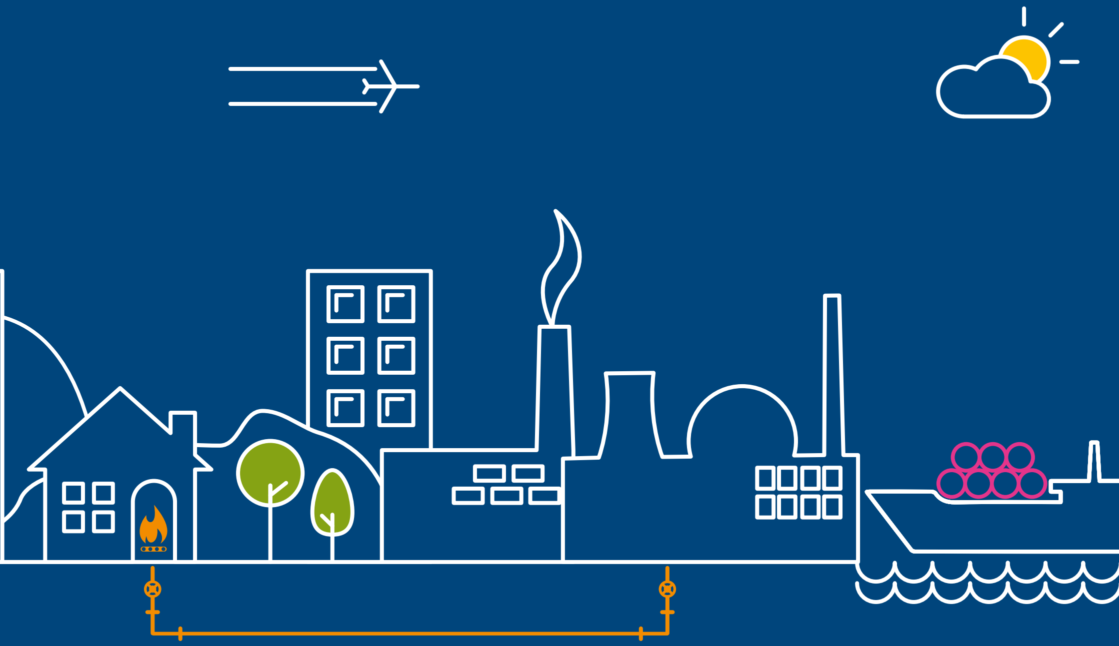
nationalgrid

Gas Ten Year Statement 2015

UK gas transmission



NOVEMBER 2015

Foreword

Welcome to the 2015 edition of the Gas Ten Year Statement (GTYS). This document is the conclusion of our annual planning cycle and describes how the gas National Transmission System (NTS) is anticipated to evolve to meet future customer needs.

In this year's Gas Ten Year Statement we discuss the impact of changing customer requirements, our Future Energy Scenarios (FES), legislative changes and asset health on the future operation and development of the NTS.

During 2015, we discussed the considerable challenges and uncertainties confronting us all as a result of the complex and evolving energy landscape ahead.

As you will read, we provide an update on our progress on the impact of emissions legislation for our compressor fleet, and expanded further on the impact of increasingly dynamic gas flow characteristics on System Flexibility. We broaden the discussion around other key topics such as asset health, EU code changes, and we introduce the potential development of a Gas System Operability Framework.

Responding to stakeholder feedback, we have built upon the changes we introduced last year by making the need case for future capability requirements much clearer. We have aligned this year's GTYS to our Network Development Process (NDP) to provide increased transparency around our internal processes and decision making. This will now become our norm going forward.

Our ambition and commitment is to build strong, collaborative relationships with you such that our collective insight and sharing of ideas and needs can be acted upon in the most efficient and effective way. Change and uncertainty are givens, and with it comes positive opportunity for us to embrace a quite different engagement experience to develop and deliver that change. Something I am both personally committed to, and excited about.

Over the coming year we aim to better understand what you truly value and need by way of capability from the Gas transmission network such that we can build this appreciation and intelligence into future documents and dialogue with you.

To this end your input and feedback is hugely important to us. Much goes into it, so please do help us to make this key document serve you as optimally as possible. Do read the Way Forward chapter for further information on our 2015 GTYS consultation process. Plus of course, please tell us what you think of it by writing to us at Box.SystemOperator.GTYS@nationalgrid.com, engaging us at future stakeholder events or meeting us.

Thank you for taking the time to read this year' publication and I look forward to receiving your feedback.

Andy Malins
Head of Network Capability and Operations, Gas

Contents

Executive Summary

Our National Transmission System (NTS) Network Development Process (NDP) is underpinned by understanding:

- how our customers want to use our system, now and in the future
- how supply and demand patterns could evolve
- how legislative change could affect our system
- how asset health will affect our system development.

This year's Gas Ten Year Statement (GTYS) focuses on these key themes because we think they will have the most significant impact on how we plan and operate our network over the next ten years.

Customer requirements

The way our customers use our NTS has changed over the last ten years. Based on what our customers are telling us they are likely to need in the near future, we may not be able to meet these needs using our current system capability and operational strategies. Using our NDP we must develop new ways to plan and operate our system so we can meet these changing requirements.

The main changes in our customers' requirements are:

- customers are using the new Planning and Advanced Reservation of Capacity Agreement (PARCA) arrangements to reserve capacity before making final investment decisions on their projects
- customers ask for higher ramp rates and shorter notice periods, particularly in response to changes in the electricity market
- Gas Distribution Network Operators (DNO) want NTS flexibility to meet their customers' requirements in a world where demand is falling. We are developing new planning and operational tools to meet their requests
- long-term auctions no longer indicate a shipper's intention to flow. Diversity and extent of supplies can mean great variation in flow on the NTS from one day to the next.

In response to our changing customer needs and their impact on NTS System Flexibility, we have commissioned the GasFlexTool. This new tool will help us to better understand how future customer requirements on the system will evolve and to plan accordingly. We are embedding this tool in our processes and are now seeing the first results (Chapter 3).

Executive Summary

Future Energy Scenarios
As part of our Future Energy Scenarios (FES) process, we have developed four supply and demand scenarios. These are based on assumptions about prosperity and green ambition. In all four scenarios, security of supply is maintained for both gas and electricity.

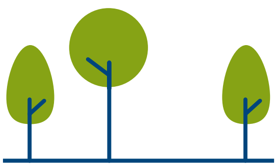
Some important issues emerging from the 2015 FES need to be considered in the context of the capability of the gas network:

- Increasing operability changes in the electricity industry – our gas NTS must be flexible and capable of dealing with changing supply and demand. Traditionally, most gas-fired electricity generation has connected to the NTS, but in future more generators could connect directly to the gas Distribution Networks (DN). This will change the network interface and make gas forecasting and balancing on the NTS more challenging. We know the NTS will need to be more flexible. We are working to understand how we can make our NTS more resilient to future operational changes
- Supply source uncertainty – future NTS developments must be designed to adapt to changing gas supply locations and types
  - There are more unconventional sources of gas supply connecting at distribution level, which may mean over-supply in the Distribution Networks (DN) during the summer
  - Decline in the St Fergus flows means we must be able to move more gas south to north. The system has limited capability to do this and based on current network operation, capability and agreements, there will need to be system reinforcement to support Scotland to meet pressure and demand. We are talking to customers and stakeholders so we can operate efficiently together. The results of these discussions will be fed into the NDP so we can reassess the network capability and refine any reinforcement works that are needed.
- Electricity Market Reform (EMR) – Contracts for gas-fired generation were issued after the first round of electricity Capacity Market auctions. We are talking to developers so we are ready for the second round of auctions.

Legislative change

Change in legislation is a major trigger for investment in our network.

- The Industrial Emissions Directive (IED) will have a big impact on our compressor fleet and how we operate it. Over the past 18 months we have talked with stakeholders about the best options for our network. The options proposed for most sites were a mixture of retaining units on limited use (500 hours per year operation from 2016), limited life time (17,500 hours operation then decommission by 2023) and/or replacing with similar units that provide the capability we need. There are more details on a site-by-site basis in Chapter 5
- Running the IED stakeholder engagement programme meant we were able to present recommended options to Ofgem. This showed how we would comply with the IED and meet future stakeholder requirements, with a value of £420m (outturn) within RIIO-T1. This compares to a like-for-like investment programme of approximately £900m
- We submitted our final proposals to Ofgem in May and on 30 September Ofgem published their decision to reject our request for additional funding to finance our proposed investment solutions
- In our view rejecting all of our investment proposals is not in the interests of consumers and users of the gas transmission network, as it creates significant regulatory uncertainty in relation to this critical IED investment programme
- We are working with Ofgem and finalising our investment decisions on the back of this decision
- As we have been considering the options about IED and its impact on the system, we have also been closely following the development of the Medium Combustion Plant Directive (MCP). The MCP sets out emission limit values for facilities that burn fuel with rated thermal output of 1–50MW and will impact 26 compressor units from our fleet. For gas compressors that are essential to the safety and security of the NTS we have been given until 2030 to comply with MCP. This extended period gives us more time to explore innovative solutions so we can comply with the directive in 2030. This pushes any system Need Case beyond the horizon of this GTYS edition. We will report on our strategy as it develops in future editions of GTYS.



Executive Summary

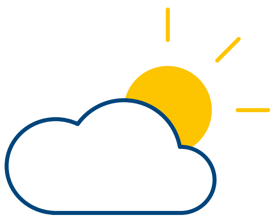
Asset health
Asset health is a key network output measure agreed with our customers, stakeholders and Ofgem as part of RIIO. Because the NTS is ageing, asset health is a key trigger for the NDP.

- Over the next year we will review some of our major strategic sites where asset health is a key driver. Rather than replace on a like-for-like basis, we will assess the ongoing and future requirements of each site so we can make the appropriate investments.

Customer and stakeholder engagement
Next year we will continue talking to you about IED, MCP and System Flexibility and tell you more about our progress with the GasFlexTool. We will arrange an industry-wide session to discuss developing a Gas System Operability Framework (GSOF). We would like to know if you would value a GSOF and what it could look like.

We will continue to develop the Gas Ten Year Statement (GTYS), taking your feedback into account to make sure that this document is valuable to you. We welcome your views on the content and scope of this year's edition.

Please let us know if you would like us to change anything or include more information in future editions. We are happy to receive feedback by any method including:
- customer seminars
- operational forums
- bilateral stakeholder meetings
- our GTYS mailbox: **Box.SystemOperator.GTYS@nationalgrid.com**
- our online survey at: **https://www.surveymonkey.com/r/GTYS2015**



Chapter one

Introduction

Introduction

Welcome to our 2015 Gas Ten Year Statement (GTYS).

We write the GTYS to provide you with a better understanding of how we intend to plan and operate the National Transmission System (NTS) over the next ten years.

We update you on current and future challenges which impact the way we plan and operate the NTS. We also discuss what we're doing to address them as System Operator (SO) and Transmission Owner (TO). We are keen to engage with you to get your feedback on what we're doing and how we're doing it.

GTYS is published at the end of the annual planning cycle. We use GTYS to provide information on an annual basis to help you to identify connection and capacity opportunities on the NTS. We summarise key projects and changes to our internal processes that may impact you.

1.1
What do we do?

Our role
We are the System Operator and Transmission Owner of the gas National Transmission System (NTS) in Great Britain. As System Operator our primary responsibility is to transport gas from supply points to exit offtake points safely, efficiently and reliably. We manage the day-to-day operation of the network including balancing supply and demand, maintaining system pressures and ensuring gas quality standards are met. As Transmission Owner we must make sure all of our assets on the NTS are fit for purpose and safe to operate. We develop and implement effective maintenance plans and asset replacement schedules to keep the gas flowing.

Our network
The NTS plays a vital part in the secure transportation of gas and facilitation of the competitive gas market. We have a network of 7,600km pipelines, presently operated at pressures of up to 94 bar, which transport gas from coastal terminals and storage facilities to exit offtake points from the system (Appendix 1). At the exit offtake points, gas is transferred to eight Distribution Networks (DNs) for onward transportation to domestic and industrial customers, or to directly connected customers including storage sites, power stations, large industrial consumers and interconnectors (pipelines to other countries).

Our regulatory framework
The RIIO (Revenue = Incentives +Innovation+Outputs) regulatory framework was implemented by Ofgem in 2013/14. RIIO uses incentives to drive innovation to develop and deliver more sustainable energy. We are currently within the RIIO-T1 period (2013–21); under this framework we have set outputs which have been agreed with our stakeholders (for more information, please see Our Performance publication[1]). We deliver these outputs in return for an agreed revenue allowance from Ofgem.

[1] http://www.talkingnetworkstx.com/our-performance.aspx

1.2
Future Energy Scenarios

We published our latest Future Energy Scenarios (FES) publication in July 2015[2]. We have created a credible range of scenarios, developed following industry feedback, which focus on the energy trilemma (sustainability, affordability and security of supply). The figure below summarises the four 2015 scenarios.

Our 2015 FES publication gives details of annual and peak gas supply for each of our four scenarios. The GTYS expands on the FES by adding locational information and highlighting implications for the future planning and operation of the NTS.

Figure 1.1
Here are the political, economic, social, technological and environmental factors accounted for in our four 2015 Future Energy Scenarios

Prosperity (+ / –)

Consumer Power
- **Economic** – moderate economic growth
- **Political** – government policies focus on indigenous security of supply and carbon reduction
- **Technological** – high innovation focused on market and consumer needs. High levels of local generation and a mixture of generation types at national level
- **Social** – consumerism and quality of life drives behaviour and desire for 'going green', not a conscious decision
- **Environmental** – long-term UK carbon and renewable ambition becomes more relaxed

Gone Green
- **Economic** – moderate economic growth
- **Political** – European harmonisation and long-term environmental energy policy certainty
- **Technological** – renewable and low carbon generation is high. Increased focus on green innovation
- **Social** – society actively engaged in 'going green'
- **Environmental** – new policy intervention ensuring all carbon and renewable targets are achieved

No Progression
- **Economic** – slower economic growth
- **Political** – inconsistent political statements and a lack of focus on environmental energy policies
- **Technological** – little innovation occurs in the energy sector with gas as the preferred choice for generation over low carbon
- **Social** – society is cost conscious and focused on the here and now
- **Environmental** – reduced low carbon policy support and limited new interventions

Slow Progression
- **Economic** – slower economic growth
- **Political** – European harmonisation, focus on low cost environmental energy policies
- **Technological** – medium levels of innovation lead to a focus on a mixture of renewable and low carbon technologies
- **Social** – society is engaged in 'going green' but choices are limited by cost
- **Environmental** – new policy interventions are constrained by affordability

Green ambition (– / +)

[2] http://fes.nationalgrid.com/

Introduction

1.3 Emerging themes

Three key themes have emerged over the last 12 to 24 months:
- customer requirements
- legislative change
- asset health.

This year's GTYS focuses on these key themes and outlines what impact they will have on how we operate and develop our network over the next ten years.

These themes are all considered against a backdrop of the Future Energy Scenarios (FES) and run through each chapter to show their impact on our day-to-day network operation and at each stage of our NDP.

Customer requirements

Customer behaviour is changing. The NTS has to be able to respond in a more dynamic way; we call it system (or network) flexibility. Often it's not a case of one customer changing how they use the system, it's the combined impact of multiple changing customer behaviours. This makes it ever more challenging to plan and operate the system.

During 2014/15 you told us that system flexibility was really important and that you wanted us to discuss it with the wider industry. So we held an external stakeholder engagement event in London on 14 May 2015 to start an industry-wide discussion on this topic. We outline the key areas of discussion from the event and what we are planning to do next in Chapter 3.

Last winter we saw a record number of high linepack swing days. This highlighted the importance of making sure that our system is flexible and capable of dealing with significant within-day changes.

We are currently analysing how future operational scenarios may play out so we can develop operational strategies that we may need out to 2020 and beyond. We aim to develop and propose system flexibility output measures that are clearly defined and can quantify both the impact of these issues and the benefits of the solutions. This work is discussed in more detail in chapters 2, 3 and 4.

Legislative change

Legislative change has a big impact on how we plan and operate our network.

In last year's GTYS we outlined the key elements of the Industrial Emissions Directive (IED) and how our network could be affected. In February 2015, we published our initial consultation stakeholder feedback document. Based on your feedback we developed an optimised strategy for our affected compressor fleet and submitted this to Ofgem in May 2015.

We discuss the impact of legislative change, including IED, in Chapters 2, 3, 4 and 5.

Asset health

The NTS comprises 7,600 km of pipeline, 24 compressor sites with 75 compressor units, 20 control valves and 530 above-ground installations (AGIs).

It's vital that we comply with all safety legislation that applies to operating the NTS while also maintaining the current level of network risk through maintenance and replacement. With so many assets on the system, including many that are ageing, we have a growing asset health issue. An ageing network needs more maintenance but we have to balance this with the changing needs on our network.

Our gas supplies have become more diverse and no longer follow the traditional north to south flows. The variability of power generation is expected to increase as renewable generation grows.

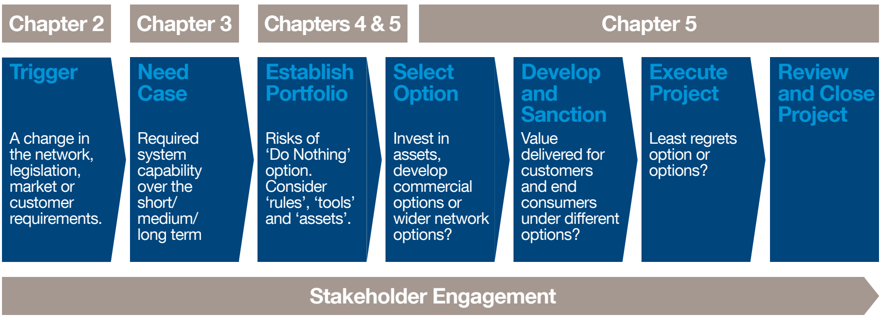
The impact of asset health on our network is covered in Chapters 2 and 5.

1.4
Network Development Process

We have changed the GTYS structure so that our investment decision process is more transparent. The 2015 GTYS is based on the initial stages of our Network Development Process (NDP).

Our NDP defines the method for decision making, optioneering, development, sanction, delivery and closure for all our projects (Figure 1.2). The goal is to deliver projects that have the lowest whole-life cost, are fit for purpose and meet stakeholder and RIIO requirements.

Figure 1.2
The Network Development Process



In GTYS, we focus on the first three stages of our NDP (Trigger, Need Case and Establish Portfolio) as these outline our internal decision-making process. The final three stages relate to physical asset build and non-physical solutions such as commercial options. These are briefly discussed in Chapter 5.

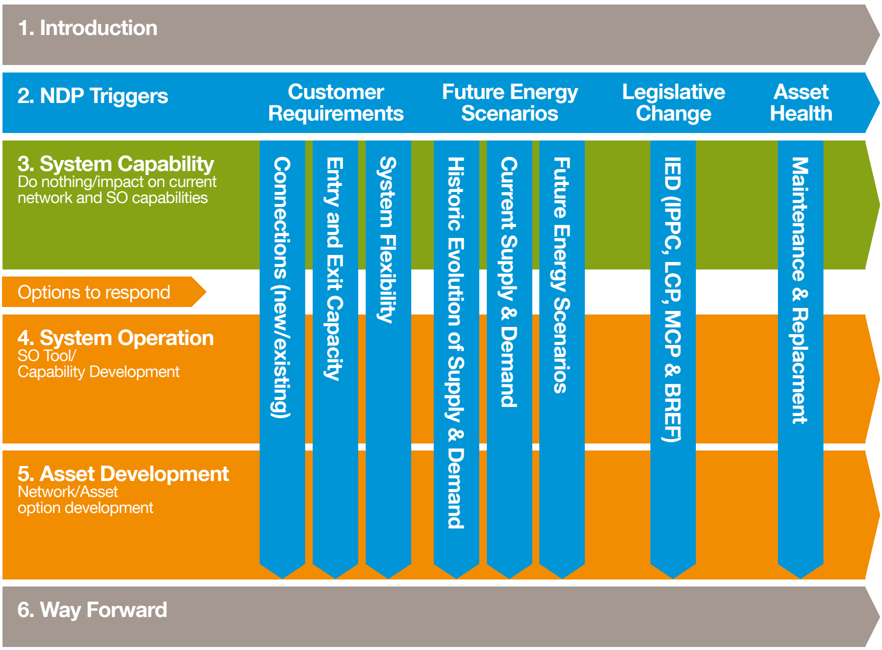
Introduction

1.5
GTYS chapter structure

Our new chapter structure (Figure 1.3) gives you a clearer overview of what happens at each stage of the NDP and how the stages link together to provide the most robust, cost-effective solution(s).

Along with our FES the impact of the three key themes are discussed throughout this year's GTYS.

Figure 1.3
2015 GTYS structure



Chapter 2. Network development inputs
There are many inputs that 'trigger' our NDP. For every trigger we assess the needs of our network to ensure it remains fit for purpose. We're in a period of great change, which may result in significant modifications to the way we currently plan and operate the NTS. We anticipate that we will have a wider range of triggers to our NDP in future.

This chapter covers four key triggers: customer requirements, the FES, legislation and asset health. We discuss these triggers and how they impact the current and future use of the NTS.

Chapter 3. System capability
This section outlines the current system capability of the NTS. System capability defines the maximum and minimum ability of our current network infrastructure to transport gas safely and effectively. We explore the Need Case stage of our NDP. This is where we assess our system capability requirements.

We provide information about system flexibility, entry and exit capacity, pressures, and the impact of the IED.

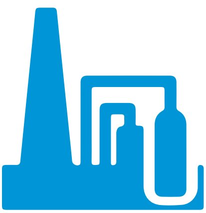
Chapter 4. System operation
This chapter explores part of the 'Establish Portfolio' stage of the NDP. We develop a portfolio of non-asset and asset solutions to meet the Need Case requirements. In this chapter we detail the specific ongoing and planned developments to our System Operator capabilities (rules and tools).

These developments make sure that we can keep planning to operate a fit-for-purpose network safely and efficiently, to deliver value for our customers and stakeholders.

Chapter 5. Asset development
Here we consider the 'Establish Portfolio' stage with our asset solutions.

It sets out NTS reinforcement projects that have been sanctioned, projects under construction in 2015/16 and potential investment options for later years as a result of the IED. It also covers our asset health review. These are all assessed against the scenarios and sensitivities in our FES publication.

Chapter 6. Way forward
We're committed to meeting your needs and want you to help shape our GTYS and NDP. This chapter discusses our plans over the coming year and tells you how you can get involved.



530
Number of above-ground installations in the NTS network

Introduction

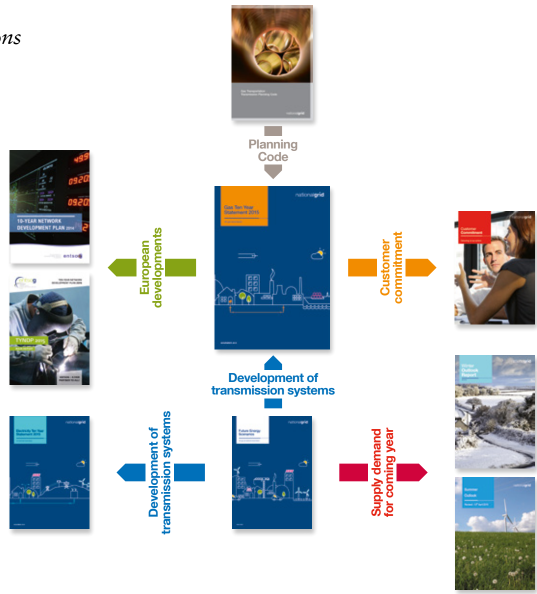
1.6
Other publications and information sources

We published the 2015 Future Energy Scenarios (FES) in July. They form the basis of the 2015 GTYS and many of our other related publications (see Figure 1.4).

You may also be interested in the following sources of information:

- our Talking Networks site discusses the impact of the Industrial Emissions Directive on our compressor fleet[3]
- our Talking Networks site includes a new area to provide you with information on the development of our strategy for System Flexibility[4]
- our industry information page includes the Gas Transportation Transmission Planning Code, which was published in April 2015[5]
- our information page for Gas Connections and application form[6]
- our information page for Planning and Advanced Reservation of Capacity Agreement (PARCA) and application form[7].

Figure 1.4
Related publications



[3] http://www.talkingnetworkstx.com/IED-welcome.aspx
[4] http://www.talkingnetworkstx.com/System-Flexibility.aspx
[5] http://www2.nationalgrid.com/UK/Industry-information/Developing-our-network/Gas-Transportation-Transmission-Planning-Code/
[6] http://www2.nationalgrid.com/uk/services/gas-transmission-connections/connect/
[7] http://www2.nationalgrid.com/UK/Services/Gas-transmission-connections/PARCA-Framework/

1.7
How to use this document

How to use this document

We've colour coded each chapter, to help you find relevant content quickly and easily. And we've highlighted the main messages at the start of each section (see Figure 1.5). We'll use the same approach in our 2015 Electricity Ten Year Statement.

We'd love to hear your views on content and structure of the 2015 GTYS. If you'd like to get in touch, please email us at **Box. SystemOperator.GTYS@nationalgrid.com**.

Figure 1.5
How to use this document

Chapter two

- Network Development Inputs
- Customer Requirements
- Future Energy Scenarios
- Legislative Change
- Asset Health

Trigger

A change in the network, legislation, market or customer requirements.

Network Development Inputs

Several inputs trigger our Network Development Process (NDP). In this year's Gas Ten Year Statement (GTYS) we focus on four triggers: customer requirements, Future Energy Scenarios (FES), legislative change and asset health. We respond to these particular triggers because they affect network requirements and future system operability.

Key messages

Customer requirements

- We are reviewing our connections processes to improve the customer experience and to help facilitate unconventional gas sources
- The Planning and Advanced Reservation of Capacity Agreement (PARCA) arrangements are in place. Customers can use them to reserve capacity before making final investment decisions in their projects
- Customers want higher ramp rates and shorter notice periods, particularly in response to changes in the electricity market
- Distribution Network Operators (DNO) want National Transmission System (NTS) flexibility to meet their customers' requirements
- Long-term auctions no longer indicate a shipper's intention to flow. Diversity and extent of supplies can mean great variation of flow on the NTS from one day to the next
- Some contracts for gas-fired generation were issued after the first round of electricity Capacity Market auctions. We are talking to developers so we are ready for the second round of auctions
- We have commissioned the GasFlexTool in response to our customers' changing needs and their impact on NTS System Flexibility.

Future Energy Scenarios

- Sources of gas supply have changed since the 2000s
- Import dependency has grown considerably since the early 2000s and could reach 90% by 2035
- Peak supply capacity is now much higher than peak demand
- Other than the 'Gone Green' scenario, annual UK gas demand is expected to hold broadly steady with residential demand decreasing slightly due to higher efficiencies
- The 'Gone Green' scenario shows a marked decline in annual demand due to more electric heating and less use of combined cycle gas turbines (CCGT)
- Daily peaks will be similar or higher until 2020 and beyond, with more generation by CCGTs rather than coal.

Legislative change

- The Industrial Emissions Directive (IED) came into force in January 2013 combining the Integrated Pollution Prevention and Control Directive (IPPC) and Large Combustion Plant Directive (LCP)
- IPPC affects eight of our 24 compressor sites
- LCP affects 17 of our compressor units.
- When it's finalised the Medium Combustion Plant Directive (MCP) will also form part of IED
- The draft MCP affects 26 of our compressor units.

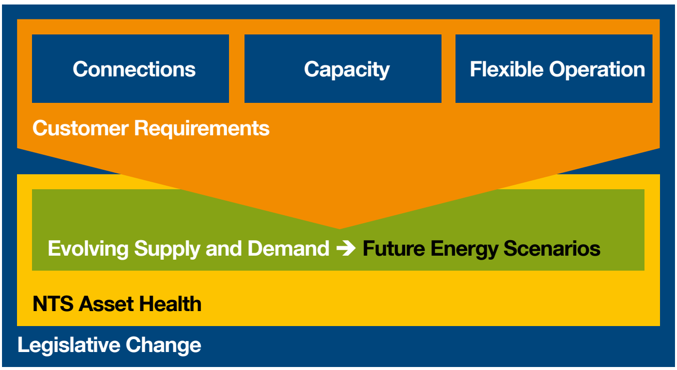
Asset health
- We have developed a programme of works to resolve known asset health issues as a result of the ageing NTS. This programme of works will take us to 2021
- We will deliver 370 Network Output Measures (NOMs) during this performance year; however as these are legacy projects they will not follow the NDP
- Approximately 3,500 NOMs have been identified which will cover RIIO years four to six (2017–19)
- We will consider the removal of assets within the NDP to avoid unnecessary maintenance.

2.1 Introduction

As we outlined in Chapter 1, our Network Development Process (NDP) defines our decision-making, optioneering and project development processes for all projects. Certain triggers initiate the NDP. Over the last 12 to 24 months, three key triggers have emerged from our NDP work: customer requirements, legislative change, and asset health. The Future Energy Scenarios (FES) also influence the NDP.

These triggers are interlinked (see Figure 2.1) so a change in one trigger will affect another. We know that customers' gas requirements may change when new legislation is introduced. An example is emissions legislation, which has resulted in generators closing or reducing their use of coal plant and using more combined cycle gas turbine (CCGT) plant instead. This has changed the supply and demand patterns on the network, which feeds into our FES.

Figure 2.1
Key NDP triggers



Network Development Inputs

Customer requirements
We have recently updated our connections and capacity processes to meet our customers' changing needs and to more closely align with our customers' project development timelines. This chapter outlines our connections and capacity processes and tells you where to find more information.

Our customers' changing behaviours mean that within-day supply and demand patterns are very different from those envisaged when the National Transmission System (NTS) was designed. These changing patterns mean that our system must be flexible enough to meet our customers' needs. This chapter explains what we mean by System Flexibility and how it is affected by changing customer behaviour.

Future Energy Scenarios
Our Future Energy Scenarios (FES) explore how the increasingly complex energy landscape is changing and what might happen. We use the FES as the basis of all of our system analysis as they provide a stakeholder-influenced view of the future of supply and demand patterns on the NTS. In this chapter we outline the evolution of supply and demand to show how our customers' needs might change under the four scenarios.

Legislative change
Recent legislative changes, such as the Industrial Emissions Directive (IED), will significantly affect how we plan and operate our network over the next ten years. Legislation is one of the main triggers for our NDP. We need to look at every compressor affected by new legislation and establish how critical each one is in maintaining our network capability. We must also be sure that we can meet future capability requirements.

Changes to the way that the European energy market is run might affect how we operate our network. The key legislative changes are outlined in this chapter.

Asset health
Many of our NTS assets are ageing and need maintaining or replacing. Our asset health campaign prioritises key assets on our network to establish if they need to be maintained or replaced.

Customer Requirements

2.2 Customer requirements

This section outlines how our customers' requirements can trigger our Network Development Process (NDP). We have provided information on customer connections, entry capacity, exit capacity, and system flexibility.

Anyone wishing to connect to the National Transmission System (NTS) can arrange for a connection directly with us. In addition we can reserve capacity for you; however, you must be aware that a shipper must buy and hold your capacity.

We can only enter into transportation arrangements with shippers and Gas Distribution Network Operators (DNO). Our Gas Transporters Licence stipulates that capacity can only be made available to these parties.

2.2.1 Our connection and capacity application processes

We have produced a high-level overview of our connection and capacity application processes in Table 2.1. We have included chapter and section numbers to help you to navigate to the relevant section of this year's GTYS.

Customer Requirements

Table 2.1
Our connection and capacity application processes

	Our connection and capacity processes					
	Connections	**Entry and Exit Capacity**				
Our customers and their key service requirements	Appliction to offer (A2O) Includes physical pipeline connections to the NTS (if required) for new connections, modifications and diversions	Quarterly System Entry Capacity (QSEC – gas years y+2 to y+17) Auctions	Exit Application Windows (unsold within baseline capacity – gas years y+1 to y+3)	Exit Application Window (Enduring Annual – gas years y+4 to y+6 – Evergreen Rights) & (Adhoc – m+6 – Evergreen Rights) Enduring annual NTS exit Capacity	Flexible Capacity for flow changes	Entry/Exit Planning and Advanced Reservation of Capacity Agreement (PARCA – reserve unsold/ additional capacity & allocation)
Find more information in GTYS go to:	Chapter 2 – Sections 2.2.2, Appendix 2	Chapter 2 – Section 2.2.3	Chapter 2 – Section 2.2.4, Appendix 2	Chapter 2 – Section 2.2.4, Appendix 2	Chapter 2 – Sections 2.2.3, 2.2.4, Appendix 2	Chapter 2 – Section 2.2.5, Appendix 2
Gas Shipper (signatory to the Uniform Network Code (UNC)) Capacity Rights to flow gas onto the system (short, medium long term)	✗	✔	✔	✔	✗	✔
Distribution Network (DN) (signatory to the UNC) B4:B9 Rights to offtake gas from the system	✔	✗	✔	✔	✔	✔
Customers New Site Developers (that are not signatory to the UNC) and or currently connected customers. Both new and currently connected customers have Capacity Rights to flow gas onto and offtake gas from the system.	✔	✗	✗	✗	✗	✔

If you need a new connection or a modification to an existing NTS connection, you will need to go through the application to offer (A2O) process (see section 2.2.2). You must be aware that our connection (A2O) and capacity processes (Planning and Advanced Reservation of Capacity Agreement – PARCA) are separate.

Our customers have the flexibility to initiate these two processes at their discretion; however, the two processes can become dependent on each other. The new PARCA process has been designed to run in parallel with the A2O process to prevent the possibility of stranded capacity. We will only allocate reserved capacity if a full connection offer (FCO) has been progressed and accepted. Typically, it can take up to 12 months to progress and sign an FCO. This means that the A2O process (if required) needs to be initiated at least 12 months before the capacity allocation date defined in the PARCA contract (see section 2.2.5 and Appendix 2 for more detail).

The connection and capacity processes initiated by our customers trigger our Network Development Process (NDP). We need to assess what impact a connection (new or modified) or a capacity change (supply or demand increase/decrease) will have on our current network capability and our operational strategies. In some cases we may need to reinforce our system to ensure we can meet our customers' connection or capacity requirements. This was one of the key drivers for implementing the new PARCA process as we can now align any works we need to complete with our customers' projects.

If you have any queries about our connections or capacity processes please contact the gas customer team directly. See Appendix 3 for our contact details.

2.2.2 **Connecting to our network**

We offer four types of connection to the NTS as well as modifications to existing NTS connections[1].

To connect your facility to the NTS you will need to initiate the A2O process. You can either have other parties build the facility's connection or have the connection adopted by the host gas transporter (depending upon their circumstances).

You can then pass the connecting assets on to a chosen System Operator/transporter, or retain ownership yourselves.

Table 2.2 summarises the four different NTS gas connections that are currently available.

[1] http://www2.nationalgrid.com/uk/services/gas-transmission-connections/connect/

Customer Requirements

Table 2.2
NTS gas connections

NTS Gas Connections Categories	
Entry Connections	Connections to delivery facilities processing gas from gas producing fields or Liquefied Natural Gas (LNG) vaporisation (importer) facilities, for the purpose of delivering gas into the NTS.
Exit Connections	These connections allow gas to be supplied from the NTS to the 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 that is not a gas transporter, for transporting gas to premises consuming more than 2,196MWh per annum.
Storage Connections	Connections to storage facilities, for supplying gas from the NTS and delivering it back later.
International Interconnector Connections	These are connections to pipelines that connect Great Britain to other countries. They can be for supply of gas from and/or delivery of gas to the NTS.

If you need to make a change to the connection arrangement (e.g. request an increase in gas supply) this request will be considered using the same approach as a new NTS connection.

Customer Connections – Application to Offer (A2O)

The Uniform Network Code (UNC)[2] provides a robust and transparent framework for new customer connections and modifications to an existing connection.

The UNC provides:

- 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 to produce a connection offer:
  – Initial connection offer – up to two months
  – Full connection offer – up to six months (simple) or nine months (medium/complex)
- timescales for customers to accept initial/full connection offer (up to three months)
- application fees for an initial connection offer (fixed) and full connection offer (variable and reconciled)
- a requirement for National Grid to review the application fees on an annual basis.

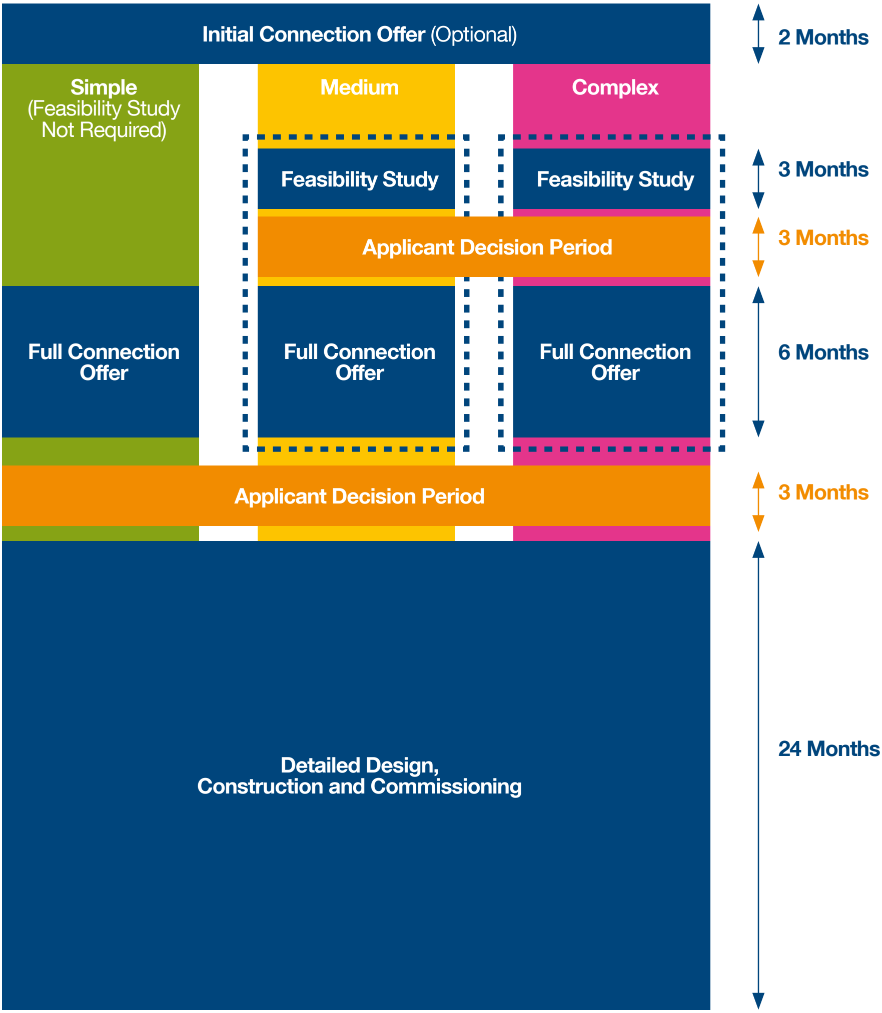
The NTS connection application form and more information on the A2O connections process can be found on our website[3].

Figure 2.2 summarises the A2O process and the timescales associated with each stage.

[2] http://www.gasgovernance.co.uk/UNC

[3] http://www2.nationalgrid.com/UK/Services/Gas-transmission-connections/Connect/Application-to-offer/

Figure 2.2
Application to Offer (A2O) Process



Customer Requirements

Connection application charges

Our charging policy for all customer connections is set out in the publication The Statement and Methodology for Gas Transmission Connection Charging[4], which complies with Licence Condition 4B[5].

When you connect to the NTS, the connection costs are calculated based on the time and materials used to undertake the activity. For a Minimum Offtake Connection (MOC) at a greenfield site, the cost of the connection is generally around £2m and can take up to three years to deliver. The costs and timescales for more complex connections can be significantly higher than those for a MOC.

Connecting pipelines

If you want to lay your own connecting pipeline from the NTS to your facility, ownership of the pipe will remain with you as our customer. This is our preferred approach for connecting pipelines.

The Statement and Methodology for Gas Transmission Connection Charging describes other options for the installation and ownership of connecting pipelines. For all options, the connecting party is responsible for the costs of the pipeline.

Connection pressures

There are four primary types of defined pressure on the NTS:

- Standard Offtake Pressures as defined in the UNC – A minimum pressure of 25 barg of gas will be made available at NTS supply meter point offtakes. For NTS/Local Distribution Zone (LDZ) offtakes see Assured Offtake Pressures
- Assured Offtake Pressures (AOP) as defined in the UNC – These are minimum pressures required to maintain security of supply to our DN customers. A significant number of these assured pressures are set at 38 barg, the anticipated minimum pressure in most sections of the NTS under normal operating conditions
- Anticipated Normal Operating Pressures (ANOP) – These are advisory pressures and indicate to our directly connected customers the minimum pressure likely to be available on the NTS in their connection area under normal operation. If our capability analysis shows an increasing likelihood that these pressures will not be met under normal operation, the customer will be notified of revised ANOPs with at least 36 months' notice
- Maximum Operating Pressure (MOP) – This is the maximum pressure that each section of the NTS can operate at and is relevant to connected NTS Exit and NTS Entry Point/ Terminals.

These pressures will be stated in the Network Entry Agreement (NEA) or Network Exit Agreements (NExA) depending on the connection you require. When agreeing or revising a NExA, we can provide information regarding historical pressures which should help you to understand how we assess pressures and indicate how AOPs and ANOPs relate to typical operating pressures.

Shippers may also 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.

General connection pressure information

NTS offtake pressures tend to be higher at entry points and outlets of operating compressors, and lower at the system extremities and inlets to operating compressors. Offtake pressure varies throughout the day, from day-to-day, season-to-season and year-to-year. We currently plan normal NTS operations with start-of-day pressures no lower than 33 barg. Note that these pressures cannot be guaranteed as pressure management is a fundamental aspect of operating an economic and efficient system.

[4] http://www2.nationalgrid.com/UK/Services/Gas-transmission-connections/Connect/Application-to-offer/

[5] https://epr.ofgem.gov.uk//Content/Documents/Gas_transporter_SLCs_consolidated%20-%20Current%20Version.pdf

Ramp rates and notice periods

Directly connected offtakes have restrictions in terms of ramp rates and notice periods written into NExAs. A ramp rate (the rate at which the offtake of gas can be increased at the offtake) of 50 MW/minute can be offered for a simple connection. Higher ramp rates can be agreed subject to completion of a ramp rate study. Notice periods are typically defined as the number of hours' notice for increases of up to 25%, up to 50% and greater than 50% of maximum offtake rate. These notice periods are required to ensure that pressures can be maintained at times of system stress including high demand. Notice periods will only be enforced in these circumstances when system flexibility is limited. More detail regarding access to system flexibility can be found on our website in the Short Term Access to System Flexibility Methodology Statement[6].

Evolving our connections process

As a result of changes in the energy sector and an increase in unconventional gas development we are seeing more connections to the NTS that were not viable or foreseen in the past. These new and unconventional gas suppliers see value in connecting to the NTS because of the system location and/or the benefits of a higher pressure network.

We have begun to see new types of connection request, for example shale and biomethane entry connections and natural gas-powered vehicle refuelling stations exit connections. The system requirements for these connections are fundamentally different to more traditional project connections. These projects tend to be fast to market and the NTS connection cost represents a significant proportion of the total development costs. Many of you have told us that the existing connection regime does not meet your project's requirements.

If our present NTS connection service continues as it is, the majority of new and unconventional gas projects could be forced to seek connections to distribution networks or try to find other ways of using the gas they produce. We want to make the NTS more accessible to these new gas sources. Our aim is to develop a low cost and timely NTS connection service for new and unconventional gas connections.

Connections and capacity

The Gas Act 1986 (as amended 1995) states that "we must develop and maintain an efficient and economical pipeline system and comply with any reasonable request to connect premises, as long as it's economic to do so".

Connecting a new supply or demand may require system reinforcement to maintain system pressures and capability. Depending on the scale, reinforcement projects may require significant planning, resourcing and construction lead-times. Therefore we need as much notice as possible. Project developers should 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.

The PARCA process (see section 2.2.5) was designed to encourage developers to approach us at the initial stages of their project. This new process allows alignment between both the developer's project timeline and any reinforcement works required on the NTS to accept or deliver capacity.

[6] http://www2.nationalgrid.com/uk/industry-information/gas-transmission-system-operations/capacity/constraint-management/

Customer Requirements

2.2.3 NTS entry capacity

Entry capacity gives shippers the right to flow gas onto the NTS. Only licenced shippers can apply for and obtain entry capacity. A licenced shipper is considered a 'User' of the NTS under the terms of the UNC.

NTS entry capacity types

We can make firm and interruptible NTS entry capacity available to the market at each Aggregated System Entry Point (ASEP)[7]. The volume of firm capacity made available at each ASEP consists of the following:

- Baseline NTS Entry Capacity (obligated) – as defined by our Gas Transporters Licence
- Incremental NTS Entry Capacity (obligated) – firm capacity made available over and above baseline, in response to market demand and backed by User commitment
- Incremental NTS Entry Capacity (non-obligated) – at our discretion, we can release additional firm NTS entry capacity at an ASEP, over and above obligated levels.

Interruptible NTS entry capacity can be made available to the market at ASEPs where it can be demonstrated that firm NTS entry capacity is not being used. The volume of Interruptible NTS entry capacity available at an ASEP consists of two parts:

- Use it or Lose it (UIOLI) – any NTS entry firm capacity that has been unused for a number of days can be resold to the market as interruptible NTS entry capacity
- Discretionary – we can make additional interruptible NTS entry capacity available to the market at our discretion.

If there is physical congestion on the network, then we may limit interruptible NTS entry capacity rights, without any compensation for the Users affected.

NTS entry capacity auctions

To obtain entry capacity a shipper can bid for capacity on the Gemini system through a series of auctions[8]. For long-term capacity shippers can bid in three auctions:

- Quarterly System Entry Capacity (QSEC)
- Annual Monthly System Entry Capacity (AMSEC)
- Rolling Monthly Trade & Transfer (RMTnTSEC).

The QSEC auction is held every March and can be open for up to ten working days. NTS entry capacity is made available in quarterly strips from October Y+2 to September Y+16 (where Y is the current gas year).

The AMSEC auction is run every February and NTS Entry Capacity is sold in monthly strips from April Y+1 through to September Y+2. This auction is 'pay as bid' and subject to a minimum reserve price. The auction is open for four days from 8am to 5pm. Each auction window is separated by two business days as detailed in the UNC. The processing and allocation is completed after 5pm on each day.

The RMTnTSEC is held on a monthly basis at the month ahead stage. Any unsold quantities from AMSEC are made available in the RMTnTSEC auction and sold in monthly bundles. The auction is 'pay as bid', and subject to the same reserve price as AMSEC.

2015 incremental obligated capacity

In order for incremental obligated entry capacity to be released, and therefore the obligated entry capacity level to be increased, enough bids for entry capacity must be received during the QSEC auctions to pass an economic test. If this capacity can be made available via capacity substitution[9] then it will be increased.

[7] http://www2.nationalgrid.com/UK/Industry-information/Gas-transmission-system-operations/Capacity/Entry-capacity/

[8] http://www2.nationalgrid.com/uk/industry-information/gas-transmission-system-operations/capacity/entry-capacity/

[9] http://www2.nationalgrid.com/UK/Industry-information/Gas-capacity-methodologies/Entry-Capacity-Substitution-Methodology-Statement/

This involves moving unused capacity from one or more system points to a point where there is excess demand. If incremental capacity requires reinforcement works it can only be triggered when the customer enters into a PARCA (see section 2.2.5).

If insufficient bids are received, capacity in excess of the obligated level can be released on a non-obligated basis, which would mean that the obligated capacity level does not increase for future auctions.

The QSEC auctions opened on Monday 16 March 2015 and closed on Tuesday 17 March 2015. No bids were received for incremental entry capacity.

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

2.2.4 NTS exit capacity

Exit capacity gives shippers and Distribution Network Operators (DNO) the right to take gas off the NTS. Only licenced shippers and DNOs can apply for and obtain exit capacity. A licenced shipper or DNO is considered a 'User' of the NTS under the terms of the UNC.

NTS exit capacity types

We make firm and Off Peak capacity available to the market at each offtake point. The volume of firm capacity made available at each offtake point consists of the following:

- Baseline Capacity (obligated) – as defined by our Gas Transporters Licence
- Incremental Capacity (obligated) – firm capacity made available over and above baseline, in response to market demand and supported by User commitment. This increase in capacity is permanent
- Incremental Capacity (non-obligated) – at our discretion, we can release additional firm capacity at an offtake point over and above obligated levels.

Off Peak capacity is made available to the market at offtake points where it can be demonstrated that firm capacity is not being used. The volume of Off Peak capacity available at an offtake consists of three parts:

- Use it or Lose it (UIOLI) – any firm capacity that has been unused over recent days, can be resold to the market as interruptible capacity
- Unused Maximum NTS Exit Point Offtake Rate (MNEPOR) – during D-1 at 13:30 the NTS Demand Forecast is published. Where this demand forecast is less than 80% of the annual peak 1-in-20 demand forecast, we are obligated to release any remaining capacity up to the MNEPOR level as Off Peak capacity
- Discretionary – we can make additional Off Peak capacity available to the market at our discretion.

If there are low pressures on the network, then we may curtail Off Peak capacity rights, without any compensation for the Users affected.

For our DNO Users we also make NTS exit (flexibility) capacity available. This allows the DNO to vary the offtake of a quantity of gas from the NTS at a steady rate over the course of a gas day. This allows the DNO to meet their 1-in-20 NTS Security Standard as well as to meet their diurnal storage requirements.

Customer Requirements

NTS exit capacity application windows
To obtain exit capacity a shipper can apply for capacity through four exit capacity application windows:

Annual NTS (Flat) Exit Capacity (AFLEC) – This application window is for capacity covering the period Y+1 to Y+3. The capacity allocated in this application window is not enduring and therefore cannot be increased or decreased. The application period for this application window is 1 to 31 July.

Enduring Annual Exit (Flat) Capacity Increase (EAFLEC) – This application window is for capacity covering the period Y+4 to Y+6 (where Y is the current gas year). The capacity bought in this application window is enduring and can be increased or decreased in a later application window (subject to User commitment). The application period for this auction is 1 to 31 July.

Enduring Annual Exit (Flat) Capacity Decrease (EAFLEC) – This application window allows a User to decrease their enduring capacity holdings from Year Y+1 (October following the July window). Further decreases and increases can be requested in subsequent application windows. The application period for this auction is 1 to 15 July.

Ad-hoc Enduring Annual Exit (Flat) Capacity – This application window allows a User to apply between 1 October to 30 June for capacity from Year Y. The capacity release date must not be earlier than the 1st of the month M+7 (where M is the month in which the application is made) and no later than 1 October in Y+6. The User (or Users in aggregate) must hold equal to or more than 125% of the Baseline NTS exit (flat) capacity for the year in which the application is received or the application must exceed 1GWh/day.

DNOs apply for NTS exit (flexibility) capacity during the 1 to 31 July enduring annual exit (flat) capacity application window.

All capacity requests are subject to network analysis to assess the impact on system capability. Where the capacity requested can be accommodated through substitution[10] the capacity request is accepted. Capacity substitution involves moving unused capacity from one or more offtakes to a point where there is excess demand. If incremental capacity cannot be met via substitution the customer will need to enter into a PARCA as reinforcement works may be required to meet the capacity request (see section 2.2.5).

Successful applications submitted in the AFLEC window will be allocated within ten business days of the application window closing. Successful applications submitted in the EAFLEC window (both increases and decreases) will be allocated on or before 30 September.

[10] http://www2.nationalgrid.com/UK/Industry-information/Gas-capacity-methodologies/Exit-Capacity-Substitution-and-Revision-Methodology-Statement/

2.2.5 The PARCA framework

The Planning and Advanced Reservation of Capacity Agreement (PARCA) is a bilateral contract that allows long-term NTS entry and/or exit capacity to be reserved for a customer while they develop their own project. The customer can buy the reserved capacity at an agreed future date.

The PARCA framework was implemented on 2 February 2015. It replaces the Advanced Reservation of Capacity Agreement (ARCA) for NTS exit capacity and the Planning Consent Agreement (PCA) for both NTS entry and exit capacity.

The PARCA framework is based on a development of the long-term NTS entry and exit capacity release mechanisms and extends the UNC ad hoc application provisions that allow users to reserve enduring NTS exit (flat) capacity and NTS entry capacity.

Baseline capacity, non-obligated incremental capacity and incremental capacity that can be provided via substitution will be made available through the annual auctions for Quarterly System Entry Capacity (QSEC) and enduring annual NTS exit (flat) capacity processes, and can also be reserved through a PARCA by a developer or a User (both DNO and shipper).

Incremental capacity that cannot be provided via substitution is only guaranteed for release where a PARCA has been agreed by us and a developer or a User (both DNO and shipper).

The PARCA framework provides a number of benefits for PARCA customers, other NTS customers/Users and us:

Benefits for PARCA Customers
It is designed to help customers to reserve NTS entry and/or exit capacity early on in their project development without full financial commitment to formally booking capacity
Reserved NTS Capacity will be exclusive to the PARCA applicant (or their nominated NTS user) and will not available to other NTS users
It provides the customer with greater certainty around when capacity can be made available should their project progress to completion
It aligns the customers and our project timelines; this is particularly important where reinforcement is required, so the projects can progress together
The customer can align the NTS capacity and connection processes for their project
The process is flexible, with logical ‘drop-out points’ before capacity allocation. Capacity allocation would be closer to the customer’s first gas day than under previous arrangements. As a result, the customer would be able to take advantage of these ‘drop-out points’, should their project become uncertain
They are available to both UNC parties and project developers and therefore available to a wider range of customers compared to the existing annual NTS capacity auction and application processes

Customer Requirements

Benefits for other NTS Customers and Users
Throughout the lifecycle of a PARCA, we will publish more information externally (compared to the existing auction/application mechanisms) increasing transparency for other NTS users
The PARCA entry capacity process includes an ad hoc QSEC auction mechanism to allow other NTS users to compete for unsold QSEC before it is reserved
The PARCA process includes a PARCA application window during which other NTS users can approach us to sign a PARCA. This provides a prompt for those customers considering entering into a PARCA. It would allow multiple PARCAs to be considered together. This way, we will make best use of unsold levels of NTS capacity and existing system capability when determining how to meet our customers' requirements. This will enable the most economic and efficient investment decisions to be made
Throughout the lifecycle of a PARCA, each customer must provide us with regular project progress updates. If a customer fails to provide the required information in the required timescales, their PARCA may be cancelled and any reserved NTS capacity would either be used for another live PARCA or returned to the market. This will ensure that NTS capacity is not unnecessarily withheld from other NTS users
A PARCA customer will be required to provide financial security to reserve NTS capacity. If the customer cancels their PARCA, a termination amount will be taken from the security provided. This would be credited to other NTS users through the existing charging mechanisms
The timescales for the release of incremental NTS capacity to the PARCA applicant will be aligned to our timescales for providing increased system capability. This will take into account the Planning Act requirements for a reinforcement project. As a result, the risk of constraint management actions taking place and any costs potentially being shared with end consumers will be reduced
They are available to both UNC parties and project developers and therefore available to a wider range of customers compared to the existing annual NTS capacity auction and application processes

Benefits for Us
Throughout the lifecycle of a PARCA, the customer will be required to provide regular project progress updates. We would not begin construction on any investment projects until the customer has received full planning permission for their project. This will allow our case for any required investment to be clearly linked to our customer requirements.

