National Grid Gas Transmission

Industrial Emissions RIIO-T1 Reopener Submission

25th May 2018

Contents

Executive Summary

This document is the formal submission by National Grid Gas Transmission (hereafter referred to as National Grid) to reduce allowances for compressor IED investment incurred and forecast to be incurred during the RIIO-T1 period as a result of emissions related legislation. This document is being submitted under the Uncertainty Mechanism – Licence Condition 5E.1 for Industrial Emissions Costs in the May 2018 reopener window. The total cost of the proposed compressor investment within this reopener for legislative environmental compliance is £192m of which £123m is within RIIO-T1. Our integrated programme, developed through stakeholder engagement and a robust approach to options assessment, represents a significant return to customers of £157m against the RIIO-T1 allowance.

The Industrial Emissions Directive (IED) consolidates a number of European emissions-related directives. Within the IED, the Large Combustion Plant Directive (LCP) sets clear emission targets for pollutants such as Nitrous Oxides (NOx) and Carbon Monoxide (CO) at a combustion unit level. The Medium Combustion Plant Directive (MCP) will apply further emissions targets from 2030 onwards. In addition, the Integrated Pollution Prevention and Control (IPPC), which in 2013 was consolidated into IED, requires progressive pollution reduction and applies at a fleet level across the NTS. The proposals presented within this reopener deliver an optimised programme in the form of an integrated plan delivering the most cost effective network solution to meet the current and future needs of our customers.

In preparing this submission, we have fully taken on board Ofgem's comments on our previous reopener submission in May 2015:

- **Cost Benefit Analysis**. Our analysis is based on a comprehensive CBA methodology with assumptions applied consistently across the analysis.
- **Range of options**. For each appraisal, we considered a comprehensive set of regulatory, commercial and asset options. Since our 2015 submission, an innovation project on Selective Catalytic Reduction (SCR) demonstrated that this is a viable abatement technology and hence we have included it within our options. We have also adjusted our approach to investment related to MCP as the date for compliance moved from 2025 to 2030.
- **Future Network Requirements**. We conducted our analysis using the latest FES data and carried out sensitivity analysis where this could shed light on material uncertainties.
- **Holistic analysis**. Based on how compressors on the NTS interact we identified those compressors that could be assessed on a 'stand-alone' basis and those that need to be considered together in a 'Cluster'. The Cluster analysis has enabled us to understand the trade-offs between coupled compressors and hence to avoid over investment. The combination of the standalone business cases and those within the Cluster form our 'Integrated Plan'.

In 2015 we undertook extensive stakeholder engagement which we have built on in the lead up to this reopener, with broad support for our proposals. The following table summarises our recommended option for each site and the associated cost and output to ensure we deliver the required emissions reduction in line with the IPPC elements of IED, and environmental compliance with the LCP elements of IED by 2023.

Site	Legislation Compliance	Programme Cost Range (£m)	RIIO-T1 Percentage	RIIO-T2 Percentage	Output
St Fergus	IPPC Phase 4	20-40	44	56	Emissions reduction on one Avon unit and emissions compliance on one RB211 unit at St Fergus.
	LCP	20-40	44	56	RIIO-T1 activities: Completion of FEED incorporating recommended option. OEM contract awarded and unit design and FAT complete. EPC contract awarded and detailed design commenced.
	LCP	<10	0	100	RIIO-T2: Decommission one RB211 in accordance with IED (LCP) requirements.
Huntingdon	IPPC Phase 4	20-40	100	0	To install one new unit at Huntingdon by the end of RIIO-T1 in accordance with IPPC Phase 4 requirements.
Peterborough	IPPC Phase 4	20-40	100	0	To install one new unit at Peterborough by the end of RIIO-T1 in accordance with IPPC Phase 4 requirements.
Carnforth-Nether Kellet	LCP	<10	100	0	Decommission two units at Carnforth–Nether Kellet compressor station and provide partial integration across the station by the end of RIIO-T1.
Hatton	LCP	40-60	35	65	IED (LCP) emissions compliance at Hatton equivalent to one large unit. RIIO-T1 activities: Completion of FEED incorporating recommended option. OEM contract awarded and unit design and FAT complete. EPC contract awarded and detailed design commenced.
Moffat	LCP	10-20	100	0	To undertake asset health works at Moffat to maintain the RB211s on 500 hours EUD.
Warrington	LCP	<10	100	0	To decommission the compressor station at Warrington by the end of RIIO-T1.
Wisbech	LCP	<10	100	0	To convert the Maxi-Avon to an Avon and undertake asset health works to maintain the existing compressor units.
Kirriemuir	LCP	<10	100	0	Decommission Unit D at Kirriemuir compressor station by the end of RIIO-T1.
Total*		**191.8**	**123.4**	**68.4**	

*Please note for commercial confidentiality reasons, the costs of the projects has been presented in a range for this public document.

