changes that we have seen, particularly in the domestic sector.

Domestic annual gas demand has been reducing since 2004. While the peak demands have also been falling, they have not been decreasing as much as annual demand. The main reason for this is attributed to domestic behaviour change. As changes in energy costs and household disposable incomes have both made energy less affordable, people have consciously used heating less when possible. This manifests itself in a shorter heating period, as people have been resisting turning the heating on until later in the autumn/winter and have been turning it off earlier in the spring. Also, during the winter heating period, we have seen greater upturns in gas demand during particularly cold weather, than seen historically. Both of these factors lead to a notably more weather sensitive domestic gas demand.

The anticipated increased reliance of CCGT being used when wind generation is low is also likely to increase the 'peaky nature' of gas demand. This is accounted for in our scenarios as more wind generation is built and connected to the electricity system. In our scenarios, as low carbon generation increases, annual gas demand in the power sector reduces. Peak gas demand capacity however does not change at a commensurate rate due to the requirement for this capacity when variable generation is low.

The flexibility required to use gas generation at times of low wind generation is anticipated to be delivered from those supplies that are best placed to respond, notably gas storage and possibly also from Liquefied Natural Gas (LNG) imports, from gas held in LNG storage tanks, and through existing or modified gas interconnectors with the continent. A further consequence of more flexible / responsive supplies is the need for a gas network able to accommodate greater flow variations including those from one day to the next. This is further detailed in Sections 3 and 4.

2.3
Supply

2.3.1
Supply overview

National Grid's UK Future Energy Scenarios publication details the gas supply components behind all three scenarios – Slow Progression, Gone Green and Accelerated Growth. Rather than replicate this information, the supply section of the 2012 Ten Year Statement contains:

- Charts detailing annual supplies for the three demand scenarios (peak supply scenarios can be found in Appendix 2)
- Some background on the historic changes of gas supply
- Supplementary high-level analysis for gas supply sources
- A gas supply infrastructure update for Europe, UK imports and UK storage
- A longer-term UK security of supply assessment
- A summary of key axioms relating to gas supply can be found at the beginning of this chapter.

The following three charts (Figures 2.3A–C) show the annual supply scenarios for Slow Progression, Gone Green and Accelerated Growth. As detailed previously the basis for these is detailed in our UK Future Energy Scenarios document. Peak supply capability scenarios can be found in Appendix 2.

Figure 2.3A:
2012 annual supply – Slow Progression
Source: National Grid

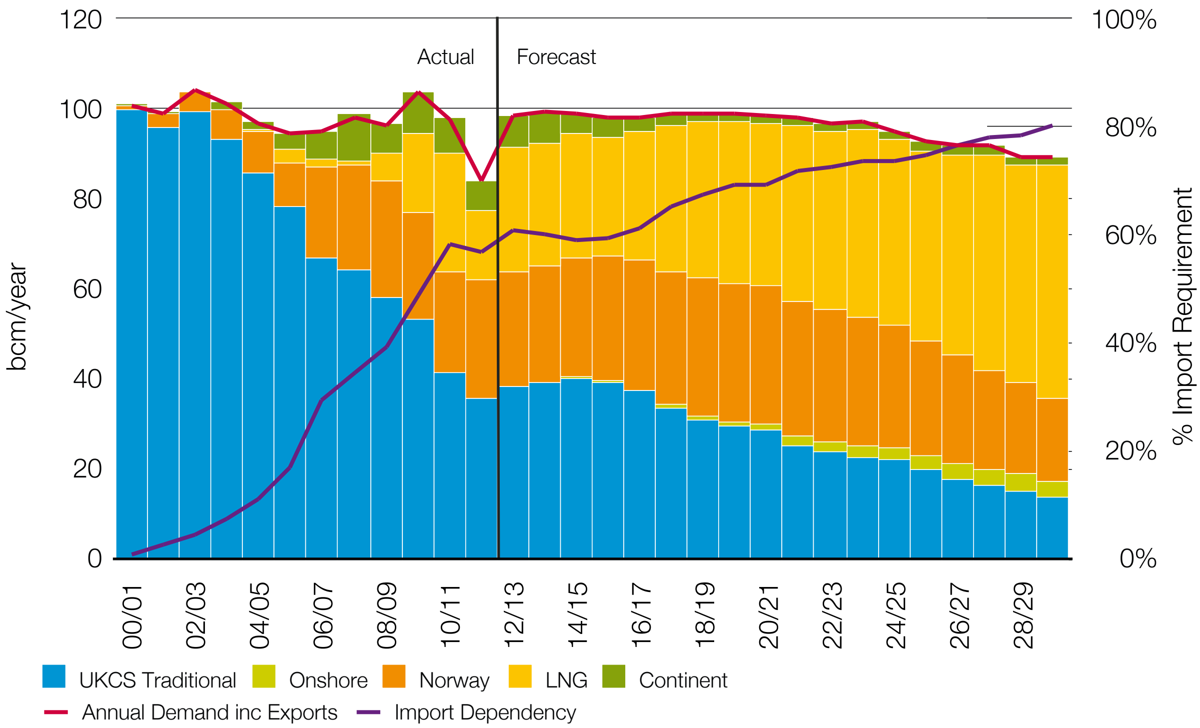


Figure 2.3B:
2012 annual supply – Gone Green
Source: National Grid

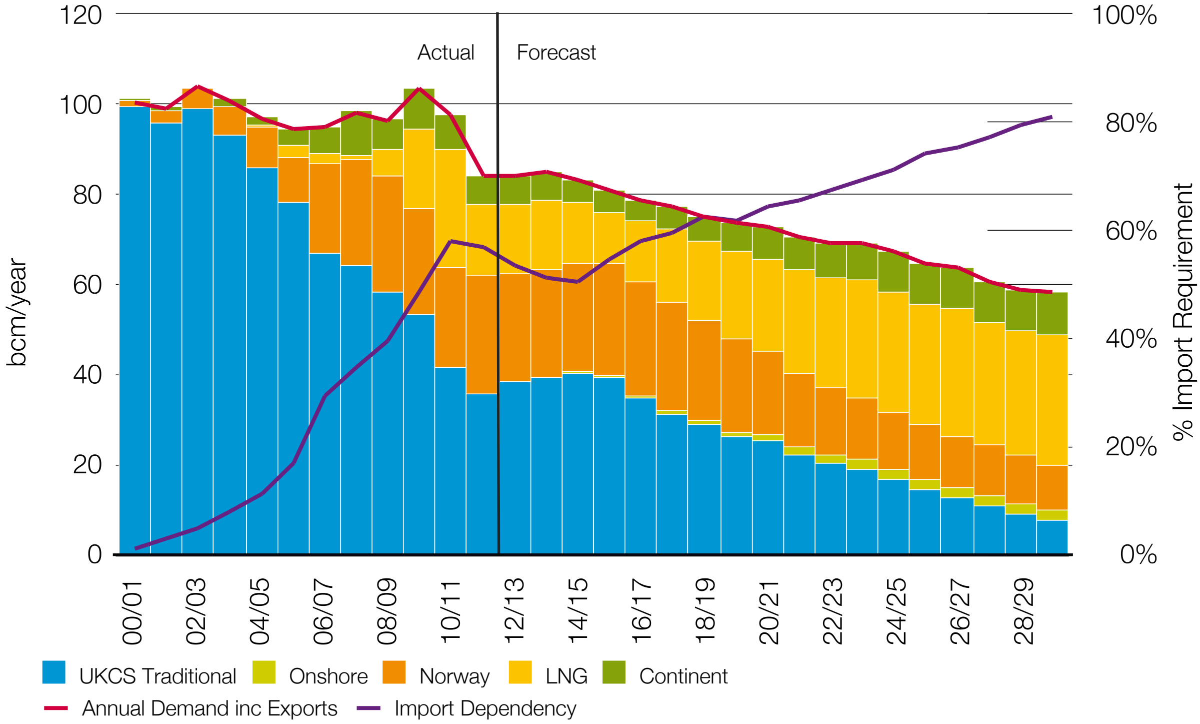
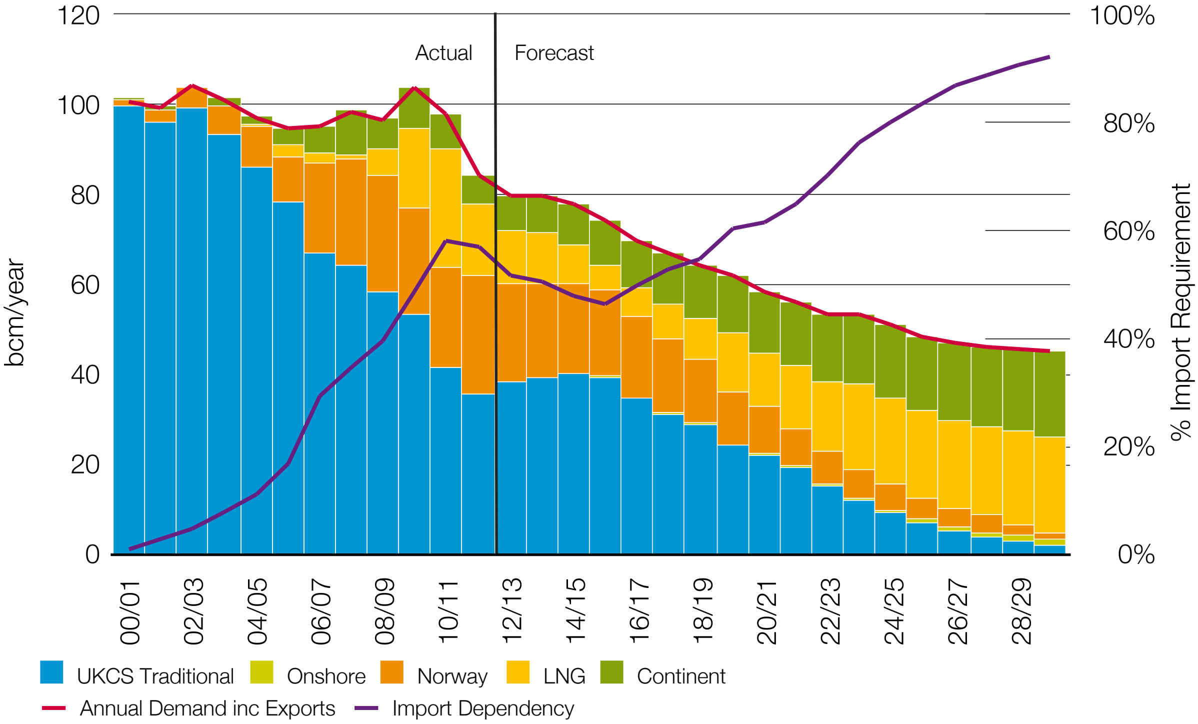


Figure 2.3C:
2012 annual supply – Accelerated Growth
Source: National Grid



16 Gas supplied to the NTS

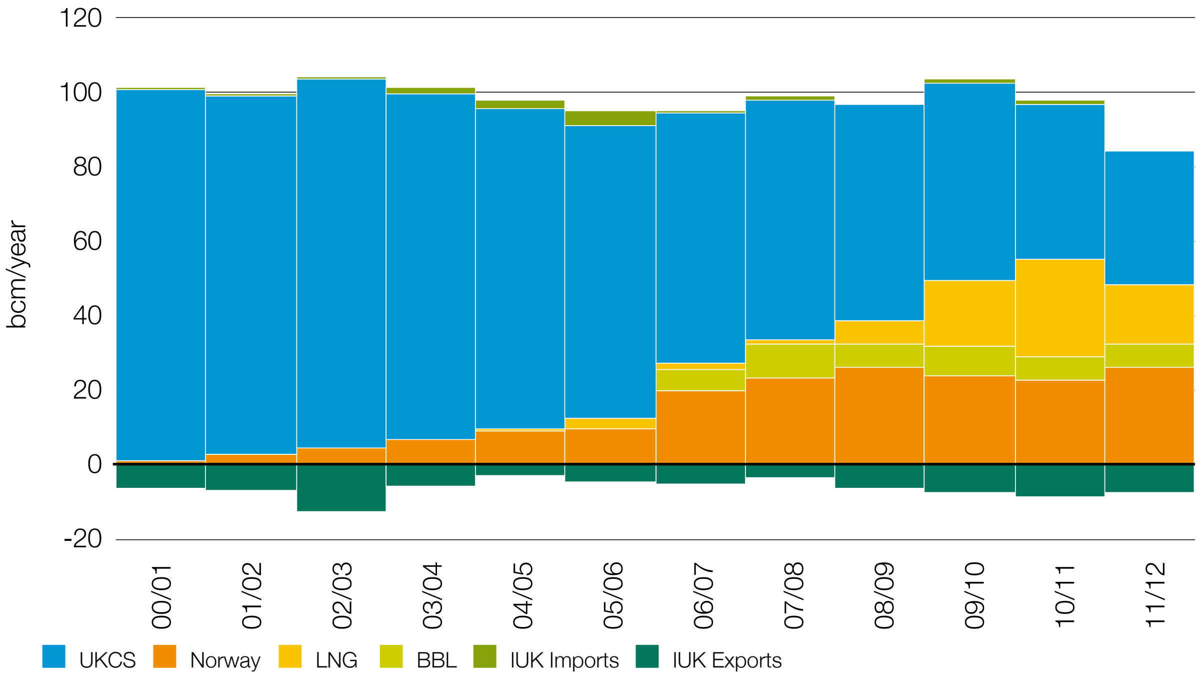
2.3.2
UK supplies since 2000

The changing nature of gas supplies to the UK since 2000 provides a good insight of how future supply patterns may develop. Until 2003/04 the UK was a net exporter of gas, since then the level of imports has progressively increased as UKCS supplies have declined. Besides the need for increased imports, recent history has provided a further understanding of the potential behaviour of imports and the interaction of international markets and global events; for example:

- The global influence of LNG supplies, notably through increased production and the recent experience of higher Asian demand
- The development of unconventional gas sources in the US
- The interaction of Norwegian gas supplies between the Continent and the UK
- The behaviour of the Interconnector (IUK) as a marginal supply source for the UK and Continental markets. Though not as obvious, the flow patterns through the BBL pipeline from the Netherlands have also been changing
- The impact of international events such as the Russia Ukraine dispute (European supplies), nuclear power plant outages in Japan (global LNG), and US hurricanes (pricing behaviour and Atlantic LNG).

Figure 2.3D below shows the changing mix of annual gas supplies to the UK[16] since 2000. The chart also shows exports through IUK.

Figure 2.3D:
Historic annual uk gas supplies and IUK exports
Source: National Grid



Supply

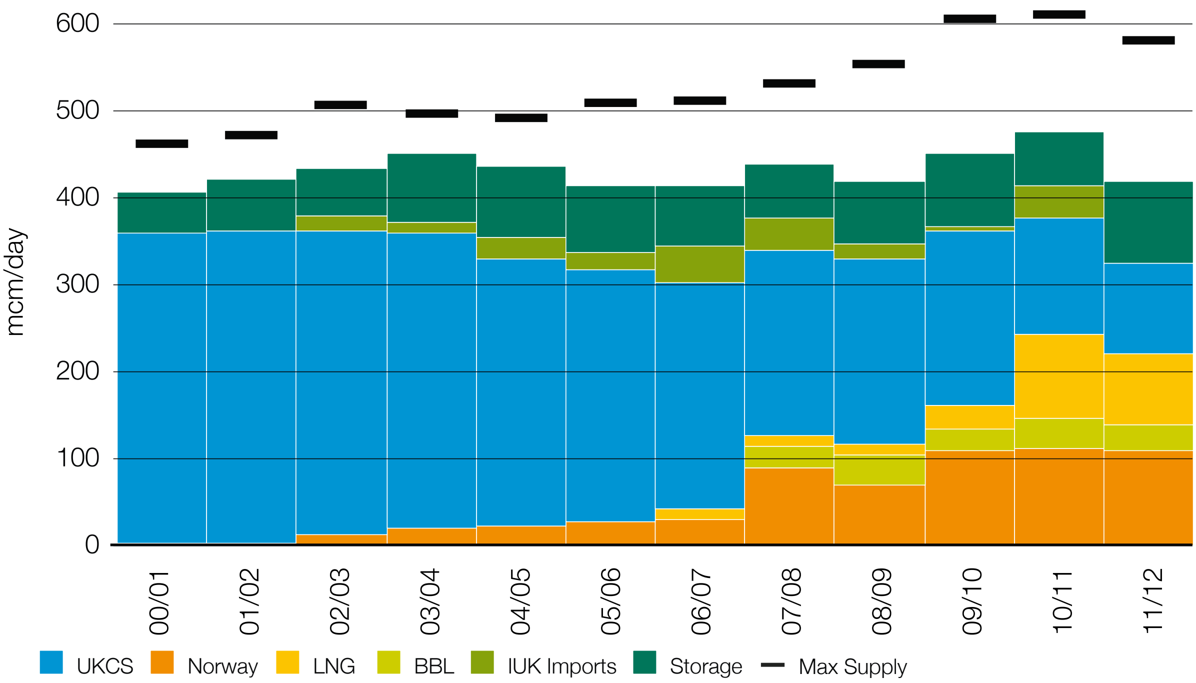
The chart highlights:

- UK self-sufficiency followed by the decline of UKCS production. UKCS represented 43% of NTS inputs in 2011/12 (41% in 2010/11)
- The increase in Norwegian gas supplies, notably post-2006/07 (Langeled)
- Imports through BBL from 2006/07
- Continued exports through the interconnector (IUK) despite increasing import dependency
- LNG imports commencing in 2004/05 (Grain 1), with further increases in 2008/09 (Grain 2), 2009/10 (South Hook 1 & 2 and Dragon[17]) and 2010/11 (Grain 3).

The make-up of supplies for the highest demand day for each winter since 2000 is shown in Figure 2.3E. This shows similar trends to Figure 2.3D, but also emphasises the contribution of storage and on occasion IUK import volumes. Also shown on the chart is the maximum supply, namely the aggregated peak flow from each terminal for UKCS, imports for each import pipeline, LNG facilities and all storage sites. This chart clearly shows how the level of maximum supply far exceeds the highest demand day and since the onset of increased import capacity in 2006/7, this level of supply has rapidly increased from about 500mcm/d to over 600mcm/d in 2010/11, marginally coming down to 580mcm/d in 2011/12 as a result of lower demand. This highlights the need for increased network capacity and operational flexibility to reflect the needs of available supply, rather than just peak day demand.

17 South Hook 1 and Dragon commissioned in gas supply year 2008/09 but after the winter

Figure 2.3E:
Historic peak gas supplies and IUK exports
Source: National Grid



2.3.3
UKCS

Historic data for 2011 shows the continued decline of UKCS gas reserves between 1997 and 2011. This has been driven by production levels that were greater than discovery rates and routine revisions to reported reserves. Since 2000, remaining reserves have been declining by ~7% per annum.

Figure 2.3F shows National Grid's Gone Green 2012 UKCS scenario and is broken down into supply components. The UKCS forecast for Slow Progression is slightly higher, Accelerated Growth is slightly lower.

Figure 2.3F:
UKCS scenario – Gone Green
Source National Grid

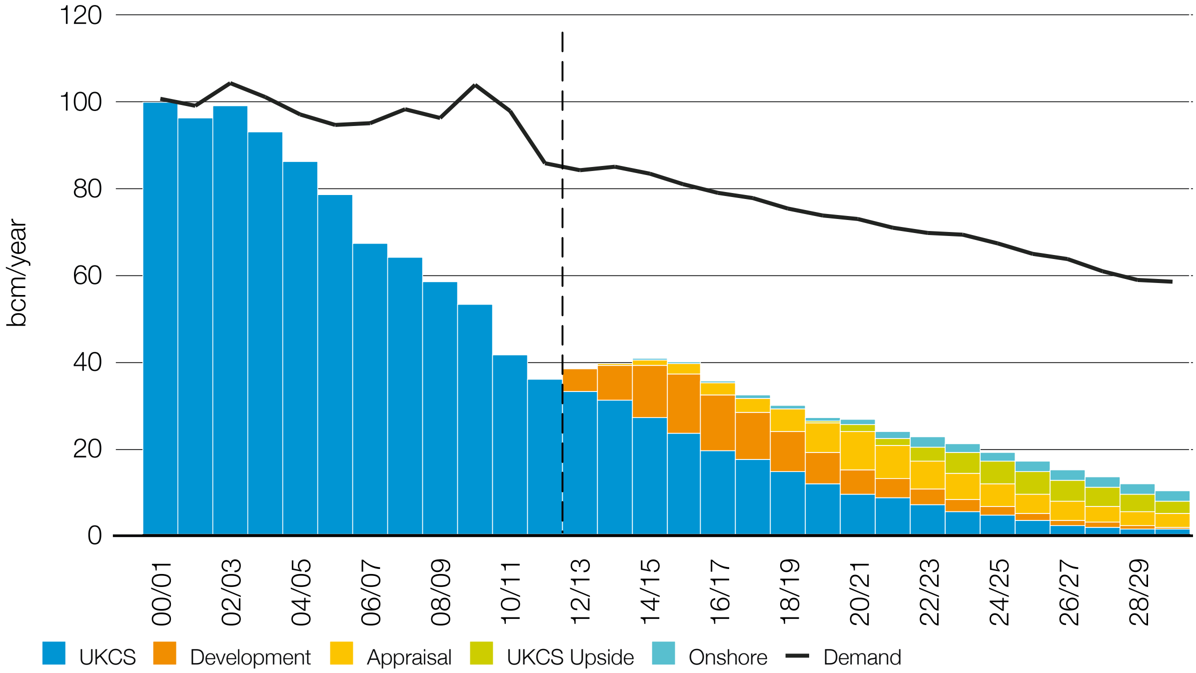
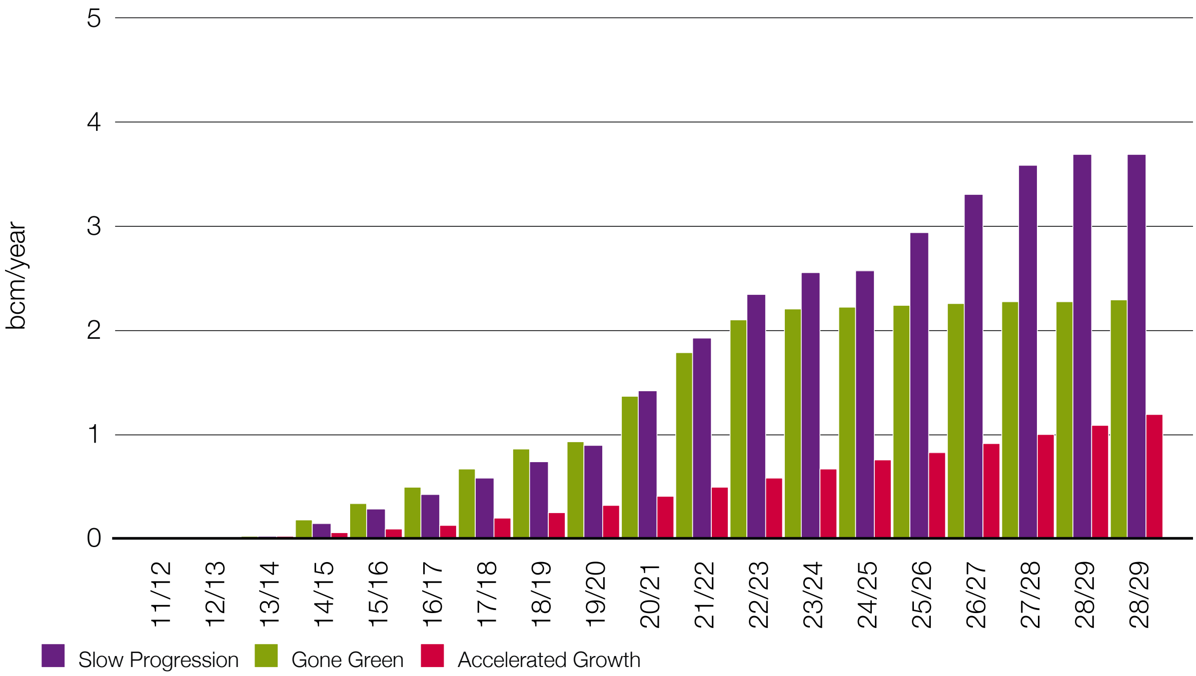


Figure 2.3F shows an increase in UKCS in supplies for the first time since 2002 with new fields such as Devenick at St Fergus and Jasmine at Teesside adding 2bcm in 2012/13. West of Shetland developments continue this trend post 2014/15. The chart also shows that fields currently producing will be mostly depleted by 2020/21, highlighting the importance of new field developments. By 2020/21, most gas may come from fields currently under development or being considered for development (appraisal). UKCS upside is an indication of what gas could come from fields that are not yet considered for development or from new discoveries.

Sustained high global prices for oil and gas have encouraged the global exploration and development of unconventional gas sources such as coal-bed methane (CBM) and shale gas, particularly in the US but also in other countries.

In the three scenarios the contribution that unconventional gas (including biogas) could make in the UK has been identified, these are shown in Figure 2.3G. These volumes are subject to considerable uncertainty, particularly the potential impact of shale gas.

Figure 2.3G:
2012 scenario contribution from unconventional gas
Source: National Grid



For each of the scenarios different assumptions are made for the development of unconventional gas sources, for example Slow Progression has a bias towards shale gas developments whilst Accelerated Growth includes more biogas.

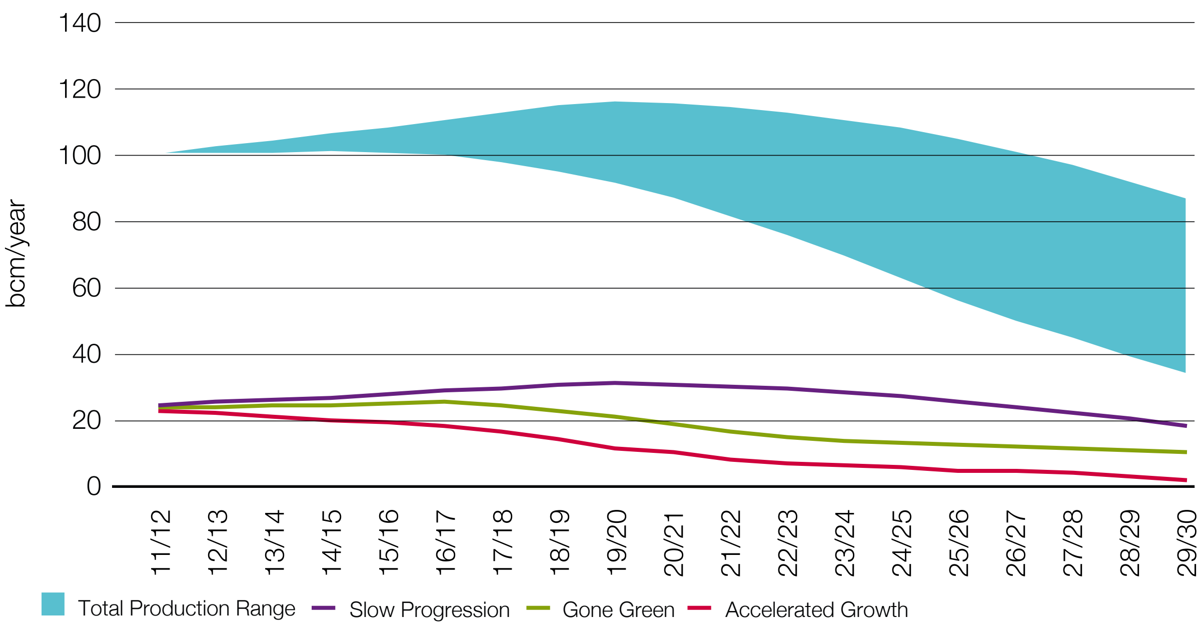
In the Gone Green and Slow Progression scenarios unconventional gas makes up 4% of UK demand by 2030. For Accelerated Growth the percentage of UK demand met by unconventional gas is 3% by 2030.

2.3.4
Norway

As detailed in the Future Energy Scenarios document each scenario has a separate assumption for Norwegian Continental Shelf (NCS) production and import levels to the UK. As described in the axioms earlier in this chapter the key driver behind this is market certainty and the resultant climate to invest in to provide long-term supplies. This in turn drives the level of development activity on the NCS which in turn determines the level of future production. Figure 2.3H shows the forecasts for Norwegian supplies to the UK along with the range of total Norwegian production across all three of the scenarios.

In Gone Green for the period until 2018/19 overall NCS production is maintained at current levels, imports to the UK grow as production increases at fields targeted to the UK. As production on the NCS starts to decline, priority is given to maintaining exports to the continent. As production on the NCS starts to decline priority is given to maintaining exports to the continent as a result of long term contracts. This results in a reduction in exports to the UK falling by about 10% pa until 2023/24 and ~5% for the remainder of the period. For Slow Progression exports to the UK increase steadily until 2020/21 driven by increasing NCS production, which sees the utilisation rates increase on the current pipelines. As with Gone Green the UK then experiences a more rapid rate of decline as Continental exports are prioritised. In Accelerated Growth overall production shows little growth and exports to the UK fall throughout the period.

Figure 2.3H:
Gone Green Norwegian imports to the UK



2.3.5
LNG

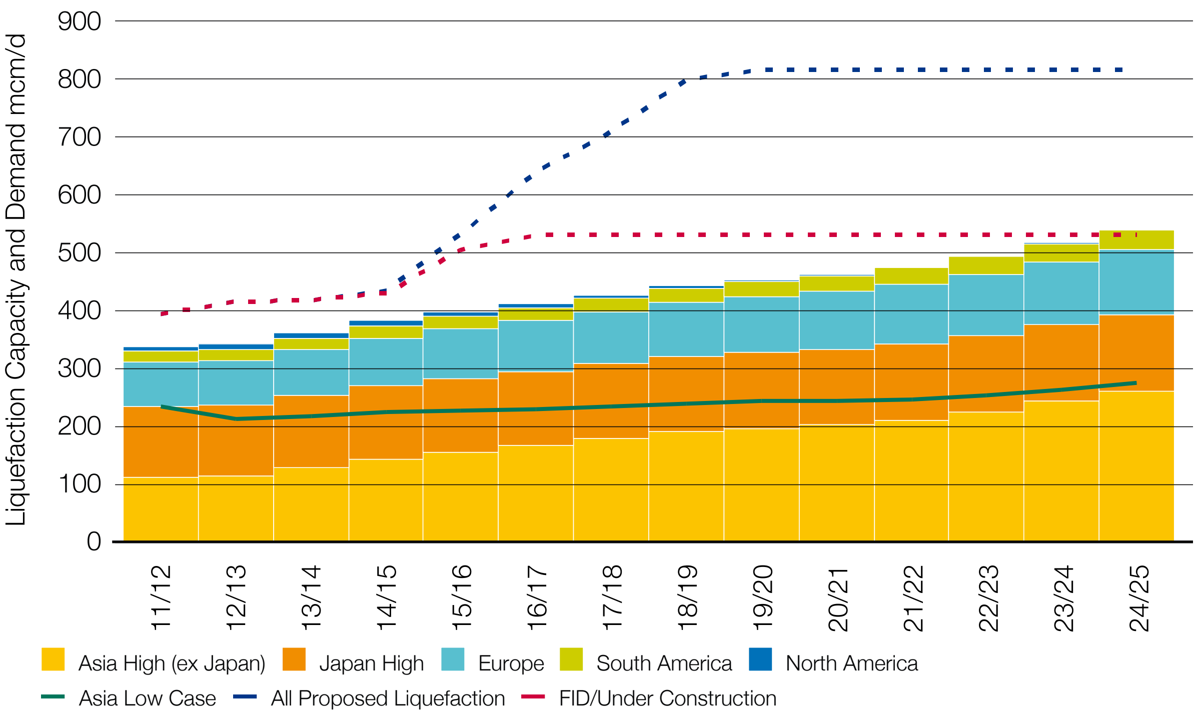
Global LNG trade continued to increase in 2011 reaching 331bcm compared with 297bcm in 2010. Japanese imports rose from 93bcm in 2010 to 107bcm in 2011 as nuclear generation was taken offline following the Fukushima incident in March 2011. Further increases in LNG demand came from South Korea, India and China. Overall volumes to Europe remained broadly the same in 2011 as 2010, but 2012 has so far seen declining volumes to some European countries as demand in Asia rose.

In 2011 the UK overtook Spain and became the largest LNG importer in Europe, but during the first half of 2012 Spain imported more LNG than the UK.

Figure 2.3I shows projected global supply and demand to 2024/25. Demand is split by region, with the main growth markets being Asia and Europe.

Figure 2.3I shows no new liquefaction capability after 2019, reflecting the information currently available. In reality some of the projects under construction and proposed may slip, and it is highly unlikely that all proposed projects will be built, hence the FID (Final Investment Decision) /

Figure 2.3I:
Projected global supply and demand of LNG
Source: National Grid, LNG journal, OIES[18], Various



18 Oxford Institute for Energy Studies

2.3 continued
Supply

Under Construction line shows our current best view of such projects. Beyond 2019 further new developments are expect to proceed.

Figure 2.3I also shows that there is very little new liquefaction capacity expected in the next few years before numerous developments post 2016 (primarily Australian). The red line shows capacity at 100%, and therefore the actual production may be lower than this. With global LNG demand rising, the market for LNG may therefore become increasingly tight before new production is brought on stream. Under these conditions those markets that rely on spot or non-contracted supplies (including the UK) may have difficulty in attracting LNG unless 'global market prices' are paid.

There are still a significant amount of known projects awaiting a Final Investment Decision, including many of those in the US waiting for approval to export LNG. The Sabine Pass liquefaction project was approved in 2012, and could come online in 2015. The commencement of US LNG exports, essentially some of the surplus of indigenous (unconventional) production, could have a market impact both in the US and globally with the potential to create higher US gas prices and increased LNG trade.

New LNG production facilities are expected in Algeria and Indonesia over the next two years, with a surge in new production in Australia due to be commissioned in or after 2016.

In terms of global demand, China remains the key uncertainty going forward. The uncertainty surrounds factors such as economic growth, volume of pipeline imports and domestic shale production.

The Japanese LNG market may grow with an increase in gas-fired generation following Fukushima; units currently under construction are expected to be commissioned over the next few years.

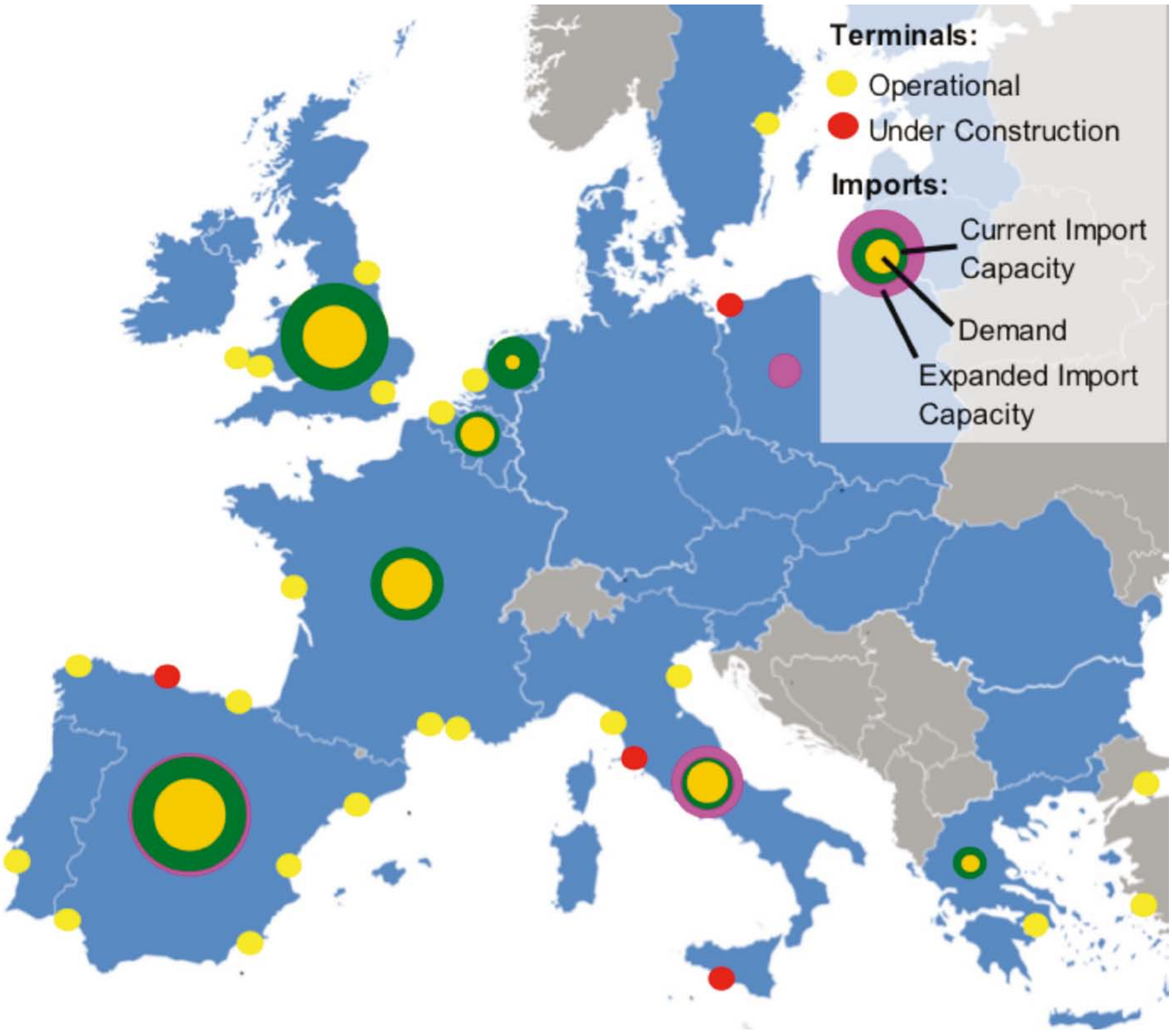
Figure 2.3J shows a map of the completed and under-construction LNG terminals in Europe. The chart also shows, as represented by the areas of the coloured circles for each country (not the diameters), the LNG imports and import capacity for the 12 months to August 2012.

Recent developments in European LNG importation include the completion of work at Milford Haven to increase import capacity and a fourth tank at the Sagunto LNG terminal in Spain. In addition, the Fos Cavaou LNG plant in France began offering a reload service in 2012.

The Polish Polskie LNG facility is currently under construction. This will have a capacity of ~5bcm per year and is expected to be commissioned in 2014.

Commissioning of the El Musel plant in Spain has been postponed and the project has been put into hibernation.

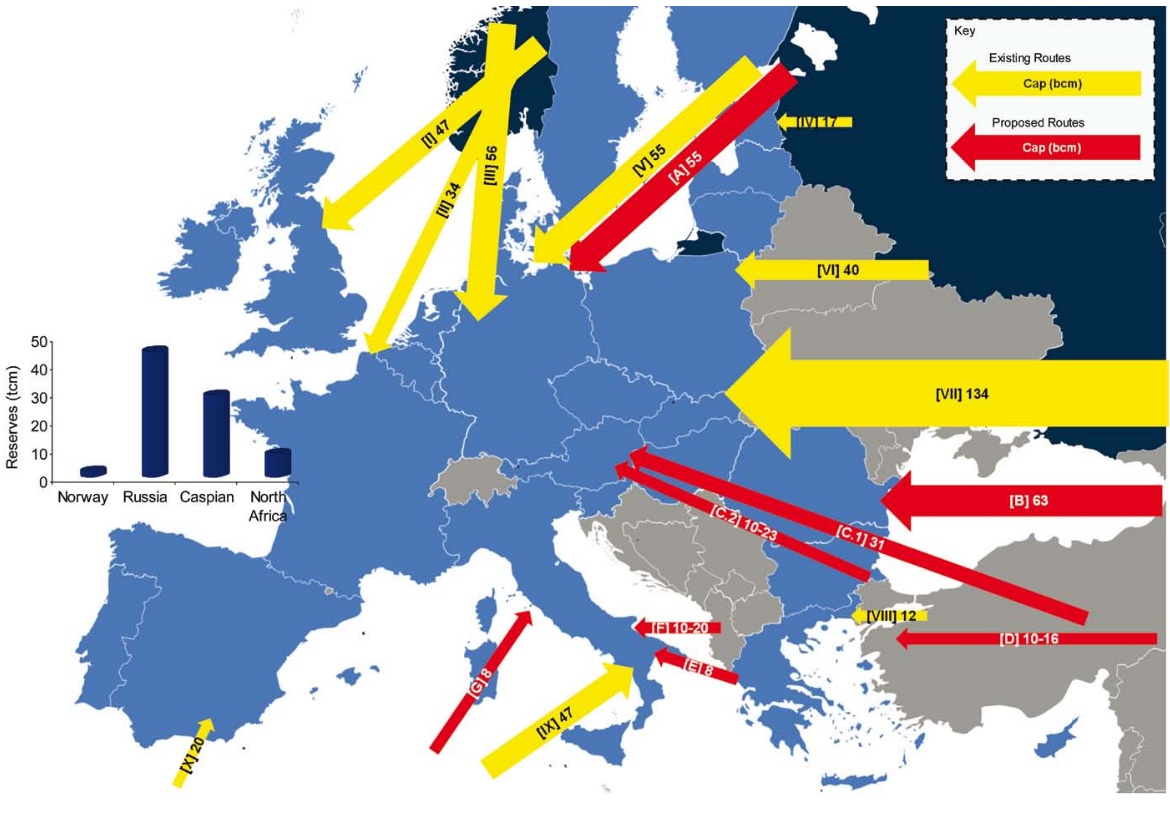
Figure 2.3J:
European LNG terminals, imports and capacity
Source: National Grid, ENTSO-G, Platts, Lloyds List, Various



2.3.6
European pipeline and LNG infrastructure

Excluding indigenous supplies and LNG imports, the European Union has three major sources of supply: Russian/Central Asian supplies from the East, North African from the South and Norwegian from the North West. Figure 2.3K highlights existing and proposed pipeline capacities from these sources.

Figure 2.3K:
European pipeline map
Source: National Grid, Wood Mackenzie, IEA, Gassco, Various[19]



19 Where available the project developer/operator website is used as the source for the capacity and route

20 Where available the project developer/operator website is used as the source for the capacity and route

Table 2.3A:
Capacity of existing routes[20]

Code	Name	Source	Capacity (bcm)	Route
I	Langeled/Vesterled/FLAGS	Norway	47	Norway–UK
II	Franpipe/Zeepipe	Norway	34	Norway–France/Belgium
III	Europipe/Norpipe	Norway	56	Norway–Germany/ Netherlands
IV	Russia–Finland/Baltics	Russia	17	Russia–Finland/Estonia/ Latvia
V	Nordstream I/II	Russia	55	Russia–Germany
VI	Yamal–Europe	Russia	40	Russia–Poland/Lithuania
VII	Brotherhood/Soyuz	Russia	134	Russia/Ukraine–Slovakia/ Hungary/Poland/Romania
VIII	ITG	Caspian	12	Turkey–Greece
IX	Greenstream/Transmed	North Africa	47	Algeria/Tunisia/Libya–Italy
X	Maghreb/Medgaz	North Africa	20	Algeria–Spain

Table 3.3B:
Capacity of proposed projects[20]

Code	Name	Source	Capacity (bcm)	Route	FID
A	Nord Stream III/IV	Russia	55	Russia–Germany	No
B	South Stream	Russia	63	Russia–Bulgaria–Austria/Italy	No
C	Nabucco	Caspian/Middle East	31	Turkey (E)–Austria	No
C.2	Nabucco West	Caspian	10–23	Turkey (W)–Austria	No
D	TANAP	Caspian	10–16	Azerbajian/Georgia–Turkey	No
E	IGI Poseidon	Caspian/Middle East	8	Greece–Italy	No
F	TAP	Caspian/Middle East	10–20	Albania–Italy	No
G	Galsi	North Africa	8	Algeria–Italy	No

2.3 continued
Supply

In order for the proposed projects to be realised there are significant hurdles to be overcome such as access to the required capital, approval from the relevant authorities, access to gas supplies, uncertainty over end user demand along with the technical challenges of the project. If all the projects were to be completed they could add over 200bcm extra import capacity to the EU.

In addition to the importation projects there are also several projects aimed at increasing the level of interconnection across Europe in order to increase security of supply and to aid the development of the internal energy market. To support these goals the European Commission has allocated over €9bn of funding through the "Connecting Europe[21]" initiative to energy infrastructure projects.

2.3.7
UK importation projects

Since late 2010 two import projects (both expansions) have been completed: the BBL pipeline and the third phase of expansion at Grain.

There are proposals for further import projects, but currently there are no importation projects under construction. The UK's import capacity is currently 153bcm/y, this is split into three near equal sources: the Continent (46.4bcm/y), Norway (53.7[22]bcm/y) and LNG (53.1bcm/y). The UK is served through a diverse set of import routes from Norway, Holland, Belgium and from other international sources through the LNG importation terminals.

Table 2.3C shows completed UK import projects and Table 2.3D shows proposals for further import projects.

Please note Tables 2.3A–2.3D represent the latest information available to National Grid at time of going to press. Developers are welcome to contact us to add or revise this data.