2.2.6 **PARCA framework structure**

Initially, a customer will submit a PARCA application requesting the capacity they need. We will use the information provided in the PARCA application to determine how and when the capacity requested can be delivered.

A customer might be a gas shipper, DNO or any other third party such as a developer and may or may not be a party signed up to the Uniform Network Code (UNC). The PARCA arrangements apply to all NTS entry and exit points, NTS storage and NTS interconnectors.

A key aspect of the PARCA is that it helps the customer and us to progress our respective projects in parallel. It also assures the customer that capacity has been reserved with the option to buy it later. Financial commitment to the capacity (allocation of capacity) is only required once the customer is certain that their project will go ahead.

The PARCA framework is split into four logical phases: Phase 0 to Phase 3 (Figure 2.3). This phased structure gives the customer natural decision points where they can choose whether to proceed to the next phase of activities.

Figure 2.3
PARCA framework phases

More information on the PARCA process is provided in Appendix 2 and on our website[11].

[11] http://www2.nationalgrid.com/UK/Services/Gas-transmission-connections/PARCA-Framework/

Customer Requirements

2.2.7 Changing customer requirements

Our customers' requirements on the NTS are interlinked with legislative (Industrial Emissions Directive (IED)) and market (Electricity Market Reform (EMR)) changes. All of these changes impact on the wider energy industry and strongly influence how we plan and operate our system. These changes cannot be looked at in isolation.

While we predict significant change ahead, the pace of NTS development, when judged by customer signals for incremental capacity, has slowed in recent years. This trend has continued in the 2015 Quarterly System Entry Capacity (QSEC) auction and the 2015 Exit Capacity window. In contrast the number of connection enquiries we are receiving remains high.

The following summarises what we currently see:

- Increasing Distribution Network (DN) exit flexibility capacity requirements (against a background of reduced DN flat capacity requirements)
- Increasing requests for higher ramp rates and reduced flow rate change notice periods for gas power generation offtakes
- Increasing requirement for south-to-north flows as a result of declining St Fergus flows (Future Energy Scenarios (FES))
- Operationally, we are seeing an increased requirement to rapidly switch between 'west-to-east' and 'east-to-west' flow in the heart of the NTS.

We need to balance the needs of our customers with the ability of the NTS to respond and the cost to the end consumer. We need to work with our customers and stakeholders to make sure that the right operational arrangements (rules), commercial options (tools) and physical investments (assets) considered across the NTS. The way we plan and operate the NTS needs to be more flexible to allow us to more quickly adapt to our customers' changing behaviour.

2.2.8 System Flexibility

Through the RIIO process System Flexibility was defined as: *"a requirement for additional operational capability driven by changing user behaviour and explicitly not the provision of incremental entry or exit capacity".*

This is quite a broad definition and you have told us that you would like to gain a better understanding of what we mean by System Flexibility.

What is System Flexibility?

We define System Flexibility as:

- The ability of the NTS to adapt to changing daily supply and demand profiles and imbalances by varying system linepack and system pressures
- The ability of the NTS to cater for supply and demand levels which occur away from the 1-in-20 peak demand level but result in network flows in some parts of the network that are higher than would occur at the 1-in-20 demand level
- The ability of the NTS to cater for the rate of change in the geographic distribution of supply and demand levels. This results in changes in the direction and level of gas flow through pipes, compressors and multi-junctions, and may require rapid changes to the flow direction in which compressors and multi-junctions operate.

The need for System Flexibility

NTS exit (flexibility) capacity

The underlying assumption in a daily balancing regime is that a quantity of gas will be supplied to match the daily demand taken off the system and it will be delivered (ignoring entry profiles) at a flat (1/24th) rate. Flex measures how much gas is taken off the system over and above this flat entry flow and therefore how much gas is taken out of system linepack. The measurement is made at 22:00 as this is when the profiled gas demand for both DN and power generation offtakes drop below the average daily rate. The volume of flex taken reduces overall system linepack.

Distribution Network Operators (DNO) offtake gas from the NTS to meet their consumers' gas requirements. DNOs tell us that they book NTS exit 'flat' (end-of-day quantity) and flex (profile) capacity, to comply with their 1-in-20 NTS Security Standard as well as to meet their diurnal storage requirements.

The DNOs can agree assured pressures as pressure can provide an alternative to flex. The reason for this is that the DNOs can use higher pressures to store more gas in their own systems in the form of linepack. They can then use more of their own linepack to meet their diurnal storage requirements i.e. offset the difference between flows from the NTS and the profiles of their customers.

DNO flexibility at a Local Distribution Zone (LDZ) (aggregate offtake rate) level is limited by the two-hour 5% rule. This limits the change in offtake rate for any hour bar to a 5% change with two hours' notice given. This rule is more onerous at lower demands as a lower demand change would represent a 5% increase. This rule has been subject to a recent UNC modification proposal which was approved on the basis that the rule would only be applied when required and hence was effectively 'off by default'.

On low demand days, defined as being when the first LDZ demand forecast on the preceding gas day is less than 50% of the 1-in-20 peak day forecast, we have the right under the UNC to require that the aggregate LDZ NTS Exit (Flexibility) capacity utilised is not greater than zero.

Direct Connect profiling

Shippers at Directly Connected (DC) offtakes are not required to book NTS Exit (Flexibility) Capacity. The impact of their gas offtake profiles is broadly the same as for DN offtakes. There are a number of key differences between DC offtakes and DN offtakes. While DNOs can trade off flex and pressure, additional pressure at a DC offtake has no impact on the required offtake (flex) profile. DNOs book flex capacity to meet the 1-in-20 NTS Security Standard and this provides a key input to the NTS planning process. DC profiling is not limited by flex bookings but power generation offtakes are limited by the electricity supply profile and hence further 'booked' capacity may not be of value.

Directly Connected (DC) offtakes have ramp rate and notice period restrictions. Typically a ramp rate (the rate at which the offtake of gas can be increased at the offtake) of 50 MW/minute is offered but increasingly higher ramp rates are being requested and agreed where they can be facilitated. Notice periods are written into the NExAs and are defined as the number of hours' notice for increases of up to 25%, up to 50% and greater than 50% of maximum offtake rate.

Forecast error and market behaviour

Within-day changes in demand with a delayed supply response are met through system linepack and consequently require system flexibility. Within-day demand changes will result in either an increase or decrease in flow rate at relevant supply points, once the demand change has been identified, as a result of shipper / market behaviour and/or balancing actions.

This behaviour is replicated when market behaviour results in supply flows starting the day at a rate that is less than the daily demand. The difference in flow rate and the period over which the imbalance persists will create a within-day imbalance requiring system linepack and flexibility.

Adherence to offtake rate change notice periods reduces the impact of within-day demand changes, and hence within-day imbalances. Notices of rate changes are required through NExAs and as a result of the DN two-hour 5% rule.

Customer Requirements

Flows at bi-directional system points (storage and interconnectors) and other system entry points are influenced by shipper behaviour. Shippers balance their portfolios taking into account their expected end-of-day demand and supply allocations at all their exit and entry points. As demand changes within-day, shippers may not immediately make supply re-nominations to balance their portfolios as they may use gas trades first. This way they can make use of NTS within-day flexibility to manage within-day imbalances. Within-day imbalances may also occur due to supply losses and, again, these may not be addressed immediately as gas trades may be carried out first.

Unexpected supply losses
Unexpected supply losses occur when offshore or delivery facilities have technical problems or failures. These supply losses will result in either an increase in flow rate at the relevant point once the problem has been rectified, or an increase in flow rate at an alternative point (as a result of shipper/market behaviour and/or balancing actions) if the problem cannot be rectified. There can be a delay between a supply loss and the market response.

Quantification of flexibility
In Chapter 3 we explain how we are seeking to quantify flexibility requirements.

Customer and stakeholder feedback

Our discussions, in customer seminars and stakeholder engagement events, have highlighted that System Flexibility is important to the wider industry. You have told us that our current analysis does not provide enough information on this area. We have developed a new tool to look specifically at System Flexibility called the GasFlexTool. We discuss the tool development and its outputs in more detail in Chapter 3. This tool will help us to clarify what effect restricted NTS Flexibility could have on the way we plan and operate the network.

We are reviewing the future flexibility requirements for the system. We are considering how different events or factors across gas days and within-day might affect the way the system is managed. This work may lead to changes in the planning processes and may require asset, commercial and operability solutions to be progressed to deliver more capability.

The categories we are considering include supply-side behaviour (e.g. supply shocks, supply profiling in response to market behaviour), demand-side behaviour (e.g. the impact of wind intermittency on CCGT use, demand profiling, ramp rates and notice periods, pressure commitments) and network flow direction changes (e.g. changes from east–west to west–east flow patterns over a short timescale, storage and interconnector behaviour). In parallel, we are also considering how our design and security standards are applied in our planning and operational processes and whether these are appropriate for supply and demand patterns and behaviour we may see in the future. More information on the work we have done so far is provided in Chapter 3.

You have told us that you would also like more information on the asset and non-asset options to address greater requirements for System Flexibility. We discuss these options in more detail in chapters 4 and 5.

System Flexibility and our NDP

There is no existing NDP trigger mechanism to enhance system capability in response to changing and/or reducing flows of gas in the network, i.e. the net impact of a number of different customers changing their use of the NTS. The current regime is based on the concept of user commitment to provide incremental capacity; however, this cannot always be the case when the way that capacity is used changes.

2.2.9 Gas System Operability Framework

To address future system operability challenges such as System Flexibility, we are considering the possibility of introducing a Gas System Operability Framework (GSOF). This will highlight how we identify current and future operability challenges. We will initially use the GTYS to document the outputs.

The SOF is a concept used by National Grid electricity transmission. The electricity SOF was first published in 2014. It draws on real-time experience on the electricity system, combined with FES, to infer potential challenges to operability of the electricity transmission system out to 2035. The electricity SOF identifies and quantifies future system challenges so that a range of mitigation measures can be developed and economically assessed.

Our aim is to operate a safe, efficient, economical and commercially viable gas system for our customers. There are a number of factors that could make this more challenging for us in the future:

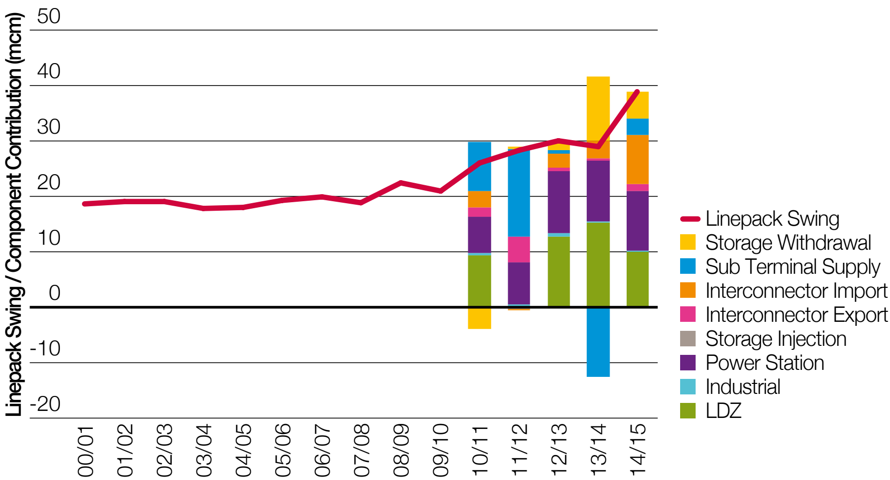
- increase in supply swings at beach terminals
- increased use of linepack by the LDZs
- increased opportunities for arbitrage between Great Britain and Europe through the Bacton–Zeebrugge interconnector
- spot and forward spreads across the Bacton–Zeebrugge interconnector
- increase in use of arbitrage by CCGTs between the gas and electricity markets
- increases in exit profiling within-day by combined cycle gas turbines (CCGTs)
- gas/coal forward spread
- changes in UK installed gas generation capacity
- changes in patterns of gas use in Ireland
- available information on reliability of offshore infrastructure
- within-day swing on a sector-by-sector basis (including at the beach, LDZs and by CCGTs)
- correlation of effects across sectors.

Linepack swing is a growing trend on the NTS. This is making the safe and reliable operation of the NTS more challenging. There are a number of other potential developments that could adversely impact system operability. These include Gas Quality and new sources of gas (e.g. biomethane and shale). Figure 2.4 shows the highest linepack swing levels for each year since 2000, as well as component contributions to the swings for the past five years.

Chapter two

Customer Requirements

Figure 2.4
Maximum linepack swing by gas year



We are in the process of establishing a mechanism for identifying planning data to reflect anticipated within-day supply and demand variation, alongside the FES process (see Chapter 3 for more detail). GSOF could be used to address this requirement, as well as other future system operation requirements.

We would like to seek your views on whether a GSOF would be useful for planning the gas NTS. Please send any comments through to our GTYS mailbox: **Box.SystemOperator.GTYS@nationalgrid.com** or speak to us at customer/stakeholder events.

Future Energy Scenarios

2.3 Future Energy Scenarios

This section describes the evolution of demand and supply, and how our customers' requirements of the NTS have changed since 2005. It establishes our view of how demand and supply could continue to evolve over the next ten years.

Every year we produce a set of credible future energy scenarios with the involvement of stakeholders from across the energy industry. Our stakeholders provided positive feedback on our 2014 scenarios and suggested evolutionary, rather than revolutionary, improvements for this year. In response, we kept our 2015 scenarios based on the energy trilemma (security of supply, sustainability and affordability). There is also a new scenario called Consumer Power, replacing the 2014 Low Carbon Life scenario, which you told us lacked clarity.

In Chapter 1 (Figure 1.2), we showed the political, economic, social, technological and environmental factors accounted for in our four 2015 Future Energy Scenarios. For more detailed information on each of our scenarios please read our Future Energy Scenarios 2015 publication[12].

2.3.1 Evolution of gas demand

The following section explains how gas demand has changed over the last decade and how it might look in future. The changes we have seen in our customers' use of the National Transmission System (NTS) have led to increasingly variable levels of national and zonal NTS demand, both on a day-to-day and within-day basis. This presents a number of challenges for us as the System Operator. In Chapters 3 and 4 we outline how we are developing our planning and operational strategies to adapt to these new challenges.

Changing GB gas demand

In the decade prior to 2010, gas demand was relatively stable at around 1,080 TWh/year. During this period, declining demand in manufacturing was counteracted by an increase in demand for gas-fired power generation. In 2010, gas demand fell sharply as lower coal prices meant that coal was favoured over gas for power generation. Gas has remained marginal within the UK power generation market ever since.

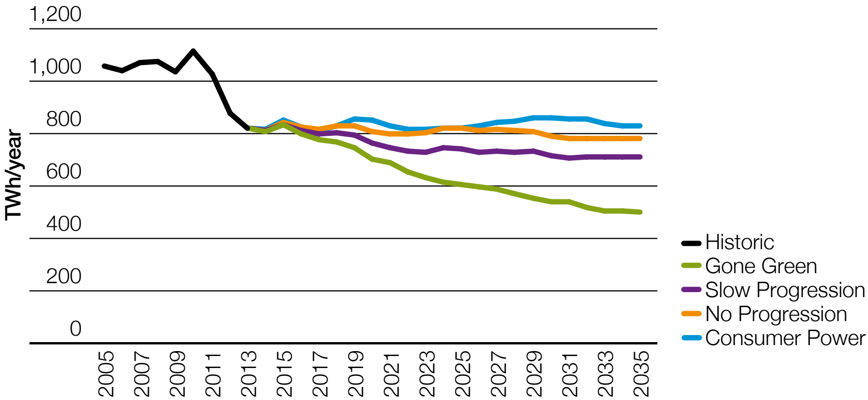
Residential gas demand hit a peak of 400 TWh/year in 2004 and has fallen steadily at an average of 2% per year. Since 2004, Government incentives and heightened consumer awareness have led to homeowners improving levels of insulation and replacing old gas boilers with new more efficient A-rated boilers.

In our FES, the Slow Progression and Gone Green scenarios show that the historical decline in gas demand in the UK will continue as more household efficiency improvements are made and alternative heating appliances are installed. Consumer Power and No Progression show increased demand as a result of lower energy efficiency uptake, combined with growth in the gas power station and distributed gas combined heat and power (CHP) sectors (Figure 2.5).

[12] http://fes.nationalgrid.com

Future Energy Scenarios

Figure 2.5
Total gas demand under our four scenarios

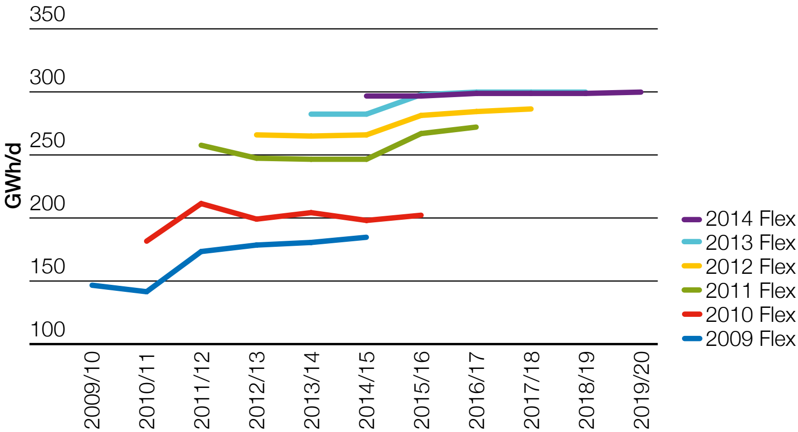


Distribution Network (DN) flexibility requirements

The changing nature of gas demand in the UK over the last five to ten years, combined with our stakeholder engagement feedback, gives us an indication of how our customers may want to use the NTS in the future.

As levels of residential demand steadily declined, Distribution Network Operators (DNO) have reduced the level of embedded storage in their networks through their gas-holder closure programme. As a result, they now increasingly rely on the use of NTS linepack to meet their required daily storage levels (see Section 2.2.7 and Chapter 3). DNOs signal their requirements for using NTS linepack by booking NTS exit (flexibility) capacity levels. We have seen a steady increase in recent years in the flex capacity being requested (see Figure 2.6). However due to the increase in risk to the operation of the NTS we cannot always accept the flex capacity requested.

Figure 2.6
NTS exit (flexibility) capacity bookings by DNOs



The role of CCGTs

Electricity generation from gas-fired plant has become increasingly marginal in recent years as coal prices have fallen significantly, making it a more favourable fuel.

The development of unconventional gas sources such as shale in the US has reduced worldwide demand for coal, which has driven the price down. Other forms of energy generation such as coal, wind, solar and nuclear generally have lower operating costs. This makes them more likely to be used for generation in preference to gas.

The role of combined cycle gas turbine (CCGT) power stations has evolved. We are seeing more variable demand from CCGTs connected to the NTS, both day-to-day and within-day. Instead of providing baseline generation, CCGTs now provide energy to cover the variable output from renewable generation on the electricity system. This means that within-day CCGT demand profiles have become more difficult to forecast.

CCGTs play an important role in balancing the electricity system alongside other balancing tools (interconnection, storage, other generation and demand-side response) which are available to the electricity System Operator. This means that CCGTs do not carry the entire balancing burden so volatility in renewable generation does not always result in volatility in CCGT gas demand.

As both the electricity System Operator and individual suppliers have a range of balancing tools available it is difficult to predict when CCGTs will be used. They tend to be used in combination with the other options to maintain a system balance. This all adds to the challenge of forecasting CCGT demand.

As a result of EU environmental directives, such as the Industrial Emissions Directive (IED), coal power stations are being retired. We are seeing increasing levels of solar and wind capacity connecting to onshore and offshore electricity grids (see Figure 2.7). This means that gas-fired generation is likely to become an even more marginal fuel (i.e. operating with low load factors) up to 2020 and beyond. The behaviour of CCGTs is expected to become more unpredictable as their requirement to generate will correlate with renewable generation output (e.g. wind, solar etc) and the interaction with other balancing tools.

Future Energy Scenarios

Figure 2.7
Forecast levels of coal, wind and solar capacity

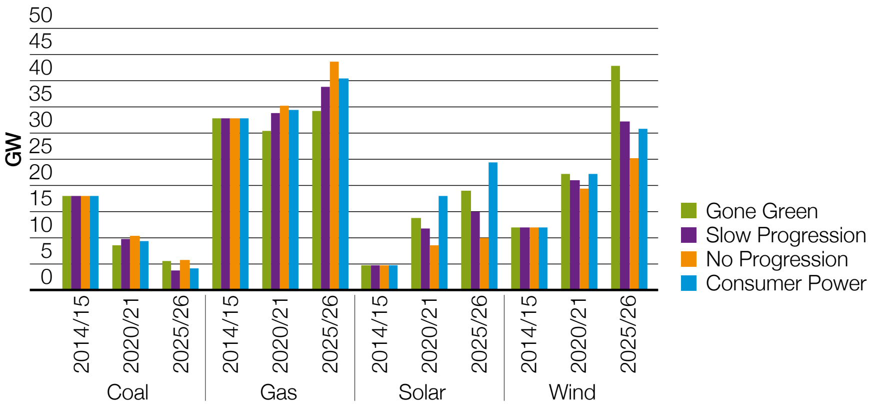
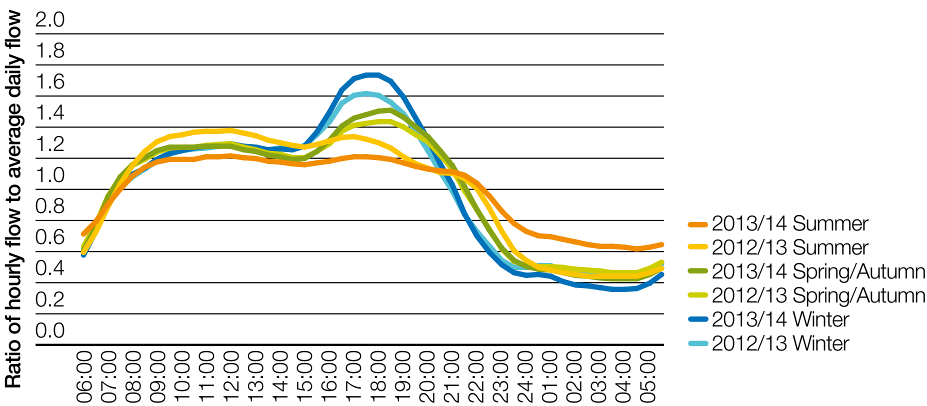


Figure 2.8 maps how the within-day profiles of CCGTs have changed in the last two years. The profiles follow expected demand patterns, peaking at 6pm in winter periods.

Figure 2.8
Normalised CCGT profiles



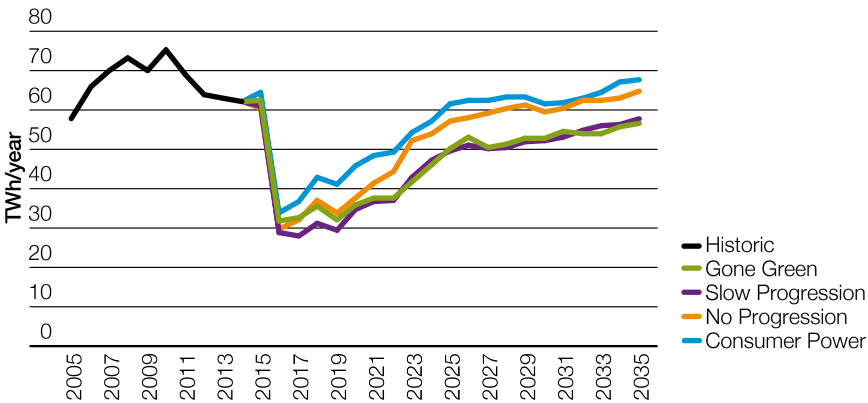
Exports

Exports account for around a sixth of total gas demand. We currently have two export interconnectors in the UK, one to Ireland and one to Europe.

The level of gas exports to Ireland is highly influenced by the timing and scale of supply from indigenous Irish supplies. In this year's FES we have assumed that the Corrib gas field will start operating in October 2015 with a step change in production rates from March 2016.

We expect that when Corrib is operational there will be a reduction in exports from Great Britain (GB). However, it is anticipated that the gas field production will be relatively short lived with rates reducing over time and the reliance on GB exports gradually returning (Figure 2.9).

Figure 2.9
Gas demand from the NTS to Ireland



Exports to Europe via the Interconnector UK (IUK) are highly sensitive to both the overall UK supply/demand balance and continental gas markets. The import and export levels flowing through IUK are subject to uncertainty.

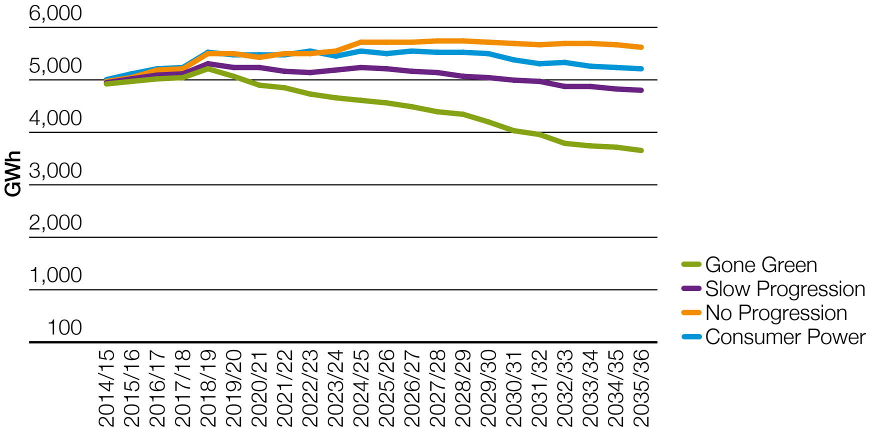
Future Energy Scenarios

Peak daily demand

Peak demand is based on the historical relationship between daily demand and weather. This relationship is combined with the expected amount of gas-fired power generation on a peak day. Figure 2.10 shows our peak demand scenarios, which are aligned to our annual demand scenarios.

The increase in peak demand over the next five years in all four of our scenarios is the result of a short period where we expect an increase in gas-fired power generation. The peak is less related to weather and more dependent on generation availability assumptions and the position of gas-fired power generation within the merit order. Our analysis assumes a low wind load factor of 7% with gas prices more favourable to coal.

Figure 2.10
1-in-20 diversified peak demand



The relationship between demand and weather is periodically reviewed with the latest industry standard taking effect on 1 October 2015. This update followed the acceptance of Mod 330, which introduced the concept of a weather station substitution methodology, into the Uniform Network Code.

A new weather history dataset was supplied by the Met Office along with a climate change methodology. This means we can complete our analysis using weather history that is adjusted to climate conditions appropriate for the period in which the demand to weather relationship will apply (2015–2020). By using this new data our 1-in-20 diversified peak has decreased by 4.8%.

Peak within-day demand

Through our FES work we do not produce within-day peak demand data. However our scenarios are used to assess changes to within-day profiling which is explained in more detail in Chapter 3.

2.3.2 Evolution of gas supply

The following section explains how gas supply has changed over the last decade and how it could look going forward. Gas supply sources have become increasingly variable which presents a number of challenges for us as the System Operator (see Chapters 3 and 4).

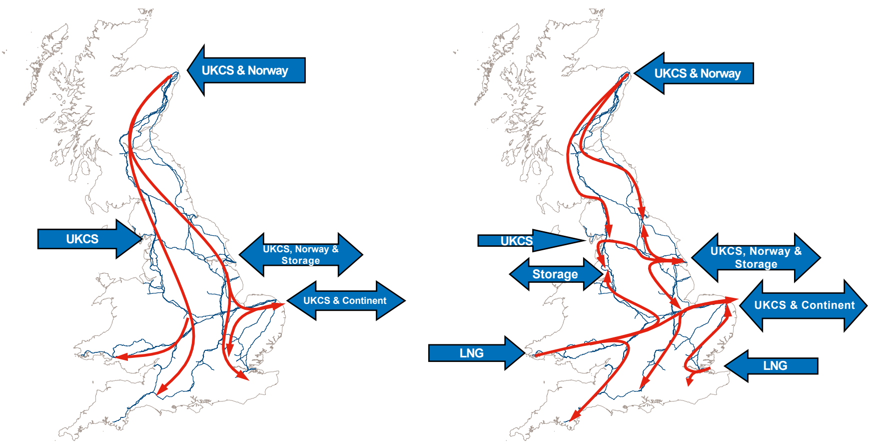
Changing GB gas supply

Our 2015 Future Energy Scenarios publication gives details of annual and peak gas supply for each of our four scenarios. The Gas Ten Year Statement (GTYS) expands on the FES by adding locational information and highlighting implications for the future planning and operation of the NTS.

In recent years we have shown how supply patterns on the NTS are changing and how they are expected to become more uncertain in the future. Figure 2.11 shows some of the changes we have seen from the mid-1990s to today.

Figure 2.11
Changing flow patterns on the NTS

Mid 90s to mid 00s **Mid 00s to 2014**



Future Energy Scenarios

From the mid-1990s to 2000s, supply patterns were relatively easy to predict as they were dominated by flows from the UK Continental Shelf (UKCS). Flows mainly entered the system at terminals on the east coast and travelled in a north to south pattern.

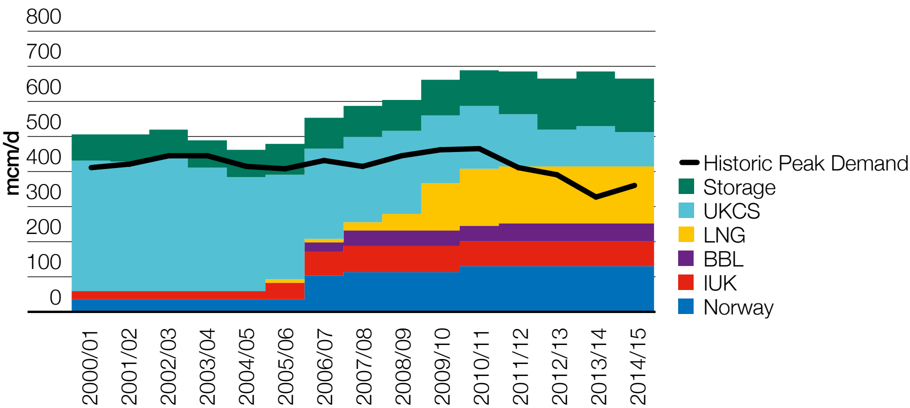
A positive consequence of this supply pattern evolution is that there are more entry points to the NTS distributed around the UK, so the average distance that gas is transported has reduced. Supply capacity in relation to peak demand has also grown significantly. These factors have helped to maintain security of supply and reduce compressor use.

The credible range of supply patterns needed to meet demand is increasing as factors such as the uncertainty in the world gas market and the development of fast cycle storage sites need to be taken into account. This affects future system planning as we have to develop a sufficiently adaptable system to be able to deal with multiple supply pattern possibilities. For example, high flows from Milford Haven support high exit capability in South Wales, but if Milford Haven flows are lower, exit capability is limited. We have to plan for this uncertainty when making exit capacity available. These issues and the implications for planning and operating our network are discussed in more detail in Chapter 3 and 4.

The changing nature of gas supplies to the UK since 2000 provides an indication of how future supply patterns may develop. The UK was a net exporter of gas until 2003/04. From that point, the level of imports has progressively increased as UKCS supplies have declined. Recent history has developed our understanding of potential import behaviour and the interaction of international markets and global events, as shown in the following examples:

- The influence of the global LNG market on UK supplies. Increases in Japanese demand for gas following the 2011 tsunami and economic growth in China meant LNG shipments preferentially went to these two countries and drove LNG prices up
- The development of cheap shale gas in the US contributed to a global surplus of coal in the export market which lowered coal prices. Cheaper imported coal was used in place of gas in the GB power generation market
- The behaviour of the Interconnector (IUK) as a flexible supply source for the UK and Continental markets

Figure 2.12
Historic gas supply capacity and peak day demand



- We are more reliant on gas supplies from outside the UK and therefore more susceptible to supply shocks from global events. We have discussed the impact of supply losses in Section 2.2.8 and we outline how we plan for and develop operational strategies to deal with supply losses on the NTS in Chapters 3 and 4.

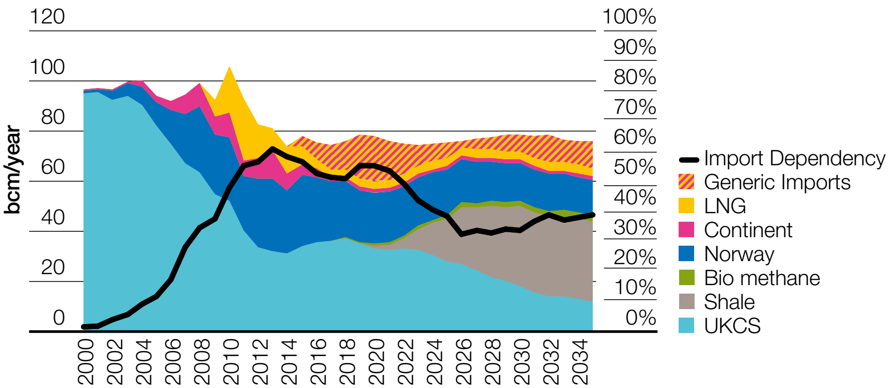
Figure 2.12 shows how peak supply capacity has increased despite the decline in UKCS production. As the UK has evolved from gas self-sufficiency to an increasing dependence on imports, there has been a considerable shift in how gas supplies are sourced to meet demand.

Historically, demand was met by UKCS supplies and, when needed, storage was used to make up for any supply shortfall. With the introduction of Norwegian imports, the Continent and LNG, the supply mix has changed considerably.

Annual and Peak Gas Supply

Figure 2.13 and Figure 2.14 show annual gas supplies in two of our scenarios: Consumer Power and Slow Progression. These represent the extreme cases for different elements of the total supply.

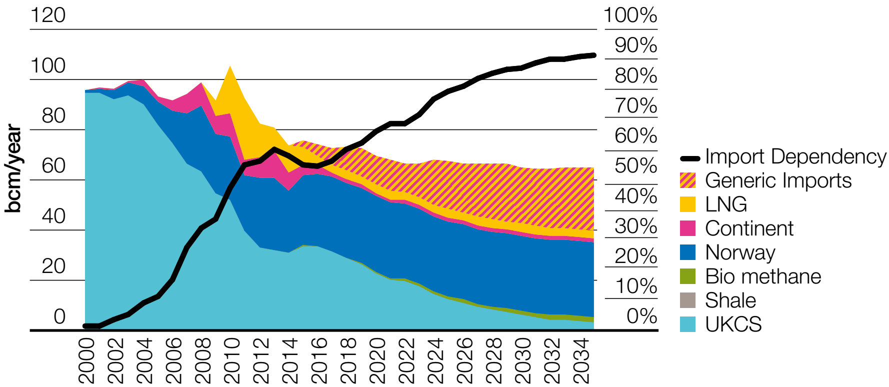
Figure 2.13
Annual gas supply for Consumer Power



In Consumer Power, supplies from the UK (including UKCS and shale gas) are higher than in any of the other scenarios which leaves less room for imports.

Future Energy Scenarios

Figure 2.14
Annual gas supply for Slow Progression

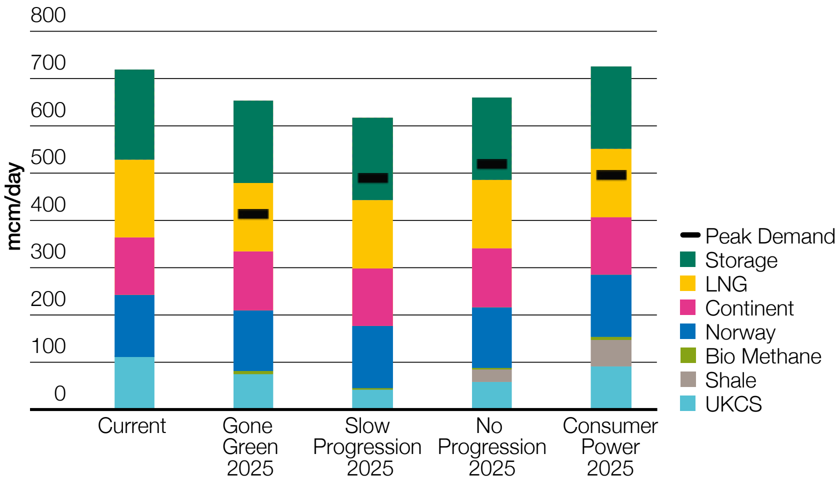


In Slow Progression, UKCS production is low and there is no shale gas, leading to much higher levels of imported gas.

The 'Generic Import' hatched area represents imported gas that could be any mixture of LNG and continental gas. The figures give some indication of the challenges we face with planning and operating the NTS. For example, in Slow Progression, the range of LNG flows in 2025 is from 3bcm up to 22bcm, dependent on how much of the generic import is LNG.

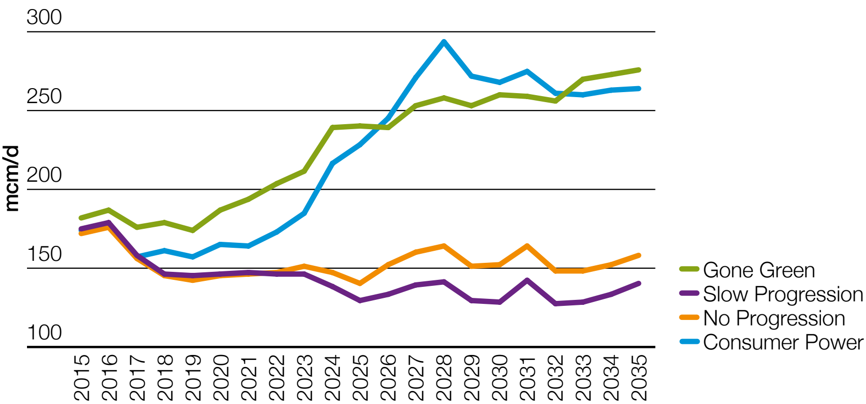
In our 2015 FES the current level of physical supply capability is more than enough to satisfy peak gas demand in all our scenarios. Figure 2.15 shows the current peak supply capability along with the peak supply capability at 2025 in the four scenarios and the peak demands in each. The chart shows that in all years the peak demand can be met by the existing supply infrastructure.

Figure 2.15
Peak supply capacity and demand



In all scenarios and all years there is at least 100 mcm/d supply capability over peak demands as shown in Figure 2.16.

Figure 2.16
Excess of supply capacity over peak demand



Future Energy Scenarios

Supply infrastructure
The peak supply chart in Figure 2.16 shows that there is no requirement for new supply infrastructure solely to meet peak demand, however, there may be commercial reasons for new developments. For example, there may be a case for operators to develop storage to make best use of shale gas, which is expected to produce at a constant rate through the year, or to support a power generation market increasingly dominated by intermittent low carbon generation. Similarly, in a scenario with high LNG import, developers may wish to open new capacity to take a share of the market.

In order to examine the implications of our gas supply scenarios on the NTS we show annual and peak flows split by supply terminal. To capture the full range of supply possibilities there are two cases for each scenario: one where the generic import is all LNG, and one where the generic import is all continental gas. Charts showing the flows by terminal are provided in Appendix 5.

Storage
Many new storage sites have been proposed over the last ten years and there are currently proposals for 7 bcm of space, both for medium-range fast-cycle facilities and for long-range seasonal storage. Details of existing and proposed storage sites are provided in Appendix 5. We have highlighted the loss of Avonmouth from 2016.

Imports
The UK has a diverse set of import options with pipelines from Norway, the Netherlands and Belgium and from other international sources in the form of LNG. There are currently no plans for increased pipeline interconnection. Details of existing and proposed LNG sites and existing Interconnectors are given in Appendix 5. These tables show the removal of the Teesport LNG terminal this year from Teesside.

Legislative Change

2.4 Legislative change

This section outlines the key legislative changes which will impact how we plan and operate the National Transmission System (NTS) over the next ten years. We will outline what impact these changes will have on our network in Chapter 3 and what we are doing in order to comply with these legislative changes in Chapter 5.

2.4.1 Industrial Emissions Directive (IED)

The European Union (EU) has agreed targets and directives that determine how we should control emissions from all industrial activity. The Industrial Emissions Directive[13] (IED) is the biggest change to environmental legislation in over a decade, with implications for everyone who relies on the NTS.

The IED came into force on 6 January 2013. It brought together a number of existing pieces of European emissions legislation. Two elements of IED, the Integrated Pollution Prevention and Control (IPPC) Directive and the Large Combustion Plant (LCP) Directive, heavily impact our current compressor fleet. Figure 2.17 overleaf, summarises the key features of IED.

The IED impacts the energy industry as a whole. Our customers, energy generators in particular, have to either close or significantly reduce their coal plant usage to comply with the emissions legislation. This means that our customers are using other sources such as Combined Cycle Gas Turbine (CCGT) plant to generate electricity instead. These emission legislation changes impact on how our customers' use the NTS and we have to be able to provide an adaptable system to accommodate these changing requirements (see Section 2.2.7 and Chapter 3).

The IPPC impacts 8 of our 24 NTS compressor sites. The LCP directive impacts 16 of our 64 compressor units. Details of what we are doing to adapt our sites to comply with this legislation are outlined in Chapter 5.

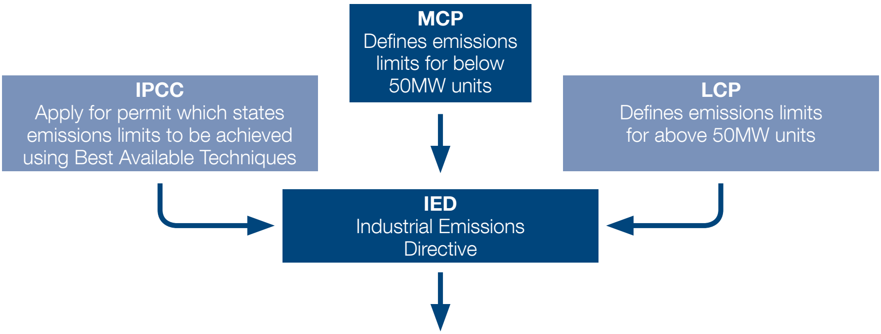
The Medium Combustion Plant (MCP) Directive is currently draft legislation, but is expected to be incorporated into IED within the next year. Based on the current draft legislation we anticipate this will impact a further 26 of our compressor units.

The IED legislation forms the new mandatory minimum emission standards that all European countries must comply with by 2023.

[13] A copy of the Industrial Emissions Directive can be found here: http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2010:334:0017:0119:EN:PDF

Legislative Change

Figure 2.17
IED key features



IED Key Features					
Below 50MW	Installations must be operated with a permit	Permits specify the ELVs to be complied with which are based on BAT	BREF documents draw conclusions on what the BAT is for each sector affected by IED	BREF document for combustion plant is likely to be finalised in mid-2016	MCP will be finalised before the end of 2015 with compliance required by 2025
Above 50MW	Set new ELV for carbon monoxide 100mg/Nm³ for new and existing plant Set new ELV for nitrogen oxide 50mg/Nm³ new plant; 75mg/Nm³ for existing plant	All our gas-driven compressors that produce emissions above the threshold set by the Industrial Emissions Directive (IED) must be compliant with new limits by 31 December 2023	Compressors not meeting new ELVs have to stop operating by 31 December 2015 unless a Limited Lifetime Derogation is applied for or the unit is entered into emergency use	Through Limited Lifetime Derogation the operator declares not to operate plant for more than 17,500 hours until 31/12/2023	Can use affected compressors that do not comply with ELVs for 'emergency use' for less than 500 hours per year

The following sections summarise the main elements of IED which impact upon our compressor fleet. More detail about what we are doing to comply with these legislative changes along with maps highlighting which compressor sites are affected are provided in Chapters 3 and 5.

Integrated Pollution Prevention and Control (IPPC) Directive

The IPPC[14], implemented in 2008, states that any installation with a high pollution potential (oxides of nitrogen (NOx) and carbon monoxide (CO)) must have a permit to operate.

To obtain a permit we must demonstrate that Best Available Techniques (BAT, see below for more information) have been used to assess all potential options to prevent emitting these pollutants. The BAT assessments provide a balance between costs and the environmental benefits of the options considered.

We have to ensure that all of our compressor units have a permit which specifies the maximum Emission Limit Values (ELVs) to the air for each unit.

We are currently working on five compressor sites in order to comply with the IPPC directive. Further information on these works can be found in Chapter 5.

BAT Reference (BREF)

BREF[15] documents have been adopted under both the IPPC directive and IED. The BREF documents outline:

- techniques and processes currently used in each sector
- current emission levels
- techniques to consider in determining the BAT
- emerging techniques to comply with the legislation.

The BAT conclusions drawn from the BREF documents will outline the permit conditions for each non-compliant unit.

The BREF document for large combustion plants is in draft form (June 2013) and it is anticipated that this will be finalised in 2016. From the date of finalisation we will have four years to implement the conclusions.

[14] A copy of the IPPC directive can be found here: http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=URISERV:l28045

[15] BREF documents can be found here: http://eippcb.jrc.ec.europa.eu/reference/

Legislative Change

Large Combustion Plant (LCP) Directive

The LCP[16], implemented in 2001, applies to all combustion plant with a thermal input of 50MW or more. All of our compressor units that fall within the LCP directive must meet the ELVs defined in the directive. The ELVs are legally enforceable limits of emissions to air for each LCP unit. ELVs set out in the directive can be met in one of two ways:

1) Choose to opt in – must comply with the ELV or plan to upgrade to comply by a pre-determined date
2) Choose to opt out – must comply with restrictions defined in the derogation including Limited Lifetime Derogation or the Emergency Use Derogation.

Limited Lifetime Derogation

In the IED it states that from January 2016 to 31 December 2023 combustion plant may be exempt from compliance with the ELVs for plant above 50MW provided certain conditions are fulfilled:

- The operator makes a declaration before 1 January 2014 not to operate the plant for more than 17,500 hours starting from 1 January 2016 and ending no later than 31 December 2023
- The operator submits each year a record of the number of hours since 1 January 2016
- The ELVs set out in the permits as per the IPPC directive are complied with.

We have already made the declaration above and have been allowed to use this derogation for our current affected units. However, we still have the option to opt out prior to January 2016 if through our IED submission to Ofgem[17] in May 2015 (see Chapters 3 and 5 for more information) an alternative way of compliance (either emergency use provision, decommissioning or replacement) is agreed.

Emergency use provision

The IED includes the possibility of using plant for emergency use:

> *"Gas turbines and gas engines that operate less than 500 operating hours per year are not covered by the emission limit values set out in this point. The operator of such plant shall record the used operating hours."*

This means that we may be able to use our non-compliant compressor units for 500 hours or less.

Further information on our compliance with LCP can be found in Chapters 3 and 5.

[16] A copy of the LCP directive can be found here: http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=URISERV:l28028

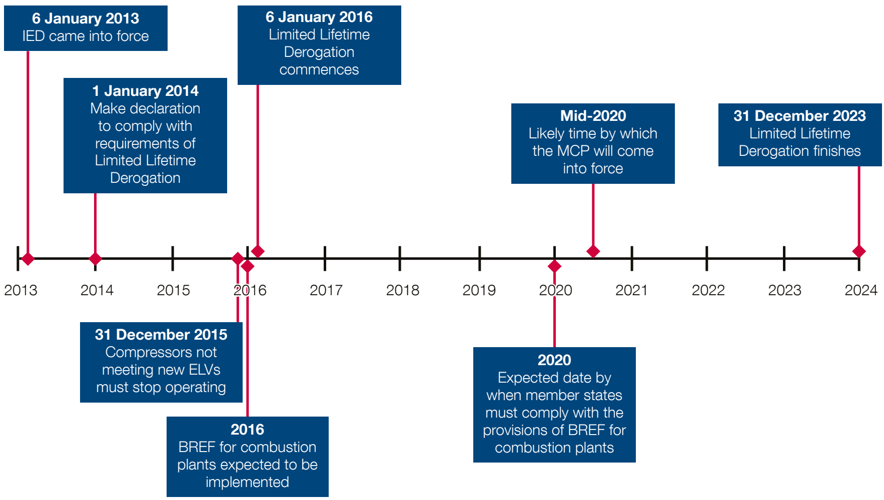
[17] http://consense.opendebate.co.uk/files/nationalgrid/transmission/IED_Investments_Ofgem_Submission_FINAL_REDACTED.pdf

Medium Combustion Plant (MCP) Directive

The MCP is expected to be implemented in 2020. It will apply limits on emissions to air for all combustion plant with a thermal input of less than 50MW. It is expected that this legislation will introduce different ELVs based on the plant's age, capacity and type of installation.

Based on the draft legislation there will be a long transition period for existing plant, up to 2025 for the larger plant (5–50MW) and up to 2030 for the smaller plant (less than 5MW). It is expected that we will have to comply with this legislation by 2025 (Figure 2.18).

Figure 2.18
Excess of supply capacity over peak demand



Legislative Change

2.4.2 Other legislation

European Union Third Package
One of the most important pieces of recent European gas and electricity markets legislation is referred to as the Third Package. This was transposed into law in Great Britain (GB) by regulations that came into force in 2011.

The Third Package creates a framework to promote cross-border trade and requires a number of legally binding Guidelines and Network Codes to be established and implemented with the aim of: promoting liquidity; improving integration between Member States' gas markets; and promoting the efficient use of interconnectors to ensure that gas flows according to price signals, i.e. to where it is valued most.

These EU legislative requirements take priority over GB domestic legislation and associated regulations and codes, including the Uniform Network Code (UNC). We, as the Transmission System Operator, have raised a series of EU related UNC Modifications to comply with the legislation.

The focus to date has been on:

(a) Commission Decision on amending Annex I to Regulation (EC) No 715/2009 on conditions for access to the natural gas transmission networks [2012/490/EU, 24/08/2012]; (Congestion Management Procedures (CMP))

This specifies rules to ensure booked capacity at Interconnection Points is used efficiently to address issues of contractual congestion in transmission pipelines

(b) Commission Regulation (EU) No 984/2013 of 14 October 2013 establishing a Network Code on Capacity Allocation Mechanisms in Gas Transmission Systems and Supplementing Regulation (EC) No 715/2009; and (CAM)

This seeks to create more efficient allocation of capacity at the Interconnection Points between adjacent Transmission System Operators. CAM introduces the revised 05:00-05:00 Gas Day arrangements at Interconnection Points

(c) Commission Regulation (EU) No 312/2014 of 26 March 2014 establishing a Network Code on Gas Balancing of Transmission Networks; (BAL)

This includes network-related rules on nominations procedures at Interconnection Points, rules for imbalance charges and rules for operational balancing between Transmission System Operators. This also reflects the new Gas Day arrangements that are applicable across the GB balancing zone via this code. It applies in Great Britain from 1 October 2015

(d) Commission Regulation (EU) No. 703/2015 of 30 April 2015 establishing a Network Code on Interoperability and Data Exchange Rules.

This obliges Transmission System Operators to implement harmonised operational and technical arrangements in order to remove perceived barriers to cross-border gas flows and thus facilitate EU market integration. Implementation is required by 1 May 2016.

For more information on our activity to date and our future activity to comply with this new EU legislation see Appendix 6.

Ofgem Significant Code Review

In January 2011, Ofgem began its Significant Code Review (SCR) into gas security of supply to address its concerns with the gas emergency arrangements. The aim of the Review was to reduce the likelihood, severity and duration of a gas supply emergency by ensuring that the market rules provide appropriate incentives to gas shippers to balance supply and demand.

In September 2014 Ofgem issued its conclusions[18] which included a reformed cash-out arrangement (the unit price at which differences in each gas shipper's supply and demand are settled) in an emergency. The reformed cash-out arrangement incentivises gas shippers to deliver supply security as price signals incorporate the costs of involuntary consumer interruptions into cash-out. These changes took effect from 1 October 2015.

Ofgem has asked us to proceed with the development of a centralised demand-side response mechanism. This will allow our large gas customers to reduce demand voluntarily ahead of an emergency. This could help to reduce the likelihood, severity and/or duration of a gas emergency. The demand-side response mechanism is expected to be in place by October 2016.

[18] https://www.ofgem.gov.uk/publications-and-updates/gas-security-supply-significant-code-review-conclusions

Asset Health

2.5
Asset health

Asset health is a becoming a more frequent trigger to our Network Development Process (NDP). This section explores asset maintenance and our asset health programme, from identification of an issue, through to resolution. The NTS comprises 7,600 km of pipeline, 24 compressor sites with 75 compressor units, 20 control valves and 530 above-ground installations (AGIs). Of these assets approximately 70% of pipeline and 77% of our other assets will be over 35 years old at the end of RIIO-T1.

We have developed our asset maintenance and asset health programmes in order to maintain the health of the National Transmission System (NTS) to appropriate levels. Our asset maintenance programme focuses on delivering routine maintenance and monitoring the health of our assets versus our expected asset life cycles; the asset health programme addresses assets that are either end of life or have failed, typically through more invasive works such as replacement or refurbishment. These programmes ensure that we can consistently deliver a safe and reliable system to meet our customers' and stakeholders' needs. The RIIO price control arrangements have changed how we report on the health of the NTS. RIIO has introduced Network Output Measures (NOMs) (previously Network Replacement Outputs) as a proxy for measuring the health and thus level of risk on the network. We must meet specific targets which are related to the condition of the NTS. This change means that asset health is a key RIIO measure in terms of allowances and output. The targets we have been set cover an eight-year period from 2013 to 2021. We have plans in place to meet these targets by the end of the eight-year period.

As the NTS is ageing and we have an increasing number of assets reaching the end of their design life we have implemented a five-year programme of works to resolve current asset issues as efficiently as possible while minimising disruption to our customers. This is our Asset Health Campaign, outlined in further detail later in this chapter.

2.5.1 **Asset maintenance**

We have a large number of asset types on the NTS. At a high level maintenance approaches are set by asset type however the amount and type of maintenance required can differ both by and within asset types.

For example, two of our asset types are valves and pipelines; we adopt a different overall approach to maintaining valves than we do to pipelines, however the maintenance required by an individual valve within the broader valve asset type will differ depending on the make and model of valve, its location on the network and its age and existing condition.

By understanding what our assets are doing and the condition we expect them to be in throughout their lifecycle we can plan, monitor and react to their maintenance requirements.

The following asset types require different approaches to maintenance:
- Pipelines – Risk-based inspection
- Instrumentation – Criticality-based, intelligent condition monitoring
- Electrical – Scheduled inspections and failure-finding functional checks
- Compressors – Condition monitoring, functional checks, scheduled inspections, and usage-based inspections
- Valves – Criticality based intervals
- Above Ground Installations (AGIs) – Functional checks.

We record issues relating to the operational status of assets by giving them a priority score. The issues identified could highlight a requirement for asset repair, failure mitigation or any other work that is deemed necessary to maintain the safe operation of an asset. Issues are scored based on a number of independent parameters with a higher weighting given to problems that have a high impact on the safe operation of the NTS.