Table 1: Reopener funding (2009/10 price base)

The table below profiles the RIIO-T1 expenditure against the ex-ante allowance:

£(m)	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	Total
Ex-ante allowance	0.0	1.6	16.2	49.1	66.3	66.6	46.9	33.9	280.5
RIIO-T1 cost	0.3	4.2	5.5	3.5	13.7	25.3	43.3	27.5	123.4
Relevant adjustment	0.3	2.6	-10.6	-45.6	-52.6	-41.2	-3.6	-6.4	-157.1

Table 2: Expenditure and allowance profile (2009/10 price base)

In summary, through listening to our stakeholders, intensely challenging the need and adopting innovative solutions, we have been able to deliver an integrated plan of compressor investments that meet the emissions legislation and deliver value for money to consumers.

The legislation and how it affects us

Environmental legislation has been developed over recent years introducing new standards to minimise the impact of industrial activities on the environment and human health. The legislation aims to reduce the pollutants discharged to air, water and land. National Grid's gas turbine driven compressors are impacted by the legislation as a result of limits on emissions of nitrogen oxide (NOx) and carbon monoxide (CO) to the environment from the combustion of natural gas.

It is mandatory for all EU countries to comply with the new minimum standards, and the legislation described below has all been transposed into UK law.

This section covers the background of the two initial pieces of relevant emissions legislation and then goes on to discuss how these were brought together in the Industrial Emissions Directive (IED) and the effect of this new legislation on our compressor units.

Large Combustion Plant directive (LCP) 2001 (Directive 2001/80/EC)

The LCP applies to all combustion plants with a thermal input of 50 MW or more. Such combustion plants must meet the Emission Limit Values (ELVs) as defined in the directive. An ELV is the maximum permissible rate at which a pollutant can be released by an installation. The ELVs set out in this directive can be met in one of two ways: (1) All equipment is fully compliant with the specified Emission Limit Values and can be operated without restriction or (2) Choose to restrict the operation of non-compliant equipment by entering it into one of the two available derogations under the IED, either the Limited Lifetime Derogation or the Emergency Use Derogation. Any non-compliant plant and equipment not operating under derogation must be either decommissioned or replaced or modified to achieve new plant standards.

Integrated Pollution Prevention and Control Directive (IPPC) 2008 (Directive 2008/1/EC)

Under the IPPC, any installation with a high pollution potential is required to have a permit. One of the pre-requisites for this permit is that Best Available Techniques (BAT) are used to prevent or reduce the emission of these pollutants. BAT assessments are required when developing a solution to avoid or reduce emissions resulting from industrial installations and to reduce the impact on the environment as a whole. They take account of the balance between costs and environmental benefits over the full lifecycle of the installation.

The impact of IPPC means that all of our compressor units are required to have a permit which specifies the maximum ELVs to air for that unit. We have an overarching IPPC strategy as agreed with the Environmental Agency (EA), Scottish Environmental Protection Agency (SEPA) and Natural Resources Wales (NRW) which allows us to review our compressors as a fleet on an annual basis, targeting those sites that emit high levels of NOx to maximise the environmental return. This process is called the Network Review and to date we have undertaken four phases of IPPC works.

The Industrial Emissions Directive (Directive 2010/75/EU)

Subsequently, the IED brought together existing pieces of European environmental legislation, including LCP and IPPC. The LCP directive is replaced by Chapter III (with Annex V) of the IED. The four major provisions of the IED which impact on National Grid and our compressor units are as follows;

1. The use of permits for installations

The IED specifies that all installations must be operated with a permit. These permits specify the ELVs for polluting substances, which are likely to be emitted from the installation concerned and also determines the environmental risk of that installation.

This mirrors the specifications set out in the IPPC whereby installations have to comply with the ELVs set out in their permit, which are based on BAT.

2. Establishment of BAT Reference documents

The IED also introduces an increased emphasis on the status of the BAT Reference (BREF) documents. These BREF documents draw conclusions on what the BAT is for each sector to comply with the requirements of IED. This then forms the reference for setting the permit conditions mentioned above.