21 Connecting Europe http://ec.europa.eu/news/energy/111019_en.htm
22 Norwegian import capacity through Tampen and Gjøa is limited by available capacity in the UK FLAGS pipeline

23 Adjusted for UK standard conditions. Value reported on interconnector.com is 25.5bcm/y at normal conditions
24 Adjusted for UK CV and standard conditions; bblcompany.com report 20.6GWh/h at CV of 35.17MJ/m3 (normal).
25 This list is by no means exhaustive, other import projects have at times been detailed in the press.
26 Final Investment Decision

Table 2.3C:
Existing UK import infrastructure
Source: National Grid

Project	Operator / Developer	Type	Location	Capacity (bcm/y)
Interconnector	IUK	Pipeline	Bacton	26.9[23]
BBL Pipeline	BBL Company	Pipeline	Bacton	19.5[24]
Isle of Grain 1–3	Isle of Grain LNG	LNG	Isle of Grain	20.4
GasPort	Excelerate	LNG	Teesside	4.1
South Hook 1–2	Qatar Petroleum and ExxonMobil	LNG	Milford Haven	21.0
Dragon 1	BG Group / Petronas	LNG	Milford Haven	7.6
Langeled	Gassco	Pipeline	Easington	25.3
Vesterled	Gassco	Pipeline	St Fergus	13.1
Tampen	Gassco	Pipeline	St Fergus	9.1
Gjøa Gas Pipeline	Gassco	Pipeline	St Fergus	6.2
			Total	**153**

Table 2.3D:
Proposed UK import projects[25]
Source: National Grid

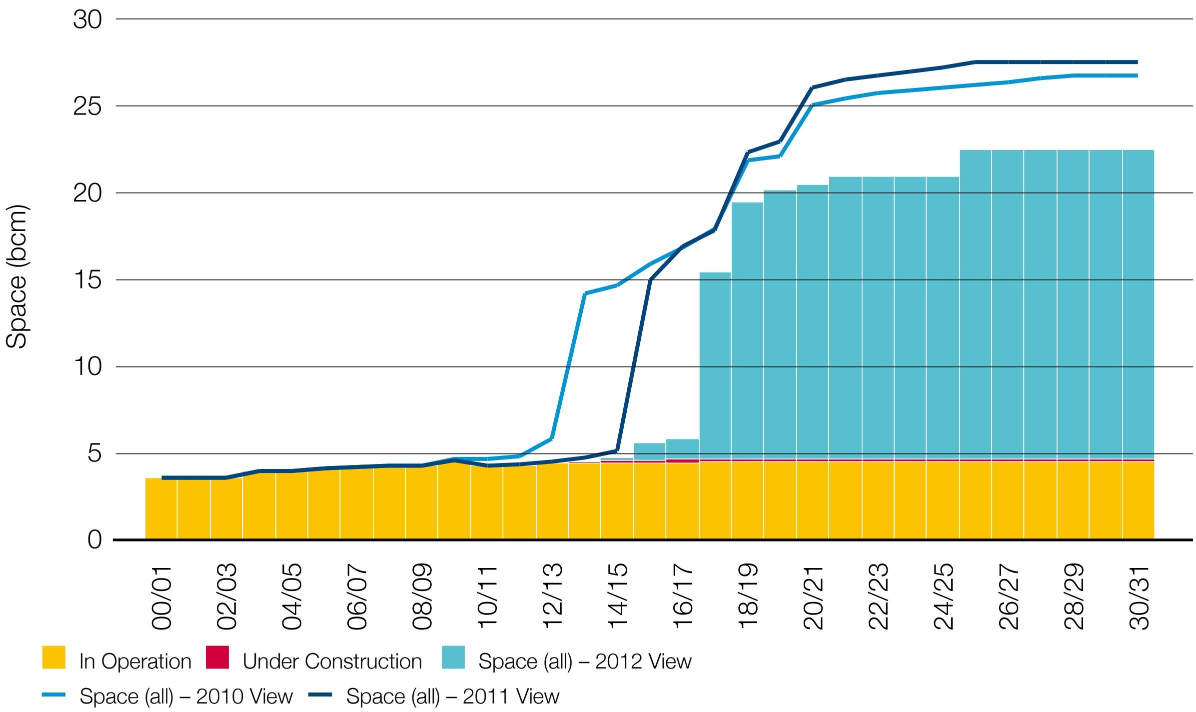
Project	Operator / Developer	Type	Location	Date	Capacity (bcm/y)	Status
Possible Dragon 2	BG Group / Petronas	LNG	Milford Haven	No current plans	Various expansion alternatives possible	Some consents granted as part of Dragon 1
Isle of Grain 4	National Grid	LNG	Isle of Grain	–	–	Open Season
Norsea LNG	ConocoPhillips	LNG	Teesside	–	~22	Planning granted, no FID[26]
Port Meridian	Hoegh LNG	LNG	Barrow	2016+	5	Planning granted, no FID
Amlwch	Halite Energy	LNG	Anglesey	TBD	~30	Approved onshore
				Total	**50+**	

2.3.8
UK storage developments

Figure 2.3L shows historic storage levels, the current status of potential storage developments in the UK and views (at the time) of storage developments since 2010. Despite numerous proposals for new developments, actual storage space has only increased by around 1bcm in the last 10 years to a present level of around 4.6bcm.

Deliverability between 2000 and 2010 has broadly remained the same at about 100mcm/d with the closures of Dynevor Arms (2009) and Partington (2011) being offset by developments at Hole House Farm, Humbly Grove and Aldbrough. Recent increases in deliverability have come from expansion at Aldbrough, the start-up of Holford and the anticipated start-up of Hill Top Farm during 2012/13. The expected start-up of Stublach in 2013/14 will on completion of all facilities under construction or expansion increase storage deliverability to a name plate capacity of about 200mcm/d. Any subsequent increase in storage space or deliverability will be from developments not yet under construction or from further enhancements at existing facilities.

Figure 2.3L:
Potential UK storage developments
Source: National Grid



The chart shows developers' views of storage developments (at the time) since 2010. These show a general trend of slippage of many projects from year to year. While many salt cavern projects are proposed, the space in the chart includes around 11bcm of proposed offshore field developments; none of these have yet received a Final Investment Decision.

Our Slow Progression Scenario includes extra seasonal storage to accommodate for high imports. Gone Green does not include any extra seasonal storage, but does include fast cycle storage to provide additional flexibility. The Accelerated Growth scenario assumes only existing and under construction developments.

To avoid being site specific, generic storage sites have been used for network planning, to allow one site to be substituted for another. For network investment purposes the proposed storage sites are evaluated on a site-by-site basis or are assessed collectively alongside demand sensitivities such as wind variability.

2.3 continued
Supply

2.3.9
UK storage projects

In the last 12 months no proposals have attained a Final Investment Decision for subsequent construction. The following tables detail UK storage in terms of existing storage sites, those under construction and proposed sites.

Please note, due to operational considerations, the space and deliverability may not be fully consistent with that used for operational planning as reported in our 2012 Winter Outlook Report.

A number of storage projects below have planning permission. Since last year's Ten Year Statement the White Hill storage project has gained planning consents.

Please note Tables 2.3E–2.3G represent the latest information available to National Grid at time of going to press. Developers are welcome to contact us to add or revise this data.

27 Access to full space is dependent on the operations regime of the facility and will increase to this figure over the first few years of operation
28 Represents final deliverability when fully complete
29 Represents final deliverability when fully complete

Table 2.3E:
Existing UK storage
Source: National Grid

Project	Operator	Location	Space (bcm)	Approximate maximum delivery (mcm/d)
Rough	Centrica Storage	Southern North Sea	3.3	41
Aldbrough I	SSE / Statoil	Yorkshire	0.3[27]	40[28]
Hatfield Moor	Scottish Power	Yorkshire	0.1	2
Holehouse Farm	EDF Trading	Cheshire	0.05	11
Holford	E.ON	Cheshire	0.2	22[29]
Hornsea	SSE	Yorkshire	0.3	18
Humbly Grove	Star Energy	Hampshire	0.3	7
LNG Storage	National Grid LNGS	Avonmouth	0.08	13
		Total	**4.6**	**154**

30 Represents completed space (fully available from 2017)
31 Data represents all phases. Phase 1 expected 2013/14, Phase 2 is currently undecided.
32 This list is in no way exhaustive, other storage projects at times have been detailed in the press
33 In some cases not all consents may have been secured

Table 2.3F:
Storage under construction
Source: National Grid

Project	Operator	Location	Space (bcm)	Deliverability (mcm/d)	Planned Start up
Hill Top Farm[30]	EDF Energy	Cheshire	0.1	15	2012/13
Stublach[31]	Storengy UK	Cheshire	0.4	30	2013/14
		Total	**0.5**	**45**	

Table 2.3G:
Proposed storage[32]
Source: National Grid

Storage Project	Operator	Location	Space (bcm)	Status[33]
Aldbrough II	SSE / Statoil	Yorkshire	0.3	Planning granted. No FID, under review
Baird	Centrica / Perenco	Offshore Bacton	1.7	Planning granted, No FID
Caythorpe	Centrica	East Yorkshire	0.2	Planning granted, No FID
Deborah	Eni	Offshore Bacton	4.6	Planning granted, No FID
Esmond	Encore Oil	Offshore Bacton	4	Conceptual
Hatfield West	Scottish Power	Yorkshire	0.04	Planning stage
Gateway Storage	Stag Energy	Irish Sea offshore Barrow	1.5	Planning granted, No FID
Islandmagee	InfraStrata & Mutual Energy	Northern Ireland	0.5	Storage licence granted
King Street	King Street Energy	Cheshire	0.3	Planning granted, No FID
Portland	Portland Gas Ltd	Dorset	1.0	Planning granted, No FID
Preesall	Halite Energy	Fleetwood	0.6	Planning Inspectorate decision due in 2013
Saltfleetby	Wingaz	Lancashire	0.7	Planning granted, No FID
Whitehill	E.ON	Yorkshire	0.4	Planning granted, No FID
		Total	**16**	

2.4
Security of supply

This year's security of supply analysis focuses on the impact of increasing within-day variations in gas-fired power station demand, driven by a combination of increasing volumes of wind generation being connected to the electricity transmission system and closures of coal-fired plant.

A model has been developed that allows an hourly electricity demand and generation match to be created for any year from the present out to 2030/31. The model uses the 2012 Slow Progression, Gone Green and Accelerated Growth power generation capacity assumptions, but for brevity only Gone Green is used in the analysis shown here. The hourly electricity demand profile for calendar year 2011 is then pro-rated in line with the 2012 Gone Green annual electricity demand assumptions to enable an electricity demand/generation match to be achieved.

For the analysis shown here the model only considers the electricity system. The model enables an electricity generation dispatch solution to be undertaken at a fuel type level, including ensuring there is sufficient reserve for frequency response and operating reserve.

There is a constraint to the limit of total generation available from wind generation and interconnector imports, as a proportion of national demand, as well as limits on part loading of plant to provide reserve and the volume of frequency response varies according to electricity demand levels.

The plant is dispatched in a predetermined order, by fuel type and the resultant hourly generation from gas-fired plant is converted into an hourly gas demand. This then enables a review to be undertaken of within-day gas demand swing driven by variations in CCGT power generation. As the relative position of gas and coal-fired plant in the generation merit order will have a major impact on the gas demand for CCGTs, two cases were considered:

- **Gas case:** gas-fired generation is scheduled on before coal, with gas plant flexing throughout the day and coal acting as the marginal plant.
- **Coal case:** Coal-fired generation is scheduled on before gas, with coal plant providing within-day flexibility and gas as the marginal plant.

Rather than show results for all 365 days of any chosen year out to 2030/31, a single day is chosen showing the highest within-day gas demand swing for each case. The years illustrated in Figures 2.4A–C are 2012/13, 2020/21 and 2030/31. The results are shown in terms of the hourly electricity demand and generation match. In addition, variations in power generation gas demand are shown in terms of resultant changes in linepack on the gas system. The model currently assumes gas supplies are steady across the day. In reality, as Chapter 3 illustrates, gas supplies are increasingly volatile and unpredictable, with an increase in within-day supply profiling. Hence linepack changes could be considerably larger than those shown here because of factors not included in the modelling. Therefore the variations in linepack shown here should not be viewed as an absolute maximum, but rather as an indicator of the potential impact of changes in the generation mix.

It is important to note that the maximum within-day gas swing occurs on different days for the two cases, due to the relative levels of gas and coal generation and variations in the within-day electricity demand profiles.

Figure 2.4A:
Hourly electricity demand and generation match 2012/13
Source: National Grid

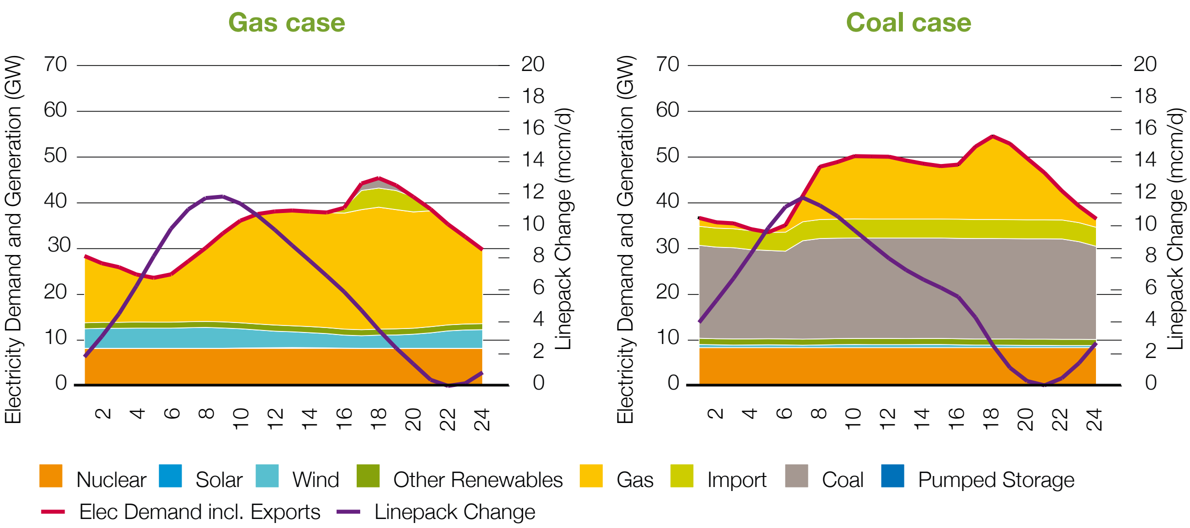


Figure 2.4A shows the maximum within-day gas swing for both the gas and coal cases for 2012/13. The chart on the left assumes gas is deployed before coal (i.e. gas case). The chart on the right assumes coal is deployed before gas (i.e. coal case). It can be seen that the maximum within-day gas swing occurs on different days for the two cases.

The 2012/13 gas case shows a maximum within-day gas swing of 74mcm/d which results in roughly a 12mcm/d linepack change. The 2012/13 coal case shows a maximum within-day gas swing of 80mcm/d, which is also roughly a 12mcm/d linepack change. In both the gas and coal cases, gas is providing a critical role in ensuring there is sufficient generation to meet the varying levels of electricity demand throughout the day.

Figure 2.4B:
Hourly electricity demand and generation match 2020/21
Source: National Grid

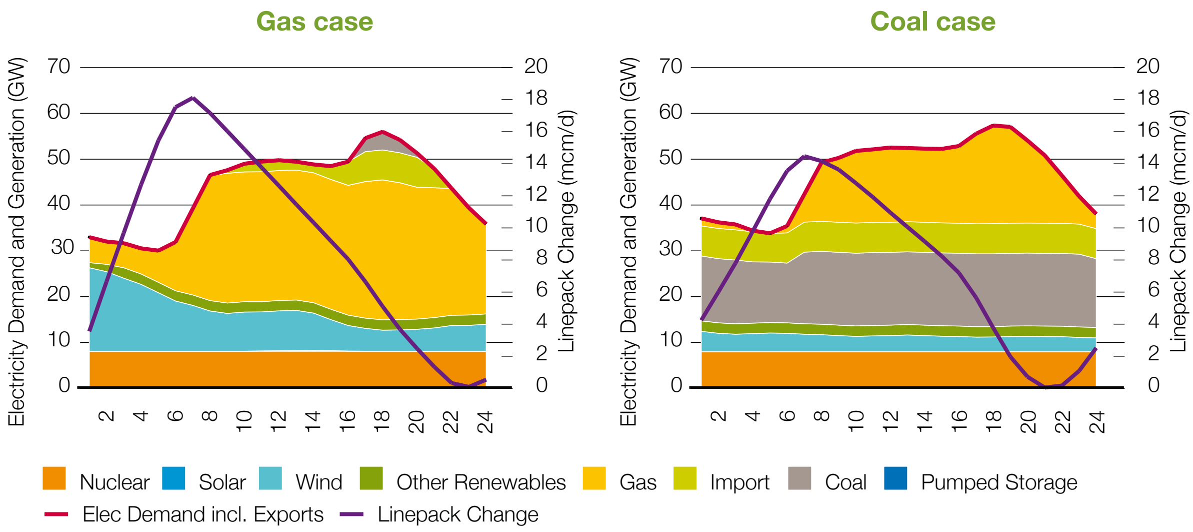


Figure 2.4B shows the day with maximum within-day gas demand swing for the gas and coal case for 2020/21.

By 2020/21 the gas case shows a maximum within-day gas swing due to changes in power station demand of 113mcm/d which results in a 18mcm/d variation in linepack. The increase is due to the increasing impact of wind intermittency as wind generation capacity increases. The 2020/21 coal case shows a maximum swing of 94mcm/d within-day gas swing and a 14mcm/d change in linepack.

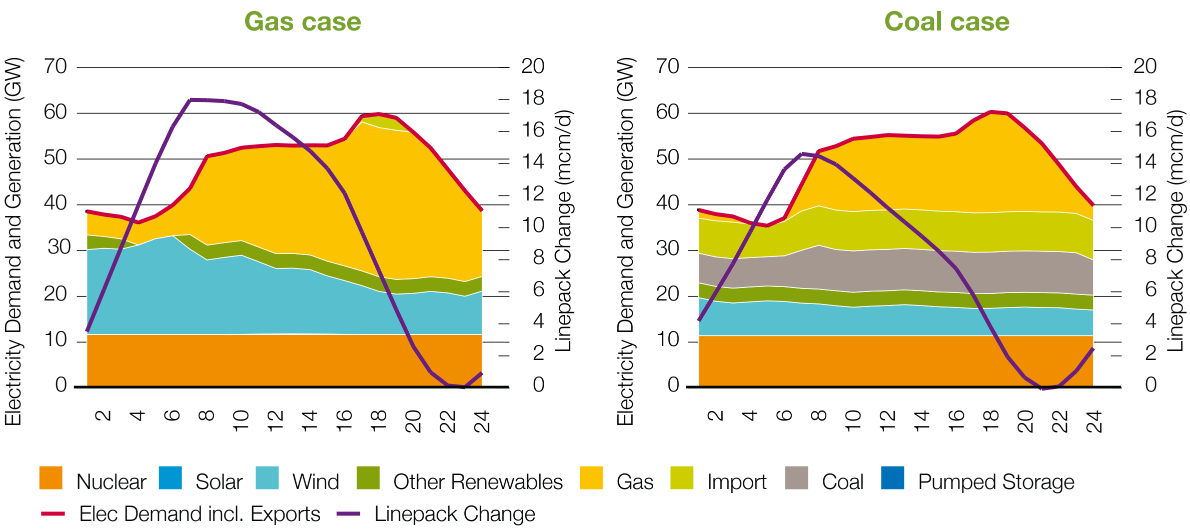
Figure 2.4C shows the day with maximum within-day gas demand swing for the gas and coal case for 2030/31.

By 2030/31 the gas case shows a 122mcm/d within-day gas swing and an 18mcm/d linepack variation. The impact of intermittent wind generation has increased as wind capacity has continued to increase. The coal case shows a maximum within-day gas swing of 96mcm/d, with a resultant linepack variation of 15mcm/d, driven by a significant reduction in generation from coal-fired plants as the total capacity of coal-fired generation has decreased substantially due to plant closures.

There are a number of conclusions that can be drawn from the analysis:

- Gas plays a crucial role in providing generation to meet the within-day electricity demand profile
- Under all cases, gas is critical to maintaining security of electricity supply out to 2030/31
- For both the gas and coal case, maximum within-day swing levels rise significantly from 2012/13 to 2020/21 and beyond to 2030/31
- Before 2020/21, the coal case shows the larger within-day gas swings: after 2020/21 the gas case shows significantly higher levels of within-day gas swing

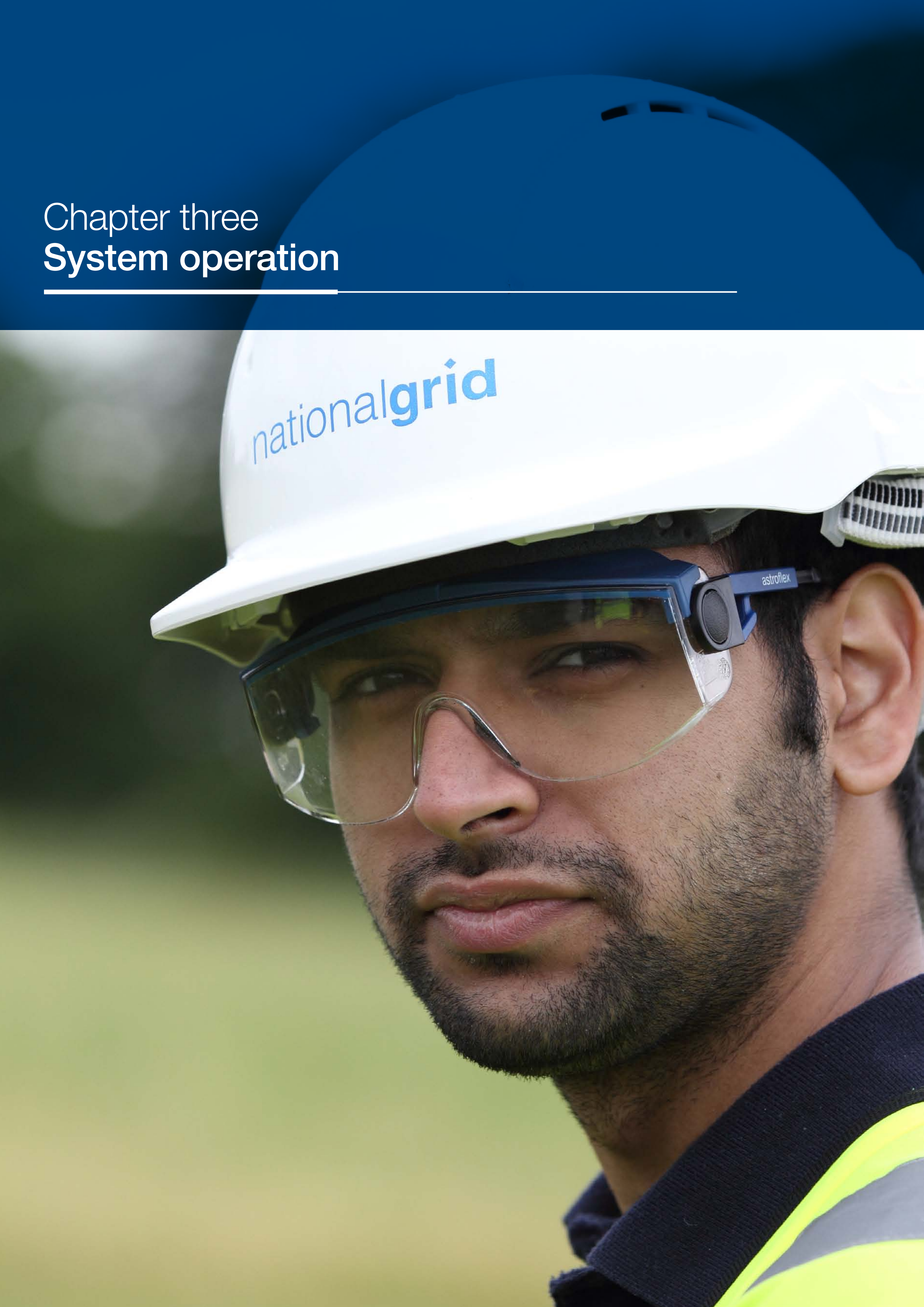
Figure 2.4C:
Hourly electricity demand and generation match 2030/31
Source: National Grid



- Whilst there are clearly differences in the within-day gas swing for the two cases analysed, the level of within-day gas swing increases significantly in the future whether gas is favoured ahead of coal or vice versa
- As wind capacity increases on the system, levels of within-day gas swing increases, particularly when gas generation is favoured ahead of coal
- As levels of coal-fired generation decrease, levels of within-day gas swing increase when coal is favoured ahead of gas
- Linepack variations increase in both cases, but increase most noticeably within the gas case. As the model makes no attempt to allow for within-day supply profiling, which is becoming increasingly volatile and unpredictable, actual linepack changes could be considerably larger than those shown here
- Within our Gone Green scenario, which achieves the 2020 renewable target and 2020, 2030 and 2050 environmental targets by decarbonisation of heat and transport by a sustained ramping up of domestic heat pumps and electric vehicles, gas-fired generation plays a crucial role in maintaining electricity demand / supply balance
- Whilst smart technologies may smooth the peaks within the electricity demand profile, gas-fired generation will continue to be the best source of flexible generation
- The increasing volatility in gas demand will cause operational challenges and require enhanced system operation capabilities and quick reconfiguration of the NTS to ensure gas supplies can be transported to points of demand. This is discussed further in Chapter 3.

Chapter three

System operation



3.1 Overview

Our primary responsibility as System Operator is to transport gas from supply to demand, on behalf of our customers, but in doing this we have a number of overriding obligations which are focused on ensuring safety for employees and the wider community. The key elements of this are:

- Ensuring that pressure within the NTS is maintained within safe limits, such that pressure does not exceed safety limits or fall below the minimum level to ensure the security of downstream networks
- Ensuring that the quality of gas transported through the NTS meets the criteria defined within the Gas Safety (Management) Regulations
- Operation of compressor fleet within environmental site specific permits
- Ensuring that capabilities and processes are in place to effectively manage a Network Gas Supply Emergency.

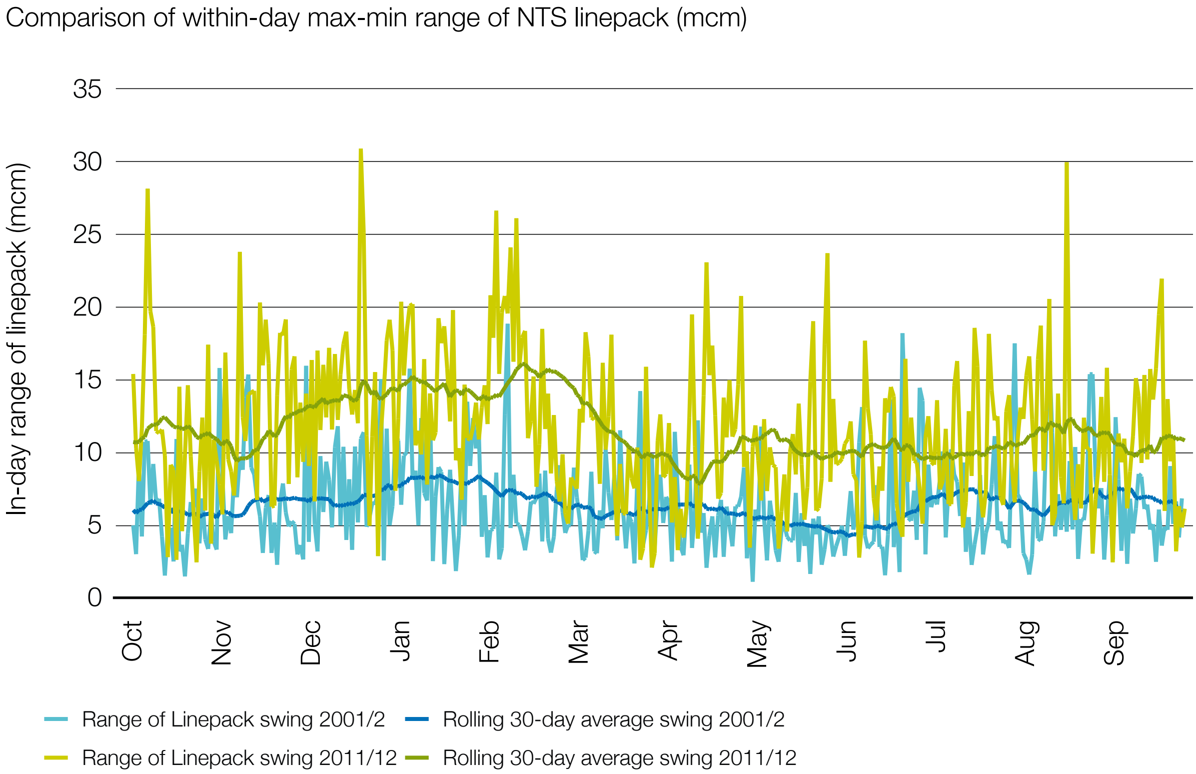
In addition to these overriding safety requirements, we have a range of responsibilities associated with operating the network and with facilitating the effective and efficient operation of the UK gas market. We must continue to make entry and exit capacity available in line with obligations and contractual rights, meet pressures contractually agreed with our customers, balance the network and signal significant shortfalls in supply, procure energy to run our compressor fleet, source Operating Margins gas to support the network in times of "distress", and manage gas quality (Calorific Value) at a zonal level to ensure consumers are fairly billed for the gas they use.

In last year's document we discussed in detail the changing operational environment in the UK and the potential impact this would have on delivering against the above commitments. We believe that the message in this year's statement remains consistent with last year, with supply and demand continuing to evolve with growing levels of uncertainty. We expect this trend to continue over the coming years, bringing various challenges in our ability to manage the network in the future.

In the following sections we provide an updated view of the major factors impacting our operations, but please refer to last year's statement for further detail on the areas highlighted.

3.2
How network gas flows have changed

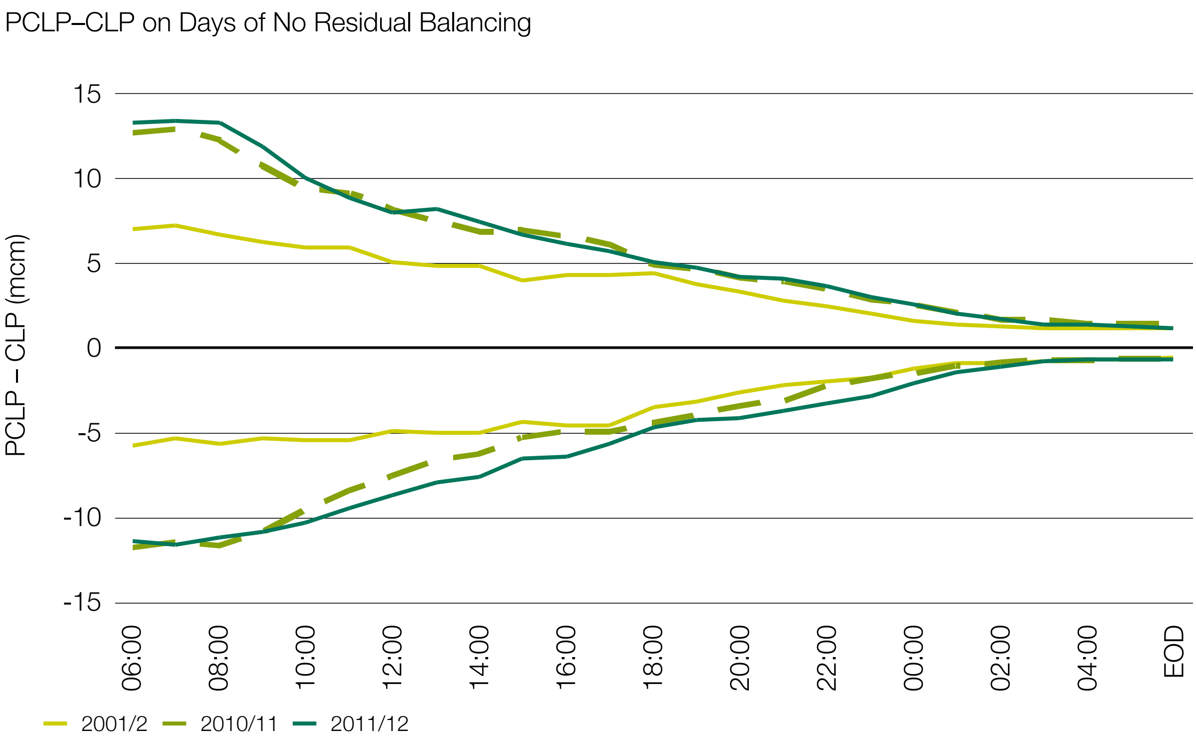
Figure 3.2A:
Within-day linepack variations
Source: National Grid



Supply sources continue to show the decline in UKCS gas that was highlighted last year (see Chapter 2 for further detail). With the decline of indigenous UKCS supplies, rapid growth in import capacity, and ability for Import facilities to operate at high capacity levels all year round, we experience day-to-day variation in supply to a far greater extent than we have traditionally experienced for supplies from the UKCS.

As identified last year this increasing trend has led to greater operational challenges, manifesting particularly with respect to the management of within-day linepack and ensuring NTS pressures remain within obligated operational and safety tolerances. Figure 3.2A clearly shows the increased frequency and magnitude of linepack variations between those seen in 2001/2 to those seen in 2011/12, with linepack volatility around double the level seen a decade ago.

Figure 3.2B:
Performance of PCLP – CLP (closing linepack)
Source: National Grid



In addition to the levels of linepack volatility we are already seeing, the analysis detailed in the security of supply section shows linepack volatility is forecast to increase further due to the changing operating regimes of power stations.

An associated trend can be seen in Figure 3.2B, showing aggregated network user notifications that feed into the end-of-day market indicator of Projected Closing Linepack (PCLP). The trend highlighted last year has continued, with the chart showing the underlying market imbalance at the start of the gas day and the time taken for the network to balance. It shows on average the PCLP at the start of the gas day is around twice as far out of balance compared to ten years ago, and in 2011/12 was slightly worse than last year.

These figures are material evidence of how users are changing the way that they use the network; the charts above demonstrate the greater operational challenge associated with a combination of increasing uncertainty where supplies will arrive, a much higher degree of supply profiling within-day and reduced accuracy of aggregate user notifications.

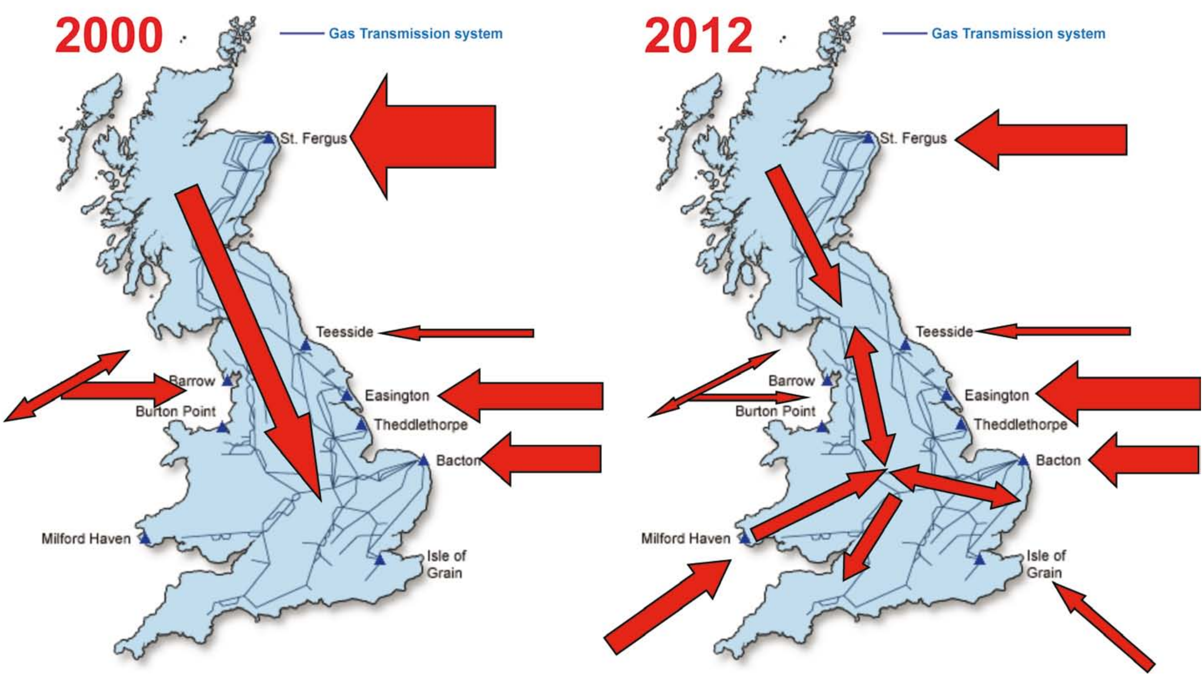
3.2 continued
How network gas flows have changed

3.2.1
How the general flow patterns have changed in the NTS

The dominant flow pattern in 2000 was characterised by high UKCS supplies at St Fergus with the challenge of moving large quantities of gas from Scotland to the areas of high demand in the South. By 2012 this pattern has changed substantially with much lower supplies at St Fergus and much larger supplies further south.

A positive consequence of this supply transition has meant that sources are much more distributed around the UK. This has brought supplies (that have the ability to significantly increase flows) closer to the demand centres, thus aiding security of supply, and enabling opportunities to better optimise compressor fuel management. However, last year's statement highlighted the associated operational challenges of managing flow patterns and within-day variations that differ significantly to those that were assumed when developing the existing network design, with increased risk and variability around supply patterns seen day to day (illustrated in Figure 3.2C).

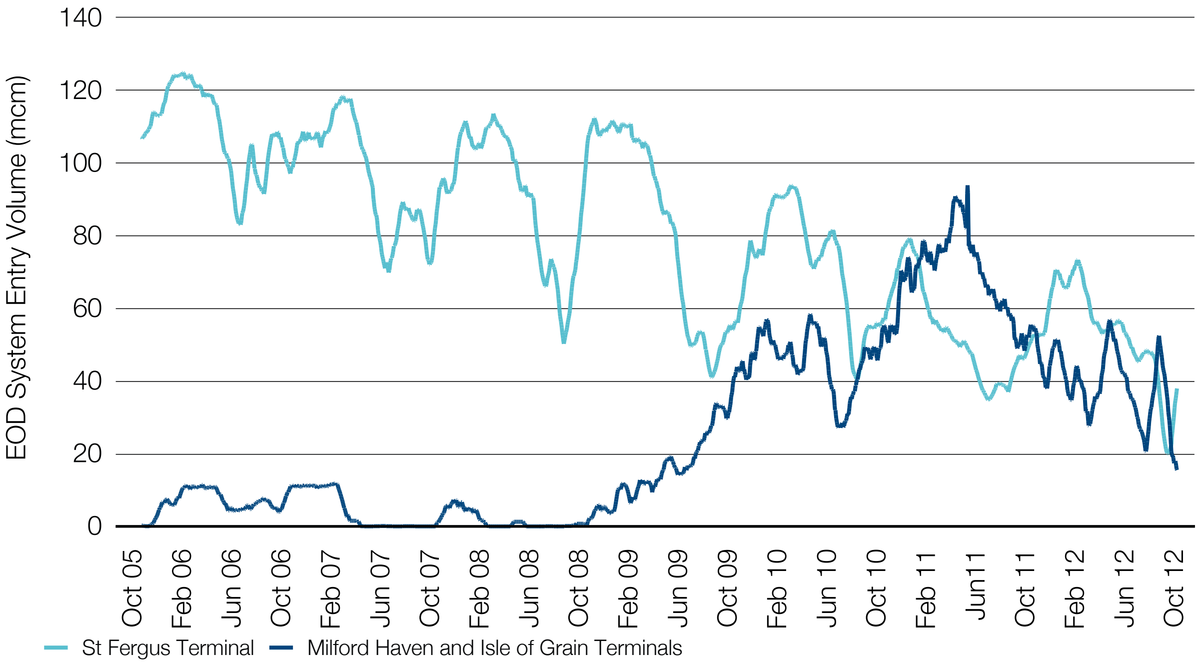
Figure 3.2C:
Flow patterns in the NTS
Source: National Grid



To help address these challenges we have included proposals within our RIIO-T1 business plan submission to provide increased network flexibility, this is discussed in further detail in Chapter 4, which covers how demand requirements in Scotland at times of low St Fergus supplies can be met.

Winter 2010/11 saw LNG inputs exceeding St Fergus flows for the first time (see Figure 3.2D), however in 2011/12 we have seen a reduction in LNG imports from the 2011 peak, due to changes in global market conditions with higher demand from other markets. This is a good example of the growing uncertainty of supply profiles and the operational requirements needed to manage them.

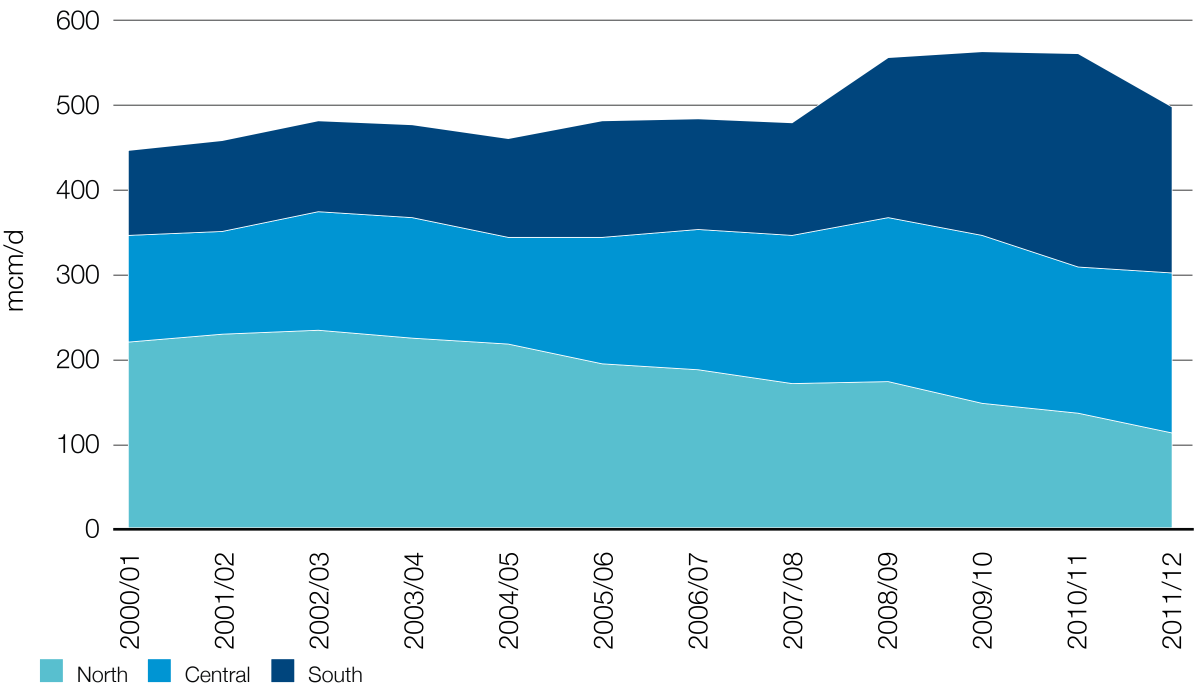
Figure 3.2D:
St Fergus and Milford Haven supply volumes – 30 day average system entry volumes October 2005–October 2012.
Source: National Grid



At a national level, the trend shown in last year's document has continued (shown in Figure 3.2E). Figure 3.2E shows this change based on peak terminal flows aggregated in terms of North (St Fergus, Teesside and Barrow), Central (Easington, Theddlethorpe and most storage) and South (Bacton, Grain and Milford Haven).

3.2 continued
How network gas flows have changed

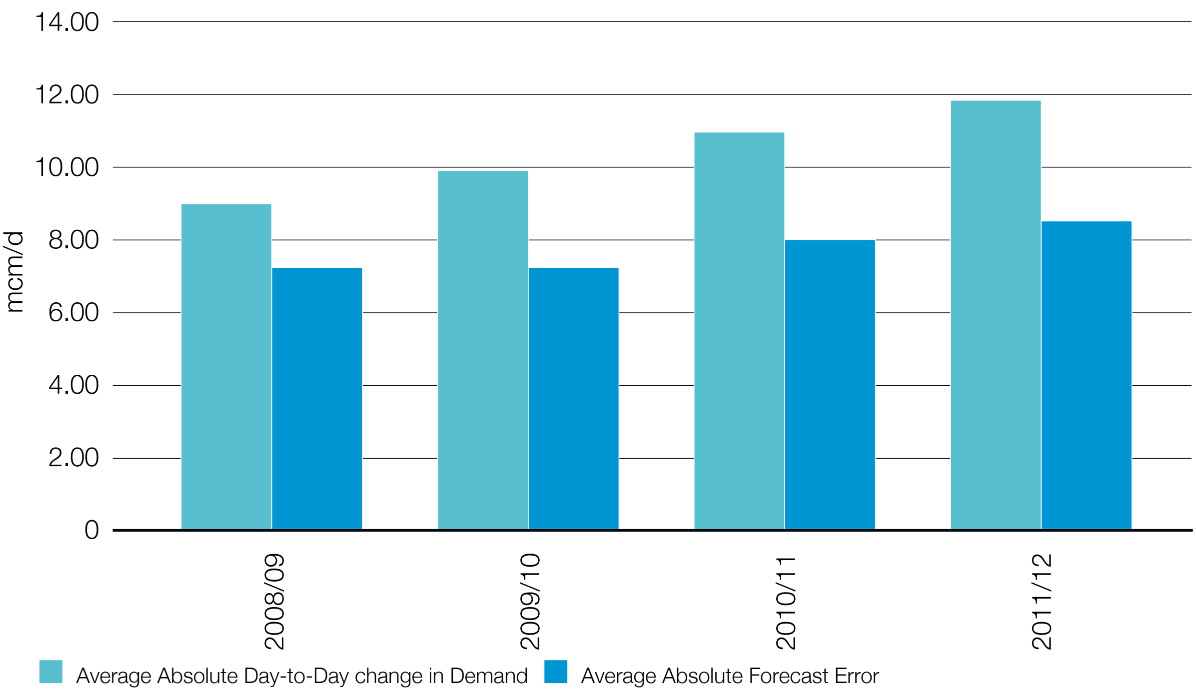
Figure 3.2E:
Peak terminal flows
Source: National Grid



The chart clearly shows the decline in northern supplies and the material increase in southern supplies. For central supplies the change has been less pronounced but still represents an increase of approximately 40%. These changes in entry flows have a considerable impact in terms of the need for network capacity, flexibility and fundamentally impact how the network must be operated.