The assets score is then used to prioritise replacement or repair of the asset. We use a Replacement Priority Matrix which is based on condition versus criticality, shown in Figure 2.19.

Asset Health

Figure 2.19
Asset replacement priority matrix

Asset Health Scores

AH1	New or as new
AH2	Good or serviceable condition
AH3	Deterioration, requires assessment or monitoring
AH4	Material deterioration, intervention requires consideration
AH5	End of serviceable life, intervention required

Criticality

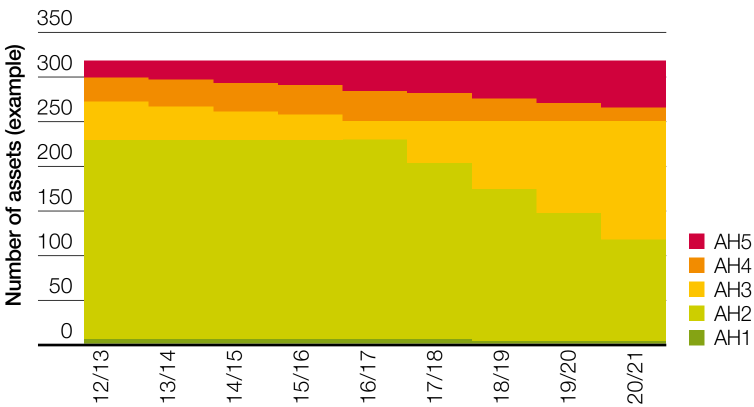
C1	Very High
C2	High
C3	Medium
C4	Low

Replacement Priority Matrix

	AH1	AH2	AH3	AH4	AH5
C1	RP4	RP3	RP2	RP1	RP1
C2	RP4	RP3	RP2	RP1	RP1
C3	RP4	RP3	RP2	RP2	RP1
C4	RP4	RP3	RP2	RP2	RP1

As an asset ages we would expect its condition to deteriorate. Depending on the age of the asset the level of deterioration will vary. Figure 2.20 outlines an example of expected asset health condition decline over a nine-year period. The Asset Ageing Model is based on the Asset Health Scores defined in Figure 2.19 for assets ranging from new to end of life.

Figure 2.20
Asset ageing model – showing an example asset condition decline over time



During 2014/15 we have invested £57m towards maintaining the health of our assets. We have delivered over 2,000 asset health improvements which have contributed approximately 150 NOMs towards our NOMs targets.

2.5.2 **The asset health campaign**

Over the past year we have been building a catalogue of known asset condition issues which will be addressed by the campaign within the next five years. The planning stages of this five-year campaign have identified which assets should be addressed first, with works starting in RIIO Year 4 (2016/17) and concluding in RIIO Year 8 (2020/21).

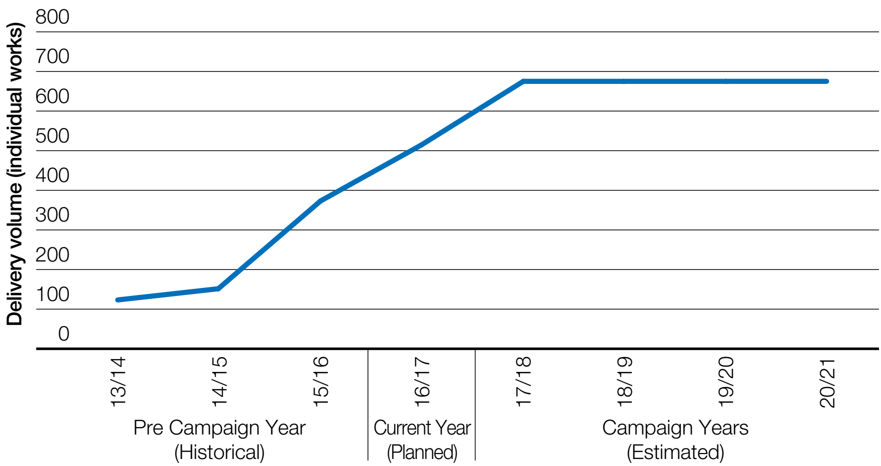
Campaign delivery

The campaign will bundle maintenance work by geographical area, tackling all issues in a particular location at once to minimise costs and provide an operational focal point.

In terms of operational delivery the NTS is split into three areas: Scotland, West and East. These three areas are then divided into zones, with four zones in the West and Scotland and five zones in the East. This approach to zonal planning has been successfully used for feeder outages.

The focused campaign approach was developed to address the growing number of asset health issues that we have identified over the next five years. Figure 2.21 shows the estimated NOM deliveries as part of the campaign.

Figure 2.21
Asset NOM delivery volumes



Minor asset issues can be resolved outside of our NDP, however where multiple options are being considered to resolve the asset issue our NDP may be used to critically assess the options.

Asset Health

Asset health and NDP

By using our NDP to resolve an asset health issue we are able to reach the most efficient and effective solution. We start with a stakeholder engagement workshop to establish a range of options which could address the asset need. We then explore the advantages and disadvantages of the options and align them to the Whole Life Prioritisation Matrix ((WLP) Appendix 1). This process narrows down the range of options for more detailed assessment. The WLP is explained further in Chapter 3.

The Establish Portfolio stage of the NDP, as described in Chapter 5, explores the asset investment options we consider to resolve asset health issues. When looking at asset investment options we not only look at the impact on NTS capability and operation, we also look at the impact on other projects and governance obligations such as to the Health and Safety Executive (HSE) and the Department of Energy & Climate Change (DECC).

We expect each of the asset health deliveries throughout the campaign (see Figure 2.21) to follow our NDP. Depending on the asset type and location it may be assessed individually or collectively.

Asset health campaign challenges

The zonal approach to asset health works can result in system access challenges as some assets will need to be taken offline to complete the required work. In order to manage this temporary impact on our network the programme of works will be designed to minimise disruption and will not affect our ability to provide a safe and reliable network for you.

Chapter three

System Capability

NDP – Defining the Need Case

System Flexibility

Customer Capacity – Exit

Customer Capacity – Entry

Impact of Legislative Change

Need Case

Required system capability over the short/ medium/ long term

Chapter three

System Capability

This section outlines the current system capability of the National Transmission System (NTS). Information is provided for entry and exit capacity, system flexibility, and the impact of the Industrial Emissions Directive (IED). This chapter also explores the Need Case stage of the Network Development Process (NDP), which we use to establish NTS capability requirements.

Key messages

We use our Network Development Process to assess system capability requirements.

- The difference between long-term entry capacity bookings and our capacity release obligations and our Future Energy Scenarios (FES) means that long-term auctions no longer provide a definitive signal of a shipper's intention to flow. Flow on the National Transmission System (NTS) can show great variation from one day to the next due to the extent and diversity of supplies
- Our system flexibility work is making good progress. We are now seeing the first results of an ongoing development project with Baringa that will dramatically improve how we model our customers' future requirements. Although it's still early days, we are continually improving how we build the 'GasFlexTool' into our analysis methods
- The first round of Electricity Market Reform (EMR) auctions has mainly resulted in capacity contracts for existing power stations with some new build. Although the initial developer activity before EMR has not resulted in any new NTS projects, we are still discussing future connections which may lead to future NTS projects
- The impact of legislative change – particularly the Industrial Emissions Directive (IED) – continues to challenge how we develop our network and improve our investment approach
- We continue to provide information about lead times and capacity across different geographical areas and we aim to make our Gas Ten Year Statement (GTYS) and our other publications more relevant to your needs
- Overall distribution network (DN) flat capacity requests are falling but the flex requests, particularly in the South West region, are increasing
- A meeting was held in October with all DNs to discuss the Exit Allocation process. This meeting helped us to gain a better understanding of our customers' changing requirements.

Introduction

3.1 Introduction

System capability and the development of the National Transmission System (NTS) is managed through the Network Development Process (NDP) which we introduced in Chapter 1. Following on, Chapter 2 explored some of the triggers for this process including: customer requirements, changing market conditions as described in our Future Energy Scenarios (FES), changes in legislation such as the IED and asset health requirements.

This chapter describes what happens once we receive a ‘trigger’ and we enter the Need Case stage of the NDP. This is where we analyse the NTS’s capability requirements.

Included within this chapter are:

- system flexibility requirements and how we are developing our understanding of this
- customer entry and exit capacity processes
- capability requirements triggered by the IED.

Understanding our system capability allows us to determine where rules, tools or asset solutions need to be found to meet our customer requirements. Chapter 4 will discuss where, as System Operator, we can better use rules and tools to make more efficient use of the system and Chapter 5 will discuss how the asset solutions are developed.

3.2
NDP – Defining the Need Case

Defining the 'Need Case' is the process through which we understand the implications of a change. We assess the level of risk to the NTS which allows us to determine the most credible method of addressing that risk. We articulate the cause of the problem or driver (the 'trigger') and consider any potential secondary drivers. This allows us to ensure we consider all opportunities and deliver the most efficient option.

An example of this could be a site with immediate asset health investment requirements. When assessing the health investment we would also consider rationalising the site to remove redundant equipment and incorporate the network future requirements. We ask ourselves the following questions: What do we repair? What do we replace? What do we enhance? This allows us to make the most efficient longer term investments and reduce the chance of stranded assets i.e. assets that are no longer required.

National Grid undertakes the role of System Operator (SO) for the NTS in Great Britain. Gas SO incentives are designed to deliver financial benefits to the industry and consumers by reducing the cost and minimising the risks of balancing the system.

Under RIIO, we are incentivised to think about Total Expenditure (TOTEX) as well as Capital Expenditure (CAPEX) and we need to demonstrate good value for money. We therefore focus on the need of the SO when considering asset and non-asset solutions. Our NDP allows us to articulate the change in risk of different options and present the SO need, both now and in the future.

We initially look at the 'Do Nothing' option. This is the minimum action we could take. This may mean no investment or the minimum investment on a like-for-like basis to ensure safety and licence requirements are met. We then assess other high-level options; these could be rules, tools or assets, against a 'Whole Life Prioritisation Scorecard' as shown in Appendix 7. This ranks the options against multiple categories such as time to deliver, ability to meet the need, and support from the industry. We filter the options to provide a cost envelope under which the development of detailed options can be assessed.

System Flexibility

3.3
Existing Approach to System Flexibility Planning

In Chapter 2, section 2.2.8 we defined what we mean by System Flexibility. We need to ensure, as the System Operator, we have the flexibility to respond to variations on our system. We use the Future Energy Scenarios (FES) to inform the variety of configurations we might require. We consider profiling and rates of change to identify the plant and equipment we might need at our compressor stations and other key multi junctions, and the operational tools we might need to manage the transition between events. Through our Industrial Emissions Directive (IED) stakeholder engagement activities, we have given the example of replacing larger non-IED compliant units with multiple smaller IED-compliant units (rather than a single unit) as an example of how we might maintain or even increase System Flexibility.

We discussed the three components of System Flexibility in Chapter 2, these are:
- within-day linepack variation as a result of varying within-day supply and demand profiles and imbalances
- geographic supply and demand distribution including locational flow requirements away from peak
- adaptability/configurability to meet changing geographic supplies and demands within-day.

We currently plan for within-day flexibility by explicitly modelling the profiling of demand. Distribution Network (DN) flex bookings (see Chapter 2) and Uniform Network Code (UNC) section H submissions (for off-peak demand levels) give us a good indication of likely DN offtake profiling and we are improving how we model gas power generation offtake profiling through the flexibility project work we are doing.

Supply changes as a market response to both demand changes and supply losses. We reflect these variations in our planning process models with assumptions on market behaviour and supply reliability factors.

We plan for supply variations by the reservation of operational linepack via the application of a design margin and via the procurement of operating margins services. More discussion on these can be found in the Transmission Planning Code[1].

We plan for geographic distribution of supply and demand using the FES. We develop sensitivities around the FES, such as minimum supply levels at times of high demand.

[1] http://www2.nationalgrid.com/UK/Industry-information/Developing-our-network/Gas-Transportation-Transmission-Planning-Code/

Chapter three

System Flexibility

3.3.1 System imbalance

Linepack is the volume of gas stored within the NTS. If demand exceeds supply, levels of linepack throughout the network will decrease along with system pressures. The opposite is true when supply exceeds demand.

Throughout a gas day, supply and demand are rarely in balance, so linepack levels fluctuate. In our role as residual balancer of the UK gas market, we need to ensure an end-of-day market balance by ensuring total supply equals, or is close to, total demand. This should ensure that system pressures and linepack are restored, ready for the start of the next gas day. We use a metric called Projected Closing Linepack (PCLP) as an indicator of end-of-day market balance.

PCLP is calculated from the physical flow notifications provided by our customers. It is the key data item that we use to determine whether we are required to take an action in the market to improve the end-of-day balance position.

We have seen an increasing trend in underlying market imbalance at the start of the gas day and the time taken for the network to be in balance by the end of the day.

Figure 3.1
Average projected closing linepack

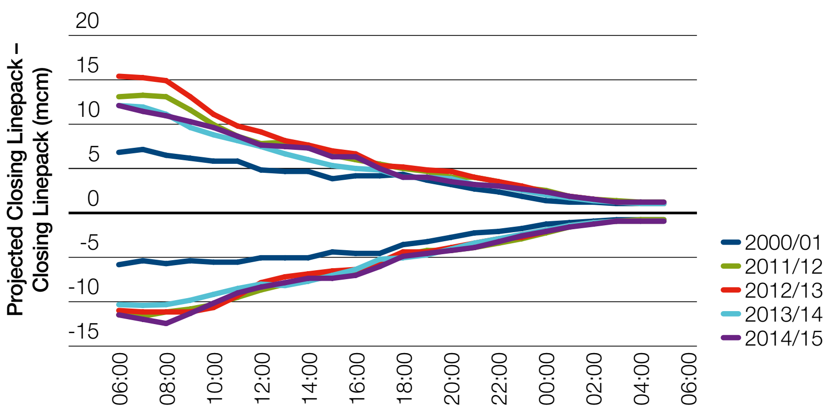


Figure 3.1 shows that average PCLP at the start of the gas day in 2014/15 was out of balance by more than twice as much when compared to 2000/01. In 2014/15 we have had a more challenging year and have been out of balance more than in 2013/14.

This reflects how our more commercially responsive customers are changing the way that they want to use our network. This includes a notable trend towards later daily balance reconciliations, along with start-of-day flow notifications that are less reflective of actual outturn flows.

3.3.2 Linepack and system pressures

To ensure that NTS pressures remain within obligated operational and safety tolerances, we manage levels of linepack on a national and zonal level.

The limits within which we can allow linepack – and therefore pressure – to change within a day are determined by the operating envelope, which determines how we manage the network (namely the maximum operating pressures of our assets and the minimum contractual pressures that we have agreed with our customers).

The levels by which linepack will change within-day in a zone of the NTS are driven by the difference between the levels and profiles of local supply and demand, plus the capability of the NTS to transport gas from zone to zone, as required.

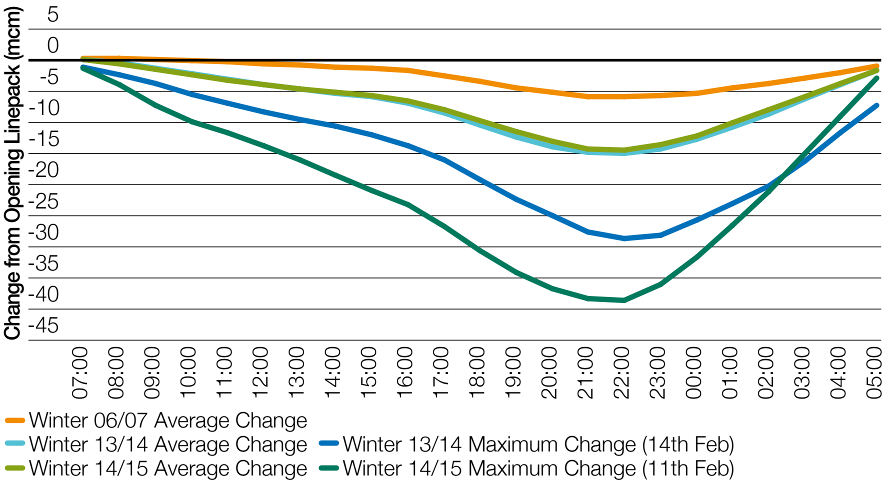
When gas is transported over long distances its pressure can drop significantly, which may mean that we are unable to meet the agreed minimum contractual pressures.

As a result, the evolution of supply patterns and within-day demand variation described in section 2.3 can significantly affect our ability to manage linepack in a controlled way, to allow for the imbalance between supply and demand, while also allowing us to meet our contracted pressures.

Over the last few years we have seen a significant increase in the average change in national linepack across a gas day (see Figure 3.2).

System Flexibility

Figure 3.2
Average and maximum change in linepack across a gas day



As well as an increase in the average change in linepack across a gas day we have seen an increased frequency of large changes.

Figure 3.3
Within-day maximum to minimum range of NTS linepack

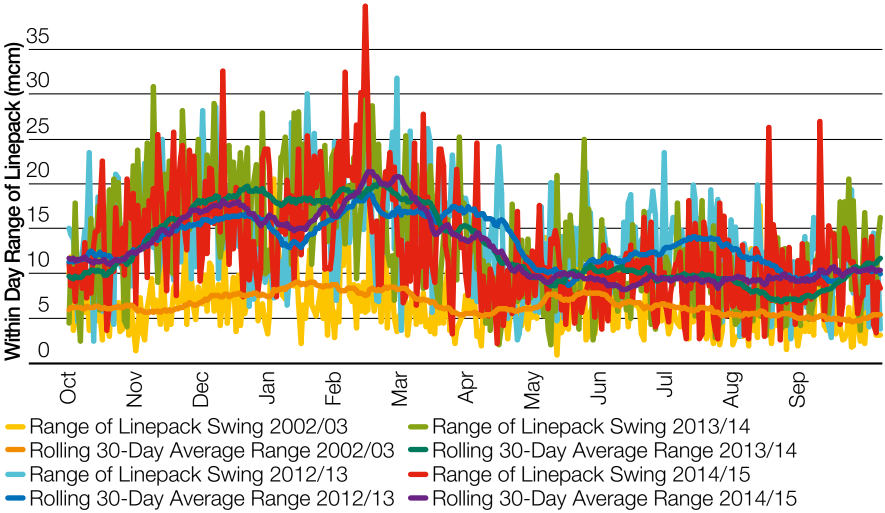


Figure 3.3 compares the within-day linepack changes seen in 2002/03 to those seen in 2014/15. It illustrates that current linepack changes at certain times of the year are up to three times the level seen a decade ago. This trend of increased linepack volatility is leading to greater operational challenges, particularly in terms of managing NTS pressures and ensuring that they remain within safety and contractual tolerances.

The future is uncertain, with a large range of potential future supply and demand patterns on the NTS. Although most will not lead to operational risks and issues, many have the potential to do so – and a small change to an anticipated supply and demand pattern on a given day can have a significant impact on the NTS and how we operate.

To ensure we can continue to assess and meet our customers' changing requirements we decided to review and improve the existing method of planning for System Flexibility.

System Flexibility

3.4
New approach to System Flexibility planning

To ensure we can continue to assess and meet our customers' changing requirements we decided to review and improve the existing method of planning for System Flexibility.

In our current NTS planning approach we use a design margin to account for variations in operational gas flows from the assumptions made in the design analysis. The design margin consists of two elements:

- flow margin
- pressure cover.

A 2% flow margin is applied to pipe flows to account for temporary flow/pressure differences on the NTS from unforseen events such as compressor station trips, forecasting errors and supply alerts. Pressure cover sets a minimum pressure at specific extremities of the NTS. Both elements of the design margin are applied to our network models to account for uncertainties that arise when undertaking network analysis ahead of the gas flow day.

The design margin was not intended for within-day supply and demand variations as large as we now see on the system. This was highlighted by our highest linepack swing, of 38.6 mscmd, which occurred on 11 February 2015. On this day, supply variation contributed 17 mscmd to the total swing. However, the design margin reserves only 3 mscmd (plus or minus). Therefore, it is really important that we have the ability to explicitly model a wider range of varying supply and demand profiles. We are developing how we model combined cycle gas turbine (CCGT) running regimes to improve our accuracy in modelling market behaviour.

We are working with Baringa Partners LLP, an external energy consultancy, to improve our modelling of System Flexibility. The 'GasFlexTool' tool has been developed to model both the UK Electricity and Gas markets.

Our customers' changing use of the system is leading to greater linepack swings which will in turn lead to greater pressure variation. This could affect the pressure requirements of other customers. Our GasFlexTool is being developed to ensure that we can plan for an appropriate level of linepack swing to reflect future system use. This development will move us towards explicitly modelling supply variability to reflect supply loss, demand change and market supply response which we have never been able to do before.

The GasFlexTool produces hourly within-day gas supply and demand flows which are used to simulate gas flows on the NTS. It simulates a large number of supply and demand scenarios based on the FES, historical within-day behaviour and real weather data. We can then filter flow patterns which are more likely to cause a constraint on the NTS. These filtered or 'flagged' scenarios are then used to drive analysis simulations of the NTS to assess if the system is capable of operating under such scenarios. The tool is based on a stochastic approach, as opposed to the deterministic approach[2] currently used, and hence also gives an indication of the likelihood of such scenarios occurring.

For the top flagged days (i.e. those representing the biggest challenge), the tool re-simulates the scenario, along with additional examples showing supply surplus/deficit and outage at specified supply sources. This allows us to also explicitly model temporary supply shortfall or surplus, which (along with normal DN and power profiling) drives linepack depletion or overstocking. This can lead to

[2] The current approach is to start from a base case then gradually vary demand and supply until a constraint is reached. With the GasFlexTool we can run a large number of randomly varying demand and supply patterns and we can filter only those that cause a constraint on the system. This gives us an indication of likelihood of that constraint occurring.

modelled breaches of minimum pressure limits or maximum pipeline operating pressure i.e. constraints. This approach attempts to closely reflect actual system user behaviour on the day and hence improve the planning process.

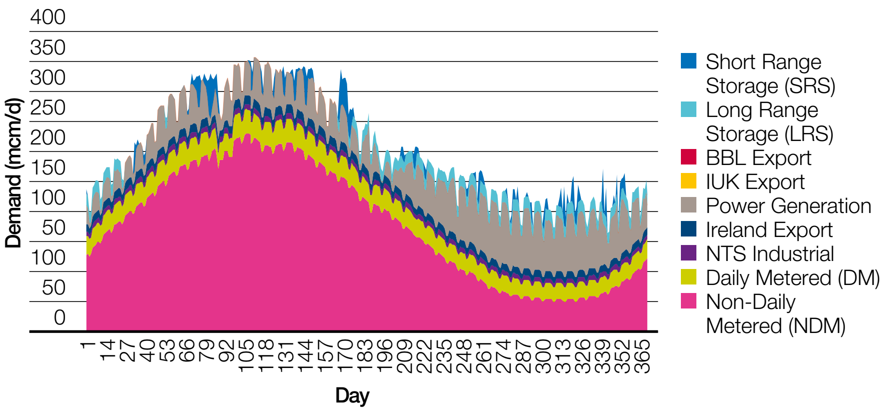
Examples of ‘flags’ could be scenarios with forecast high linepack swing across the NTS, or forecast high demand in a particular region of the NTS with minimal local forecast supply (e.g. high South West demand coupled with low flows at Milford Haven Liquefied Natural Gas (LNG) terminal).

We have provided two examples, both looking ahead to year 2021. They demonstrate how the impact of supply variation may be modelled using the GasFlexTool.

Example 1

Days with more extreme supply or demand positions can lead to larger within-day swings. Here is an example from our GasFlexTool from Gone Green in 2020. Overall the scenario is balanced on a daily basis as shown in Figures 3.4a–c.

Figure 3.4a
GasFlexTool demand mix for 365 days for 2020 Gone Green scenario



System Flexibility

Figure 3.4b
GasFlexTool supply mix for 365 days for 2020 Gone Green scenario

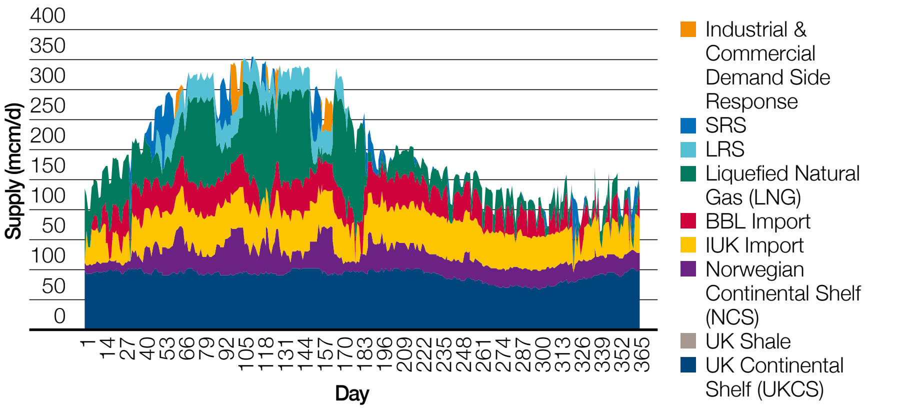
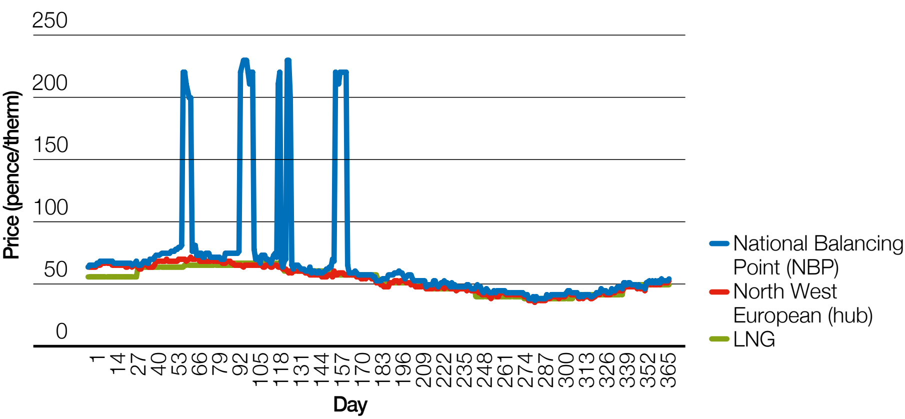
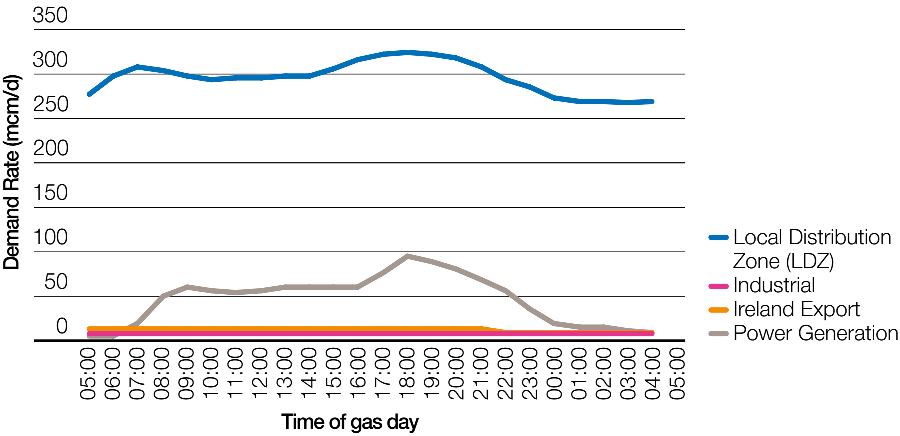


Figure 3.4c
GasFlexTool respective price profiles for 365 days for 2020 Gone Green scenario



Figures 3.5a–c show the individual high demand day. Early in the gas day, an undersupply of 20mcmd is predicted due to the high demands, which is met by system linepack. This causes pressures at some offtakes to fall towards their lower limits. Later in the day, the market tries to balance its position. A supply response to this shortfall occurs at 13 (17:00) and 16 hours (22:00). This results in 23 mcmd of linepack swing. This can lead to reduced pressure at offtakes in Flex constrained areas, such as the South West. In this example we would take system balancing actions (such as locational actions, on-the-day Commodity Market (OCM), National Balancing Point (NBP) title or over-the-counter (OTC) NBP transactions) if we thought the pressure levels resulting from this linepack drop would become unacceptable i.e. if the obligated pressures were likely to be breached.

Figure 3.5a
GasFlexTool output within-day rate of gas demand split by type



Chapter three

System Flexibility

Figure 3.5b
GasFlexTool output within-day rate of gas supply split by source

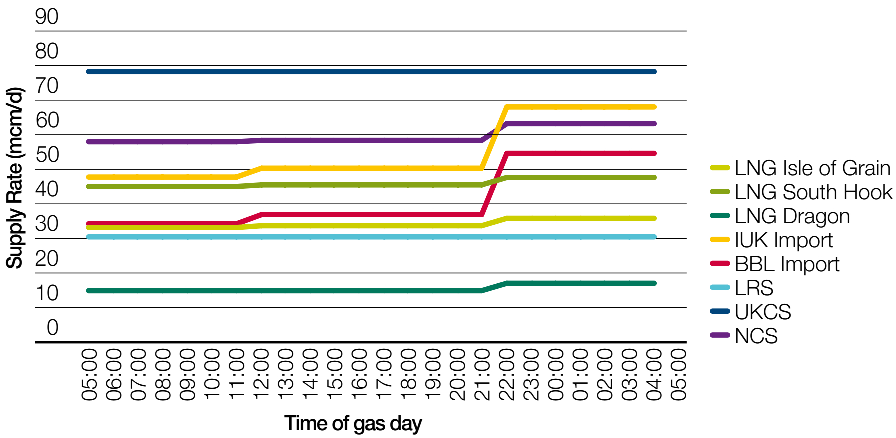
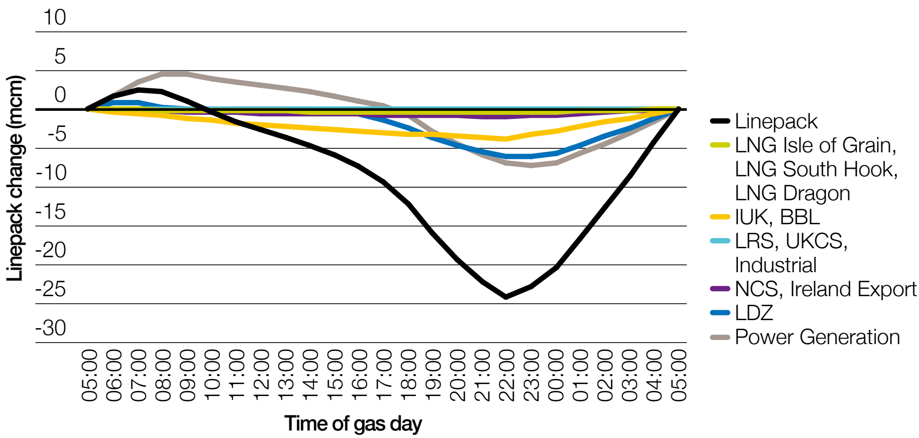


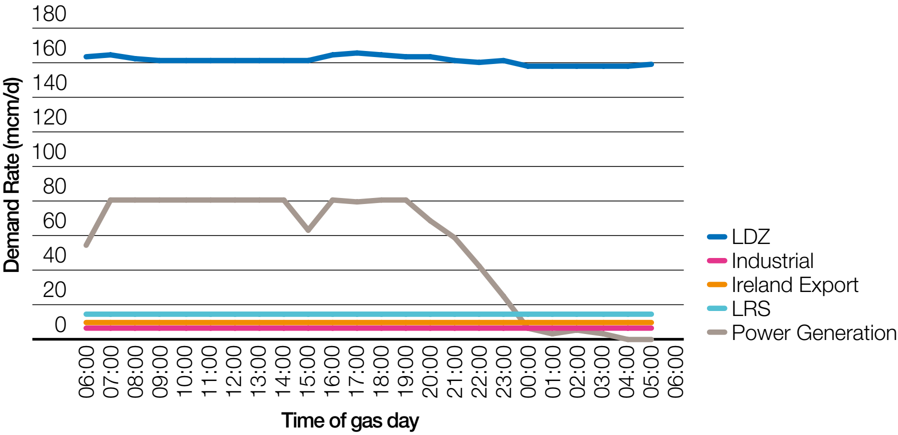
Figure 3.5c
GasFlexTool output within-day linepack swing



Example 2
Another future cause of high linepack swing is the ramp up and down of CCGT generation within-day in response to intermittent generation, such as wind generation.

Figures 3.6a–c show an example output from the GasFlexTool. The wind generation behaviour is based on actual historical wind data (1967). Although the linepack swing at national level as depicted in this chart (Figure 3.6c) may not appear adverse, due to the location of the power stations relative to the supply points, it could lead to large depletions in local pipe stocks. This in turn could lead to fast decay in local lower pressure limits. Such rapid decay could make it difficult or even impossible for an operational change, e.g. turning on a compressor, to take effect, and an obligated pressure level would be breached as a result.

Figure 3.6a
GasFlexTool output within-day rate of gas demand split by type



System Flexibility

Figure 3.6b
GasFlexTool output within-day rate of gas supply split by source

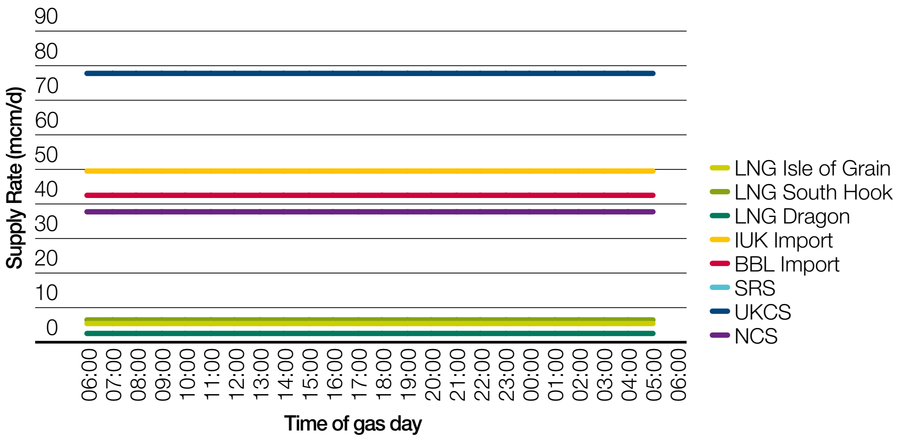
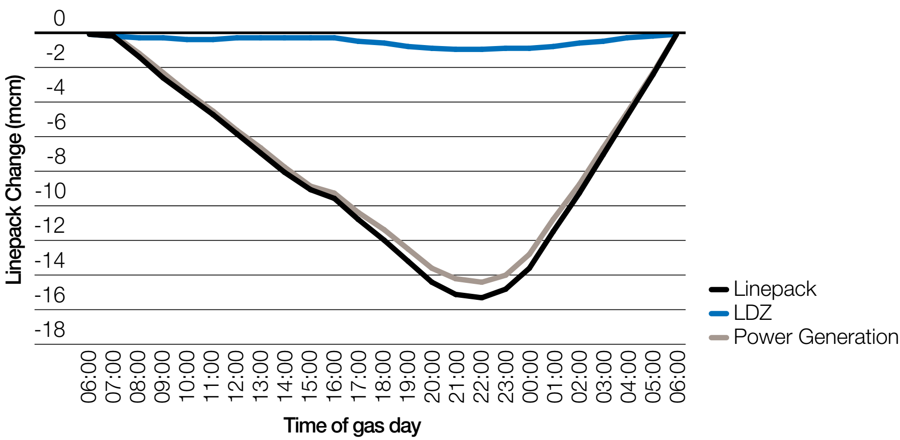


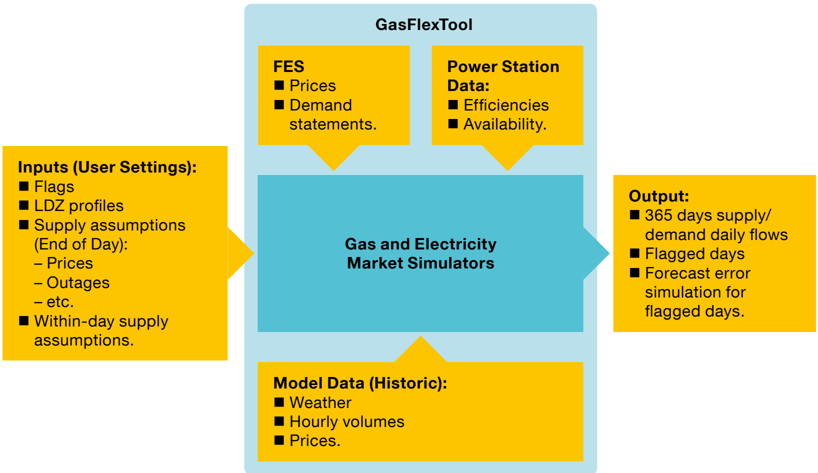
Figure 3.6c
GasFlexTool output within-day linepack swing



Situations like the one shown in example 2 could be dealt with if the gas control room is given suitable notice of the anticipated operation of the relevant CCGT. This allows operational action, i.e. appropriate network configuration change to be made in advance, to create suitable linepack levels in the respective zones. Without suitable notification it would be difficult to manage situations like these. Therefore an enhancement to the network could be required to reduce or eliminate this need. Alternatively, operational solutions such as commercial contracts or code/market amendments could be used.

Figure 3.7 below illustrates components of the GasFlexTool.

Figure 3.7
Components of the GasFlexTool



System Flexibility

3.4.1 System Flexibility Scenarios

Using our GasFlexTool we have identified some future scenarios where the network may not have sufficient capability to meet the requirements of users. We are currently working to understand the full impact so that we can develop the right solutions to ensure we maintain a reliable and adaptable system for our customers to use. These scenarios are based on trends being observed on the system, which are used to stretch the FES.

Table 3.1 shows some of the scenarios we are developing further. The GasFlexTool will start to give an indication of the likelihood of their occurrence, while network analysis will assess the impact on the system.

With regard to the development and operation of the NTS, taking changing user behaviour into account in our planning processes may trigger requirements for additional operational tools or reinforcement projects. This may also lead to changes to how we plan NTS compression and flow control.

Table 3.1
GasFlexTool Scenarios

Scenario	Description
CCGT Profiling	Within-day changes in gas power generation, driven by a number of factors affecting electricity balancing. This scenario impacts at national level as well as regional.
Supply Profiling	The impact of flow rate changes at terminals across the NTS due to factors including: ■ Response to forecast errors ■ Back-loading and front-loading ■ Outages and losses.
Storage Profiling	Impact of rapid flow rate variation, within-day, at storage facilities. This could be driven by: ■ Price arbitrage ■ Response to forecast errors ■ Response to outages elsewhere on the NTS.
Irish Interconnector Profiling	Impact of flow rate variation at Moffat on the north of the NTS, especially when there are low supplies through St Fergus.
High Linepack Swing Day	Days when there is a high linepack swing across the NTS. This could arise from a combination of the above scenarios.
High Regional Flexing	Specific cases where linepack loss in a region is severe. This could be due to a high demand change or forecast error in that region when the supply response is not local.

Example System Flexibility Scenario – CCGT Profiling

Using the GasFlexTool, we have simulated a possible NTS linepack swing range from the current annual peak level out to gas year 2029/30 based on the FES (see Figure 3.8).

Figure 3.8
Total NTS linepack swing range, driven by a very high wind (based on historical data) and cold weather assumption

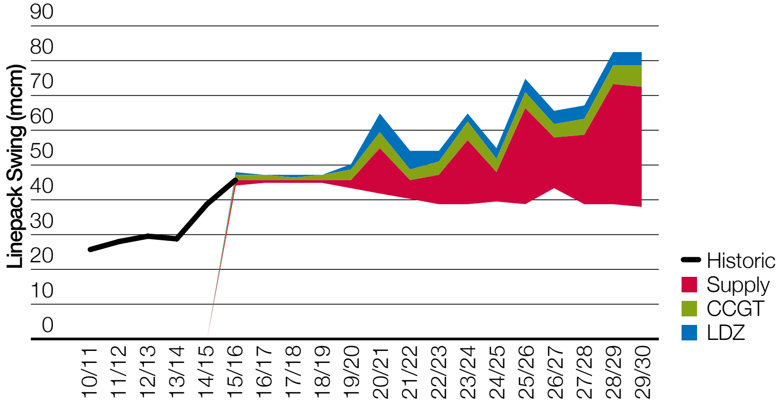


Figure 3.8 shows that the maximum NTS linepack swing has the potential to approach more than double the current level by the end of the next decade. The outputs from the tool are based on the assumption of high CCGT flexible operation and high supply within-day variation. The supply variation assumption is based on recent behaviour of specific supply points on the highest linepack swing day ever observed on the NTS.

The high CCGT flexing is assumed to be driven by wind intermittency. Hence, high wind historical data has been used, together with cold weather conditions. Figure 3.9 shows the CCGT contribution to the maximum NTS swing using these assumptions for each FES.

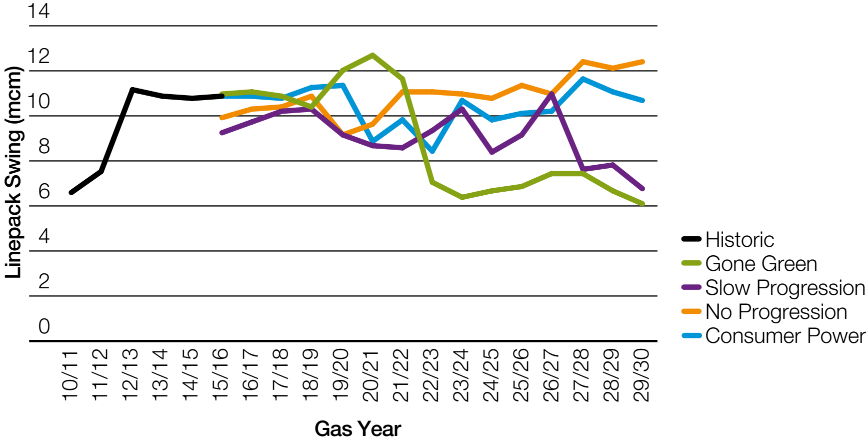
By improving our modelling so that it factors in future customer behaviour we can develop and adopt operating strategies that can manage pressure variability effectively and make use of notice period limits. We welcome your feedback on the data produced and the parameters we have used to model the scenarios.

Feedback can be provided through our Talking Networks site[3] or our GTYS mailbox: **Box. SystemOperator.GTYS@nationalgrid.com**

[3] http://www.talkingnetworkstx.com/System-Flexibility.aspx

System Flexibility

Figure 3.9
CCGT contribution total NTS linepack swing for each FES scenario, driven by a very high wind (based on historical data) and cold weather assumption



3.4.2 Incorporating stakeholder engagement outcomes

We held a System Flexibility stakeholder engagement event on 14 May 2015. At the event we defined the components of system flexibility, as described in Chapter 2, and focused on within-day linepack flexibility. We asked for views on how we should plan for the four main components of within-day flexibility, namely: DN profiling, direct connect profiling (mainly power generation), supply losses, and supply profiling due to delayed market response to demand change ('forecast error').

At this event, stakeholders did not think that there was an immediate concern as their flexibility needs were being met. However, they agreed with our requirement to look into the future and assess how the flexibility requirements may change. They were supportive of our quest to further investigative and quantify the system flexibility.

The feedback we received also highlighted the need for more planning information sharing between National Grid and system users, e.g. Distribution Network Operators (DNOs) and Offshore operators. It is hoped that through this, more detailed information such as flexibility usage, the probability of supply losses, and market-driven supply lag will be gathered. This should enhance current assumptions within the GasFlexTool.

The feedback also highlighted the need for more data sharing on power generation between National Grid Gas and National Grid Electricity to feed into long-term planning. This would enhance the modelling of CCGT operation, due to the coupled Gas and Electricity markets model approach used in the GasFlexTool. Assumed electricity market parameters and behaviour have not been shared between National Grid Electricity and National Grid Gas due to our business separation Licence obligations. We have started to look at the information that could be shared to benefit our within-day system flexibility planning approach, and how we might overcome our Licence restrictions.

There was also feedback on what attendees did not want. There were concerns expressed about placing limits and restrictions on users in terms of how they use their capacity. The feedback was that we should not introduce any arrangements that might undermine the wholesale markets or undermine daily balancing. We should not introduce new mandatory obligations on users. We rarely reject access to flexibility via offtake profile notices and users would like to see this continue. Restricting access to flexibility would have a negative impact on DNOs' ability to meet their customers' requirements and would have a negative impact on gas power generators' ability to participate in the balancing mechanism.

It should be noted that in the prevailing approach to planning for System Flexibility, due to variation of supplies within-day, is including a 2% flow margin. Recent NTS trends have shown that this figure may underestimate the magnitude of supply flow rate variation within-day. Stakeholders suggested that the design margin may no longer be fit for purpose and should be reviewed.

3.4.3 System Flexibility next steps

Over the next 12 months we will continue to develop and test the GasFlexTool to allow us to better quantify and understand future System Flexibility requirements. We will be using our Talking Networks site to keep the industry updated on our progress.

If we use the GasFlexTool as our standard way of assessing System Flexibility, we will include it within the Transmission Planning Code (TPC). The TPC describes the methodology used to determine the physical capability of the system, inform parties, wishing to connect to and use the NTS, of the key factors affecting the planning and development of the system. We consulted with the industry on the TPC in 2014 and 2015 to include RIIO and Planning and Advanced Reservation of Capacity Agreement (PARCA) related changes. We will consult with the industry to gain agreement on the proposed System Flexibility changes to our system planning process. This is also likely to involve revising the design margin, which includes the flow margin.

FES

Much of our data is consulted through the Future Energy Scenarios

The next version of the TPC will reflect these developments, and views will be sought from stakeholders through the consultation.

We are developing an approach based on future whole system planning rather than customer specific limits and products. This will involve setting parameters within the planning process such as the volume and duration of supply losses and the extent of demand variation with an associated supply response lag time. We would appreciate feedback on our planning approach and the approach to parameter setting.

As we mentioned in Chapter 2, section 2.2.9, we would welcome feedback on whether a Gas System Operability Framework (GSOF) would help in terms of setting and consulting on parameters within our planning process.

We plan to carry out further stakeholder engagement activities on our System Flexibility work, GSOF proposal, potential changes to the Transmission Planning Code and the upcoming Gas Standards initiative over the next 12 months.

Customer Capacity – Exit

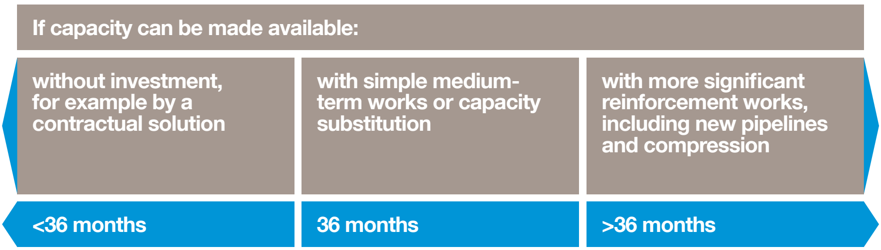
3.5
Customer capacity – exit

Understanding our customers' gas demand (exit capacity) requirements across the NTS allows us to plan and operate our system efficiently and effectively. When we receive an exit capacity request we analyse our current system to assess what impact an increase in demand has on the current system capability. This allows us to identify and plan for any geographical constraints which may arise from increasing customer exit capacity demand in a particular area of the NTS. Where constraints to current system capability are encountered we use the NDP to identify options to meet our customers' needs in the most cost effective and efficient way.

The following section provides shippers, Distribution Network Operators (DNOs) and developers with information about the lead time for providing NTS entry and exit capacity. If unsold NTS exit (flat) capacity is available at an existing exit point then it can be accessed through the July application process for the following winter.

The obligated capacity level, less any already sold, is the amount of capacity that we make available through the application and auction processes. We can increase capacity above the obligated levels when system capability allows, through substitution and via funded reinforcement works.

Figure 3.10
Capacity leadtimes



If we identify reinforcement works or increased operational risk, we investigate substituting unsold capacity. Capacity substitution involves moving our obligation to make capacity available from one system point to another. This is intended to avoid the unnecessary construction of new assets. (Further information on substitution is available in the TPC[4] and via the methodology statements[5].

If substitution is not possible, we will consider whether a Need Case has been triggered and hence reinforcement works and contractual solutions will be investigated. Works on our existing sites, such as modification of compressors and above-ground installations (AGIs) may not require planning permission, so may have shorter lead times. Significant new pipelines require a Development Consent Order (DCO), as a consequence of The Planning Act (2008). This can result in capacity lead

[4] http://www2.nationalgrid.com/UK/Industry-information/Developing-our-network/Gas-Transportation-Transmission-Planning-Code/
[5] http://www2.nationalgrid.com/uk/industry-information/gas-capacity-methodologies/

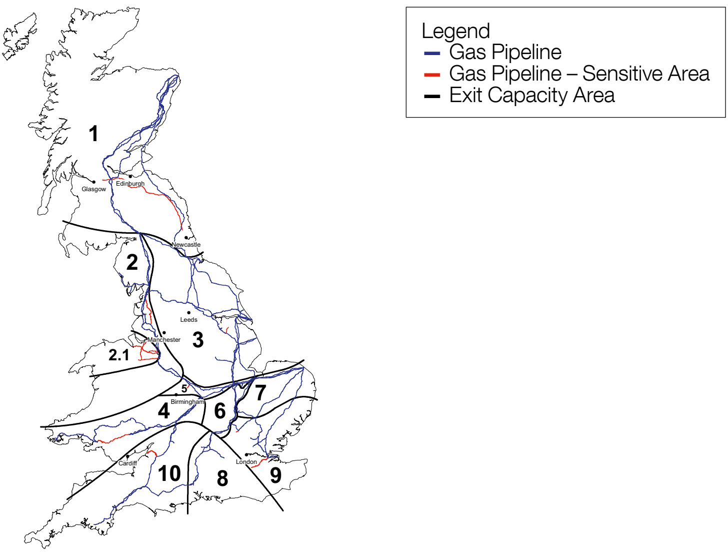
times of 72 to 96 months. Construction of new compressor stations may also require DCOs if a new high-voltage electricity connection is needed and, subject to local planning requirements, may require similar timescales to pipeline projects.

3.5.1 NTS exit capacity map

Figure 3.11 – NTS exit capacity map divides the NTS into zones based on key compressor stations, and multi-junctions. Within these zones, any new connection and/or capacity request is likely to either be met through substitution within the zone or by a similar reinforcement project. It is likely that substitution within a zone will be close to a 1 to 1 basis. These zones are purely for information and were created for the Gas Ten Year Statement (GTYS). All our substitution analysis is carried out to the substitution methodology statement rules and, while it is very likely that capacity will be substituted from within a zone, it is not guaranteed.

We have provided a commentary explaining the potential capacity lead times and likelihood of substitution in each zone, including areas of sensitivity. This information is an indication and actual capacity lead times and availability will depend on the quantity of capacity requested from all customers within a zone and interacting zones. This information recognises the impact EMR may have on interest in NTS connections and capacity.

Figure 3.11
NTS exit capacity map



Customer Capacity – Exit

3.5.2 Available (unsold) NTS exit (flat) capacity

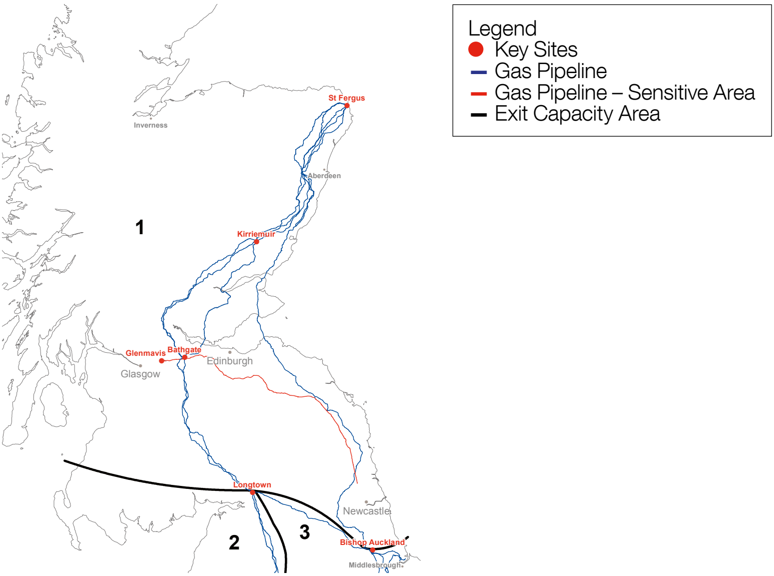
Table 3.2 includes the quantities of unsold NTS exit (flat) capacity in each zone that could be used to make capacity available at other sites through exit capacity substitution. The table also shows how unsold capacity has changed since the publication of the 2014 Gas Ten Year Statement (GTYS).

Table 3.2
Quantities of unsold NTS exit (flat) capacity

Region Number	Region	Obligated	Unsold		
		(GWh/d)	(GWh/d)	% of unsold capacity	% change from 2014 GTYS
1	Scotland & the North	718	108	15%	+7%
2	North West & West Midlands (North)	1,110	347	31%	+3%
2.1	North Wales & Cheshire	315	199	63%	-2%
3	North East, Yorkshire & Lincolnshire	1,570	579	37%	+8%
4	South Wales & West Midlands (South)	569	48	8%	0%
5	Central & East Midlands	281	113	40%	0%
6	Peterborough to Aylesbury	126	29	23%	0%
7	Norfolk	368	121	33%	+4%
8	Southern	526	208	40%	0%
9	London, Suffolk & the South East	1,504	408	27%	+5%
10	South West	461	69	15%	0%

Region 1 – Scotland and the North

Figure 3.12
Region 1 – Scotland and the North



NTS Location:
North of Long Town and Bishop Auckland

NTS/DN exit zones:
SC1, 2, 3, 4, NO1, 2

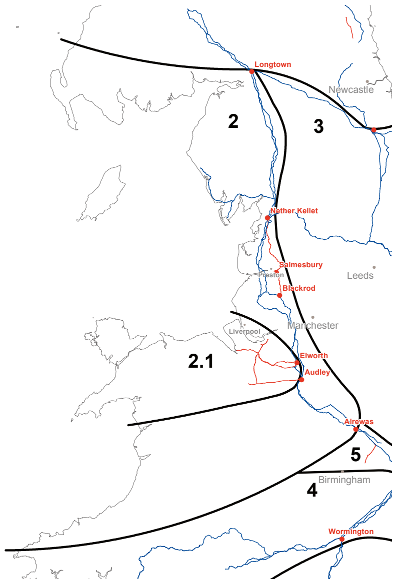
This region is sensitive to St Fergus flows.

High St Fergus flows mean exit capacity will be available. As St Fergus flows reduce, exit capacity will be constrained. There is only a small quantity of substitutable capacity in the area, but compressor flow modifications, including reverse flow capability, can be delivered to provide significant quantities of capacity without requiring Planning Act timescales. Capacity may be more limited in the sensitivity area (feeder 10 Glenmavis to Saltwick) due to smaller diameter pipelines.