3. The updating of ELVs for installations above 50 MW

The IED states that for installations with a thermal input over 50 MW it is mandatory to comply with the following ELVs to be complied with;

Carbon Monoxide (CO) – 100mg/Nm3
Nitrogen Oxide (NOx) – 75mg/Nm3 for existing installations
Nitrogen Oxide (NOx) – 50mg/Nm3 for new installations.

The IED mirrors the requirements set out in the LCP directive. These new limits introduced through the IED affect 16 of 64 units in the National Grid compressor fleet. Compressors that could not meet the new ELVs for CO and NOx had to stop operating on 31st December 2015, unless the unit had received a derogation.

4. Limited Lifetime Derogation (LLD)

The requirements for a Limited Lifetime Derogation state that from 1st January 2016 to 31st December 2023 combustion plant may be exempted from compliance with the ELVs for installations above 50 MW provided certain conditions are fulfilled:

(a) The operator makes a declaration before 1st January 2014 not to operate the plant for more than 17,500 operating hours within the derogation period, which started on the 1st January 2016 and ends on the 31st December 2023;
(b) The operator submits each year a record of the number of operating hours since 1st January 2016

National Grid has duly made the required declaration and entered a number of high usage compressors into this derogation. Additionally, if existing non-compliant installations can be modified to achieve the ELVs for new installations (rather than existing) before the 31st December 2023 deadline, the unit could be deemed compliant and be re-permitted for continued operation, subject to being able to demonstrate that the proposed solution represents BAT.

5. Emergency Use Derogation (EUD)

The IED allows an enduring derogation from the requirement to meet the specified ELVs for equipment used in emergencies and less than 500 hours per year. As with the Limited Lifetime Derogation, this derogation has been applicable from 1st January 2016 and a number of our operating units have been entered into this derogation.

6. 1,500 hours derogation

The IED legislation provides for a further derogation for gas turbines which were granted a permit before November 2002. This applies to units which do not operate for more than 1,500 hours per year as a rolling average over a period of 5 years, increasing the emission limit value for NOx to 150 mg/Nm3, with the limit for CO remaining at 100 mg/Nm3. However, our compressor units produce more NOx than the limit specified in this derogation and therefore this does not represent a viable option.

Medium Combustion Plant directive (MCP) (Directive (EU) 2015/2193)

The MCP applies specific limits on emissions to air from combustion plant with a net thermal input of between 1MW and 50 MW. This legislation introduces ELVs that are differentiated according to the plant's age, capacity and type of installation. The gas compressor stations impacted by MCP directive are exempt until 1st January 2030. After this point it is assumed within this reopener that units would be restricted to 500 operating hours per year, as a rolling average over a period of five years.

NTS Impact

Sixteen units are impacted by the LCP element of the IED. Thirteen of which are Rolls-Royce (now Siemens) RB211 gas turbine driven compressor units, located across seven compressor stations. As presented on the map, these are:

- Hatton
- Kirriemuir
- Carnforth
- Warrington
- Moffat
- St Fergus
- Wisbech

Three non RB211 units impacted by LCP are Aylesbury Units A and B and Wisbech Unit B. The Aylesbury Avon DLE units were converted with CO abatement and the Wisbech Maxi Avon was converted to a standard Avon in 2015. These three units are now compliant with the legislation.

The three priority sites impacted by IPPC all have Rolls-Royce (now Siemens) Avon gas driven compressor units:

- St Fergus
- Peterborough
- Huntingdon

The MCP impacts a further 24 of our compressor units which have an exemption until 2030.

What this means? Each compressor site is impacted in different ways by the legislation. There are the requirements of IPPC, known impacts of the LCP elements of IED, and the derogations which have already been put into place as well as the future implications of MCP that must also be considered as part of our overall integrated plan.