3.3
Evolution of demand

Figure 3.3A:
Day-to-day demand volatility and D-1 13:00 forecast error
Source: National Grid



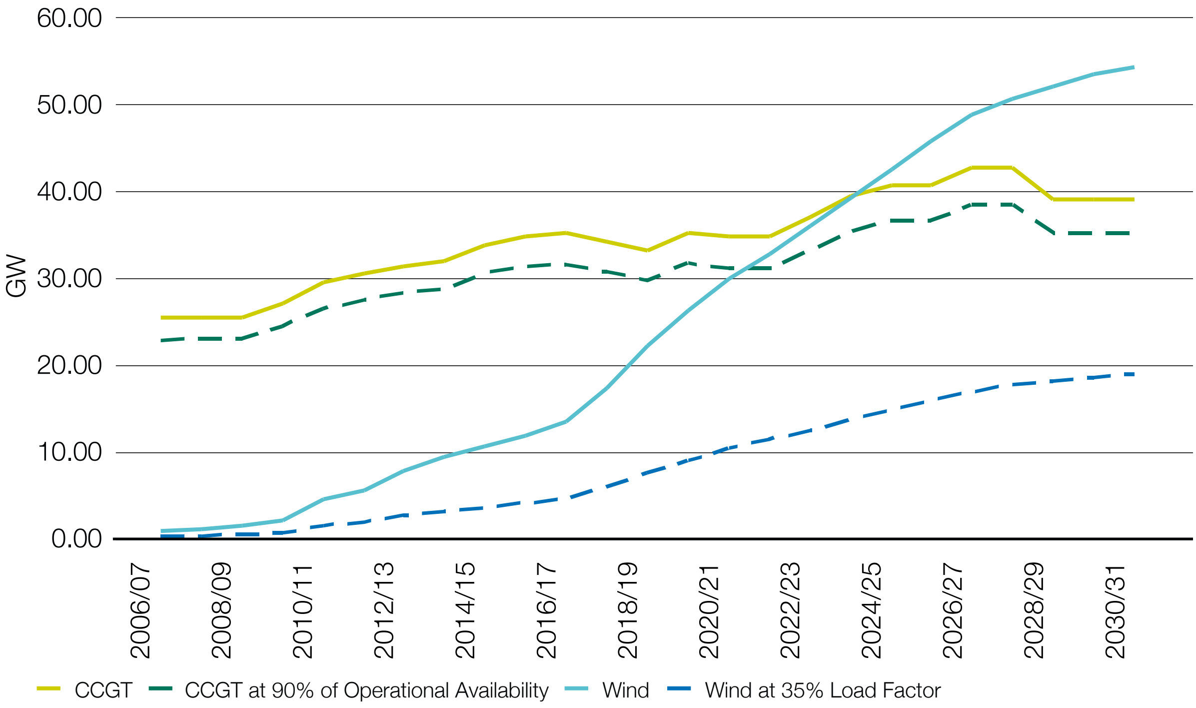
Increases in fast cycle storage and commercial interconnector operation has already resulted in an increase in the proportion of price responsive demand. This growing volatility and the difficulties it creates for forecasting are illustrated in Figure 3.3A.

The chart shows the absolute change in demand between days (mcm) averaged over each year and the associated absolute average error of the D-1 13:00 demand forecast. This trend in demand volatility is expected to continue.

As in 2011, the predicted increase in CCGT connections is still a key issue for the real time operation of the NTS. Demand levels from CCGTs is expected to become increasingly variable and unpredictable as their role in providing balancing generation to cover the increasingly intermittent renewable generation on the electricity system increases (illustrated in Figure 3.3B).

3.3 continued
Evolution of demand

Figure 3.3B:
Generation capacity for CCGTs and wind including likely load factor[34]
Source: National Grid



34 Based on the Gone Green scenario

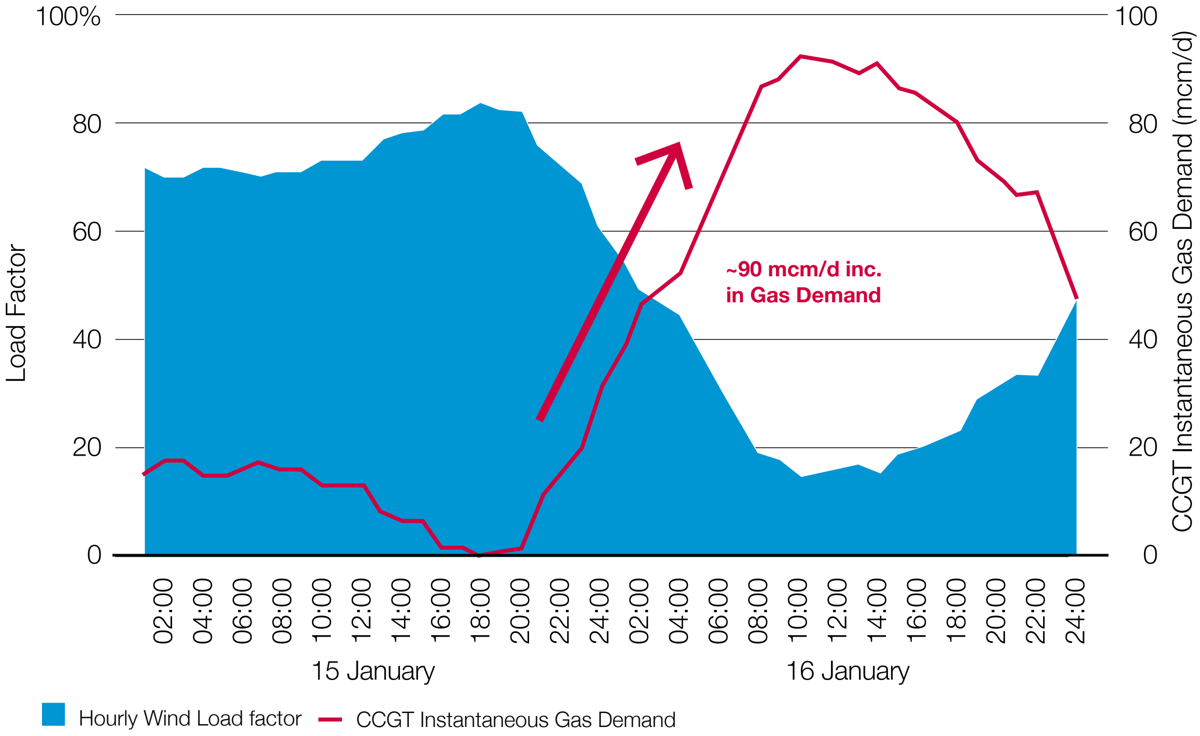
This issue is also described in greater detail in the security of supply section which highlights the potential level of within-day gas demand swings and associated linepack variations as CCGT demand becomes more unpredictable. This level of demand volatility causes operational challenges and requires enhanced system operation capabilities and quick reconfiguration of the NTS to ensure gas supplies can be transported to the points of demand.

Last year our modelling predicted that in 2011/12 we would experience a small number of demand swings (<10 per annum) of 30mcm and would expect only one swing of 50mcm in the year, however we have in fact observed 27 interday demand swings of 30 mcm, and 1 of 50 mcm.

This data suggests that demand volatility is actually growing faster than the predictions shown last year, and we will need to monitor this closely going forward to identify whether this is a long-term trend (and if so the reasons for this), or an anomaly.

As shown last year, for extreme events, the magnitude of change will be far greater going forward. Figure 3.3C is taken from the July 2011 Transporting Britain's Energy (TBE) process and highlights a possible, extreme event in 2020/21 (based on extrapolated 2007 data) with total wind generation at 30 GW. Over a period of 15 hours, wind load factor decreases from 84% to 15%. If we assume all the reduction in generation from wind is met by an upturn in CCGT generation, then this equates to an increase in within-day gas demand of roughly 90mcm/day.

Figure 3.3C:
Gas demand in response to variability of 30 GW of wind generation
Source: National Grid

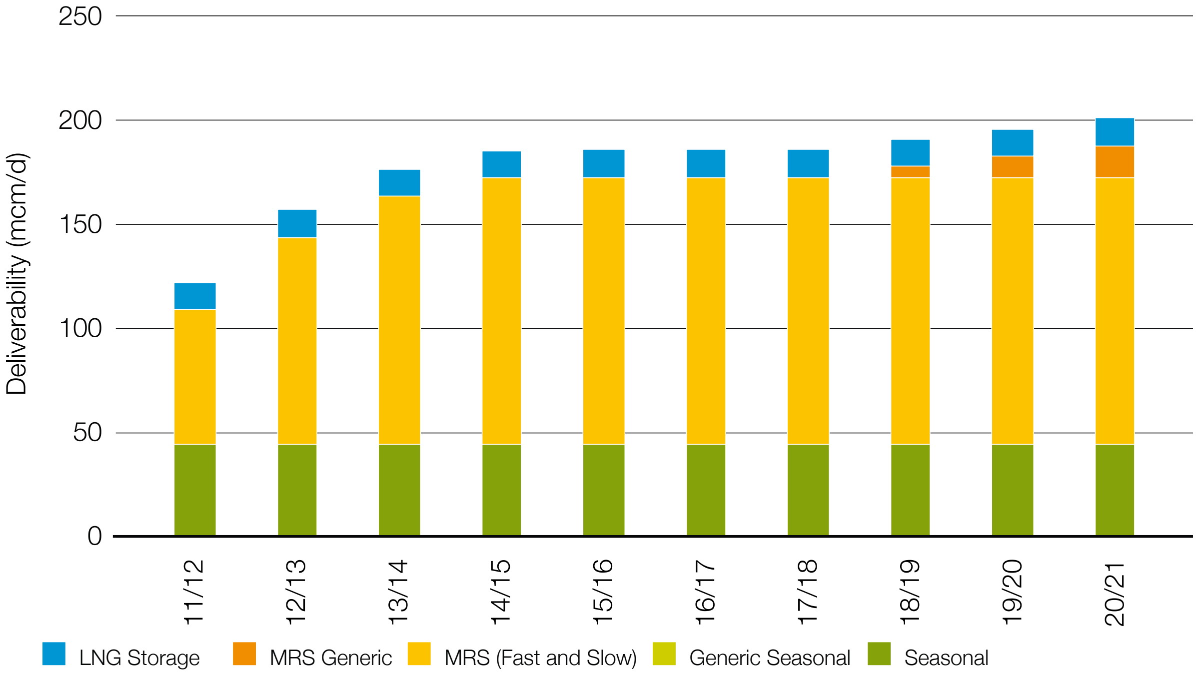


In addition to wind variability, it is worth noting that high levels of installed photovoltaic power in Germany have seen PV power plants supply up to 22 GW in 2012 with installed capacity at 30 GW. Although the take up of photovoltaic technology in the UK has been at a much slower rate, as this increases it will present its own operational challenges going forward.

Considering the issues raised above, this previously unseen level of demand profiling on the NTS would create challenges for the System Operator to manage the network and continue to meet pressure obligations, this is described further in section 3.5.

3.4
Impact of storage flow capabilities

Figure 3.4A:
Actual and forecast storage by type[35] (Gone Green)
Source: National Grid



35 Chart from 2011 RIIO submission

As stated last year, by 2020 we anticipate there will be further flexible storage and that deliverability from storage sites may increase significantly, predominantly from mid-range fast cycle plants. We still also predict the operating regime of these storage plants may create a number of operational challenges for us. In 2012 we have already seen price-driven behaviour with current mid-range fast cycle plants injecting and withdrawing on the same gas day.

Should planned additional storage not materialise, we still expect LNG importation to provide the additional deliverability as stated last year. The effect on the NTS under either scenario will be the same; with greater demand volatility at short notice, we will see greater volatility in supplies.

3.5
System operator challenges

There will be instances when the timing and quantity of supply and demand profiles requested by customers cannot be accommodated from a system pressure or linepack perspective, but may remain acceptable from an end-of-day national balance perspective. When this situation occurs, we will need to take time-bound and locational actions to resolve it (for example, to meet pressure requirements and ensure capacity rights can be delivered to users). The customers' ability to see the NTS as a single balancing point will reduce as the physical restrictions of the system limit our capability to allow customers to flow gas in an unrestricted manner (through restriction of flexibility or utilisation of commercial tools).
Whilst it is possible for these issues to arise today, it is rare given:

- The current drivers and capabilities on supply and demand
- The robustness of the system that has been built to meet existing design assumptions
- The proactive stance taken by transmission and distribution operators in utilising all available operational tools to maximise system flexibility for users.

This is to some extent enabled by the tools available to the operator, however with changes to the future risk profile we may be required to take on a much more active role in managing system risk, through commercial and operational actions.

Through our RIIO stakeholder engagement process, our stakeholders have indicated a preference for limiting new products and complexity.

An alternative approach would be to develop the commercial rules and the incentives on customers to incentivise them to minimise their profile of supply and/or demand. This could materially impact both customers' ability to flow gas as they have indicated they wish to and the ability of the electricity system to accommodate significant volumes of wind generation. During the RIIO stakeholder engagement process, customers made it clear that they did not wish to see this form of restriction, with one stakeholder offering the view that if we were to hold them rigidly to their current contractual rights and obligations, this would preclude them from participating in the electricity Balancing Mechanism.

Against this future landscape, managing the increasing volatility of supply and demand will require a combination of the following:

Network Operability
Physical infrastructure vs. Commercial regime

Commercial (Rules) Shape commercial regime, products, tools and incentives to better align cost of customer actions, to encourage efficient behaviour and allow flexibility of usage-desired
Operational (Tools) Enhance capabilities and tools to enable optimal use of the NTS under evolving rapid dynamic within-day conditions
Investment (Assets) Targeted investment to NTS to support dynamic operation at strategic points on the network in order to meet customer requirements

3.5 continued
System operator challenges

System operator challenges – summary

Based on our experience in 2011/2012, the trends shown in this document suggest the challenges highlighted in our RIIO-T1 business plan submission and last year's Ten Year Statement remain credible, with fundamental changes in the way gas is supplied to, and taken from, the NTS.

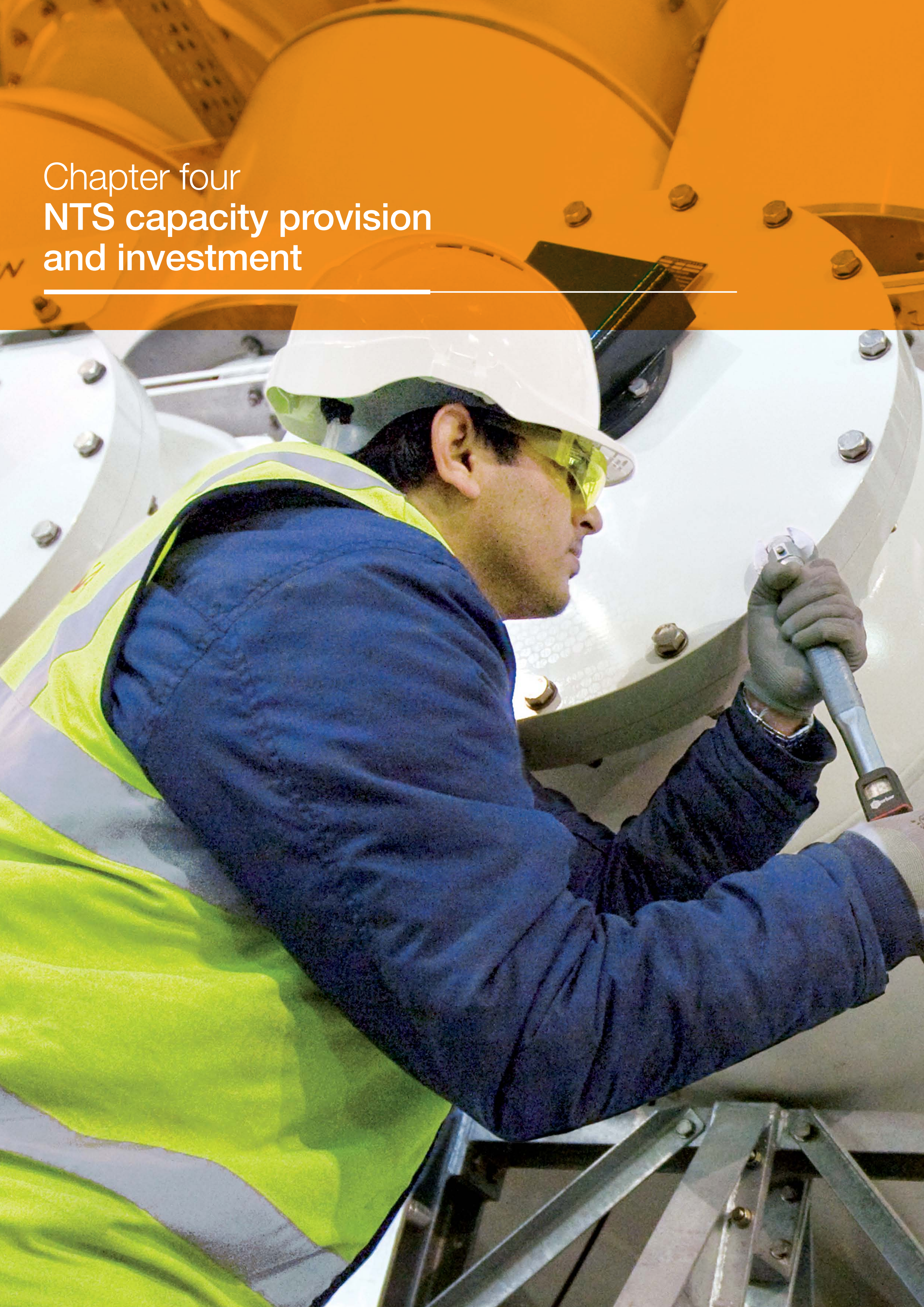
The decline in UKCS supplies and subsequent increase in import capacity has materially changed the UK's gas supply landscape. Indeed, the resulting high (surplus) capacity of importation sources has fundamentally changed the dynamics of supply from that of near predictability to considerable uncertainty.

This uncertainty will be compounded by increased within-day and between-day demand variation due to an increase in gas-fired generation, more price arbitrage across energies, the effects of increasing renewable energy driving dynamic operation of CCGTs, and increasing utilisation of the European interconnectors in response to maturity of EU energy market reforms.

As both supply and demand become more dynamic and unpredictable, we need to meet these challenges to ensure we maintain the safe operation of the NTS, provide security of supply and provide a reliable service to our customers.

Gas Ten Year Statement
December 2012

Chapter four
NTS capacity provision and investment



4.1 Overview

This section provides information on recent and future investment proposals on the National Transmission System necessary to comply with legislation and other requirements.

NTS user requirements continue to evolve and both environmental legislation and market reforms such as the Electricity Market Reform (EMR) will impact on future system operation. Hence this section also outlines the upcoming period of significant change and development of the National Transmission System (NTS).

Set out in this section are the currently sanctioned NTS reinforcement projects, those that are presently under construction for 2013 and indicative investment options for later years, consistent with the supply Gone Green scenario detailed in the Future Energy Scenarios document and signals received in the recent entry capacity auctions. The information in this section is consistent with that presented in our RIIO-T1 business plan although it should be noted that financial totals will not align due to the different time periods considered (the next ten years in this document; the eight year RIIO-T1 period in our RIIO-T1 business plan).

The annual planning process performs a critical role in allowing us to prepare for likely future investment requirements whilst also ensuring that historical investment decisions that have not yet progressed to construction remain valid in light of the latest supply and demand information. Maps showing the current NTS and approved future investments are presented in Appendix 4.

The 2012 planning process, although taking place against the wider background of our preparation for our RIIO-T1 price control submission, has been undertaken on a similar basis to previous years, with the Future Energy Scenarios consultation process providing the primary source of information, supplemented by auction signals.

Whilst we predict significant change in the period ahead, the pace of development of the NTS, when judged by investment in incremental capacity, has slowed in recent years. This is evidenced in the relative lack of customer signals received in recent years, with this trend continuing in the 2012 Quarterly System Entry Capacity (QSEC) auction. In contrast to the level of signals, however, the number of connection enquiries we are receiving remains far higher than in the past.

It is also notable that user requirements from the NTS continue to change and evolve beyond that which has been traditionally seen. We continue to see:

- Increased Distribution Network (DN) flex capacity requirement (against a background of reduced DN flat capacity requirements)
- An increased requirement for South to North flows as a result of declining St Fergus flows
- An increased requirement to rapidly switch between ‘West-to-East’ and ‘East-to-West’ flow directions in the heart of the network.

Overview

Through our RIIO Talking Networks stakeholder engagement, we have discussed with the industry whether these changes (and others) merit re-examining the existing design standards against which we plan the network. With the Transmission Planning Code updated during 2012 but expected to be reviewed in light of the RIIO-T1 final proposals, this is an important opportunity to continue this discussion.

Looking forward, as wider energy market processes move towards conclusion, (in particular the Electricity Market Reform process) and more stringent environmental legislation is introduced, we are seeing strong indications of an upcoming period of significant change and renewed development activity.

This likely activity makes it even more important that we work together with our stakeholders and customers to ensure that the right combination of commercial options (rules), operational arrangements (tools) and physical investments (assets) are available to us in order to determine the most efficient overall solution.

4.2
Developments

4.2.1
Planning consents

Since the publication of the 2011 Gas Ten Year Statement the White Hill Farm gas storage project has obtained planning approval, although no Final Investment Decision has yet been made.

Halite Energy submitted their application to the Infrastructure Planning Committee in December 2011 for the Preesall storage facility and the application was accepted for further examination. A decision from the Planning Inspectorate is expected in 2013.

Information relating to the Planning Act (2008) can be found in Appendix 1.

4.2.2
Entry capacity – auction results summary

The QSEC auctions opened on Monday 19 March 2012 and closed on Tuesday 20 March 2012.

In order for incremental obligated entry capacity to be released, sufficient bids for this incremental obligated entry capacity must be received during the QSEC auctions to pass an economic test.

During the March 2012 QSEC auctions, bids were received for incremental entry capacity at the Easington (for Q1 2014 and 2015) Aggregate System Entry Point (ASEP). The bids received were insufficient to pass the economic test for the release of incremental obligated entry capacity, however following a risk assessment process non-obligated entry capacity was released to meet all the bids at Easington (for Q1 2014 and Q1 2015) as the incremental risk created by volumes requested, over the specific periods in question, was identified as being operationally manageable and unlikely to lead to disproportionate commercial risk.

Bids received at all other ASEPs were satisfied from current unsold obligated levels for future quarters and no incremental obligated entry capacity was released.

4.2.3
Entry capacity – investment implications

No direct investments were identified or triggered, since no incremental bids received at the QSEC 2012 could pass the economic test.

4.2.4
Exit capacity – user commitment summary

Aggregate NTS Exit (Flat) Capacity allocations have increased by approximately 4% compared to levels previously signalled. This increase in NTS Exit (Flat) Capacity has also been met with a marked increase (4–8%) in aggregate NTS Exit (Flex) Capacity, facilitated through both the NTS Exit (Flat) Capacity reduction and reductions in key Assured Offtake Pressures across the NTS agreed in 2011.

Tables 4.2A and 4.2B detail the percentage change between Exit Capacity allocated to each Local Distribution Zone (LDZ) in the 2011 and 2012 Exit Capacity Allocation Processes. A negative number indicates a reduction in allocated capacity agreed between the NTS and DNs. The tables compare bookings for the same gas year across the 2011 and 2012 planning cycles.

Table 4.2A:
Percentage change between exit capacity allocated in the 2011 and 2012 Exit Capacity Allocation processes
Source – National Grid

LDZ	NTS Exit (Flat) Capacity (% Change)					
	Enduring					
	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18
Scotland	0.03	-0.30	-0.01	-0.01	0.00	0.00
North	0.38	0.07	0.00	0.00	0.00	0.00
North East	1.29	0.38	0.07	0.00	0.00	0.00
North West	1.50	1.63	0.00	0.00	0.00	0.00
East Anglia	0.30	0.47	0.00	0.00	0.00	0.00
East Midlands	5.57	6.66	0.00	0.00	0.00	0.00
West Midlands	0.92	0.92	0.00	0.00	0.00	0.00
North Thames	2.82	2.87	0.00	0.00	0.00	0.00
Wales North	0.00	0.00	0.00	6.09	6.09	6.09
Wales South	0.00	0.00	0.00	1.13	1.13	1.13
South	0.00	-4.15	-3.33	-3.33	-3.33	-3.33
South East	0.00	-7.10	0.00	0.00	0.00	0.00
South West	0.00	0.00	0.00	0.14	0.14	0.14

LDZ	NTS Exit (Flex) Capacity (% Change)					
	Enduring					
	2012/13	1203/14	2014/15	2015/16	2016/17	2017/18
Scotland	-5.99	-4.28	-7.62	-11.23	-11.09	-10.86
North	-2.08	-2.22	-2.32	-2.30	-2.57	-3.15
North East	4.54	5.39	5.13	4.90	5.11	5.11
North West	16.48	19.52	22.20	6.53	8.10	8.10
East Anglia	-10.87	-10.67	-10.51	-10.23	-10.37	-10.37
East Midlands	20.65	23.13	24.11	25.29	25.94	25.94
West Midlands	22.88	24.88	29.47	31.56	37.80	37.80
North Thames	0.00	0.00	7.85	8.67	2.32	2.32
Wales North *	–	–	–	–	–	–
Wales South	21.73	21.73	21.73	21.73	21.73	21.73
South	0.00	0.00	0.00	0.00	0.00	0.00
South East	30.29	22.80	19.02	16.93	5.83	11.69
South West	16.53	0.01	0.01	0.01	0.01	0.01

* Previous NTS Exit (Flex) Capacity allocations were zero thus revised allocations cannot be represented in percentage terms

Table 4.2B:
Total exit capacity allocated to DNs through the 2012 Exit Capacity Allocation process
Source National Grid

Aggregate DN Allocations	**NTS Exit (Flat) Capacity**					
	2012 Exit Capacity Allocation Process					
	Enduring					
	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18
Total (GWh/d)	4664.11	4619.08	4609.80	4621.49	4621.61	4621.61
Change from 2011	1.23%	0.09%	-0.27%	-0.15%	-0.15%	-0.15%

Aggregate DN Allocations	**NTS Exit (Flex) Capacity**					
	2012 Exit Capacity Allocation Process					
	Enduring					
	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18
Total (GWh/d)	264.94	264.49	265.46	280.8	284.21	285.51
Change from 2011	7.25%	7.35%	7.88%	5.22%	4.5%	4.98%

All obligated NTS Exit (Flat) Capacity requests from DNs have been allocated in full. Requested increases in non-obligated NTS Exit (Flat) Capacity and NTS Exit (Flexibility) Capacity were rejected if they could not be accommodated within the capability of the system whilst maintaining existing entry and exit commitments, or if the release would significantly increase operational costs (for example use of shrinkage gas).

4.2 continued
Developments

4.2.5
Recently commissioned projects

One major project was completed in 2012:

Tirley Pressure Reduction Installation (PRI)

The Tirley PRI was commissioned in September 2012. This installation forms part of the network reinforcement necessitated by the construction of two LNG importation facilities at Milford Haven in South Wales; once remaining commissioning works are completed, this will enable the pipelines to operate at full capacity.

The construction of the PRI was delayed by refusal of planning permission for the originally proposed site at Corse, near Tirley. The Secretary of State recognised the national importance and urgency for the construction of a PRI in this locality as it would allow the gas pipeline to operate at its full capacity, efficiently and economically, enabling it to carry up to 20% of the UK's gas supplies. Planning consent for an alternative site was subsequently granted in December 2010 whereupon construction commenced.

Following commissioning of Tirley the force majeure has been lifted and final commissioning of the Felindre compressor station may now be undertaken, however commissioning activities are dependent upon suitable entry flows being delivered through the Milford Haven terminals.

4.3 Future investment

4.3.1 Transmission Planning Code

The Transmission Planning Code is a document which describes National Grid's approach to planning and developing the NTS in accordance with its duties as a Gas Transporter and other statutory obligations relating to safety and environmental matters, and is published in accordance with Special Condition C11 of National Grid's Gas Transporter Licence in respect of the NTS.

National Grid must review the Transmission Planning Code at least every two years, after consultation with the gas industry. The next review will be scheduled for no later than 2014. Modifications to this code must be approved by the Gas and Electricity Markets Authority (GEMA) before they are implemented.

For further information on the Transmission Planning Code see Appendix 1.

4.3.2 Investment planning scenarios

Chapter 3 discussed the uncertainties in future supply mix that arise from both existing supplies and potential new developments that are in aggregate capable of exceeding most peak demand scenarios. These uncertainties are exacerbated to a certain extent by Gas Transporters Licence requirements for National Grid to make obligated capacity available to shippers up to and including the gas flow day. This creates a situation where National Grid is unable to take long-term auctions as the definitive signal from shippers about their intentions to flow gas on any particular day.

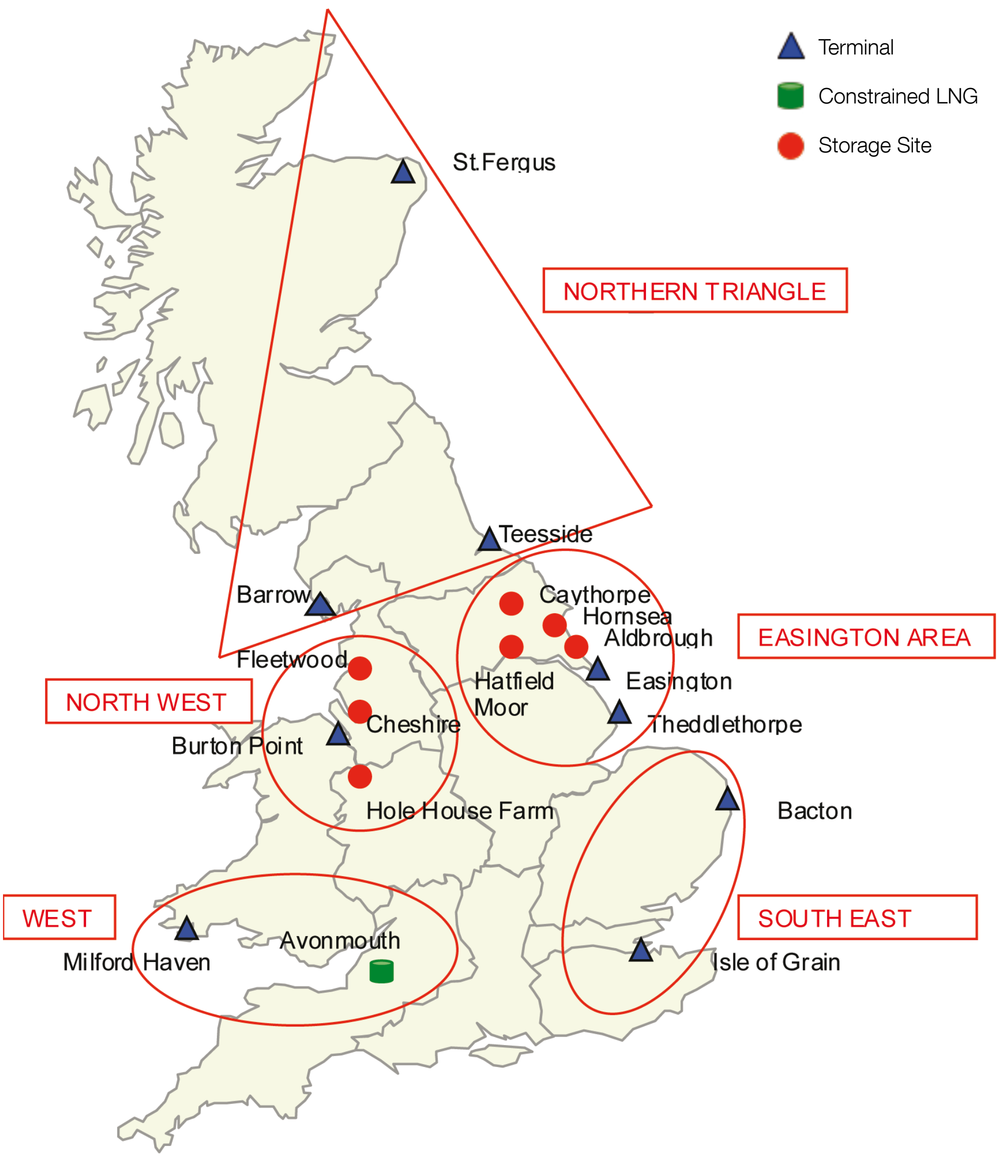
National Grid continues to develop its processes to better manage the risks that arise from such uncertainties.

In order to aid understanding of entry capability, we have used the concept of entry zones which contain groups of ASEPs (Figure 4.3A). The entry points contained within each zone will tend to make use of common sections of infrastructure to transport gas from entry to market, and therefore have a high degree of interaction. However, there remain key interactions between supplies in different zones which mean that interactions between key supplies must also be determined when undertaking entry capability analysis. Examples are the interactions between Milford Haven and Bacton, or Easington and Bacton entry points.

The commonly used zonal groupings are:

- South East – includes Bacton and Grain; both use common infrastructure away from the Bacton area
- Easington area – includes Easington, Rough, Aldbrough, Hornsea and Caythorpe; all use common routes out of the Yorkshire area
- Northern Triangle – includes St Fergus, Teesside and Barrow; all of these northern supplies need to be transported down either the East or West coast of England to reach major demand centres in the Midlands and South of the country
- West UK – this zone enables sensitivity analysis around potential supplies from Milford Haven
- North West Corridor – includes storage at Hole House Farm and Cheshire.

Figure 4.3A:
Zonal grouping of interacting supplies
Source National Grid



An example of this approach is that the analysis of the South East could consider higher flows from the Bacton and Isle of Grain entry points whilst reducing the other supplies to create a demand balance for the day being considered.

Key scenarios examined through the investment planning process include:
- High West to East flows generated by increased entry flows in the West travelling east across the country to support demands in the East and South east of the UK
- High South to North flows created by reduced entry flows into St. Fergus with a corresponding increase in entry flows in the South requiring gas to be moved from South to North.

In addition to the traditional geographical scenarios, several commercially driven sensitivities are also investigated. For example, a sensitivity with a reduction in imported gas requiring high MRS (medium range storage) entry flows to meet winter demand.

Historically these scenarios have been considered on an individual basis using ‘steady state’ gas flows consistent with an overall ‘end of day’ energy balance. As user requirements from the network evolve, it is increasingly necessary to consider the ability of the system to switch between different flow scenarios, explicitly considering ‘transient’ (changing) flows on the network.

If this technique indicates future requirements from the network are outside of current capability, a range of possible solutions (regulatory, commercial and physical) are investigated where appropriate. This ensures a broad spectrum of solutions are identified. Where investment in assets is the optimum solution, this would be developed with further optioneering through the planning consents framework.

4.3 continued
Future investment

4.3.3
Investment in 10-year period

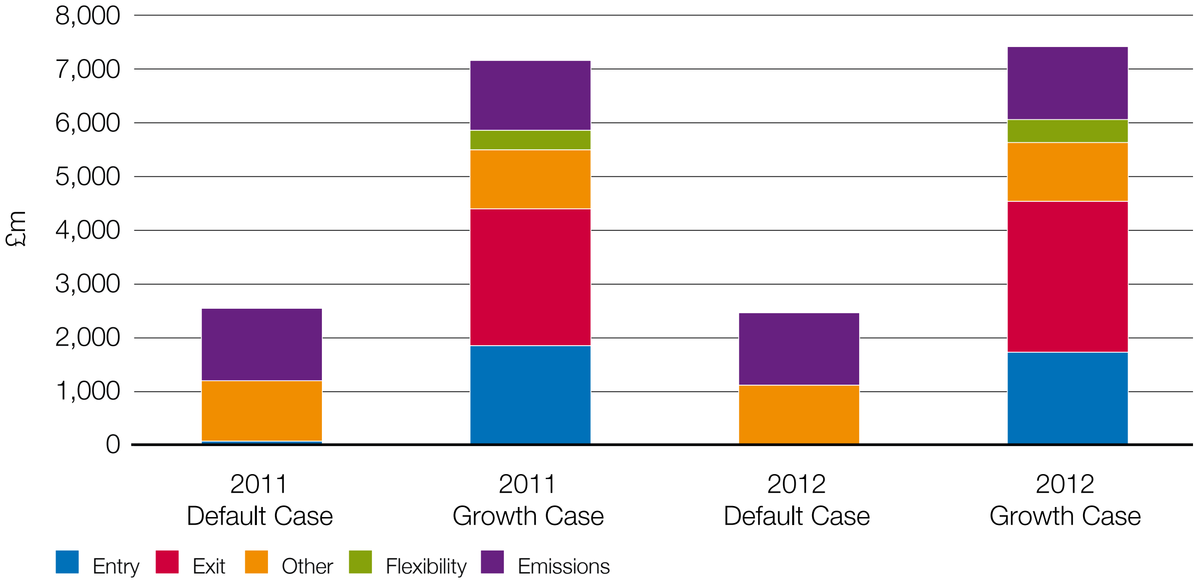
Figure 4.3B shows our view of the investment required over the 10-year period, compared to the same forecast from 2011.

The 'Default Case' represents the investment we would expect to undertake on the network if no user signals for incremental capacity are received. The 'Growth Case' sensitivities represent views of potential investment required as a result of receiving user signals for incremental capacity. The 2012 scenarios are consistent with our RIIO-T1 business plans, although as already noted, financial totals will not align precisely due to the different time frames considered. The Default Case aligns with the ex-ante funding which we are seeking under RIIO-T1; the Growth Case is aligned to our 'base' RIIO-T1 plan which includes both ex-ante and indicative incremental user signals.

2012 Default Case

In Figure 4.3B, 'Entry' relates to approved investment currently being undertaken to meet entry auction signals and the forecast levels of supply over the period. 'Exit' relates to growth investment consistent with the obligations placed on National Grid under its Gas Transporters licence to meet exit capacity requirements. This considers the commitments made under the exit capacity allocation processes, contracted loads and forecast directly connected loads over the period. 'Other' includes 'non-load' related investment such as the refurbishment, re-life/ overhaul and replacement of assets that have

Figure 4.3B:
Potential spend by investment category for 2012 compared to 2011
Source National Grid



reached the end of their technical design life. Forecast 'Emissions' investment is driven by the need to comply with environmental legislation. The general base level of entry and exit investment over the next 10-year period decreases from the previous year. This is due to the following reasons:

- The majority of the investment on Milford Haven has been completed
- There have been no further investments triggered as a result of long-term entry auction signals.

Further reinforcement of the NTS may be required to support new storage projects and large new power stations should signals be received from users under the commercial arrangements for releasing additional NTS exit capacity. Such projects are not included in our Default Case scenario but are included in the Incremental sensitivities shown in Figure 4.3B.

Delivery of the first emission reduction driver schemes at St Fergus, Kirriemuir and Hatton are all in the later stages and a further programme of emissions reduction investment is now planned at the other priority sites.

2012 Growth Case

There exists a significant uncertainty relating to entry, exit and storage projects (and associated investment requirements) in the latter half of the 10-year period considered. The '2012 Growth Case' shown in Figure 4.3B considers the potential impact of this uncertainty on investment requirements.

National Grid has seen an upturn in entry, CCGT and storage connection enquiries to the NTS. Whilst the Default Case includes a selection of new CCGT plants to meet future generation requirements, investment is sensitive to the location of these facilities and the requirement for firm capacity rights. Should any of the potential new exit connections require firm capacity in the constrained South East, Southern or South West areas of the system then it is likely significant investment will be required. Large storage sites requiring firm exit capacity in the North West will also trigger significant investment.

National Grid has also increased exit capacity obligations arising from the introduction of the enduring exit regime. Increased levels of firm capacity requirements in the constrained areas can arise from traditionally interruptible loads (including industrial, power generation, interconnector and storage sites on the NTS and loads within Distribution Networks) and may result in additional investment.

The factors mentioned provide a significant potential upward pressure to exit and entry investment compared to the '2012 Default Case' and is shown within the '2012 Growth Case'. This is consistent with the level of customer enquiries for connection to the network that we are currently seeing.

Investment related to network flexibility is described in section 4.3.5.

Section 4.3.9 gives more detail on where we believe network reinforcement may be required over the next 10-year period if user signals for incremental capacity are received.

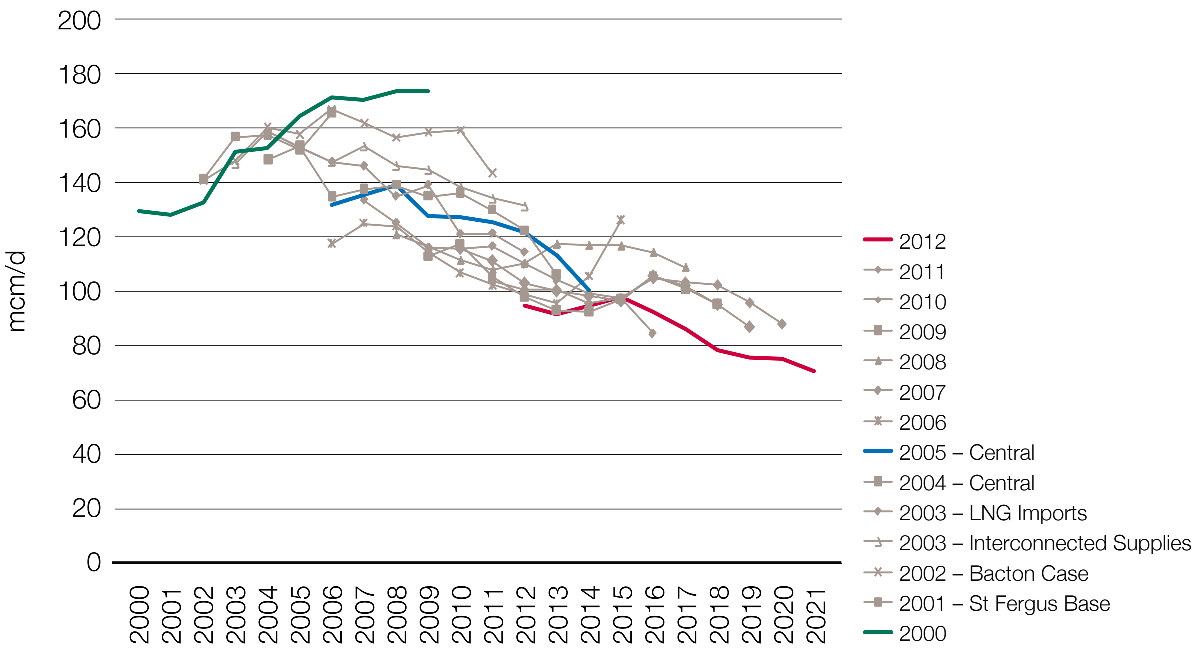
4.3.4
1-in-20 Obligation for Scotland

Figure 4.3C shows ten years of forecast gas supplies at St Fergus as informed by our industry consultative processes. It clearly shows that supplies are dropping away far quicker than anyone (including the shippers bringing the gas to shore) had previously anticipated.

Against this backdrop of falling supplies, demand in Scotland (including the Moffat offtake to Ireland) has risen, reaching the point where on some days this demand is already marginally greater than the supplies from St Fergus. For a number of years our scenarios have strongly indicated this situation will worsen over the coming years as existing UKCS supplies through St Fergus continue to decline.

The reduction in supply at St Fergus has been compensated for by additional supplies at Southern ASEPs. To maintain supplies in Scotland it will therefore be increasingly necessary to route gas 'South to North' within the network. The network has historically been designed around high St Fergus gas flows and hence significant 'North to South' flows; it presently has very limited physical capability to actively move gas 'South to North'. Our planning analysis shows that we are approaching a point where, without additional

Figure 4.3C:
Forecast flows from the St Fergus ASEP
Source: National Grid



network capability to deliver 'South to North' flows, we will not be able to meet our 1-in-20 demand obligations in Scotland.

As noted above, the reduction in St Fergus flows has been compensated for by additional supplies at Southern ASEPs, however, we have not seen signals for incremental capacity sufficient (either individually or in combination) to trigger these projects through the existing industry processes. As the current regime is based on customer commitment underpinning the provision of incremental capacity and this situation has arisen through changing / decremental flows there is no clear trigger mechanism to identify these projects and provide funding for a solution (be it commercial, operational or asset based).

We have identified a number of modifications to the network designed to enhance the capability to provide 'South to North' flows. Taking account of our licence obligations and having considered non-investment options we believe that these projects represent the optimum solution.