Customer Capacity – Exit

Region 2 – North West and West Midlands (North)

Figure 3.13
Region 2 – North West and West Midlands (North)



Legend
- Key Sites
- Gas Pipeline
- Gas Pipeline – Sensitive Area
- Exit Capacity Area

NTS Location:
South of Longtown, north of Alrewas and east of Elworth

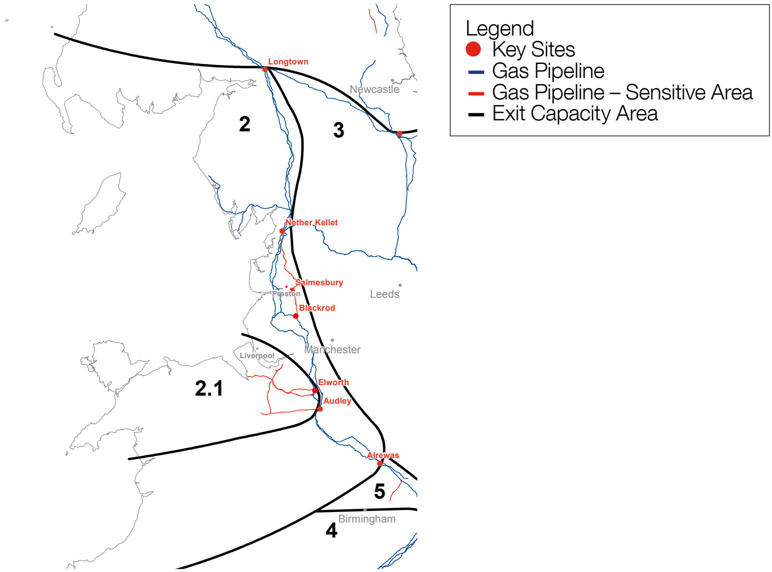
NTS/DN exit zones:
NW1, WM1

The region is highly sensitive to national supply patterns and use of storage; this area was historically supplied with gas from the north but increasingly receives gas from the south and from the east across the Pennines.

The amount of unsold capacity in the region indicates that capacity could be made available by exit capacity substitution. A capacity request in zone 2 is likely to be met through substitution from zone 2, including zone 2.1, and then from the downstream zones, in this case zone 5. Capacity is likely to be available on the main feeder sections between Carnforth and Alrewas. Potential non-Planning Act reinforcements could release capacity, but then significant pipeline reinforcement would be required, particularly in the sensitive region around Samlesbury and Blackrod (North Lancashire and Greater Manchester).

Region 2.1 – North Wales and Cheshire

Figure 3.14
Region 2.1 – North Wales and Cheshire



NTS Location:
West of Elworth and Audley (feeder 4)

NTS/DN exit zones:
NW2, WA1

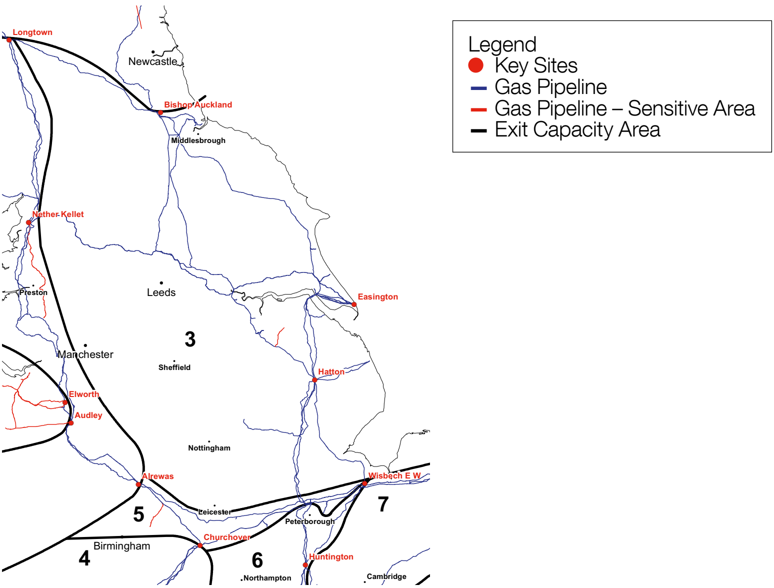
This is an extremity of the system with limited local supplies (Burton Point) but has a significant number of storage facilities.

The quantity of unsold capacity within the region indicates a good probability that capacity could be made available via exit capacity substitution, but this is from direct connect offtakes where the capacity could be booked. Potential non-Planning Act reinforcements could release small amounts of additional capacity, but significant pipeline reinforcement would be required, resulting in long (Planning Act) timescales.

Customer Capacity – Exit

Region 3 – North East, Yorkshire and Lincolnshire

Figure 3.15
Region 3 – North East, Yorkshire and Lincolnshire



NTS Location:
South of Bishop Auckland, north of Peterborough and Wisbech and east of Nether Kellet

NTS/DN exit zones:
NE1, 2, 3, EM1, 2

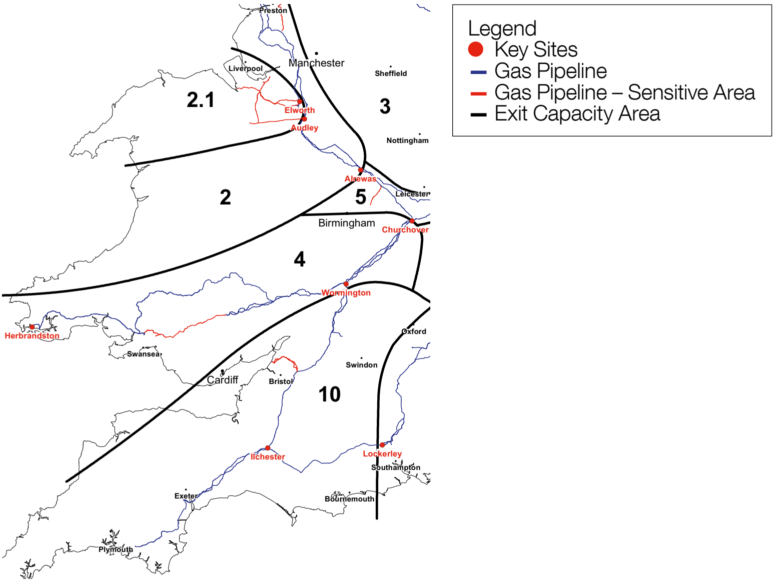
There are a number of power stations in this region and this may impact on future ramp rate agreements (the rate at which flows can increase at an offtake, as set out in the Network Exit Agreement – NExA).

The amount of unsold capacity in the region indicates that capacity could be made available through exit capacity substitution. Further capacity should be available without needing reinforcement, assuming stable north-east supplies; however, this may be limited on smaller diameter spurs, including Brigg (shown as a sensitive pipe).

Non-Planning Act reinforcements, including compressor modifications, could be carried out to make additional capacity available.

Region 4 – South Wales and West Midlands South

Figure 3.16
Region 4 – South Wales and West Midlands South



NTS Location:
West of Churchover

NTS/DN exit zones:
WM3, SW1, WA2

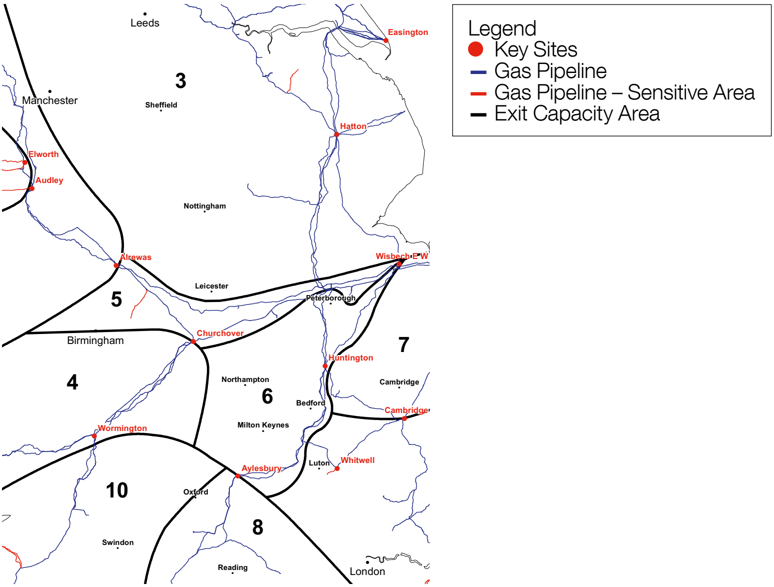
Exit capacity availability is highly sensitive to Milford Haven flows. Low Milford Haven flows result in reduced South Wales pressures, which limit capacity. High Milford Haven flows result in reduced pressures in the West Midlands which may limit capacity.

The quantity of unsold capacity within the region indicates a limited quantity of capacity could be substituted. Potential non-Planning Act reinforcements could release small quantities of capacity, but significant pipeline reinforcement would be required, since the area south of Cilfrew is a sensitive area (shown in red) due to the different pressure ratings.

Customer Capacity – Exit

Region 5 – Central and East Midlands

Figure 3.17
Region 5 – Central and East Midlands



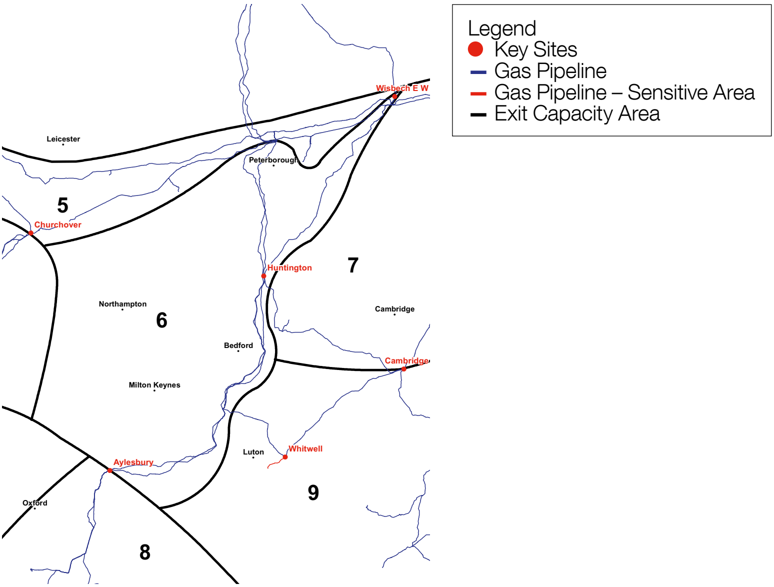
NTS Location:
South of Alrewas, north of Churchover, west of Wisbech

NTS/DN exit zones:
EM3, 4, WM2

The unsold capacity here indicates a limited scope for substitution. Potential non-Planning Act reinforcements could be carried out to release a small amount of capacity, but significant pipeline reinforcement would be required, in particular for the sensitive area Austrey to Shustoke (shown in red).

Region 6 – Peterborough to Aylesbury

Figure 3.18
Region 6 – Peterborough to Aylesbury



NTS Location:
North of Aylesbury, south of Peterborough and Wisbech, west of Huntingdon

NTS/DN exit zones:
EA6, 7

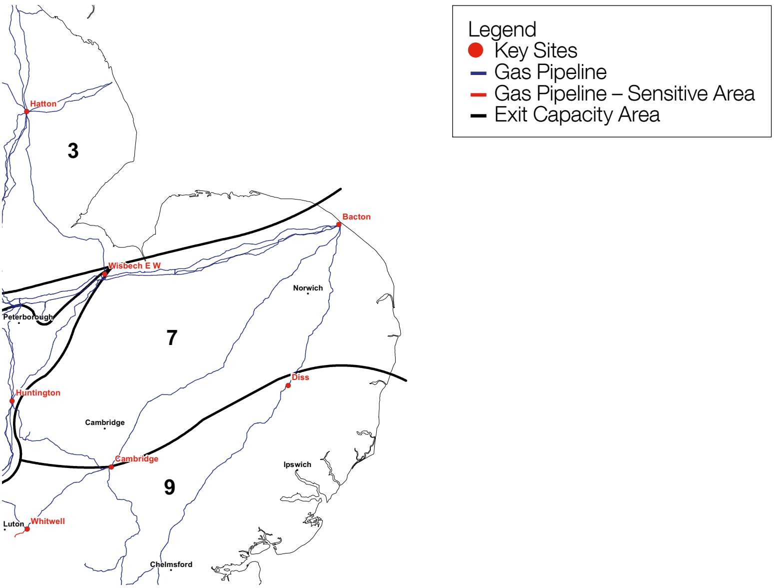
Capacity availability is sensitive to demand increases downstream in region 10, the South West.

The quantity of unsold capacity indicates limited scope for exit capacity substitution from the single offtake in the region, but there may be scope for substitution from the southern region downstream of Aylesbury. Potential non-Planning Act reinforcements could be carried out to release capacity.

Customer Capacity – Exit

Region 7 – Norfolk

Figure 3.19
Region 7 – Norfolk



NTS Location:
North of Diss and Cambridge, east of Wisbech

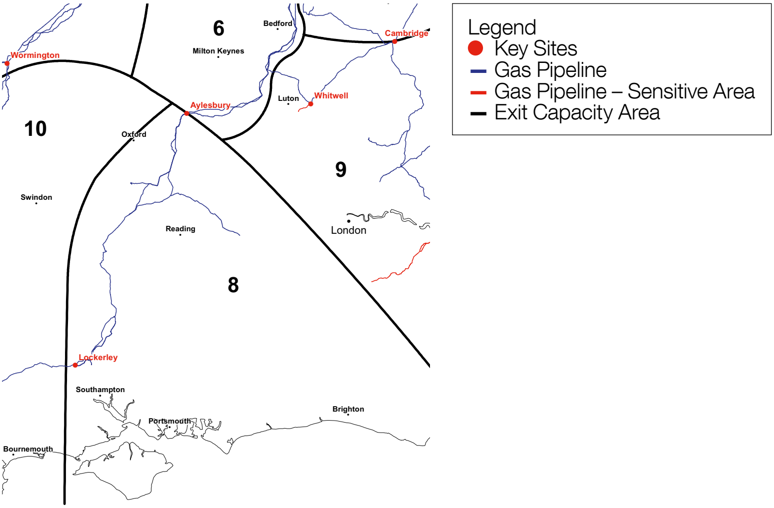
NTS/DN exit zones:
EA1, 2, 3

The region is sensitive to South East demand; if demand increases in the South East, capacity may become more constrained.

Unsold capacity here indicates a good probability that capacity could be substituted. Additional capacity could be made available without reinforcement works, assuming stable Bacton supplies.

Region 8 – Southern

Figure 3.20
Region 8 – Southern



NTS Location:
South of Aylesbury and north of Lockerley

NTS/DN exit zones:
SO1, 2

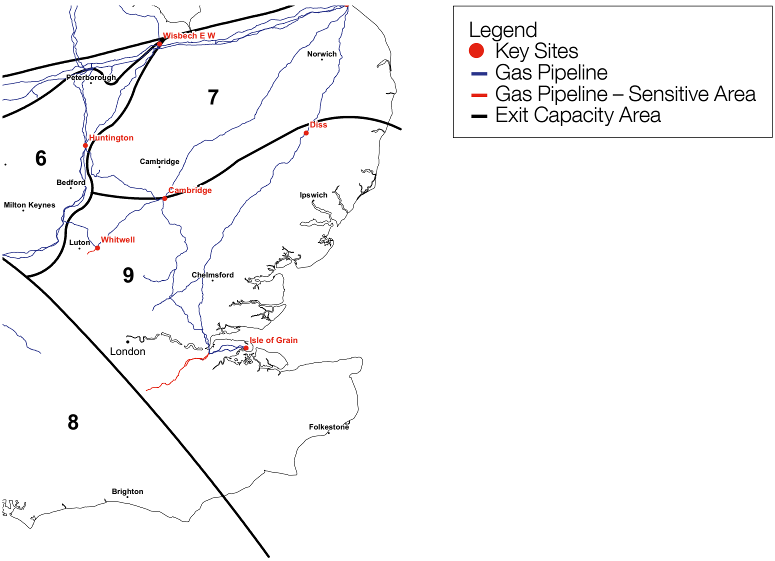
The region is sensitive to demand in the South West; if demand increases, capacity may become more constrained.

The amount of unsold capacity indicates a good chance that capacity could be made available via exit capacity substitution. Potential non-Planning Act reinforcements (compressor station modifications) could release a small amount of capacity.

Customer Capacity – Exit

Region 9 – London, Suffolk and the South East

Figure 3.21
Region 9 – London, Suffolk and the South East



NTS Location:
South Diss, Cambridge, east of Whitwell

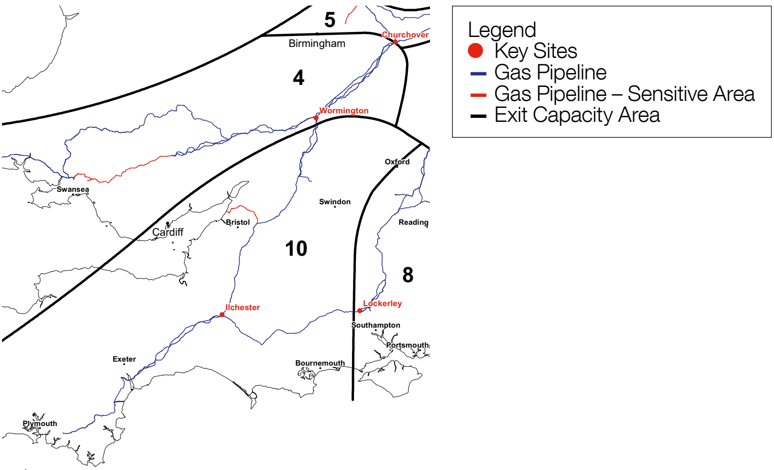
NTS/DN exit zones:
EA4, 5, NT1, 2, 3, SE1, 2

The region is sensitive to Isle of Grain flows, with low flows limiting capacity. Capacity may be more limited in the sensitive areas at the extremities of the system shown in red (Tatsfield, Peters Green). The significant number of power stations in the region may impact on future ramp rate agreements (the rate at which flows can increase at an offtake, as set out in the Network Exit Agreement – NExA).

Unsold capacity indicates a good chance that capacity could be made available via exit capacity substitution, however, exchange rates may vary between locations. Potential non-Planning Act reinforcements could be carried out to release small quantities of additional capacity but significant pipeline reinforcement would be needed.

Region 10 – South West

Figure 3.22
Region 10 – South West



NTS Location:
South of Wormington and Lockerley

NTS/DN exit zones:
SW2, 3

The quantity of unsold capacity in this region indicates limited scope for capacity being made available through exit capacity substitution. Exchange rates may be high due to small diameter pipelines. Potential non-Planning Act reinforcements could release small quantities of additional capacity, but significant pipeline reinforcement would be needed, resulting in long (Planning Act) timescales, particularly in the sensitive area shown in red (west of Pucklechurch on the feeder 14 spur) due to small diameter pipelines. There is some sensitivity to low Milford Haven flows.

Customer Capacity – Exit

3.5.3 Directly Connected exit points

The following Table shows which region the current Directly Connected (DC) offtakes fall within. There are no such offtakes in region 6.

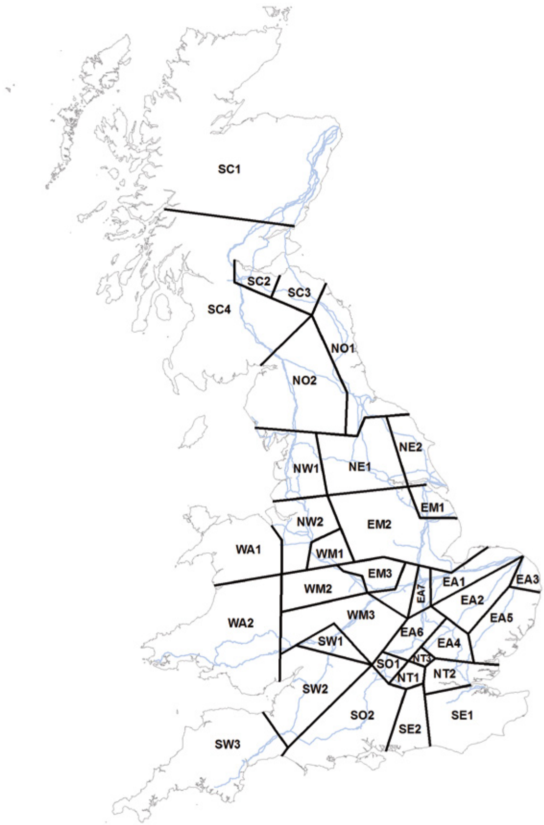
Table 3.3
Direct Connect offtakes by region

Region	Offtake
1	Blackness (BP Grangemouth)
	Cockenzie Power Station
	Glenmavis Max Refill
	Gowkhall (Longannet)
	St. Fergus (Peterhead)
	St. Fergus (Shell Blackstart)
2	Barrow (Bains)
	Barrow (Black Start)
	Barrow (Gateway)
	Carrington (Partington) Power Station
	Caythorpe
	Ferny Knoll (AM Paper)
	Holford
	Partington Max Refill
	Roosecote Power Station (Barrow)
	Sellafield Power Station
	Harwarden (Shotton, aka Shotton Paper)
	Stublach (Cheshire)
	Willington Power Station
	Pickmere (Winnington Power, aka Brunner Mond)
	Wyre Power Station
2.1	Shotwick (Bridgewater Paper)
	Burton Point (Connahs Quay)
	Deeside
	Hole House Max Refill
	Weston Point (Castner Kelner, aka ICI Runcorn)
	Weston Point (Rocksavage)
	Shellstar (aka Kemira, not Kemira CHP)
3	Garton Max Refill (Aldbrough)
	Bishop Auckland (test facility)
	Teesside (BASF, aka BASF Teesside)
	Hatfield Moor Max Refill
	Teesside Hydrogen
	Saltend BPHP (BP Saltend HP)
	Blyborough (Brigg)
	Brine Field (Teesside) Power Station
	Blyborough (Cottam)
	Enron Billingham
	Goole (Guardian Glass)
	Hatfield Power Station
	Hornsea Max Refill
	Billingham ICI (Terra Billingham)
	Thornton Curtis (Humber Refinery, aka Immingham)
	Eastoft (Keadby Blackstart)
	Eastoft (Keadby)
	Phillips Petroleum, Teesside
	Rough Max Refill
	Rosehill (Saltend Power Station)
	Saltfleetby Storage (Theddlethorpe)
	Spalding 2 (South Holland) Power Station
	Wragg Marsh (Spalding)
	Stallingborough
	Staythorpe
	Sutton Bridge Power Station
	Thornton Curtis (Killingholme)
	West Burton Power Station
	Zeneca (ICI Avecia, aka 'Zenica')
4	Tonna (Baglan Bay)
	Dynevor Max Refill
	Pembroke Power Station
	Upper Neeston (Milford Haven Refinery)
5	Caldecott (Corby Power Station)
	Drakelow Power Station
	Peterborough (Peterborough Power Station)
7	Bacton (Baird)
	Deborah Storage (Bacton)
	Saddle Bow (Kings Lynn)
	St. Neots (Little Barford)
8	Didcot
	Barton Stacey Max Refill (Humbly Grove)
9	Barking (Horndon)
	Coryton 2 (Thames Haven) Power Station
	Stanford Le Hope (Coryton)
	Middle Stoke (Damhead Creek, aka Kingsnorth Power Station)
	Epping Green (Enfield Energy, aka Brimsdown)
	Grain Power Station
	Bacton (Great Yarmouth)
	Medway (aka Isle of Grain Power Station, NOT Grain Power)
	Ryehouse
	Tilbury Power Station
10	Avonmouth Max Refill
	Centrax Industrial
	Langage Power Station
	Marchwood Power Station
	Seabank (Seabank Power Station phase II)
	Abson (Seabank Power Station phase I)
	Terra Nitrogen (aka ICI, Terra Severnside)

3.5.4 NTS/DN exit zones

Figure 3.23 and Table 3.4 show which distribution network exit zones the current NTS/DN offtakes fall within.

Figure 3.23
NTS exit zones



Customer Capacity – Exit

Table 3.4
NTS/DN exit zones

Exit Zone	Offtake
EA1	Eye
	West Winch
	Brisley
EA2	Bacton Terminal
	Great Wilbraham
	Roudham Heath
EA3	Bacton Terminal
	Yelverton
EA4	Matching Green
	Royston
	Whitwell
EA5	Hardwick
EM1	Thornton Curtis 'A'
	Walesby
EM2	Kirkstead
	Sutton Bridge
	Silk Willoughby
	Gosberton
	Blyborough
EM3	Alrewas Compressor
	Blaby
	Tur Langton
EM4	Market Harborough
	Caldecott
NE1	Towton
	Rawcliffe
	Baldersby
	Pannal
	Asselby
	Burley Bank
NE2	Ganstead
	Hornsea
	Easington
	Pickering
	Paull
NO1	Guyzance
	Cowpen Bewley
	Coldstream
	Corbridge
	Thrintoft
	Saltwick
	Humbleton
	Little Burdon
	Elton
NO2	Wetheral
	Keld
	Tow Law
NT1	Winkfield (NIL)
NT2	Horndon 'A'
NT3	Peters Green
NW1	Blackrod
	Samlesbury
	Lupton
NW2	Mickle Trafford
	Malpas
	Warburton
	Weston Point
	Holmes Chapel
	Eccleston
	Audley
SC1	Careston
	Balgray
	Kinknockie
	Aberdeen
SC2	Broxburn
	Armadale
SC3	Hulme
	Soutra
SC4	Nether Howleugh
	Lockerbie
	Pitcairngreen BV
SC4	Drum
SE1	Tatsfield
	Shorne
	Farningham
	Isle of Grain (LNG
SE2	Winkfield (SE)
SO1	North Stoke (Ipsden)
SO2	Mappowder
	Braishfield 'A'
	Winkfield (SO)
SW1	Fiddington
	Evesham
	Ross
SW2	Littleton Drew
	Avonmouth (LNG)
	Easton Grey
	Cirencester
	Ilchester
	Pucklechurch
SW3	Kenn (South)
	Aylesbeare
WA2	Dyffryn Clydach
	Dynevor Arms Tee
	Gilwern
WM1	Aspley
	Audley
	Milwich
WM2	Shustoke
	Austrey
	Alrewas Compressor
WM3	Ross
	Rugby
	Leamington Spa
	Stratford-Upon-Avon

Customer Capacity – Entry

3.6
Customer capacity – entry

As with exit capacity it is important for us to understand our customers' gas supply (entry capacity) requirements to the NTS to again allow us to plan and operate our system efficiently and effectively. When we receive an entry capacity request we analyse our current system to assess what impact an increase in supply at a particular part of our system has on the current capability. This allows us to identify and plan for any geographical constraints which may arise from an increase in customer entry capacity in a particular area of the NTS. Where constraints to current system capability are encountered we use the NDP to identify options to meet our customers' needs in the most cost effective and efficient way.

This section contains information about capacity availability and the lead time for providing NTS entry capacity as a guide for shippers and developers. Unsold NTS entry capacity available at an existing Aggregate System Entry Point (ASEP) can be accessed via the daily, monthly and annual entry capacity auction processes. If unsold capacity is not available, including at new entry points, the lead times may be longer.

We aim to help you understand the likely lead time associated with new entry points. New entry points can result in significant changes to network flow patterns and we encourage you to approach our customer service team to discuss specific requirements. This information is just an indication; actual capacity availability will depend on the amount of capacity requested from all customers at an ASEP and interacting ASEPs.

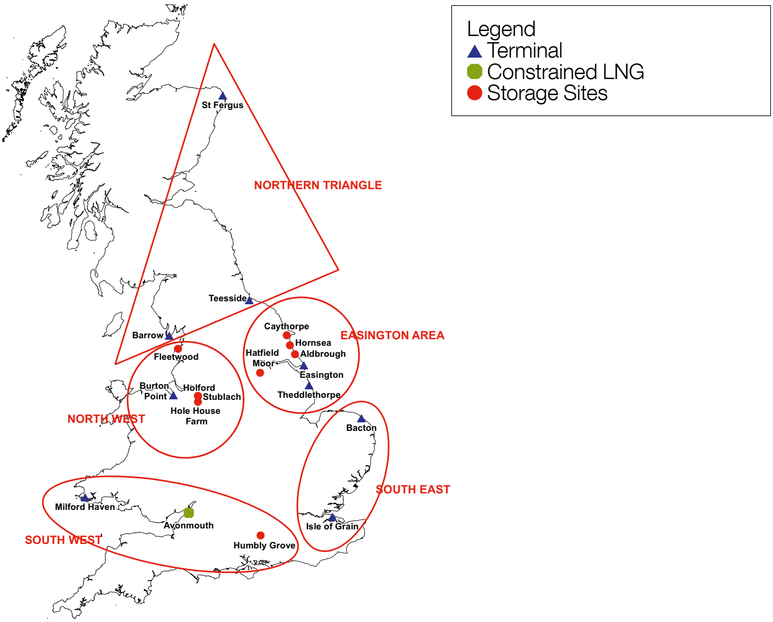
3.6.1 Entry planning scenarios

Chapter 2, section 2.2 discussed the uncertainties in the future supply mix that arise from both existing supplies and potential new developments. The available supplies, in aggregate, are greater than peak demand. The supply uncertainty is further increased by the Gas Transporters Licence requirements for us to make obligated capacity available to shippers up to and including the gas flow day. This creates a situation where we are unable to take long-term auctions as the definitive signal from shippers about their intentions to flow gas. We are continuing to develop our processes to better manage the risks that arise from such uncertainties as part of our System Flexibility work.

To help understanding of entry capability, we use the concept of entry zones which contain groups of ASEPs (Figure 3.24). These zones are discussed in further detail in 3.6.2. The entry points in each zone often make use of common sections of infrastructure to transport gas, and therefore have a high degree of interaction. There are also interactions between supplies in different zones which mean that interactions between 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 where shared infrastructure assists capacity provision at both ASEPs by moving gas east–west or west–east across the country.

Customer Capacity – Entry

Figure 3.24
Zonal grouping of interacting supplies



Key scenarios we examine through the 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, including IUK export.

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, we may also investigate several **commercially driven sensitivities**. For example, a sensitivity scenario with a reduction in imported gas balanced by high medium-range storage entry flows to meet winter demand.

Historically, we have considered these scenarios on an individual basis using 'steady state' gas flows consistent with an overall 'end of day' energy balance. As customer requirements from the network evolve, it is increasingly necessary for us to consider the ability of the system to switch between different flow scenarios, explicitly considering changing flows on the network.

If this technique indicates that future requirements from the network are outside of current capability, we would investigate a range of possible solutions (regulatory, commercial and physical). This ensures that a broad spectrum of solutions is identified. Where investment in assets is the optimum solution, we would carry out further optioneering through the planning process.

3.6.2 Available (unsold) NTS entry capacity

Table 3.5 indicates the quantities of obligated and unsold NTS entry capacity at each ASEP within each entry zone. This unsold capacity (obligated less any previously sold) is available at each relevant ASEP and could also be used to make capacity available at other ASEPs through entry capacity substitution. Substitution may also be possible across entry zones.

Table 3.5
Quantities of entry capacity by zone

Entry Zone	ASEP	Obligated Capacity GWh/day	Unsold Capacity 2015/2016 GWh/day	Unsold Capacity 2019/2020 GWh/day	Unsold Capacity 2022/2023 GWh/day
Northern Triangle	Barrow	340.01	30.91	37.06	60.27
	Canonbie	0	0	0	0
	Glenmavis	99	99	99	99
	St Fergus	1,670.70	1,180.61	1,547.43	1,635.89
	Teesside	445.09	212.87	354.3	414.52
North West	Burton Point	73.5	45.09	60.36	73.5
	Cheshire	542.7	28.59	28.59	28.59
	Fleetwood	650	650	650	650
	Hole House Farm	296.6	0	13.16	13.16
	Partington	215	215	215	215
Easington Area	Caythorpe	90	0	0	0
	Easington (incl. Rough)	1,407.15	103.12	106.20	138.28
	Garton	420	0	0	0
	Hatfield Moor (onshore)	0.3	0.3	0.3	0.3
	Hornsea	233.1	27.31	27.31	27.31
	Hatfield Moor (storage)	25	3	3	25
	Theddlethorpe	610.7	586.31	601.5	610.7
South West	Avonmouth	179.3	179.3	179.3	179.3
	Barton Stacey	172.6	82.6	82.6	172.6
	Dynevor Arms	49	49	49	49
	Milford Haven	950	0	0	150
	Wytch Farm	3.3	3.3	3.3	3.3
South East	Bacton	1,297.80	608.11	1,020.59	1,181.50
	Bacton UKCS	485.60	0.00	0.00	0.00
	Isle of Grain	699.68	43.6	35.38	35.38

Customer Capacity – Entry

Table 3.5 contains the ASEP names as defined in the NTS Licence. For clarity, the Garton ASEP contains the Aldborough storage facility, the Barton Stacey ASEP contains the Humbly Grove storage facility, and the Cheshire ASEP contains the Hill Top Farm, Holford and Stublach gas storage facilities. More information on storage facilities can be found in Appendix 5 table A5.4.

Appendix 5 figures A5.2 A to H provide further information about the level of booked and obligated entry capacity at each ASEP, excluding those that are purely storage. The figures also provide data points representing historic maximum utilisation and the range of future peak flow scenarios for these ASEPs. While all un-booked capacity can be considered for entry capacity substitution, future bookings may change and the gap between the scenario peak flow data and the obligated capacity level may be a better indication of the capacity available for substitution. Using this indicator, significant capacity for substitution exists at St Fergus and Theddlethorpe.

Entry Zone – Northern triangle

ASEPs: Barrow, Canonbie, Glenmavis, St Fergus, Teesside (and Moffat)

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.

The amount of unsold capacity in this region, combined with the reduced St Fergus forecast flows, indicates a high likelihood that capacity could be made available through entry capacity substitution. Potential non-Planning Act reinforcements, including compressor reverse flow modifications, could release further quantities of additional capacity.

Entry Zone – North West

ASEPs: Burton Point, Cheshire, Fleetwood, Hole House Farm, Partington

These five ASEPs use common infrastructure and the main west coast transportation route to move gas into the rest of the system.

The unsold capacity in this region indicates that some capacity could be made available via entry capacity substitution; however, entry capability will not necessarily match entry capacity and exchange rates may be greater than one to one. Potential non–Planning Act reinforcements, including compressor reverse flow modifications, could release additional capacity but significant pipeline reinforcement would then be required, resulting in long (Planning Act) timescales.

Entry Zone – Easington area

ASEPs: Caythorpe, Easington (incl. Rough), Garton, Hatfield Moor (onshore), Hornsea, Hatfield Moor (storage), Theddlethorpe
All these ASEPs use common routes out of the Yorkshire area.

The quantity of unsold capacity in this region indicates a limited scope for additional capacity to be made available via entry capacity substitution. Potential non-Planning Act reinforcements, including compressor reverse flow modifications, could release some additional capacity but significant pipeline reinforcement would be needed, resulting in long (Planning Act) timescales.

Entry Zone – South West

ASEPs: Avonmouth, Barton Stacey, Dynevor Arms, Milford Haven, Wytch Farm

This zone enables sensitivity analysis around potential LNG supplies from Milford Haven.

The quantity of unsold capacity in this zone is principally at the Avonmouth and Dynevor Arms ASEPs associated with the LNG storage facilities. Due to the short duration of deliverability of these facilities, it is unlikely that the capacity could be made available for entry capacity substitution other than for equivalent facilities. Significant pipeline reinforcement and additional compression would be required to provide incremental capacity resulting in long (Planning Act) timescales.

Entry Zone – South East

ASEPs: Bacton UKCS, Bacton IP, Isle of Grain

The ASEPs use common infrastructure away from the Bacton area.

While there is a high degree of interaction between the Bacton (UKCS & IP) and Isle of Grain ASEPs, the quantity of unsold capacity in this zone cannot be interpreted as an indication of suitability for entry capacity substitution. This is due to constraints on the network in terms of the ability to transport gas south to north. Potential non Planning Act reinforcements, including compressor reverse flow modifications, could release some additional capacity, but significant pipeline reinforcement would then be required resulting in long (Planning Act) timescales.

Impact of Legislative Change

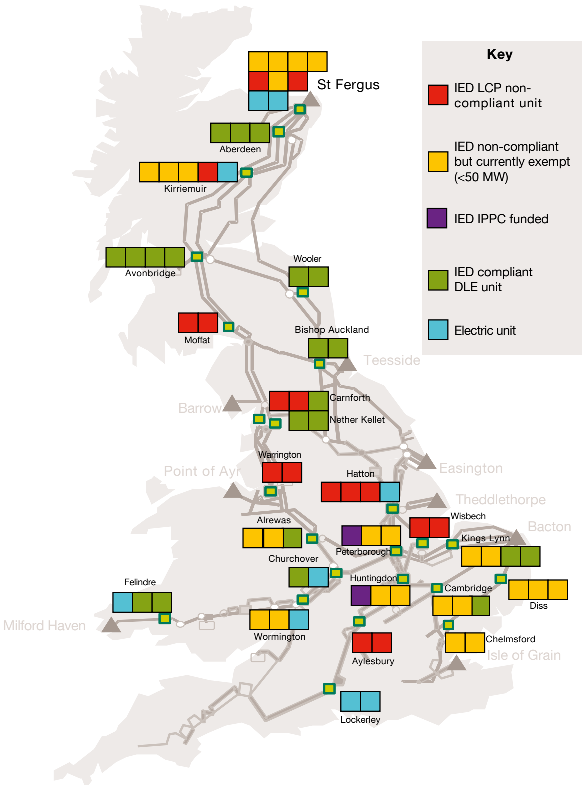
3.7
Impact of legislative change

Industrial Emissions Directive

As we outlined in Chapter 2.3, two elements of IED, the Integrated Pollution Prevention and Control Directive (IPPC) and the Large Combustion Plant Directive (LCP) directive, heavily impact our current compressor fleet (Figure 3.25).

The following sections detail the impact of the legislation before Chapter 5 covers what we are doing to address these legislative changes to ensure our compressor fleet is compliant by 2023.

Figure 3.25
Impact of IED on our current compressor fleet[6]



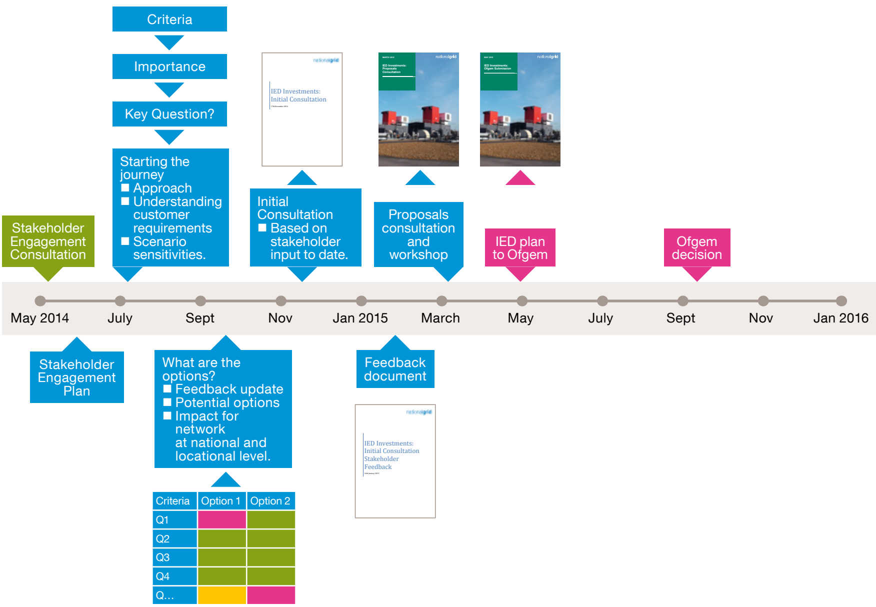
3.7.1 IED stakeholder engagement

We held several stakeholder consultation events in 2014–15 to get industry input on what options we should consider to meet the IED requirements. During these events our stakeholders helped us to develop the Gas Network Development scorecard to identify key network capability criteria. We published two documents following these events: IED Investments: Initial Consultation[7] and IED Investments: Proposals Consultation[8].

Figure 3.26 outlines the stakeholder consultation process we followed for IED along with the key outputs developed following your feedback.

During the consultation process the general stakeholder consensus was for us to, where possible, use the derogations available to enable us to keep our options open with the uncertainty around the upcoming legislation.

Figure 3.26
IED timeline



[6] After seeking further clarification, one of the units at St Fergus was re-classified and so is not subject to LCP. Therefore, in this document you will see reference to 16 units rather than 17.

[7] http://consense.opendebate.co.uk/files/nationalgrid/transmission/IED_Investments_-_Initial_Consultation_17Nov2014.pdf

[8] http://consense.opendebate.co.uk/files/nationalgrid/transmission/IED_Investments_Proposals_Consultation_.pdf

Impact of Legislative Change

3.7.2 Medium Combustion Plant (MCP) Directive

The MCP directive, which is currently in draft, will apply emission limits to all units below 50 MW thermal input. As this directive has not been implemented we are not sure exactly what impact this will have on our compressor fleet. Based on the draft MCP directive, it could potentially impact 26 of our gas-driven units.

Over the next year we anticipate more analysis to be undertaken on our compressor fleet to assess what impact this legislation will have. We will then be approaching the industry again to get input on how we should approach complying with this new legislation.

3.7.3 Best Available Technique References (BREF)

As defined in Chapter 2, section 2.3 BREF has been adopted under IPPC and IED. The BREF for combustion plant is currently in draft form and is due to be finalised in 2016. We will be taking BREF into account when determining the Best Available Technique (BAT) for all options considered on IED non-compliant units going forward. We do not anticipate any significant changes to the BAT process we currently follow when assessing our compressor options.

Chapter four

System Operation

What are System Operator Capabilities?

Deciding between System Operator Capabilities and Assets?

Investing in our System Operator Capabilities

Deferred Asset Investments

Establish Portfolio

Risks of 'Do Nothing' option. Consider 'rules', 'tools' and 'assets'.

System Operation

This chapter describes how we are investing in our capabilities as System Operator to make the most of our network. These investments mean we can continue to plan to operate, and then operate, our network safely and efficiently.

The non-asset solutions, the 'rules and tools', we are developing are triggered as part of the Establish Portfolio stage of our Network Development Process; we discuss this progression in more detail.

Key messages

- As System Operator we must provide a safe and reliable network for you to use. We know you want to flow gas using within-day profiles that meet your operational, commercial and contractual drivers, and you want minimal restrictions
- Our challenge is to make the most efficient investment decisions to make the most of our existing network before we build new assets
- We are enhancing our capabilities as the System Operator by improving our processes and investing in our systems and tools
- We are deferring investment in assets by continuously improving our approach to optimise our existing network.

Introduction

4.1 Introduction

As System Operator (SO), our primary responsibility is to transport gas from supply points to offtakes providing a safe and reliable network for you to use. Where operational strategies cannot be used to maintain transportation of supply we need to make physical changes to our network. These physical changes are outlined in Chapter 5. Here we discuss how we operate our current network. The way we operate the National Transmission System (NTS) is affected by a number of obligations.

Safety and system resilience:
- We must plan and develop the NTS to meet Pipeline System Security Standards
- We must maintain NTS pressures within safe limits
- We must maintain the quality of gas transported through the NTS to meet the criteria defined within the Gas Safety (Management) Regulations (GS(M)R) to comply with UK gas appliances.
- We must maintain network capabilities to effectively manage or mitigate a gas supply emergency.

Environment:
- We must minimise our environmental impact.

Facilitating efficient market operation:
- We must meet the pressures contractually agreed with our customers
- We must provide you with information and data that you need to make effective and efficient decisions
- We must make NTS entry and exit capacity available in line with our licence obligations and contractual rights
- We must take commercial actions in the event that system capability is lower than contractual rights
- We must manage gas quality (calorific value) at a zonal level to ensure consumers are fairly billed for the gas they use
- We must optimise the use of NTS infrastructure.

You have told us that you value the ability to flow gas using within-day profiles to meet your operational, commercial and contractual needs, with minimal restrictions. You want us to maximise our performance in this area. To do this, we are focusing on:

- Operating the NTS effectively and efficiently to maximise its capability while meeting our statutory and commercial obligations
- Developing methods to quickly identify, manage and mitigate any network issues to minimise the impact on you
- Optimising, scheduling and managing access to the NTS for maintenance and construction activities to minimise the impact on you
- Providing you with flexibility to flow gas at the most efficient profile for you, even where this flexibility exceeds contractual rights. As you would expect, we must make sure that this operational flexibility does not create unacceptable system risks or have a detrimental impact on our other customers.

So our challenge is to maximise value from our existing network by investing in our capabilities as the SO.

In this chapter we describe current and planned developments to our SO capabilities and explain how we make decisions between investing in our capabilities and installing new assets.

What are System Operator Capabilities?

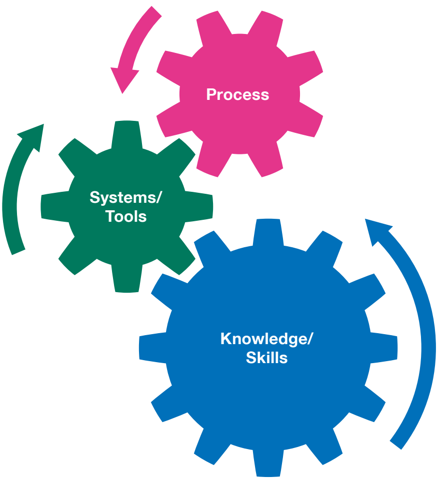
4.2
What are System Operator Capabilities?

Our SO capabilities describe what we need to do to be able to produce outputs that, when combined, deliver the most value for you.

Figure 4.1
Examples of some of the inputs and outputs from our SO capability

To make sure our outputs are fit for purpose, each SO capability requires a combination of efficient business processes, effective technology (systems/tools), skilled and knowledgeable people.

Figure 4.2
Key inputs required for our SO capabilities



Deciding between System Operator Capabilities and Assets?

4.3
Deciding between System Operator capabilities and assets?

We use our Network Development Process (NDP) to assess system capability requirements; this was introduced in Chapter 1. Here we discuss how we consider and improve the capability of the system and use the NDP to assess our capability as System Operator (SO).

Following on, Chapter 2 explored some of the triggers for this process and Chapter 3 described the Need Case stage of the NDP where we calculate the NTS's capability requirements.

Understanding our system capability and our capability as the SO allows us to determine where rules, tools or asset solutions need to be found to meet our customer requirements. This chapter will discuss where, as SO, we can better use rules and tools to make more efficient use of the system. Chapter 5 will follow on from this by discussing how the asset solutions are developed.

Under RIIO, we are incentivised to think about Total Expenditure (TOTEX) as well as Capital Expenditure (CAPEX) and we need to demonstrate good value for money. We therefore focus on the need of the SO, both now and in the future, when considering the solutions to meeting our system capability requirements.

We do this through the use of our Whole Life Prioritisation scoring model as detailed in Appendix 7. This uses a qualitative approach comparing a range of solutions against key criteria including: flexibility, customer charges, future proofing, current capability and obligations, resilience, and barriers to new investment. We use this scoring method to rank the available options for the next stages of our processes. These can be asset solutions or non-asset solutions or sometimes a combination of the two. At the Establish Portfolio stage no options are fully discounted nor final choices made. These are the least regrets options used to set the bounds for further investigation and options development. Should optioneering result in the breaking of these bounds the projects will return to earlier stages of the process for reassessment.

An asset solution may not always be the most efficient way to meet a system capability requirement and deliver financial benefits to the industry and consumers by reducing costs and minimising the risks of balancing the system. We therefore, in our role as SO, consider our non-asset solutions.

A non-asset solution, in simple terms, is where we 'sweat our assets' by assessing what the maximum capability is of our existing network. We also look at contractual solutions. We may be willing to accept commercial risk rather than invest in a more expensive asset solution; an example of where we have done this is at Avonmouth detailed in section 4.5. We actively work with our customers to ensure we understand their needs and that together we can make informed decisions that are right for end consumers. Later on in this chapter we will give some examples of work we are doing in this area.

We are constantly reviewing our current systems and processes in order to refine what we do and how we do it. This maximises the value we get from our existing network (through improved forecasting, analysis, risk assessment and decision making (across all time horizons)) before we invest in asset solutions.

Investing in our System Operator Capabilities

4.4
Investing in our System Operator capabilities

Our SO capabilities can be grouped into categories, these have been summarised in Figure 4.3 below.

Figure 4.3
Examples of our SO capabilities

- Commercial Balancing, Settlement & Wholesale Operation
  - Information Provision & Market Facilitation
  - NTS Shrinkage Management
  - NTS Capacity Management
  - Energy Balancing & Settlement
  - Energy Trading & Risk Management
- Operational
  - Supply & Demand Forecasting
  - Planning
  - Operational Strategy
  - Operational Control
  - Situational Awareness
  - Review
  - Emergency Planning & Management
- Support & Change
  - Business Support
  - Systems Support
  - Customer & Stakeholder Management
  - Capability and Change Management
  - Leadership & Governance

In the following sections we focus on our operational capabilities. We use a combination of these capabilities to deliver our daily operational strategies and plans which make sure we provide a safe and reliable network for you.

Figure 4.4
How our operational capabilities link together

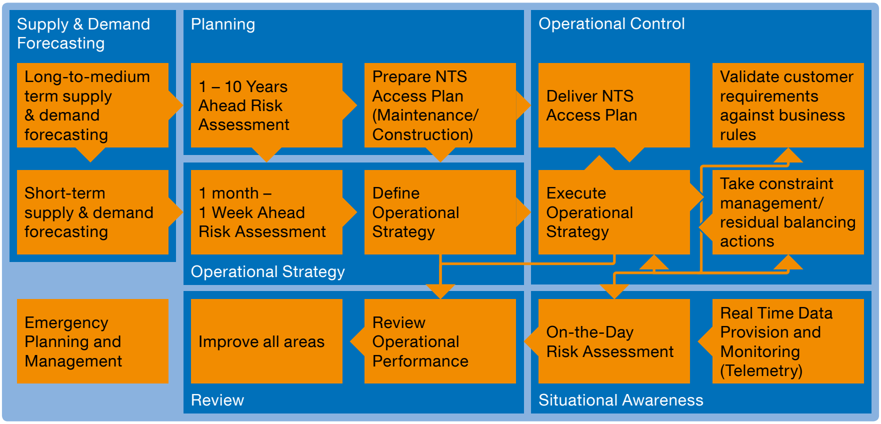


Figure 4.4 above shows how information flows between our operational capabilities; it does not represent our organisational structure. We are committed to developing our people to make sure they have the right knowledge, skills and experience to drive efficiency and maximise our process and system performance to deliver a reliable network for our customers.

The following tables provide more detail on each of our operational capabilities including how we are improving our processes, and what investments we are making to develop our systems and tools.

Investing in our System Operator Capabilities

4.4.1 Supply and demand forecasting

What is it?

- Effective and accurate forecasting is critical to our SO decision-making processes, particularly with increasingly uncertain future supply and demand patterns
- Our supply and demand forecasts are based on our Future Energy Scenarios as well as latest market information. Forecasts are produced annually, monthly, weekly and daily, depending on the time horizon being forecast
- The forecasts we produce are used by all of our operational capabilities.
- The forecasts feed into Planning (one to ten years ahead), Operational Strategy (one month to one week ahead), Operational Control and Operational Situational Awareness in real time.
- We share our forecasts with you through our information provision systems to facilitate an efficient market[1], by helping you manage your supply/demand balance position.

Drivers for change

- Diversity of supply imports
- Increased arbitrage through interconnectors
- Changes in UK installed gas generation capacity and gas/coal forward spread
- Price sensitive operation of fast cycle storage.

How are we improving?

Process

Long to medium term

- We continuously improve our long-to-medium term supply and demand forecasts by ensuring we have an effective feedback loop from the operational and short-term teams to the longer-term forecasting teams to capture and resolve any data gaps or inconsistencies quickly.

Short term

- We aim to maximise the efficiency of our current processes using our existing tools and systems. As we develop new forecasting tools, we revise and optimise our existing processes to make the most of the new technology.

Chapter four

[1] http://marketinformation.natgrid.co.uk/gas/frmPrevalingView.aspx

Systems/Tools
Long to medium term ■ As we discussed in Chapter 3 we are working with Baringa Partners LLP to develop the GasFlexTool. This tool will allow us to produce a large number of supply and demand scenarios into the future, based our Future Energy Scenarios (FES). The additional functionality of this tool provides significant benefits in ensuring that our network, and our capabilities as the System Operator, enable us to meet our customers' requirements. You can find further information on the GasFlexTool in Chapter 3.
Short term ■ We have initiated a project to develop a new prototype for short-term supply and demand forecasting. The project will deliver enhanced modelling of market behaviours that currently limit our forecasting abilities (e.g. price sensitivities and interactions between gas and electricity markets). It will provide more detailed outputs to feed into our other operational capabilities (e.g. supply and demand ranges with confidence levels and improved within-day flow forecasts) ■ This will help us to plan to configure our network on a day-to-day basis to continue to meet your flow and pressure requirements in an evolving operational environment ■ This prototype will be funded via our Network Innovation Allowance ■ Once delivered, tested and proven capable, the prototype will be incorporated into our core control room and support systems.

Investing in our System Operator Capabilities

4.4.2 Planning

What is it?

- Planning considers a time horizon of approximately one to ten years ahead. Analytical risk assessments (incorporating commercial and physical factors) are used to identify and quantify possible future system constraints, which may affect our system capability
- We assess the capability of our system to operate safely while meeting our regulatory and contractual obligations, e.g. Assured Offtake Pressures (AOP), while delivering your anticipated flow profile requirements
- If the network has insufficient capability we are able to use our SO constraint management tools, such as capacity substitution, bilateral contracts, constrained Liquefied Natural Gas (LNG) and on-the-day flow swaps as part of long-term commercial and operational strategies to deliver a reliable service for you
- We consider whether variations to existing industry rules and our associated obligations would impact our network capability
- Other outputs from Planning include our NTS Access Plan where we agree mutually acceptable timescales with the TO for maintenance and construction activities. This enables us to notify you when critical maintenance activities affecting your assets will be carried out
- As described in Chapter 2, our focus on asset health means that we are likely to be undertaking a larger number of maintenance activities than we have in the past. Our aim is always to minimise the impact on you by effective works planning and clear communications
- In Planning we also identify a Need Case for Operating Margins (OM) gas. We can use OM when there is an operational balancing requirement which cannot be satisfied by taking other system balancing actions or as a result of damage or failure on any part of the NTS.

Drivers for change

- Increased number of possible future supply and demand forecasts
- Large day-to-day and within-day change in supply and demand
- Our large programme of asset health works out to 2021.

How are we improving?