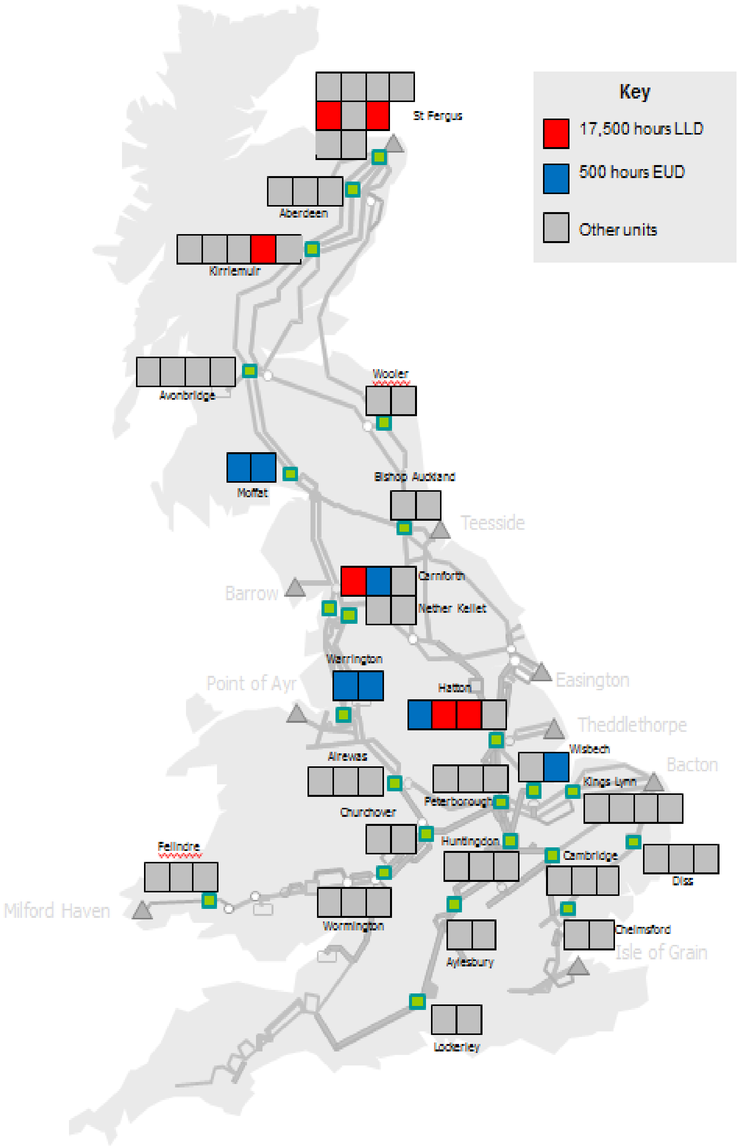

Figure 1: LCP impacted sites

How we use compressors on the NTS

There has been a significant shift in the way the gas transmission network is utilised. Historically the NTS has operated on a north to south flow pattern with compression used to pull and push the gas from the main entry point at St Fergus to the high demand areas in England. However, over the last 20 years this has changed significantly. There are now more entry points onto the system and these are distributed around the country. The UK continental shelf supplies have declined and in 2004 the UK became a net importer of gas on an annual basis.

The main reasons we have compressors are:

- to transport gas from the supply points to the demand centres;
- to provide and maintain pressures within network design safety parameters;
- to meet contractual capacity and exit pressure commitments;
- to provide system flexibility to meet rapidly changing use and conditions;
- to provide network resilience against supply losses or very high demand; and
- occasional use to facilitate maintenance.

The evolution of the network has resulted in changes to compressor utilisation. Some compressors are now required to support reverse flows: moving gas in the opposite direction from their original design; some compressors have become increasingly important across a large demand range; and some are only used during peak demand conditions or certain supply patterns in order to avoid significant constraints. Figure 2 illustrates the distribution of the different types of units across the NTS.