We have sought ex-ante funding for these projects under both our TPCR4 Rollover and initial RIIO-T1 price control submissions (delivery of these projects would take place through both price control periods) against the new category of Network Flexibility due to the absence of an existing funding mechanism. In response to feedback received during our RIIO Talking Networks stakeholder consultation process we are seeking ex-ante funding for these projects in our final RIIO-T1 submission and have re-categorised them as '1-in-20 Licence Obligation'.

We are already actively progressing these projects through our internal governance processes towards approval for construction to ensure that we continue to meet our obligations.

4.3.5 Network flexibility

As previously described in Sections 2 and 3 we are already seeing a significant change in user requirements from the NTS, resulting in very different gas flow patterns than those for which the network was originally designed. Again, as already described above, the current regime is based on the concept of user commitment to support the provision of incremental capacity. There is no existing mechanism to trigger the enhancement of system capability required specifically in response to changing and/or reducing flows of gas in the network, i.e. the net impact of a number of different users changing their use of the NTS.

Our planning analysis continues to identify a number of projects which are required to improve network capability to meet these changing flow requirements. These projects are categorised as 'Network Flexibility (not triggered)' in our RIIO-T1 submission, the need case for each being discussed with stakeholders as we receive more evidence in support of their enduring requirement.

Currently identified Network Flexibility investments mainly comprise modifications to existing compressors and the installation of flow control valves to enable greater control and configuration of the NTS to meet emerging user requirements from the system. These projects increase the resilience of the network to meet variations in supply and demand patterns, including response to unforeseen events such as major supply outages. They provide the System Operator with enhanced capability to operate the network in the flexible manner which users are indicating that they require.

4.3 continued
Future investment

One example of this is our proposal to enhance the capability in the 'Central Corridor'[36] of the network. The network was designed around East to West flows of gas in this area, with later incremental additions to allow the supply of gas from the West. We are now seeing that our users increasingly require the ability to vary their individual gas flows such that net gas flows through this part of the network are required to switch between 'West to East' and 'East to West' regularly (and rapidly), even within the gas day. The current network infrastructure was not designed to provide this directional switching on such a regular or rapid basis.

As noted in 4.3.4 above, in response to stakeholder feedback we have reviewed our proposals for Network Flexibility, aggregating projects according to specific drivers. This has resulted in projects required to meet our licence obligations being separated out (specifically Scotland 1-in-20 as noted above), however a number of specific Network Flexibility projects to manage changing network flows remain.

Having considered alternative solutions (e.g. use of commercial contracts, existing 'tools' for managing the system etc.) we believe that these projects still provide the best solutions to meet the requirements of network users and our wider stakeholders. In our final RIIO-T1 submission we requested sufficient ex-ante funding to progress the initial design of these projects. We have committed to continue direct engagement with stakeholders to discuss this issue further through the appropriate industry processes. If agreement is reached that these projects are necessary, we will then seek appropriate funding through the RIIO-T1 period using an Uncertainty Mechanism.

This solution recognises the long lead-times for asset based solutions and by allowing front-end work to progress keeps these options open (within the required timeframe) at minimum cost.

It is important to note that our current Network Flexibility proposals do not address the potential future changes in flows on the network as a result of the projected increased variability of future demand (e.g. from gas-fired generation in response to variable wind generation) and the corresponding supply side response. These potential changes are discussed in detail in section 3. We are therefore managing the Network Flexibility issues that are apparent now, and will engage with stakeholders going forward to enquire about their changing / increasing CCGT usage in the future. We intend to use the stakeholder consultation processes discussed above to investigate the impact of these changes on the network and, where investing in assets is agreed to be the required solution, will seek funding for the RIIO-T1 period through an Uncertainty Mechanism.

We believe these projects are necessary to avoid occurrence of potential significant constraints on the NTS and to enable the continued flexible operation of the system that users have indicated that they value. Failure to invest where there are potential significant constraints is likely to increase user costs (and hence ultimately for end consumers), both through direct constraint management costs and through any additional costs incurred by users as a result of not being able to operate in the manner they require.

36 The area broadly covered by the Midlands, East Anglia and South East, i.e. between the Milford Haven ASEP in the West and Bacton and Isle of Grain ASEPs in the East.

4.3.6
Emissions-related investment

National Grid uses gas generators as the prime mover to power a significant number of the compressors necessary to move gas around the NTS. National Grid is committed to the monitoring and reduction of emissions from these machines such that full legal compliance is maintained whilst ensuring the safe, secure and reliable transportation of natural gas across the UK.

Compressor utilisation is largely driven by gas supply and demand patterns across the network which, as already outlined above, are increasingly uncertain into the future. Some compressors that traditionally saw high annual operating hours have experienced a marked reduction in operating hours as a consequence of changes to supply patterns whilst others have seen flow directions through the station reverse. Some of these changes can be expected to continue for the foreseeable future but further changes to gas supply patterns could see the usage of these stations increase along with the usage of other stations which have historically seen much lower operating hours. These changes will inevitably influence future investment decisions.

In order for National Grid to continue to meet their statutory and legal obligations, it is essential to develop and maintain a robust strategy for the operation, maintenance, upgrading and replacement of the compressor fleet. This strategy is key to the delivery of efficient, economic investment and effective operation of the compressor fleet.

The objectives of this strategy are to:
- deliver improvements to resource efficiency at NTS compressor stations, which will drive benefits to the end consumer through reduced operating costs and,
- ensure maximum benefit to the environment, through continuing emissions reduction.

As a consequence of changing gas flows and hence changing compressor utilisation levels, this strategy and the priority sites for investment to reduce local air emissions are reviewed on a regular basis.

Emissions related investment is currently progressing at the following sites:
- St Fergus – Commissioning of the Electrically Driven Compressors being installed to provide the bulk compression duty, these are scheduled to be operational during 2013.
- Kirriemuir – Commissioning of the Electrically Driven Compressor to provide the bulk compression duty. This is currently expected to be operational in very late 2012 or early 2013.
- Hatton – Commissioning of the Electrically Driven Compressor to provide the bulk compression duty. This is scheduled for 2013.
- Initiation of the Front End Engineering Design study for the Peterborough site as part of the Phase 3 Emissions Reduction Programme.
- Ongoing work to establish the likely costs and viability of a High Voltage connection to the Huntingdon site as part of the initial option evaluation process for this site. Due to the proximity and interconnection between the compressor stations at Peterborough and Huntingdon, the installation and commissioning of any new compression plant at Huntingdon must follow the works at Peterborough.

4.3 continued
Future investment

4.3.7
Industrial Emissions Directive

The European Union Industrial Emissions Directive (IED) must be transposed into UK law no later than January 2013. The IED imposes strict emissions limits on gas turbines of greater than 50 MW thermal input. The implication of the IED for National Grid is that a number of the larger gas turbines operated by National Grid will need modifying or replacing in order to meet the new emission limit values for oxides of nitrogen (NOx) and carbon monoxide (CO). Compliance with the new emissions limits is mandatory after 1st January 2016 however, National Grid will be entering those machines in its fleet which are not compliant with the requirements of the IED into a limited life derogation, allowing the continued operation of these non-compliant machines until either 31 December 2023, or when the machine has accumulated a total of 17,500 operating hours (whichever is soonest).

The precise details of how the Directive will be transposed into UK law and the subsequent impact on National Grid's gas generator fleet remains uncertain at the time of writing.

The European Commission has committed to reviewing this Directive by December 2012 with a view to its application to smaller, lower powered machines. If the IED compliance threshold is reduced, this would significantly increase the number of gas turbines in the National Grid fleet that are affected.

37 We have conducted early network analysis studies on the Sapperton to Easton Grey pipeline given the uncertainty regarding SW demand growth, however, have limited information that may be shared with the industry at this time given the needs case is still under review.

4.3.8 Projects approved for construction in 2012 onwards

The tables below indicate the status of existing construction projects. Those identified as 'Load related' were triggered by incremental capacity release during the current price control.

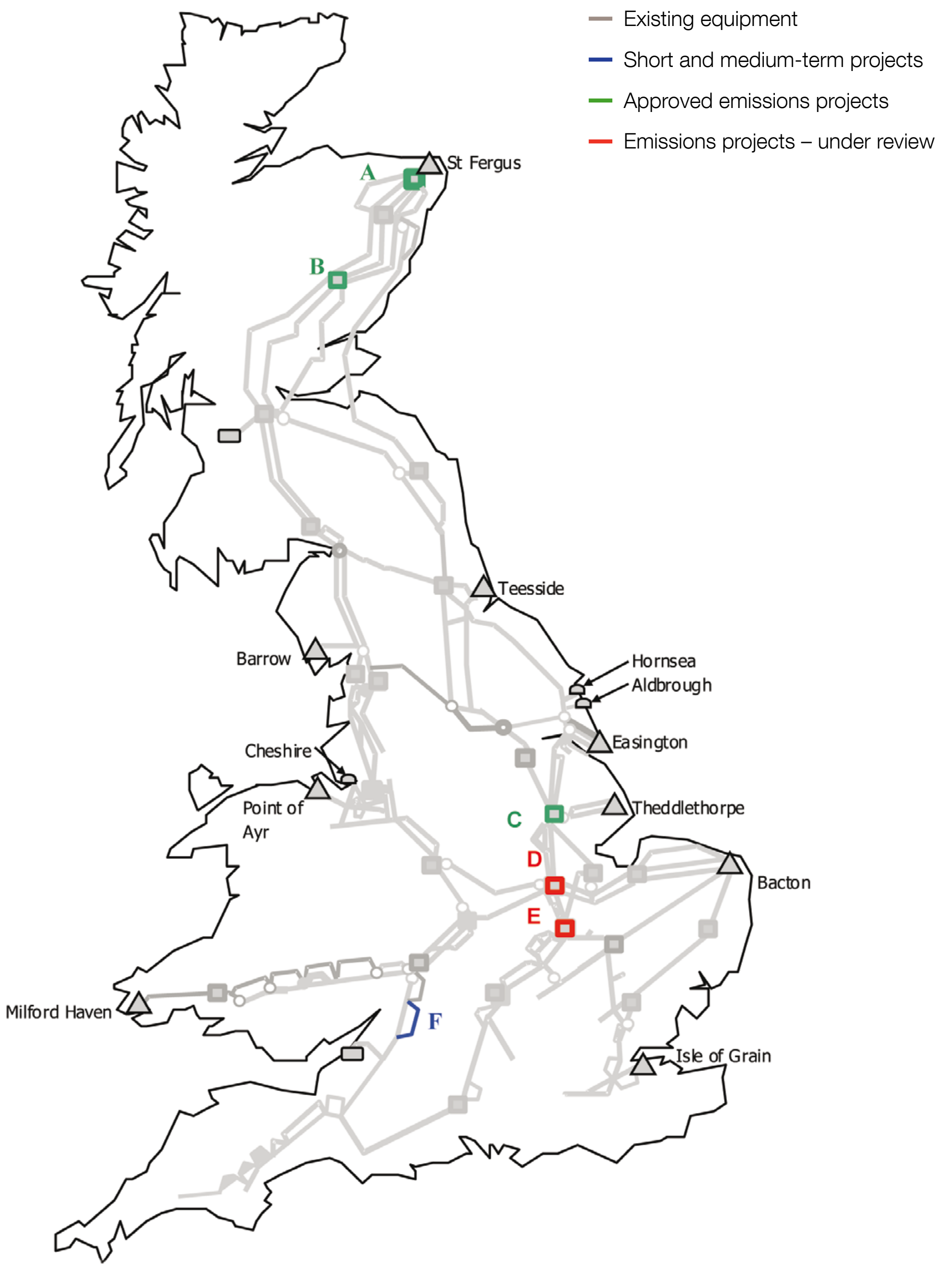
Table 4.3A:
Projects approved for construction in 2013 onwards

Map ref.	Project	Scope	Driver
A	St. Fergus Compressor Station	New Unit	Emissions Reduction
B	Kirriemuir Compressor Station	New Unit	Emissions Reduction
C	Hatton Compressor Station	New Unit	Emissions Reduction

Table 4.3B:
Projects under review
(note that locations are indicative and subject to change as we progress through the planning process)

Map ref.	Project	Scope
D	Peterborough Compressor Station	New Unit (Emissions Reduction driven)
E	Huntingdon Compressor Station	New Unit (Emissions Reduction driven)
F	Sapperton to Easton Grey Pipeline	16.7km x 900mm (Load related)[37]

Figure 4.3D:
NTS projects, completed, approved and under review
Source: National Grid



4.3.9
Longer-term projects

A key part of our planning process is understanding what system reinforcements may be necessary to meet future customer requirements as a result of the enquiries we receive for new connections to the network. This process enables us to give a view on where there may be spare capability in the system, (to meet new connection requests without reinforcement), and conversely where the system is operating close to its current capability and any new connection will likely result in a requirement for reinforcement.

If physical reinforcement were to be identified as the required solution, NTS projects post-2013 that would be considered to provide capacity beyond the requirements of medium term supply patterns include:

- Reinforcement across the Midlands and East Anglia for new storage connections on the East Coast of England.
- Reinforcement in the South East of England for new power station connections.
- Reinforcement in the South West of England for new power station connections.
- Reinforcement in the North West of England for potential increased levels of supply.
- Reinforcement in the South East of England for potential increased levels of supply.
- Reinforcement in South Wales for potential increased levels of supply.
- Reinforcement of the feeder in the South West of England to meet the long-term requirement for Operating Margins as LNG storage may not be able to continue to provide reliable services, and potentially no service at all beyond the end of the rollover period.
- As discussed in section 4.3.5, we are also considering the need for projects to increase the flexibility of the network in response to changing supply and demand patterns, including the impact of intermittency in wind power generation.

It is important to stress that these projects are indicative and dependent on the receipt of appropriate user signals. The timing of such projects will, in part, be dependent on the effect of entry and exit capacity substitution but will be endorsed by the signals received through entry and exit commercial processes. It is unlikely that substitution will remove the need for investment in the system in the long term, but may delay a small number of projects where anticipated flows are capped by obligated capacity levels over a period until incremental entry capacity is re-signalled by shippers.

Chapter five

Industry Frameworks Developments

5.1 Overview

38 Uniform Network Code

National Grid remains committed to the development of commercial arrangements that encourage timely and appropriate market responses to secure energy supply demand balances. This chapter reflects ongoing industry discussions, the details of which can be found on our website or the relevant industry code administrators' website. A number of initiatives have been developed during this year and where applicable will be further developed over the coming year. The major areas of commercial developments are:

- RIIO-T1
- Enduring NTS Exit Capacity Arrangements
- Entry Capacity Regime Developments
- Transmission Charging
- European Developments
- Facilitation of new types of NTS entry facilities
- Revision to the Gas Balancing Alert Arrangements
- SO incentives
- Security of Supply – Significant Code Review
- UNC[38] Modification 0373 "Governance of the NTS Connection processes"
- Aligning NTS Capacity and Connections Processes.

5.2 RIIO-T1

RIIO-T1 (Revenue = Incentives + Innovation + Outputs) is the first Transmission price control under Ofgem's new model of regulation and will run from April 2013 to March 2021.

In July 2011 and in March 2012, National Grid submitted Transmission Owner (TO) business plans for the RIIO-T1 period which were developed in conjunction with our stakeholders.

We then submitted our System Operator (SO) External Incentives business plan to Ofgem in May 2012 which also included further information in relation to our proposals for constraint management and NTS Capacity delivery.

Further information on National Grid's RIIO-T1 business plans can be found at www.talkingnetworkstx.com.

Ofgem published its initial proposals for RIIO-T1 on 27 July 2012, to which we issued our response on 21 September 2012.

We are currently awaiting Ofgem's final proposals for RIIO-T1, which will be published on 17 December 2012.

5.3 Enduring NTS Exit Capacity Arrangements

The Enduring NTS Exit Capacity Arrangements introduced following the implementation of UNC modification 0195AV went live on 1 October 2012.

In summary, the UNC modification introduced (but is not limited to) the following arrangements for all NTS offtakes (inclusive of NTS/LDZ Offtakes):

- An annual July application process to increase and/or decrease Enduring annual NTS Exit (Flat) Capacity, subject to defined lead-times
- An annual July application process allowing Users to apply for, in annual tranches, any Unsold Firm NTS Exit (Flat) Capacity
- Ad hoc processes allowing Users to increase or decrease their Enduring annual NTS Exit (Flat) Capacity
- ARCA (Advanced Reservation Capacity Agreement) arrangements for non-Users
- Daily NTS Exit (Flat) Capacity auctions, including provisions for Off-peak NTS Exit (Flat) Capacity
- NTS Exit (Flat) Capacity constraint management tools
- Full assignment of Firm NTS Exit (Flat) Capacity
- Transfer of Firm NTS Exit (Flat) Capacity
- NTS Exit (Flat) Capacity Overrun arrangements.

The final phase of exit reform introducing the daily processes was implemented on 29 July 2012 enabling these processes to be utilised from 24 September 2012 for gas flow day 1 October 2012 onwards and therefore all phases of the Gemini Exit Reform system are now live, enabling all enduring activities to be conducted online.

The following UNC Modifications to the Enduring Exit regime were implemented in 2012:

- 0393S – Interruptible to Firm – NTS Supply Points Transition
- 0401 – Amendments to the provisions for agreeing pressures at the Offtakes from the National Transmission System to Distribution Networks
- 0408S – Moffat and Bacton Interconnectors: Changes to Agreements to Align to UNC Modification 0195AV
- 0409S – Removing the restriction on the Users' application quantity for annual NTS Exit (Flat) Capacity
- 0412 – Changes to the Stages of Emergency Resulting from Changes Introduced by Exit Reform
- 0413S – DN Adjustment of notices for the reduction of Enduring annual NTS Exit (Flat) Capacity
- 0417S – Notice for Enduring Exit Capacity Reduction Applications.

5.4
Entry capacity regime developments

5.4.1
Amendment to the NTS System Entry Overrun Charge

In May 2012, National Grid raised UNC modification 0426 to introduce an additional entry overrun charging component in order to remove instances where a user may generate a chargeable System Entry overrun quantity and not incur a System Entry Overrun Charge.

There have been a number of occurrences where users have generated System Entry Overruns and incurred either a zero or no overrun charge, which weakens the incentive on users to procure NTS Entry Capacity in line with their gas flow requirements undermining the "ticket to ride" principle.

We proposed the introduction of a further entry overrun charge component of 8 x NTS Entry Capacity reserve price (i.e. the Annual Monthly System Entry Capacity (AMSEC) Auction reserve price) which would be applicable in instances where

- all NTS Entry Capacity held at an Aggregate System Entry Point (ASEP) on a Gas Flow Day had been bought at zero price, or
- where there was no NTS Entry Capacity booked at an ASEP on a Gas Flow Day by any User.

Following discussion at Transmission Workgroup, this UNC modification proceeded to consultation and has subsequently been recommended for implementation by the modification panel. At the time of writing, we are awaiting Ofgem's final decision.

Further information on this modification can be found on the Joint Office website at www.gasgovernance.co.uk/0426.

5.5 Transmission charging

39 Final (rather than indicative) NTS Exit (Flat) Capacity charges for 1 October 2012 were published for the first time on 1 May 2012 to align with DN charging requirements.

40 www.nationalgrid.com/uk/gas/charges

The UNC facilitated NTS Charging Methodologies Forum ("NTS CMF") is now the industry forum that reviews gas transmission charging arrangements. This follows the implementation of the Ofgem Industry Codes Review final conclusions which resulted in the NTS Transportation and Connection Charging Methodologies being included in the UNC. All shippers, and those conferred Materially Affected Party status, can now propose changes to the charging methodologies via a UNC Modification Proposal.

During 2011, the industry continued to review the issue of exit capacity charge volatility with a focus on modelled supply and demand levels. Following the publication of the 2010 Ten Year Statement, it became clear that the NTS Transportation Charging Methodology, in respect of the setting of NTS Exit (Flat) Capacity charges from 1 October 2012, was no longer workable as total modelled demand, based on the obligated exit capacity levels, exceeded available modelled supplies.

UNC Modification 0356 was raised to seek to address this issue by using forecast demand data as the demand input to the Transportation Model for setting NTS Exit (Flat) Capacity charges from 1 October 2012. An alternative Modification Proposal 0356A was also raised and proposed using booked NTS Exit (Flat) Capacity data as the demand input to the Transportation Model. Modification 0356 was implemented on 1 May 2012 and final NTS Exit (Flat) Capacity charges for 1 October 2012 were published on the same day[39].

The issue of volatility in Transportation Charges, particularly NTS Exit (Flat) Capacity charges, continues to be the subject of industry debate. Particular concerns have been highlighted as the industry transitions from TPCR4 to the new RIIO-T1 price control. National Grid continues to actively engage with the industry on this issue through the NTS CMF.

National Grid has continued the review of entry charging principles. This was in response to continued industry concern about the increasing rate of the TO entry commodity charge. National Grid analysed the existing and potential future entry capacity procurement and in 2010 consulted on the removal of the zero entry capacity reserve prices and discounts for daily capacity. Any potential solutions will need to take account of EU developments on charging including the development of EU network codes on capacity allocation, congestion management and harmonised transmission tariff structures.

The NTS CMF has continued to review all aspects of the NTS Entry and Exit Charging arrangements with initiatives to seek to provide greater transparency with regard to charge setting, including holding a number of industry workshops. Supporting information is available in the Gas Charging area of the National Grid[40] website including a range of reports and presentation material along with details of how to obtain a copy of the Transportation Model used for determining NTS Entry and Exit capacity prices.

5.6
European developments

In September 2009 the European Commission's "Third Package" of legislative proposals for gas and electricity markets entered into force, becoming applicable from 3 March 2011. They outline a new energy framework to better enable progress towards liberalised and open European energy markets. The package implements new rules on EU Transmission companies which include the promotion of ownership unbundling, alongside restrictions on ownership of Transmission companies by non-EU entities.

Another key facet of the regulation is the establishment of a European Network of Transmission System Operators for Gas (ENTSOG), which was created on 1 December 2009. European Transmission companies, certified under the Third Package, have a formal obligation to cooperate through ENTSOG. ENTSOG has been designated with a number of key tasks, through the Third Package legislation which will require the support of all the ENTSOG membership, these tasks include:

- The drafting of up to 12 European Network Codes, based on framework guidelines produced by ACER[41]
- Annual European winter and summer supply outlook reports
- The bi-annual creation of a European Ten Year Network Development Plan (TYNDP)
- Enhancing the provision of information to the market and delivering common network operational tools to coordinate network operation

ENTSOG is now comprised of 39 TSOs members and 2 associated partners from 24 European countries.

5.6.1
Capacity Allocation Mechanism

On 21 June 2011 ENTSOG published the first draft of one of 12 European Network Codes. The draft Capacity Allocation Mechanism (CAM) Network Code was developed after an extensive and interactive stakeholder dialogue and represents the first priority area of European Network Code Development.

On 3 August 2011, the Agency for the Cooperation of Energy Regulators (ACER) submitted the final CAM Framework Guideline to the EU Commission for its review. On the same date, ENTSOG closed its consultation on its draft CAM Network Code. As a result of the responses ENTSOG received on its draft CAM Network Code a second consultation commenced on 24 October 2011. This consultation covered those issues that have changed in the final ACER Framework Guideline and issues on which ENTSOG had re-evaluated its position following feedback to the original consultation. The CAM Network Code was formally issued to ACER on 6 March 2012.

A number of meetings were held between ENTSOG and ACER relating to the content of the CAM Code, culminating in ACER providing an opinion on the compliance with the CAM Framework Guideline on 5 June 2012. It was felt by ACER that it "Generally shows a high degree of compliance with the Agency's Framework Guidelines (FGs). However some specific provisions were not in line with the FGs; or with the objectives; or are out of scope." Following the ACER opinion on the CAM Code, ENTSOG

41 Agency for the Cooperation of Energy Regulators

issued a Stakeholder 'engagement' document on 27 July 2012. This sought industry views on potential changes to the CAM Code and provided further detail where ENTSOG had not accepted some suggested changes proposed by ACER.

A revised second version of the CAM code was delivered to ACER on 17 September. This revised version is not fully in line with the ACER Opinion provided to ENTSOG on 5 June. This Network Code and an ACER final 'qualified recommendation' was issued to the EU Commission on 5 October. The CAM code is expected to enter the Comitology process in December 2012.

5.6.2 Congestion Management Procedures

After the consultation closed on the initial version of the Congestion Management Procedures (CMPs) Comitology Guideline, the Commission presented the results to the Member States on 7 July 2011. As a result of the comments received notably from ENTSOG, a further draft CMP Guideline was issued by the Commission on 11 November 2011. Some of the issues raised by ENTSOG had been addressed, however a number remained. ENTSOG together with other stakeholders had the opportunity to review and respond. On 17 November 2011 Member States met to discuss the proposed CMP arrangements. A further revised version was issued on 20 December 2011. DECC sought GB Stakeholder views on the current version.

The 1st Comitology meeting for Member States was held on 26 January 2012. A number of changes were proposed and a revised version of the CMP Guideline was sent to Member States in order to gather further comments to assist in the next Comitology meeting. The CMP Guidelines were agreed and approved by Member States at the 2nd Comitology meeting on 20 April 2012. The Guidelines are now issued in the Official European Union Journal dated 24 August 2012. The European market has to be compliant with the Guidelines by 1 October 2013.

5.6.3 European Gas Balancing Code

A European gas balancing network code represents the second EU Commission priority area. The gas balancing network code includes rules on nomination procedures, imbalance charges and operational balancing between Transmission System Operators (TSOs) systems.

The 12-month code development process to prepare a gas balancing network code started on 4 November 2011 and the final draft network code was submitted to ACER on 26 October 2012. ACER is required to provide their formal opinion of the draft network code by 26 January 2013. If the draft gas balancing network code is considered to be in line with the ACER gas balancing framework guidelines it will be sent to the EU Commission for them to conduct the Comitology process, which will result in the network code entering into law (expected to take 6–12 months).

National Grid currently considers that the draft gas balancing network code is broadly consistent with the GB regime but, if approved, there would be some impacts on the current UNC. The GB gas industry will have 12 months to comply with the European gas balancing network code once it has been adopted into law but, may choose to request an additional 12 months

5.6.4 Interoperability European Network Code

Interoperability represents the third priority area of European Network Code Development, and refers to the ability of diverse transmission networks to work together (inter-operate) so as to facilitate the exchange of gas across the EU. The aim of the Code is to introduce greater harmonisation in a number of areas of TSO operation that have been identified as potential barriers to the smooth functioning of the EU gas market.

It is envisaged that the Interoperability Code will establish rules to deliver greater levels of harmonisation in the following areas:

- Interconnection agreements
- Nomination and allocation arrangements for interconnectors
- Harmonisation of units
- Gas quality
- Odourisation
- Methods of data exchange between TSOs, and between TSOs and shippers.

Rules concerning Capacity Calculation were originally envisaged to be contained within the Interoperability Code, however at the time of writing, the EC had stated that it was minded to address this within the CAM code at the comitology stage.

In respect of gas quality, it is envisaged that the Interoperability Code will address the potential for flow restrictions across borders due to different specifications and will establish rules concerning the provision of gas quality information by TSOs to parties whose processes could be affected by such changes. The development of a harmonised EU standard for gas quality is a separate project that is being carried out by CEN, the European standards body. Phase 1 of this project (assessment of combustion characteristics) and a cost benefit analysis[42] have been completed and work is now progressing through phase 2 which is looking at the non-combustion parameters. It is currently expected that the standard will be finalised by 2014 and a phased implementation is envisaged. A group of five EU countries (Spain, France, Germany, Belgium and Denmark) for whom the eventual standard is likely to be a more 'natural fit' compared to their prevailing national specifications are already engaged in a 'pilot' exercise to investigate implementation challenges.

ENTSOG are obliged to deliver the Interoperability Code to the EC by 11 September 2013, and have an extensive programme of stakeholder engagement and consultation in place to help achieve this. Following the conclusion of the comitology process it is expected that TSOs will have a period of 12 months to become compliant with its terms.

5.6.5 Security of Supply Regulation

The EU Regulation Concerning Security of Gas Supplies (Regulation 994/2010/EC) which became legally binding on 2 December 2010 had a number of key milestones that had to be met during 2012:

- A Security of Supply Assessment was undertaken at Moffat to see if there was any security of supply benefit for enabling physical reverse flow. This assessment along with the Market Assessment was undertaken in co-operation with TSOs from Ireland. The findings from the Security of Supply Assessment were negative

42 http://ec.europa.eu/energy/gas_electricity/studies/doc/gas/2012_gas_quality_harmonisation_cost_benefit_analysis_.pdf

- Exemption requests for both Moffat and BBL for enabling physical reverse flow were submitted to DECC by 3 March 2012 deadline
- In August 2012 DECC gave exemptions to both Moffat and BBL for enabling physical reverse flow, after taking into consideration the position of the regulators and the European Commission
- Regarding the Supply Standard outlined DECC provided clarity on their website in order to identify the natural gas undertakings responsible for taking measures to ensure gas supply to protected customers under the supply standard conditions as gas shippers
- DECC produced a draft Preventative Action Plan and Emergency Action Plan within the timescales stipulated in the Regulation, National Grid supported this process where requested
- Publication of the Preventative and Emergency Action Plans is due by 2 December 2012, National Grid understands this deadline will be met.

5.6.6 Energy Infrastructure Package

The European Commission released a proposal for an energy infrastructure regulation on 19 October 2011. The proposal was based on the Commission's communication on 'energy infrastructure priorities for 2020' published in November 2010. The key points of the proposed regulation are:

- Creation of Projects of Common Interest
- Improving Permitting Procedures
- Improving Regulatory Treatment
- Improving Financial Conditions

The text is in the final stages of negotiation between the Commission, European Parliament and the Council. It is expected to be approved by the end of 2012 and enacted in Q1 2013.

5.6.7 Ten Year Network Development Plan 2013–2022

ENTSOG have an obligation as stated in the 3rd Energy Package, to produce a non-binding community-wide Ten Year Network Development Plan every two years. The last iteration of the report was published in February 2011 (TYNDP 2011–2020). The report was seen as a significant improvement on the pilot report. ENTSOG are now developing the next version of the TYNDP, based on stakeholder feedback, and the best practices from the Network Code development process. ENTSOG hosted seven stakeholder joint working sessions, and announced the results at the TYNDP workshop in June 2012. The indicative publication date for the next version of the TYNDP is early 2013.

5.6.8 European reporting obligations

Regulation EC 715/2009 obliges TSOs to publish the technical information necessary for network users to gain effective access to the system. This requirement was amended with the introduction of the new legislation on congestion management principles to require TSOs to publish all data as of 1 October 2013 on one Union-wide central platform, established by ENTSOG.

5.6 continued
European developments

Further reporting obligations are required by the European Regulation on Energy Market Integrity and Transparency (REMIT) which sets up a framework for the monitoring of wholesale energy markets with the aim of detecting and deterring any market abuses. In October 2012 National Grid launched a new voluntary web-based service to support GB Market Participants obligated under Article 4 of Regulation (EC) No 1227/2011 (REMIT), to disclose inside information. The service enables market participants to manage their REMIT inside information notifications on a central site and allow interested parties to view notifications via their chosen internet browser. There is also the facility to receive notifications via email or Twitter. This service is free to use and open to all.

5.7 Facilitation of new types of NTS entry facilities

43 Gas Safety (Management) Regulations

Since summer 2010, National Grid has worked with the industry to consider and develop new commercial arrangements that could facilitate the connection and delivery of a new and unconventional source of gas – coal bed methane (CBM) – to the National Transmission System. The developer of the first CBM project in the UK has requested, and National Grid agreed, in principle, to facilitate the project by constructing two NTS connections, one for NTS exit and the other for NTS entry. This would facilitate the offtake of GS(M)R[43] compliant gas from the NTS through the exit connection to the coal bed methane facility where it would be commingled by the facility operator with non-GS(M)R compliant coal bed methane gas. Where the resulting blended gas met GS(M)R compliance, this gas could then enter the NTS via another pipeline linking the coal bed facility to the entry connection.

To further facilitate this project, National Grid raised UNC Modification 0363 "Commercial Arrangements for NTS Commingling Facilities", which was implemented on 1 October 2012. This Modification introduced the concept of an "NTS Commingling Facility" into UNC whose charging and allocation arrangements are to be based on the net daily flows of gas measured at the exit point and the entry point.

5.8 Revision to the gas balancing alert arrangements

Modification 0415, Revision to the Gas Balancing Alert Arrangements, seeks to improve information to the market provided by the System Operator. The modification looks to split the current day ahead and on-the-day Gas Balancing Alerts (GBA) into a Margins Notice (equivalent to the current day ahead GBA) and a Gas Deficit Warning (similar to the current on-the-day GBA). The modification was approved in October 2012 and went live at the beginning of December.

5.9
SO incentives

For incentive year 2012/13 five of National Grid's seven SO incentive schemes were rolled over for a single year[44] from 2011/12. With the remaining two schemes having being set for a two year period from April 2011, all seven schemes will expire at the end of March 2013 and are currently under review to determine the optimum approach to incentivisation of the System Operator over the eight-year RIIO-T1 period from April 2013. The only notable change for 2012/13 was the replacement of the 'unaccounted for gas' financial incentive with a reputational scheme in the form of a new licence obligation.

For the RIIO-T1 period, Ofgem has proposed that the framework for existing System Operator incentive schemes be fixed for eight years to align with the Transmission Owner (TO) price control period. For new schemes (in respect of our maintenance and national demand forecasting activities) it is proposed that an initial two-year duration is appropriate. Subsequently, the new schemes will be reassessed to determine suitability for the remainder of the RIIO-T1 period.

Development of the incentive schemes is ongoing[45], with Ofgem's Final Proposals for SO incentives in the RIIO-T1 period expected in mid December 2012.

44 A summary of the current incentive schemes can be found here: www.nationalgrid.com/NR/rdonlyres/D51340E1-5868-41BA-A567-8D1BBA92DDDC/53243/SupportingInformationDocumentv40pdf.pdf

45 Ofgem's initial proposals with responses from stakeholders are available here: www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=306&refer=MARKETS/WHLMKTS/EFFSYSTEMOPS/SYSTOPINCENTSupportingInformationDocumentv40pdf.pdf

5.10
SCR security of supply – significant code review

Ofgem initiated a Significant Code Review on the arrangements governing a gas deficit emergency in January 2011. This review looks to improve the current security of supply arrangements. As part of the SCR process, Ofgem are considering the emergency cash out arrangements and payments for involuntary reduction of firm demand. Ofgem's Proposed Final Decision[46] document outlines the proposed arrangements. Ofgem aim to implement their proposals for winter 2013/14.

Whilst these proposals will affect commercial arrangements, it is not anticipated that they will have a significant impact upon the day-to-day operation of the National Transmission System.

46 http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/GasSCR/Pages/GasSCR.aspx

5.11
UNC modification 0373 "Governance of the NTS Connection processes"

47 http://www.nationalgrid.com/uk/Gas/Connections/National+Transmission+System+-+Gas+Connections/

UNC Modification 0373 was implemented on 1 August 2012 to formalise applications for NTS Connections by providing a transparent, clearly defined, robust and time-bound process.

National Grid fully supported the development of 0373 and engaged in industry discussion to shape the final process and associate documentation.

Further information on the processes introduced following the implementation of modification 0373 can be found on National Grid's website[47].

5.12
Aligning NTS capacity and connections processes

The Planning Act (2008) introduced a new process for planning decisions for Nationally Significant Infrastructure Projects (NSIPs), which are applicable to gas infrastructure projects. For NSIPs, the new planning process requires extensive optioneering and consultation with the community prior to the consideration of the application by the Planning Inspectorate and decision by the Secretary of State. This is likely to increase lead-times for complex construction projects to between an estimated 72 and 96 months from the point of a formal capacity signal to delivery of that capacity. However, the default lead-times contained within National Grid's Transporter licence places an obligation on National Grid to deliver Incremental Entry and Exit NTS capacity to a 42 and 36-month lead-time respectively.

In response to the changes introduced by the Planning Act, National Grid has developed a generic multi-stage timeline, which has been shared with the industry, to illustrate the planning process stages leading up to a submission to the Planning Inspectorate. It is important to note that this is a generic timeline, and the actual duration of each stage will be dependent on the nature and complexity of each construction project.

Planning Stage		Activity	Duration
1a	Strategic Optioneering	Establish the need case and identify technical options	Up to 6 months
1b		Develop Strategic Options Report (SOR)	Up to 6 months
2	Outline Routing and Siting	Identify Preferred Route Corridor / Siting Studies	Up to 15 months
3	Detailed Routing and Siting	Undertake EIA (Environmental Impact Assessment) and detailed design	Up to 24 months
4	Development Consent Order (DCO) Application Preparation	Formal consultation, finalising project, preparation of application documentation	
5	DCO Application, Hearings and Decision	Submission and examination	Up to 15 Months
6		Approval process	

Please note this table does not include construction activities.

Through our Talking Networks events held in 2011, we highlighted that the impact of the Planning Act (2008) meant that the current obligated lead-times applicable to Incremental entry and exit capacity were not achievable where significant network investment would be required. Releasing Incremental NTS Capacity to these obligated lead-times could result in considerable constraint management costs to the industry.

National Grid's March 2012 RIIO-T1 business plan submission included a number of proposals that could address this issue whilst facilitating the overarching objective of delivering connections and capacity together, in the most efficient lead-time and in a transparent manner. Following this, National Grid and the industry have been working together in order to further develop two potential solutions to modify and align the NTS Capacity and Connections Processes more effectively. Each of the solutions proposes the introduction of a bi-lateral contract for parties wishing to signal Incremental capacity and would enable customer and National Grid timelines to be aligned, with connections and capacity being delivered together. This process aims to provide more certainty to project developers, with transparency of all the process steps and deliverables required from both parties and sets out a timeline from initial contact through to capacity release whilst also allowing the review, discussion and potential revision of that timeline and break-out points. The timelines will be developed in conjunction with our customers and will be assessed on a site-by-site / project-by-project basis and as a result lead-times may be variable. This would be accompanied by a phased user commitment that would ramp up in line with progression through the process, culminating in full user commitment once a formal capacity signal is received in line with the current UNC principles.

Further detail on each of the two solutions can be found below:

a. **Planning and Advanced Reservation of Capacity Agreement (PARCA)**
   This solution develops the long-term NTS Entry and Exit capacity release mechanisms and extends the current UNC ad hoc application provisions that allow Users to reserve Enduring NTS Exit Capacity to allow the reservation of both NTS Exit and Entry Capacity.
   - Based upon the existing Advanced Reservation of Capacity Agreement (ARCA) for NTS Exit Capacity which is currently available to developers.
   - Incremental NTS Capacity, which cannot be provided via substitution, is only guaranteed to be released where a PARCA has been agreed by National Grid and a Developer or a User.
   - Where a PARCA has been agreed, the associated Incremental NTS Capacity at an NTS Entry / Exit Point is exclusive to the PARCA signatory or the PARCA signatory's Nominated User.
   - Baseline NTS Capacity, Non-obligated Incremental NTS Capacity and Incremental NTS Capacity that can be provided via substitution will be made available through Annual Quarterly System Entry Capacity auctions and annual Enduring Annual NTS Exit (Flat) Capacity processes or can be reserved through a PARCA by a Developer or a User.
   - This solution ensures that a PARCA Signatory has exclusive rights to the capacity and allows lead-times to be determined on an individual project basis.

5.12 continued
Aligning NTS capacity and connections processes

b. Split Auctions with Pre-Capacity Agreement (PCA)

This solution develops the long-term NTS Entry and Exit capacity release mechanisms to provide greater alignment of customer and National Grid timescales and clarity of Incremental Capacity release timescales and quantities.

- Incremental NTS Capacity, which cannot be provided via substitution, will only be guaranteed to be released where a Pre-Capacity Agreement (PCA) has been agreed by National Grid and a Developer/User.
- Where a PCA has been agreed, the associated Incremental NTS Capacity is exclusive to the PCA signatory.
- In order to ensure this, Incremental NTS Capacity, which cannot be provided via substitution, will only be made available through ad hoc Quarterly System Entry Capacity auctions and ad hoc Enduring Annual NTS Exit (Flat) Capacity processes and only to a PCA signatory.
- Baseline NTS Capacity, Non-obligated Incremental NTS Capacity and Incremental NTS Capacity that can be provided via substitution will still be made available through Annual Quarterly System Entry Capacity auctions and annual Enduring Annual NTS Exit (Flat) Capacity processes.
- This solution maintains the existing processes and principles for the release of Incremental NTS Capacity whilst ensuring that a PCA Signatory has exclusive rights to the capacity.

The detail of these solutions were developed and presented at the monthly Transmission Workgroup Meetings and National Grid issued draft UNC modification proposals in order to facilitate further discussion. The current industry view is that the PARCA solution is the most appropriate, and we are therefore prioritising the development of this option.

National Grid anticipates submitting a formal UNC modification for development in Spring 2013, and will discuss the associated changes to our Gas Transporters Licence and Methodology Statements with the industry. To complement this we will also issue the PARCA contract for further development. In order to achieve this submission date, we have proposed a step-by-step plan where we will progressively develop different aspects of the business rules (and hence the eventual UNC modification) along with the PARCA contract itself. Each aspect of the solution will be discussed at Transmission Workgroup meetings, allowing the industry to participate in shaping the final solution.

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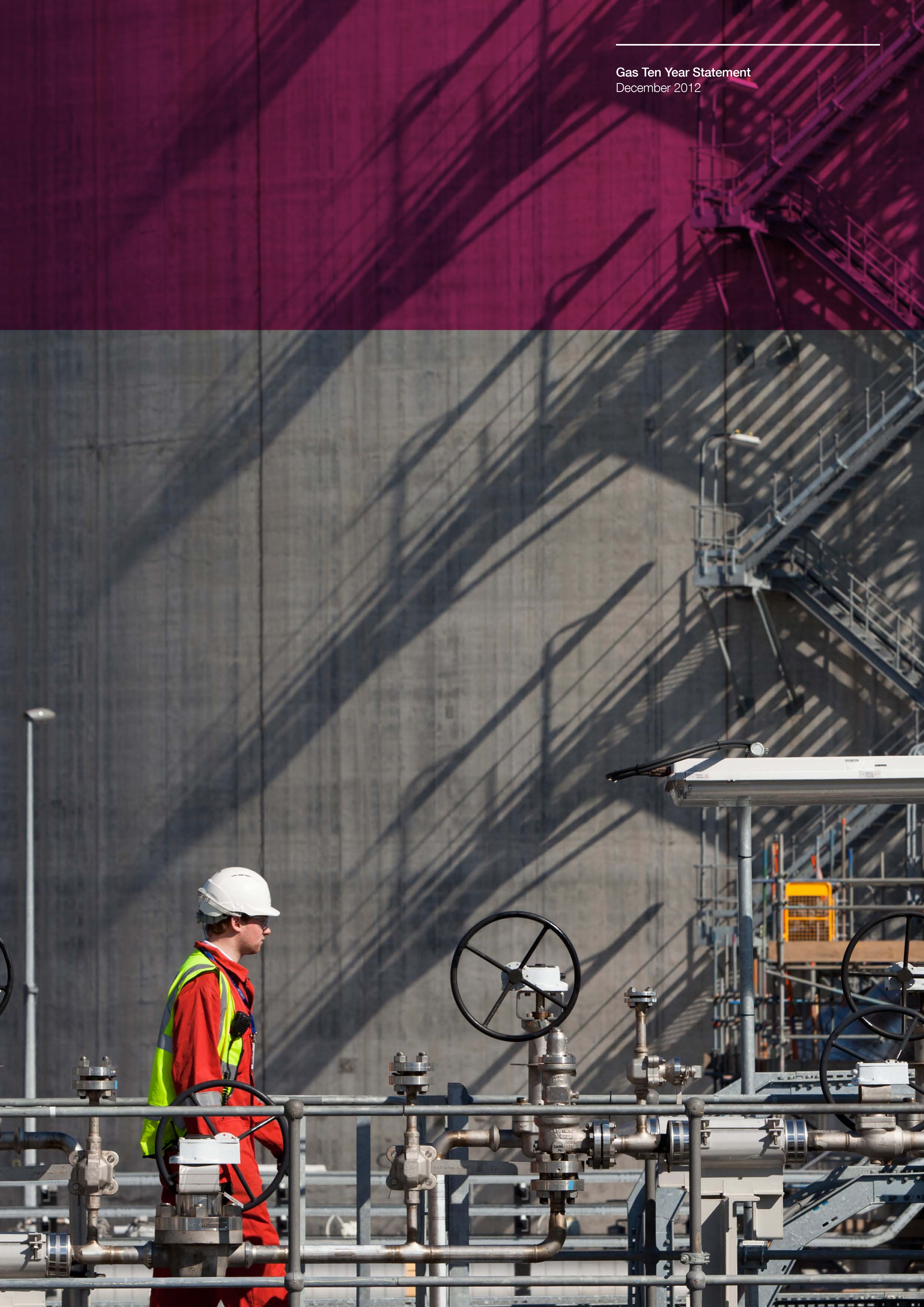


Appendix one
Process methodology

A1.1 Demand

48 www.nationalgrid.com/uk/Gas/OperationalInfo/operationaldocuments/

The purpose of this section is to give a brief overview of the methodology that is adopted to develop scenarios of annual and peak demand. All three scenarios are based on different axioms (explained further in the Future Energy Scenarios document). Unlike previous years, whilst the axioms vary, the same methodology is used for each scenario. The methodology can be categorised into three main modelling areas: annual demand, demand/weather and peak demand modelling. For more information please see our Gas Demand Forecasting Methodology document[48].