Process

- We continue to develop improved relationships and ways of working with our TO colleagues to ensure that construction and maintenance activities can be delivered without affecting our ability to provide a safe and reliable network for you
- At the end of this chapter we describe in more detail how improvements to our processes for assessing the Need Case for Operating Margins (OM) gas has allowed us to defer asset investment as a result of the anticipated closure of Avonmouth LNG facility
- We are exploring changes to the way Assured Offtake Pressures (AOP) are agreed between ourselves and Distribution Network Operators (DNO). Changing this process may improve our current network capability, enabling us to defer asset investment.

Systems/Tools

- Given the increasingly uncertain environment, and the time horizons being considered in Planning, the number of possible supply and demand forecasts that we need to consider has increased in recent years. The ability to effectively analyse this wide range of scenarios in order to understand the impact on system operation and capability is becoming increasingly critical
- We have developed our ability to complete Multi-Scenario (or 'Batch') Network Analysis. This allows us to better understand the operational impact of more supply and demand forecasts (using our existing network analysis software) than we have been able to in the past
- We can use the Multi-Scenario Analysis approach to assess future Need Cases. When combined with the improvements in long-to-medium term supply and demand forecasting, this will enable us to develop more comprehensive, robust and probabilistic long-term commercial, investment and operational strategies, thereby minimising costs for the community
- These improvements will also allow us to develop a more informed NTS Access Plan with reduced risk of maintenance activities on your assets being cancelled or deferred as a result of operational constraints
- The next steps in the evolution of these network analysis enhancements will be to add functionality to automatically update our network model to remove / modify any assets which are planned to be out of service for the time period being considered / analysed. This is currently a lengthy manual process and reduces the time available for our experts to develop long-term commercial and operational strategies which deliver value for you.

Investing in our System Operator Capabilities

4.4.3 Operational Strategy

What is it?

- In Operational Strategy we develop short-term plans to ensure that we can configure our network and associated assets in an optimum configuration to meet your flow and pressure requirements on each gas day
- These short-term plans are developed from approximately one month ahead, through to week-ahead and end with on-the-day control room support. Our plans are based on our long-term risk assessments and are continually refined and optimised using up-to-date market and customer intelligence plus the latest supply and demand forecasts
- Our short-term plans identify and mitigate risks to the safe and reliable operation of the system. We provide our control room with the latest, up-to-date commercial and physical information so that they can facilitate NTS access while maximising the capability of the network for you to use
- We identify opportunities to perform against our SO incentives, which have been structured and agreed with the regulator to deliver value for our customers and stakeholders.

Drivers for change

- Large day-to-day and within-day change in supply and demand
- Price sensitive operation
- Shorter customer notice periods, particularly in response to changes in the electricity market.

How are we improving?

Process

- We regularly review and develop our Operational Strategy processes to ensure efficiency and to confirm that we are continuing to deliver the needs of our control room, who, in turn, deliver for you.

Systems/Tools

- The Multi-Scenario (or ‘Batch’) Network Analysis enhancements described in our Planning capability are also being used to realise benefits in Operational Strategy. These analysis enhancements allow us to target our efforts into more detailed, in-depth analysis for areas at higher risk of impacting our ability to meet customer requirements or where there are system improvement opportunities for the SO
- We plan to add future functionality to automatically undertake ‘What If’ analysis. This will help us to quickly understand the impact of unforeseen events such as large supply losses or asset outages and what impact this has on our ability to deliver the profiles and pressures that you want
- These enhancements, when combined with the improvements in short-term supply and demand forecasting described earlier, and improved visualisation of analysis results, will allow us to provide more informed and optimised plans to the control room to mitigate the risk of your operation being affected.

4.4.4 Operational Situational Awareness

What is it?

- Operational Situational Awareness is the first of our operational capabilities that relates to the real-time operation of the NTS
- During day-to-day operation, our control room must be aware of the level of operational risk and how this affects our ability to meet our daily customer requirements. Real-time information allows us to make informed decisions to ensure that we efficiently operate the system so that you can flow gas safely
- We continuously monitor and assess both the current and predicted status of assets, flows, pressures, linepack, gas quality parameters and national energy balance
- Operational Situational Awareness and Operational Control could be considered as a single capability. In Operational Situational Awareness we receive, process, and interpret real-time data to determine current and future operational risks. In Operational Control we resolve any system issues to maintain safe and efficient operation.

Drivers for change

- Within-day change in supply and demand
- Price sensitive operation
- Increasing range of quality of gas (within GS(M)R limits).

How are we improving?

Process

- In line with the replacement of our existing operational systems, new fit for purpose processes will be developed and implemented where appropriate.

Systems/Tools

- We are replacing our current core control room and support systems. This programme of work is being developed and implemented in phases. The new systems and infrastructure will be scalable, simpler to maintain and configured to facilitate future change more easily
- We continue to develop the use of the 'Online' version of our network analysis software in our control room. SIMONE (Online) is connected to our Supervisory Control and Data Acquisition SCADA systems and receives your flow notifications as well as our telemetered data. SIMONE allows us to undertake current state and predicted future operational risk assessments. We are developing enhancements that will maximise the benefits of real-time simulation to provide continuous advice to our control room. This will allow us to anticipate constraints on the network ahead of time, enabling us to put mitigating actions in place (in Operational Control) to minimise the risk of your operation being affected
- Our Enhanced Gas Measurement Programme is replacing ageing gas quality monitoring equipment with the latest technology. This means the gas used in your home appliances is compliant with specifications defined by the Health and Safety Executive.

Investing in our System Operator Capabilities

4.4.5 Operational Control

What is it?

- Operational Control use inputs from all of our other operational capabilities to ensure that our control room can make informed and efficient decisions when operating the network
- The processes and systems that we use in Operational Control enable us to operate NTS assets, react to unplanned events, validate customer flow notifications against commercial rules, take commercial actions such as energy balancing or constraint management and engage effectively with customers to initiate third-party actions
- As gas flows and our customers' behaviours continue to evolve, more control actions will be required to ensure:
  - our system operates safely,
  - we maintain a national energy balance and
  - that we meet our customers' daily needs.

  The tools and communication methods we currently use are fit for purpose. However as the complexity of the actions required and the levels of risk being managed increase we may need to develop these tools and systems to ensure they continue to be fit for purpose in the future.

Drivers for change

- Within-day change in supply and demand
- Price sensitive operation
- Increasing range of quality of gas (within GS(M)R limits).

How are we improving?

Process

- In line with the replacement of our existing operational systems, new fit for purpose processes will be developed and implemented when appropriate.

Systems/Tools

- The replacement of our current core control room and support systems will improve the way that we collate and present operational data in our control room. This will allow us to bring together relevant information from all other operational capabilities to ensure that the control room makes operational decisions and takes control actions based upon the most up-to-date data and analysis. This will enable us to mitigate issues to minimise the risk of your operation being affected
- In the future, we anticipate increased communication with our customers. We have recently updated our Automatic Notification System (ANS) service to provide improved communications. We are planning further enhancements to our communication routes so that we can inform you of relevant developing network risks and continue to support your needs
- With increasing market volatility and uncertainty, we anticipate that you will face increasing challenges in managing your daily balancing position. To help you with this, we will be investing in improved within-day information provision systems to ensure the market is able to operate effectively and efficiently.

4.4.6 Operational Review

What is it?

- We are continuously improving how we operate our network to ensure we are providing the best service for you
- As we take on a more active role in managing and balancing the network, the number of commercial and operational actions that we make will inevitably increase. The amount of review, validation and analysis will increase as we are required to take more actions
- Given the changing, increasingly uncertain supply and demand environment, we will not be able to rely on our past experiences of operating our network. As a result, this places greater emphasis on the development of effective feedback loops from Operational Review into Planning, Operational Strategy and Operational Control
- We increasingly need to monitor our customers' compliance with contractual obligations and technical standards. We provide feedback to those parties that may be operating outside their obligations' particularly if their operation has a knock-on effect on us being able to deliver a reliable service for you.

Drivers for change

- Evolving customer requirements and supply/demand environment
- Anticipated increased number of control actions.

How are we improving?

Process

- We want to continue to improve our relationships and ways of working with our customers and stakeholders. When customer compliance incidents occur, particularly those which affect your ability to operate, we always review and, where possible, share any lessons learnt to reduce the risk of repeat occurrences
- We are increasingly sharing more information on our operational performance with you in the Operational and System Operator Forums. We host the forum with shippers and Distribution Network Operators, and through documents that we publish, such as this Gas Ten Year Statement.

Systems/Tools

- New systems will help us to draw conclusions more quickly, ensure that effective learning is developed and fed back into our other operational processes and systems so that we continuously improve our service to you
- The availability and quality of operational data are key to an effective operational day review. As part of the replacement of our current core control room and support systems we are investing in new software to store and visualise data in new and innovative ways which will allow us to complete more in-depth data analysis.

Deferred Asset Investments

4.5 Deferred asset investments

Here we describe how improvements in our Planning processes have helped us to defer asset investment.

4.5.1 Avonmouth

The Liquefied Natural Gas Storage (LNGS) facility at Avonmouth, in the South West, was built and connected to the NTS in the 1970s. As well as providing commercial storage services to shippers, it also provides regulated services to us to maintain operational security via Operating Margins (OM); and capacity to meet our 1-in-20 design standard via Constrained LNG (CLNG).

It also provides a service for Scotia Gas Networks (SGN) by supplying LNG via tankers to four towns in Scotland (known as the Scottish Independent Undertakings (SIUs)), which are not connected to a gas distribution network.

Figure 4.5
Avonmouth location map

Chapter four

National Grid LNG Storage has decided to close the storage facility as significant levels of investment are needed to continue safe and efficient operation in the long term. It is anticipated that the facility will stop operating in 2018.

An allowance was given in RIIO-T1 to build two new pipelines that would, as a minimum, replace the capabilities (capacity and locational OM) provided by Avonmouth. In the 2014 GTYS we confirmed that the construction of these new pipelines was not in the best interest of consumers.

In the past 12 months we have been discussing the impact of no longer having the OM with the Distribution Network Operators (DNO) and the Health and Safety Executive (HSE). We have also updated our 'capacity' risk analysis for the South West without the CLNG provided by Avonmouth.

Impact on operating margins

We purchase operating margins (OM) on an annual basis in line with both the Uniform Network Code (UNC) requirements and obligations as described in the National Grid Gas Safety Case in respect of the NTS (the 'Safety Case'). The Safety Case obliges us to maintain OM at certain levels and locations determined throughout the year. The OM service is used to maintain system pressures in the period before other system management services become effective (e.g. national or locational balancing actions). Primarily, OM will be used in the immediate period after any of the following have taken place and all the other SO actions are ineffective:

- Supply loss: terminal, sub-terminal, interconnector, LNG importation terminal
- Pipe break (including loss of infrastructure that renders pipe unusable)
- Compressor failure
- Demand forecast error.

A further quantity of OM is also procured to manage the orderly run-down of the system in the event of a Network Gas Supply Emergency (NGSE), while firm load shedding takes place.

Deferred Asset Investments

Operating Margin Review

Over the last 12 months we have fundamentally reviewed the process by which we assess the driver for the OM capability that Avonmouth provides. Currently the facility provides OM services for certain pipe breaks and compressor failures in the South West and for supply losses on a national basis. The national requirement for OM will need to be met by other providers across the network. We are not obligated to have the OM capability in the South West by our Safety Case and we do not provide this level of security in other parts of the network. However, we recognise that the closure of Avonmouth could be perceived as a reduction in safety so we have engaged with all affected parties, notably local Distribution Network Operators (DNO) and the Health and Safety Executive (HSE), to discuss and ensure any impacts are mitigated.

We met with the HSE in March 2014 to discuss the impact the planned closure of Avonmouth will have on our network. We outlined that OM from Avonmouth could be used for the pipeline isolation between Sapperton and Pucklechurch in the event of a pipe break. To fully mitigate this risk, the lowest cost solution would be to reinforce our network with a new pipeline between these two points.

The HSE wanted to understand the risk of doing no works compared to the cost of building a new pipeline. They were keen that a full risk assessment was carried out to demonstrate that the risk is low.

We commissioned a risk assessment in September 2014. The cost benefit analysis showed that the level of capital investment when compared to the level of risk was very high. There is an extremely low likelihood of a pipe break, between Sapperton to Pucklechurch, occurring on the high demand days.

It was therefore concluded that investment in a pipeline solution is not justified. Based on the findings from the risk assessment, the HSE accepted our proposal not to build the new pipeline. We have received formal confirmation from the HSE stating that the “HSE does not oppose your justification against construction of a parallel section of pipeline from Sapperton to Pucklechurch.”

We discussed potential DNO options with Wales and West Utilities. To facilitate the flow swaps needed to mitigate the risk, investment in 90km of pipeline and extensive offtake uprating would be required.

We have also considered the potential of contracting with local demand sources. We currently procure OM and Transmission Support Services (TSS) from providers in the South West, and we review the requirements and contracts annually. The contractual arrangements in place with these existing service providers would not fully replace the services offered by Avonmouth. It is unlikely, due to the lack of volume offered, that we would be able to fill the gap in capability with other providers in the South West.

These findings combined with the outcome of the risk assessment resulted in all options being discounted as they were not in the best interest of consumers.

Impact on NTS capability

In addition to the OM requirement in the South West, there is also a need for Transmission Support Services (TSS) which are defined in our Safety Case as a substitute for pipeline capability at high demands to support a 1-in-20 peak day. We currently have two different forms of TSS available to us: contracts under the Long Run Contracting Incentive and Constrained LNG (CLNG). Contracts funded under the Long Run Contracting Incentive are required in order to deliver obligated baseline capacity at five specifically named sites in the South West that were classed as interruptible prior to the introduction of the exit reform arrangements in October 2012. The Constrained LNG (CLNG) service is a regulated service that gives us access to instruct withdrawals from the Avonmouth LNG facility at high demands. This service has been used historically in the South West of the system to defer pipeline investment and to provide flexibility to ensure we comply with our NTS Security Standard while managing the risk of uncertainty in future supply and demand patterns.

We have seen a significant decline in the level of 1-in-20 peak day demand within our FES. As a result, we have completed further analysis to review the 'capacity' Need Case for pipeline investment following the closure of the Avonmouth LNG facility. This assessment has shown that the capability of our network will be equivalent to the anticipated capacity bookings from DNOs and power stations in the South West region. This assessment assumed that the DNOs and power stations will continue to run at their current capability. It provides no headroom to cover increased use within the current capacity baseline or to cover operational issues should our customers in the region require all of the capacity they have booked.

As part of the analysis we also considered a number of developments that could lead to a constraint as a result of the reduced capability when combined with the high level of bookings and the available headroom between current use and our baseline obligation, for example:

(a) New power station developments
(b) Embedded generation growth within distribution networks (DNs)
(c) Storage injection rather than withdrawal on a high demand day
(d) Loss of Lockerley compressor station on a high demand day.

The latest analysis confirmed that the installation of a second pipeline to retain capacity at the current levels is not in the best interest of consumers and should not be pursued. Longer term, the impact of Avonmouth's closure can be mitigated as the DN demand is shown to be reducing in the latest FES. However in the short to medium term there is a requirement to manage this risk.

We will be actively managing the associated risks once Avonmouth closes to continue to deliver a safe and reliable service for you to use, in the short, medium and long term.

We will continue to drive improvements in our Planning processes and systems. We will continue to progress our Operational Situational Awareness and Operational Control capabilities to assess real-time risk to ensure that we take the optimum control decisions at the right times.

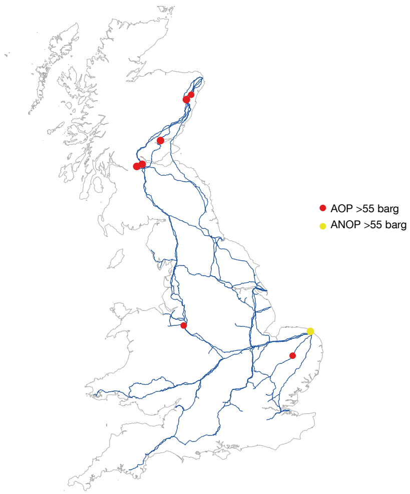
Deferred Asset Investments

4.5.2 Scotland pressures (1 in 20)

Overview
Our network has historically been designed around high St Fergus flows and has primarily been used to transport gas from north to south. To move the large volumes of gas south, compression in Scotland was consistently used, resulting in higher network pressures when compared to the rest of our network.

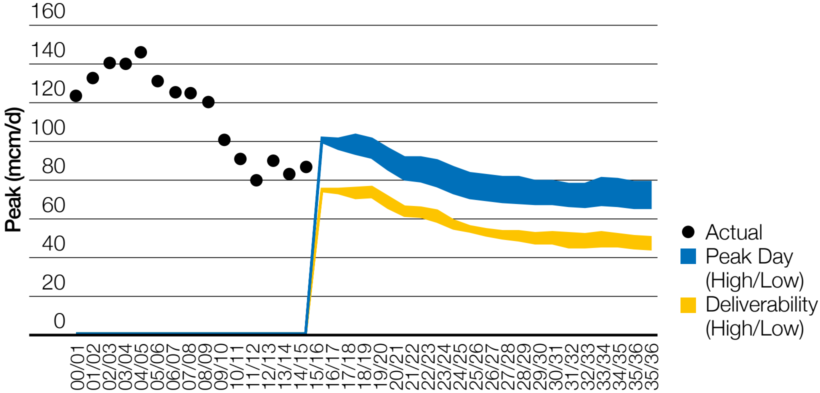
As a result, when independent DNOs were created, Assured Offtake Pressures (AOPs) were agreed at higher levels in Scotland than elsewhere in the network as indicated by Figure 4.6.

Figure 4.6
AOP and ANOP above 55 barg



We have seen a steady decline in the levels of supply at St Fergus, as can be seen in Figure 4.7. Year on year reductions in supply have stabilised in recent years, but the expected peak supply levels are still approximately 30 to 50mcm/d lower than the terminal's full deliverability.

Figure 4.7
Forecast flows from the St Fergus ASEP 2015



Deferred Asset Investments

Changing network requirements

Against this backdrop of reduced supplies, demand in Scotland (including through the Moffat interconnector to Ireland) has risen, reaching the point where on some days this demand is greater than the supply from St Fergus.

This means we are seeing larger south to north flows with less of a requirement to run compressors in Scotland.

The rate of decline from the St Fergus terminal has reduced across our FES. However, these still strongly indicate this situation will worsen over the coming years as existing UK Continental Shelf (UKCS) supplies through St Fergus continue to decline.

Further uncertainty around levels of supply at St Fergus is mainly driven by Norwegian supplies, which can flow to European markets, or arrive elsewhere in the UK via the Easington terminal.

Our network has limited capability to actively move gas south to north. We are approaching a point where, without additional network capability to deliver south to north flows, we will not be able to provide AOPs in Scotland at high demand levels, up to our 1-in-20 design obligation levels, or when St Fergus supplies are particularly low on a given day.

The reduction in supplies at St Fergus has been compensated for by additional supplies at Southern ASEPs. However, these have not been accompanied by signals for incremental capacity sufficient, either individually or in combination, to enable us to invest via existing regulatory processes.

The existing processes are based on customer commitment underpinning the provision of incremental capacity and associated flows.

The St Fergus/Scotland AOP situation has arisen through changing flow patterns. There is currently no clear trigger mechanism to provide funding for a solution to this issue whether it be investing in assets, changing how we operate or delivering commercial change.

We identified asset investment options, designed to enhance the capability of our network to provide AOPs in Scotland and enhance south to north flows. In response to feedback received during our RIIO Talking Networks Stakeholder Consultation process, we requested funding for these projects in our final RIIO-T1 submission and categorised the funding under ‘1-in-20 Licence Obligation’.

In our 2014 GTYS we confirmed that we had paused our work on the Scotland 1-in-20 projects. We wanted to review, update and improve our Planning processes and the methods we use to assess Need Cases for investment given other drivers of change.

We wanted to confirm that the optimum asset investment options had been identified given the impact of the Industrial Emissions Directive (IED) on affected sites, and our latest FES.

Next steps

Over the coming 12 months we will be working together with our customers and stakeholders to develop a better understanding of the interactions between our networks. In particular we will work with Scotia Gas Networks (SGN) to investigate innovative operational and collaborative solutions that will increase the current capability of each of our networks before we further refine our options based on these discussions.

We still expect to deliver any necessary works by the end of 2020. Any asset investment options are most likely to be modifications to (and within the current boundary of) existing operational sites. This will not trigger the need for major planning applications.

Aside from the planning application process, the factors that are expected to impact our ability to deliver our asset investment options the most are the availability of long lead items and gaining network access for construction works. These factors will not affect our ability to continue to provide a safe and reliable network for you to use.

Chapter five

Current Projects

Future Projects

Chapter five

Establish Portfolio

Risks of 'Do Nothing' option. Consider 'rules', 'tools' and 'assets'.

Asset Development

This chapter considers the most efficient way of delivering current and future network needs where asset investment has been evaluated as the preferred option. It sets out sanctioned National Transmission System (NTS) reinforcement projects, projects under construction in 2015/16, and potential investment options for later years as a result of the Industrial Emissions Directive (IED) and our asset health review. These are assessed against the scenarios and sensitivities in our Future Energy Scenarios (FES) publication. This chapter also explores the Establish Portfolio stage of our Network Development Process (NDP).

Key messages

- Increasing uncertainty around supply and demand scenarios makes planning future capability on the Gas National Transmission System (NTS) more challenging
- All of our gas-driven compressors that produce emissions above the Industrial Emissions Directive (IED) threshold must comply with new limits by 31 December 2023
- The decline of flows from St Fergus means we must be able to move more gas south-to-north. We currently have limited capability to do this but we do have time to assess potential solutions against the network changes resulting from the Industrial Emissions Directive. Flows are monitored and we expect to meet the necessary timescales to deliver any investments
- Delivering Asset Health works is a key Ofgem RIIO measure, in terms of allowances and output. Over the next three years we will make effective asset management decisions so we can deliver the right levels of network performance for our customers and stakeholders.

Introduction

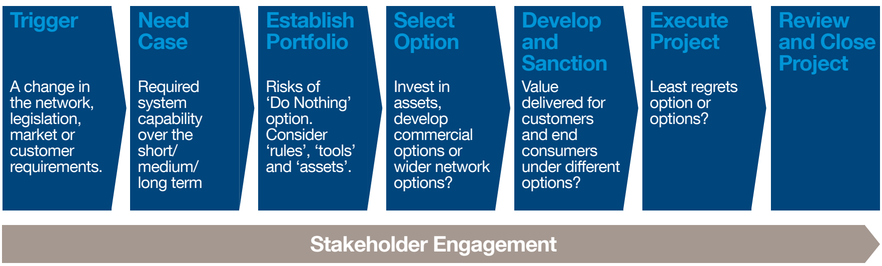
5.1 Introduction

Chapter 1 introduced our Network Development Process (NDP), in this section we expand on the asset solution element of the ‘Establish Portfolio’ stage. This stage is only reached if a solution to a trigger cannot be found within the existing capabilities of the system.

The aim of this stage is to establish a portfolio of, in this case, physical investment options that address the Need Case. A range of options are investigated during the network analysis phase, including a ‘Do Nothing’ option. This allows for the comparison of options both in terms of effectiveness at meeting the Need Case requirements and overall cost. The implications of each option we have considered are summarised and discussed at stakeholder engagement workshops. The options are then narrowed down to identify a preferred option which not only addresses the Need Case but delivers the most cost effective solution.

Figure 5.1 shows the stages of the NDP between Need Case and project closure.

Figure 5.1
The Network Development Process



Current Projects

5.2
Industrial Emissions Directive (IED)

As we outlined in Chapter 3, IED has a significant impact on our current compressor fleet.

RIIO-T1 outlined our initial baseline allowance this included; £150m (2009/10 prices) for the Integrated Pollution Prevention and Control (IPPC) Directive-affected units at Peterborough and Huntingdon and Large Combustion Plant (LCP) Directive units at Aylesbury; £269m for the remaining IED LCP affected units. There was no defined solution for the LCP-affected units and so are subject to what is called a re-opener window in 2018. During the re-opener window the £269m allowance for the LCP affected units will be reviewed by Ofgem.

Through our NDP we analysed the LCP-affected units and developed an optimised set of investments. These investments were developed to make sure the NTS can continue to best meet our customer needs and future challenges in the most efficient way.

On 15 May 2015 we delivered our IED Investments: Ofgem Submission which was based on our network analysis and the stakeholder feedback we had received. In our submission we requested an additional £41m of funding in order to deliver our IED investment strategy.

The proposed set of investment options are shown in Table 5.1 below. We made use of the derogations available under the LCP at seven of our affected sites; this was supported by our stakeholders. Where derogating and decommissioning non-compliant compressor units were shown to compromise system capability, a replacement unit was proposed. We believe, and the stakeholder feedback supports, that these proposals represent the best way forward in balancing the various needs of our customers with the requirements of IED.

Table 5.1
Summary of compressor options in the IED Ofgem submission

Station	Recommended option	Recommended option – anticipated allowance (outturn prices)
St Fergus (LCP)	17,500 hour derogation on units 2A and 2D and then decommission by 31 December 2023	<£10m
Kirriemuir	Unit D – 17,500 hour derogation and then decommission Unit E – De-rate and re-wheel (electric unit) Unit C – Decommission and install one new unit (MCP unit)	£50–£100m
Moffat	500 hour derogation both units	£10–£20m
Carnforth	Unit A – 17,500 hour derogation and then decommission Unit B – 500 hour derogation Site reconfiguration	£10–£20m
Hatton	17,500 hour derogation on three affected units and then decommission by 31 December 2023. Install three medium sized units	£100m+
Warrington	500 hour derogation both units	£10–£20m
Wisbech	Unit A – 500 hour derogation Unit B – Maxi Avon conversion to Avon	<£10m
St Fergus (IPPC)	Two replacement units and decommission two units	£50–£100m
Peterborough (IPPC)	Two replacement units and decommission three units	£50–£100m
Huntingdon (IPPC)	Two replacement units and decommission three units	£50–£100m

Ofgem published their decision to reject our request for additional funding to finance our proposed investment solutions on 30 September 2015. You can read our response to their consultation here **http://consense.opendebate.co.uk/files/nationalgrid/transmission/NGGT_IED_Response.pdf**.

Ofgem's decision means that we retain £419m as defined in RIIO-T1 of which £269m will be open to review in the re-opener window in 2018. This may change when we make investment decisions and how we bundle projects in order to manage both the cost and the risk of review in 2018.

We will work with Ofgem on our investment programme and in GTYS 2016 we will be able to provide an update on our plan of work to ensure compliance with the IED requirements by 2023.

We will revisit the Medium Combustion Plant (MCP) Directive programme of works as part of the 2018 re-opener window. The following outputs are appropriate for ex-ante funding during the RIIO-T1 period:

LCP element
- Kirriemuir rewheel and derate Unit E
- Moffat retained operational capability under 500 hours (asset health expenditure Units A&B)
- Carnforth decommission Unit A, site reconfiguration, retained operational capability under 500 hours Unit B (asset health expenditure)
- Hatton three replacement units in construction
- Warrington retained operational capability under 500 hours (asset health expenditure Units A&B)
- Wisbech change out of maxi Avon (Unit A) for an Avon, retained operational capability under 500 hours Unit B (asset health expenditure).

IPPC4 element
- St Fergus two replacement units commissioned
- Peterborough two replacement units commissioned
- Huntingdon two replacement units commissioned.

Current Projects

5.3 Integrated Pollution Prevention and Control (IPPC) Directive

5.3.1 IPPC Phase 1 and 2

Phases 1 and 2 of our IPPC Emissions Reduction Programme are now complete. The following sites were operationally accepted and commissioned in early 2015:

- St Fergus (two new electrically-driven compressor units)
- Kirriemuir (one new electrically-driven compressor unit)
- Hatton (one new electrically-driven compressor unit).

5.3.2 **IPPC Phase 3**

Phase 3 of the Emissions Reduction Programme includes investment at Huntingdon and Peterborough to comply with IPPC NOx and CO emissions limits by 2021.

Extensive network analysis completed in 2014 confirmed that both sites are critical to current and future network operation. The analysis assessed network flows across a range of supply and demand conditions using our Future Energy Scenarios. This showed that future capability requirements are very similar to current capability provided at these sites. A range of options were assessed and the preferred option was to replace the existing units.

The operation of both sites is affected by supply flows (from the terminals to the North, Bacton terminal and Liquefied Natural Gas (LNG) imports from the Milford Haven and Isle of Grain terminals) and demand in the south of the system. The sites are needed to manage network flows in the south and east of the system particularly at the 1-in-20 peak day demand level described by our Design Standard[1] as defined in our transportation licence.

Peterborough and Huntingdon stations are critical to maintaining flows and pressures in the system. At high demand levels, for example during winter, they are required to operate together. At lower demands they can be used interchangeably, depending on network flows. This interchangeability can provide network resilience, for example allowing maintenance to be undertaken on one of the sites or maintaining minimum system pressures during unplanned outages.

Peterborough is also a key site for the north–south, east–west and west–east transfer of gas to manage flows from the north, from Milford Haven terminal and to/or from Bacton terminal.

The early stages of the Front End Engineering Design (FEED) study concluded that electrically driven compressors were not viable at Peterborough but remained a possibility at Huntingdon. However, following the tender process for Huntingdon the Best Available Technique (BAT) assessment concluded that electric drives do not represent the BAT. The BAT identified that 15.3MW gas turbine units at both sites were the most effective at reducing emissions and were cost effective.

The feasibility and conceptual design stages of the FEED study are complete. The main works contract tender process is also complete and the contract will be awarded by the end of 2015.

[1] To plan the system to meet the 1-in-20 peak aggregate daily demand, including but not limited to, within-day gas flow variations on that day.

Current Projects

5.3.3 IPPC Phase 4

Alrewas, Diss and Chelmsford compressor sites were originally provisionally identified for inclusion in the IPPC Phase 4 works based on prevailing and forecast future network flows at the time. As part of our Phase 4 site analysis we re-assessed compressor station running hours. All three of the provisionally identified stations were found to have declining running hours, with five-year historical averages of less than 500 hours, and similar future operating requirements. The focus of the Phase 4 works shifted to other units with significantly higher current and forecast future running hours, this flagged units at St Fergus, Huntingdon, Peterborough and Wormington.

At St Fergus two new electric drives have been commissioned as part of Phase 1 and 2. These are direct replacements for two non-compliant units at the site; however these new units are not expected to reduce the usage of the remaining non-compliant units at St Fergus. It is anticipated that the non-compliant units will continue to have a high level of running hours to maintain the entry capability at St Fergus; the installation of two additional units at St Fergus is therefore proposed.

At Huntingdon and Peterborough we considered the impact of the upcoming MCP (as described in Chapter 2, section 2.3) legislation when assessing these two sites. The BAT assessment identified that having three equally sized units at both sites was the ideal solution. One unit is being replaced at each site as part of Phase 3 and we plan to install two additional new units at both sites as part of Phase 4. This will ensure that these two critical compressor sites will be IED compliant. Installing two units at the same time provides the most efficient and cost effective option.

Commissioning Felindre compressor station in South Wales and our increasing confidence in the electric drive unit at Wormington are likely to reduce the operating hours of the two non-compliant units at Wormington. Over the last five years the running hours of the two units have been falling and there has been a growing reliance on the electric drive. While the two non-compliant units are required to provide resilience in the event that the electric drive is unavailable, for example due to maintenance, the currently forecast running hours would not support additional investment at this time. No further works are proposed at Wormington as part of Phase 4. Table 5.2 details Wormington running hours for each calendar year from 2010 to 2014.

Table 5.2
Wormington compressor run hours for the last five years

Year		**2010**	**2011**	**2012**	**2013**	**2014**	**5yr Average**
Site	Turbine Unit	Running Hours	Running Hours	Running Hours	Running Hours	Running Hours	Running Hours
Wormington	A	2561	2599	446	33	21	1132
	B	1185	2450	95	48	19	759
	C	1098	2021	961	926	615	1124
	Total	**4844**	**7070**	**1502**	**1007**	**655**	**3015**

5.4 Large Combustion Plant Directive (LCP)

The LCP has been superseded by IED. In this respect, the IED mirrors the requirements set out in the LCP. Of our 64 gas-driven compressor units, 16 are affected by the LCP. To decide what we should do we have looked at each affected site on a unit-by-unit basis. Work to comply with the LCP is currently underway at Aylesbury. Options for the other sites which have non-compliant units are included in our IED Investment: Ofgem Submission.

To comply with the LCP all installations with a thermal input over 50MW must have Emission Limit Values (ELVs) below the following:

- carbon monoxide (CO) – 100mg/Nm3
- nitrogen oxide (NOx) – 75mg/Nm3 for existing installations
- nitrogen oxide (NOx) – 50mg/Nm3 for new installations.

5.4.1 Aylesbury

We received an upfront allowance under RIIO-T1 to fund the LCP Phase 1 works on two units at Aylesbury. The existing gas compressor units at Aylesbury have a thermal input over 50MW and therefore are required to comply with the LCP directive. The existing units are compliant with the nitrogen oxide (NOx) Emission Limit Values (ELVs) stated in the directive but are non-compliant with the carbon monoxide (CO) ELVs.

Aylesbury is a key site in a series of compressor stations between Hatton in Lincolnshire and Lockerley in the South West. These sites move flows around the system and are critical to support 1-in-20 peak day demand levels in the South West.

At lower demand levels than the 1-in-20 peak day demand, these compressors can be operated to manage linepack within the system, maintaining system resilience to plant failure, plant unavailability and within-day flow variation to the levels experienced on the network today.

Under lower demand conditions Aylesbury provides an important role as a gas-powered backup site to Lockerley compressor station (downstream of Aylesbury). Lockerley only has electrically driven compressor units installed as a consequence of strict local planning constraints.

Network analysis completed in 2014 determined that Aylesbury is required to meet 1-in-20 peak day demand levels in the south of the system. We also identified that the site may require enhancement to accommodate additional flows from the Bacton or Isle of Grain terminals or to support system pressures if new Combined Cycle Gas Turbines (CCGTs) connect in the South West.

The Aylesbury FEED study highlighted that the CO ELV can be achieved by the addition of a CO oxidation catalyst in the exhaust stack. We are working with Siemens to develop this innovative solution. A number of other asset-related works are scheduled for delivery at Aylesbury during 2015 as part of an overall upgrade package. The project is set for completion in December 2016, subject to outages.

Current Projects

5.5
Medium Combustion Plant (MCP) Directive

As we indicated in Chapter 2, section 2.3, the MCP directive is currently in draft. Based on the draft legislation we have anticipated the likely impact on our compressor fleet, however, further analysis will need to be undertaken to assess what options are available to comply with this new legislation. Stakeholder engagement activities, as used with the IED and IPPC programmes, will be undertaken to ensure the best possible solutions are found.

5.6
Asset health review

As indicated in Chapter 2, section 2.4, the National Transmission System (NTS) is ageing. This means that asset health is becoming a more prominent issue for us. Previously, the strategy we adopted for asset health investment, as supported by you, our stakeholders, was to focus on maintaining the condition of our primary and secondary assets (entry points, pipelines, multi-junctions, compressor stations and exit points) to avoid costly asset replacement. This strategy reduces the risk of long outages and network disruption minimising the likelihood of disturbance to you our customers.

Going forward, as part of the NDP, for every asset health issue we will now consider whether the asset is still required, or if there is a more suitable alternative option. This will consider all options including whether to maintain, replace or remove the asset. Reviewing each case like this will drive the most cost effective solutions at each site.

Future Projects

5.7 System Flexibility

As described in Chapter 3, we are using the GasFlexTool to improve our modelling to give us a better understanding of the levels of System Flexibility required to operate the NTS effectively. We are not currently establishing a portfolio of options for investment to increase System Flexibility while the GasFlexTool development and stakeholder engagement is ongoing.

5.8 Meeting future flow patterns

The way gas enters and exits the NTS is changing. As we identified in our FES document, the degree of change is highlighted by our four scenarios, offering insight into gas usage behaviour both for the consumer and the supplier.

One clear change is the decline in flows from St Fergus. Historically the NTS was designed and operated to move the majority of UK gas supply from St Fergus (north) to demand in England and Wales (south). As part of our ongoing strategy, flows are monitored and the flow decline has not been as severe as expected, which allows us to assess potential solutions against the network changes which the IED will bring.

Chapter six

Way Forward

Way Forward

This chapter outlines our plans to continue the development of the Gas Ten Year Statement (GTYS) and how we propose to engage with you over the coming year. In the past 12 months we have talked with you at customer and stakeholder events including the Industrial Emissions Directive (IED) consultation workshops, the System Flexibility workshop, the Gas Storage and Transmission Conference, the Gas Storage Operators Group, the Future Energy Scenarios (FES) launch and our Gas Customer Seminar. We also received feedback throughout the year via the GTYS online survey and GTYS mailbox.

Key messages

- We have responded to the feedback we received from you over the past year via our IED workshop, System Flexibility workshop, GTYS survey and the GTYS mailbox
- During the next 12 months we would like your views on:
  - Asset Health
  - Gas Planning Standards
  - Industrial Emission Directive
  - Network Development Policy
  - System Flexibility
  - System Operability Framework.
- You can help us to shape the GTYS by telling us which areas are/are not of value to you. Let us know by completing our short GTYS survey (**https://www.surveymonkey.com/r/GTYS2015**) or use our GTYS mailbox **Box.SystemOperator.GTYS@nationalgrid.com**
- You can check our project progress at our Talking Networks website[1].

[1] http://talkingnetworkstx.consense.co.uk/

6.1
Continuous Development of GTYS

GTYS is an opportunity for us to outline our current operational and asset-based plans for developing the National Transmission System (NTS) to ensure we continue to meet the needs of our customers and stakeholders. We use this document to highlight any challenges that we see facing our future operation and planning of the NTS. As part of our annual review of the GTYS we analyse all customer and stakeholder feedback to ensure the publication is valuable for you and is fit for purpose.

We want to continue to engage with you, by involving you in our decision-making process, providing transparency on our processes and keeping you informed of our plans.

We have adopted the following principles to enable the GTYS to continue to add value:
- Seek to identify and understand the views and opinions of all our customers and stakeholders
- Provide opportunities for engagement throughout the GTYS process, enabling constructive debate
- Create an open and two-way communication process around assumption, drivers and outputs
- Respond to all customer and stakeholder feedback and demonstrate how this has been considered.

6.2
2014/15 stakeholder feedback

Since our 2014 GTYS publication we have held two stakeholder workshops, one as part of the Industrial Emissions Directive (IED) options consultation and one on System Flexibility.

IED workshop

You told us that you wanted to be kept up to date with our IED progress. We created the external IED Talking Networks site[2] which has all of the consultation documents produced to date along with the final IED submission to Ofgem in May 2015. The website contains timelines and more information about the legislation and its impact on our network. We have outlined Ofgem's decision on our IED submission in this year's GTYS in Chapters 3 and 5.

We will continue to consult with you as we would appreciate your invaluable input to help us to develop a robust compressor plan for units affected by the Medium Combustion Plant (MCP) Directive.

[2] http://talkingnetworkstx.consense.co.uk/IED-welcome.aspx

Way Forward

System Flexibility workshop

You told us at the IED workshops that System Flexibility was an area of concern which should be discussed with the wider industry. As a result we held a workshop in May 2015 which brought together representatives from across the gas industry.

You told us that you want more information sharing between:
- Transmission System Operator (TSO) and Distribution Network Operators (DNOs) (collaboration and whole system planning)
- Gas and Electricity
- Onshore and offshore (Operator groups).

As we mentioned in Chapter 3 we are looking into the best way to approach this. We will be discussing options with you over the next 12 months.

You told us that you do not want us to introduce any arrangements that:
- Undermine the wholesale markets
- Undermine daily balancing
- Introduce new mandatory obligations.

You want us to look at new or improved:
- Forward-looking indicators and forecasts
- Storage products.

We have started engaging with the storage operators via the Gas Storage Operators Group (GSOG) to understand what storage products are available to help with System Flexibility going forward. Internally we are looking at what improvements we can make to our indicators and forecasts. The improvements we have identified to date have been outlined in Chapter 4.

You want us to:
- Confirm if the design margin used within the NTS planning process to plan for supply variation is still appropriate
- Confirm if there really is a problem with System Flexibility
- Confirm what the costs of System Flexibility are.

We have started to look into the above and have outlined our progress to date in Chapter 3.

We presented a System Flexibility overview at the Gas Storage and Transmission Conference in June, Gas Storage Operators Group in July and at the Gas Customer Seminar in September. We spoke to a number of you after the presentations about the challenges of System Flexibility and what we are planning to do over the coming 12 months. We will continue to keep you updated and involved.

Since the event in May we have created an external System Flexibility Talking Networks[3] site which includes a summary of the main areas discussed at the stakeholder event. We have been developing the GasFlexTool, as outlined in Chapter 3, to improve our ability to model System Flexibility. We will continue to develop this tool and will keep you informed on its progress.

GTYS 2014 feedback

You asked if we could provide more clarity on our internal decision-making process when constraints are identified on the NTS. This year's GTYS structure has been shaped around the initial stages of our Network Development Process (NDP). This was designed to make our internal decision-making process more transparent to you.

You told us that you would value clarity on which Direct Connect offtakes are located in each exit region. To address this we have included a new table in Chapter 3: Table 3.3.

You asked if we could include information on storage injectability by site as this would be of interest to you. We have included this information this year in Appendix 5, Table A5.4A.

[3] http://talkingnetworkstx.consense.co.uk/System-Flexibility.aspx

6.3
Future engagement

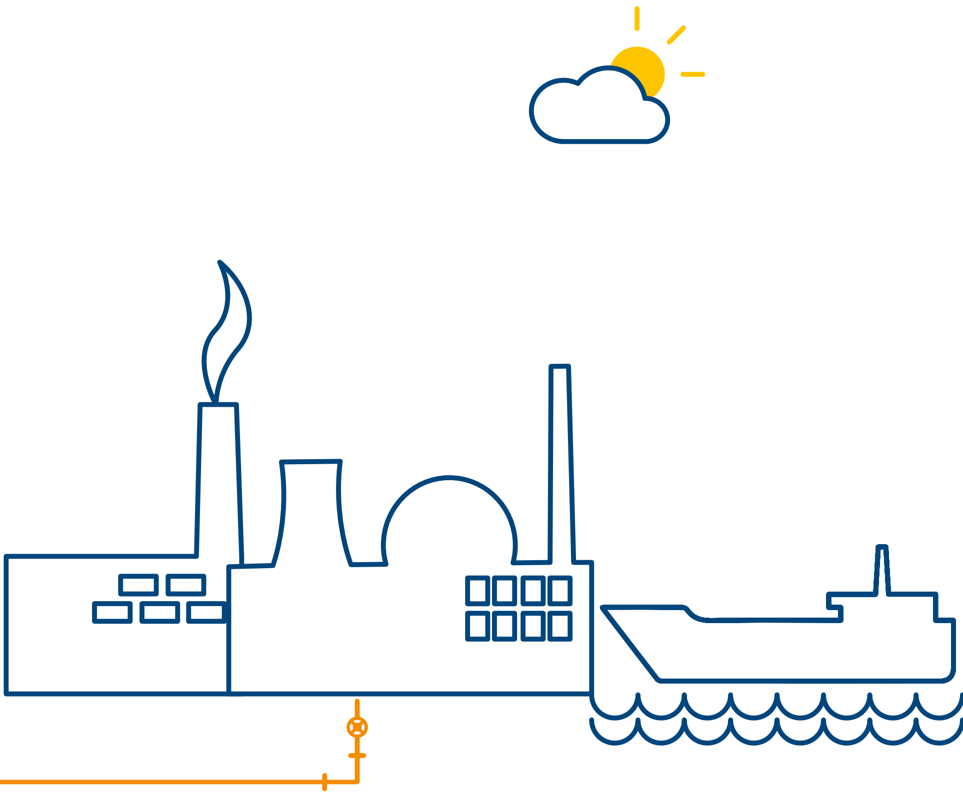
We welcome your feedback and comments on this edition of GTYS as it helps us to tailor the document to areas you value. Below are some questions which we are particularly keen to get your feedback on.

- Does the GTYS:
  - Explain the process we follow in order to develop the NTS?
  - Illustrate the future needs and development of the NTS in a coordinated and efficient way?
  - Provide information to assist you in identifying opportunities to connect to the NTS?
- Which areas of the GTYS are of most value to you?
- Which areas of the GTYS can we improve?
- Is there any additional information you would like to see included in the GTYS?

We will be engaging with you over the next 12 months to discuss the following topics in more detail:

- Asset Health
- Gas Planning Standards
- Industrial Emissions Directive
- Network Development Policy
- System Flexibility
- System Operability Framework.

We are happy to receive your feedback through a variety of channels including our short online survey (**https://www.surveymonkey.com/r/GTYS2015**), our GTYS mailbox (**Box.SystemOperator.GTYS@ nationalgrid.com**) and of course any other opportunities where we get to meet over the coming year. We look forward to hearing from you.



Chapter seven

Appendices 1–10

Appendix 1 – National Transmission System (NTS) Maps

Figure A1.1
Scotland (SC) – NTS

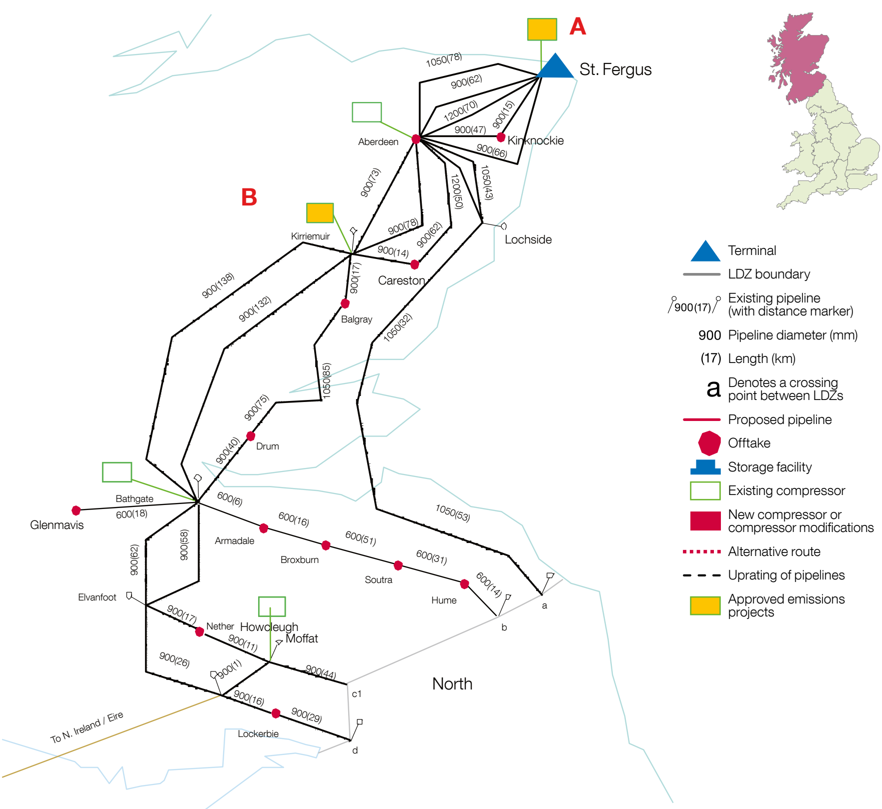
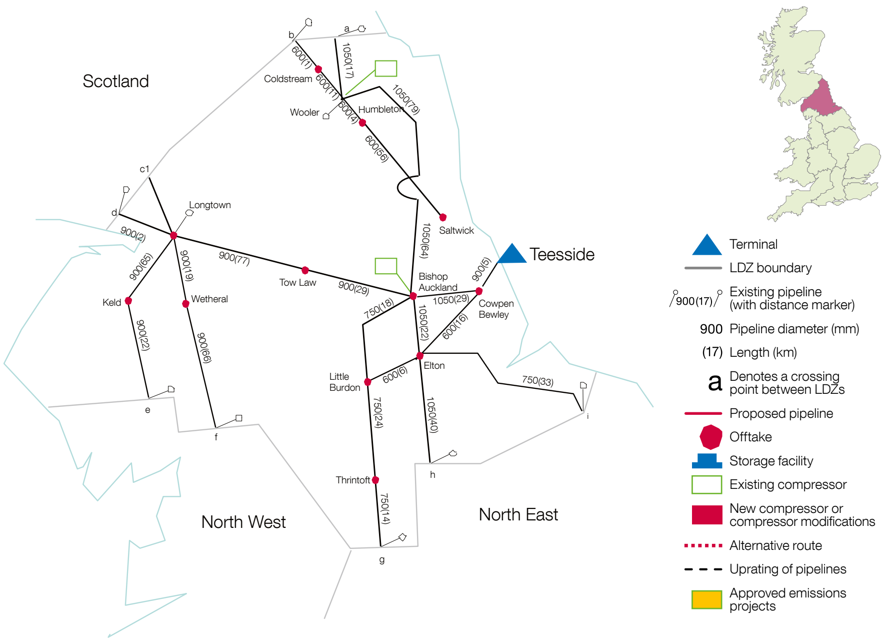


Figure A1.2
North (NO) – NTS



Appendix 1 – **National Transmission System (NTS) Maps**

Figure A1.3
North West (NW) – NTS

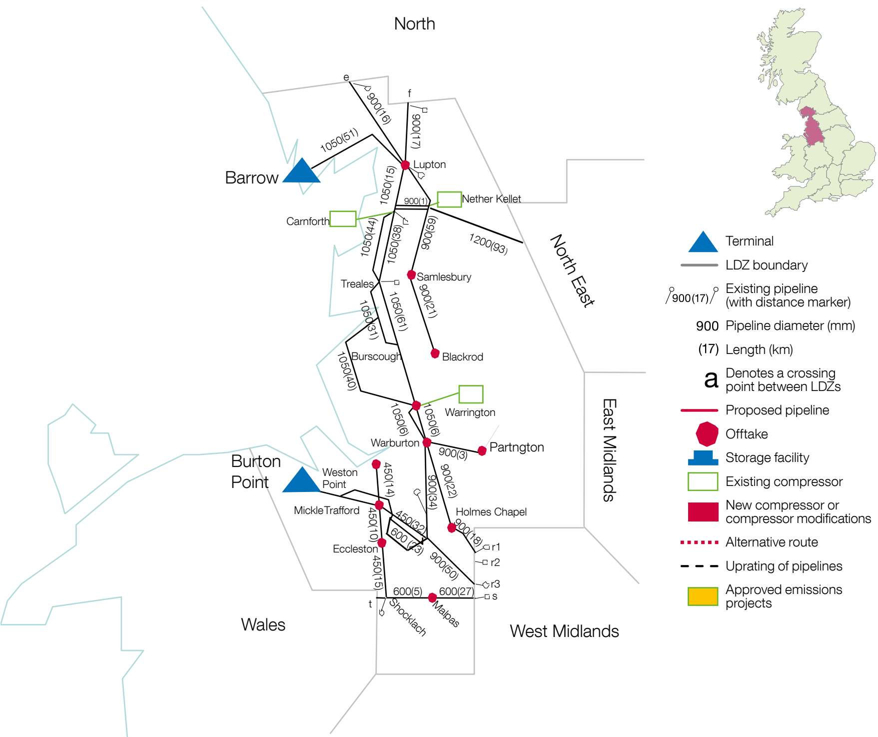
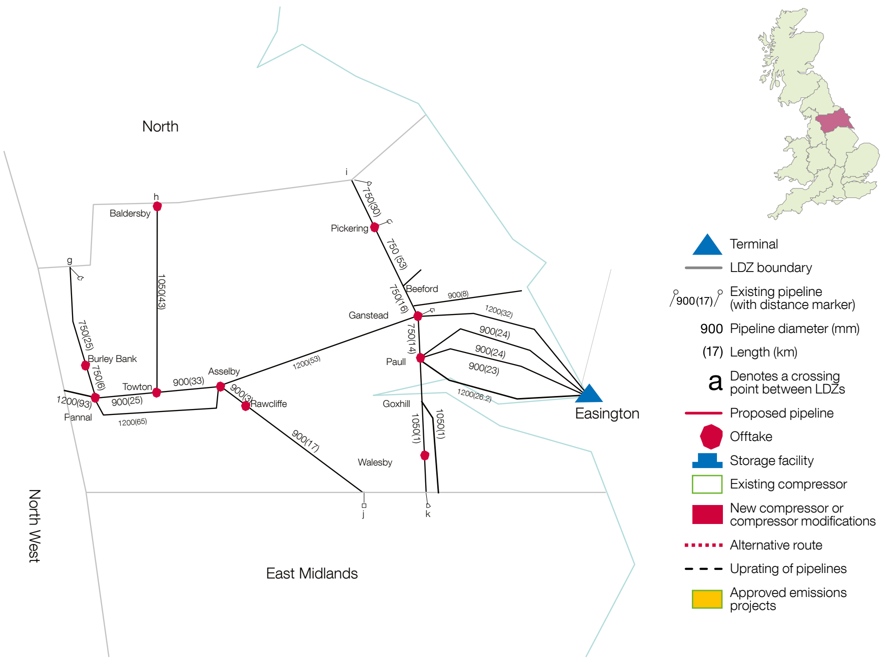


Figure A1.4
North East (NE) – NTS



Appendix 1 – National Transmission System (NTS) Maps

Figure A1.5
East Midlands (EM) – NTS

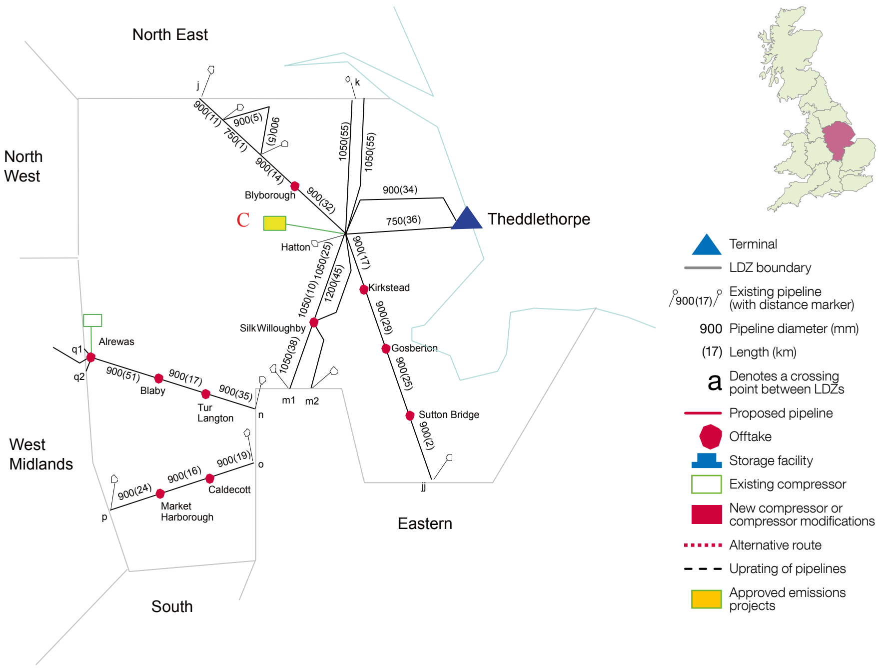
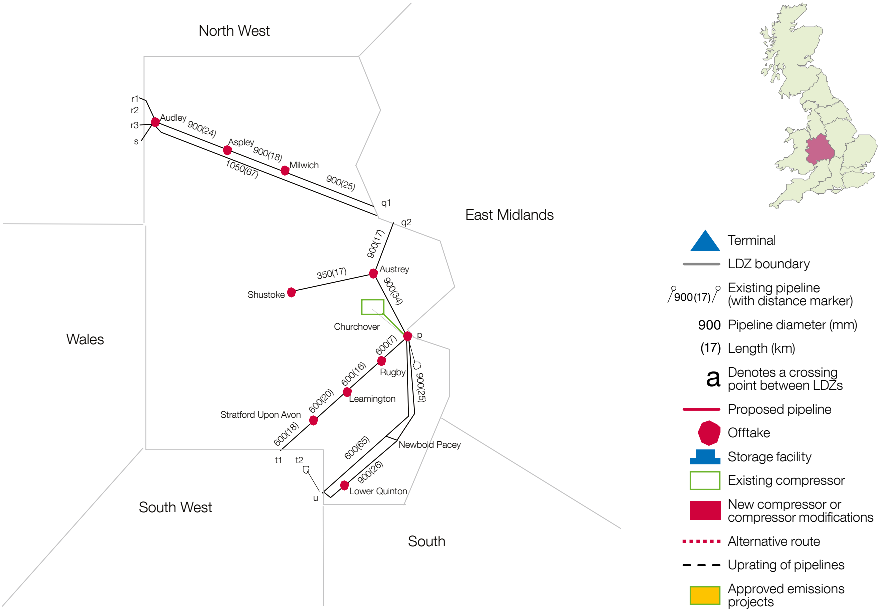