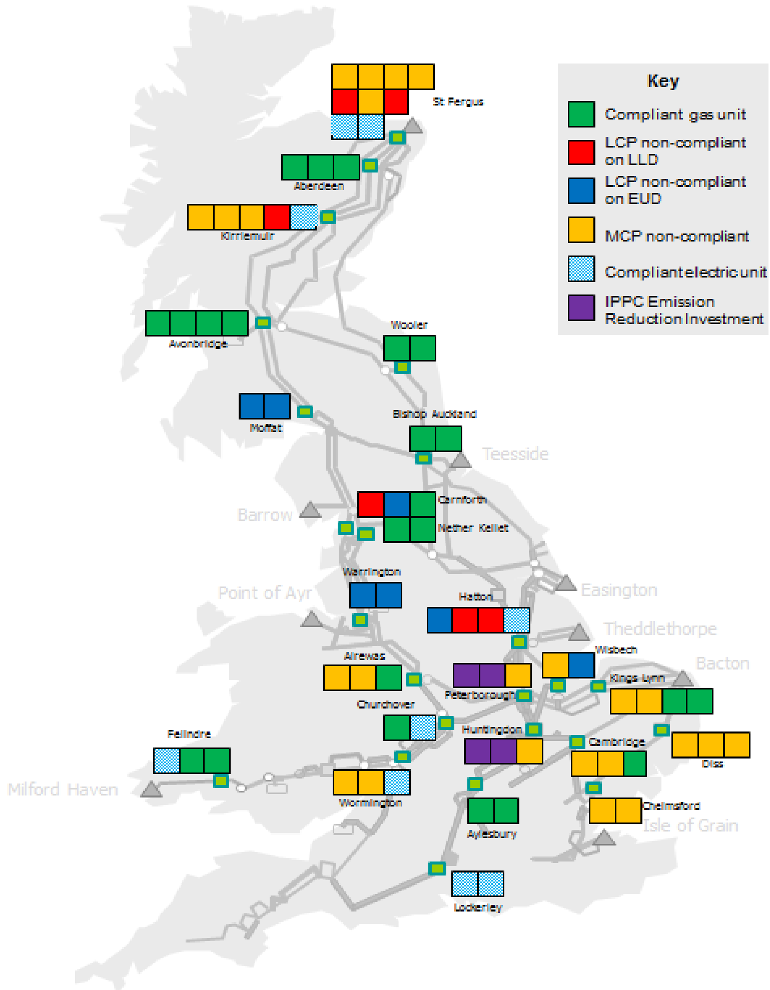

Figure 2: Compressor unit type and compliance with environmental legislation

Annual compressor operational patterns are strongly defined. As shown on Figure 3, the high demand in winter months results in almost twice as many run hours as the low demand, summer months. A full list of all NTS compressors with run hours, associated NOx emissions and a high level description of usage is presented in the table below. Those assessed within this reopener are highlighted in red:

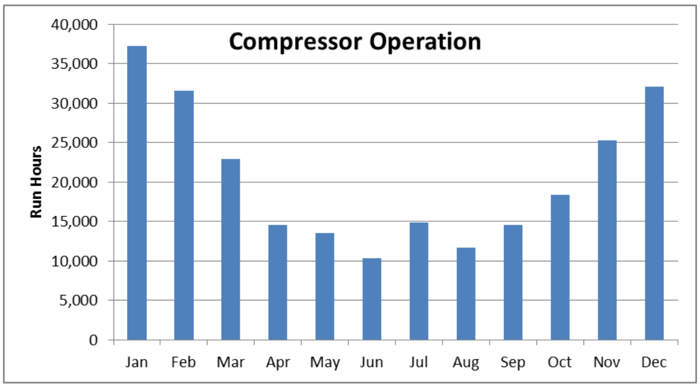

Figure 3: Compressor operation 2013- 2018

Site	Run Hours*	Usage
St Fergus	11,800	Pressurises gas from the NSMP (North Sea Midstream Partners) sub terminal
Avonbridge	5,700	Supports Scotland offtake pressures
Peterborough	5,600	Transmission of gas south, east and west and supports 1-in-20
Aberdeen	5,600	Required under medium to high St Fergus flows and to maintain Scotland offtake pressures
Hatton	4,200	Supports the Easington baseline and north to south flows on the East coast. Supports East to West flows including Teesside, Theddlethorpe and the IUK interconnector and supports 1-in-20.
Carnforth-Nether Kellet	3,100	Supports high flows north to south and high Easington flows
Huntingdon	2,500	Supports southern flows into the South East and South West during high demand and supports 1-in-20
Bishop Auckland	2,300	Supports high Teesside and St Fergus flows
Kirriemuir	2,200	Required under high St Fergus flows, to maintain Scotland offtake pressures and as back up to Aberdeen and Avonbridge
Wormington	1,600	Facilitates low and high Milford Haven flows and supports pressures in the South West and Wales.
Churchover	800	Facilitates low and high Milford Haven flows and supports pressures in Wales.
Diss	700	Supports high Bacton flows and high South East demand
Wooler	600	Required under high St Fergus flows and to manage gas stock in Scotland
Lockerley	500	Supports pressures in the South West during high demand
Kings Lynn	500	Facilitates IUK export flows and other Bacton high and low flows
Chelmsford	400	Supports high Bacton flows
Alrewas	400	Facilitates high Milford Haven flows and supports North West storage and pressures in Wales.
Wisbech	300	Supports high flows to Peterborough; supports Bacton entry flows and network resilience
Cambridge	200	Facilitates low and high Isle of Grain flows
Moffat	200	Used for network resilience and to manage gas stock in Scotland
Felindre	<100	Facilitates high Milford Haven flows
Aylesbury	<100	Supports pressures in the South West. (Low run hours due to recent site works)
Warrington	<100	Specific activities e.g. maintenance and resilience