A1.1.1 Annual demand modelling

The development of annual gas demand scenarios considers a wide range of factors, from complex econometrics to an assessment of individual load enquiries. For any scenario process a set of planning assumptions is required, which if necessary can be flexed to create alternative scenarios. In the case of the scenarios presented in this document, assumptions include economic, fuel prices, environmental and tax policies, etc. A number of these assumptions are based on data from independent organisations. Our scenarios are also benchmarked against the work of a number of recognised external sources, such as DECC. These are referred to as axioms and differ between scenarios (explained further in the Future Energy Scenarios document).

To gain a better understanding of how these assumptions are utilised and the modelling approach adopted it is necessary to consider the LDZ and NTS processes separately.

A1.1.2 LDZ modelling

LDZ demand is split into 3 NDM (non-daily metered) load bands and total DM (daily metered) demand. For each sector models have been developed that make allowance for economic conditions, local demand intelligence, new large load enquiries, relative fuel prices, potential new markets and other factors, such as the Climate Change Levy, that could affect future growth in demand.

By adopting this approach we are able to take account of varying economic conditions and specific large loads within different LDZs.

A1.1.3 NTS modelling

Historically, NTS demand (i.e. loads with their own connection to the NTS) was limited to a small number of large industrial sites and chemical works. However, with the advent of gas-fired power generation and interconnectors to Ireland and Continental Europe, a new methodology had to be developed. This methodology can best be described by looking at each sector in turn.

A1.1 continued
Demand

A1.1.4
Power generation

The power generation forecast consists of two main elements, firstly, the capacity available to generate and secondly, how frequently this capacity is in operation.

The first element is developed by comparing information from connections requests and load enquiries with feedback received from the Future Energy Scenarios consultation process and a range of commercial sources. In addition, the influence of commercial arrangements, Government policies and legislation are taken into account when deciding which power stations will be built or closed.

To complete the second element, a model has been developed to forecast the demand for electricity generation by fuel type and individual station over the forecast period. The modelling process takes account of station specific operating assumptions, constraints, costs and availability. Actual station data is also used to support the process.

The resultant power generation forecast, encompassing all fuel types, is then used to derive a split between gas-fired stations supplied by the NTS (or embedded within the DNs) and those with their own dedicated pipeline delivering supplies direct from the beach.

A1.1.5
Exports

Forecast flow rates to and from Europe via the Belgium Interconnector (IUK) are based on a market assessment between Continental Europe and the UK, allowing for the seasonal variation of UK gas demand.

Exports to Ireland are derived from a sector-based analysis of energy markets in Northern Ireland and the Republic of Ireland, including allowances for the depletion and development of indigenous gas supplies, feedback from the Future Energy Scenarios consultation, commercial sources and regulatory publications.

A1.1.6
Industrials

The production of forecasts within this sector is dependent on forecasts of individual new and existing loads based on recent demand trends, Future Energy Scenarios feedback, load enquiries and commercial sources.

49 The CWV used for Demand Estimation and published in Data Item Explorer on the National Grid website remains unchanged from last year

A1.1.7 Demand/weather modelling

Demand models are based on Composite Weather Variables (CWVs) defined and optimised for each LDZ. The CWV combines temperatures and wind speeds into a single weather variable that is linearly related to NDM demand. Seasonal normal CWVs (one for each day and each LDZ) are produced using the EP2 methodology, which adjusts seasonal normal weather for climate change. All seasonal normal and average demand forecasts are now based on an EP2 average condition. National Grid has modified the CWV used for these forecasts.[49] The modification results in a slight increase in demand in very cold weather to account for the consistent under forecast that occurs when using the unmodified version.

A1.1.8 Peak day demand modelling

Once the annual demand forecasts and daily demand/weather models have been developed, a simulation methodology is employed, using historical weather data for each LDZ, to determine the peak day (in accordance with statutory/ Licence obligations) and severe winter demand estimates. Where possible, the peak day demand of the NTS supplied loads, such as the power stations, are based on the contractual arrangements. Export demands are treated slightly differently; the Belgian Interconnector is assumed not to be exporting at times of peak demand, due to the high price of British gas, and Irish demand is derived from the market-sector based approach mentioned above. The post exit undiversified peak day is the sum of the expected peak demand at each location and differs from contractual obligations based on sold capacity and baseline capacity.

A1.2
Supply

The main purpose of our supply scenarios is to allow a picture of supply and demand to be derived, which can be used to assess potential National Transmission System (NTS) investments and other business requirements such as compressor utilisation and security of supply analysis. In the past, this process was dominated by developments in the UKCS, as our assessments of Aggregated System Entry Point (ASEP) capacity requirements were dependent on accurate forecasts of UKCS field production. While UKCS data is still an important element of this process, we continue to adapt our processes to manage increasing levels of imported gas. In terms of network design and operation it is not just about the increasing level of imports but how the supply diversity brought about by a combination of surplus of import capacity and potential storage developments will be utilised.

In constructing our long-term gas supply scenarios, we continue to rely on information received from market participants, which we supplement with data from commercial sources. This year we have again had an excellent response to our Future Energy Scenarios consultation process in relation to UKCS supplies, with information from upstream players again accounting for approximately 90% of the total used to compile our UKCS scenarios. As a result, we believe our 2012 UKCS supply scenarios continue to reflect the collective expectations of the upstream UK gas industry.

In terms of future imports we also continue to receive a good response from developers through our Future Energy Scenarios consultation. Indeed in aggregate, the total supply capacity of import projects far exceeds the UK's existing and even future import requirement. On a peak basis the addition of numerous proposals for new storage projects compounds the supply uncertainty as does increasing requirements for network exit capacity from networks, gas-fired power stations and for storage injection. In previous years, National Grid has used various supply scenarios to assist our planning process and stimulate industry debate. Our 2012 supply scenarios relate to our current demand scenarios.

For each of the demand scenarios, we have created different supply scenarios which diverge over time to match the demand scenarios. The supply forecasts also deviate to reflect changing supply requirements. The characteristics of the demand scenarios influence the make up of the supply forecasts, with Gone Green requiring flexibility from fast cycle storage and LNG imports (from gas held in LNG storage tanks) to meet swings in gas demand not least through wind intermittency. Additionally, interconnectors with the Continent could play a role in providing flexibility. A further consequence of more flexible / responsive supplies is the need for a gas network able to accommodate greater flow variations including those from one day to the next to the extent that the level of supply that now needs to be accommodated is appreciably higher than peak demand.

When forecasting future levels of gas storage, to avoid being site specific we have used generic sites which can be substituted for one another as explained in Chapter 3.

A1.3
NTS capacity planning

Using the supply/demand match as an input, we use a network analysis software package to analyse the performance of the transportation system. The network analysis software allows us to identify the location of potential network capacity constraints and helps in the development of suitable reinforcement options that ensure the appropriate level of system security is maintained.

Having identified potential constraints on the system, we evaluate options for adding capacity to the network that represent a safe, economic and efficient solution, whilst maintaining system security. The options available to us to increase capacity include:
- Uprating pipeline operating pressures
- Changing the way the system is configured (changing flow patterns and reversing flows)
- Constructing new pipelines or compressors stations
- Uprating or modifying existing compressors or installing new compressor units
- Building additional flow control valves (regulators) and offtakes.

Investment options are considered with the primary aim of minimising the net-present costs, in accordance with our "economic" and "efficient" obligations under the Gas Act. The drivers for investment are:
- Provision of 1-in-20 peak day capacity, in accordance with Standard Special Condition A9 of the GT Licence in respect of the NTS
- Maximisation of incentives income (e.g. provision of entry capacity)
- Reduction of environmental emissions from compressor stations
- Delivering customer contracted quantities of capacity.

The aim of minimising the net-present costs associated with investment requires network analysis to be applied over a long-term (at least ten years) horizon, and many demand conditions (1-in-20 peak day through to summer conditions).

Further information on our investment planning process and how this interacts with commercial processes for capacity release may be found in our Transmission Planning Code, available on our website at www.nationalgrid.com/uk/Gas/TYS/TPC.

A1.4
Investment procedures and project management

All investment projects must comply with our Transmission Investment Management Procedure, which set out the broad principles that should be followed when evaluating high value investment or divestment projects. These guidelines are supported by specific guidelines for the UK Transmission and Distribution businesses.

The investment guidelines define the methodology to be followed for undertaking individual investments in a consistent and easy to understand manner. Together with the planning and budgeting methodology, they are used to ensure maximum cost-efficiency is obtained. For non-mandatory projects, the key investment focus in the majority of cases is to undertake only those projects that carry an economic benefit. For mandatory projects, such as safety-related work, the focus is on minimising the net-present cost whilst not undermining the project objectives or the safety or reliability of the network.

The successful management of major investment projects is central to our business objectives. Our project management strategy involves:

- Determining the level of financial commitment and appropriate method of funding for the project
- Undertaking preliminary studies to ensure projects are feasible and confirm budget estimates
- Developing the most appropriate purchasing contracts methodology
- Monitoring and controlling the progress of the project to ensure that financial and technical performance targets are achieved
- Post-project and post-investment review to ensure compliance and capture lessons learnt.

When a Transmission project is approved, a multi-discipline team prepares an Invitation to Tender in accordance with the EU Utilities Directive. For major projects, specialist consultants with experience of preparing and evaluating tender documents are used.

Tenders are received and evaluated against previously agreed technical, quality, safety, financial and programme criteria. They are compared on a cost basis with a database of capital projects. An award is then made to the most economically advantageous tender consistent with these criteria.

The successful contractor completes the project in accordance with an agreed programme of works. It remains the contractor's responsibility to manage and supervise the works. We monitor the work on a day-to-day basis and manage the funding of the project by careful cost control. Following completion, a Post Completion Review is carried out to provide feedback to management on project performance and to improve future decision-making processes. Our project management of major investment projects is designed to ensure that they are delivered on time, to the appropriate quality standards at minimum cost. The project management process in particular makes use of professional consultants and specialist contractors, all of who are appointed subject to competitive tender. When the project is complete a financial closure report is submitted to the level of management appropriate to the total cost. Lessons learnt are then recorded for future utilisation.

A1.5
Transmission planning code

Special Condition C11 requires that National Grid prepares and maintains a Transmission Planning Code that describes the methodology used to determine the physical capability of the system. It is intended to inform parties wishing to connect to and use the NTS of the key factors affecting the planning and development of the system.

National Grid undertakes investment planning up to a ten year planning horizon on an annual basis. The investment plan is developed using long term supply and demand scenarios which are informed by information gathered through the commercial processes to reserve capacity on the system.

National Grid will commence its annual planning cycle after the initial data has been gathered through the Future Energy Scenarios consultation process and will use this data to compile long term supply and demand scenarios. The planning process will consider those investments that may be required to respond to potential entry and exit capacity signals from the market. National Grid will use detailed network models of the NTS under different supply and demand scenarios in order to understand how the system may behave under different conditions up to the ten year planning horizon.

During this process, Distribution Network Operators (DNOs) and Shippers can apply for exit capacity from the NTS to support their long-term needs, and Shippers may signal their requirements in the long-term entry capacity auctions, under rules set out in the Uniform Network Code (UNC). The information received from these commercial processes will be used to decide the final set of investments that are necessary to develop the system.

National Grid will consider long-term signals received for additional capacity above the prevailing obligated/contracted capacity levels and long term capacity bookings/reservations within obligated/contracted capacity levels within the same annual planning process.

Commercial options available to National Grid will also be considered to avoid or defer investment and to determine the most economic and efficient outcome. Commercial arrangements can include (but are not limited to) booking of constrained services at LNG storage sites, supply turn up contracts, buy-back contracts and interruption contracts.

In light of industry and regulatory developments, the Transmission Planning Code was reviewed and a consultation carried out during 2012 covering changes resulting from the impact of the Industrial Emissions Directive, the European Union Third Package, the Planning Act 2008, and the Capacity and Connections processes. A further review is anticipated in light of RIIO-T1 final proposals.

A1.6
Planning Act (2008)

The Planning Act (2008) introduced a number of changes to the planning system. The establishment of a single consenting regime streamlines the planning system to provide greater certainty, efficiency and consistency for all, whilst ensuring the quality of decision-making, including appropriate community and stakeholder involvement, is improved.

The Act also made statutory the inclusion of pre-application consultation. Engaging earlier in the project development process and using a range of methods to help stakeholders understand the proposal (for example using 3D virtual modelling to demonstrate developments) has shown that the pre-application consultation is fundamental to ensuring effective community engagement. This, coupled with definitive timescales for formal consultation stages of the planning process, should provide greater certainty for delivery of Nationally Significant Infrastructure Projects (NSIP).

The situations where the requirements of the Planning Act 2008 may apply to our gas pipeline projects (new pipelines or diversions) are set out in section 20 of the Act:

a. the pipeline must be wholly or partly in England; and
b. either:
    i. the pipeline must be more than 800 millimetres in diameter and more than 40 kilometres in length, or
    ii. the construction of the pipeline must be likely to have a significant effect on the environment; and
c. the pipeline must have a design operating pressure of more than 7 bar gauge; and
d. the pipeline must convey gas for supply (directly or indirectly) to at least 50,000 customers, or potential customers, or one or more gas suppliers.

A1.6.1
Project lead-times

The Planning Act (2008) has introduced a more stringent planning decision process for projects that qualify as NSIPs. For gas pipeline projects that qualify as NSIPs, the new planning process requires extensive optioneering and consultation with the community prior to the consideration of the application by the Planning Inspectorate and decision by the Secretary of State. This is likely to increase lead-times for complex construction projects to between an estimated 72 and 96 months for the delivery of capacity.

In response to the changes introduced by the Planning Act, National Grid has developed a generic multi-stage timeline, which has been shared with the industry, to illustrate the planning process stages leading up to a submission to the Planning Inspectorate. It is important to note that this is a generic timeline, and the actual duration of each stage will be dependent on the nature and complexity of the construction project.

Figure 5.2A:
Indicative multi-stage timeline
Source: National Grid

Planning Stage		Activity	Duration
1a	Strategic Optioneering	Establish the need case and identify technical options	Up to 6 months
1b		Develop Strategic Options Report (SOR)	Up to 6 months
2	Outline Routeing and Siting	Identify Preferred Route Corridor / Siting Studies	Up to 15 months
3	Detailed Routeing and Siting	Undertake Environmental Impact Assessment (EIA) and detailed design	Up to 24 months
4	Development Consent Order (DCO) Application Preparation	Formal consultation, finalising project, preparation of application documentation	
5	DCO Application, Hearings and Decision	Submission and examination	Up to 15 Months
6		Approval process	

Please note this table does not include construction activities.

We recognise that this investment timeline is not consistent with the default lead-times contained within National Grid's Transporter Licence which places an obligation on National Grid to deliver Incremental entry and exit NTS capacity to a 42-and 36-month[50] lead-time respectively.

National Grid's March 2012 RIIO-T1 business plan submission includes a number of proposals that could address this issue whilst facilitating the overarching objective of delivering connections and capacity together, in the most efficient lead-time and in a transparent manner.

Following this, National Grid and the Industry have been working together in order to further develop two potential solutions to modify and align the NTS Capacity and Connections Processes more effectively. Further information on the ongoing work to align capacity and project development timelines can be found in Chapter 5.

50 The 36-month timeline is from exit capacity allocation following the exit capacity application window.

Appendix two
Gas demand and supply volume scenarios

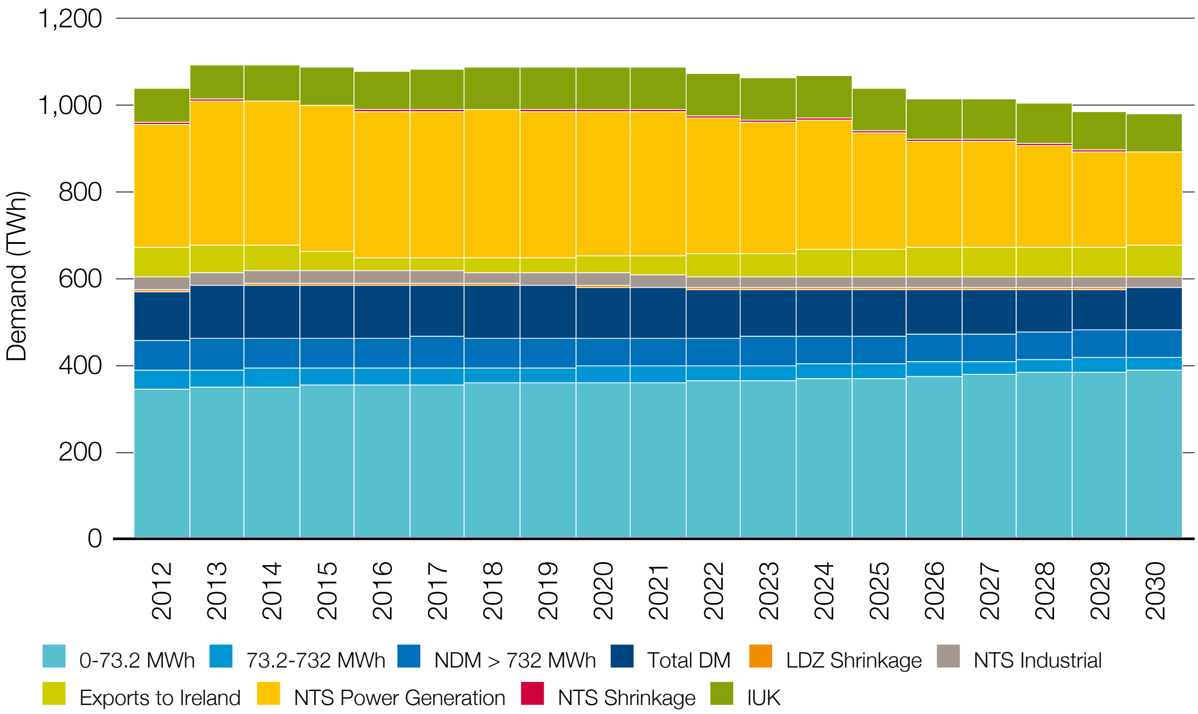
Table A2.1.A:
Slow Progression Scenario: annual demand – Split by load categories (TWh)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
0–73.2 MWh	341	346	349	351	353	355	356	357	358	359	361	363	367	369	373
73.2–732 MWh	44	43	42	41	40	39	38	37	37	36	35	35	34	33	33
NDM > 732 MWh	69	70	70	70	70	70	69	68	68	67	67	66	66	65	64
Total NDM	**454**	**459**	**461**	**462**	**463**	**463**	**463**	**463**	**463**	**462**	**462**	**464**	**467**	**467**	**470**
Total DM	117	122	122	122	122	120	119	118	117	116	113	110	109	107	105
LDZ Shrinkage	4	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Total LDZ	**574**	**584**	**586**	**587**	**588**	**587**	**585**	**584**	**583**	**580**	**578**	**577**	**578**	**577**	**577**
NTS Industrial	30	30	29	29	29	28	28	27	27	27	26	26	26	26	25
Exports to Ireland	65	63	61	46	32	31	32	37	42	47	51	55	62	65	66
NTS Power Generation	287	332	331	336	336	340	342	336	333	332	316	302	300	269	247
NTS Consumption	**382**	**425**	**421**	**411**	**397**	**399**	**402**	**401**	**402**	**406**	**393**	**383**	**388**	**359**	**339**
NTS Shrinkage	4	4	4	3	3	3	3	3	3	3	3	3	3	3	3
Total excluding IUK	**960**	**1014**	**1011**	**1002**	**987**	**989**	**990**	**988**	**988**	**989**	**974**	**963**	**969**	**939**	**918**
IUK	78	78	82	85	89	93	97	100	100	100	100	100	100	98	96
Total including IUK	**1038**	**1091**	**1093**	**1087**	**1076**	**1082**	**1087**	**1088**	**1089**	**1089**	**1074**	**1063**	**1069**	**1037**	**1015**

Figures may not sum exactly due to rounding

A2.1
Demand

Figure A2.1A:
Slow Progression: annual demand



Demand

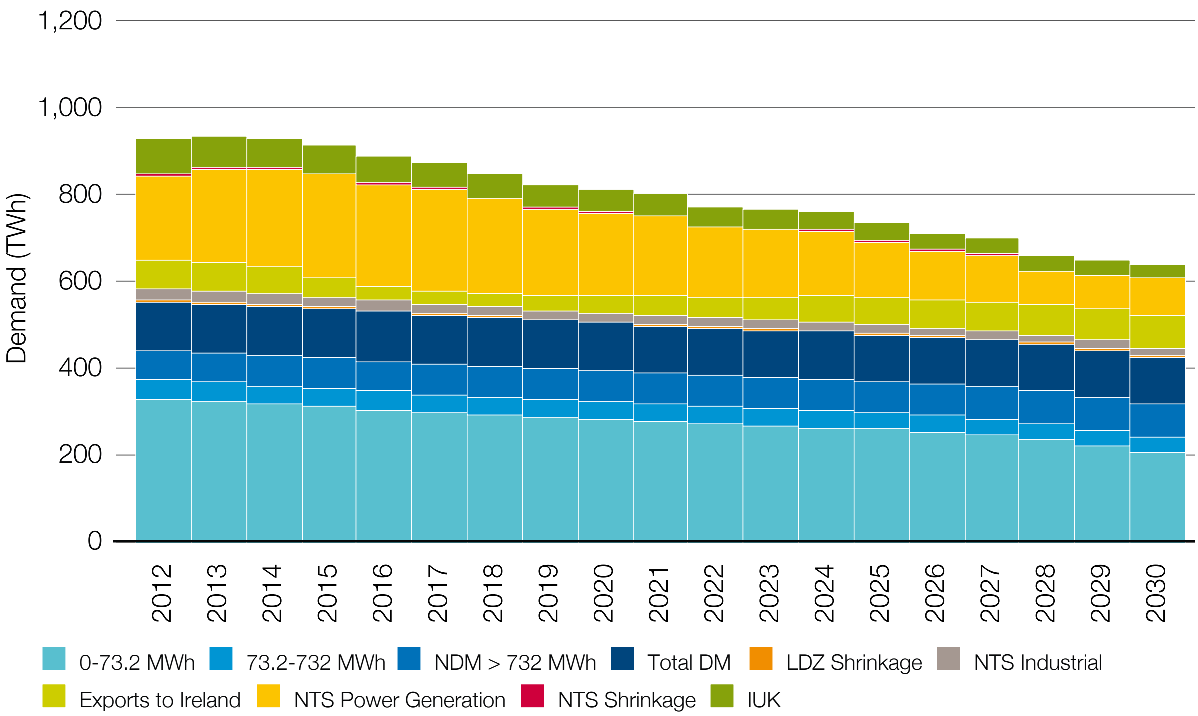
Table A2.1.B:

Gone Green Scenario: annual demand – Split by load categories (TWh)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
0-73.2 MWh	329	324	319	313	305	299	293	288	283	278	273	269	266	261	255
73.2-732 MWh	44	43	43	42	41	41	40	40	40	39	39	38	38	37	37
NDM > 732 MWh	68	68	69	69	70	70	71	71	72	72	72	73	73	73	74
Total NDM	**441**	**436**	**431**	**425**	**417**	**410**	**404**	**399**	**394**	**389**	**384**	**380**	**377**	**372**	**365**
Total DM	110	112	113	114	114	114	112	111	111	110	107	107	107	107	106
LDZ Shrinkage	4	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Total LDZ	**555**	**551**	**547**	**542**	**534**	**527**	**520**	**513**	**508**	**502**	**494**	**490**	**487**	**481**	**475**
NTS Industrial	28	27	24	21	21	21	21	20	20	20	20	20	19	19	19
Exports to Ireland	65	63	61	45	30	29	30	35	40	44	48	52	60	62	65
NTS Power Generation	195	213	226	235	237	233	219	197	187	181	161	156	149	127	110
NTS Consumption	**288**	**304**	**311**	**302**	**288**	**283**	**269**	**253**	**248**	**245**	**229**	**228**	**228**	**209**	**194**
NTS Shrinkage	4	4	4	3	3	3	3	3	3	3	3	3	3	3	3
Total excluding IUK	**847**	**859**	**861**	**847**	**825**	**813**	**792**	**769**	**758**	**750**	**726**	**721**	**718**	**693**	**671**
IUK	78	71	67	63	59	56	53	52	50	48	46	44	42	40	38
Total including IUK	**925**	**931**	**929**	**911**	**885**	**869**	**845**	**820**	**808**	**798**	**772**	**764**	**760**	**733**	**709**

Figures may not sum exactly due to rounding

Figure A2.1B:
Gone Green: annual demand



A2.1 continued
Demand

Table A2.1.C:
Accelerated Growth Scenario: annual demand – split by load categories (TWh)

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
0-73.2 MWh	325	309	294	282	270	257	246	235	225	215	207	197	185	172	158
73.2-732 MWh	45	44	44	43	43	43	42	42	42	42	41	41	41	40	40
NDM > 732 MWh	68	69	70	71	72	72	73	74	74	74	74	75	75	75	76
Total NDM	**439**	**422**	**408**	**397**	**385**	**372**	**362**	**351**	**341**	**331**	**322**	**313**	**301**	**288**	**274**
Total DM	106	107	110	114	114	114	111	111	110	109	108	108	109	109	109
LDZ Shrinkage	4	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Total LDZ	**548**	**532**	**521**	**514**	**502**	**489**	**476**	**465**	**454**	**443**	**434**	**424**	**413**	**399**	**386**
NTS Industrial	29	28	26	23	23	23	22	22	22	22	22	21	21	21	21
Exports to Ireland	65	63	60	43	27	24	24	28	32	35	39	43	48	50	52
NTS Power Generation	189	197	212	218	208	190	165	155	131	113	87	73	76	60	49
NTS Consumption	**282**	**288**	**298**	**285**	**258**	**237**	**211**	**206**	**185**	**170**	**148**	**137**	**145**	**132**	**122**
NTS Shrinkage	4	4	4	3	3	3	3	3	3	3	3	3	3	3	3
Total excluding IUK	**835**	**824**	**823**	**802**	**762**	**730**	**690**	**674**	**642**	**616**	**584**	**564**	**561**	**534**	**511**
IUK	75	51	47	43	40	36	34	32	30	28	26	24	22	20	18
Total including IUK	**910**	**875**	**870**	**845**	**802**	**765**	**724**	**705**	**671**	**644**	**610**	**588**	**583**	**554**	**529**

Figures may not sum exactly due to rounding

Figure A2.1C:
Accelerated Growth: annual demand

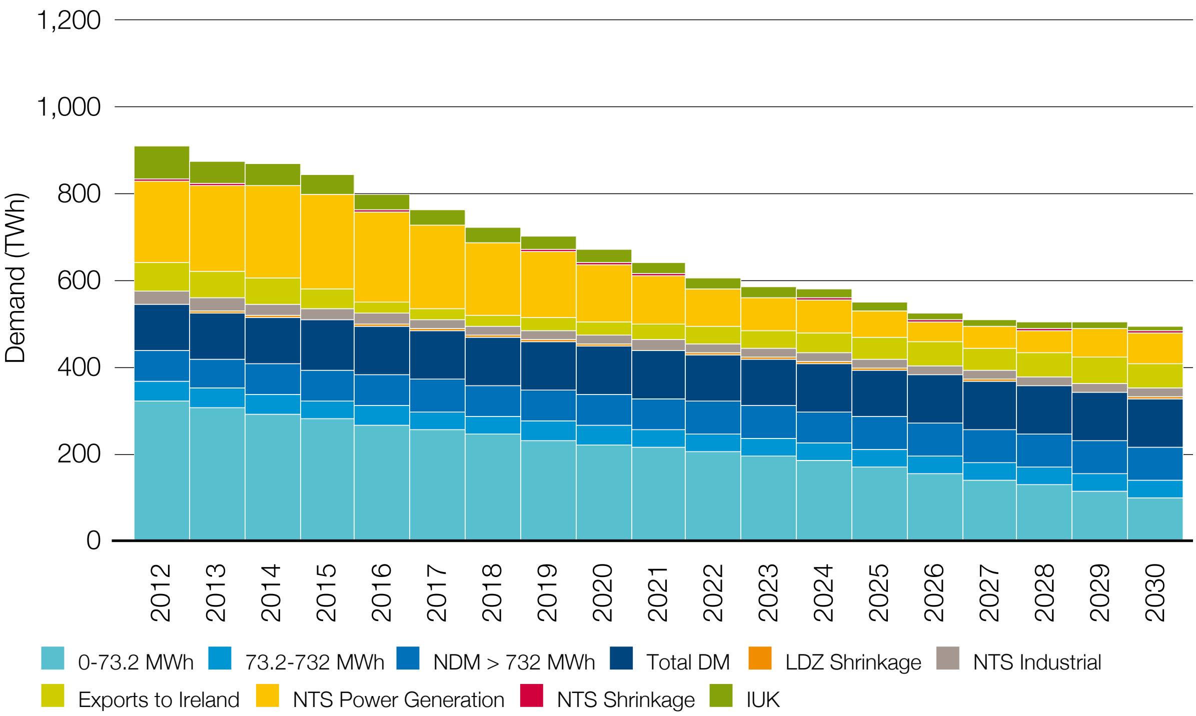
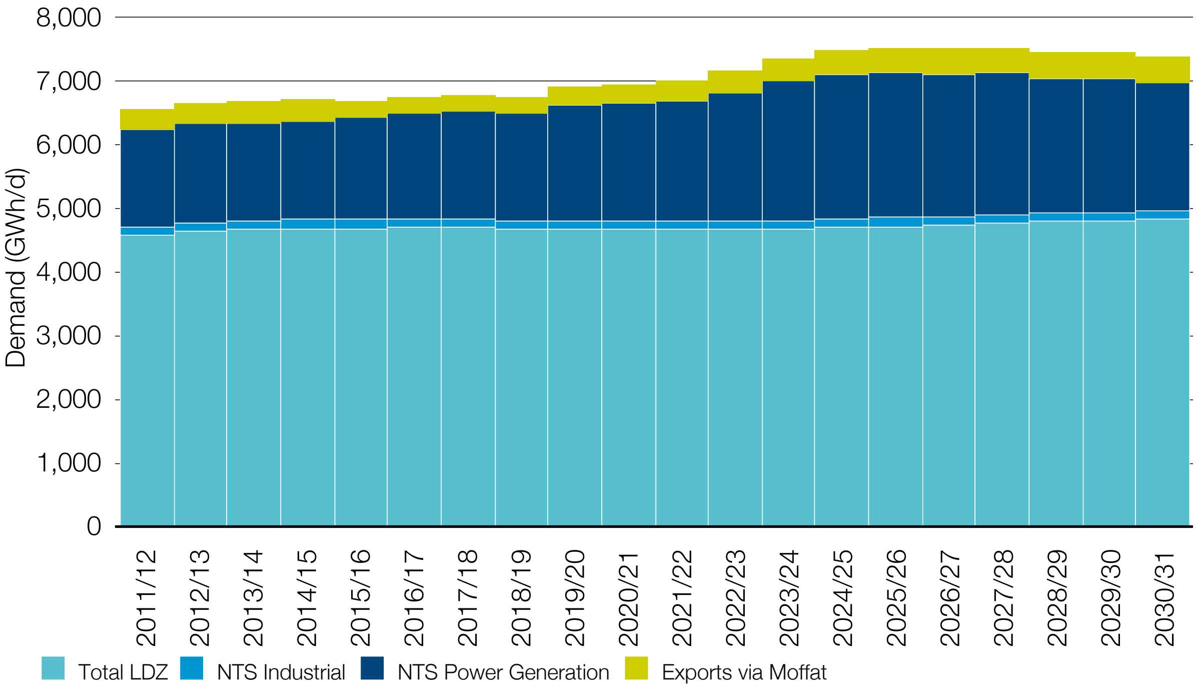


Table A2.1D:
Slow Progression: 1-in-20 peak day undiversified demand (GWh/day)

National	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26
Scotland	349	354	358	359	359	360	361	361	361	362	363	364	366	369	372
Northern	239	241	242	242	241	241	241	240	238	238	238	238	237	238	238
North West	537	548	552	553	552	552	550	548	544	544	542	542	541	542	543
North East	285	288	292	294	294	296	297	297	296	297	297	298	298	300	301
East Midlands	467	475	466	467	467	470	469	469	467	468	469	469	468	470	472
West Midlands	401	407	409	410	409	410	410	410	408	409	408	409	410	411	413
Wales North	51	52	52	51	51	51	51	51	51	51	51	51	51	51	51
Wales South	221	232	234	234	233	233	232	222	219	219	219	220	221	222	222
Eastern	362	369	372	373	373	376	376	376	375	376	376	378	379	381	383
North Thames	483	490	490	490	489	490	490	489	486	486	485	485	485	487	487
South East	514	522	526	527	526	528	528	527	526	527	526	527	521	523	525
Southern	360	366	369	370	370	373	374	374	373	375	376	378	379	381	383
South West	286	291	294	296	296	298	298	299	298	299	300	301	302	304	306
Total LDZ	**4554**	**4635**	**4656**	**4666**	**4660**	**4679**	**4678**	**4662**	**4643**	**4649**	**4651**	**4659**	**4658**	**4679**	**4696**
NTS Industrial	122	122	122	139	139	139	139	134	134	134	134	134	134	134	134
NTS Power Generation	1544	1544	1533	1544	1611	1653	1689	1681	1811	1842	1873	2004	2182	2275	2275
Exports via Moffat	327	329	350	353	249	256	261	263	282	303	325	337	353	383	390
Exports via IUK	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total NTS	**1994**	**1995**	**2006**	**2035**	**1999**	**2047**	**2089**	**2078**	**2226**	**2280**	**2332**	**2475**	**2670**	**2792**	**2799**
Total	**6548**	**6630**	**6662**	**6702**	**6659**	**6727**	**6767**	**6740**	**6869**	**6929**	**6983**	**7134**	**7327**	**7471**	**7495**

Figures may not sum exactly due to rounding

Figure A2.1D:
Slow Progression: 1-in-20 peak day undiversified demand



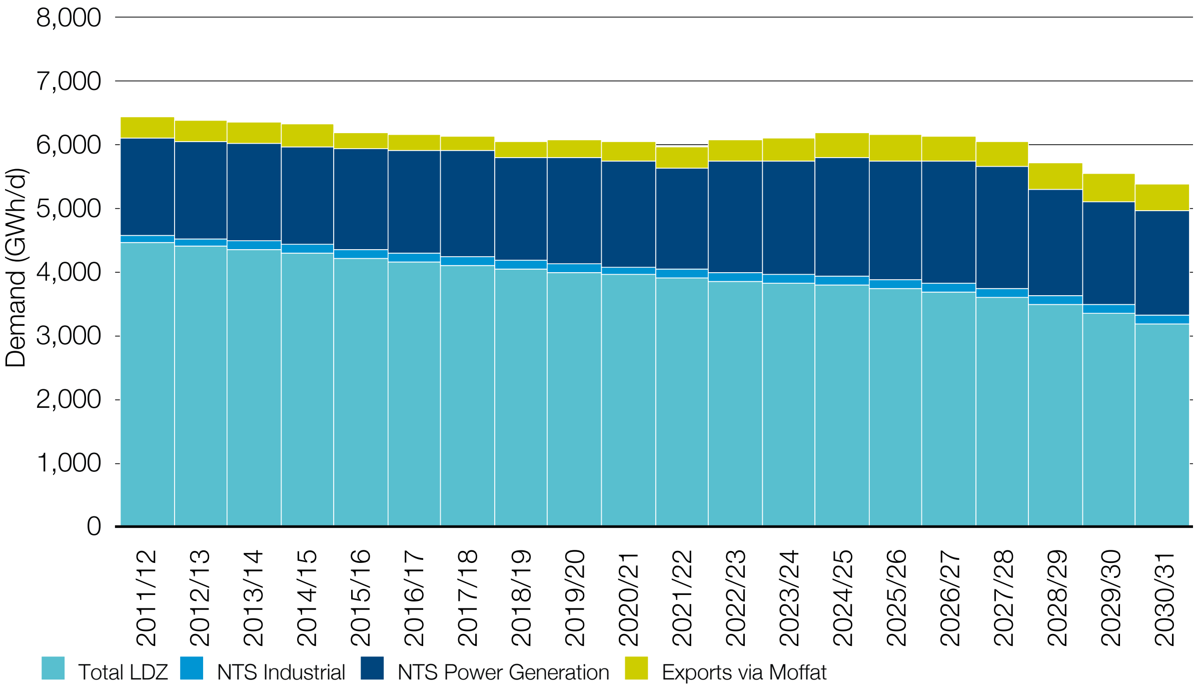
A2.1 continued
Demand

Table A2.1E:
Gone Green: 1-in-20 peak day undiversified demand (GWh/day)

National	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26
Scotland	342	338	334	331	325	320	317	313	308	305	302	299	296	294	290
Northern	235	230	227	225	221	219	216	214	211	209	207	205	203	202	199
North West	529	528	525	521	512	505	499	492	485	481	476	471	466	462	456
North East	278	274	272	269	263	258	255	252	248	246	244	242	239	238	234
East Midlands	459	453	447	431	422	417	412	406	400	397	392	388	384	381	375
West Midlands	394	390	385	379	371	366	361	356	350	348	344	340	336	333	328
Wales North	50	50	49	48	48	47	46	45	45	44	44	43	43	42	42
Wales South	221	215	214	213	206	204	202	200	198	198	195	193	192	191	189
Eastern	356	353	349	346	339	335	331	327	322	320	314	311	307	305	301
North Thames	476	472	467	463	453	447	442	437	430	427	422	418	414	411	405
South East	505	501	495	489	478	472	466	452	444	440	434	429	424	420	414
Southern	353	349	346	341	334	329	325	321	316	314	311	308	305	302	298
South West	280	277	274	270	264	261	257	254	249	247	244	241	238	236	233
Total LDZ	**4477**	**4430**	**4383**	**4325**	**4236**	**4182**	**4131**	**4069**	**4005**	**3976**	**3929**	**3890**	**3846**	**3816**	**3763**
NTS Industrial	122	122	122	137	137	137	137	137	137	137	137	137	137	137	137
NTS Power Generation	1544	1533	1533	1544	1589	1611	1666	1629	1696	1648	1592	1742	1788	1877	1877
Exports via Moffat	327	329	349	350	246	256	241	242	266	310	327	337	359	395	401
Exports via IUK	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total NTS	**1994**	**1984**	**2005**	**2032**	**1973**	**2005**	**2044**	**2008**	**2099**	**2095**	**2055**	**2216**	**2284**	**2410**	**2416**
Total	**6471**	**6414**	**6388**	**6357**	**6209**	**6187**	**6174**	**6077**	**6104**	**6071**	**5984**	**6106**	**6131**	**6225**	**6178**

Figures may not sum exactly due to rounding

Figure A2.1E:
Gone Green: 1-in-20 peak day undiversified demand



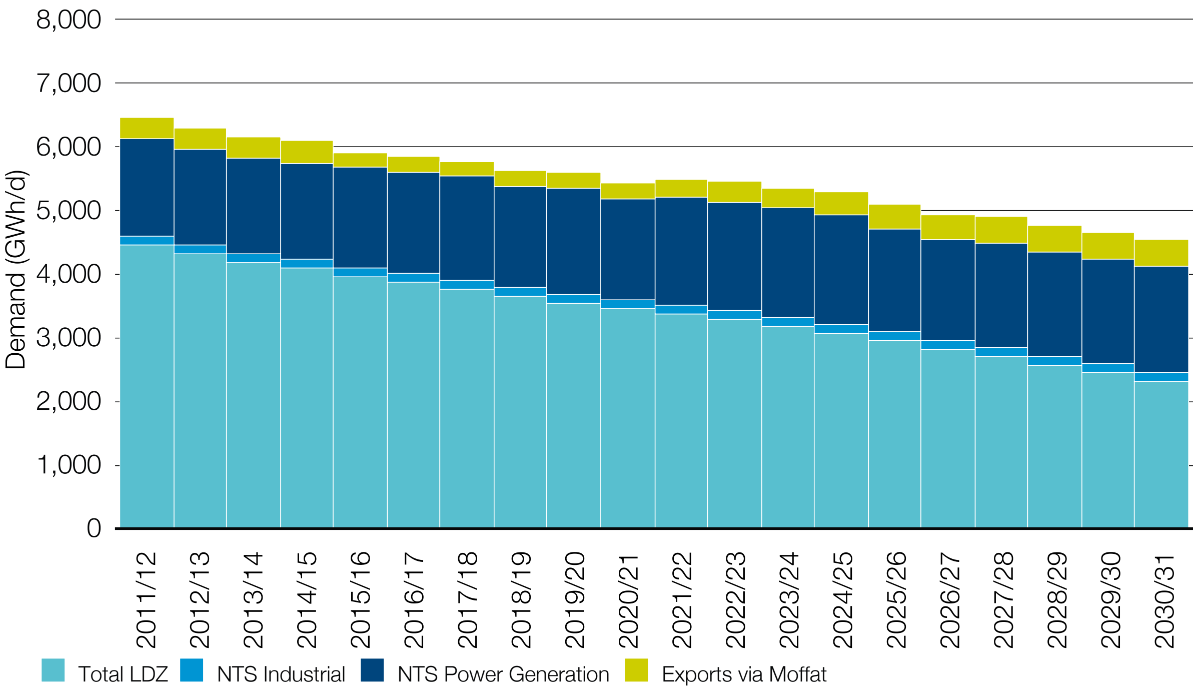
A2.1 continued
Demand

Table A2.1F:
Accelerated Growth: 1-in-20 peak day undiversified demand (GWh/day)

National	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26
Scotland	342	333	323	316	308	300	293	286	278	272	266	260	253	244	235
Northern	234	225	219	215	209	204	199	194	188	184	180	176	171	165	159
North West	528	516	500	488	474	461	448	435	422	413	403	392	379	366	351
North East	278	270	262	256	249	241	235	229	223	218	214	209	202	196	189
East Midlands	459	434	418	409	398	390	380	369	358	350	343	334	323	311	299
West Midlands	394	382	369	357	346	336	327	318	308	301	293	285	276	265	254
Wales North	50	49	47	46	45	44	42	41	40	39	38	37	36	35	34
Wales South	216	210	206	203	199	195	191	187	181	178	175	172	168	164	160
Eastern	356	346	335	330	321	313	305	298	287	277	270	264	255	246	236
North Thames	476	463	447	436	421	410	400	389	377	368	360	350	339	327	314
South East	504	488	471	457	442	429	408	396	383	373	363	352	338	325	309
Southern	353	342	330	322	311	304	296	289	281	275	269	263	255	246	236
South West	280	273	263	256	248	242	235	229	221	216	211	205	198	190	182
Total LDZ	**4470**	**4330**	**4191**	**4091**	**3971**	**3868**	**3760**	**3659**	**3547**	**3465**	**3385**	**3299**	**3192**	**3081**	**2956**
NTS Industrial	122	122	122	137	137	137	137	137	137	137	137	137	137	137	137
NTS Power Generation	1544	1526	1515	1526	1571	1593	1648	1589	1678	1573	1681	1705	1705	1718	1628
Exports via Moffat	327	326	344	343	246	246	236	238	254	272	282	317	328	375	384
Exports via IUK	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total NTS	**1994**	**1974**	**1982**	**2006**	**1955**	**1976**	**2020**	**1964**	**2069**	**1982**	**2100**	**2159**	**2170**	**2230**	**2150**
Total	**6464**	**6305**	**6173**	**6098**	**5926**	**5845**	**5780**	**5623**	**5616**	**5447**	**5485**	**5458**	**5362**	**5311**	**5106**

Figures may not sum exactly due to rounding

Figure A2.1F:
Accelerated Growth: 1-in-20 peak day undiversified demand



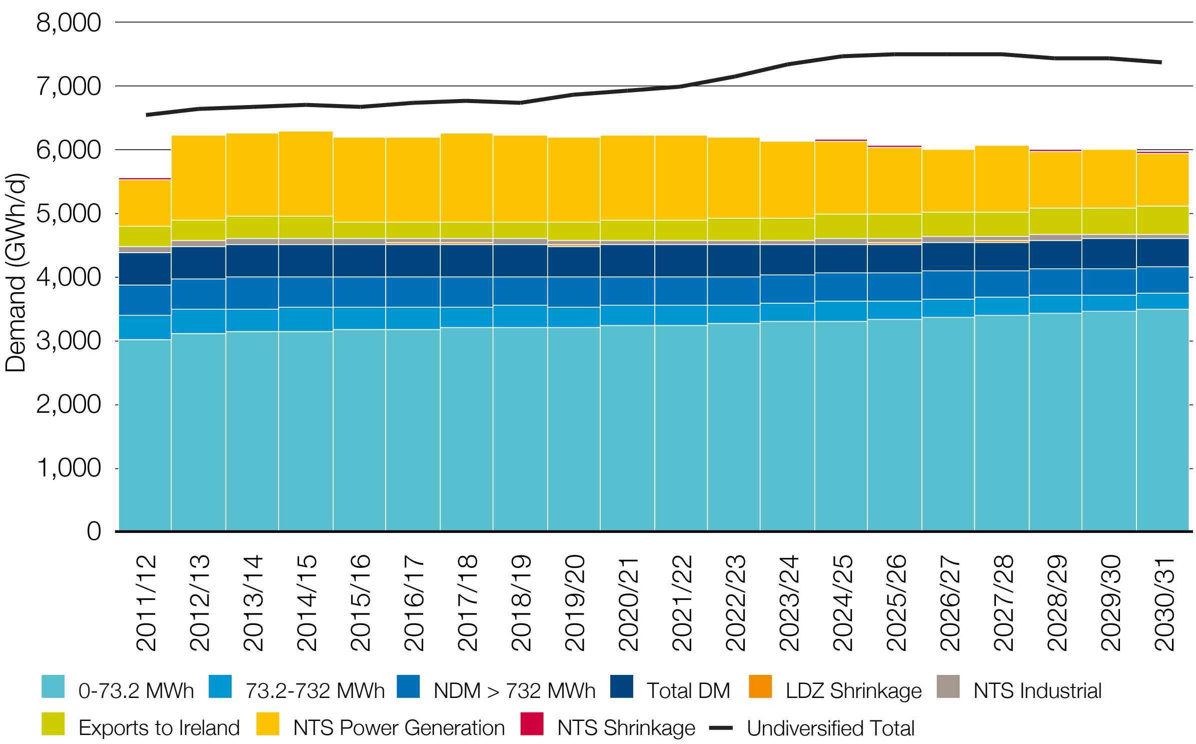
A2.1 continued
Demand

Table A2.1G:
Slow Progression: 1-in-20 peak day diversified demand (GWh/d)