Figure A1.6
West Midlands (WM) – NTS



Appendix 1 – National Transmission System (NTS) Maps

Figure A1.7
Wales (WN & WS) – NTS

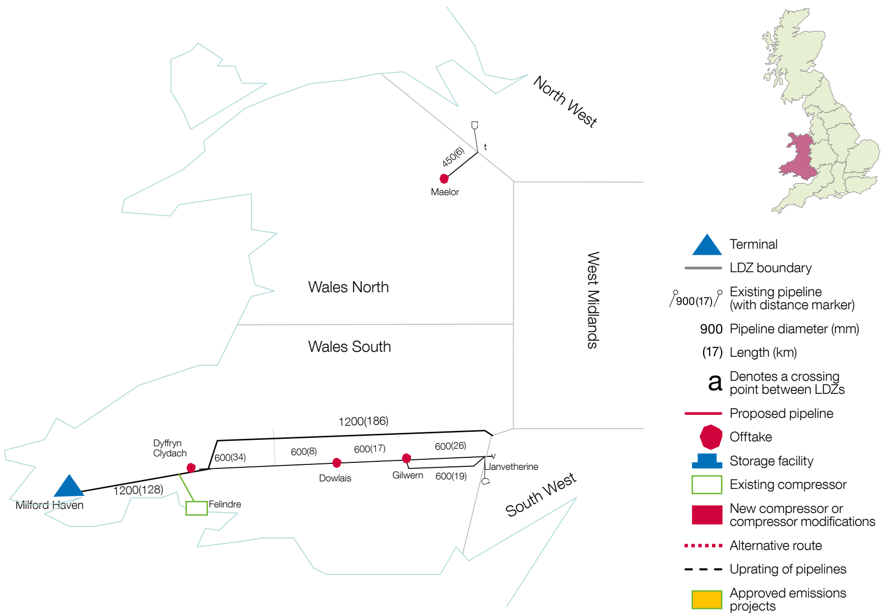
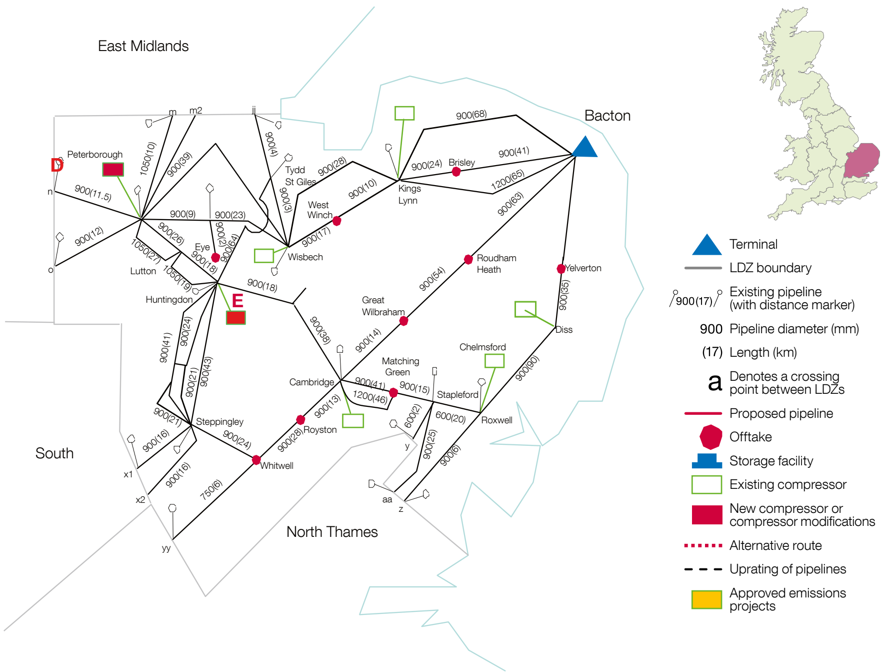


Figure A1.8
Eastern (EA) – NTS



Appendix 1 – **National Transmission System (NTS) Maps**

Figure A1.9
North Thames (NT) – NTS

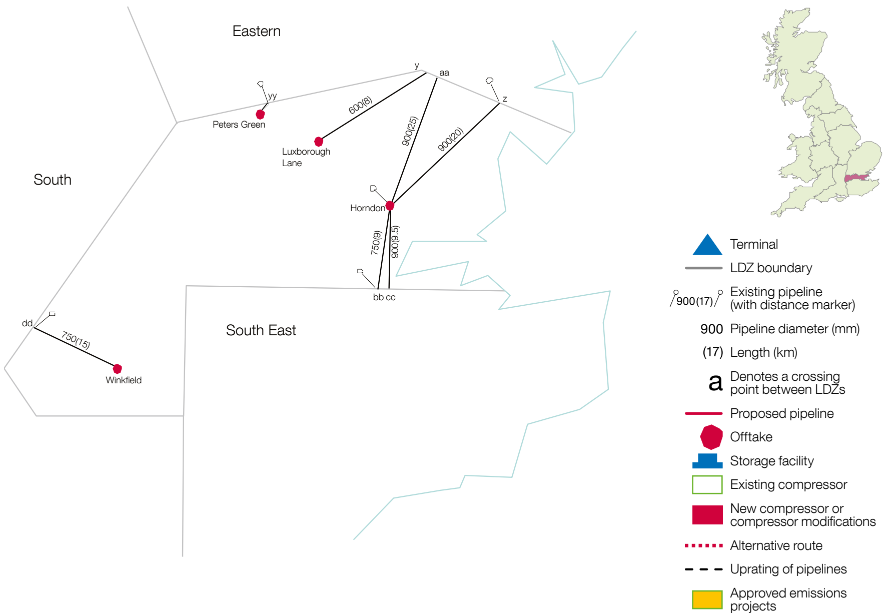
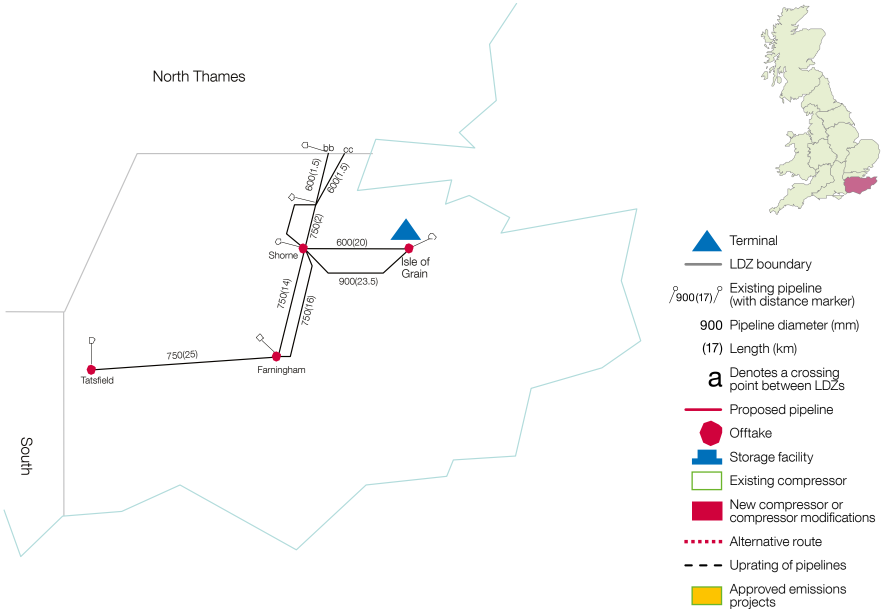


Figure A1.10
South East (SE) – NTS



Appendix 1 – **National Transmission System (NTS) Maps**

Figure A1.11
North Thames (NT) – NTS

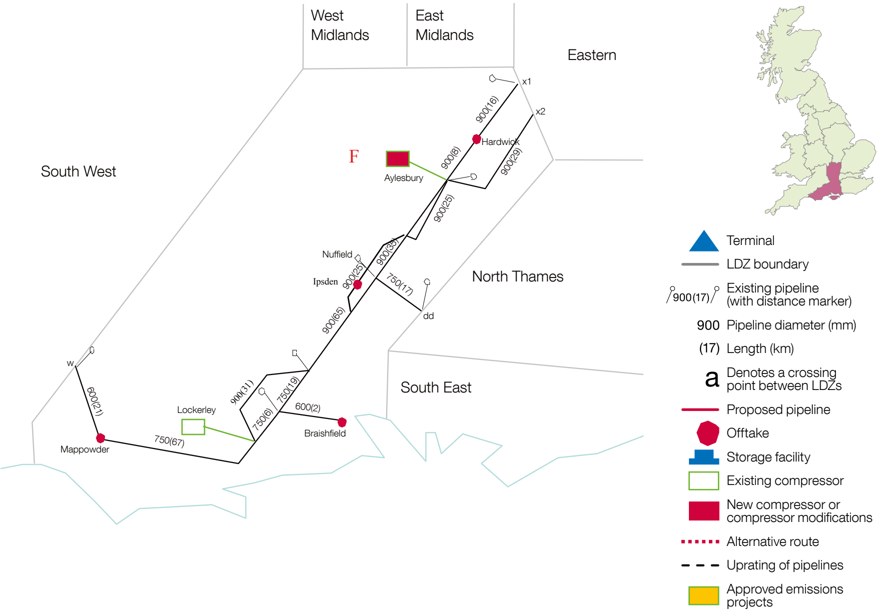
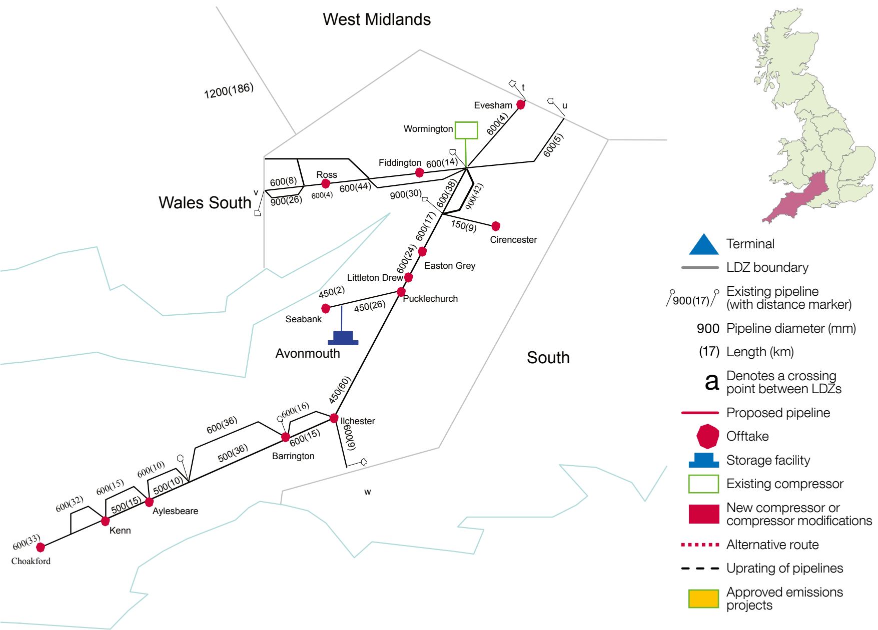


Figure A1.12
South West (SW) – NTS



Appendix 2 – Customer connections and capacity information

2.1 Additional Information specific to system entry, storage and interconnector connections

We require a network entry agreement, storage connection agreement or interconnector agreement, as appropriate, with the respective operators of all delivery, storage and interconnector facilities.

These agreements 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.

2.1.1 Renewable gas connections

We are committed to environmental initiatives that combat climate change. During the last year, an increasing number of customers have asked about entry into our pipeline system for biomass-derived renewable gas. We have also received requests for gas entry from unconventional sources, such as coal bed methane.

We welcome these developments and would like to help connect these supply sources to the network, but note that all existing network entry quality specifications, as detailed in the following section, still apply.

It should be recognised that the pressure requirements of biomass-derived renewable gas mean it may need to be connected to the gas distribution networks instead of the National Transmission System. For information about connections to the gas distribution networks, please read the documents for the relevant distribution network.

The twelve local distribution zones (LDZs) are managed within eight gas distribution networks. The owners of the distribution networks are:

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 information visit **http://www.scotiagasnetworks.co.uk/**

Wales and the West (Wales LDZ and South West LDZ) is owned and managed by Wales and West Utilities. For information visit **http://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 information visit **http://www.northerngasnetworks.co.uk/**

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 go to **www.nationalgrid.com**

2.1.2 Network entry quality specification

For any new entry connection to our system, the connecting party should tell us as soon as possible what the gas composition is likely to be. We will then determine whether gas of this composition would be compliant with our statutory obligations and our existing contractual obligations. From a gas quality perspective our ability to accept gas supplies into the NTS is affected by a range of factors including the composition of the new gas, the location of the system entry point, volumes provided and the quality and volumes of gas already being transported within the system.

In assessing the acceptability of the gas quality of any proposed new gas supply, we will consider:

- our ability to continue to meet statutory obligations (including, but not limited to, the Gas Safety (Management) Regulations 1996 (GS(M)R))
- the implications of the proposed gas composition on system running costs
- the implications of the new gas supply on our ability to continue to meet our existing contractual obligations.

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

Appendix 2 – **Customer connections and capacity information**

Table A2.1
Gas Quality Specification

Gas Element	Quality Requirement
Hydrogen sulphide	Not more than 5mg/m3
Total sulphur	Not more than 50mg/m3
Hydrogen	Not more than 0.1% (molar)
Oxygen	Not more than 0.001% (molar)
Hydrocarbon dewpoint	Not more than -2°C at any pressure up to 85 barg
Water dewpoint	Not more than -10°C at 85 barg
Wobbe number (real gross dry)	The Wobbe number shall be in the range 47.20 to 51.41MJ/m3
Incomplete combustion factor (ICF)	Not more than 0.48
Soot index (SI)	Not more than 0.60
Carbon dioxide	Not more than 2.5% (molar)
Contaminants	The gas shall not contain solid, liquid or gaseous material that might 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
	Ofgem agree that No NGG action required
Organo halides	Not more than 1.5 mg/m3
Radioactivity	Not more than 5 becquerels/g
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 that does not have a distinctive and characteristic odour
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, which will vary from time to time	
The entry pressure shall not exceed the maximum operating pressure at the delivery point	
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 agreement to include an operational tolerance to ensure compliance with the GS(M)R. We may also need agreement on upper limits of rich gas components such as ethane, propane and butane in order to comply with our safety obligations.

2.1.3 Gas quality developments

At the end of its 'three-phase' gas quality exercise, initiated in 2003, the UK Government reaffirmed in 2007 that it will not propose any changes to the GB gas specifications in the GS(M)R to the Health and Safety Executive until at least 2020. The Government's forward plan proposed continued engagement with the European Commission (EC) and Member States on gas quality, with particular regard to the CEN (Comité Europeén de Normalisation, the European committee for standardisation) mandate M/400. Under this mandate, CEN was invited to draw up the broadest possible standards for natural gas quality, within reasonable costs.

Following public consultation in 2014, the Wobbe Index proposals for the standard were removed and the standard proceeded to national vote on the remaining parameters in September 2015, resulting in a majority vote to adopt it. Of itself, this does not require any change to GB gas quality arrangements; however the European Commission has indicated that it will seek to make the standard binding on member states via an amendment to the EU Interoperability Network Code. It is not yet clear how this will happen and what the consequences for GB gas quality arrangements will be but we will continue to monitor developments and keep the industry informed.

Under the Interoperability Code, TSOs are obliged to engage with domestic stakeholders to explore whether enhanced information provision for parties that are sensitive to changes in gas quality would be desirable and achievable. We plan to commence our engagement on this topic shortly.

Carbon dioxide limits have been the subject of GB industry debate (UNC Modification Proposals 0498 and 0502) in seeking to bring additional gas to market from the UKCS. This debate centred on whether a higher limit at the Teesside entry terminals would be more economic and efficient than upstream installation of CO_2 removal plant and operating it when necessary. The other side of the debate included consideration of potential impacts for operators downstream of NTS exit points in terms of potential costs for plant integrity, operation, and emissions. In September 2015, Ofgem directed that these Modifications should be implemented.

The development of shale gas is still in its infancy in the UK and at present there is uncertainty over the quality of such gas until wells are drilled. We will continue to work with customers and monitor developments in this area.

Appendix 2
The PARCA Framework Process

2.2
The PARCA Framework Process

The PARCA framework is split into four logical phases: Phase 0 to Phase 3. This phased structure gives the customer natural decision points where they can choose whether to proceed to the next phase of activities.

Regardless of these natural decision points the PARCA process is flexible enough to allow the customer to leave the process at any time before full financial commitment to the capacity though capacity allocation.

2.2.1 Overview of the four phases

Phase 0 – Bilateral Discussions (no defined timescales)

This phase is a bilateral discussion phase between the customer and National Grid with no defined timescales. It allows the customer and National Grid to understand each other's processes and potential projects before the customer decides whether to formally enter the PARCA process. If the customer wants to proceed into the PARCA process after these discussions they must submit a valid PARCA application form and pay a PARCA application fee. Our PARCA application form can be by using the following link: **http://www2.nationalgrid.com/UK/Services/Gas-transmission-connections/PARCA-framework/PARCA-Framework-1/**

Phase 1 – Works and PARCA contract (up to six months)

Phase 1 Up to 6 months	National Grid confirm receipt of the application within 2 business days	National Grid provides formal acceptance of a competent application to the customer within 6 business days	National Grid initiate Phase 1 Works	Within 10 business days National Grid may trigger a PARCA Window and an adhoc QSEC capacity auction	National Grid will issue the customer with the Phase 1 Output Report & the PARCA contract

When we receive a valid PARCA application form and payment of the application fee from the customer, we will tell them their PARCA application has been successful and Phase 1 of the PARCA process will begin. During Phase 1 we will publish relevant information to the industry and, through the opening of a PARCA window, invite PARCA applications from other customers.

In our desktop study, we will explore a number of ways of delivering the capacity. This may be wholly through (or a combination of) existing network capability, substitution of capacity, a contractual solution or physical investment in the NTS. We will complete these works within six months of the start of Phase.

We also release long-term NTS capacity through established UNC capacity auction and application processes, more specifically:
- Long-term NTS entry capacity that is sold in quarterly strips through the Quarterly System Entry Capacity auction (QSEC) held annually in February and
- Long-term NTS Exit Capacity that is sold as an enduring evergreen product through the Enduring Annual NTS Exit Application process held annually in July.

So it's important to bear in mind that existing system capacity that could be used to fully or partly satisfy a PARCA request may also be requested by our customers through those processes detailed above. As such it may not be appropriate to initiate the Phase 1 works of a PARCA while the QSEC or enduring annual processes are running because it may not be clear how much existing capacity will be available to satisfy a PARCA request for the purposes of the Phase 1 studies.

The timetable below (Figure A6.1) shows the annual QSEC auction and enduring exit capacity application and potential periods where we decide not to start Phase 1 PARCA Works:

Figure A2.1
Annual Entry and Exit capacity application windows

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Annual QSEC Auction		QSEC invitation	QSEC bid window	Allocaton of QSEC bids								
Entry Capacity PARCA Annual		Phase 1 of an entry capacity PARCA may not be initiated if there is an interaction with the ongoing annual QSEC auction process										
Enduring Exit Application						Exit invitation	Exit capacity window	Alloaction of exit capacity				
Exit Capacity PARCA						Phase 1 of an entry capacity PARCA may not be initiated if there is an interaction with the ongoing annual Exit capacity application window						

Appendix 2
The PARCA Framework Process

PARCA Window

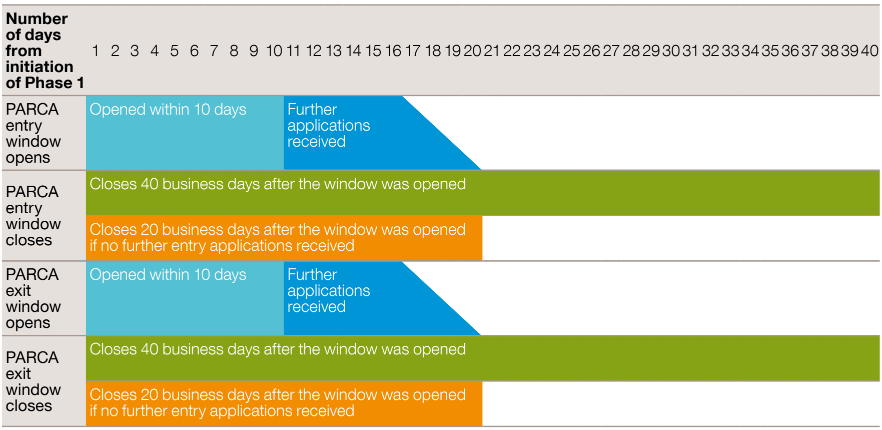
The purpose of the PARCA window is to encourage those customers considering applying for a PARCA to submit their application at this time, so that we can assess how to meet their capacity need alongside other potential projects.

For any PARCA application deemed competent outside a relevant PARCA window, within 10 business days of the initiation of the Phase 1 works of that PARCA we will open (where a window is not already open) either a PARCA entry or exit window, a notice will be published on our PARCA webpages, which can be found by using the following link: **http://www2.nationalgrid.com/UK/Services/Gas-transmission-connections/PARCA-Framework/**

We guarantee to consider together all PARCA applications submitted and deemed competent within this window. However, it is important to note that if you wish to be considered for capacity alongside other PARCA applications, in order to ensure we can conduct our competency check within the PARCA window timescales, please endeavour to submit your application as early as practically possible.

The diagram below (figure A2.2) shows the PARCA Window timeline:

Figure A2.2
PARCA window timeline



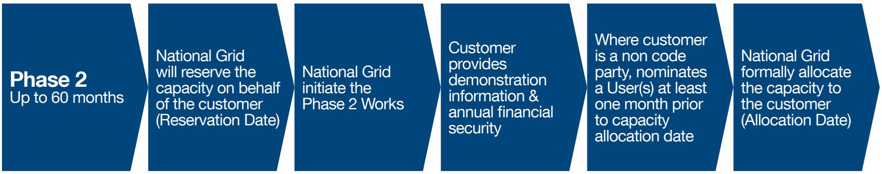
The PARCA window is open for a maximum of 40 consecutive business days but will close after 20 consecutive business days if no further PARCA applications have been received within that time. There are two types of PARCA window:

- Entry window – triggered if a PARCA requests NTS entry capacity
- Exit window – triggered if a PARCA requests NTS exit capacity.

Only one entry and/or exit PARCA window can be open at any one time. So if a PARCA application requesting entry/exit capacity is deemed competent within an open entry/exit PARCA window, an additional PARCA window will not be triggered.

On completion of the Phase 1 works we will provide the customer with a Phase 1 output report, which will include a need case report (establishes and documents the potential need case for investment, a technical options report and a PARCA contract.

Phase 2 – (up to 60 months)



When the contract is counter-signed, we will reserve the capacity on the customer's behalf, from the date provided in the Phase 1 output report.

If the Phase 1 output report shows that physical reinforcement of the NTS is needed to provide the customer with their capacity, we will start the statutory planning consent at this stage; either the Planning Act or Town & Country Planning. If no physical reinforcement is needed we will continue to reserve the capacity in accordance with the timelines provided as part of the Phase 1 output report.

Phase 2 ends when the reserved capacity is allocated to the customer or, where the customer is a non-code party, a nominated code party(s). Once allocated and the capacity is financially committed to, the PARCA contract ends and we begin the capacity delivery phase (Phase 3).

Appendix 2
The PARCA Framework Process

Phase 3 – (up to 24 months)

Once the capacity is formally allocated, the PARCA contract expires and the capacity delivery Phase 3 is initiated. This is where we carry out necessary activities, such as reinforcing the NTS to deliver the allocated capacity. Please note that on allocation of any reserved NTS capacity, the Uniform Network Code (UNC) user commitment applies.

The PARCA allows you to reserve capacity but it does not provide you with an NTS connection.

If you need a new connection to the NTS, or a modification to an existing NTS connection, you will need to go through the application to offer (A2O) process.

The A2O process typically takes three years from application to the construction of the physical connection.

Appendix 3 – Introducing the Gas Customer Team

3.1
Our Gas Account Management Team

Our role is to effectively manage business relationships with all our gas industry customers and stakeholders through ownership of the overall customer experience.

We coordinate a consistent customer approach across all value streams and transportation operations.

We deliver customer intelligence and represent the voice of our customers within our business to help shape and inform key business decisions through a deeper understanding of your business requirements.

Our dedicated customer account management team will be your first point of contact:-

Kyla Berry
Gas Customer Manager
kyla.berry@nationalgrid.com

Tracy Phipps
Gas Customer Account Manager

James Abrahams
Gas Customer Account Manager

Teresa Thompson
Gas Customer Account Manager

Abby Hayles
Gas Customer Account Manager

Melissa Albray
Gas Customer Account Manager

Appendix 3 – **Introducing the Gas Customer Team**

3.2
Our Gas Contract Management Team

Our role is to manage and deliver all commercial aspects of your connection, diversion and/or PARCA processes by understanding and developing solutions that meet your needs.

We deliver all commercial and contractual changes to distribution network offtake arrangements, associated framework changes, and manage the UNC customer lifecycle processes and obligations.

Our dedicated contract management team will manage your connection, diversions and all PARCA applications:-

Eddie Blackburn
Gas Contract Portfolio Manager
eddie.j.blackburn@nationalgrid.com

Andrea Godden
Gas Contracting Commercial Manager

Alex Curtis
Gas Connections Contract Manager

Belinda Agnew
Gas Connections Contract Manager

Claire Gumbley
Gas Connections Contract Manager

Louise McGoldrick
Gas Connections Contract Manager

Jeremy Tennant
Gas Connections Support Assistant

Gillian Culverwell
Gas Connections Contract Officer

Appendix 4 – Actual Flows 2014/15

This appendix describes annual and peak flows during the calendar year 2014 and gas year 2014/15.

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 reallocation of demand between 0–73.2MWh/y and >73.2MWh/y firm load bands to allow for reconciliation, loads crossing between thresholds, etc. The load band splits shown in Table A4.1 are slightly different from those incorporated in the National Grid Accounts.

Table A4.1 provides a comparison of actual and weather-corrected demands during the 2014 calendar year with the forecasts presented in the 2014 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 A4.1
Annual demand for 2014 (TWh) – LDZ / NTS split

	Actual Demand (TWh)	**Weather-Corrected Demand (TWh)**	**GTYS (2014) GG Demand**
0–73.2MWh	298	318	328
73.2–732MWh	43	45	43
>732MWh Firm	167	171	179
Total LDZ Consumption	**508**	**534**	**551**
NTS Industrial	23	23	30
NTS Power Generation	176	176	173
Exports	115	115	113
Total NTS Consumption	**314**	**314**	**316**
Total Consumption	**823**	**849**	**867**
Shrinkage	8	8	8
Total System Demand	**831**	**857**	**875**

Table A4.1 indicates that our 1-year ahead forecast for 2014 was accurate to 3.1% at an LDZ level. The combined forecasts of the NTS Industrial, NTS Power Generation and Exports were accurate to 0.6%. Total system demand was accurate to 2.1%.

Appendix 4 – Actual Flows 2014/15

4.1 Peak and minimum flows

4.1.1 System entry – maximum day flows

For the 2014/15 gas year, the day of highest supply to the NTS was 19 January 2015 (364.1mcm), whilst the day of highest demand for the same period was 2 February 2015 (364.9mcm). These are both higher than the highest supply and demand days in the 2013/14 gas year (327mcm, both supply and demand). The day of lowest supply and demand for the gas year 2014/15 was 12 September 2015 (142mcm), which is higher than the lowest supply and demand days in the 2013/14 gas year (135mcm and 138mcm, respectively).

Table A4.2
IGMS M+15 physical NTS entry flows: 19 January 2015 (mcm/d)

Terminal	Maximum Day	GTYS (2014) GG Supply Capability	Highest Daily (per terminal)
Bacton inc. IUK and BBL	66	150	75
Barrow	3	8	7
Easington inc. Rough & Langeled inc. incRoughRLLanaLangeled	122	122	126
Isle of Grain (excl. LDZ inputs)	0	59	22
Milford Haven	39	86	60
Point of Ayr (Burton Point)	1	0	3
St Fergus	86	96	87
Teesside	13	35	25
Theddlethorpe	10	9	12
Sub-total	382	566	416
MRS & LNG Storage	24	102	52
Total	**364**	**667**	**468**

Notes
- The maximum supply day for 2014/15 refers to NTS flows on 19 January 2015
- 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 2014 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.

4.1.2 System entry – minimum day flows

Table A4.3
IGMS M+15 physical NTS entry flows: 12 September 2015 (mcm/d)

Terminal	Minimum Day
Bacton inc. IUK and BBL	14
Barrow	0
Easington inc. Rough & Langeled inc. incRoughRLLanaLangeled	35
Isle of Grain (excl. LDZ inputs)	0
Milford Haven	32
Point of Ayr (Burton Point)	3
St Fergus	43
Teesside	16
Theddlethorpe	0
Sub-total	142
MRS & LNG Storage	0
Total	**142**

Notes
- The minimum supply day for 2014/15 refers to NTS flows on 12 September 2015. 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.

Appendix 4 – Actual Flows 2014/15

4.1.3 System exit – maximum and peak day flows

Table A4.4 shows actual flows out of the NTS on the maximum demand day of gas year 2014/15 compared to the forecast peak flows.

Table A4.4
IGMS D+5 physical LDZ demand flows: 2 February 2015 (mcm/d)

LDZ	Maximum Day	GTYS (2014) 1 in 20 Undiversified GG Peak
Eastern	23	33
East Midlands	30	39
North East	19	24
Northern	15	21
North Thames	28	42
North West	34	47
Scotland	23	30
South East	29	45
Southern	22	33
South West	16	25
West Midlands	25	34
Wales (North & South)	15	22
LDZ Total	**278**	**395**
NTS Total	**87**	**169**
Compressor Fuel Usage (CFU)	**1**	
Total	**365**	**594**

Notes
- The maximum day for gas year 2014/15 refers to 2 February 2015. 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 1-in-20 Peak Day Firm Demand forecast was published in the 2014 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.

4.1.4 System exit – minimum day flows

Table A4.5
IGMS D+5 physical LDZ demand flows: 12 September 2015

Terminal	Minimum Day
Eastern	5
East Midlands	6
North East	5
Northern	5
North Thames	6
North West	8
Scotland	8
South East	4
Southern	4
South West	3
West Midlands	5
Wales (North & South)	4
LDZ Total	**63**
NTS Total	**79**
Compressor Fuel Usage (CFU)	**0**
Total	**142**

Notes
– The minimum day for gas year 2014/15 refers to 12 September 2015. 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 5 – **Gas Demand and Supply Volume Scenarios**

5.1 Demand

Table A5.1A
Slow Progression: Annual demand – Split by load categories (TWh)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
0–73.2MWh	317	310	306	302	298	293	290	287	283	281	279	278	277	276	274	273	272	271	270	269	267
73.2–732MWh	45	44	44	43	43	43	42	42	41	40	40	38	37	36	35	34	32	31	30	29	28
NDM > 732MWh	78	78	80	82	83	84	84	85	86	87	88	88	88	88	88	88	89	89	89	89	89
Total NDM	**439**	**432**	**429**	**427**	**423**	**420**	**416**	**413**	**411**	**408**	**406**	**404**	**402**	**400**	**397**	**395**	**393**	**391**	**389**	**387**	**384**
Total DM	95	97	98	99	98	97	96	94	92	91	91	91	91	90	90	90	90	90	90	90	90
LDZ Shrinkage	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Total LDZ	**537**	**532**	**530**	**528**	**524**	**519**	**516**	**511**	**506**	**502**	**500**	**497**	**495**	**493**	**490**	**488**	**486**	**484**	**482**	**480**	**477**
NTS Industrial	23	23	23	24	24	24	24	24	24	24	23	23	23	23	23	23	23	23	23	23	23
Exports to Ireland	61	29	28	31	29	35	37	37	43	47	49	51	50	50	52	52	53	55	56	56	58
NTS Power Generation	154	173	160	165	167	143	134	133	136	157	157	152	162	161	163	147	141	145	148	150	150
NTS Consumption	238	225	211	220	220	202	195	194	202	228	230	227	236	235	239	223	218	223	227	230	231
NTS Shrinkage	3	3	3	3	3	3	3	3	3	4	4	4	3	3	3	3	3	3	3	3	4
Total excluding IUK	779	760	745	751	747	725	714	708	712	734	734	728	734	731	732	715	707	711	712	713	712
IUK	59	58	56	55	52	44	36	28	22	16	10	6	2	2	2	2	2	2	2	2	2
Total including IUK	**838**	**817**	**800**	**806**	**799**	**769**	**750**	**736**	**734**	**750**	**744**	**734**	**736**	**734**	**735**	**717**	**710**	**713**	**715**	**715**	**714**

Figure A5.1A
Slow Progression: Annual demand

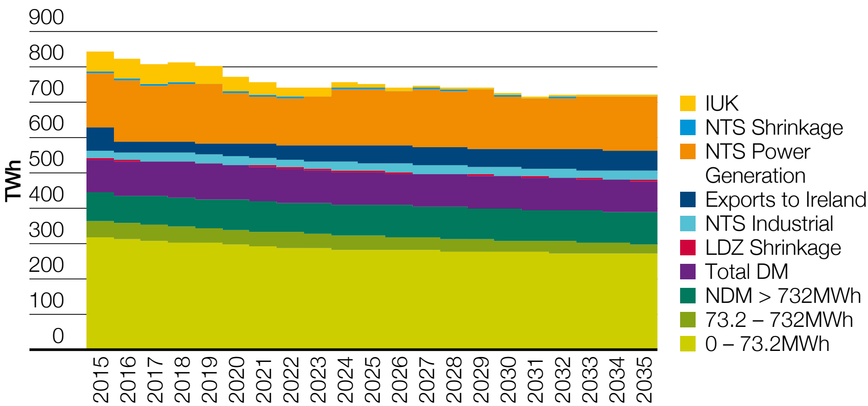
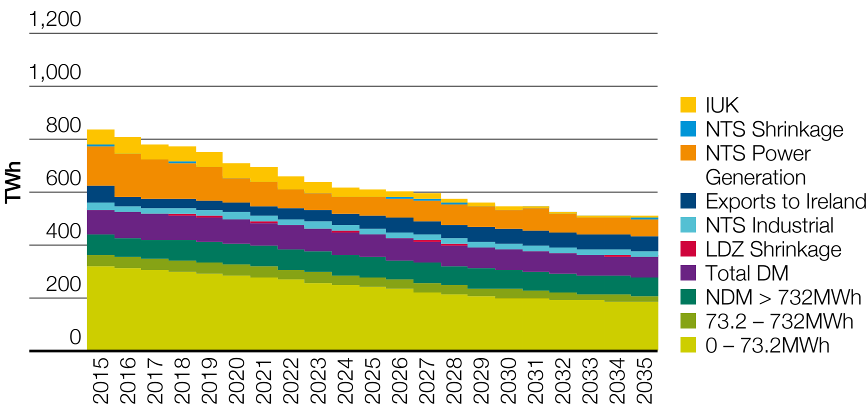


Table A5.1B
Gone Green: Annual demand – Split by load categories (TWh)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
0–73.2MWh	316	308	302	297	291	283	275	266	256	247	239	230	221	211	205	200	195	191	188	186	184
73.2–732MWh	44	43	43	42	42	42	41	40	40	38	37	36	34	33	31	30	28	27	26	25	24
NDM > 732MWh	75	74	73	75	76	76	76	75	77	77	77	76	75	73	72	71	70	69	68	68	68
Total NDM	**435**	**425**	**418**	**414**	**410**	**401**	**392**	**382**	**373**	**363**	**353**	**341**	**330**	**317**	**308**	**300**	**293**	**287**	**283**	**279**	**276**
Total DM	95	95	94	96	95	92	90	89	86	84	83	82	82	81	80	79	78	77	77	77	77
LDZ Shrinkage	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Total LDZ	**533**	**523**	**516**	**513**	**507**	**496**	**485**	**473**	**462**	**450**	**439**	**426**	**414**	**401**	**391**	**382**	**374**	**367**	**362**	**358**	**356**
NTS Industrial	24	23	23	23	23	23	23	23	23	23	22	22	22	22	22	21	21	21	22	22	22
Exports to Ireland	63	32	33	35	32	36	37	38	42	46	50	53	50	51	53	53	54	54	54	56	57
NTS Power Generation	154	163	146	138	128	92	87	72	64	59	67	73	82	80	77	74	85	71	64	63	61
NTS Consumption	240	218	202	196	184	151	148	132	128	128	140	148	154	153	151	148	161	146	139	141	139
NTS Shrinkage	3	3	3	3	3	3	3	3	3	4	4	4	3	3	3	3	3	3	3	3	4
Total excluding IUK	776	745	721	713	694	651	636	609	593	581	582	578	571	557	545	533	538	516	504	502	498
IUK	60	60	58	58	57	56	54	50	43	36	28	24	20	16	12	8	4	4	4	4	4
Total including IUK	**836**	**804**	**779**	**770**	**751**	**707**	**691**	**659**	**637**	**617**	**610**	**602**	**591**	**574**	**558**	**542**	**543**	**521**	**509**	**507**	**503**

Figure A5.1B
Gone Green: Annual demand



Appendix 5 – **Gas Demand and Supply Volume Scenarios**

Table A5.1C
No Progression: Annual demand – Split by load categories (TWh)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
0–73.2MWh	319	315	313	312	310	308	307	305	304	303	303	302	302	301	301	300	300	299	298	298	297
73.2–732MWh	45	45	45	45	45	45	45	44	44	43	42	41	39	38	37	36	34	33	32	31	30
NDM > 732MWh	78	78	79	83	87	90	93	95	97	98	99	99	100	100	101	101	102	102	103	103	104
Total NDM	**443**	**438**	**438**	**439**	**442**	**443**	**444**	**445**	**444**	**444**	**444**	**442**	**441**	**440**	**439**	**437**	**436**	**434**	**433**	**432**	**430**
Total DM	97	99	100	102	103	103	103	102	102	101	101	101	100	100	100	100	100	100	100	101	101
LDZ Shrinkage	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Total LDZ	**543**	**540**	**541**	**544**	**548**	**549**	**550**	**550**	**549**	**548**	**547**	**546**	**544**	**543**	**541**	**540**	**539**	**537**	**536**	**535**	**533**
NTS Industrial	25	25	26	26	26	26	26	26	26	26	25	25	25	25	25	25	25	25	25	25	25
Exports to Ireland	60	30	32	37	34	37	41	44	52	54	57	58	59	61	61	60	61	62	62	63	65
NTS Power Generation	154	173	160	165	167	143	134	133	136	157	157	152	162	161	163	147	141	145	148	150	150
NTS Consumption	240	228	218	228	227	207	202	204	214	237	240	236	246	247	250	232	226	232	235	238	240
NTS Shrinkage	3	3	3	3	3	3	3	3	3	4	4	4	3	3	3	3	3	3	3	3	4
Total excluding IUK	786	771	762	776	778	760	755	757	767	788	790	785	794	793	794	775	769	773	774	776	777
IUK	59	59	58	58	56	52	48	44	40	36	32	28	24	20	19	16	14	12	10	8	6
Total including IUK	**845**	**830**	**820**	**833**	**834**	**812**	**804**	**801**	**807**	**825**	**823**	**813**	**818**	**814**	**813**	**792**	**783**	**786**	**785**	**785**	**783**

Figure A5.1C
No Progression: Annual demand

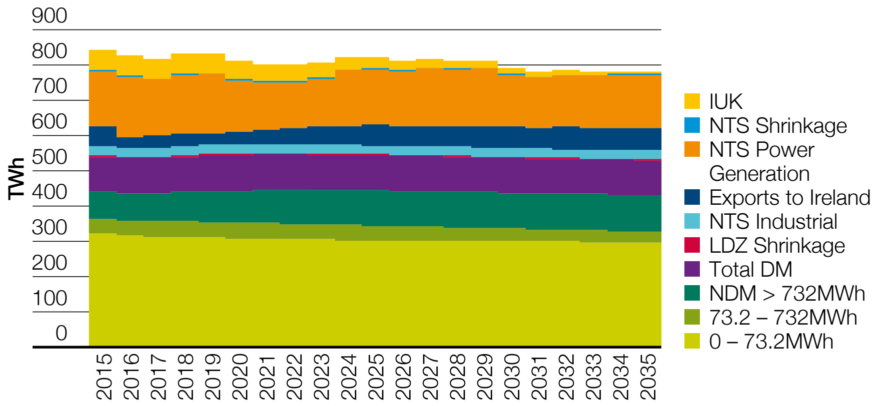
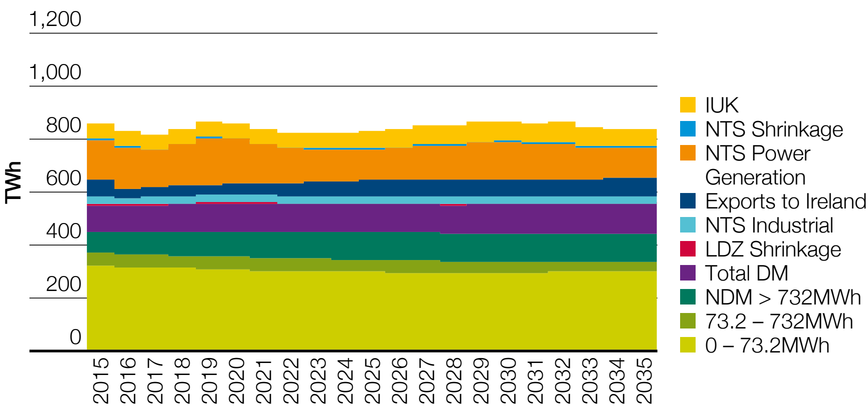


Table A5.1D
Consumer Power: Annual demand – Split by load categories (TWh)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
0–73.2MWh	319	314	311	308	305	302	300	298	296	294	294	293	292	292	292	292	292	293	293	294	294
73.2–732MWh	47	47	48	48	48	48	48	48	48	47	47	46	45	43	42	41	40	39	38	36	35
NDM > 732MWh	82	82	85	88	91	94	96	98	100	102	103	104	105	105	107	107	108	109	109	110	111
Total NDM	**447**	**443**	**443**	**445**	**445**	**444**	**444**	**443**	**444**	**444**	**443**	**442**	**441**	**441**	**441**	**441**	**441**	**440**	**440**	**440**	**440**
Total DM	100	101	102	105	108	110	108	106	105	105	105	106	106	106	107	107	108	108	108	109	109
LDZ Shrinkage	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Total LDZ	**550**	**548**	**549**	**553**	**556**	**557**	**555**	**552**	**551**	**551**	**551**	**550**	**550**	**550**	**551**	**551**	**551**	**551**	**551**	**551**	**552**
NTS Industrial	26	27	27	27	27	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28	28
Exports to Ireland	65	34	37	43	41	46	48	49	54	57	62	62	63	63	63	61	62	63	65	67	68
NTS Power Generation	151	157	141	151	177	165	143	132	122	122	116	120	132	132	142	144	136	138	121	117	116
NTS Consumption	242	218	204	221	246	239	219	209	205	207	206	211	222	224	234	233	226	229	214	212	212
NTS Shrinkage	3	3	3	3	3	3	3	3	3	4	4	4	3	3	3	3	3	3	3	3	4
Total excluding IUK	795	769	756	777	805	799	777	764	759	762	760	765	776	777	787	788	781	783	769	767	767
IUK	60	59	58	57	56	56	55	57	59	61	66	68	71	73	75	76	77	77	72	68	65
Total including IUK	**855**	**828**	**814**	**834**	**861**	**854**	**832**	**822**	**818**	**823**	**826**	**833**	**847**	**850**	**863**	**864**	**857**	**860**	**841**	**835**	**832**

Figure A5.1D
Consumer Power: Annual demand



Appendix 5 – **Gas Demand and Supply Volume Scenarios**

Table A5.1E
Slow Progression: 1 in 20 peak day undiversified demand (GWh/d)

National	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36
Scotland	341	333	330	328	325	322	320	318	316	313	313	311	309	307	305	304	303	300	299	298	296	294
Northern	208	204	202	201	199	197	196	194	193	191	191	190	188	187	186	185	184	183	182	181	180	178
North West	480	470	467	464	460	454	453	450	446	442	442	439	437	433	432	430	428	424	424	421	419	415
North East	247	241	240	238	236	233	233	231	229	227	227	226	224	222	222	221	220	218	218	217	215	213
East Midlands	393	385	382	380	376	372	370	368	365	360	359	357	355	352	351	350	348	345	345	343	341	337
West Midlands	347	340	338	335	333	328	327	325	323	319	318	316	315	312	311	310	308	305	305	303	301	298
Wales North	43	42	42	41	41	40	40	40	39	39	39	39	38	38	38	38	37	37	37	37	37	36
Wales South	192	189	189	185	183	180	179	177	175	173	173	172	170	169	168	167	167	165	165	164	163	123
Eastern	324	318	317	315	313	310	309	309	294	293	293	291	290	287	287	286	285	282	282	281	279	277
North Thames	413	405	403	401	398	393	393	390	388	384	384	382	380	376	376	374	372	369	369	367	365	361
South East	435	425	423	421	419	414	413	410	408	403	383	401	400	377	376	375	373	390	390	368	366	363
Southern	316	311	310	309	307	304	303	301	298	294	293	292	290	288	288	286	285	282	282	281	280	277
South West	231	226	225	224	223	220	220	218	217	215	215	214	213	211	211	210	209	207	207	206	205	203
Total LDZ	**3,975**	**3,892**	**3,873**	**3,848**	**3,819**	**3,774**	**3,760**	**3,736**	**3,697**	**3,660**	**3,634**	**3,635**	**3,616**	**3,564**	**3,557**	**3,542**	**3,525**	**3,513**	**3,508**	**3,473**	**3,452**	**3,380**
NTS Industrial	136	132	132	132	132	132	132	132	132	132	128	128	128	128	128	128	128	128	128	128	128	128
NTS Power Generation	1,285	1,270	1,296	1,381	1,375	1,306	1,212	1,212	1,174	1,202	1,256	1,161	1,049	1,049	1,150	1,150	980	1,126	1,126	1,088	1,015	1,015
Exports via Moffat	231	236	263	266	292	323	328	345	345	345	345	345	345	345	345	345	345	345	345	345	345	345
Exports via IUK	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total NTS	**1,652**	**1,637**	**1,691**	**1,779**	**1,799**	**1,761**	**1,671**	**1,688**	**1,651**	**1,679**	**1,729**	**1,634**	**1,522**	**1,522**	**1,622**	**1,622**	**1,453**	**1,599**	**1,599**	**1,561**	**1,488**	**1,488**
Total	**5,626**	**5,530**	**5,563**	**5,626**	**5,617**	**5,534**	**5,432**	**5,424**	**5,348**	**5,338**	**5,363**	**5,268**	**5,138**	**5,086**	**5,179**	**5,164**	**4,978**	**5,112**	**5,107**	**5,034**	**4,940**	**4,868**

Figure A5.1E
Slow Progression: 1 in 20 peak day undiversified demand

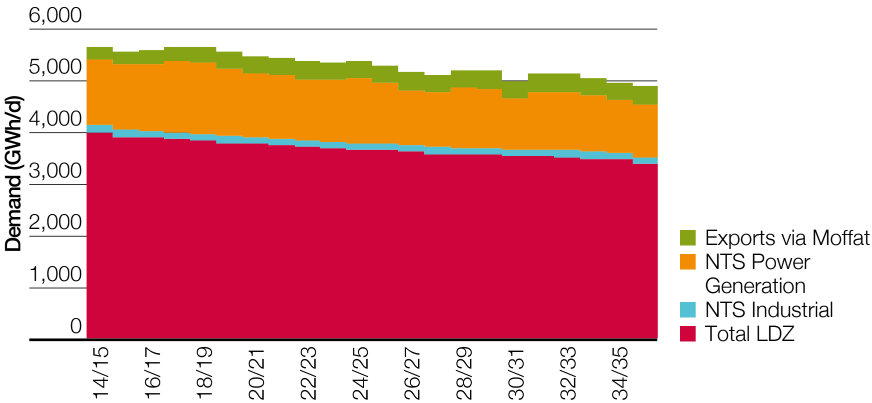
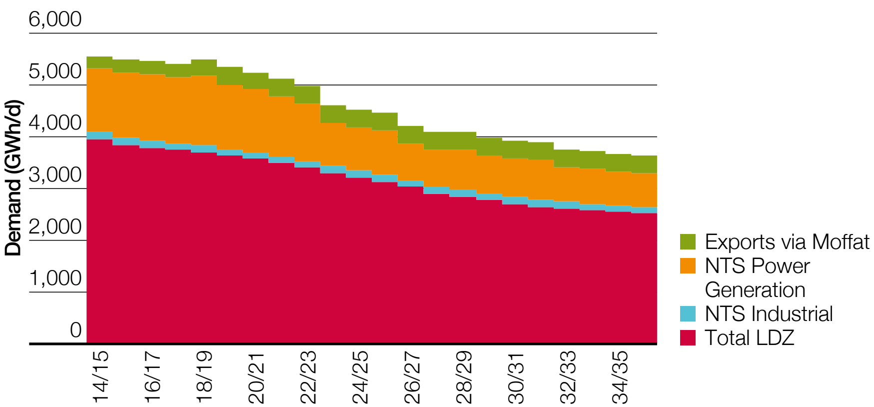


Table A5.1F
Gone Green: 1 in 20 peak day undiversified demand (GWh/d)

National	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36
Scotland	338	328	323	319	316	310	304	297	291	283	276	269	260	250	243	237	231	226	222	219	217	215
Northern	206	201	198	196	194	191	187	183	179	174	170	165	161	155	151	147	145	141	139	138	136	135
North West	476	463	456	451	447	438	431	421	409	397	389	377	366	352	343	335	328	320	316	312	309	305
North East	245	238	235	232	230	225	222	216	212	206	201	195	190	183	178	174	170	166	164	162	160	158
East Midlands	391	380	375	370	366	359	353	344	336	325	317	307	298	286	279	272	266	259	256	253	250	247
West Midlands	344	335	330	326	323	316	311	303	296	287	280	271	263	252	246	239	233	227	224	221	219	216
Wales North	43	42	41	40	40	39	38	37	36	35	34	33	32	31	30	29	29	28	28	27	27	27
Wales South	193	187	183	179	177	170	166	164	161	157	155	152	149	145	142	139	137	134	133	131	130	129
Eastern	322	314	310	307	305	298	294	290	270	263	257	250	242	233	227	222	217	212	209	207	205	203
North Thames	409	399	394	389	386	378	372	363	356	346	338	328	318	306	298	290	284	276	273	270	267	264
South East	434	419	413	408	405	398	392	383	374	362	353	344	334	302	312	304	280	291	288	267	264	261
Southern	314	307	303	300	298	292	287	281	274	265	259	251	244	235	229	224	219	214	211	209	207	205
South West	229	223	220	218	216	211	208	203	199	193	188	183	177	170	166	162	158	154	152	151	149	148
Total LDZ	**3,948**	**3,843**	**3,788**	**3,742**	**3,710**	**3,630**	**3,571**	**3,491**	**3,398**	**3,299**	**3,224**	**3,132**	**3,040**	**2,906**	**2,850**	**2,780**	**2,703**	**2,653**	**2,620**	**2,572**	**2,548**	**2,519**
NTS Industrial	136	132	132	132	132	132	132	132	132	132	128	128	128	128	128	128	128	128	128	128	128	128
NTS Power Generation	1,240	1,270	1,296	1,271	1,352	1,257	1,210	1,143	1,106	835	835	860	705	725	779	730	744	783	673	673	659	659
Exports via Moffat	231	236	263	266	292	323	328	345	345	345	345	345	345	345	345	345	345	345	345	345	345	345
Exports via IUK	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total NTS	**1,607**	**1,637**	**1,691**	**1,669**	**1,775**	**1,712**	**1,670**	**1,619**	**1,583**	**1,311**	**1,308**	**1,332**	**1,177**	**1,197**	**1,252**	**1,203**	**1,217**	**1,256**	**1,146**	**1,146**	**1,131**	**1,131**
Total	**5,554**	**5,481**	**5,478**	**5,411**	**5,485**	**5,342**	**5,240**	**5,111**	**4,981**	**4,610**	**4,531**	**4,464**	**4,217**	**4,103**	**4,102**	**3,983**	**3,920**	**3,909**	**3,766**	**3,718**	**3,679**	**3,650**

Figure A5.1F
Gone Green: 1 in 20 peak day undiversified demand



Appendix 5 – **Gas Demand and Supply Volume Scenarios**

Table A5.1G
No Progression: 1 in 20 peak day undiversified demand (GWh/d)