Table 3: Compressor Utilisation *Five year average for the site from 2013/14 to 2017/18

Future use of the gas system

The gas landscape has changed considerably in the last 20 years. With the continued decline of UK Continental Shelf (UKCS) supplies and the need to decarbonise, we expect gas supply and demand patterns to continue to change going forwards. However, to what extent is unclear. Given this uncertainty, it is impossible to forecast a single energy future over the long term. Each year in July we publish our Future Energy Scenarios (FES). The scenarios are based on the energy trilemma (security of supply, sustainability and affordability) and provide credible pathways for Great Britain's energy future out to 2050. We create these scenarios by drawing on our own analysis and input from stakeholders across the energy industry. Our scenarios flex the two variables of affordability and sustainability, giving the following four 2017 FES scenarios: Two Degrees, Slow Progression, Steady State and Consumer Power.

The key messages from the FES 2017 are:

1. Gas plays a vital role in Great Britain's economy and represents good value for domestic, industrial and commercial consumers. As the cleanest fossil fuel, it will continue to play a key role as we transition to a decarbonised energy future.

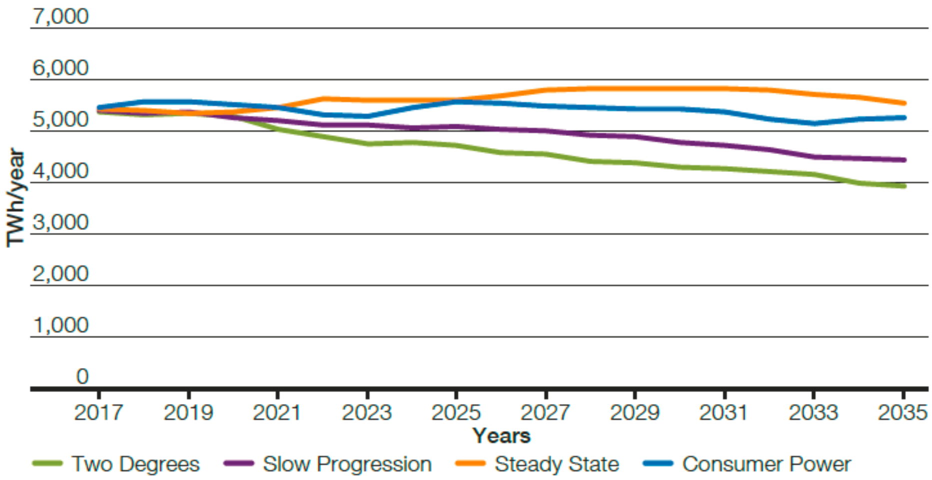

Figure 4: Peak gas demand for all scenarios

2. The wide range of pathways reflects the level of uncertainty around the future shape, size and mix of the energy network in Great Britain. Importantly, the relatively steady peak gas demand across all scenarios shows a continued need for the gas transmission network with associated gas compression.

Changing gas supply mix

From the mid-1990s to 2000s, supply patterns were dominated by the UKCS. Over the last 15 years, production from the UKCS has declined from 95bcm in 2000 to 35bcm in 2016. Great Britain has thus gone from being self-sufficient in gas in 2000 to being dependant on imported gas for half its needs in 2016. Over the next 20 years, across all scenarios, we expect the UKCS to continue to decline. How Great Britain's supply mix will look in the future will depend on:

- incentive to maximise production from the UKCS
- support for shale gas, bioSNG and biomethane production
- global gas markets including interconnectors and LNG

The gas supply mix will become increasingly dynamic with closer integration with European markets through transit gas, more agile supply sources and markets balancing close to real time.

Figures 5 and 6 illustrate how future levels of annual UKCS supply and gas import dependency could change depending on the energy pathway taken.