Diversified Peak	**11/12**	**12/13**	**13/14**	**14/15**	**15/16**	**16/17**	**17/18**	**18/19**	**19/20**	**20/21**	**21/22**	**22/23**	**23/24**	**24/25**	**25/26**
0–73.2 MWh	3024	3102	3137	3154	3163	3190	3198	3216	3220	3230	3246	3262	3290	3314	3340
73.2–732 MWh	386	377	366	358	347	342	334	328	317	315	307	302	293	290	283
NDM > 732 MWh	468	479	484	484	479	478	475	470	461	463	455	451	444	444	440
Total NDM	3879	3957	3987	3995	3988	4009	4007	4013	3999	4009	4008	4016	4028	4048	4062
Total DM	**504**	**522**	**513**	**516**	**516**	**514**	**511**	**497**	**491**	**489**	**484**	**480**	**468**	**464**	**461**
LDZ Shrinkage	10	10	9	9	9	9	9	9	9	9	8	8	8	8	8
Total LDZ	**4393**	**4488**	**4509**	**4521**	**4513**	**4532**	**4527**	**4518**	**4498**	**4506**	**4501**	**4504**	**4504**	**4521**	**4532**
NTS Industrial	81	83	82	81	80	78	77	76	75	74	74	73	72	71	70
Exports to Ireland	327	329	350	353	249	256	261	263	282	303	325	337	353	383	390
NTS Power Generation	733	1315	1298	1329	1344	1330	1389	1351	1327	1329	1321	1272	1182	1167	1050
NTS Consumption	**1142**	**1727**	**1730**	**1764**	**1673**	**1664**	**1727**	**1690**	**1684**	**1707**	**1720**	**1682**	**1607**	**1621**	**1511**
NTS Shrinkage	13	12	11	10	9	8	8	8	8	8	8	8	8	8	8
Total excluding IUK	5548	6227	6251	6294	6195	6204	6262	6216	6190	6221	6228	6194	6119	6149	6050
IUK	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total including IUK	**5548**	**6227**	**6251**	**6294**	**6195**	**6204**	**6262**	**6216**	**6190**	**6221**	**6228**	**6194**	**6119**	**6149**	**6050**

Figures may not sum exactly due to rounding

Figure A2.1G:
Slow Progression: 1-in-20 peak day diversified demand



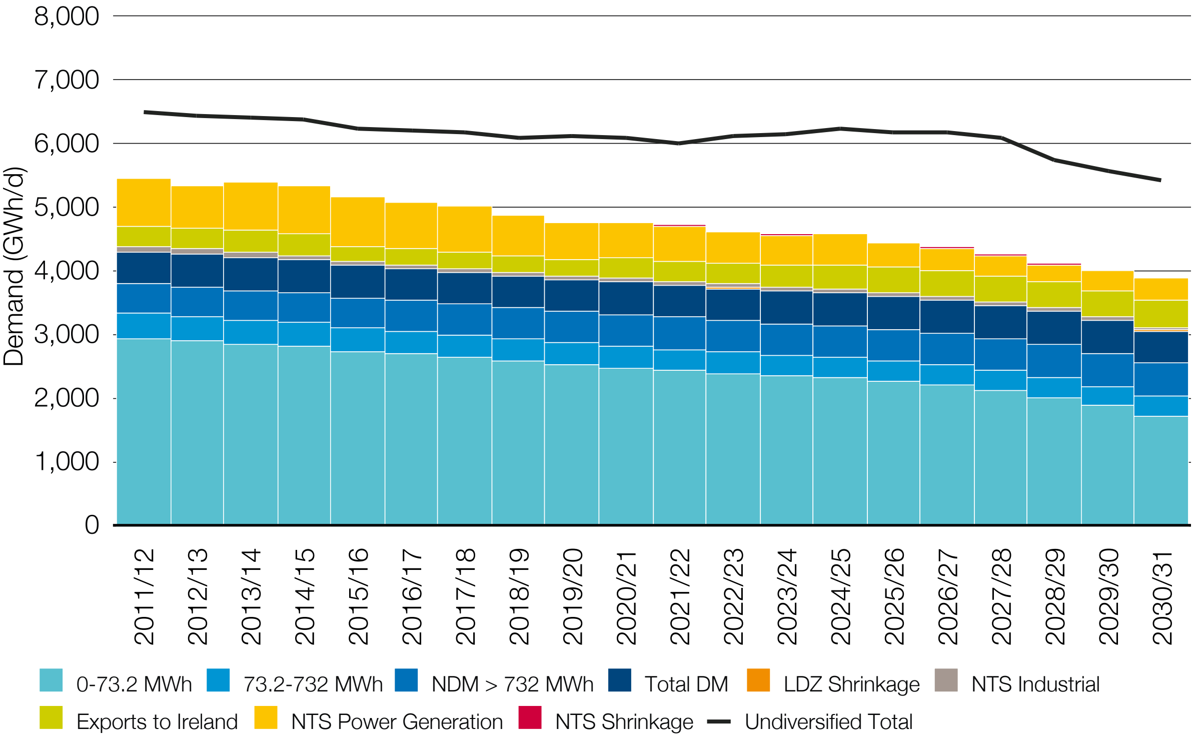
A2.1 continued
Demand

Table A2.1H:
Gone Green: 1-in-20 peak day diversified demand (GWh/d)

Diversified Peak	**11/12**	**12/13**	**13/14**	**14/15**	**15/16**	**16/17**	**17/18**	**18/19**	**19/20**	**20/21**	**21/22**	**22/23**	**23/24**	**24/25**	**25/26**
0–73.2 MWh	2940	2911	2860	2828	2743	2697	2637	2584	2522	2490	2442	2402	2355	2322	2270
73.2–732 MWh	388	380	372	368	363	359	354	350	344	342	337	334	329	326	322
NDM > 732 MWh	463	464	468	474	478	482	486	490	490	493	494	497	499	502	504
Total NDM	**3790**	**3755**	**3700**	**3670**	**3584**	**3539**	**3476**	**3425**	**3357**	**3325**	**3273**	**3232**	**3183**	**3149**	**3096**
Total DM	503	500	503	494	494	493	496	489	490	495	493	494	496	497	499
LDZ Shrinkage	10	10	10	9	9	9	9	9	9	9	9	8	8	8	8
Total LDZ	**4303**	**4265**	**4212**	**4173**	**4088**	**4041**	**3981**	**3923**	**3856**	**3829**	**3774**	**3734**	**3687**	**3655**	**3603**
NTS Industrial	78	76	77	60	59	58	58	57	56	56	55	55	54	54	53
Exports to Ireland	327	329	349	350	246	256	241	242	266	310	327	337	359	395	401
NTS Power Generation	728	655	735	747	760	720	735	639	568	547	547	477	459	464	373
NTS Consumption	**1133**	**1060**	**1161**	**1157**	**1065**	**1035**	**1034**	**938**	**891**	**913**	**929**	**869**	**872**	**912**	**827**
NTS Shrinkage	13	12	11	10	9	8	8	8	8	8	8	8	8	8	8
Total excluding IUK	5449	5337	5384	5340	5162	5083	5023	4869	4754	4750	4711	4611	4567	4574	4437
IUK	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total including IUK	**5449**	**5337**	**5384**	**5340**	**5162**	**5083**	**5023**	**4869**	**4754**	**4750**	**4711**	**4611**	**4567**	**4574**	**4437**

Figures may not sum exactly due to rounding

Figure A2.1H:
Gone Green: 1-in-20 peak day diversified demand



A2.1 continued
Demand

Table A2.1l:
Accelerated Growth: 1-in-20 peak day diversified demand (GWh/d)

Diversified Peak	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26
0–73.2 MWh	2930	2804	2661	2547	2429	2324	2220	2114	2009	1930	1852	1769	1662	1550	1428
73.2–732 MWh	390	386	380	380	376	374	371	367	363	361	358	355	351	349	347
NDM > 732 MWh	465	469	475	488	490	497	500	504	505	508	509	510	511	514	516
Total NDM	**3785**	**3658**	**3516**	**3415**	**3294**	**3195**	**3091**	**2984**	**2877**	**2799**	**2719**	**2634**	**2524**	**2414**	**2291**
Total DM	500	489	495	509	515	517	513	516	512	512	513	515	517	519	522
LDZ Shrinkage	10	10	9	9	9	9	9	9	9	9	8	8	8	8	8
Total LDZ	**4294**	**4157**	**4020**	**3933**	**3818**	**3722**	**3612**	**3509**	**3398**	**3320**	**3241**	**3157**	**3050**	**2941**	**2821**
NTS Industrial	80	80	75	67	64	63	63	62	61	61	60	60	59	58	58
Exports to Ireland	327	326	344	343	246	246	236	238	254	272	282	317	328	375	384
NTS Power Generation	727	714	852	829	757	651	648	475	458	314	368	270	280	264	210
NTS Consumption	**1134**	**1120**	**1271**	**1239**	**1067**	**960**	**946**	**775**	**774**	**647**	**710**	**647**	**667**	**698**	**652**
NTS Shrinkage	13	12	11	10	9	8	8	8	8	8	8	8	8	8	8
Total excluding IUK	5441	5288	5302	5182	4894	4690	4567	4292	4179	3975	3958	3811	3724	3646	3480
IUK	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total including IUK	**5441**	**5288**	**5302**	**5182**	**4894**	**4690**	**4567**	**4292**	**4179**	**3975**	**3958**	**3811**	**3724**	**3646**	**3480**

Figures may not sum exactly due to rounding

Figure A2.1I:
Accelerated Growth: 1-in-20 peak day diversified demand

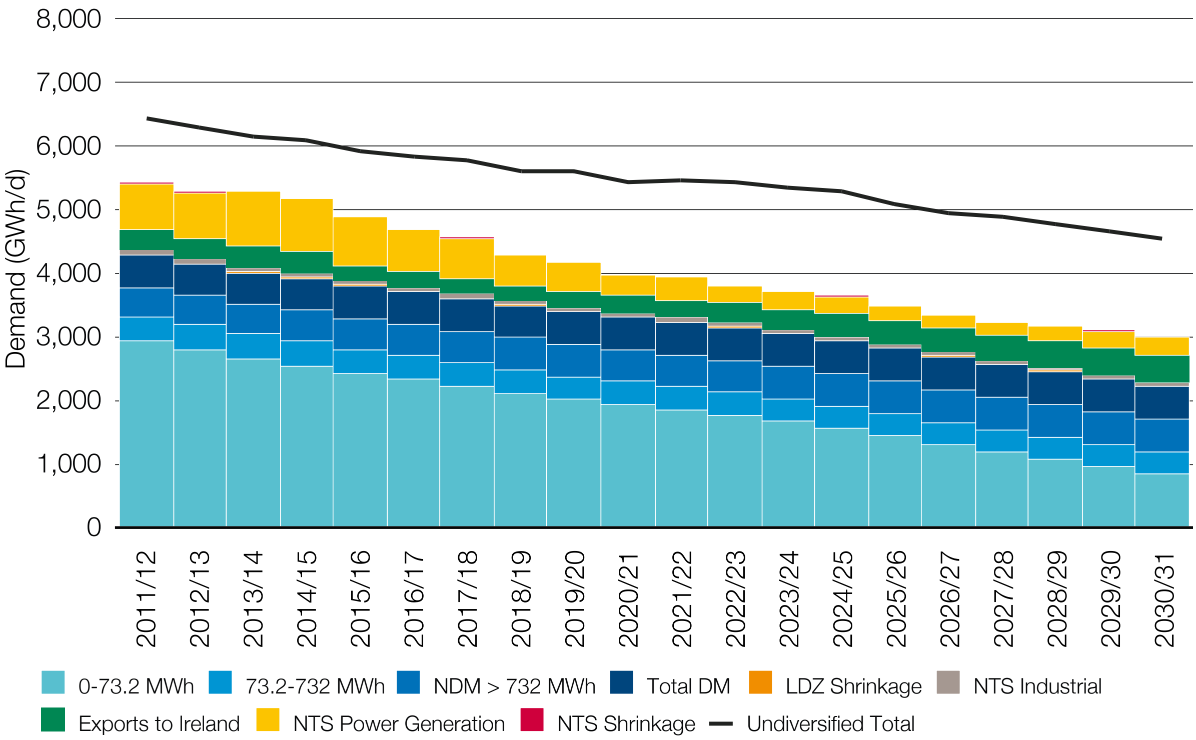


Figure A2.1J:
2012/13 load curve – Slow Progression

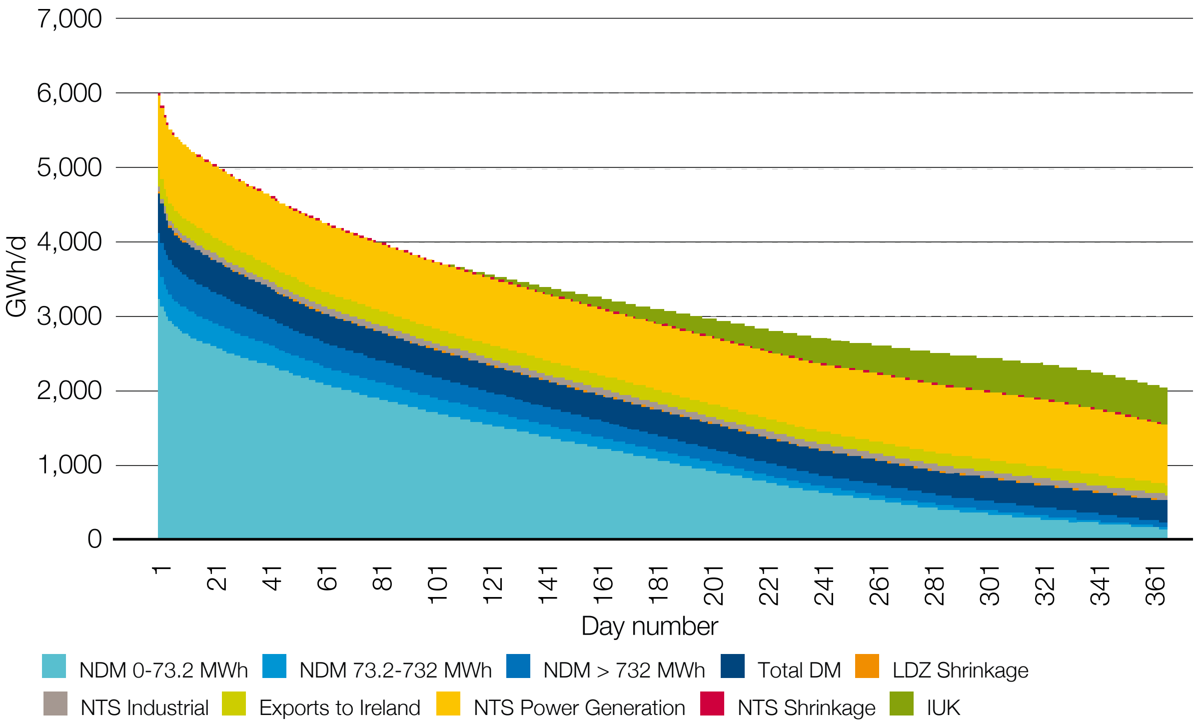


Figure A2.1K:
2012/13 load curve – Gone Green

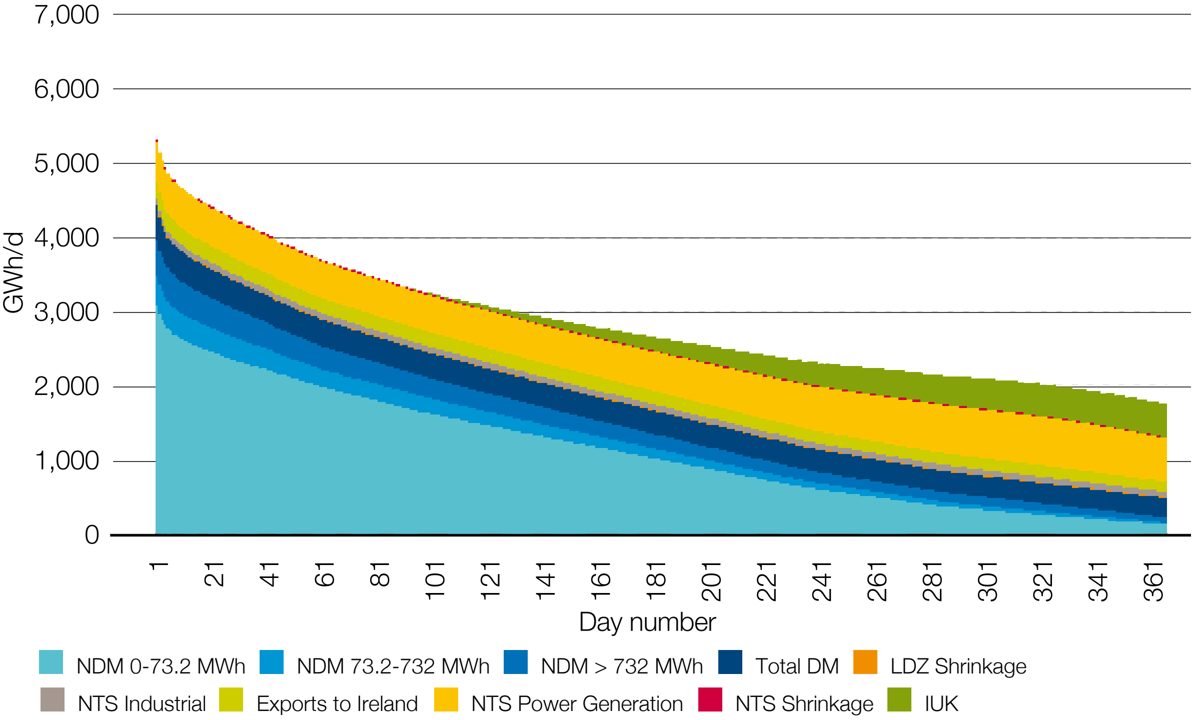
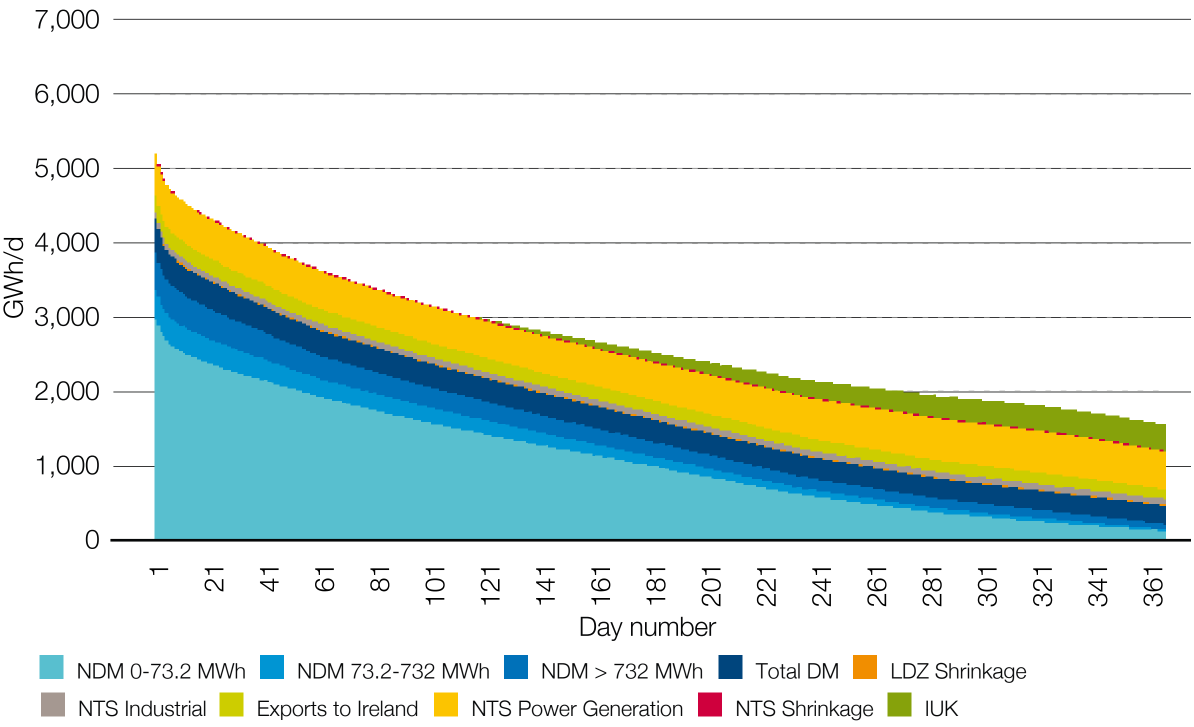


Figure A2.1L:
2012/13 load curve – Accelerated Growth



Note: Figures A1.2J – A.12L are severe 1-in-50 Load Duration Curves.

Gas Ten Year Statement

December 2012

A2.2
Supply scenarios

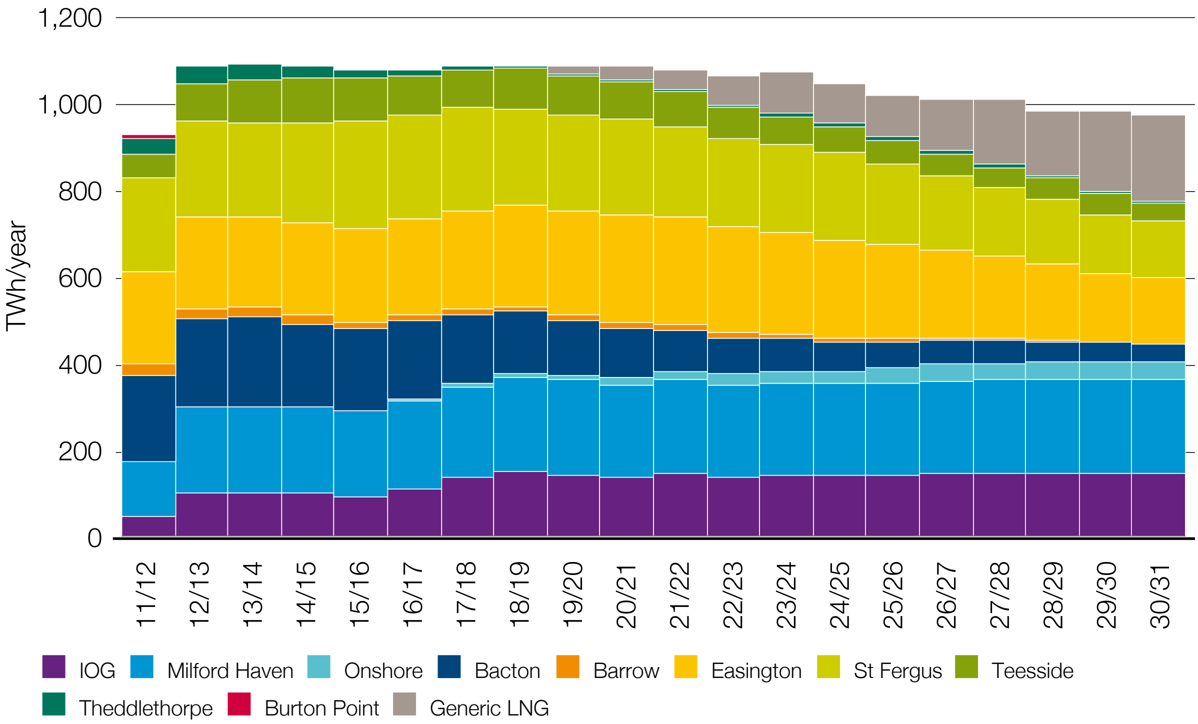
Table A2.2A:
Slow Progression: annual supplies (TWh / year)

	11/12[51]	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26
Bacton	198	200	206	190	188	184	162	143	128	113	94	83	75	68	61
Barrow	30	25	23	20	16	13	12	13	13	14	14	11	9	8	7
Easington	212	211	209	214	216	220	225	235	242	249	247	243	237	228	217
St Fergus	214	225	218	231	250	242	239	219	219	224	209	206	202	203	189
Teesside	56	83	101	104	97	87	87	95	91	85	83	70	64	59	54
Theddlethorpe	38	41	38	29	22	16	10	8	6	6	5	7	8	8	8
Onshore	0	0	0	2	3	5	6	8	10	16	21	26	28	28	32
Burton Point	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0
IOG	47	99	99	99	91	107	134	150	142	136	143	137	140	139	141
Milford Haven	126	201	200	200	197	204	211	217	218	214	218	214	214	214	215
Generic LNG	0	0	0	0	0	0	0	0	19	29	44	67	93	90	96
Total	**926**	**1085**	**1093**	**1089**	**1079**	**1077**	**1087**	**1089**	**1089**	**1085**	**1078**	**1065**	**1071**	**1045**	**1020**

Figures may not sum exactly due to rounding

51 Actuals

Figure A2.2A:
Slow Progression: annual supplies (TWh / year)



A2.2 continued
Supply scenarios

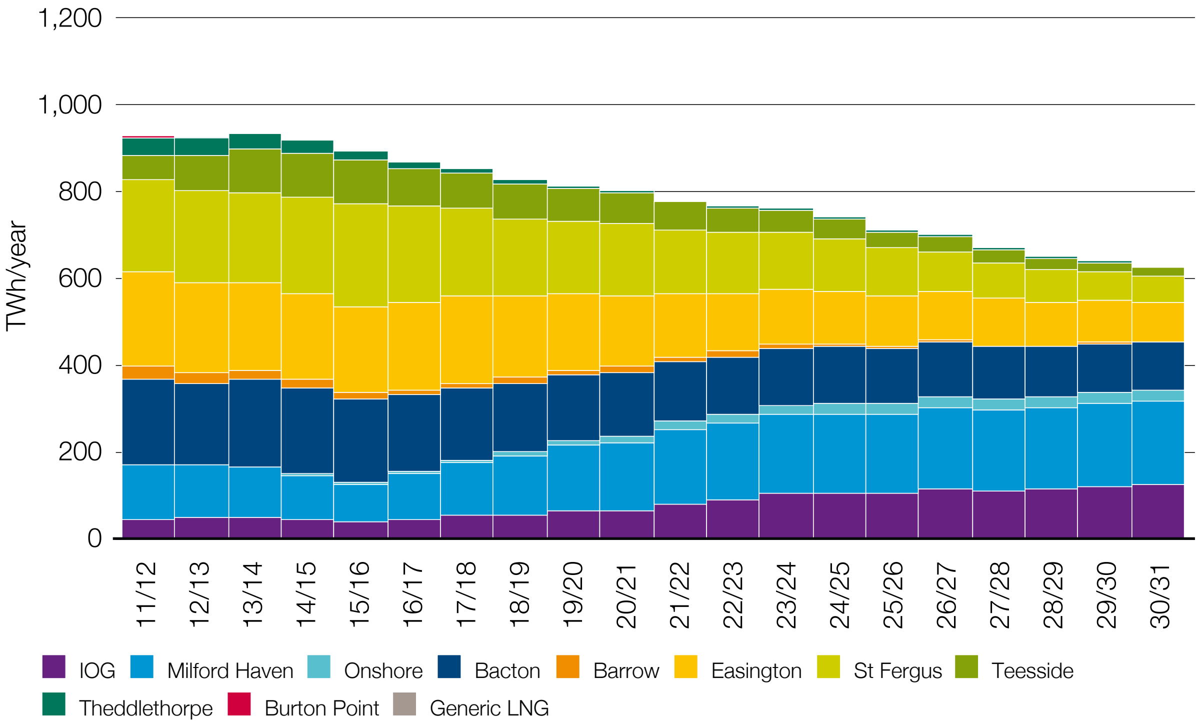
Table A2.2B:
Gone Green: annual supplies (TWh / year)

	11/12[52]	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26
Bacton	198	186	199	197	192	174	163	157	150	144	135	131	129	128	127
Barrow	30	25	23	20	16	13	12	13	13	13	13	11	8	7	5
Easington	212	205	201	199	194	200	203	188	177	166	147	135	126	121	116
St Fergus	214	214	205	219	240	224	202	176	166	165	146	139	133	120	107
Teesside	56	81	99	103	96	84	79	83	75	69	62	55	51	45	39
Theddlethorpe	38	40	38	29	22	16	10	8	4	4	3	4	5	5	5
Onshore	0	0	0	2	4	5	7	9	10	15	20	23	24	25	25
Burton Point	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0
IOG	47	52	51	45	39	46	53	58	65	67	82	92	105	108	107
Milford Haven	126	120	117	104	90	106	123	134	151	156	170	174	180	182	181
Generic LNG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	**926**	**924**	**934**	**917**	**892**	**868**	**853**	**827**	**812**	**800**	**778**	**765**	**761**	**740**	**713**

Figures may not sum exactly due to rounding

52 Actuals

Figure A2.2B:
Gone Green: annual supplies (TWh / year)



A2.2 continued
Supply scenarios

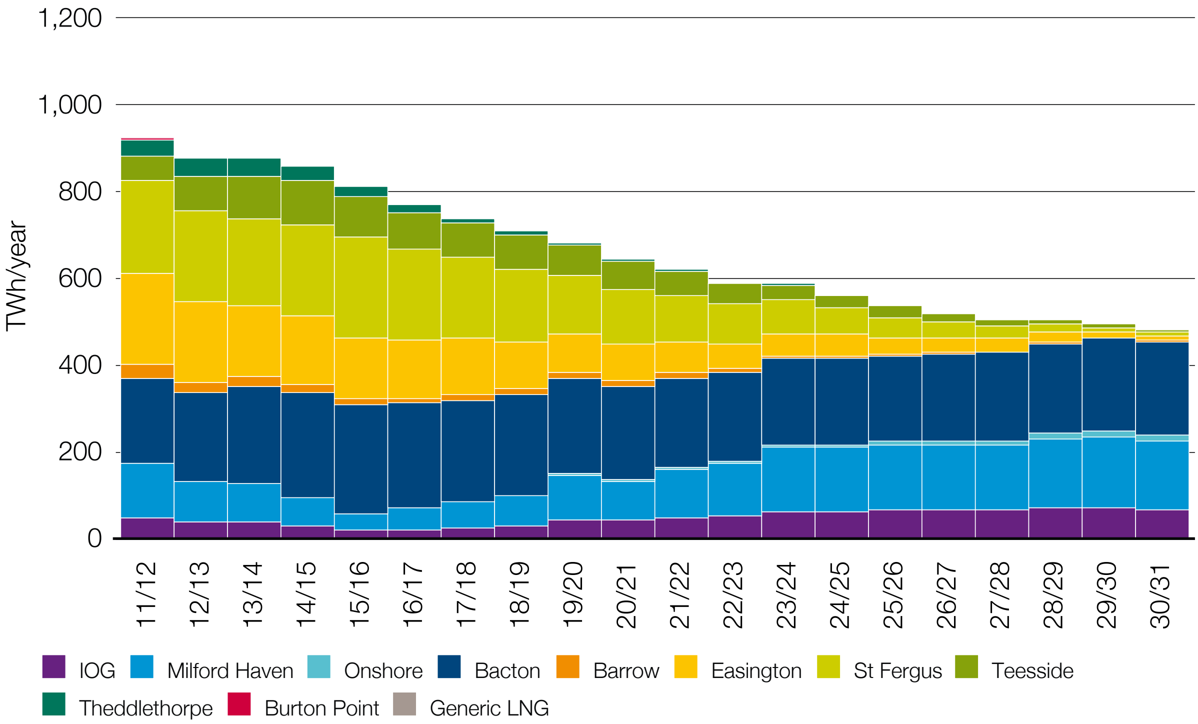
Table A2.2C:
Accelerated Growth: annual supplies (TWh / year)

	11/12[53]	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26
Bacton	198	204	224	241	247	240	230	229	221	213	206	200	197	197	198
Barrow	30	25	23	20	16	13	12	13	13	13	13	10	7	5	4
Easington	212	185	168	157	144	134	130	112	89	85	69	57	53	50	39
St Fergus	214	212	201	213	232	213	190	164	133	128	111	96	77	62	48
Teesside	56	81	99	103	96	85	79	83	75	65	59	46	37	30	24
Theddlethorpe	38	40	38	29	22	16	10	8	4	3	2	1	1	1	0
Onshore	0	0	0	1	1	1	2	3	4	4	5	6	7	8	9
Burton Point	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0
IOG	47	39	38	28	17	21	25	29	44	40	47	52	63	63	64
Milford Haven	126	90	87	64	39	48	59	67	101	93	109	120	145	146	149
Generic LNG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	**926**	**876**	**878**	**856**	**815**	**769**	**738**	**709**	**684**	**644**	**620**	**589**	**587**	**561**	**534**

Figures may not sum exactly due to rounding

53 Actuals

Figure A2.2C:
Accelerated Growth: annual supplies (TWh / year)



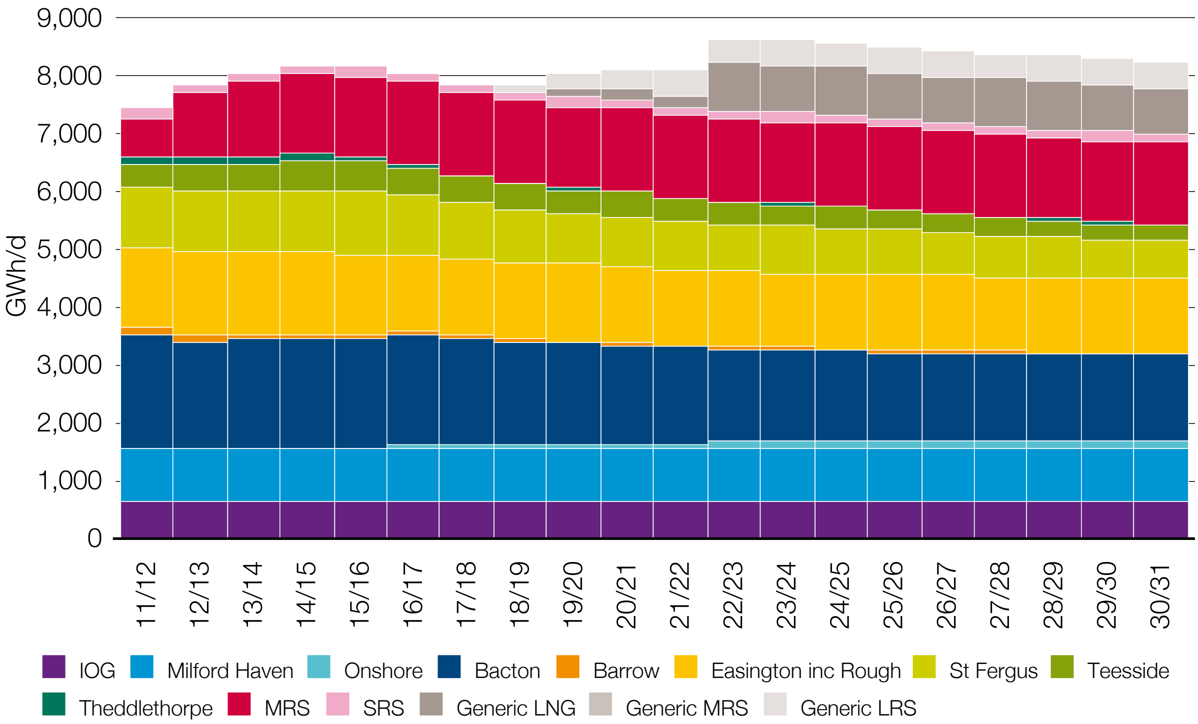
A2.2 continued
Supply scenarios

Table A2.2D:
Slow Progression: peak capability (GWh/d)

	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26
Bacton	1940	1801	1836	1856	1842	1873	1815	1782	1732	1684	1624	1587	1561	1538	1517
Barrow	113	101	91	79	64	52	47	48	48	49	47	39	33	27	23
Easington inc Rough	1354	1418	1407	1400	1378	1358	1337	1322	1310	1310	1301	1303	1304	1303	1300
St Fergus	1014	1047	1011	1041	1077	1019	949	870	854	859	816	815	805	818	781
Teesside	399	465	522	530	506	465	447	455	440	422	399	381	366	350	333
Theddlethorpe	120	121	113	88	66	47	31	23	17	18	16	22	26	28	27
Onshore	0	0	0	5	10	14	19	24	30	47	64	78	85	85	98
IOG	650	650	650	650	650	650	650	650	650	650	650	650	650	650	650
Milford Haven	950	950	950	950	950	950	950	950	950	950	950	950	950	950	950
MRS	706	1091	1305	1401	1408	1408	1408	1408	1408	1408	1408	1408	1408	1408	1408
SRS	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143
Generic LNG	0	0	0	0	0	0	0	0	185	185	185	807	807	807	807
Generic MRS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Generic LRS	0	0	0	0	0	0	0	110	220	330	440	440	440	440	440
Total	**7389**	**7787**	**8028**	**8143**	**8094**	**7979**	**7796**	**7785**	**7987**	**8055**	**8043**	**8623**	**8578**	**8547**	**8477**

Figures may not sum exactly due to rounding

Figure A2.2D:
Slow Progression: peak capability (GWh/d)



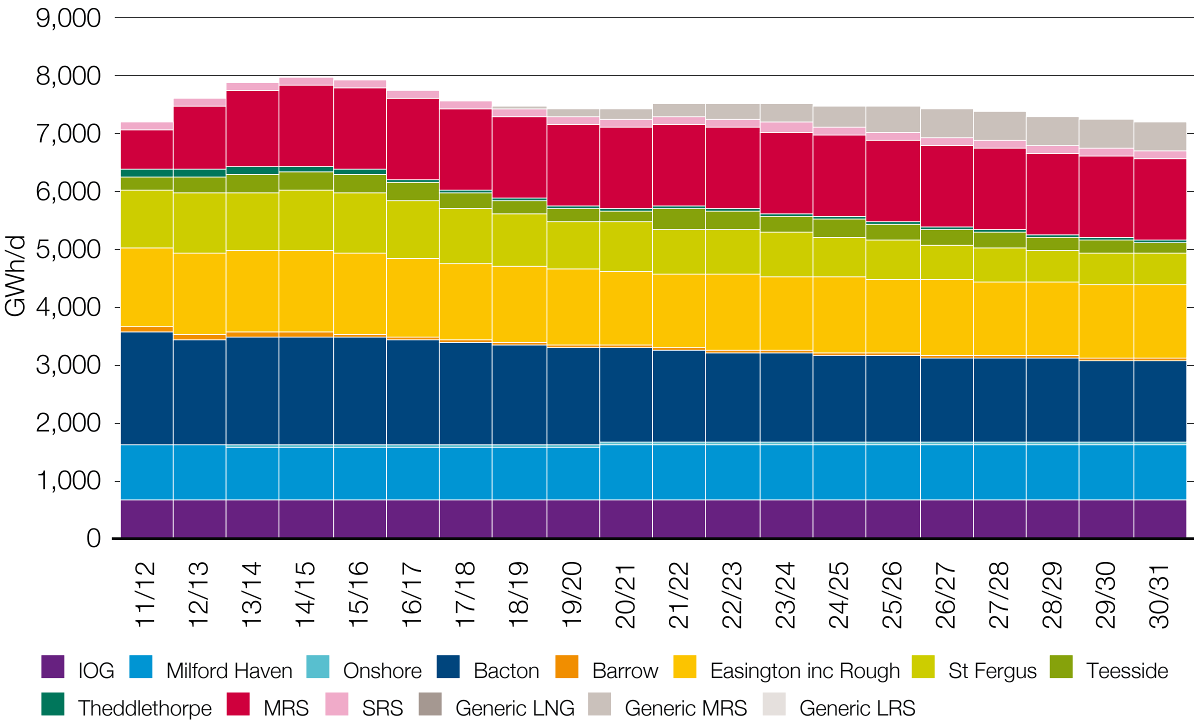
A2.2 continued
Supply scenarios

Table A2.2E:
Gone Green: peak capability (GWh/d)

	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26
Bacton	1940	1801	1836	1856	1842	1794	1738	1708	1654	1612	1563	1533	1513	1495	1478
Barrow	113	101	91	79	64	52	47	48	47	47	45	36	29	24	19
Easington inc Rough	1354	1418	1407	1400	1378	1358	1337	1322	1307	1305	1295	1295	1294	1292	1289
St Fergus	1014	1047	1011	1041	1077	1019	949	870	836	836	787	775	757	718	679
Teesside	214	280	338	345	321	280	263	271	244	224	383	358	339	320	303
Theddlethorpe	120	121	113	88	66	47	31	23	13	13	10	13	16	17	16
Onshore	0	0	1	6	11	16	22	28	31	46	60	70	73	74	74
IOG	650	650	650	650	650	650	650	650	650	650	650	650	650	650	650
Milford Haven	950	950	950	950	950	950	950	950	950	950	950	950	950	950	950
MRS	706	1091	1305	1401	1408	1408	1408	1408	1408	1408	1408	1408	1408	1408	1408
SRS	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143
Generic LNG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Generic MRS	0	0	0	0	0	0	0	55	110	165	220	275	330	385	440
Generic LRS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	**7204**	**7602**	**7845**	**7959**	**7910**	**7717**	**7538**	**7476**	**7393**	**7399**	**7514**	**7505**	**7501**	**7475**	**7448**

Figures may not sum exactly due to rounding

Figure A2.2E:
Gone Green: peak capability (GWh/d)



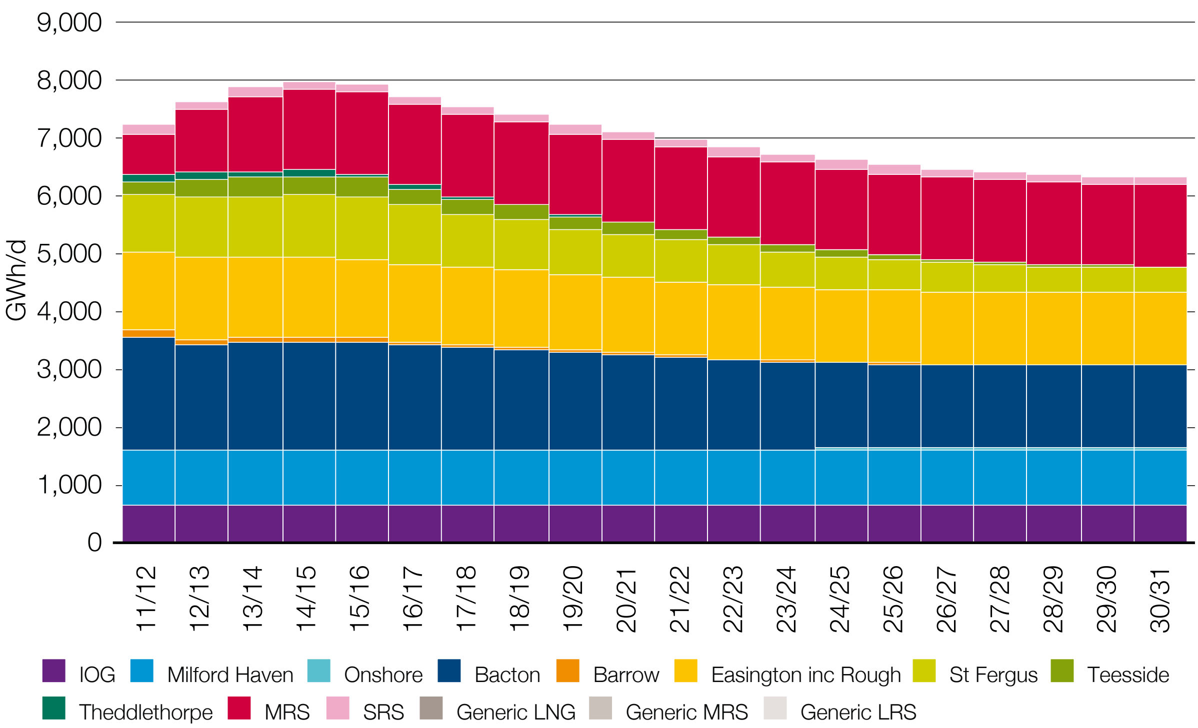
A2.2 continued
Supply scenarios

Table A2.2F:
Accelerated Growth: peak capability (GWh/d)