National	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36
Scotland	343	337	336	337	338	339	340	341	340	339	340	339	338	336	335	334	333	331	330	330	329	326
Northern	209	206	206	206	206	207	207	207	207	206	206	205	205	203	203	202	202	200	200	199	198	197
North West	483	476	475	475	477	477	480	480	480	477	478	477	476	473	473	472	470	467	467	465	464	460
North East	249	244	244	244	245	245	247	247	246	245	246	245	244	243	243	242	241	240	240	239	238	236
East Midlands	396	390	389	390	391	391	393	393	393	390	390	389	388	386	386	385	384	381	381	380	379	376
West Midlands	349	344	343	344	345	345	348	348	348	345	346	345	344	342	342	341	340	337	338	337	335	332
Wales North	43	43	42	42	42	42	43	43	42	42	42	42	42	42	41	41	41	41	41	41	40	40
Wales South	194	192	193	190	189	189	188	187	187	186	185	184	183	182	182	181	180	179	178	178	177	176
Eastern	326	321	322	322	324	325	327	328	328	326	327	326	326	324	324	324	323	321	322	321	320	317
North Thames	415	409	410	411	413	414	418	419	419	417	418	417	417	414	414	413	412	409	410	409	407	404
South East	438	429	429	430	433	434	437	439	439	437	438	438	437	415	436	435	414	432	433	412	411	408
Southern	318	314	314	316	318	318	320	321	321	318	318	318	317	315	316	315	314	312	312	312	311	309
South West	232	229	229	230	231	232	234	234	234	233	234	234	234	232	233	232	232	230	231	230	230	228
Total LDZ	**4,001**	**3,940**	**3,938**	**3,943**	**3,961**	**3,962**	**3,988**	**3,993**	**3,990**	**3,966**	**3,974**	**3,965**	**3,957**	**3,911**	**3,933**	**3,923**	**3,892**	**3,885**	**3,888**	**3,858**	**3,845**	**3,814**
NTS Industrial	136	132	132	132	132	132	132	132	132	132	128	128	128	128	128	128	128	128	128	128	128	128
NTS Power Generation	1,285	1,270	1,296	1,381	1,375	1,306	1,212	1,212	1,174	1,202	1,256	1,161	1,049	1,049	1,150	1,150	980	1,126	1,126	1,088	1,015	1,015
Exports via Moffat	231	236	263	266	292	323	328	345	345	345	345	345	345	345	345	345	345	345	345	345	345	345
Exports via IUK	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total NTS	**1,652**	**1,637**	**1,691**	**1,779**	**1,799**	**1,761**	**1,671**	**1,688**	**1,651**	**1,679**	**1,729**	**1,634**	**1,522**	**1,522**	**1,622**	**1,622**	**1,453**	**1,599**	**1,599**	**1,561**	**1,488**	**1,488**
Total	**5,652**	**5,578**	**5,629**	**5,722**	**5,760**	**5,723**	**5,659**	**5,681**	**5,640**	**5,645**	**5,703**	**5,599**	**5,479**	**5,433**	**5,555**	**5,545**	**5,346**	**5,484**	**5,487**	**5,419**	**5,333**	**5,302**

Figure A5.1G
No Progression: 1 in 20 peak day undiversified demand

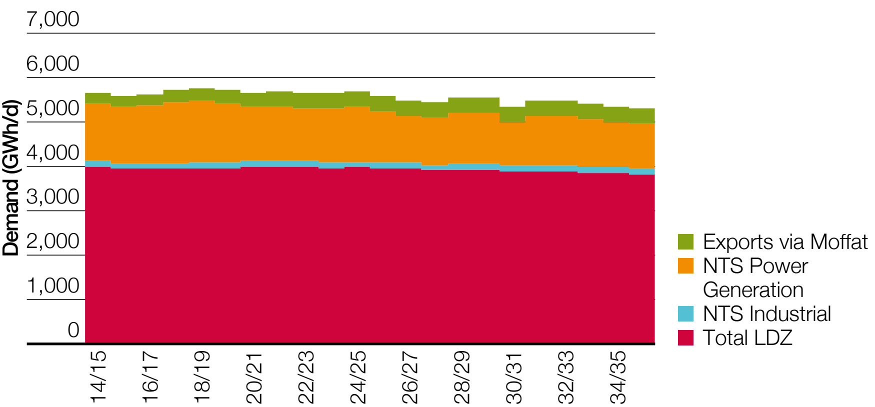
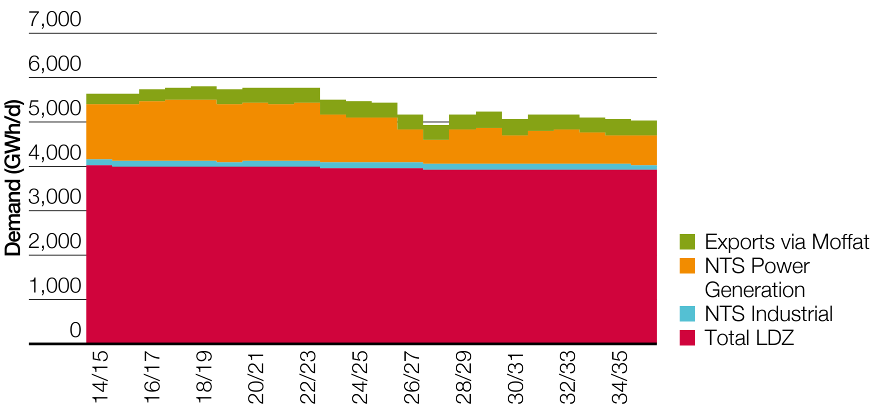


Table A5.1H
Consumer Power: 1 in 20 peak day undiversified demand (GWh/d)

National	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36
Scotland	346	341	341	342	343	342	342	343	342	342	343	343	342	341	341	342	342	341	341	341	341	340
Northern	210	208	208	208	208	208	208	207	207	206	207	206	206	204	205	205	205	204	204	204	204	203
North West	487	481	481	482	483	480	482	482	481	479	481	480	479	477	478	478	478	476	478	478	477	475
North East	250	247	247	248	248	247	248	248	248	247	247	247	247	245	246	246	246	245	246	246	246	244
East Midlands	399	394	394	395	395	393	394	394	394	391	391	390	390	388	389	390	390	388	390	390	389	388
West Midlands	352	348	348	349	349	347	348	348	348	346	347	346	346	344	345	345	345	344	345	345	345	343
Wales North	44	43	43	43	43	43	43	43	43	43	43	43	42	42	42	42	42	42	42	42	42	42
Wales South	195	194	194	191	191	191	191	188	186	185	185	185	184	183	183	183	182	182	182	182	181	181
Eastern	328	324	325	326	327	325	327	327	326	324	325	325	325	323	324	325	325	323	325	325	325	324
North Thames	419	415	416	417	418	416	418	419	419	417	419	418	418	416	418	418	418	416	418	418	417	415
South East	440	432	432	433	434	432	433	433	433	431	412	431	431	409	410	411	411	409	411	411	411	409
Southern	320	318	318	320	321	319	320	320	320	317	318	317	317	315	316	316	316	315	316	316	316	315
South West	234	232	232	233	234	232	234	233	234	233	234	234	234	232	234	234	234	233	234	234	234	233
Total LDZ	**4,030**	**3,983**	**3,986**	**3,993**	**4,000**	**3,981**	**3,994**	**3,990**	**3,986**	**3,967**	**3,958**	**3,971**	**3,966**	**3,925**	**3,938**	**3,940**	**3,940**	**3,923**	**3,938**	**3,938**	**3,936**	**3,917**
NTS Industrial	136	132	132	132	132	132	132	132	132	132	128	128	128	128	128	128	128	128	128	128	128	128
NTS Power Generation	1,240	1,270	1,354	1,370	1,366	1,290	1,312	1,293	1,310	1,070	1,022	1,003	722	541	755	812	640	756	756	687	648	648
Exports via Moffat	231	236	263	266	292	323	328	345	345	345	345	345	345	345	345	345	345	345	345	345	345	345
Exports via IUK	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total NTS	**1,607**	**1,637**	**1,748**	**1,768**	**1,790**	**1,744**	**1,771**	**1,770**	**1,786**	**1,547**	**1,494**	**1,476**	**1,195**	**1,014**	**1,227**	**1,285**	**1,113**	**1,228**	**1,228**	**1,160**	**1,121**	**1,121**
Total	**5,637**	**5,620**	**5,735**	**5,761**	**5,790**	**5,726**	**5,765**	**5,760**	**5,772**	**5,514**	**5,453**	**5,446**	**5,161**	**4,939**	**5,165**	**5,225**	**5,053**	**5,151**	**5,166**	**5,097**	**5,057**	**5,038**

Figure A5.1H
Consumer Power: 1 in 20 peak day undiversified demand



Appendix 5 – **Gas Demand and Supply Volume Scenarios**

Table A5.1I
Slow Progression: 1 in 20 peak day diversified demand (GWh/d)

Diversified Peak	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36
0–73.2MWh	2,531	2,468	2,440	2,412	2,378	2,329	2,301	2,269	2,239	2,207	2,217	2,189	2,181	2,173	2,175	2,168	2,160	2,123	2,122	2,126	2,118	2,130
73.2–732MWh	345	342	338	334	331	327	329	325	320	311	307	298	289	280	271	262	253	243	236	229	219	211
NDM > 732MWh	489	486	498	510	515	519	528	532	539	543	548	549	550	552	552	553	554	553	558	562	560	560
Total NDM	**3,364**	**3,295**	**3,276**	**3,255**	**3,223**	**3,174**	**3,158**	**3,126**	**3,099**	**3,062**	**3,071**	**3,036**	**3,020**	**3,005**	**2,998**	**2,983**	**2,966**	**2,919**	**2,916**	**2,916**	**2,896**	**2,901**
Total DM	461	452	456	457	458	458	460	461	448	446	426	446	445	423	424	424	425	443	444	424	424	385
LDZ Shrinkage	8	8	8	8	8	8	8	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Total LDZ	**3,834**	**3,756**	**3,740**	**3,720**	**3,690**	**3,641**	**3,625**	**3,595**	**3,554**	**3,515**	**3,505**	**3,489**	**3,472**	**3,436**	**3,429**	**3,414**	**3,398**	**3,370**	**3,367**	**3,347**	**3,327**	**3,292**
NTS Industrial	75	72	73	74	74	75	75	75	75	74	74	73	73	73	73	74	73	73	73	74	73	73
Exports to Ireland	231	236	263	266	292	323	328	345	345	345	345	345	345	345	345	345	345	345	345	345	345	345
NTS Power Generation	797	738	822	801	970	847	770	774	776	833	889	906	807	853	826	864	783	859	886	866	790	839
NTS Consumption	1,103	1,047	1,158	1,141	1,336	1,245	1,172	1,194	1,196	1,252	1,308	1,325	1,225	1,271	1,245	1,282	1,202	1,277	1,305	1,285	1,208	1,257
NTS Shrinkage	10	9	9	9	9	9	9	9	9	10	10	10	10	9	10	9	10	10	9	9	9	10
Total excluding IUK	4,946	4,812	4,907	4,869	5,035	4,894	4,807	4,798	4,758	4,778	4,823	4,824	4,707	4,716	4,683	4,705	4,609	4,656	4,681	4,641	4,544	4,559
IUK	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total including IUK	**4,946**	**4,812**	**4,907**	**4,869**	**5,035**	**4,894**	**4,807**	**4,798**	**4,758**	**4,778**	**4,823**	**4,824**	**4,707**	**4,716**	**4,683**	**4,705**	**4,609**	**4,656**	**4,681**	**4,641**	**4,544**	**4,559**
Total Undiversified	5,626	5,530	5,563	5,626	5,617	5,534	5,432	5,424	5,348	5,338	5,363	5,268	5,138	5,086	5,179	5,164	4,978	5,112	5,107	5,034	4,940	4,868
Low power	525	261	327	259	203	173	141	92	61	75	39	39	40	43	40	35	32	32	32	29	28	27
High power	798	942	1,021	1,044	1,259	1,201	1,197	1,156	1,169	1,261	1,314	1,301	1,272	1,279	1,225	1,202	1,173	1,172	1,096	1,095	1,089	1,081
Diversified Total + High Power	4,947	5,016	5,106	5,112	5,324	5,248	5,234	5,180	5,152	5,205	5,248	5,218	5,172	5,142	5,082	5,044	4,999	4,969	4,891	4,870	4,844	4,801
Diversified Total + Low Power	4,674	4,334	4,412	4,327	4,269	4,220	4,178	4,117	4,043	4,020	3,973	3,957	3,940	3,906	3,897	3,877	3,858	3,829	3,827	3,804	3,783	3,748

Figure A5.1I
Slow Progression: 1 in 20 peak day diversified demand

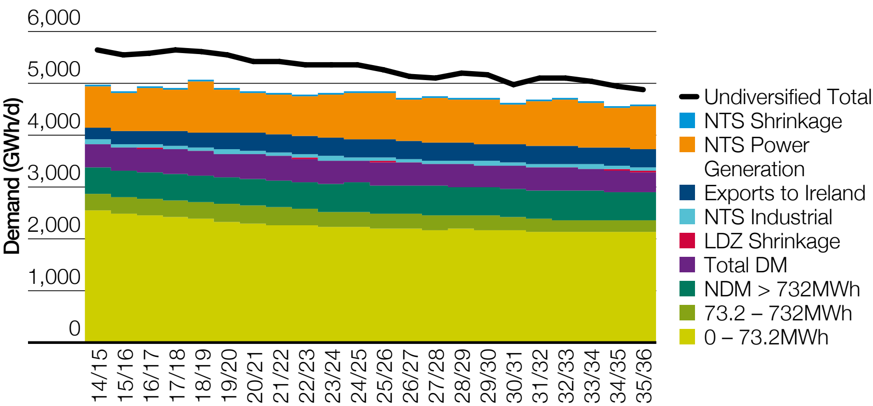
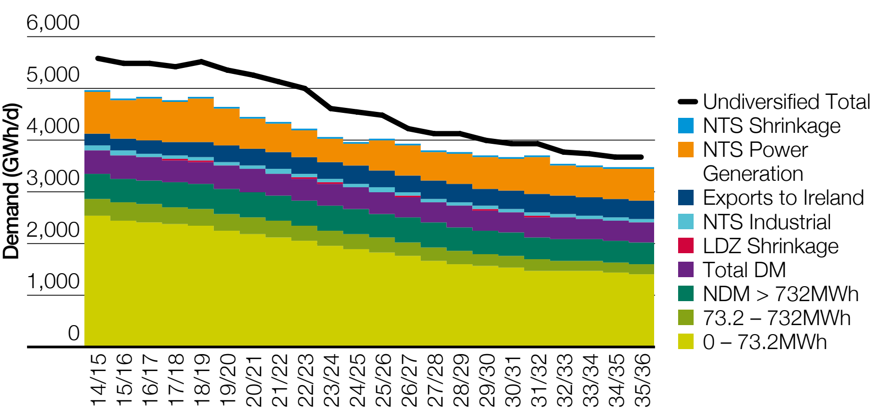


Table A5.1J
Gone Green: 1 in 20 peak day diversified demand (GWh/d)

Diversified Peak	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36
0–73.2MWh	2,527	2,456	2,422	2,382	2,336	2,260	2,197	2,124	2,046	1,959	1,896	1,827	1,755	1,678	1,616	1,569	1,545	1,493	1,470	1,465	1,447	1,427
73.2–732MWh	339	337	332	329	326	321	321	315	308	299	291	279	268	257	243	232	222	208	201	195	188	180
NDM > 732MWh	474	466	459	466	477	477	478	473	481	484	481	474	470	463	453	445	440	426	427	427	428	427
Total NDM	**3,340**	**3,259**	**3,213**	**3,176**	**3,138**	**3,058**	**2,996**	**2,912**	**2,835**	**2,742**	**2,668**	**2,579**	**2,492**	**2,398**	**2,312**	**2,246**	**2,207**	**2,127**	**2,098**	**2,087**	**2,062**	**2,034**
Total DM	459	445	439	437	441	438	436	437	421	418	415	414	412	389	404	401	382	395	394	375	376	376
LDZ Shrinkage	8	8	8	8	8	8	8	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Total LDZ	**3,807**	**3,712**	**3,661**	**3,621**	**3,587**	**3,504**	**3,441**	**3,357**	**3,264**	**3,167**	**3,090**	**3,001**	**2,912**	**2,794**	**2,724**	**2,654**	**2,596**	**2,530**	**2,498**	**2,469**	**2,445**	**2,416**
NTS Industrial	75	73	73	73	74	74	73	73	72	71	71	70	69	69	68	68	68	68	68	68	69	69
Exports to Ireland	231	236	263	266	292	323	328	345	345	345	345	345	345	345	345	345	345	345	345	345	345	345
NTS Power Generation	798	749	783	774	842	694	551	539	510	429	428	569	550	540	590	589	613	717	596	603	580	595
NTS Consumption	1,104	1,058	1,119	1,114	1,208	1,091	953	957	927	846	844	984	964	953	1,003	1,002	1,026	1,130	1,010	1,017	994	1,009
NTS Shrinkage	10	9	9	9	9	9	9	9	9	10	10	10	10	9	10	9	10	10	9	9	9	10
Total excluding IUK	4,921	4,779	4,789	4,743	4,804	4,604	4,402	4,323	4,200	4,022	3,943	3,995	3,886	3,756	3,736	3,665	3,631	3,669	3,517	3,495	3,448	3,435
IUK	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total including IUK	**4,921**	**4,779**	**4,789**	**4,743**	**4,804**	**4,604**	**4,402**	**4,323**	**4,200**	**4,022**	**3,943**	**3,995**	**3,886**	**3,756**	**3,736**	**3,665**	**3,631**	**3,669**	**3,517**	**3,495**	**3,448**	**3,435**
Total Undiversified	5,554	5,481	5,478	5,411	5,485	5,342	5,240	5,111	4,981	4,610	4,531	4,464	4,217	4,103	4,102	3,983	3,920	3,909	3,766	3,718	3,679	3,650
Low power	525	283	319	236	174	112	72	53	37	30	24	25	25	25	24	25	26	28	29	29	27	26
High power	800	941	1,022	1,070	1,261	1,174	1,063	1,062	1,041	1,069	1,099	1,131	1,167	1,175	1,200	1,120	1,019	1,020	872	865	851	822
Diversified Total + High Power	4,924	4,971	5,029	5,039	5,223	5,084	4,914	4,845	4,731	4,662	4,614	4,556	4,503	4,392	4,346	4,197	4,037	3,972	3,793	3,757	3,719	3,661
Diversified Total + Low Power	4,648	4,313	4,326	4,205	4,136	4,021	3,923	3,836	3,728	3,623	3,539	3,450	3,360	3,242	3,171	3,101	3,045	2,980	2,950	2,921	2,895	2,866

Figure A5.1J
Gone Green: 1 in 20 peak day diversified demand



Chapter **seven**

Appendix 5 – **Gas Demand and Supply Volume Scenarios**

Table A5.1K
No Progression: 1 in 20 peak day diversified demand (GWh/d)

Diversified Peak	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36
0–73.2MWh	2,545	2,502	2,495	2,488	2,471	2,440	2,427	2,413	2,404	2,384	2,389	2,383	2,381	2,377	2,371	2,370	2,379	2,346	2,349	2,359	2,355	2,337
73.2–732MWh	349	350	350	348	347	345	348	345	340	332	326	317	308	299	288	277	269	258	251	243	232	222
NDM > 732MWh	492	487	494	509	535	556	580	595	604	611	618	622	626	630	632	633	637	637	645	650	651	648
Total NDM	**3,386**	**3,339**	**3,338**	**3,345**	**3,353**	**3,341**	**3,356**	**3,352**	**3,348**	**3,327**	**3,333**	**3,322**	**3,315**	**3,306**	**3,291**	**3,280**	**3,284**	**3,241**	**3,245**	**3,251**	**3,238**	**3,207**
Total DM	465	459	461	463	471	478	484	486	486	484	484	484	485	463	484	484	465	484	485	465	466	466
LDZ Shrinkage	8	8	8	8	8	8	8	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Total LDZ	**3,860**	**3,807**	**3,807**	**3,816**	**3,832**	**3,827**	**3,847**	**3,846**	**3,842**	**3,818**	**3,824**	**3,814**	**3,806**	**3,776**	**3,782**	**3,771**	**3,756**	**3,732**	**3,738**	**3,724**	**3,711**	**3,680**
NTS Industrial	79	79	80	81	82	83	82	82	81	80	80	79	79	78	78	78	78	77	77	77	77	77
Exports to Ireland	231	236	263	266	292	323	328	345	345	345	345	345	345	345	345	345	345	345	345	345	345	345
NTS Power Generation	795	738	828	815	982	853	774	785	794	849	904	916	819	870	849	880	793	865	889	868	796	845
NTS Consumption	1,105	1,053	1,171	1,162	1,357	1,259	1,184	1,211	1,220	1,274	1,329	1,340	1,243	1,293	1,271	1,303	1,216	1,287	1,312	1,290	1,218	1,267
NTS Shrinkage	10	9	9	9	9	9	9	9	9	10	10	10	10	9	10	9	10	10	9	9	9	10
Total excluding IUK	4,974	4,869	4,988	4,987	5,198	5,095	5,040	5,067	5,071	5,102	5,162	5,163	5,059	5,078	5,063	5,083	4,982	5,029	5,058	5,023	4,938	4,956
IUK	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total including IUK	**4,974**	**4,869**	**4,988**	**4,987**	**5,198**	**5,095**	**5,040**	**5,067**	**5,071**	**5,102**	**5,162**	**5,163**	**5,059**	**5,078**	**5,063**	**5,083**	**4,982**	**5,029**	**5,058**	**5,023**	**4,938**	**4,956**
Total Undiversified	5,652	5,578	5,629	5,722	5,760	5,723	5,659	5,681	5,640	5,645	5,703	5,599	5,479	5,433	5,555	5,545	5,346	5,484	5,487	5,419	5,333	5,302
Low power	525	292	367	288	284	246	195	186	193	195	229	190	165	182	166	170	140	126	127	130	136	132
High power	797	920	1,028	1,055	1,293	1,269	1,176	1,233	1,240	1,312	1,461	1,472	1,473	1,551	1,531	1,519	1,501	1,512	1,524	1,533	1,531	1,523
Diversified Total + High Power	4,976	5,051	5,189	5,227	5,509	5,510	5,443	5,515	5,517	5,564	5,719	5,719	5,712	5,759	5,746	5,722	5,690	5,676	5,693	5,688	5,673	5,634
Diversified Total + Low Power	4,704	4,423	4,527	4,460	4,499	4,487	4,462	4,468	4,469	4,448	4,487	4,437	4,405	4,391	4,381	4,372	4,328	4,290	4,296	4,285	4,279	4,244

Figure A5.1K
No Progression: 1 in 20 peak day diversified demand

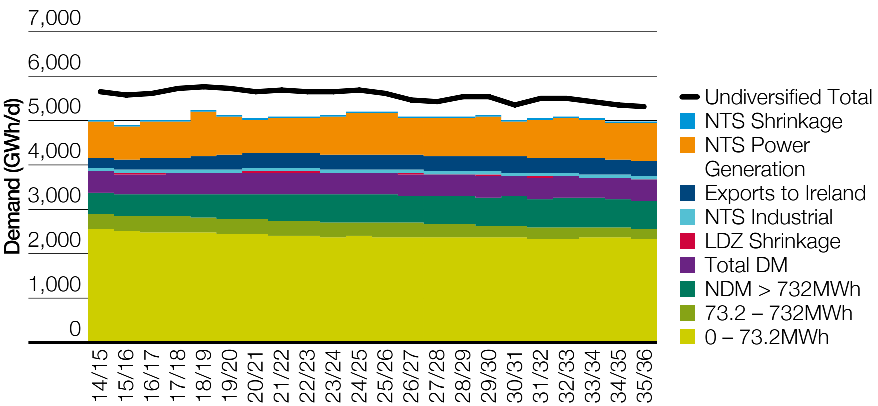
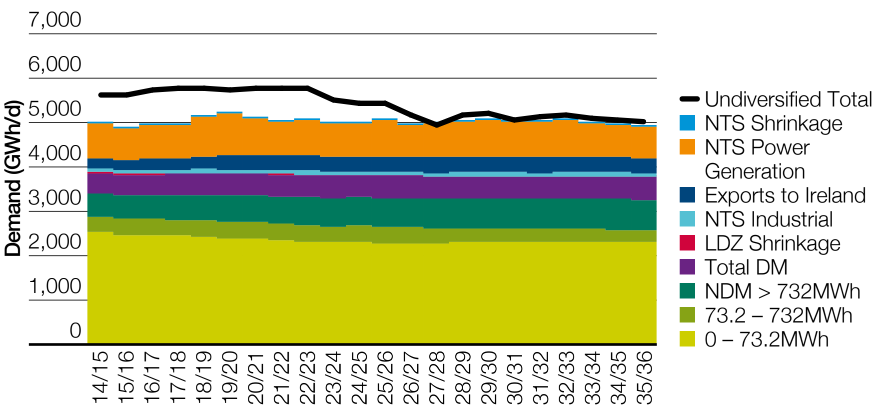


Table A5.1L
Consumer Power: 1 in 20 peak day diversified demand (GWh/d)

Diversified Peak	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36
0–73.2MWh	2,540	2,488	2,474	2,456	2,439	2,402	2,383	2,356	2,338	2,313	2,326	2,305	2,299	2,298	2,310	2,311	2,313	2,307	2,317	2,326	2,328	2,319
73.2–732MWh	358	365	368	370	371	373	377	375	373	367	365	356	349	340	332	323	314	303	296	286	276	265
NDM > 732MWh	512	514	526	548	568	584	601	612	622	632	645	649	657	661	669	674	679	680	690	691	696	696
Total NDM	**3,409**	**3,367**	**3,367**	**3,374**	**3,378**	**3,359**	**3,361**	**3,343**	**3,333**	**3,313**	**3,336**	**3,310**	**3,305**	**3,299**	**3,311**	**3,309**	**3,306**	**3,289**	**3,304**	**3,303**	**3,299**	**3,280**
Total DM	473	470	474	478	486	492	498	499	499	498	481	502	505	484	488	490	492	492	494	495	497	496
LDZ Shrinkage	8	8	8	8	8	8	8	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Total LDZ	**3,891**	**3,845**	**3,849**	**3,860**	**3,872**	**3,859**	**3,867**	**3,850**	**3,839**	**3,818**	**3,824**	**3,820**	**3,817**	**3,791**	**3,805**	**3,806**	**3,805**	**3,788**	**3,805**	**3,805**	**3,803**	**3,783**
NTS Industrial	81	83	85	85	86	86	87	88	88	87	88	87	87	87	87	88	88	88	88	88	88	88
Exports to Ireland	231	236	263	266	292	323	328	345	345	345	345	345	345	345	345	345	345	345	345	345	345	345
NTS Power Generation	798	726	759	742	904	931	824	745	806	758	731	796	703	760	782	827	786	797	834	745	707	697
NTS Consumption	1,109	1,045	1,107	1,093	1,282	1,341	1,239	1,178	1,239	1,190	1,164	1,228	1,135	1,192	1,215	1,260	1,219	1,230	1,267	1,178	1,140	1,130
NTS Shrinkage	10	9	9	9	9	9	9	9	9	10	10	10	10	9	10	9	10	10	9	9	9	10
Total excluding IUK	5,009	4,900	4,965	4,962	5,163	5,208	5,115	5,037	5,087	5,018	4,997	5,058	4,962	4,992	5,030	5,076	5,034	5,027	5,082	4,992	4,953	4,923
IUK	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total including IUK	**5,009**	**4,900**	**4,965**	**4,962**	**5,163**	**5,208**	**5,115**	**5,037**	**5,087**	**5,018**	**4,997**	**5,058**	**4,962**	**4,992**	**5,030**	**5,076**	**5,034**	**5,027**	**5,082**	**4,992**	**4,953**	**4,923**
Total Undiversified	5,637	5,620	5,735	5,761	5,790	5,726	5,765	5,760	5,772	5,514	5,453	5,446	5,161	4,939	5,165	5,225	5,053	5,151	5,166	5,097	5,057	5,038
Low power	525	265	294	200	205	110	123	92	90	77	58	53	48	47	47	52	56	62	67	57	56	55
High power	799	942	1,005	1,031	1,283	1,211	1,192	1,191	1,270	1,193	1,288	1,240	1,300	1,309	1,274	1,257	1,127	1,090	1,089	1,017	1,008	1,000
Diversified Total + High Power	5,011	5,115	5,211	5,251	5,542	5,488	5,483	5,483	5,551	5,453	5,554	5,502	5,559	5,541	5,522	5,505	5,375	5,321	5,336	5,264	5,253	5,227
Diversified Total + Low Power	4,737	4,438	4,500	4,420	4,465	4,387	4,414	4,384	4,371	4,337	4,324	4,315	4,308	4,279	4,295	4,300	4,304	4,293	4,314	4,304	4,301	4,281

Figure A5.1L
Consumer Power: 1 in 20 peak day diversified demand



Appendix 5 – **Gas Demand and Supply Volume Scenarios**

Figure A5.1M
2015/16 Load curve – Slow Progression

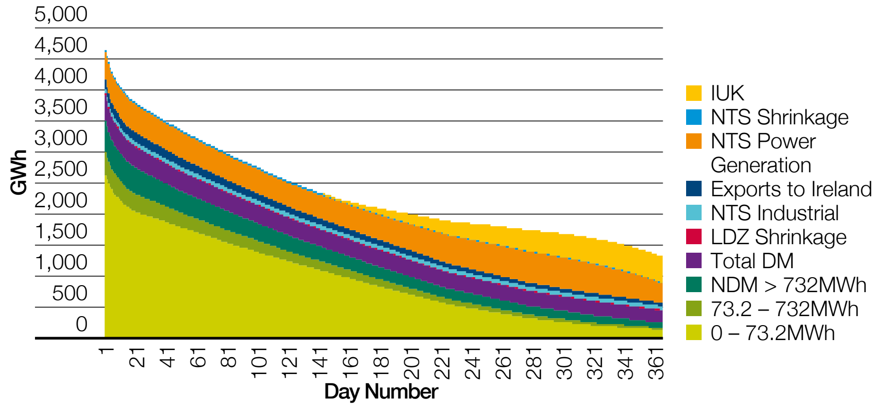


Figure A5.1N
2015/16 Load curve – Gone Green

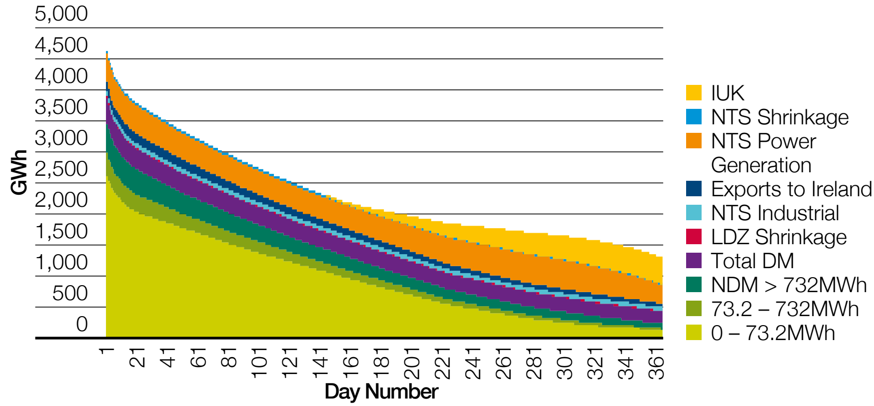


Figure A5.1O
2015/16 Load curve – No Progression

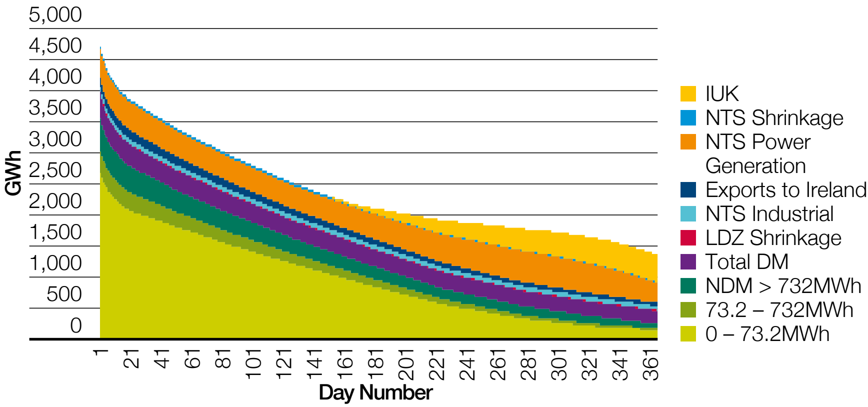
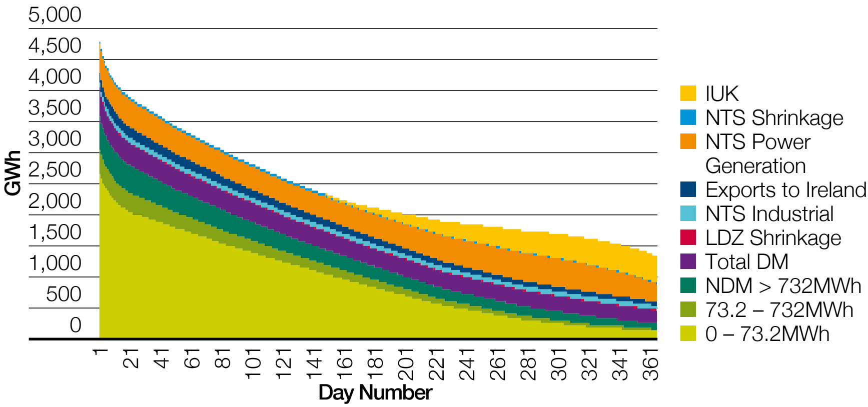


Figure A5.1P
2015/16 Load curve – Consumer Power



Appendix 5 – **Gas Demand and Supply Volume Scenarios**

Figure A5.1Q
2025/26 Load curve – Slow Progression

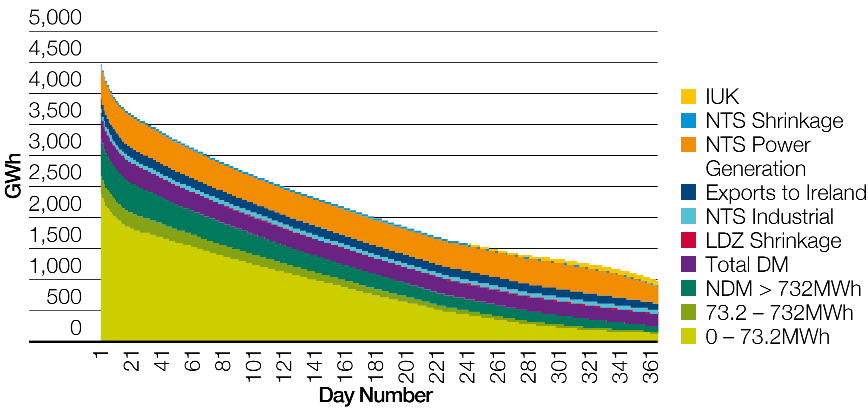


Figure A5.1R
2025/26 Load curve – Gone Green

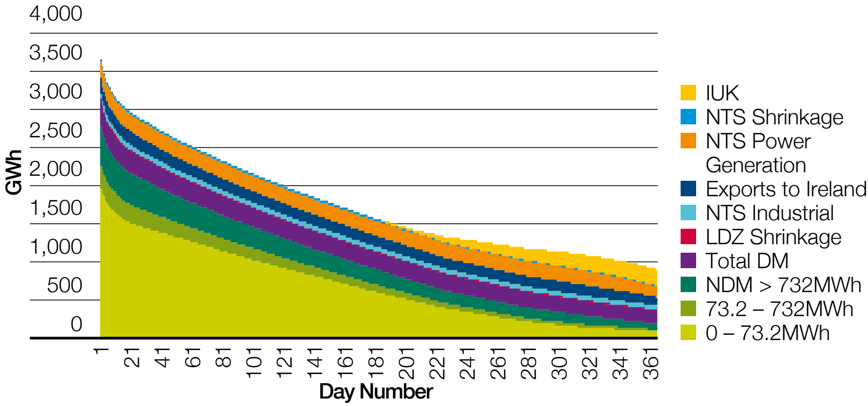


Figure A5.1S
2025/26 Load curve – No Progression

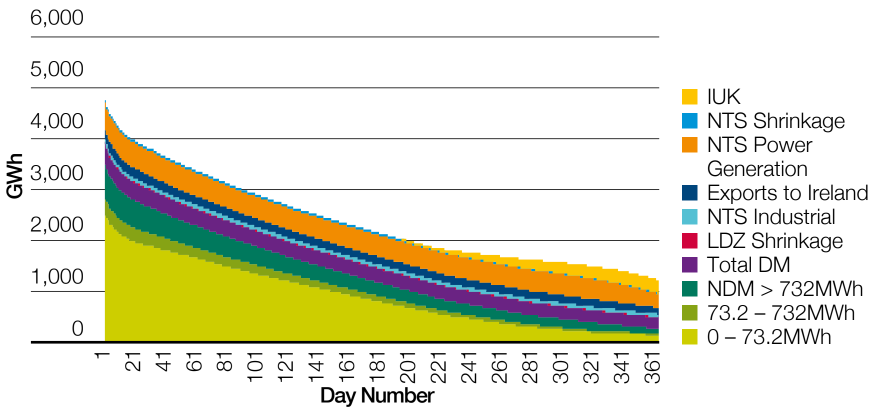
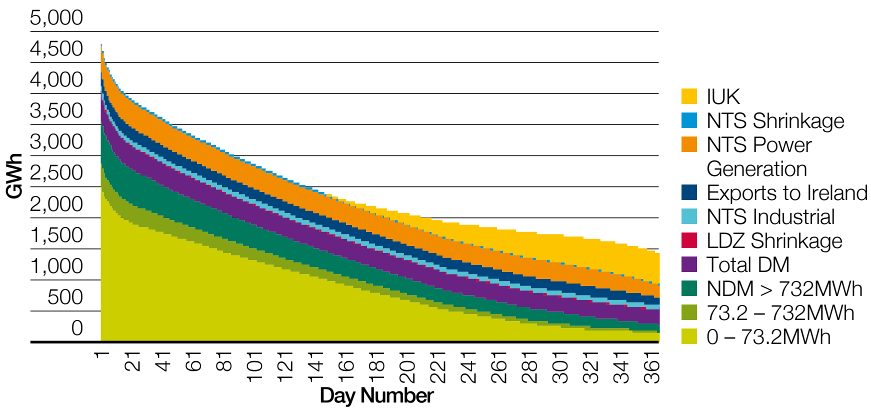


Figure A5.1T
2025/26 Load curve – Consumer Power



Appendix 5 – **Gas Demand and Supply Volume Scenarios**

Figure A5.1U
2030/31 Load curve – Slow Progression

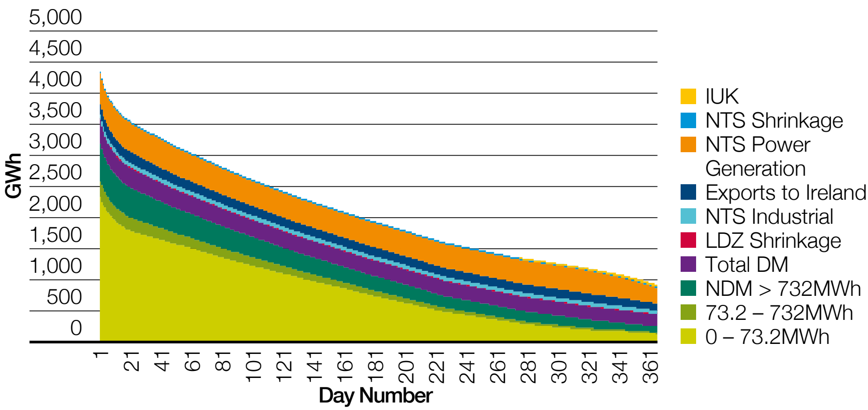


Figure A5.1V
2030/31 Load curve – Gone Green

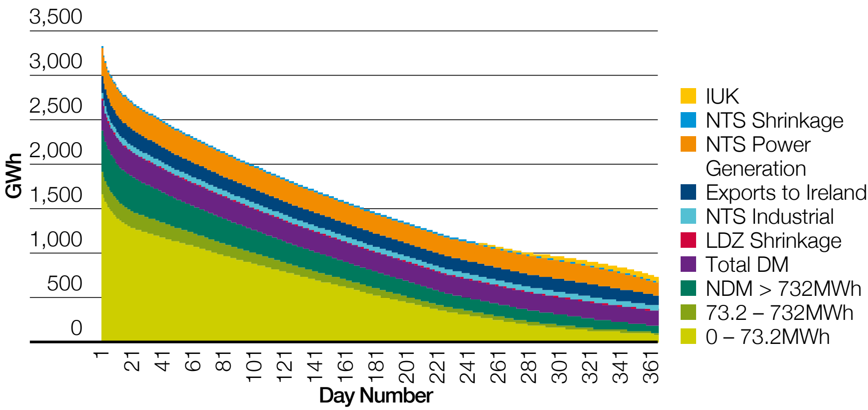


Figure A5.1W
2030/31 Load curve – No Progression

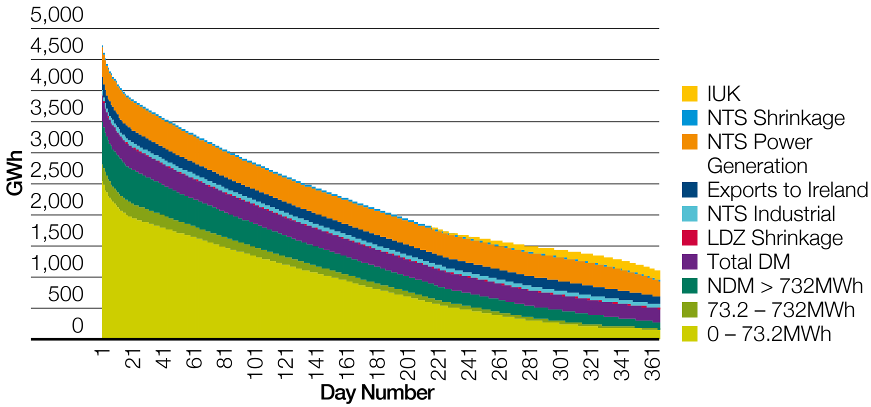
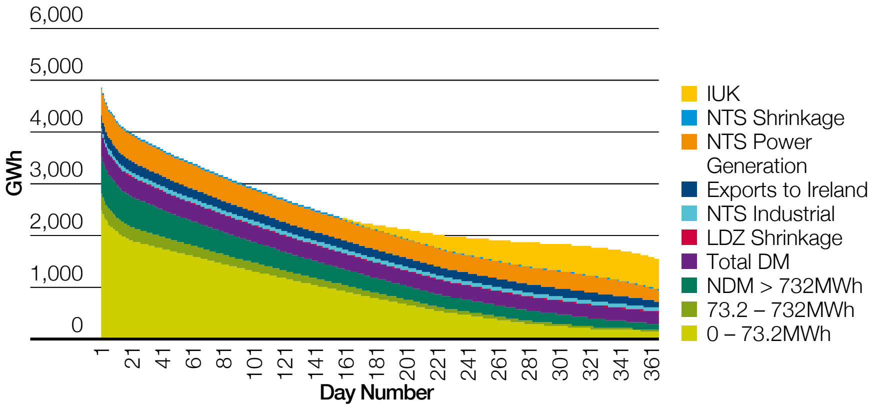


Figure A5.1X
2030/31 Load curve – Consumer Power



Appendix 5 – **Gas Demand and Supply Volume Scenarios**

5.2 Supply

Figure A5.2A
Peak Bacton scenarios (mcm/d)

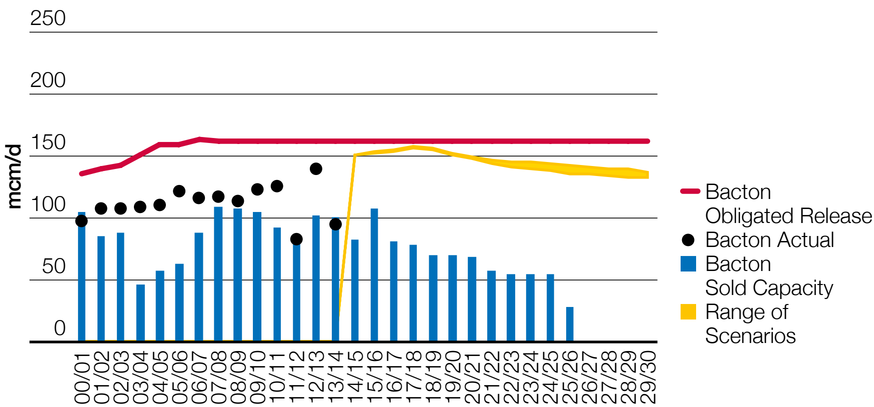


Figure A5.2B
Peak Barrow scenarios (mcm/d)

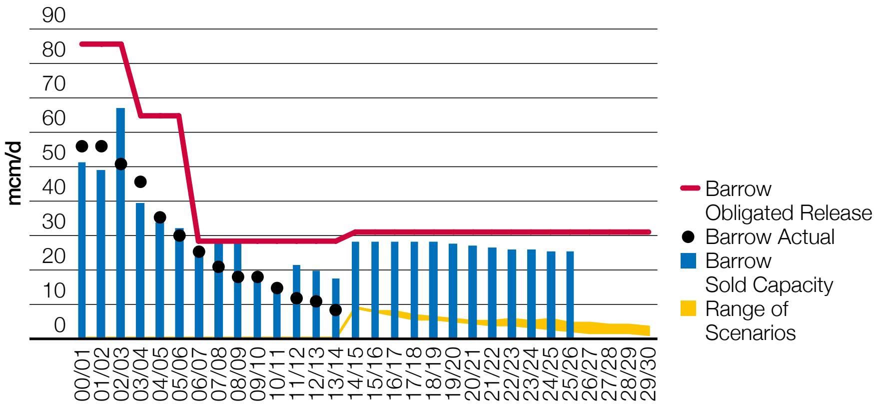


Figure A5.2C
Peak Easington scenarios (mcm/d)

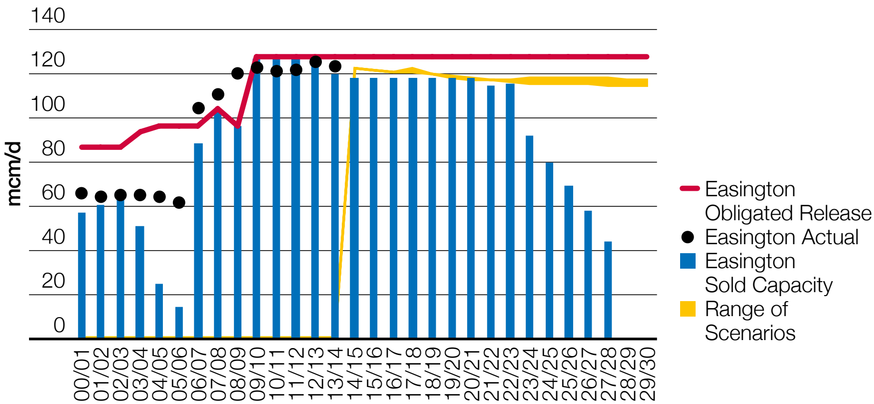
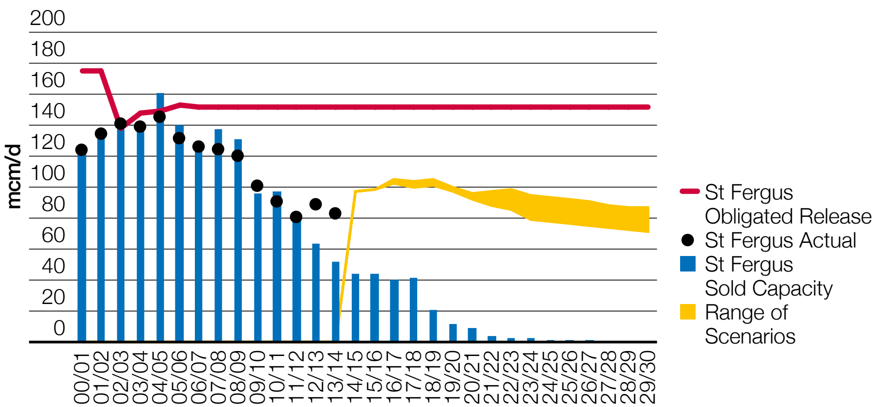


Figure A5.2D
Peak St. Fergus scenarios (mcm/d)



Appendix 5 – **Gas Demand and Supply Volume Scenarios**

Figure A5.2E
Peak Teesside scenarios (mcm/d)

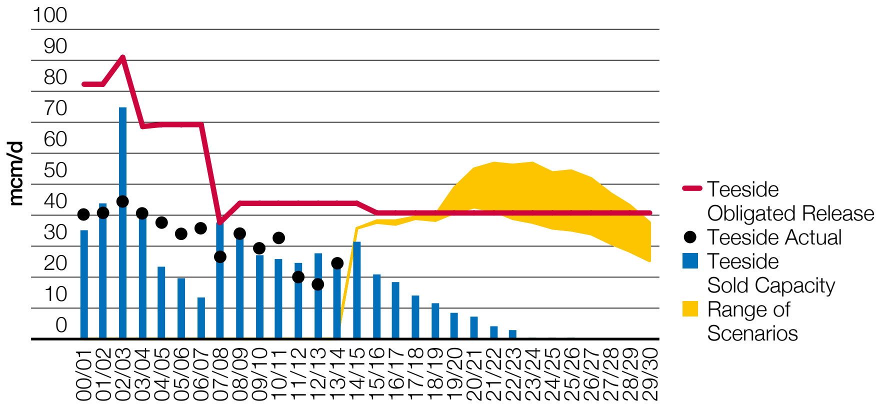


Figure A5.2F
Peak Theddlethorpe scenarios (mcm/d)

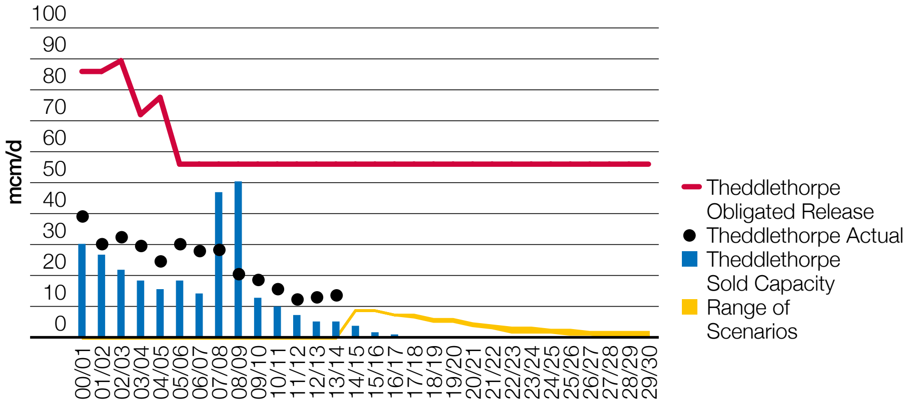


Figure A5.2G
Peak Grain LNG scenarios (mcm/d)

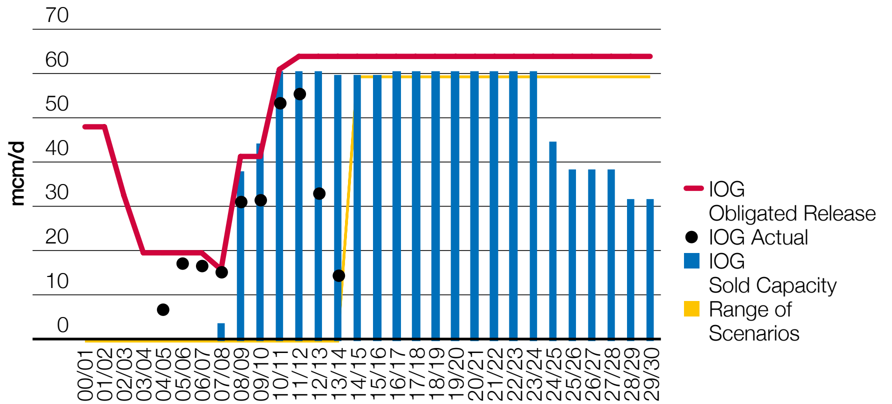
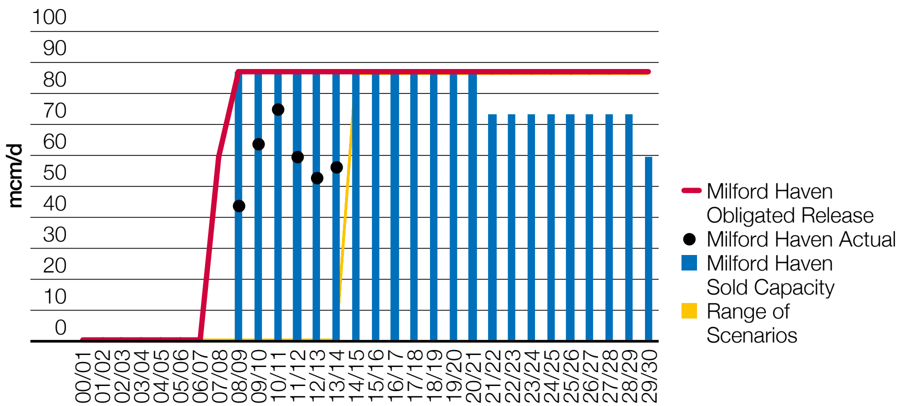


Figure A5.2H
Peak Milford haven scenarios (mcm/d)