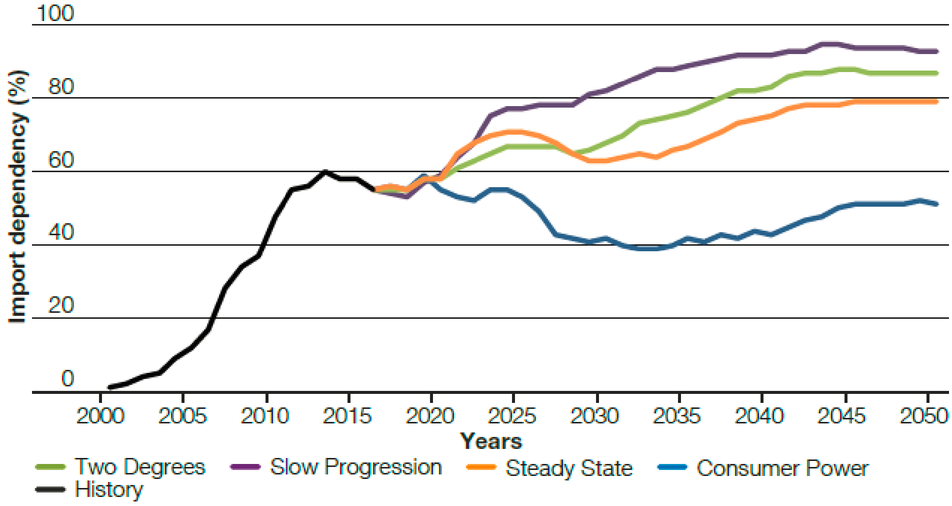

Figure 5: Gas supply import dependency

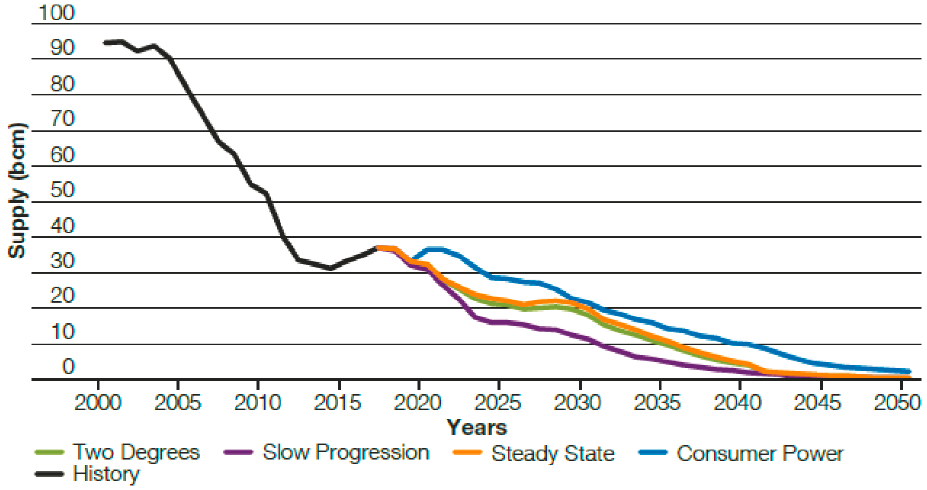

Figure 6: Annual supply pattern from UKCS

Across three of our four scenarios, we see our dependency on imports increasing to above 75% by 2050. This increase in reliance on gas from Norway, continental Europe and the rest of the world (LNG) creates numerous operational challenges. Compressors surrounding these terminals will play an increasingly important role in transporting gas away to demand centres. This must be done whilst ensuring pressures continually remain within network design safety parameters. The only scenario that does not see an increase in import dependency is Consumer Power. Gas demand is instead met by a significant increase in UK shale, biogas and bioSNG production. The Bowland region (highlighted in red in the figure below) represents the most likely location for shale recovery in Great Britain. However, with both shale and green gases, it is not clear whether development will be successful and in what

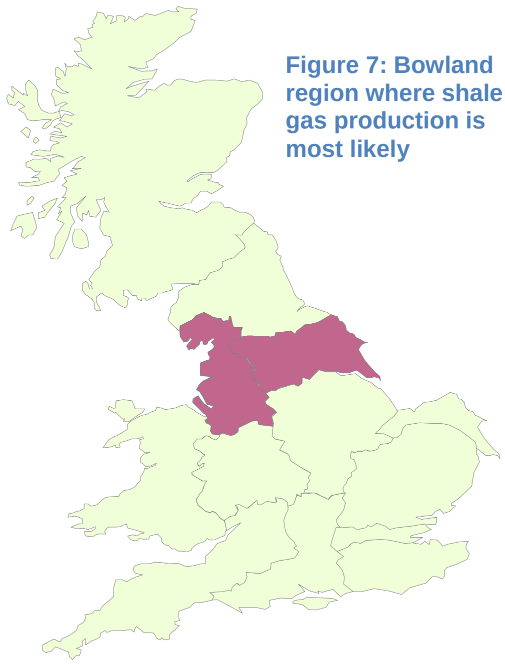

Figure 7: Bowland region where shale gas production is most likely

quantities. In the absence of long term clarity, it is important that we do not reduce the system flexibility our current compressor fleet provides.