	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26
Bacton	1940	1801	1836	1856	1842	1794	1738	1708	1651	1599	1553	1508	1479	1457	1439
Barrow	113	101	91	79	64	52	47	48	47	45	44	33	25	18	14
Easington inc Rough	1354	1418	1407	1400	1378	1358	1337	1322	1305	1299	1291	1285	1281	1277	1274
St Fergus	1014	1047	1011	1041	1077	1019	949	870	782	762	720	680	619	573	533
Teesside	214	280	338	345	321	280	263	271	241	209	188	147	118	95	77
Theddlethorpe	120	121	113	88	66	47	31	23	12	8	6	4	3	2	1
Onshore	0	0	1	2	3	4	6	8	11	13	16	19	22	25	28
IOG	650	650	650	650	650	650	650	650	650	650	650	650	650	650	650
Milford Haven	950	950	950	950	950	950	950	950	950	950	950	950	950	950	950
MRS	706	1091	1305	1401	1408	1408	1408	1408	1408	1408	1408	1408	1408	1408	1408
SRS	143	143	143	143	143	143	143	143	143	143	143	143	143	143	143
Generic LNG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Generic MRS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Generic LRS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	**7204**	**7602**	**7845**	**7955**	**7902**	**7705**	**7522**	**7401**	**7200**	**7086**	**6969**	**6827**	**6698**	**6598**	**6517**

Figures may not sum exactly due to rounding

Figure A2.2F:
Accelerated Growth: peak capability (GWh/d)



A2.3
Peak terminal scenarios

Notes

Range of Scenarios	Range of peak capability within the scenarios
2012 QSEC	Long-term capacity sold in 2012 as of 01/10/2012
Sold Capacity	Long-term capacity sold prior to 2012 (as of 01/10/2011)
Release Obligation	Published QSEC release obligations

Figure A2.3A:
Peak Bacton scenarios (mcm/d)

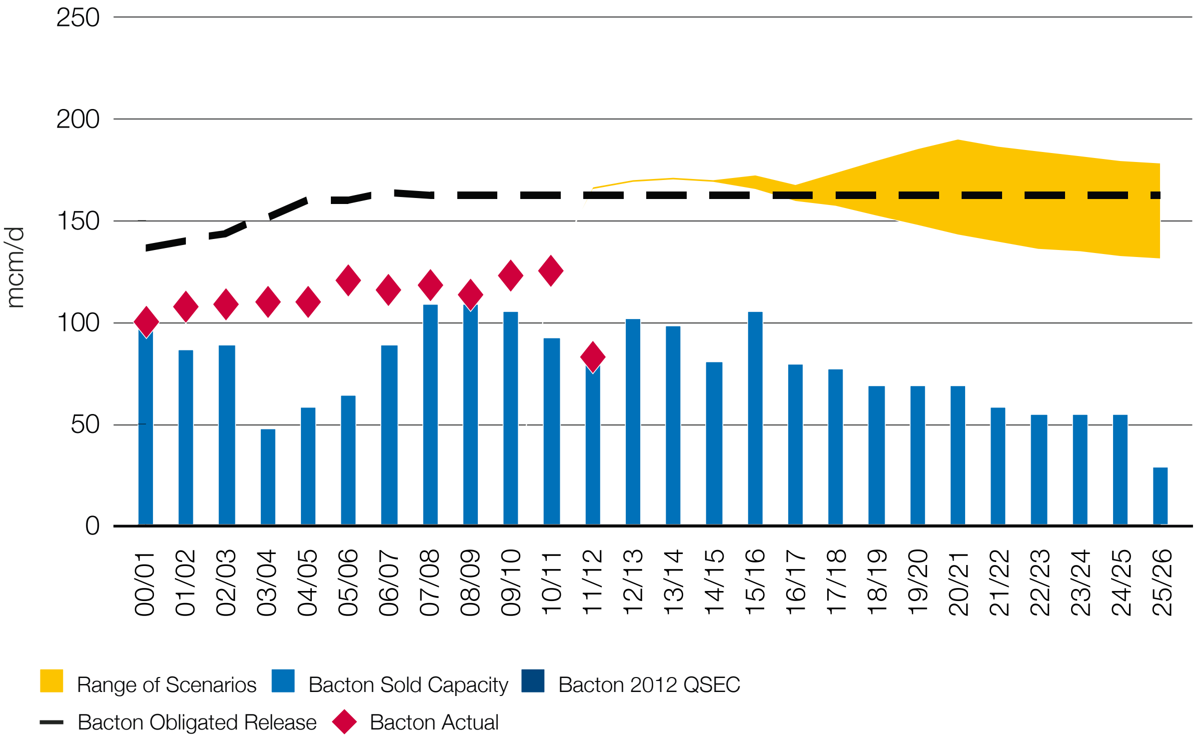
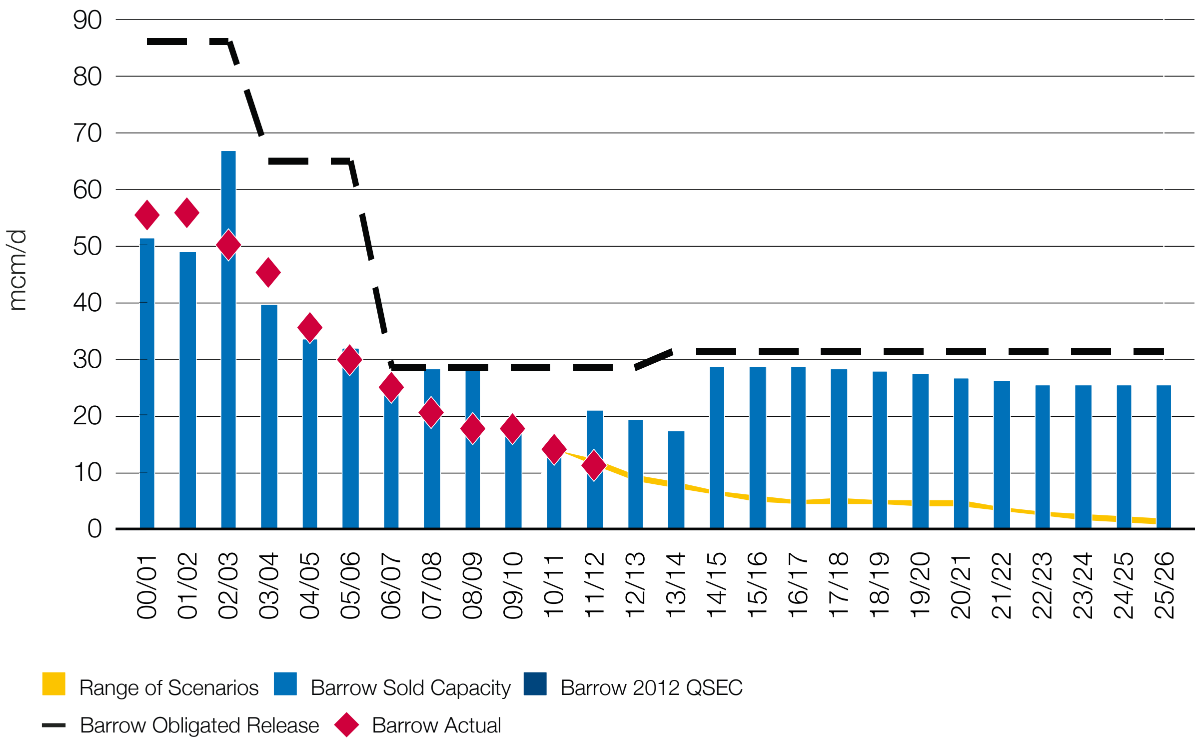


Figure A2.3B:
Peak Barrow scenarios (mcm/d)



Peak terminal scenarios

Figure A2.3C:
Peak Easington scenarios (mcm/d)

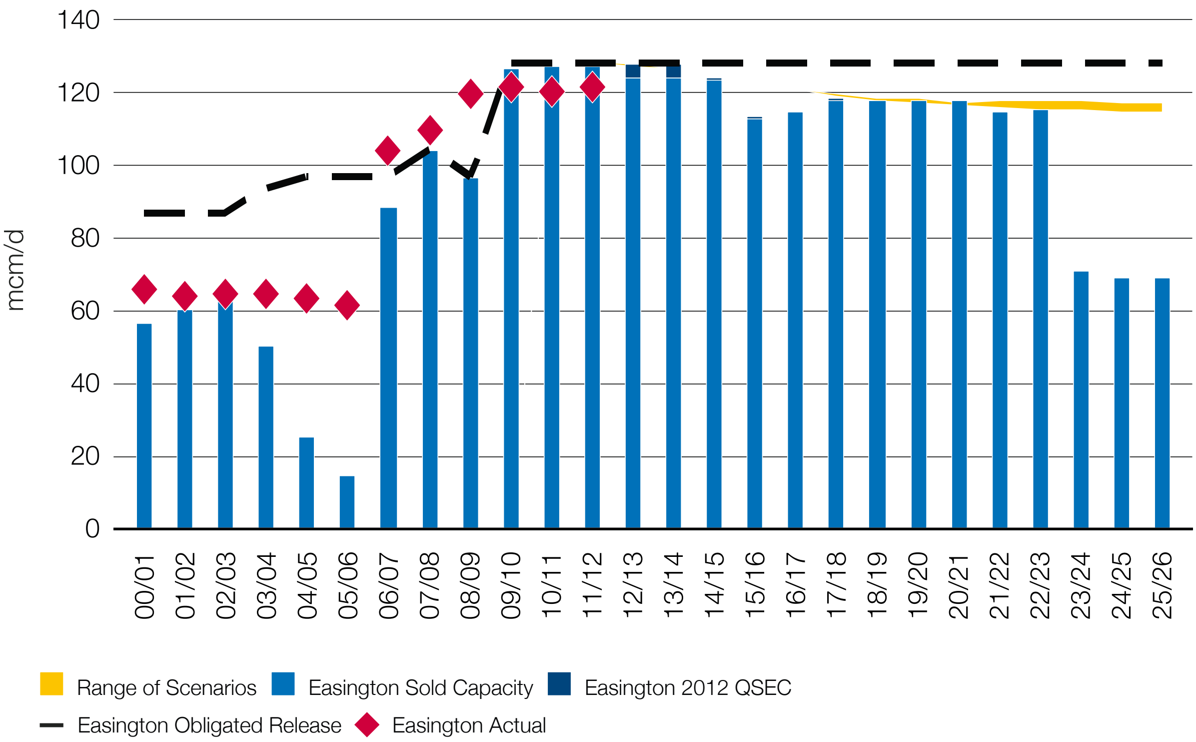
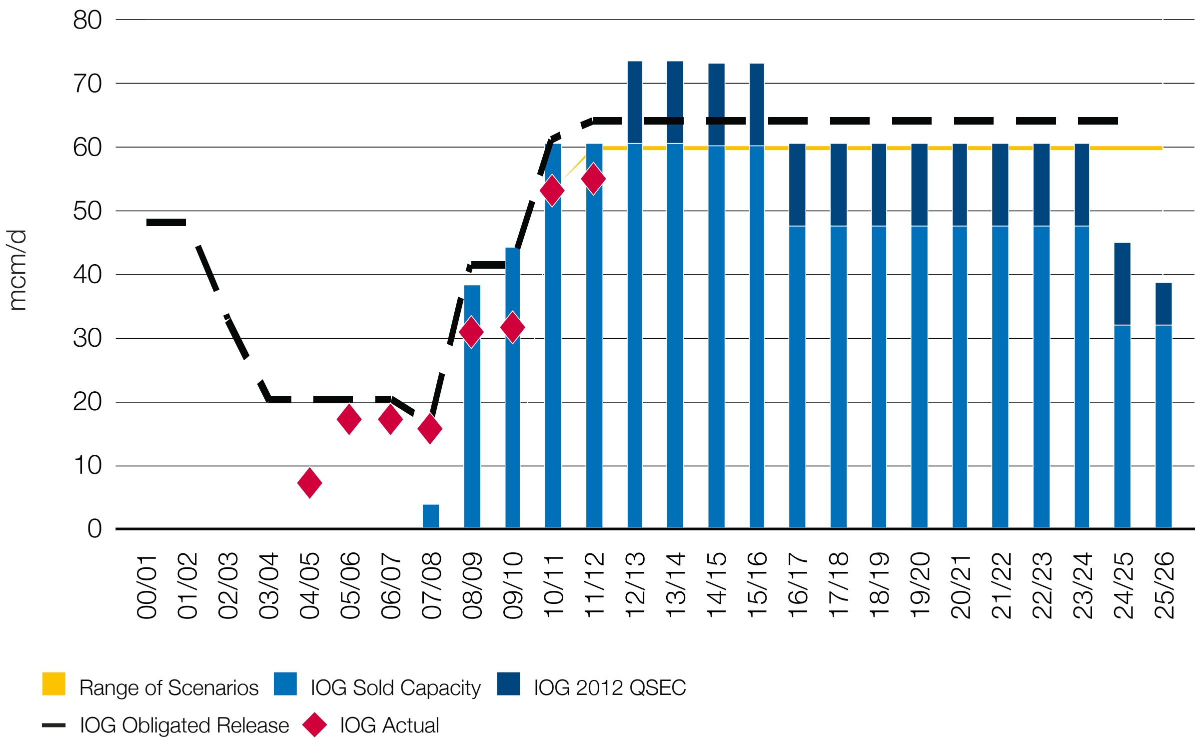


Figure A2.3D:
Peak Grain LNG scenarios (mcm/d)



Peak terminal scenarios

Figure A2.3E:
Peak Milford Haven scenarios (mcm/d)

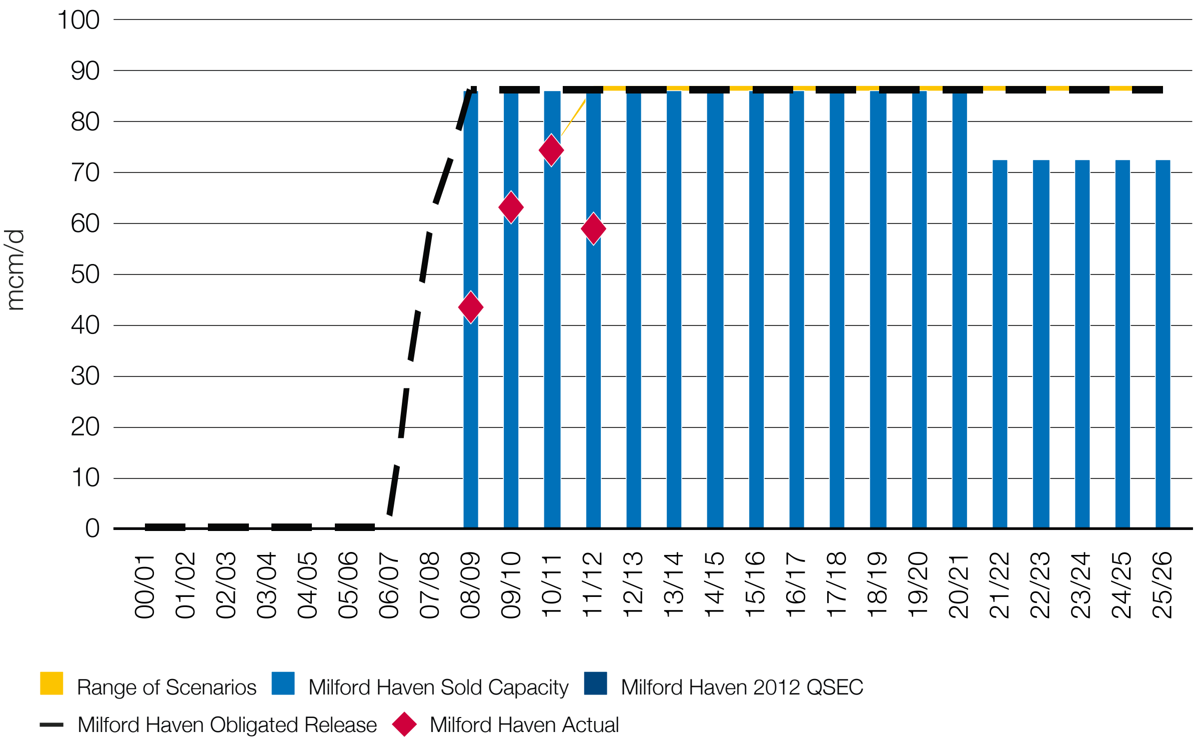
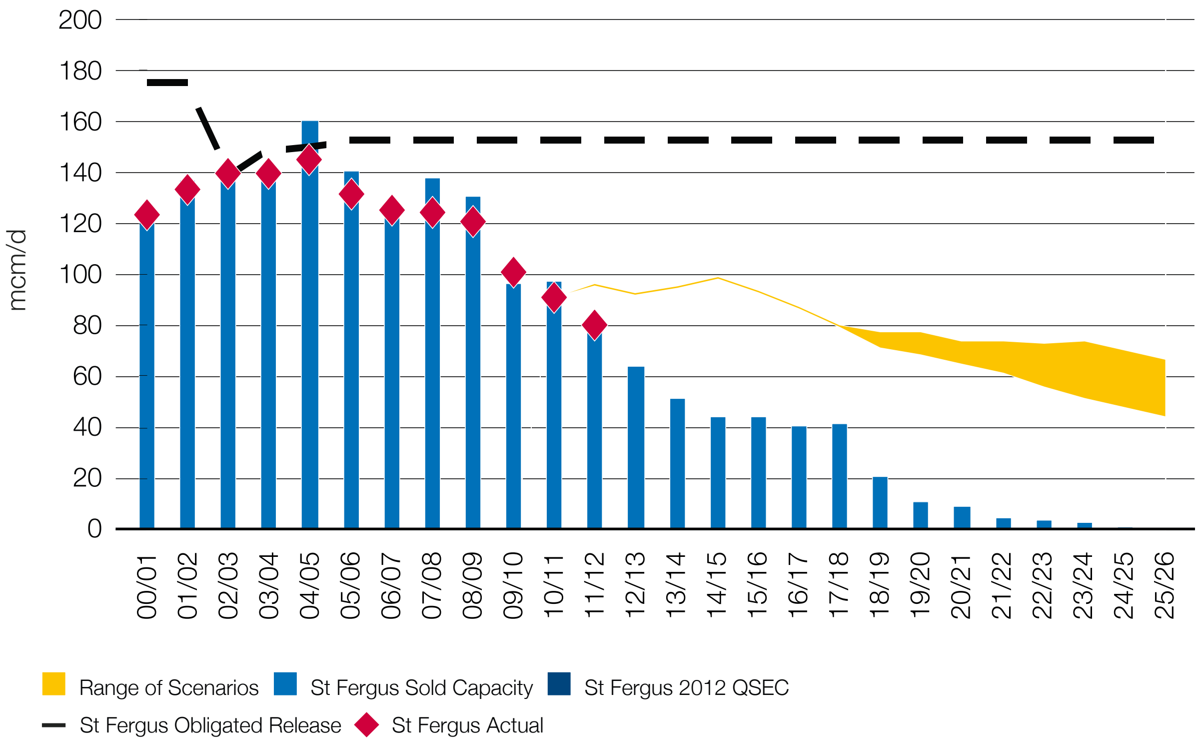


Figure A2.3F:
Peak St Fergus scenarios (mcm/d)



Peak terminal scenarios

Figure A2.3G:
Peak Teesside scenarios (mcm/d)

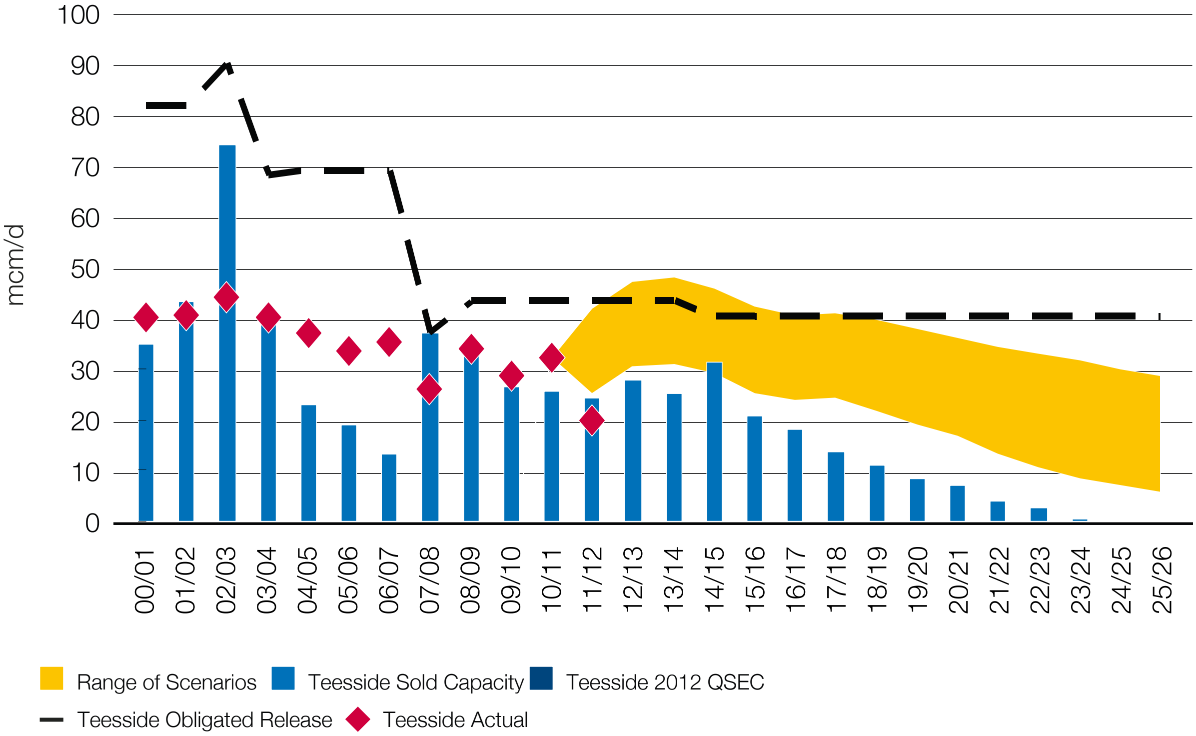
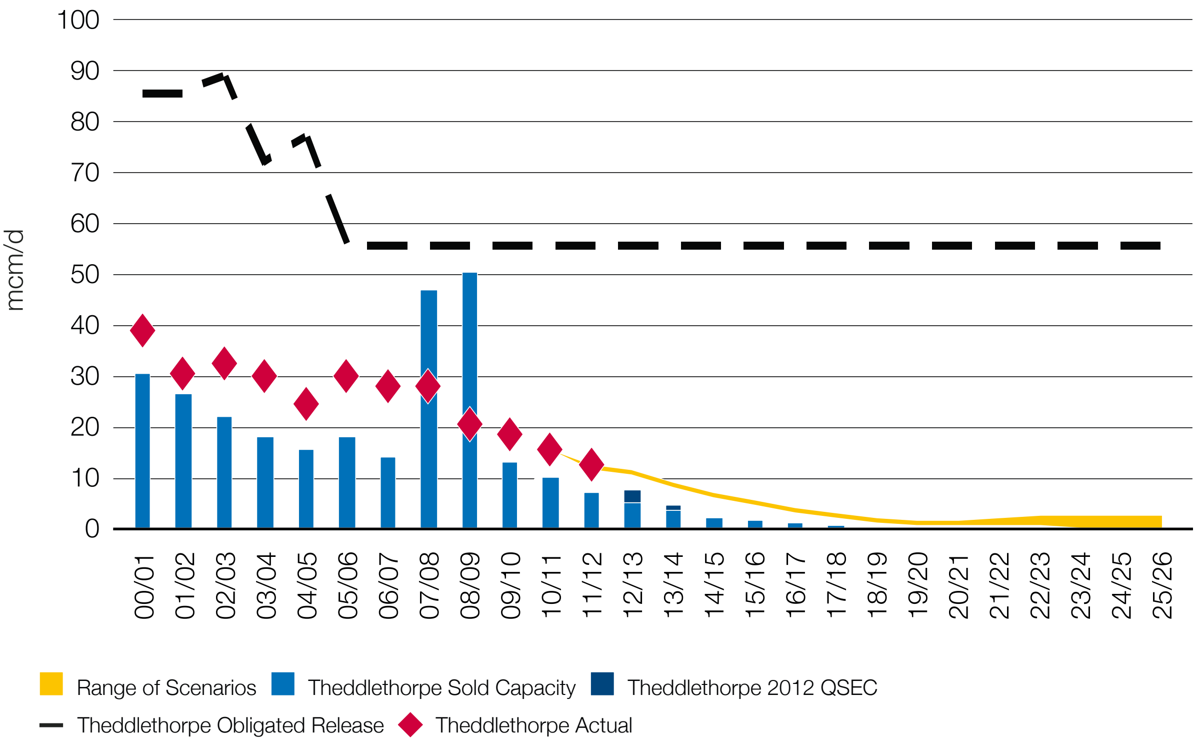


Figure A2.3H:
Peak Theddlethorpe scenarios (mcm/d)



Appendix three
Actual flows 2011/12

This appendix describes annual and peak flows during the calendar year 2011 and gas year 2011/12.

A3.1
Annual flows

Annual forecasts are based on average weather conditions. Therefore, when comparing actual demand with forecasts, demand has been adjusted to take account of the difference between the actual weather and the seasonal normal weather. The result of this calculation is the weather corrected demand.

Actual demands incorporate a re-allocation of demand between 0-73.2 MWh/y and >73 MWh/y firm load bands to allow for reconciliation, loads crossing between thresholds, etc. The load band splits shown in Table A3.1 are slightly different from those incorporated in the National Grid Accounts.

Table A3.1A provides a comparison of actual and weather corrected demands during the 2011 calendar year with the forecasts presented in the 2011 Ten Year Statement. Annual demands are presented in the format of LDZ and NTS load bands/categories, consistent with the basis of system design and operation.

Table A3.1A indicates that our one year ahead forecast for 2011 was accurate to 2.5% at an LDZ level. The combined forecasts of the NTS Industrial, NTS Power Generation and Exports were accurate to 6.0%. Total system demand was accurate to 4.2%.

Table A3.1A:
Annual demand for 2011 (TWh) – LDZ / NTS split

	Actual Demand (TWh)	Weather Corrected Demand (TWh)	G-TYS (2011) GG Demand
0-73.2 MWh	319	337	347
73.2-732 MWh	44	46	47
>732 MWh Firm	181	183	187
Total LDZ Consumption	**544**	**566**	**581**
NTS Industrial	29	29	30
NTS Power Generation	243	243	269
Exports and Shrinkage	177	177	180
Total NTS + Exports	**449**	**449**	**479**
Total Consumption	**993**	**1,015**	**1,061**

Figures may not sum exactly due to rounding

A3.2
Peak and minimum flows

A3.2.1
System entry – maximum day flows

For Winter 2011/12, the day of highest supply to the NTS was also the day of highest demand. This was 2 February 2012, when 414 mcm fed a demand of 419 mcm. This is significantly lower than the highest demand day in the 2010/11 gas year, in which 476 mcm of gas was supplied for a demand of 465 mcm.

The day of minimum demand in 2011/12 was 8 September 2012, when NTS demand was 115 mcm. This was also the day of minimum supply, when 117 mcm of gas was supplied to the NTS.

Table A3.2A:
IGMS M+15 physical NTS entry flows: 2 February 2012 (mcm/d)

Terminal	Max Day 2 February 2012	G-TYS (2011) GG Supply Capability	Highest Daily (per terminal)
Bacton inc IUK and BBL	70	175	82
Barrow	7	10	11
Easington inc Rough and Langeled	117	123	122
Isle of Grain (exc. LDZ inputs)	52	59	52
Milford Haven	26	68	59
Point of Ayr	0	0	4
St Fergus	71	101	81
Teesside	11	39	20
Theddlethorpe	10	12	13
Sub Total	**364**	**587**	**444**
MRS and LNG Storage	50	71	50
Total	**414**	**658**	**494**

Notes

- The maximum supply day for 2011/12 refers to NTS flows on 2 February 2012
- This was the overall highest supply day, but individual terminals may have supplied higher deliveries on other days
- Supply Capability refers to that published in the 2011 Gas Ten Year Statement. Conversions to mcm have been made using a CV of 39.6MJ/m3
- Due to linepack changes, there may be a difference between total demand and total supply on the day
- Figures may not sum exactly due to rounding

A3.2.2
System entry – minimum day flows

Table A3.2B:
IGMS M+15 physical NTS entry flows: 8 September 2012 (mcm/d)

Terminal	**Minimum Day 8 September 2012**
Bacton inc IUK and BBL	29
Barrow	10
Easington inc Rough and Langeled	26
Isle of Grain (incl. LDZ inputs)	3
Milford Haven	16
Point of Ayr	3
St Fergus	8
Teesside	9
Theddlethorpe	9
Sub Total	**113**
MRS and LNG Storage	4
Total	**117**

Notes

- The minimum supply day for 2011/12 refers to NTS flows on 8 September 2012. This was the overall lowest supply day, but individual terminals may have supplied lower deliveries on other days
- Due to linepack changes, there may be a difference between total demand and total supply on the day
- Figures may not sum exactly due to rounding.

A3.2 continued
Peak and minimum flows

A3.2.3
System exit – maximum and peak day flows

Table A3.2C shows actual flows out of the NTS on the maximum demand day of gas year 2011/12 compared to the forecast peak flows.

Table A3.2C:
IGMS D+5 physical LDZ demand flows: 2 February 2012 (mcm/d)

LDZ	Maximum Day 2 February 2012	G-TYS (2011) 1-in-20 Undiversified GG Peak
Eastern	26	33
East Midlands	32	40
North East	19	24
Northern	16	23
North Thames	33	42
North West	37	46
Scotland	25	31
South East	33	44
Southern	25	31
South West	19	23
West Midlands	27	35
Wales (North and South)	17	24
LDZ Total	**309**	**396**
NTS Loads	**110**	**209**
Total	**419**	**605**

Notes
- The maximum day for gas year 2011/12 refers to 2 February 2012. This was the overall highest demand day, but individual LDZs may have seen higher demands on other days
- NTS actual loads include interconnector demand
- Due to linepack changes, there may be a difference between total demand and total supply on the day
- The Gone Green (GG) 1-in-20 Peak Day Firm Demand forecast was published in the 2011 Gas Ten Year Statement. Conversions to mcm have been made using a CV of 39.6MJ/m3
- Figures may not sum exactly due to rounding

A3.2.4
System exit – minimum day flows

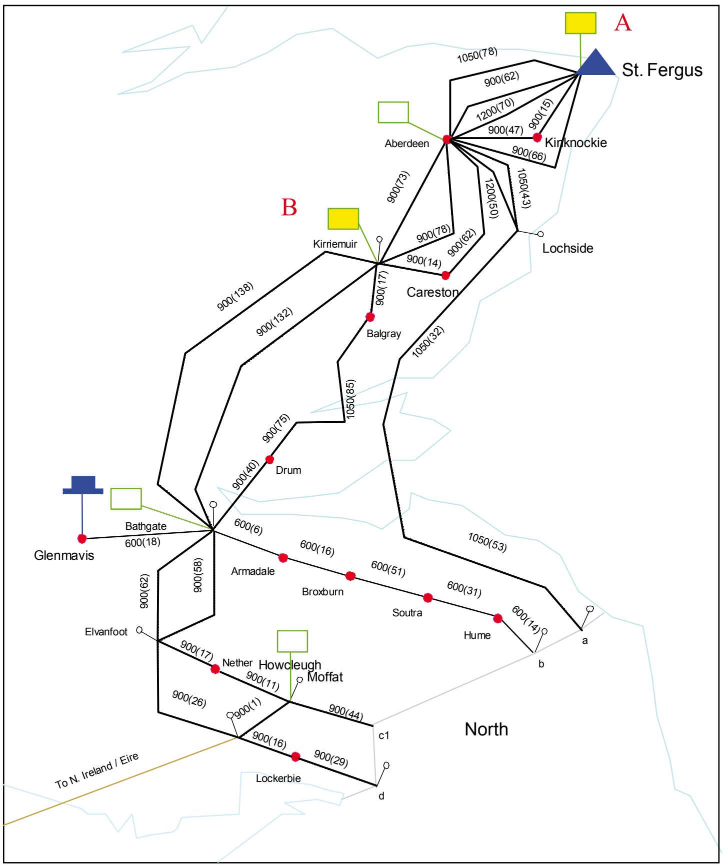
Table A3.2D:
IGMS D+5 physical LDZ demand flows: 8 September 2012 (mcm/d)

LDZ	Minimum Day
8 September 2012	
Eastern	4
East Midlands	6
North East	4
Northern	4
North Thames	5
North West	7
Scotland	6
South East	2
Southern	5
South West	3
West Midlands	4
Wales (North and South)	4
LDZ Total	**54**
NTS Loads	**61**
Total	**115**

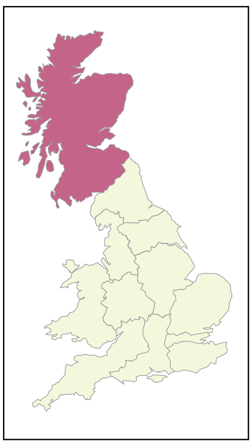
Notes
- The minimum day for gas year 2011/12 refers to 8 September 2012. This was the overall lowest demand day, but individual LDZs may have seen lower demands on other days
- NTS actual loads include interconnector demand
- Due to linepack changes, there may be a small difference between total demand and total supply on the day
- Figures may not sum exactly due to rounding

Appendix four
The gas transportation system

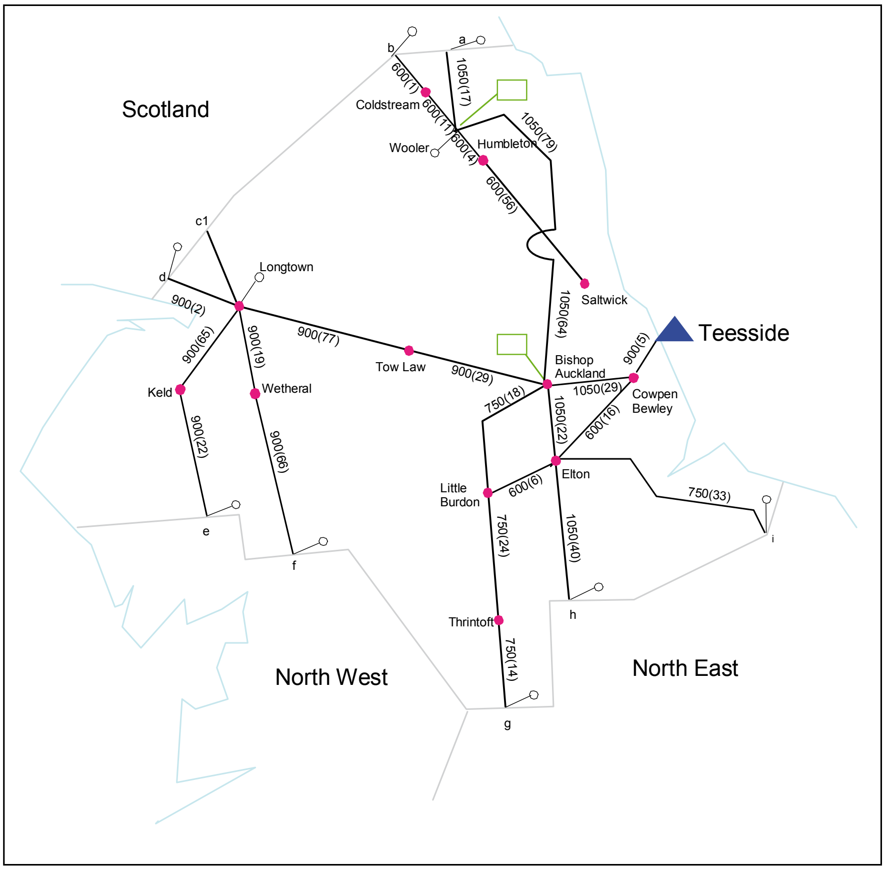
Scotland (SC) – NTS



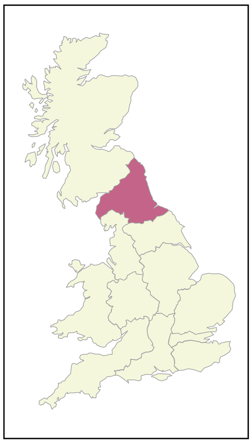
- Terminal
- LDZ boundary
- 900(17) Existing pipeline (with distance marker)
- 900 Pipeline diameter (mm)
- (17) Length (km)
- a Denotes a crossing point between LDZs
- Proposed pipeline
- Offtake
- Storage facility
- Existing compressor
- New compressor or compressor modifications
- Alternative route
- Uprating of pipelines
- Approved emissions projects



North (NO) – NTS

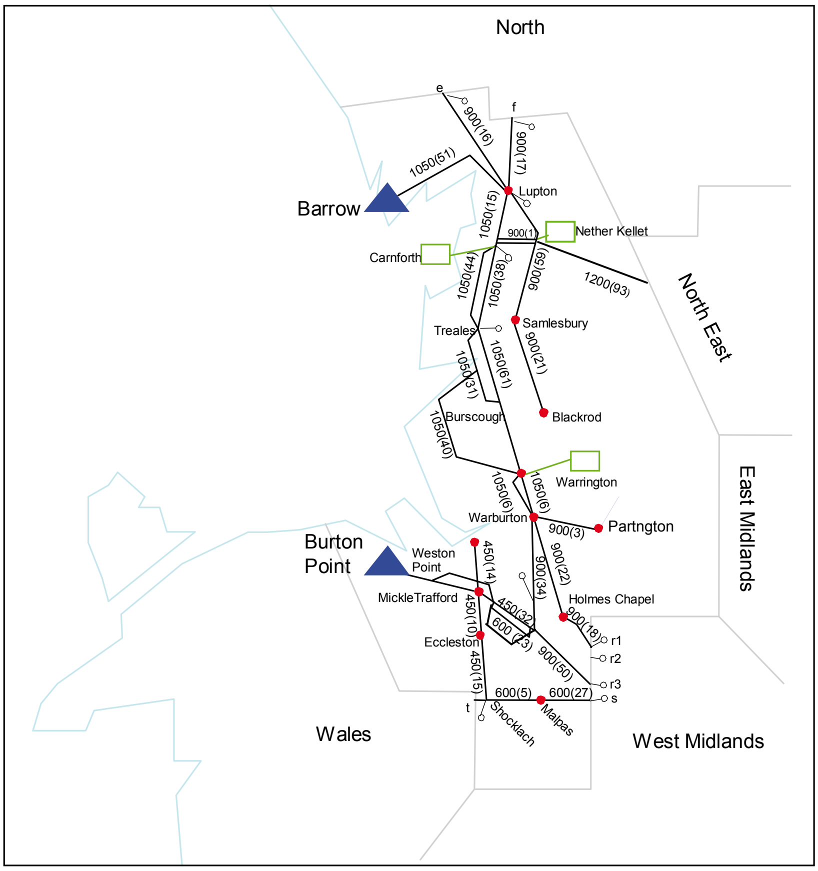


Terminal
LDZ boundary
Existing pipeline (with distance marker)
Pipeline diameter (mm)
(17) Length (km)
a Denotes a crossing point between LDZs
Proposed pipeline
Offtake
Storage facility
Existing compressor
New compressor or compressor modifications
Alternative route
Uprating of pipelines
Approved emissions projects



The gas transportation system

North West (NW) – NTS



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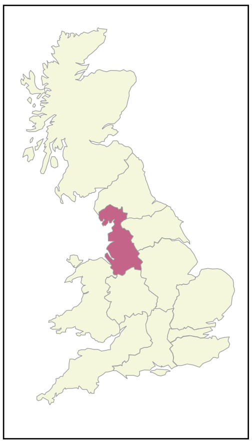
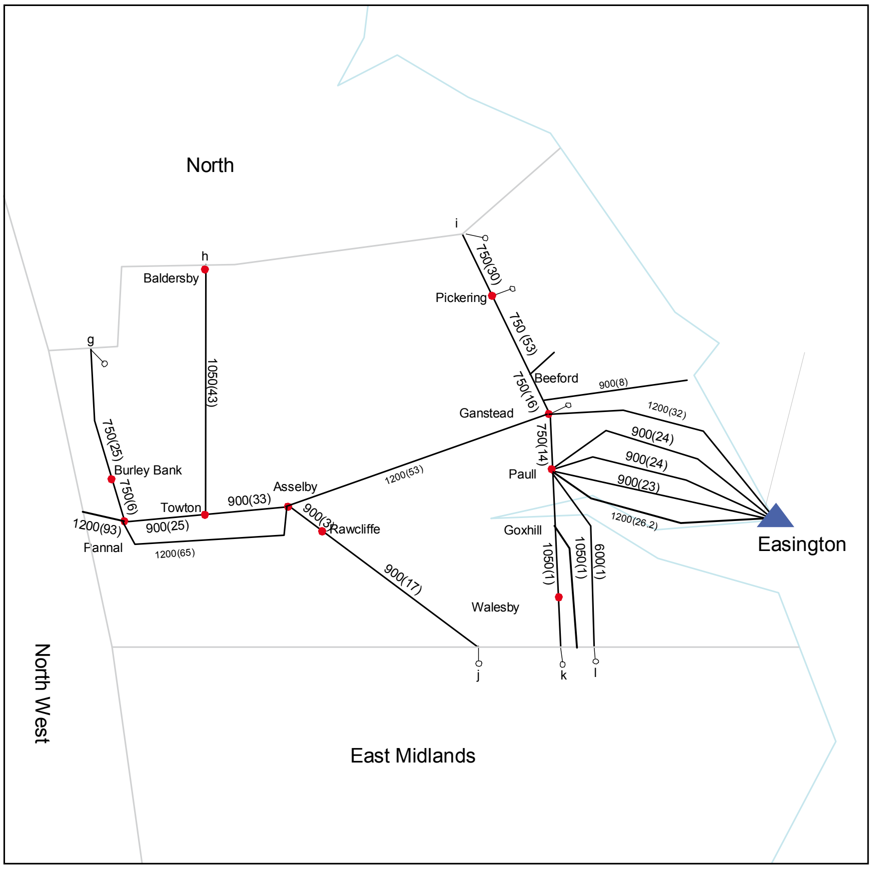
- Uprating of pipelines
- Approved emissions projects



North East (NE) – NTS



- Terminal
- LDZ boundary
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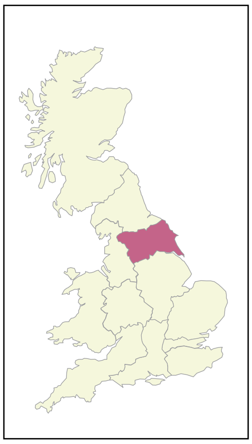
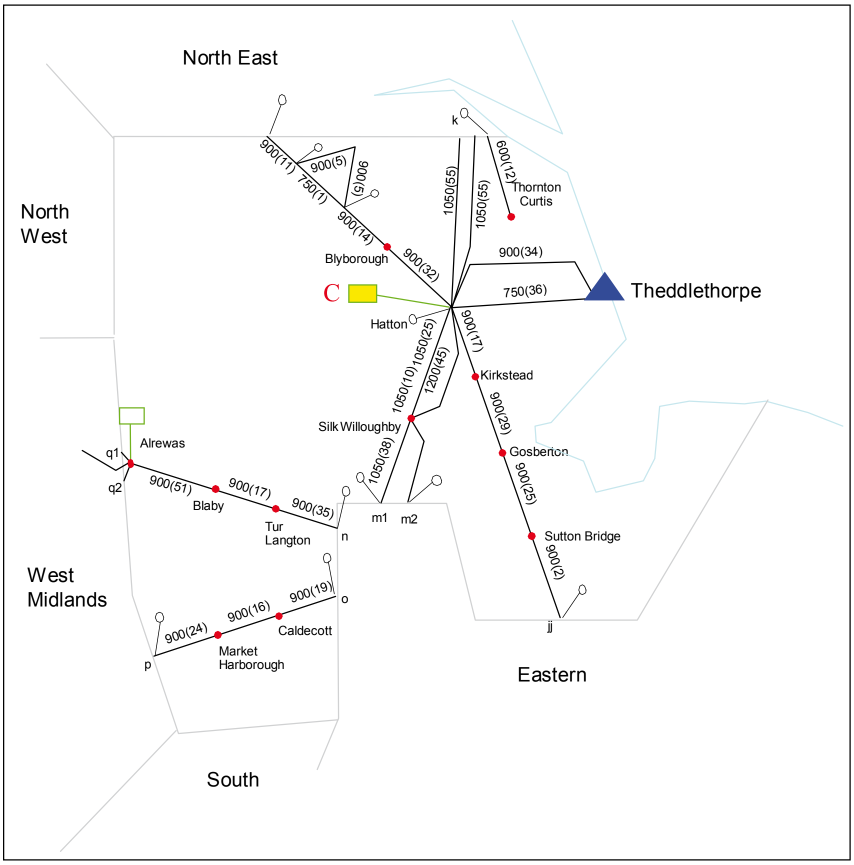
- Approved emissions projects