Chapter seven

Appendix 5 – **Gas Demand and Supply Volume Scenarios**

Figure A5.2I
Annual supply by terminal. Gone Green high continent/low LNG case

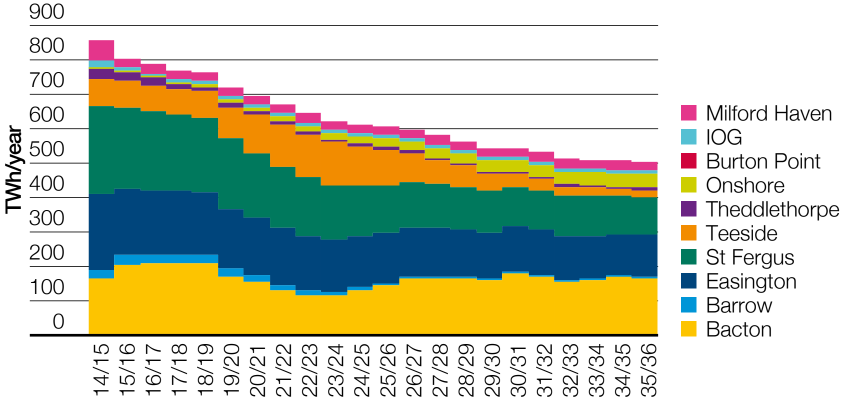


Figure A5.2J
Annual supply by terminal. Gone Green low continent/high LNG case

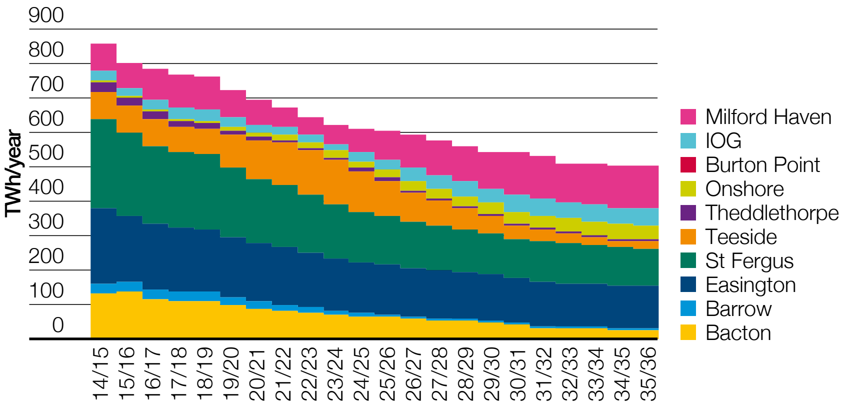


Figure A5.2K
Peak supply by terminal. Gone Green

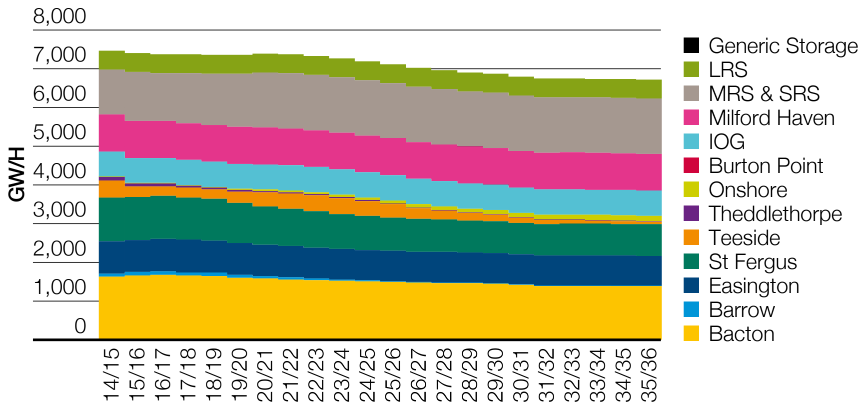
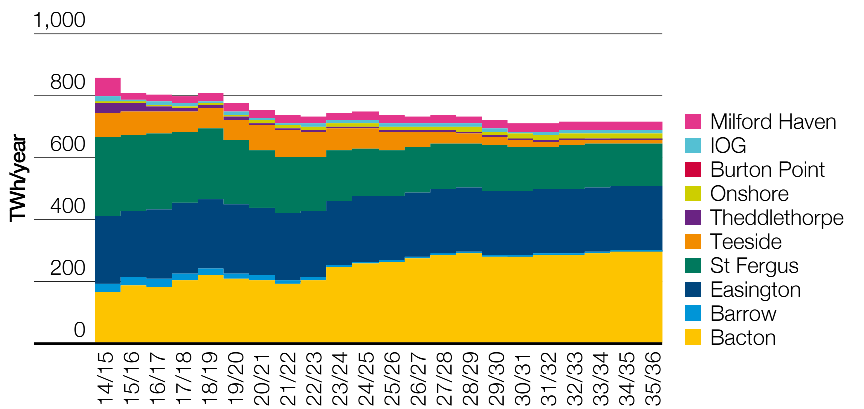


Figure A5.2L
Annual supply by terminal. Slow Progression high continent/low LNG case



Appendix 5 – **Gas Demand and Supply Volume Scenarios**

Figure A5.2M
Annual supply by terminal. Gone Green high continent/low LNG case

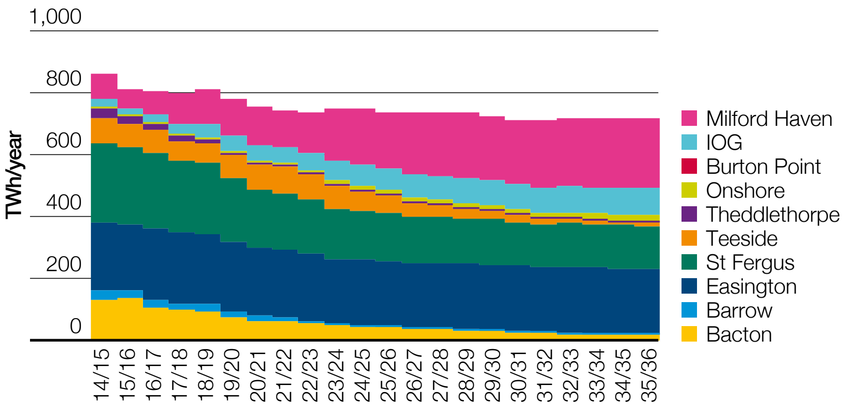


Figure A5.2N
Peak supply by terminal. Slow Progression

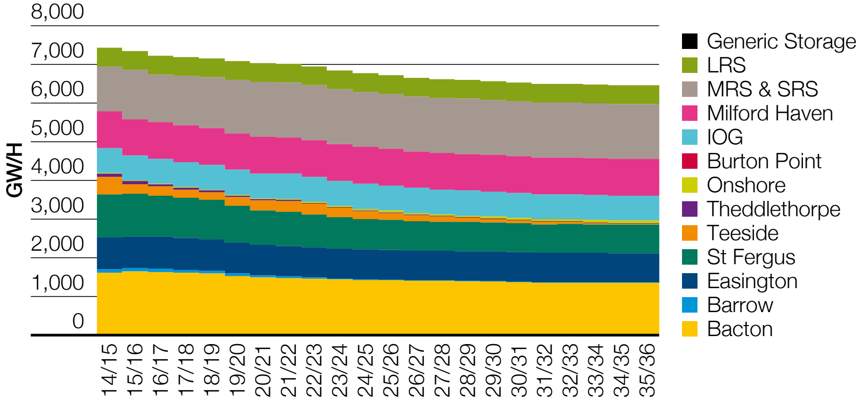


Figure A5.2O
Annual supply by terminal. No Progression high continent/low LNG case

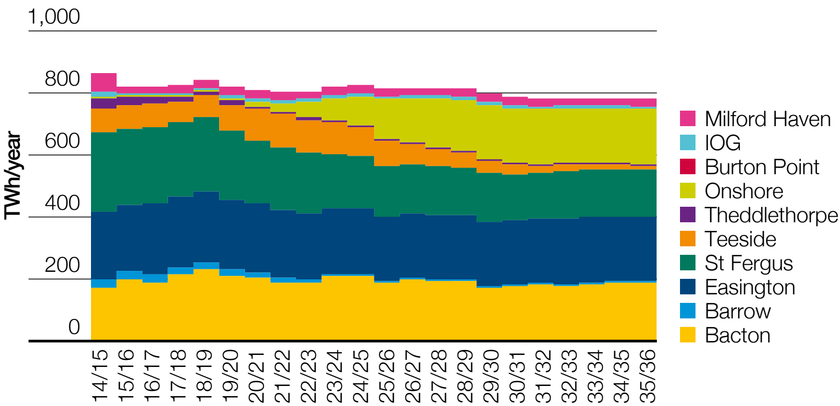
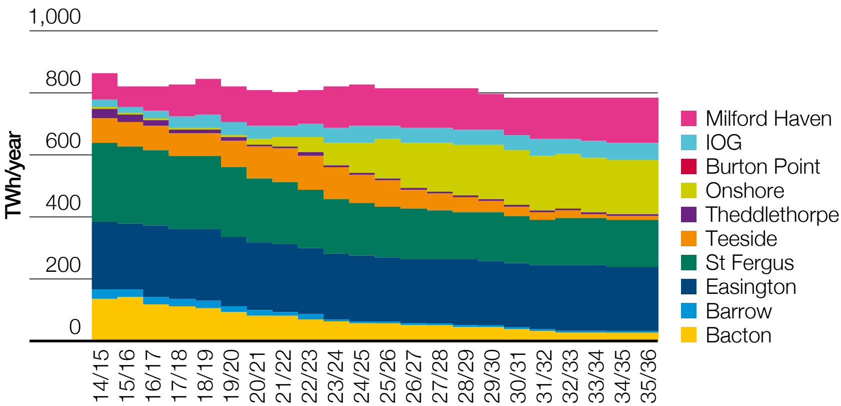


Figure A5.2P
Annual supply by terminal. No Progression low continent/high LNG case



Appendix 5 – **Gas Demand and Supply Volume Scenarios**

Figure A5.2Q
Peak supply by terminal. No Progression

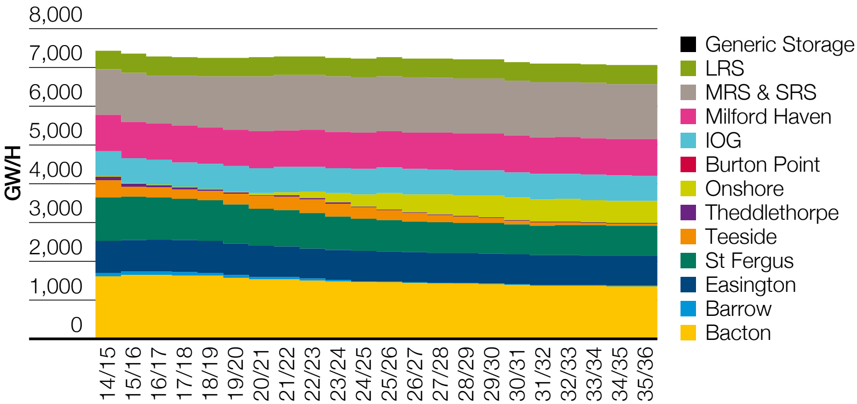


Figure A5.2R
Annual supply by terminal. Consumer Power high continent/low LNG case

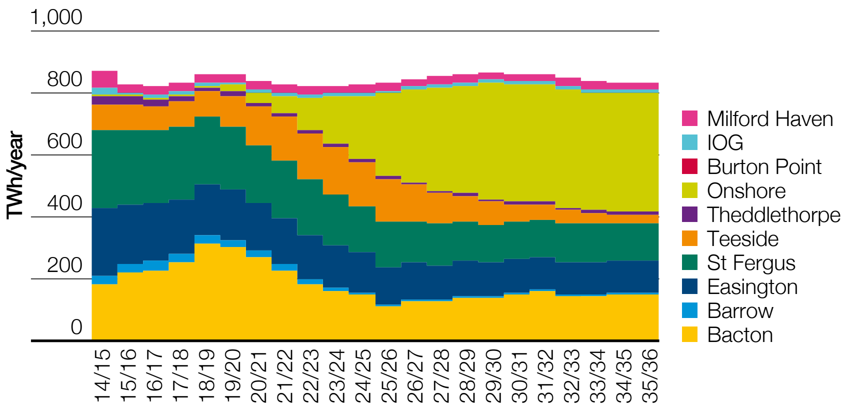


Figure A5.2S
Annual supply by terminal. Consumer Power low continent/high LNG case

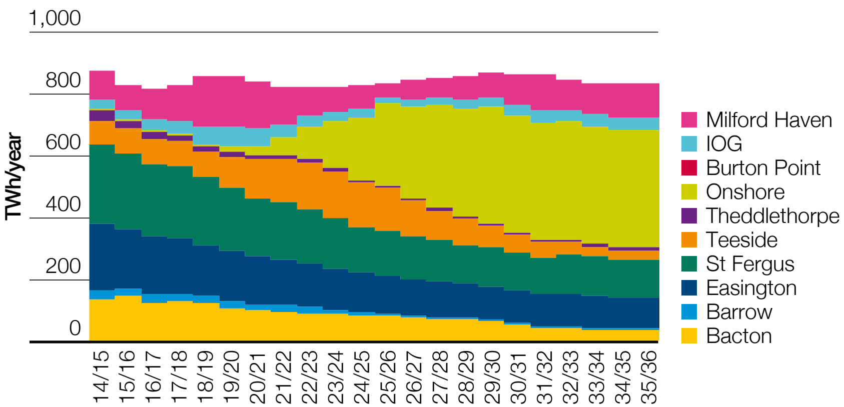
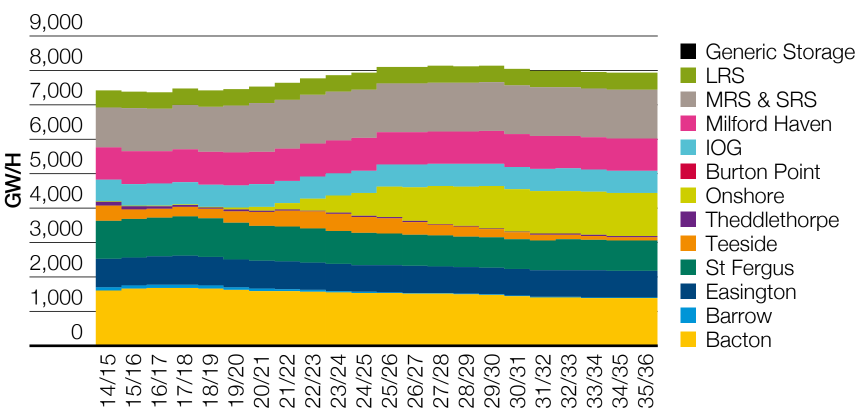


Figure A5.2T
Peak supply by terminal. Consumer Power



Appendix 5 – **Gas Demand and Supply Volume Scenarios**

5.3
UK Importation Projects

While there are proposals for further import projects, currently no importation projects are under construction. The UK's import capacity is currently around 152 bcm/y, this is split into three near equal sources: the Continent (46 bcm/y), Norway (56 bcm/y) and LNG (49 bcm/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 A5.3A shows existing UK import infrastructure and Table A5.3B shows proposals for further import projects.

Table A5.3A
Existing UK import infrastructure

Project	Operator/Developer	Type	Location	Capacity (bcm/y)
Interconnector	IUK	Pipeline	Bacton	26.9
BBL Pipeline	BBL Company	Pipeline	Bacton	19.5
Isle of Grain 1-3	National Grid	LNG	Kent	20.4
South Hook 1-2	Qatar Petroleum and ExxonMobil	LNG	Milford Haven	21
Dragon 1	Bg Group/Petronas	LNG	Milford Haven	7.6
Langeled	Gassco	Pipeline	Easington	26.3
Vesterled	Gassco	Pipeline	St Fergus	14.2
Tampen	Gassco	Pipeline	St Fergus	9.8
Gjoa	Gassco	Pipeline	St Fergus	6.2
			Total	152

Source: National Grid

Table A5.3B
Proposed UK import projects[1]

Project	Operator/ Developer	Type	Location	Start-up	Capacity (bcm/y)	Status
Isle of Grain 4	National Grid	LNG	Kent	~	~	Open Season
Norsea LNG	ConocoPhillips	LNG	Teeside	~	~	Planning Granted, no FID. Currently on Hold
Port Meridian	Port Meridian Energy	LNG	Barrow, Cumbria	~	5	Open Season
Amlwch	Halite Energy	LNG	Anglesey	~	~30	Approved
				Total		

Source: National Grid

Please note: Tables A5.3A and A5.3B 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.

[1] This list is in no way exhaustive; other import projects have at times been detailed in the press.

Appendix 5 – **Gas Demand and Supply Volume Scenarios**

5.4
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.

Table A5.4A
Existing UK storage

Project	Operator/Developer	Location	Space (bcm)	Approximate max delivery (mcm/d)	Injection (mcm/d)
Rough	Centrica Storage	Southern North Sea	3.1	44.7	28
Aldborough	SSE/Statoil	East Yorkshire	0.3	40	19.7
Hatfield Moor	Scottish Power	South Yorkshire	0.07	2	1.9
Holehouse Farm	EDF Trading	Cheshire	0.05	11	10.8
Holford	E.ON	Cheshire	0.2	22	22.1
Hornsea	SSE	East Yorkshire	0.3	18	2
Humbly Grove	Humbly Grove Energy	Hampshire	0.3	7	8.2
Avonmouth	National Grid LNGS	Avon and Somerset	0.08	13	0
Hill Top Farm	EDF Energy	Cheshire	0.02	2.1	5.5
Stublach	Storenergy	Cheshire	0.2	15	29.7
		Total	**4.6**	**175**	**127.9**

Source: National Grid

Note, due to operational considerations, the space and deliverability may not be fully consistent with that used for operational planning as reported in our 2015/16 Winter Outlook Report.

Over the last few years, a number of projects have been put on hold or cancelled. These include Aldborough 2, Baird, Caythorpe, Gateway and Portland. Table A5.4B shows other storage site.

Table A5.4B
Proposed storage[2]

Project	Operator/Developer	Location	Space (bcm)	Approximate max delivery (mcm/d)
Deborah	Eni	Offshore Bacton	4.6	Planning granted, no FID
Islandmagee	InfrasStrata	County Antrim, Northern Ireland	0.5	Planning granted, no FID
King Street	King Street Energy	Cheshire	0.3	Planning granted, no FID
Preesail	Halite Energy	Lancashire	0.6	Planning granted, no FID
Saltfleetby	Wingaz	Lincolnshire	0.8	Planning granted, no FID
Whitehill	E.ON	East Yorkshire	0.4	Planning granted, no FID
		Total	**7.2**	

Source: National Grid

Please note: Tables A5.4A and A5.4B represent the latest information available to National Grid at the time of going to press. Developers are welcome to contact us to add or revise this data.

[2] This list is in no way exhaustive; other storage projects at times have been detailed in the press.

Appendix 6
EU Activity

6.1
Our activity to date

In chapter 2.3 we discussed the European Union (EU) Third Package of EU legislation which was introduced in 2009. Over the last five years, we have been working with the European Network of Transmission System Operators for Gas (ENTSOG), EU Commission, European Regulators, Ofgem, other Transmission System Operators (TSOs) and our customers to enable the development of the Capacity Allocation Mechanism (CAM) and Balancing (BAL) EU Codes.

We have influenced the EU Code developments and supported the industry and our customers, through a process of extensive dialogue with market participants, stakeholder working sessions, technical workshops and a number of consultations.

We have changed our current contractual arrangements at Bacton (connecting to Belgium and Holland) and at Moffat (connecting Northern and Southern Ireland to the UK) to ensure we comply with the new legislation.

On the 1 October 2015 the UK market will align to the EU standard gas day of 5am – 5am. We have changed a number of internal processes in preparation for the gas day change.

To date, the modifications proposed to implement the EU Codes and Guidelines are:

a 0449 (Introduction of Interconnection Points and new processes and transparency requirements to facilitate compliance with the EU Congestion Management Procedures). Implemented with effect from 06:00 on 1 October 2013; it is superseded by text introduced under 0500
b 0461 (Changing the UNC Gas Day to Align with Gas Day under EU Network Codes). Implemented with effect from 05:00 on 1 October 2015
c 0485 (Introduction of Long-term use-it-or-lose-it mechanism to facilitate compliance with EU Congestion Management Procedures). Implemented with effect from 06:00 on 30 September 2014; it is superseded by text introduced under 0500
d 0489 (EU Gas Balancing Code – Information Provision changes required to align the UNC with the EU Code). Implemented with effect from 05:00 on 1 October 2015
e 0493 (EU Gas Balancing Code Daily Nominations at Interconnection Points (IP)). Implemented with effect from 06:00 on 19 June 2015

f 0494 (Imbalance Charge amendments required to align the UNC with the Network Code on Gas Balancing of Transmission Networks). Implemented with effect from 05:00 on 1 October 2015
g 0500 (EU Capacity Regulations Capacity Allocation Mechanisms with Congestion Management Procedures). Implemented with effect from 06:00 on 19 June 2015
h 0501V (Treatment of Existing Entry Capacity Rights at the Bacton ASEP to comply with EU Capacity Regulations). Implemented with effect from 06:00 on 21 July 2015. The process established by this modification (for allocation of capacity held by shippers between the new ASEPs at Bacton) was completed on 28 August 2015
i 0510V (Reform of Gas Allocation Regime at GB Interconnection Points). To be implemented with effect from 05:00 on 1 October 2015
j 0519 (Harmonisation of Reference Conditions at Interconnection Points). To be implemented with effect from 05:00 on 1 October 2015
k 0525 (Enabling EU compliant Interconnection Agreements). To be implemented with effect from 05:00 on 1 October 2015
l 0546S (Reduction of the Minimum Eligible Quantity (100,000kWh) for European IP capacity)
m 0547S (Corrections to the EID arising from implementation of Modifications 0493/0500).

Appendix 6
EU Activity

6.2
Our future activity

As part of our obligations under Article 6 (Capacity calculation and maximisation) and Article 11(8) of the CAM Code, we have agreed to meet with other European Transmission System Operators (TSO) at least once a year to discuss the amount of Available IP Capacity (and any additional capacity) that will be offered in the upcoming annual yearly capacity auction. The aim of this is to allow all TSOs to jointly analyse the technical capacities in each System and maximise the bundled capacity available. Our analysis will include a detailed comparison with our connecting TSOs of:

- technical capacity in each system; and
- available IP capacity in each system.

Any differences will be noted and quantified with the reasons where possible. The analysis will take account of assumptions made in the EU-wide 10 year development plan, existing national investment plans, relevant obligations under the applicable national laws, and any relevant contractual obligations.

We will assess all relevant parameters, including but not limited to: pressure commitments, relevant supply and demand scenarios, and calorific values. Any options for adjusting these parameters will be discussed with other TSOs. We will also consider information that our customers (gas shippers) may provide regarding expected future flows. We will consider our regulatory regime and obligations as part of this process.

Once the analysis is complete (including a cost benefit analysis), we will identify if there is an opportunity to increase available IP Capacity. Where we propose an increase to available IP Capacity, we will consider what impact this action may have on:

- the timescales required for its increase
- any increased costs and if the regulatory regime(s) will allow for the recovery of these costs (especially if there are any cross-subsidies between TSOs)
- other points on either System and stakeholders (including terminal operators, Shippers, other TSOs).

6.2.1 Future activity on Codes & Guidelines

We have a programme of changes planned for delivery on 1 May 2016 which will include the following:

- Delivery of Modification 0519 (Harmonisation of Reference Conditions at Interconnection Points) change to the Gemini system to manage the impact of different reference conditions for shipper nominations and allocations at the Bacton interconnection points
- Delivery of a new data exchange solution in line with Interoperability Code requirements to enable shippers to submit nominations and receive confirmed quantities at interconnection points in Edigas format over the internet
- Disapplication of scheduling charges in respect of interconnection points, as implemented by Modification 0510V (Reform of Gas Allocation Regime at GB Interconnection Points)
- Enable delivery of additional transparency requirements in respect of capacity data and hourly flow at interconnection points
- Amendments to functionality in Gemini to allow it to send within-day capacity and tariff values to PRISMA.

6.2.2 2016 onwards

An EU-wide Network Code on Harmonised Transmission Tariff Structures for Gas;

- Amendment proposal to the Network Code on Capacity Allocations Mechanisms on Incremental Capacity. This will be an amendment to Commission Regulation (EU) No 984/2013 which aims to introduce a process for the release of incremental capacity at interconnection points.

Both are expected to go through the formal comitology process in 2016 and be adopted by the European Commission by December 2016. The timescales for their implementation shall be agreed during comitology. Comitology in the European Union refers to a process by which EU law is modified or adjusted and takes place within “comitology committees” chaired by the European Commission.

Appendix 7
Network development process

The following table outlines the criteria we use to prioritise all of the options considered as part of our Network Development Process (NDP). The scoring from the Whole Life Prioritisation Model aids our decision making process and allows us to discount unsuitable options at an early stage of the NDP.

Criteria	Description	
Does this option allow National Grid to meet future flexibility requirements?	Reduces system flexibility and will impact users' current requirements.	Reduces system flexibility and may impact users' future requirements.
Does this option remove barrier for encouraging new investment?	Will reduce network capability and how the NTS is currently used and will create a barrier to new investment.	Will reduce network capability and may create a barrier to new investment.
Does this option have a negligible impact on customer charges?	The cost is in excess of £100m.	The cost is between £50–£100m.
Is this option future proof? (flexibility is covered above so this deals with legislation i.e. BREF and MCP)	When future legislation is implemented will need to revisit.	It is likely that when future legislation is implemented will need to revisit.
Can National Grid meet Exit Capacity obligations considering this option?	Existing obligations that users currently require will not be able to be met.	Existing obligations that users may require to use in the future will not be met.
Does this option allow National Grid to retain current capability?	Will reduce capability and impact how the NTS is currently used.	Capability reduced to a level insufficient to meet sold capacity and /or FES levels
Does this option represent an appropriate level of resilience on the network?	Does not provide resilience for the loss of the largest credible unit(s) at the station.	Reduces resilience considering the loss of units at interacting stations, where the affected units are currently next in line.
Can National Grid meet Entry Capacity obligations considering this option?	Existing obligations that users currently require will not be able to be met.	Existing obligations that users may require to use in the future will not be met.
Does this option allow the network to be operated in sensitivities beyond FES?	FES cannot be met.	Significantly reduces capability to exceed FES.

We use the Whole Life Prioritisation Model twice; once during the Need Case stage and then again at the end of the Establish Portfolio stage of our NDP. The model is used to rank the wide range of options identified during the Need Case process. At the end of this ranking process we have a narrower range of options to investigate in more detail during the Establish Portfolio stage. We use the model criteria again to rank the narrower range of options once more detailed costs and other information is available.

The criteria included in the model help us to determine which option is the most robust and should be taken forward to the next stages of our NDP – Select Option, Develop and Sanction. The definition of current capability now references sold and FES levels and assesses each option against the ability to meet these.

Reduces system flexibility, but this is unlikely to affect users' future requirements.	Provides similar level of system flexibility as the existing situation.	Increases the system flexibility to assist in meeting users' future requirements.
Will reduce network capability, but unlikely to be a barrier to new investment.	Maintains network capability – no impact on new investment.	Increases network capability, facilitating new investment.
The cost is between £20–£50m.	The cost is between £10–£20m.	The cost is <£10m.
May need to be revisited when future legislation is implemented.	Although there is some interaction with future legislation should not require revisiting.	Ability to respond to future legislation
Existing obligations that users are unlikely to use in the future will not be met.	The ability to meet existing obligations is maintained.	Increases the ability to meet existing obligations.
Capability reduced to potentially be insufficient to meet sold capacity and /or FES levels	Sufficient capability to meet sold capacity and /or FES levels	Increased capability to meet sold capacity and/or FES levels.
Reduces resilience for the loss of units at interacting stations, where the affected units are not currently first in line.	Provides similar level of resilience as the existing situation.	Increases the resilience of the network.
Existing obligations that users are unlikely to use in the future will not be met.	Ability to meet existing obligations is maintained.	Increases the ability to meet existing obligations.
Reduces capability to exceed FES.	Provides similar capability as the existing situation to exceed FES.	Enhances the ability over the existing situation to exceed FES.

Appendix 8
Meet the GTYS team

There are a number of teams across National Grid that feed into the Gas Ten Year Statement. Below is a summary of the key contributors to this year's edition.

If you would like to get in touch with us for any further information or would like to give us any feedback please contact us via email:
Box.systemoperator.gtys@nationalgrid.com

System Operator – Network Capability and Operations, Gas – Gas Network Development

We are responsible for dealing with customer queries regarding new and existing connection and capacity requests (Chapter 2). We complete the first stage of our Network Development Process, the Need Case (see Chapters 1 and 3 for more detail). We assess the current and future capability of the National Transmission System taking into account customer requirements, Future Energy Scenarios, legislative changes and operability requirements. We also look at possible operational solutions (rules and tools) to resolve any capability constraints identified in the Need Case as part of the Establish Portfolio stage of our NDP (Chapter 4).

Craig Dyke
Gas Network Development Manager

Rhys Ashman
Operational Capability Development Manager

Eddie Blackburn
Gas Contract Portfolio Manager

Andrea Godden
Commercial Gas Contracting Manager

Lauren Moody
Gas Network Strategy Manager

Mark Hamling
Senior Gas Network Analyst

Neil Sorrell
Senior Gas Network Analyst

Robert Longwe
Lead Gas Network Analyst

Aoife McNally
Lead Gas Network Analyst

Matt Wainwright
Lead Gas Network Analyst

System Operator – Network Capability and Operations, Gas – Operational Performance

We are responsible for analysing and reporting on the daily performance of our National Transmission System. We have contributed the actual flow data for gas year 2014/15 in Appendix 4.

Harjinder Kandola
Operational Performance Manager

Jon Emery
Operational Reporting Lead

Colin Sutton
Operational Reporting Analyst

Transmission Owner – Gas Transmission Asset Management

We are part of the Transmission Owner and are involved in the day to day asset management and asset health assessment works (Chapter 2). We look at asset solutions to resolve capability constraints identified during the Need Case as part of the Establish Portfolio stage of our NDP (Chapter 5).

Mark McKenzie
System Capability Manager

Danielle Stewart
Senior Network Analyst

Gary Bateman
Network Analyst

System Operator – UK Energy Strategy – Gas Demand

As the gas demand team we project the usage of gas in both the Industrial and Commercial markets and the residential sector. We provide input to the evolution of gas demand as part of the Future Energy Scenarios (Chapter 2 and Appendix 5).

Rob Nickerson
Senior Gas Demand Analyst

Phil Clough
Gas Demand Analyst

Appendix 8
Meet the GTYS team

System Operator – UK Energy Strategy – Gas Supply

We use the gas demand projections provided by our Gas Demand team to calculate how much gas will be coming onto the network and from where. We provide input to the evolution of gas supply as part of the Future Energy Scenarios (Chapter 2 and Appendix 5).

Simon Durk
Gas Supply Manager

Chris Thompson
Senior Gas Supply Analyst

Christian Parsons
Gas Supply Analyst

Appendix 9
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.

	GWh	mcm	Million therms	Thousand toe
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 calorific value (CV) of 39.6 MJ/m^3

GWh = Gigawatt hours
mcm = Million cubic metres
Thousand toe = Thousand tonne of oil equivalent
MJ/m^3 = One million joules per metre cubed

Appendix 10
Glossary

Acronym	Term	Definition
	Annual power demand	The electrical power demand in any one fiscal year. Different definitions of annual demand are used for different purposes.
ACS	Average cold spell	Average cold spell: defined as a particular combination of weather elements which gives rise to a level of winter peak demand which has a 50% chance of being exceeded as a result of weather variation alone. There are different definitions of ACS peak demand for different purposes.
AGI	Above-Ground Installation	To support the safe and efficient operation of the pipeline, above ground installations (AGIs) are needed at the start and end of the cross-country pipeline and at intervals along the route.
ANOP	Anticipated Normal Operating Pressure	A pressure that we may make available at an offtake to a large consumer connected to the NTS under normal operating conditions. ANOPs are specified within the NExA agreement for the site.
AOP	Assured Offtake Pressure	A minimum pressure at an offtake from the NTS to a DN that is required to support the downstream network. AOPs are agreed and revised through the annual OCS process.
AQ	Annual Quantity	The AQ of a Supply Point is its annual consumption over a 365-day year.
ARCA	Advanced Reservation of Capacity Agreement	This was an agreement between National Grid and a shipper relating to future NTS pipeline capacity for large sites in order that shippers can reserve NTS Exit Capacity in the long term. This has been replaced by the PARCA process. (See also PARCA)
ASEP	Aggregate System Entry Point	A System Entry point where there is more than one, or adjacent Connected Delivery Facilities; the term is often used to refer to gas supply terminals.
	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.
BAT	Best Available Technique	A term used in relation to Industrial Emissions Directive (IED) 2010. In this context BAT is defined as Best Available Technique and means applying the most effective methods of operation for providing the basis for emission limit values and other permit conditions designed to prevent and, where that is not practicable, to reduce emissions and the impact on the environment as a whole.
BBL	Balgzand - Bacton Line	A gas pipeline between Balgzand in the Netherlands and Bacton in the UK. http://www.bblcompany.com. This pipeline is currently uni-directional and flows from the Netherlands to the UK only.
	Baseload electricity price	The costs of electricity purchased to meet minimum demand at a constant rate.
bcm	billion cubic metres	Unit or measurement of volume, used in the gas industry. 1 bcm = 1,000,000,000 cubic metres
	Biomethane	Biomethane is a naturally occurring gas that is produced from organic material and has similar characteristics to natural gas. http://www.biomethane.org.uk/
	Boil-off	A small amount of gas which continually boils off from LNG storage tanks. This helps to keep the tanks cold.
BREF	BAT Reference Documents	BAT Reference Documents draw conclusions on what the BAT is for each sector to comply with the requirements of IED. The BAT conclusions drawn as a result of the BREF documents will then form the reference for setting permit conditions.
	Capacity	Capacity holdings give NTS Users the right to bring gas onto or take gas off the NTS (up to levels of capacity held) on any day of the gas year. Capacity rights can be procured in the long term or through shorter term processes, up to the gas day itself.
CCGT	Combined Cycle Gas Turbine	Gas turbine that uses the combustion of natural gas or diesel to drive a gas turbine generator to generate electricity. The residual heat from this process is used to produce steam in a heat recovery boiler which in turn, drives a steam turbine generator to generate more electricity. (See also OCGT)

Acronym	Term	Definition
CCS	Carbon Capture and Storage	Carbon (CO_2) capture and storage (CCS) is a process by which the CO_2 produced in the combustion of fossil fuels is captured, transported to a storage location and isolated from the atmosphere. Capture of CO_2 can be applied to large emission sources like power plants used for electricity generation and industrial processes. The CO_2 is then compressed and transported for long-term storage in geological formations or for use in industrial processes.
CEN	Comité Europeén de Normalisation	European committee for standardisation concerned with the development, maintenance and distribution of standards and specifications.
CfD	Contract for Difference	Contract between the Low Carbon Contracts Company (LCCC) and a low carbon electricity generator designed to reduce its exposure to volatile wholesale prices.
CHP	Combined heat and power	A system whereby both heat and electricity are generated simultaneously as part of one process. Covers a range of technologies that achieve this.
CLNG	Constrained LNG	A service available at some LNG storage facilities whereby Shippers agree to hold a minimum inventory in the facility and flow under certain demand conditions at National Grid request. In exchange Shippers receive a transportation credit from National Grid.
CM	Capacity Market	The Capacity Market is designed to ensure security of electricity supply. This is achieved by providing a payment for reliable sources of capacity, alongside their electricity revenues, ensuring they deliver energy when needed.
CNG	Compressed natural gas	Compressed natural gas is made by compressing natural gas to less than 1 percent of the volume it occupies at standard atmospheric pressure.
CO2	Carbon Dioxide	Carbon dioxide (CO_2) is the main greenhouse gas and the vast majority of CO_2 emissions come from the burning of fossil fuels (coal, natural gas and oil).
CO2e	Carbon Dioxide equivalent	A term used relating to climate change that accounts for the "basket" of greenhouse gasses and their relative effect on climate change compared to carbon dioxide. For example UK emissions are roughly 600m tonnes CO_2e. This constitutes roughly 450m tonnes CO_2 and less than the 150m tonnes remaining of more potent greenhouse gasses 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.
CSEP	Connected System Exit Point	A point at which natural gas is supplied from the NTS to a connected system containing more than one supply point. For example a connection to a pipeline system operated by another Gas Transporter.
CV	Calorific Value	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.
CWV	Composite Weather Variable	A measure of weather incorporating the effects of both temperature and wind speed. We have adopted the new industry wide CWV equations that take effect on 1 October 2015.
DC	Directly Connected (offtake)	Direct connection to the NTS typically to power stations and large industrial users. I.e. the connection is not via supply provided from a Distribution Network.
DCO	Development Consent Order	A statutory Order under The Planning Act (2008) which provides consent for a development project. Significant new pipelines require a DCO to be obtained, and the construction of new compressor stations may also require DCOs if a new HV electricity connection is required.
DECC	Department of Energy and Climate Change	A UK government department: The Department of Energy & Climate Change (DECC) works to make sure the UK has secure, clean, affordable energy supplies and promote international action to mitigate climate change.
DFN	Daily Flow Notification	A communication between a Delivery Facility Operator (DFO) and National Grid, indicating hourly and end of day entry flows from that facility.
DFO	Delivery Facility Operator	The operator of a reception terminal or storage facility, who processes and meters gas deliveries from offshore pipelines or storage facilities before transferring the gas to the NTS.

Appendix 10 Glossary

Acronym	Term	Definition
	Distribution System	A network of mains operating at three pressure tiers:
	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 in the form of linepack within transmission, i.e. >7 barg, pipeline systems.
DM	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.
DN	Distribution Network	A gas transportation system that delivers gas to industrial, commercial and domestic consumers within a defined geographical boundary. There are currently eight DNs, each consisting of one or more Local Distribution Zones (LDZs). DNs typically operate at lower pressures than the NTS.
DNO	Distribution Network Operator	Distribution Network Operators own and operate the Distribution Networks that are supplied by the NTS.
EIA	Environmental Impact Assessment	Environmental study of proposed development works as required under EU regulation and the Town and Country Planning (Environmental Impact Assessment) Regulations 2011. These regulations apply the EU directive “on the assessment of the effects of certain public and private projects on the environment” (usually referred to as the Environmental Impact Assessment Directive) to the planning system in England.
ELV	Emission Limit Value	Pollution from larger industrial installations is regulated under the Pollution Prevention and Control regime. This implements the EU Directive on Integrated Pollution Prevention and Control (IPPC) (2008/1/EC). Each installation subject to IPPC is required to have a permit containing emission limit values and other conditions based on the application of Best Available Techniques (BAT) and set to minimise emissions of pollutants likely to be emitted in significant quantities to air, water or land. Permit conditions also have to address energy efficiency, waste minimisation, prevention of accidental emissions and site restoration.
EMR	Electricity Market Reform	A government policy to incentivise investment in secure, low-carbon electricity, improve the security of Great Britain’s electricity supply, and improve affordability for consumers. The Energy Act 2013 introduced a number of mechanisms. In particular: ■ A Capacity Market, which will help ensure security of electricity supply at the least cost to the consumer. ■ Contracts for Difference, which will provide long-term revenue stabilisation for new low carbon initiatives. Both will be administered by delivery partners of the Department of Energy and Climate Change (DECC). This includes National Grid Electricity Transmission (NGET).
ENA	Energy Networks Association	The Energy Networks Association is an industry association funded by gas or transmission and distribution licence holders.
ENTSOG	European Network of Transmission System Operators for Gas	Organisation to facilitate cooperation between national gas transmission system operators (TSOs) across Europe to ensure the development of a pan-European transmission system in line with European Union energy goals.
ETYS	Electricity Ten Year Statement	The ETYS illustrates the potential future development of the National Electricity Transmission System (NETS) over a ten year (minimum) period and is published on an annual basis.
	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.
FEED	Front End Engineering Design	The FEED is basic engineering which comes after the Conceptual design or Feasibility study. The FEED design focuses on the technical requirements as well as an approximate budget investment cost for the project.
FES	Future Energy Scenarios	The FES is a range of credible futures which has been developed in conjunction with the energy industry. They are a set of scenarios covering the period from now to 2050, and are used to frame discussions and perform stress tests. They form the starting point for all transmission network and investment planning, and are used to identify future operability challenges and potential solutions.
	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.
	Gasholder	A vessel used to store gas for the purposes of providing diurnal storage.

Acronym	Term	Definition
	Gas Supply Year	A twelve-month period commencing 1 October, also referred to as a Gas Year.
	Gone Green	A National Grid scenario defined in the Future Energy Scenarios (FES) document whereby the 2020 renewables target is met.
GB	Great Britain	A geographical, social and economic grouping of countries that contains England, Scotland and Wales.
GSOF	Gas System Operability Framework	To address future system operability challenges on the gas network, such as System Flexibility, National Grid gas are considering the possibility of introducing a Gas System Operability Framework (GSOF). This will highlight how current and future operability challenges are identified. The SOF is a concept used by National Grid electricity transmission and was first published in 2014. It draws on real-time experience on the electricity system, combined with FES, to infer potential challenges to operability of the electricity transmission system out to 2035. The electricity SOF identifies and quantifies future system challenges so that a range of mitigation measures can be developed and economically assessed.
GS(M)R	Gas Safety (Management) Regulations 1996	Regulations which apply to the conveyance of natural gas (methane) through pipes to domestic and other consumers and cover four main areas: (a) the safe management of gas flow through a network, particularly those parts supplying domestic consumers, and a duty to minimise the risk of a gas supply emergency; (b) arrangements for dealing with supply emergencies; (c) arrangements for dealing with reported gas escapes and gas incidents; (d) gas composition. Gas Transporters are required to submit a safety case to the HSE detailing the arrangements in place to ensure compliance with GS(M)R requirements.
	Gas Transporter	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.
GTYS	Gas Ten Year Statement	The Gas Ten Year Statement is published annually in accordance with National Grid Gas plc's obligations in Special Condition 7A of the Gas Transporters Licence relating to the National Transmission System and to comply with Uniform Network Code (UNC) requirements
GW	Gigawatt	1,000,000,000 watts, a measure of power.
GWh	Gigawatt hour	1,000,000,000 watt hours, a unit of energy.
gCO2/kWh	Gram of carbon dioxide per kilowatt hour	Measurement of CO2 equivalent emissions per kWh of energy used or produced.
HSE	Health and Safety Executive	The HSE regulates the onshore pipeline operators to maintain and improve the health and safety performance within the industry.
IEA	International Energy Agency	An intergovernmental organisation that acts as energy policy advisor to 28 member countries.
IED	Industrial Emissions Directive	The Industrial Emissions Directive came into force on 6th January 2011. IED recasts seven existing Directives related to industrial emissions into a single clear, coherent legislative instrument. The recast includes IPPC, LCP, the Waste Incineration Directive, the Solvents Emissions Directive and three Directives on Titanium Dioxide.
IGMS	Integrated Gas Management Control System	Used by National Grid System Operation to control and monitor the Gas Transmission system, and also to provide market information to interested stakeholders within the gas industry.
	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 (IUK) 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.

Appendix 10
Glossary

Acronym	Term	Definition
IPPC	Integrated Pollution Prevention & Control Directive 1999	Emissions from our installations are subject to EU wide legislation; the predominant legislation is the Integrated Pollution Prevention & Control (IPPC) Directive 1999, the Large Combustion Plant Directive (LCPD) 2001 and the Industrial Emissions Directive (IED) 2010. The requirements of these directives have now been incorporated into the Environmental Permitting (England and Wales) (Amendment) Regulations 2013 (with similar regulations applying in Scotland). IPPC aims to reduce emissions from industrial installations and contributes to meeting various environment policy targets and compliance with EU directives. Since 31 October 2000, new installations are required to apply for an IPPC permit. Existing installations were required to apply for an IPPC permit over a phased timetable until October 2007.
IUK	Interconnector (UK)	A bi-directional gas pipeline between Bacton in the UK and Zeebrugge Belgium. http://www.interconnector.com
KWh	Kilowatt Hour	A unit of energy used by the gas industry. Approximately equal to 0.0341 therms. One Megawatt hour (MWh) equals 1000 kWh, one Gigawatt hour (GWh) equals 1000MWh, and one Terawatt hour (TWh) equals 1000 GWh.
LCP	Large Combustion Plant Directive 2001	The Large Combustion Plant Directive is a European Union Directive which introduced measures to control the emissions of sulphur dioxide, oxides of nitrogen and dust from large combustion plant, including power stations.
LDZ	Local Distribution Zone	A gas distribution zone connecting end users to the (gas) National Transmission System.
	Linepack	The volume of gas within the National or Local Transmission System at any time. (See Also: PCLP)
LNG	Liquefied Natural Gas	LNG is formed by chilling gas to -161˚C so that it occupies 600 times less space than in its gaseous form. www2.nationalgrid.com/uk/Services/Grain-lng/what-is-lng/
LNGS	Liquefied Natural Gas Storage	The storage of Liquefied Natural Gas.
	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.
	Low Carbon Life	A National Grid scenario defined in the Future Energy Scenarios (FES) document whereby compared to the Gone Green scenario more money is available and there is less emphasis on sustainability. There is higher economic growth and society has more disposable income which results in higher uptake of electric vehicles, and more renewable generation at a local level.
LRS	Long range storage or seasonal storage	There is one long-range storage site on the national transmission system: Rough, situated off the Yorkshire coast. Rough is owned by Centrica and mainly puts gas into storage (called ‘injection’) in the summer and takes gas out of storage in the winter. http://www2.nationalgrid.com/UK/Our-company/Gas/Gas-Storage/
LTS	Local Transmission System	A pipeline system operating at >7 barg that transports gas from NTS / LDZ offtakes to distribution system low pressure pipelines. Some large users may take their gas direct from the LTS.
LTSEC	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. This is also known as Quarterly System Entry Capacity (QSEC).
m3	Cubic Metre	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.
mcm	Million cubic metres	Unit or measurement of volume, used in the gas industry. 1 mcm = 1,000,000 cubic metres

Acronym	Term	Definition
	Margins Notice	The purpose of the Margins Notice 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.
MCP	Medium Combustion Plant (Directive)	The Medium Combustion Plant (MCP) directive will apply limits on emissions to air from sites below 50MW thermal input. MCP is likely to come into force by 2020.
MRS	Medium-Range Storage	Typically, these storage facilities have very fast injection and withdrawal rates that lend themselves to fast day to day turn rounds as market prices and demand dictate.
MWh	Megawatt hour	1,000,000 watts, a measure of power usage or consumption in 1 hour.
NBP	National Balancing Point	The wholesale gas market in Britain has one price for gas irrespective of where the gas comes from. This is called the national balancing point (NBP) price of gas and is usually quoted in price per therm of gas.
NCS	Norwegian Continental Shelf	The Norwegian Continental Shelf (NCS) comprises those areas of the sea bed and subsoil beyond the territorial sea over which Norway exercises rights of exploration and exploitation of natural resources. NCS gas comes into the UK via St Fergus and Easington terminals.
NDM	Non-Daily Metered	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 73.2MWh pa, reconciled individually when the meter is read.
NDP	Network Development Process	NDP defines the method for decision making, optioneering, development, sanction, delivery and closure for all National Grid gas projects. The aim of the NDP is to deliver projects that have the lowest whole-life cost, are fit for purpose and meet stakeholder and RIIO requirements.
NEA	Network Exit Agreement	A NEA is signed by the gas shipper prior to any gas flowing on to the system. Within the NEA the gas transporter sets out the technical and operational conditions of the connection such as the gas quality requirements, the maximum permitted flow rate and ongoing charges.
NExA	Network Exit Agreement	A NExA is signed by a gas shipper or Distribution Network Operator prior to any gas being taken off the system. Within the NExA the gas transporter sets out the technical and operational conditions of the offtake such as the maximum permitted flow rate, the assured offtake pressure and ongoing charges.
NGSE	Network Gas Supply Emergency	A NGSE occurs when National Grid is unable to maintain a supply – demand balance on the NTS using its normal system balancing tools. A NGSE could be caused by a major loss of supplies to the system as a result of the failure of a gas terminal or as the result of damage to a NTS pipeline affecting the ability of the system to transport gas to consumers. In such an event the Network Emergency Co-ordinator (NEC) would be requested to declare a NGSE. This would enable National Grid to use additional balancing tools to restore a supply – demand balance. Options include requesting additional gas supplies be delivered to the NTS or requiring gas consumers, starting with the largest industrial consumers, to stop using gas. These tools will be used, under the authorisation of the NEC, to try to maintain supplies as long as possible to domestic gas consumers.
NOM	Network Output Measure	RIIO has introduced Network Output Measures (NOMs) (previously Network Replacement Outputs) as a proxy for measuring the health and thus level of risk on the gas network. There are specific targets which are related to the condition of the NTS which must be met. Asset health is a key RIIO measure in terms of allowances and output. The targets cover an eight year period from 2013 to 2021.
NOx	Nitrous Oxide	A group of chemical compounds, some of which are contributors to pollution, acid rain or are classified as greenhouse gases.
NP	No Progression Scenario	Compared to Gone Green there is less money available and less emphasis on sustainability. There is slower economic recovery and Government policy and regulation remains the same as today, and no new targets are introduced. The 2020 renewable energy target for 2020 is unlikely to be met.
NTS	National Transmission System	A high-pressure gas transportation system consisting of compressor stations, pipelines, multijunction sites and offtakes. NTS pipelines transport gas from terminals to NTS offtakes and are designed to operate up to pressures of 94 bar(g).

Appendix 10
Glossary

Acronym	Term	Definition
	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, odourisation equipment etc.
NWE	North West European (Hub)	The wholesale gas market in North West Europe has one price for gas irrespective of where the gas comes from. This is called the North West European (NWE) hub price of gas and is usually quoted in price per therm of gas.
	Oil & Gas UK	Oil & Gas UK is a representative body for the UK offshore oil and gas industry. It is a not-for-profit organisation, established in April 2007. http://www.oilandgasuk.co.uk
OCGT	Open Cycle Gas Turbine	Gas turbines in which air is first compressed in the compressor element before fuel is injected and burned in the combustor. (See also, CCGT)
OCM	On the Day Commodity Market	This market constitutes the balancing market for GB and enables anonymous financially cleared on the day trading between market participants.
	Odourisation	The process by which the distinctive odour is added to gas supplies to make it easier to detect leaks.
OFGEM	Office of Gas and Electricity Markets	The UK's independent National Regulatory Authority, a non-ministerial government department. Their principal objective is to protect the interests of existing and future electricity and gas consumers.
OM	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	Gas used by National Grid to operate the transportation system. Includes gas used for compressor fuel, heating and venting.
pa	Per annum	Per year
PARCA	Planning and Advanced Reservation of Capacity Agreement	A solution developed in line with the enduring incremental capacity release solutions which have been developed following the implementation of the Planning Act (2008). PARCAs were implemented on 1st February 2015 and replace the functions of PCAs and ARCAs. (See also ARCA & PCA)
PCA	Planning Consent Agreement	Planning Consent Agreements were made in relation to NTS Entry and Exit Capacity requests and comprised a bilateral agreement between National Grid and developers, DNOs or Shippers whereby National Grid assessed the Need Case for NTS reinforcement and would undertake any necessary planning activities ahead of a formal capacity signal from the customer. Where a Need Case was identified, the customer would underwrite National Grid NTS to undertake the required statutory Planning Act activities such as strategic optioneering, Environmental Impact Assessment, statutory and local community consultations, preparation of the Development Consent Order (DCO) and application. This has now been replaced by the PARCA process. (See PARCA)
PCLP	Projected Closing Linepack	Linepack is the volume of gas stored within the NTS. Throughout a gas day linepack levels fluctuate due to imbalances between supply and demand over the day. National Grid, as residual balancer of the UK gas market, need to ensure an end-of-day market balance where total supply equals, or is close to, total demand. The Projected Closing Linepack (PCLP) metric is used as an indicator of end-of-day market balance. (See Also: Linepack)
	Peak Day 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 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	NTS entry capacity available on a long term basis (up to 17 years into the future) via an auction process. Also known as Long Term System Entry Capacity (LTSEC).
	RIIO-T1	RIIO relates to the current Ofgem price control period which runs from 1 April 2013 to 31 March 2021. For National Grid Transmission this is referred to as RIIO-T1.

Acronym	Term	Definition
	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.
SEAL	Shearwater Elgin Area Line	The offshore pipeline from the Central North Sea (CNS) to Bacton.
SEPA	Scottish Environment Protection Agency	The environmental regulator for Scotland.
	Shale Gas	Shale gas is natural gas that is found is shale rock. It is extracted by injecting water, sand and chemicals into the shale rock to create cracks or fractures so that the shale gas can be extracted. https://www.gov.uk/government/publications/about-shale-gas-and-hydraulic-fracturing-fracking
	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.
SHQ	Supply Hourly Quantity	Supply Hourly Quantity
SNCWV	Seasonal Normal Composite Weather Variable	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. (See Also: CWV)
	System Operability	The ability to maintain system stability and all of the asset ratings and operational parameters within pre-defined limits safely, economically and sustainably.
SO	System Operator	An entity entrusted with transporting energy in the form of natural gas or power on a regional or national level, using fixed infrastructure. Unlike a TSO, the SO may not necessarily own the assets concerned. For example, National Grid operates the electricity transmission system in Scotland, which is owned by Scottish Hydro Electricity Transmission and Scottish Power.
SOQ	Supply Offtake Quantity	The maximum daily consumption at a Supply Point.
SOR	Strategic Options Report	Output of the PCA, ARCA and PARCA statutory Planning Act activities reporting to the customer on the findings of optioneering analysis by National Grid in relation to the customer request for NTS Entry or Exit Capacity.
SP	Slow Progression Scenario	A National Grid scenario defined in the Future Energy Scenarios (FES) document whereby the 2020 renewable energy target for 2020 is not met. Although regulation and targets are similar to the Gone Green scenario there is less economic growth which prevents delivery of environmental policy and targets.
SRS	Short Range Storage	These are commercially operated sites that have shorter injection/withdrawal times so can react more quickly to demand, injecting when demand or prices are lower and withdrawing when higher.
	Substitution	Capacity substitution is the process of moving unsold capacity from one or more system points to another, where demand for that capacity exceeds the available capacity quantities for the relevant period. This avoids the construction of new assets or material increases in operational risk.
	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 Point	A group of one or more meter points at a site.

Appendix 10 Glossary

Acronym	Term	Definition
	Therm	An imperial unit of energy. Largely replaced by the metric equivalent: the kilowatt hour (kWh). 1 therm equals 29.3071 kWh.
TO	Transmission Owner	National Grid owns the gas National Transmission System (NTS) in Great Britain. As the TO National Grid must make sure all assets on the NTS are fit for purpose and safe to operate. Effective maintenance plans and asset replacement schedules are developed and implemented to keep the gas flowing.
TPC	Transmission Planning Code	The Transmission Planning Code 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. The document is subject to approval by the Gas and Electricity Markets Authority (GEMA).
	Transmission System Operator	Operator of a Gas Transmission Network under licence issued by the Gas and Electricity Markets Authority (GEMA) and regulated by OFGEM
TWh	Terrawatt hour	1,000,000,000,000 watt hours, a unit of energy
UAG	Unaccounted for Gas	Gas "lost" during transportation. Includes leakage, theft and losses due to the method of calculating the Calorific Value.
UK	United Kingdom of Great Britain and Northern Ireland	A geographical, social and economic grouping of countries that contains England, Scotland, Wales and Northern Ireland.
UKCS	United Kingdom Continental Shelf	The UK Continental Shelf (UKCS) comprises those areas of the sea bed and subsoil beyond the territorial sea over which the UK exercises sovereign rights of exploration and exploitation of natural resources.
UNC	Uniform Network Code	The Uniform Network Code is the legal and commercial framework that governs the arrangements between the Gas Transporters and Shippers operating in the UK gas market. The UNC comprises different documents including the Transportation Principal Document (TPD) and Offtake Arrangements Document (OAD).
VSD	Variable Speed Drives	Compressor technology where the drive speed can be varied with changes in capacity requirement. Variable speed drive compressors compared to constant speed compressors are more energy efficient and operate more quietly by varying speed to match the workload.
	Weather corrected	The actual demand figure that has been adjusted to take account of the difference between the actual weather and the seasonal normal weather.
WLP	Whole Life Prioritisation	The WLP provides the criteria used to prioritise all of the options considered as part of the Network Development Process (NDP). The scoring from the WLP Model aids the decision making process by discounting unsuitable options at an early stage of the NDP.

Disclaimer

This statement is produced for the purpose of and in accordance with National Grid Gas plc's obligations in Special Condition 7A[3] of its Gas Transporters' Licence relating to the National Transmission System and section O4.1 of the Transportation Principal Document of the Uniform Network Code in reliance on information supplied pursuant to section O of the Transportation Principal document of the Uniform Network Code. Section O1.3 of the Transportation Principal document of the Uniform Network Code applies to any estimate, forecast or other information contained in this statement.

For the purpose of the remainder of this statement, National Grid Gas plc will be referred to as National Grid.

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[3] Special Condition 7A requires 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.

Continuing the conversation

Join our mailing list to receive email updates for GTYS or any of our Future of Energy documents.
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Access our current and past GTYS documents and data at:
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