East Midlands (EM) – NTS



- Terminal
- LDZ boundary
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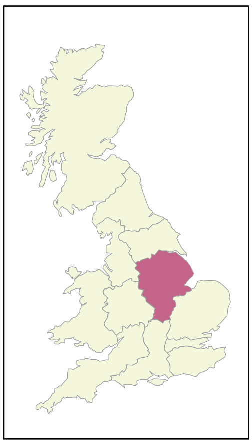
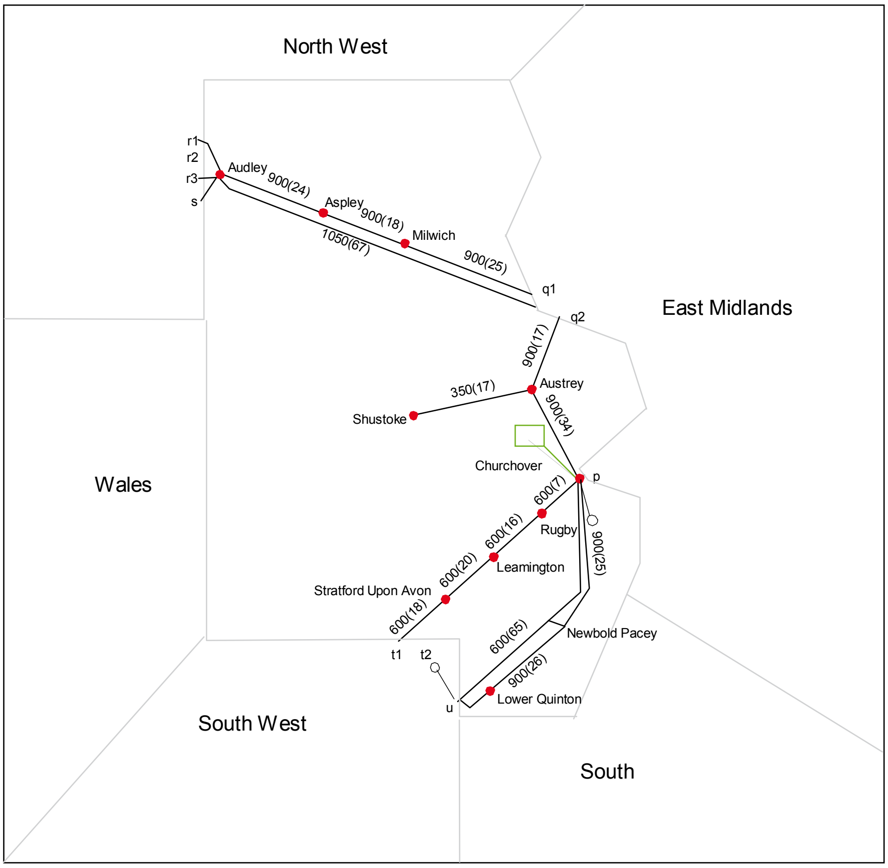
- Existing compressor
- New compressor or compressor modifications
- Alternative route
- Uprating of pipelines
- Approved emissions projects



West Midlands (WM) – NTS



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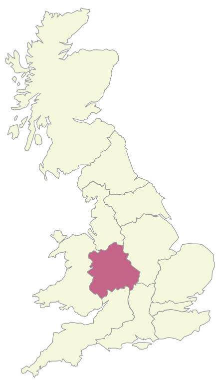
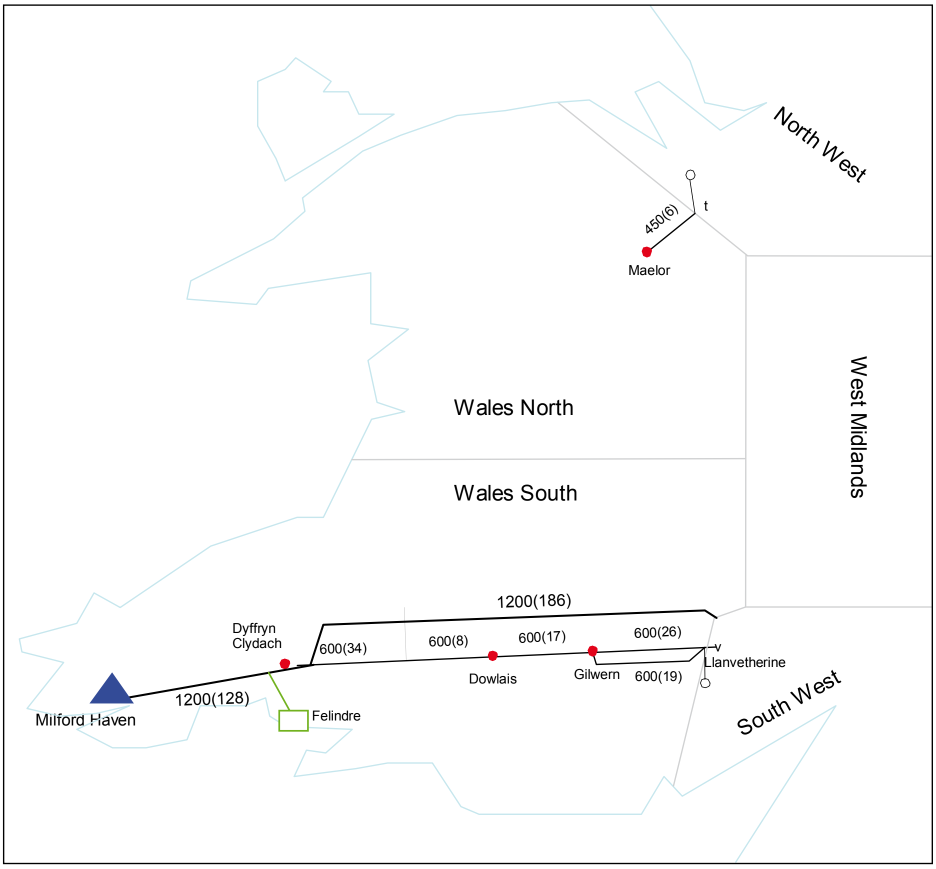


Wales (WN & WS) – NTS



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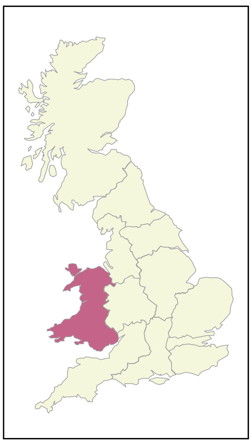
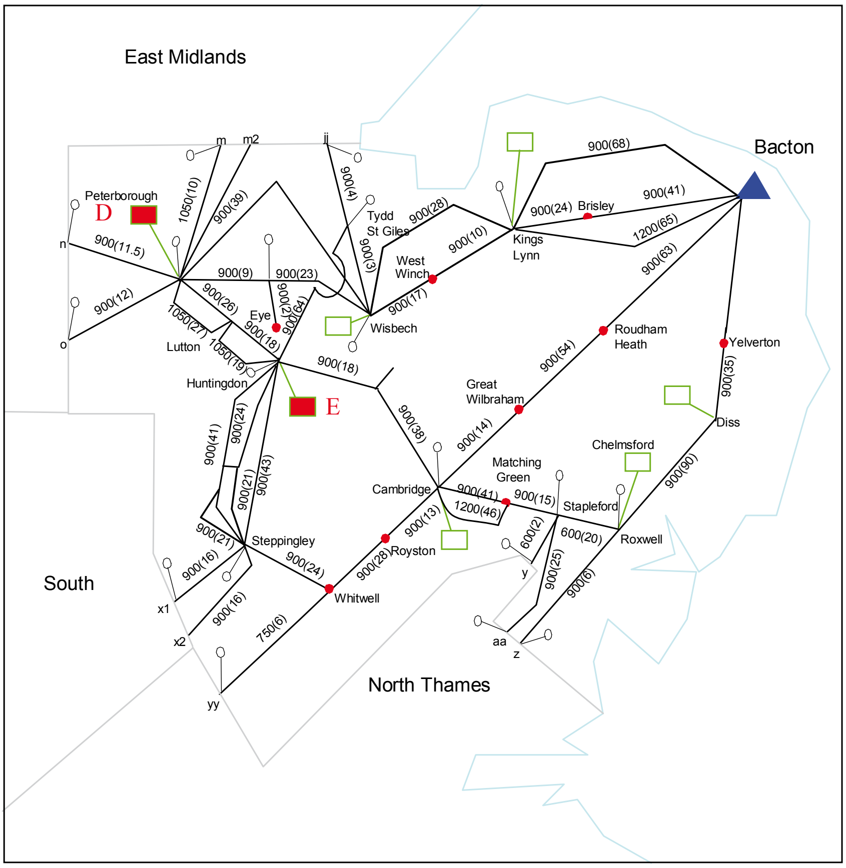


Eastern (EA) – NTS



Terminal
LDZ boundary
900(17) Existing pipeline (with distance marker)
900 Pipeline diameter (mm)
(17) Length (km)
a Denotes a crossing point between LDZs
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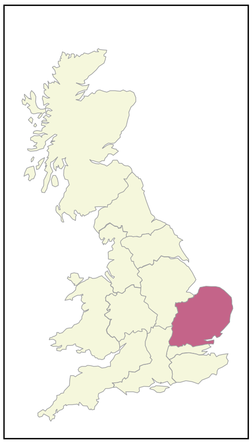
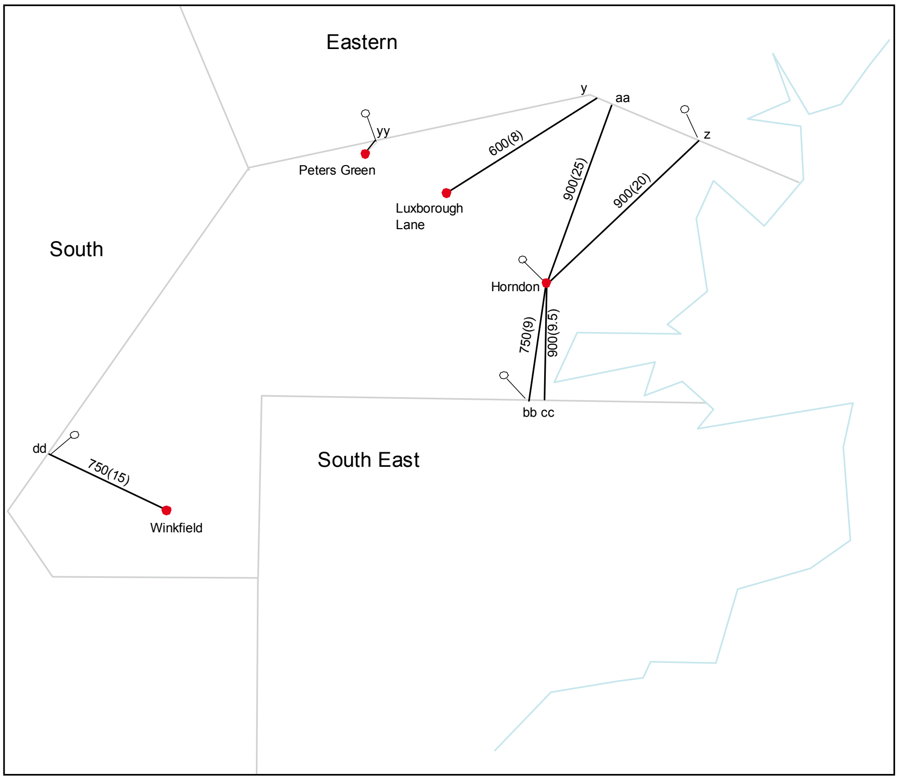
Offtake
Storage facility
Existing compressor
New compressor or compressor modifications
Alternative route
Uprating of pipelines
Approved emissions projects



Continued
The gas transportation system

North Thames (NT) – NTS



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- 900 Pipeline diameter (mm)
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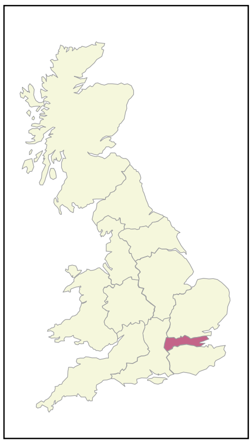
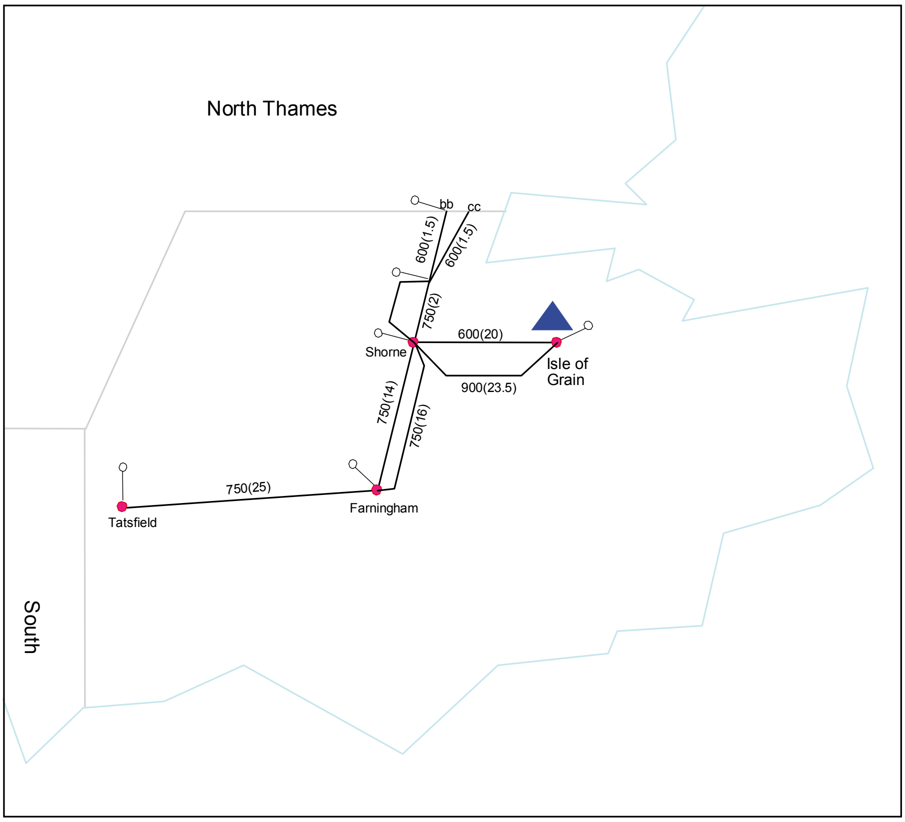


South East (SE) – NTS



Terminal
LDZ boundary
Existing pipeline (with distance marker)
Pipeline diameter (mm)
(17) Length (km)
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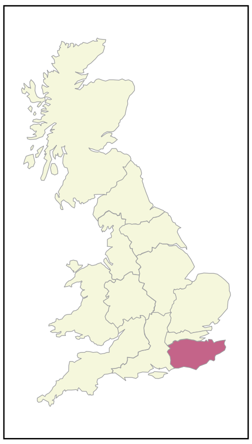
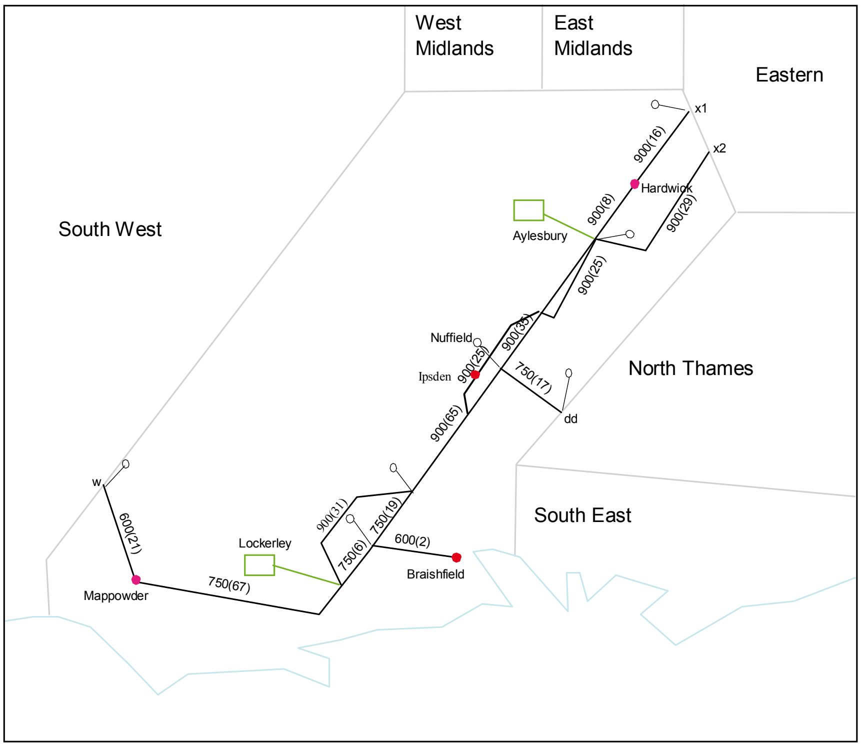
Uprating of pipelines
Approved emissions projects



Continued
The gas transportation system

South (SO) – NTS



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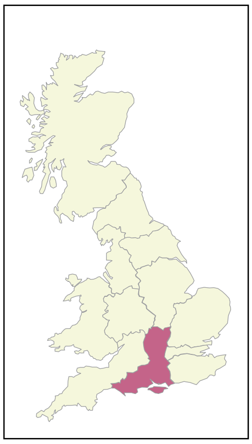
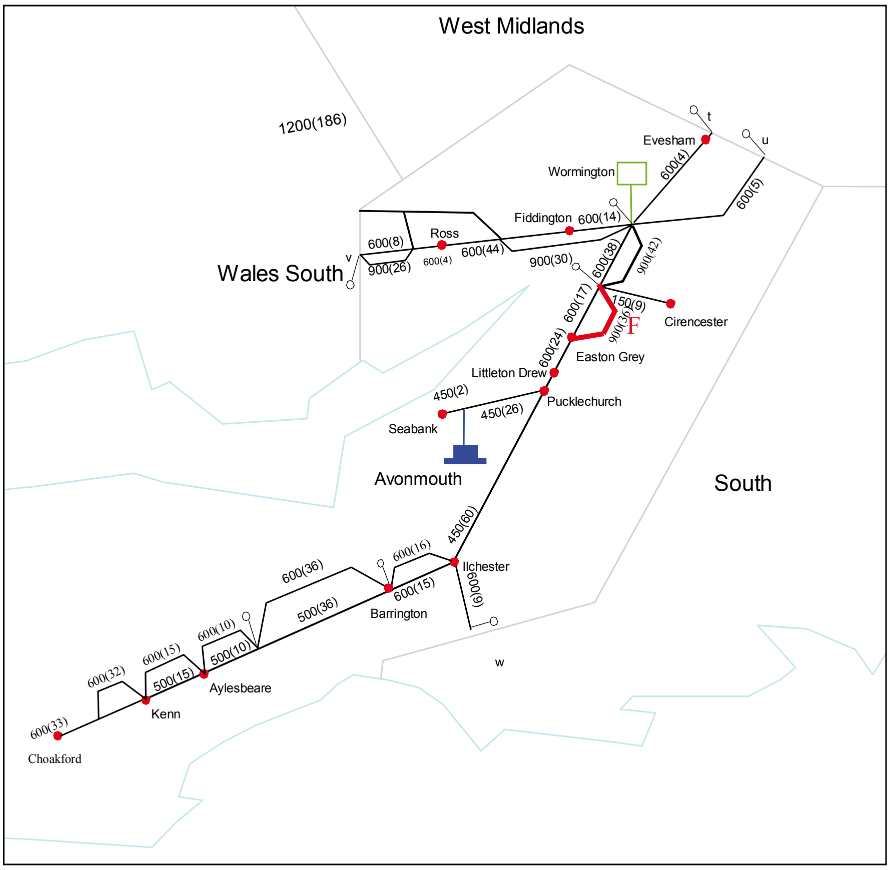
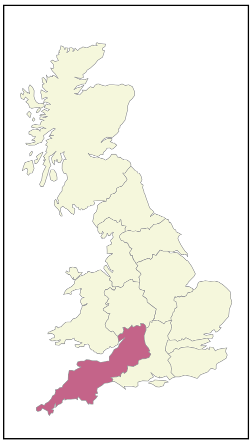


South West (SW) – NTS



- Terminal
- LDZ boundary
- 900(17) Existing pipeline (with distance marker)
- 900 Pipeline diameter (mm)
- (17) Length (km)
- a Denotes a crossing point between LDZs
- Proposed pipeline
- Offtake
- Storage facility
- Existing compressor
- New compressor or compressor modifications
- Alternative route
- Uprating of pipelines
- Approved emissions projects



Appendix five

Connections to the National Transmission System (NTS)

A5.1 Introduction

We, and other gas transporters, continue to offer connection services in line with our Gas Act obligations. However customers and developers have the option to choose other parties to build their facilities, have the connection adopted by the host gas transporter (depending upon circumstances), pass assets to a chosen system operator, transporter, or retain ownership of them. The following are the generic classes of connection:

- Entry Connections: connections to delivery facilities processing gas from gas producing fields or LNG vaporisation (i.e. importation) facilities, for the purpose of delivering gas into our system.
- Exit Connections: connections that allow gas to be offtaken from our system to premises (a 'Supply Point'), to a Distribution Network (DN) or to Connected Systems (at Connected System Exit Points (CSEPs)). There are several types of connected system including:
  - A pipeline system operated by another gas transporter
  - A pipeline operated by a party, who is not a gas transporter, for the purpose of transporting gas to premises consuming more than 2,196 MWh per annum
  - Storage Connections: connections to storage facilities for the purpose of temporarily offtaking gas from our system and delivering it back at a later date
  - International Interconnector Connections: connections to pipelines connecting Great Britain to other countries that may both offtake gas from and/or deliver gas to our System.

Please note that Storage and International Interconnector Connections may both deliver gas to the system and offtake gas from the system and therefore specific arrangements pertaining to both Entry and Exit Connections will apply.

Any requirement to change the connection arrangements (e.g. increased supply of gas) at an existing connection will be treated in the same way as for a new connection.

A5.2
General information regarding connections

In July 2012, Ofgem approved Uniform Network Code (UNC) Modification Proposal 0373 "Governance of the NTS connections processes" and this was subsequently implemented by National Grid with effect from 1 August 2012. UNC0373 now provides a robust and transparent framework for our customers that require a new connection to, or a revision to an existing connection on, the National Transmission System (NTS) summarised as follows:

- a formal Connection Application template for customers to complete
- definition of the content of an Initial Connection Offer
- definition of the content of a Full Connection Offer
- how to request a modification to a Full Connection Offer

Timescales for National Grid produce a Connection Offer:

- initial Connection Offer – up to 2 months
- full Connection Offer – up to 6 months (simple), 9 months (medium/complex)
- timescales for customers to accept an Initial/Full Connection Offer (up to 3 months);
- application fees for an Initial Connection Offer (fixed) and Full Connection Offer (variable);
- a requirement for National Grid to review the application fees on an annual basis.

Further information relating to the processes for new connections and changes to existing connections can be found on our website.[54]

It should be noted that any person wishing to connect to the NTS or requiring changes to their existing connection arrangements should contact us as early as possible to ensure that requirements can be met in time, particularly as system reinforcements and/or a NTS Licence change may be required as outlined in A5.4.3.

Our connection charging policy for all categories of connection is set out in the publication "The Statement and Methodology for Gas Transmission Connection Charging" which complies with the "Licence Condition 4B Statement". A link to this document can be found within the connection information on our website referred to above.

54 www.nationalgrid.com/uk/Gas/Connections/National+Transmission+System+-+Gas+Connections/

A5.3
Additional information specific to system entry, storage and interconnector connections

55 www.nationalgrid.com/uk/Gas/TYS/LTDP/index.htm

We require a Network Entry Agreement, Storage Connection Agreement or Interconnector Agreement, as appropriate, with the respective operator of all delivery, storage and interconnector facilities to establish, among other things, the gas quality specification, the physical location of the delivery point and the standards to be used for both gas quality and the measurement of flow.

A5.3.1
Renewable gas connections

National Grid has a commitment to environmental initiatives that combat climate change. Recently we have started to receive an increasing number of customer requests regarding entry into our pipeline system for biomass derived renewable gas. In addition, we have also received a number of requests for gas entry from unconventional sources such as coal bed methane.

National Grid welcomes these developments and is willing to facilitate the connection of such supply sources to the network, however it must be identified that all existing network entry quality specifications as detailed in Section A5.3.2 still apply.

It should be recognised that biomass-derived renewable gas may need to be connected to the Gas Distribution Networks instead of the National Transmission System, due to the pressure requirements. For information regarding connections to the Gas Distribution Networks please see the relevant documentation for the relevant Distribution Network (DN).

The twelve LDZs are managed within eight gas distribution networks. Following the sale by National Grid of four of the distribution networks, the owners of the distribution networks are now:

- North West, London, West Midlands and East of England (East Midlands LDZ and East Anglia LDZ) are owned and managed by National Grid. To contact National Grid-owned DNs about new connections please see Section 6 of the Long Term Development Plan[55], (directly via link or navigate from www.nationalgrid.com, select ‘Gas’, ‘Ten Year Statement’, then ‘Long term Development Plan’).
- Scotland and South of England (South LDZ and South East LDZ) are owned and managed by Scotia Gas Networks – operating as Scotland Gas Networks and Southern Gas Networks respectively. For further information visit www.scotiagasnetworks.co.uk
- Wales and the West (Wales LDZ and South West LDZ) is owned and managed by Wales and West Utilities. For further information visit www.wwutilities.co.uk
- North of England (North LDZ and Yorkshire LDZ) is owned by Northern Gas Networks, who have contracted operational activities to United Utilities Operations. For further information visit www.northerngasnetworks.co.uk

A5.3 continued
Additional information specific to system entry, storage and interconnector connections

A5.3.2
Network Entry Quality Specification

For any new entry connection to our system, the connecting party should notify us as soon as possible as to the likely gas composition. We will then determine whether the gas can be accepted taking into consideration our existing statutory and contractual obligations. Our ability to accept gas supplies into the system is affected by, among other things, the composition of the new gas, the location of the system entry point, volumes entered and the quality and volumes of gas already being transported within the system. In assessing the acceptability of any proposed new gas supply, we will take account of:

a) Our ability to continue to meet statutory obligations (including, but not limited to, the Gas Safety (Management) Regulations 1996 (GS(M)R))
b) The implications of the proposed gas composition on system running costs
c) Our ability to continue to meet our contractual obligations

For indicative purposes, the specification set out below is usually acceptable for most locations. This specification encompasses but is not limited to the statutory requirements set out in the GS(M)R.

1. Hydrogen sulphide
   - Not more than 5mg/m^3
2. Total sulphur
   - Not more than 50mg/m^3
3. Hydrogen
   - Not more than 0.1% (molar)
4. Oxygen
   - Not more than 0.001% (molar)
5. Hydrocarbon dewpoint
   - Not more than -2°C at any pressure up to 85barg
6. Water dewpoint
   - Not more than -10°C at 85barg
7. Wobbe Number (real gross dry)
   - The Wobbe Number shall be in the range 47.20 to 51.41MJ/m^3
8. Incomplete Combustion Factor (ICF)
   - Not more than 0.48
9. Soot Index (SI)
   - Not more than 0.60
10. Carbon dioxide
   - Not more than 2.5% (molar)
11. Contaminants
   - The gas shall not contain solid, liquid or gaseous material that may interfere with the integrity or operation of pipes or any gas appliance within the meaning of regulation 2(1) of the Gas Safety (Installation and Use) Regulations 1998 that a consumer could reasonably be expected to operate
12. Organo-halides
   - Not more than 1.5 mg/m^3
13. Radioactivity
   - Not more than 5 Becquerels/g

14. Odour
    - Gas delivered shall have no odour that might contravene the statutory obligation not to transmit or distribute any gas at a pressure below 7 barg, which does not possess a distinctive and characteristic odour

15. Pressure
    - The delivery pressure shall be the pressure required to deliver natural gas at the Delivery Point into our Entry Facility at any time taking into account the back pressure of our System at the Delivery Point as the same shall vary from time to time
    - The entry pressure shall not exceed the Maximum Operating Pressure at the Delivery Point.

16. Delivery Temperature
    - Between 1°C and 38°C

Note that the Incomplete Combustion Factor (ICF) and Soot Index (SI) have the meanings assigned to them in Schedule 3 of the GS(M)R.

In addition, where limits on gas quality parameters are equal to those stated in GS(M)R (Hydrogen Sulphide, Total Sulphur, Hydrogen, Wobbe Number, Soot Index and Incomplete Combustion Factor), we may require an operational tolerance to be included within an agreement to ensure compliance with the GS(M)R.

Due to continuous changes being made to the system, any undertaking made by us on gas quality prior to signing an agreement will normally only be indicative.

A5.3.3 Gas Quality Developments

- The UK Government's 3-phase gas quality exercise, initiated in 2003, concluded in 2007 with the Government reaffirming that it will not propose to the Health and Safety Commission to make any changes to the GB gas specifications contained in the GS(M)R. The Government's forward plan proposed continued engagement with the European Commission and Member States on the issue of gas quality, with particular regard to the CEN (Comité Européen de Normalisation, European committee for standardisation) mandate M/400, under which CEN was invited to draw up standards for natural gas quality that were the broadest possible within reasonable costs.
- Mandate M/400 envisaged two phases of work – the first being focused on the Wobbe index via a testing programme to assess the performance of domestic appliances using different gas qualities and the second being to consider the non-combustion parameters and the drafting of European Standard(s) for natural gas quality. A final report on the phase 1 work has now been completed (2011) and phase 2 has now commenced with an expected completion in 2014. In addition, mandate M/400 required a cost-benefit analysis of gas quality harmonisation on the whole European gas supply chain to be conducted and the EC's consultants GL Noble Denton and Poyry produced a preliminary report for consultation in July 2011. A final report of this work was produced in 2012 following further engagement with stakeholders.
- National Grid is also aware of, and continues to monitor, continental developments that could, under some circumstances, combine to limit the UK's ability to import gas due to differences in prevailing gas quality specifications between the UK and continental Europe.

A5.4
Additional information specific to system exit connections

Any person can contact us to request a connection, whether a shipper, operator, developer or consumer. However, gas can only be offtaken from that new Supply Point if it has been confirmed by a shipper, in accordance with the Uniform Network Code.

A5.4.1
National Transmission System (NTS) offtake pressures

The Applicable Offtake Pressure for the NTS, as referred to in the Uniform Network Code Section J 2.1 is normally 25barg. Although system pressure is typically higher, it will be subject to variation over time and location on the network. We currently plan normal NTS operations with start of day pressures no lower than 33barg, but such pressure cannot be guaranteed as pressure management is a fundamental aspect of the operation of an economic and efficient system. NTS offtake pressures at any location will vary due to:

- gas demand
- gas supply pressures at entry points
- compressor operation
- pipeline sizes and maximum operating pressures
- special operations such as maintenance and system development works

Offtake pressure also varies within day, from day to day, season to season and year to year. As a general rule, NTS offtake pressures tend to be higher at pressure sources such as entry points and outlets of operating compressors, and lower at the system extremities and inlets to operating compressors.

Our policy is to provide, on reasonable request, forecast information and illustrative historical records for specific NTS connection enquiries.

Notwithstanding the above, shippers may request a “specified pressure” for any Supply Meter Point, connected to any pressure tier, in accordance with the Uniform Network Code Section J 2.2.

A5.4.2
Connecting pipelines

Where a party wishes to lay their own connecting pipeline from the NTS to premises expected to consume more than 2,196 MWh per annum, ownership of the pipe shall remain with that party. This is National Grid’s preferred approach for connecting pipelines.

However, the “Statement and Methodology for Gas Transmission Connection Charging” describes alternative options regarding installation and ownership of connecting pipelines, though the costs of the pipeline remain with the connecting party for all options.

A5.4.3
Reasonable demands for capacity

Operating under the Gas Act 1986 (as amended 1995), we have an obligation to develop and maintain an efficient and economical pipeline system and, subject to that, to comply with any reasonable request to connect premises, provided that it is economic to do so.

In many instances, specific system reinforcement may be required to maintain system pressures for the winter period after connecting a new supply or demand. Please note that dependent on scale, reinforcement projects may have significant planning, resourcing and construction lead-times and that as much notice as possible should be given. Therefore, we encourage project developers to approach us as soon as they are in a position to discuss their projects so that we can assess the potential impact on the NTS and help inform their decision-making. In practice, we find the optimum time is at least several years before customers need to book capacity through the formal Uniform Network Code (UNC) processes[56].

56 In collaboration with our customers, National Grid is currently developing options to mitigate the challenges presented by the introduction of the Planning Act 2008. These options include aligning the arrangements pertaining to the physical NTS connections and, the commercial capacity regime; in addition, we are assessing short-term options for transitional capacity products. We anticipate that any changes to the UNC capacity regime might be introduced from April 2014 – subject to Ofgem approval.

Appendix six
Industry terminology

Accelerated Growth (AG)
A National Grid scenario whereby the 2020 renewables target is met early.

Advanced Reservation of Capacity Agreement (ARCA)
An agreement between us and Shippers relating to future NTS pipeline capacity for large sites in order that Shippers can book NTS Exit Capacity in accordance with Uniform Network Code provision to meet gas requirements of large projects at a later date.

Annual Quantity (AQ)
The AQ of a supply point is its annual consumption over a 365-day year, under conditions of average weather.

ASEP (Aggregate System Entry Point)
A term used to refer to gas supply terminals.

Balgzand–Bacton Line (BBL)
A pipeline connecting Balgzand in the Netherlands to Bacton in the UK. This pipeline is currently uni-directional and flows from the Netherlands to the UK only.

Bar
The unit of pressure that is approximately equal to atmospheric pressure (0.987 standard atmospheres). Where bar is suffixed with the letter g, such as in barg or mbarg, the pressure being referred to is gauge pressure, i.e. relative to atmospheric pressure. One millibar (mbarg) equals 0.001 bar.

Calorific Value (CV)
The ratio of energy to volume measured in Megajoules per cubic metre (MJ/m^3), which for a gas is measured and expressed under standard conditions of temperature and pressure.

Composite Weather Variable (CWV)
A measure of weather incorporating the effects of both temperature and wind speed. A separate composite weather variable is defined for each LDZ.

Combined Cycle Gas Turbine (CCGT)
A Combined Cycle Gas Turbine is a unit whereby electricity is generated by a gas-powered turbine and also a second turbine. The hot exhaust gases expelled from the first turbine are fed into the heat exchanger to generate steam, which powers the second turbine.

CO_2e
Carbon dioxide equivalent. A term used relating to climate change that accounts for the “basket” of greenhouse gases and their relative effect on climate change compared to carbon dioxide. For example UK emissions are roughly 600 m tonnes CO_2e. This constitutes roughly 450m tonnes CO2 and less than the 150m tonnes remaining of more potent greenhouse gases such as methane; which has 21 times more effect as a greenhouse gas, hence its contribution to CO_2e will be 21 times its mass.

Compressor station
An installation that uses gas turbine or electricity driven compressors to boost pressures in the pipeline system. Used to increase transmission capacity and move gas through the network.

Connected System Exit Point (CSEP)
A connection to a more complex facility than a single supply point. For example a connection to a pipeline system operated by another Gas Transporter.

Cubic metre (m3)
The unit of volume, expressed under standard conditions of temperature and pressure, approximately equal to 35.37 cubic feet. One million cubic metres (mcm) are equal to 106 cubic metres, one billion cubic metres (bcm) equals 109 cubic metres.

Daily Flow Notification (DFN)
A communication between a Delivery Facility Operator (DFO) and us, indicating hourly and end of day entry flows from that facility.

Daily Metered Supply Point
A supply point fitted with equipment, for example a datalogger, which enables meter readings to be taken on a daily basis.

DECC
Department of Energy and Climate Change. DECC was formed in 2008 from the Energy Division of BERR and parts of DEFRA. Some references to BERR still exist and some energy related publications still reside on the BERR website, although the responsibility now resides with DECC.

Delivery Facility Operator (DFO)
Operators of the reception terminals, which process and meter gas deliveries from offshore pipelines before transferring the gas to our system.

Distribution Network (DN)
An administrative unit responsible for the operation and maintenance of the local transmission system (LTS) and <7barg distribution networks within a defined geographical boundary. There are currently eight DNs, each consisting of one or more LDZs, supported by a national Emergency Services organisation.

Distribution system
A network of mains operating at three pressure tiers: intermediate (2 to 7barg), medium (75mbarg to 2barg) and low (less than 75mbarg).

Diurnal storage
Gas stored for the purpose of meeting, among other things, within-day variations in demand. Gas can be stored in special installations, such as gasholders, or in the form of linepack within transmission, i.e. >7barg, pipeline systems.

E-TYS
Electricity Ten Year Statement.

ENTSOG
European Network of Transmission System Operators for Gas.

ENA
Energy Networks Association.

Exit zone
A geographical area (within an LDZ) that consists of a group of supply points that, on a peak day, receive gas from the same NTS offtake.

Future Energy Scenarios (FES)
Our annual industry-wide consultation process encompassing questionnaires, workshops, meetings and seminars to seek feedback on our latest scenarios and shape future scenario work. The Future Energy Scenarios document is produced annually and contains our latest scenarios.

G-TYS
Gas Ten Year Statement.

Continued
Industry terminology

Gas Deficit Warning
The purpose of a Gas Deficit Warning is to alert the industry to a requirement to provide a within-day market response to a physical supply / demand imbalance.

Gas Transporter (GT)
Formerly Public Gas Transporter (PGT). GTs, such as National Grid, are licensed by the Gas and Electricity Markets Authority (GEMA) to transport gas to consumers.

Gasholder
A vessel used to store gas for the purposes of providing diurnal storage.

Gas Supply Year
A twelve-month period commencing 1 October, also referred to as a Gas Year.

Gone Green (GG)
A National Grid scenario whereby the 2020 renewables target is met.

IEA
International Energy Agency. An intergovernmental organisation that acts as energy policy adviser to 28 member countries.

Interconnector
A pipeline transporting gas to another country. The Irish Interconnector transports gas across the Irish Sea to both the Republic of Ireland and Northern Ireland. The Belgian Interconnector transports gas between Bacton and Zeebrugge. The Belgian Interconnector is capable of flowing gas in either direction. The Dutch Interconnector (BBL) transports gas between Balgzand in the Netherlands and Bacton. It is currently capable of flowing only from the Netherlands to the UK.

IUK
Owner and operator of the UK–Belgian interconnector.

Kilowatt hour (kWh)
A unit of energy used by the gas industry, approximately equal to 0.0341 therms.

Large Combustion Plant Directive (LCPD)
European Union directive, effective from 2008, which aims to control emissions of sulphur dioxide, nitrogen oxides and dust from large combustion plants, including power stations.

Linepack
The volume of gas within the National or Local Transmission System at any time.

Liquefied Natural Gas (LNG)
Gas stored and / or transported in liquid form.

Load Duration Curve (1-in-50 Severe)
The 1-in-50 severe load duration curve is that curve which, in a long series of years, with connected load held at the levels appropriate to the year in question, would be such that the volume of demand above any given demand threshold (represented by the area under the curve and above the threshold) would be exceeded in one out of fifty years.

Load Duration Curve (Average)
The average load duration curve is that curve which, in a long series of winters, with connected load held at the levels appropriate to the year in question, the average volume of demand above any given threshold, is represented by the area under the curve and above the threshold.

Local Distribution Zone (LDZ)
A geographic area supplied by one or more NTS offtakes. Consists of LTS and distribution system pipelines.

Local Transmission System (LTS)
A pipeline system operating at >7barg that transports gas from NTS/LDZ offtakes to distribution system low pressure pipelines. Some large users may take their gas direct from the LTS.

Long-Term System Entry Capacity (LTSEC)
NTS entry capacity available on a long-term basis (up to 17 years into the future) via an auction process. Also known as Quarterly System Entry Capacity (QSEC).

Margins Notice
The purpose of the Margins Notice (MN) is to provide the industry with a day ahead signal that there may be the need for a market response to a potential physical supply / demand imbalance.

National Balancing Point (NBP)
A notional point which represents the System for balancing purposes.

National Transmission System (NTS)
A high-pressure system consisting of terminals, compressor stations, pipeline systems and offtakes. Designed to operate at pressures up to 85 bar. NTS pipelines transport gas from terminals to NTS offtakes.

National Transmission System Offtake
An installation defining the boundary between NTS and LTS or a very large consumer. The offtake installation includes equipment for metering, pressure regulation, etc.

Non-Daily Metered (NDM)
A meter that is read monthly or at longer intervals. For the purposes of daily balancing, the consumption is apportioned, using an agreed formula, and for supply points consuming more than 73.2 MWh pa, reconciled individually when the meter is read.

Odourisation
The process by which the distinctive odour is added to gas supplies to make it easier to detect leaks.

Office of Gas and Electricity Markets (Ofgem)
The regulatory agency responsible for regulating Great Britain's gas and electricity markets.

On the day Commodity Market (OCM)
This market constitutes the Balancing Market for GB and enables anonymous financially cleared on the day trading between market participants.

Operating margins
Gas used by National Grid Transmission to maintain system pressures under certain circumstances, including periods immediately after a supply loss or demand forecast change, before other measures become effective and in the event of plant failure, such as pipe breaks and compressor trips.

Own Use Gas (OUG)
Gas used by us to operate the transportation system. Includes gas used for compressor fuel, heating and venting.

Planning and Advanced Reservation of Capacity Agreement (PARCA)
A solution being developed in line with the enduring incremental capacity release solutions which have been developed following the implementation of the Planning Act.

Price Control Review (PCR)
Ofgem's periodic review of our allowed returns. The current price control period which ends 31 March 2012 is being extended by one year, and the new RIIO-T1 price control period will run from 1 April 2013 to 31 March 2021.

Peak day demand (1-in-20 peak demand)
The 1-in-20 peak day demand is the level of demand that, in a long series of winters, with connected load held at the levels appropriate to the winter in question, would be exceeded in one out of 20 winters, with each winter counted only once.

QSEC
Quarterly System Entry Capacity – see LTSEC

RHI (Renewable Heat Incentive)
The domestic Renewable Heat Incentive (RHI) is due to start in July 2013, and provides long-term financial support for renewable heat technologies so households can move away from fossil fuels for heating and to contribute to the UK's 2020 renewable energy target. The longer-term objective is to prepare the country for the deployment of renewable technologies in the next decade to help meet the Government's carbon reduction targets. The Heat Strategy published in March 2012, provides the direction of travel on implementation of renewable heat to 2050.

ROC (Renewable Obligation Certificate)
Administered by Ofgem. Awarded to owners of renewable projects for renewably generated electricity. Large electricity generators are required to have a minimum amount of electricity generated from renewable generation, any less and ROCs have to be bought to cover the shortfall, any excess can be sold via ROCs.

Safety monitors
Safety monitors in terms of space and deliverability are minimum storage requirements determined to be necessary to protect loads that cannot be isolated from the network and also to support the process of isolating large loads from the network. The resultant storage stocks or monitors are designed to ensure that sufficient gas is held in storage to underpin the safe operation of the gas transportation system under severe conditions. There is now just a single safety monitor for space and one for deliverability. These are determined by National Grid to meet its Uniform Network Code requirements and the terms of its Safety Case. Total shipper gas stocks should not fall below the relevant monitor level (which declines as the winter progresses). National Grid is required to take action (which may include use of emergency procedures) in order to prevent storage stocks reducing below this level.

Seasonal Normal Composite Weather Variable (SNCWV)
The seasonal normal value of the CWV is the smoothed average of the values of the applicable CWV for that day in a significant number of previous years.

Shearwater Elgin Area Line (SEAL)
The offshore pipeline from the Central North Sea (CNS) to Bacton.

Shipper or Uniform Network Code (Shipper) User
A company with a Shipper Licence that is able to buy gas from a producer, sell it to a supplier and employ a GT to transport gas to consumers.

Shrinkage
Gas that is input to the system but is not delivered to consumers or injected into storage. It is either Own Use Gas or Unaccounted for Gas.

Slow Progression (SP)
A National Grid scenario where the 2020 renewable energy target for 2020 is not met until some time between 2020 and 2025.

Supplier
A company with a Supplier's Licence contracts with a shipper to buy gas, which is then sold to consumers. A supplier may also be licensed as a shipper.

Supply Hourly Quantity (SHQ)
The maximum hourly consumption at a supply point.

Supply Offtake Quantity (SOQ)
The maximum daily consumption at a supply point.

Supply Point
A group of one or more Meter Points at a site.

Therm
An imperial unit of energy. Largely replaced by the metric equivalent: the kilowatt hour (kWh). 1 therm equals 29.3071 kWh.

TSO
Transmission System Operator.

Unaccounted for Gas (UAG)
Gas "lost" during transportation. Includes leakage, theft and losses due to the method of calculating the Calorific Value.

Uniform Network Code (UNC)
The Uniform Network Code replaced the Network Code and, as well as covering the arrangements within the Network Code, covers the arrangements between National Grid Transmission and the Distribution Network Operators.

UKCS
United Kingdom Continental Shelf.

Appendix seven
Conversion matrix

To convert from the units on the left hand side to the units across the top multiply by the values in the table.

	To: Multiply	**GWh**	**mcm**	**million therms**	**thousand toe**
From:	**GWh**	1	0.091	0.034	0.086
	mcm	11	1	0.375	0.946
	million therms	29.307	2.664	1	2.520
	thousand toe	11.630	1.057	0.397	1

Note: all volume to energy conversions assume a CV of 39.6 MJ/m^3

GWh = gigawatt hours
mcm = million cubic metres
thousand toe = thousand tonne of oil equivalent

Notes

Notes

57 Special Condition C2 requires that the Ten Year Statement, published annually, shall provide a ten-year forecast of transportation system usage and likely system developments that can be used by companies, who are contemplating connecting to our system or entering into transport arrangements, to identify and evaluate opportunities.

The Statement explains our latest volume forecasts, system reinforcement projects and investment plans. It has been published at the end of the 2012 planning process following a re-appraisal of our analysis of the market and expands on the work in the second edition of our Future Energy Scenarios document published in September 2012. The Statement forms the basis of our industry-wide revised consultation process, Future Energy Scenarios, due to restart in the New Year, and is the first element of our 2013 planning process.

Please Note:
This document does not take into account Ofgem's final proposals for the 8-year RIIO-T1 period starting in April 2013.

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