The role of gas in decarbonising electricity generation

Gas fired generation, being easily controllable and flexible to patterns of energy demand, plays a vital role in Great Britain's generation mix. In recent years we have seen a significant increase in gas demand for electricity generation as a combination of energy and environmental policy, such as the carbon floor price, which have made coal plant less competitive.

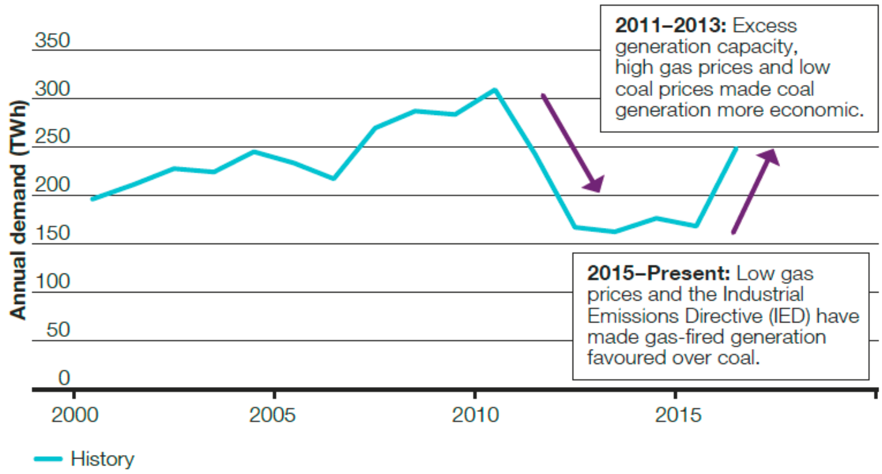

Figure 8: Gas fired generation demand

Today, gas fired generation is critical in maintaining energy security and affordability. In 2016, around 42% of electricity generation was supplied by gas-fired power stations. Going forwards, the shift towards a decentralized and decarbonised energy future is evident in all the future energy scenarios. It is only the pace and extent of this change that differs. During this transition, gas fired generation is expected to continue to provide a flexible and low cost source of electricity. Alongside other balancing mechanisms, it will help to meet the variability associated with renewables, particularly in times of peak demand and low renewable generation. Depending on the energy pathway taken, annual transmission connected gas-fired generation demand could vary between 7-40% of the total electricity generation by 2035. Given the wide range in gas demand, it is clearly important that we retain an appropriate level of network capability through compressor flexibility to manage more changeable demand patterns and demand uncertainty.

Maintaining compressor optionality

Our Future Energy Scenarios demonstrate that out to 2050, gas networks will continue to be an important part of the future energy picture. However, the exact nature of the role gas will play is less clear. All of the challenges outlined above will impact on our current compressor fleet and its usage going forward. We are already seeing customers changing their use of the system with day to day and within day volatility in the levels of regional demand and supply at entry points. This could increase further in the future. Our network will need to react to these changing supply and demand patterns. Compression will be pivotal in providing the level of system flexibility needed to ensure we continue to meet our customer's needs.

Potential solutions

The existing fleet of standard Rolls-Royce (now Siemens) RB211 and Rolls-Royce (now Siemens) Avon gas turbine driven compressors will ultimately be non-compliant with the environmental legislation. All the RB211 units are classified under the LCP elements of IED, and are now operating under the 500 hours Emergency Use Derogation (EUD) or with restricted operating life under the IED Limited Life Derogation (LLD). This derogated plant will have to be permanently closed in 2023 or upgraded through emission abatement technology to meet the required ELVs for a new installation. All units impacted by the IPPC elements of the IED Avon units. Looking forward, the remaining fleet of Avon units will be captured under MCP and are likely to be subject to similar constraints to the Emergency Use Derogation under the LCP directive; run hours limited to 500 hours but with the flexibility that this restriction is applied on a rolling average basis.

Commercial and regulatory options

Commercial and regulatory options are the first consideration when assessing how to meet the network needs, as these solutions potentially avoid the physical use of compressors, and consequently reduce the emissions impact of the fleet overall. Typically, the commercial and regulatory options are suited to short term scenarios, meeting a peak demand and supply pattern linked to a single entry point, rather than a complete alternative option to investment in the compressor fleet. In essence, there are three commercial and regulatory options to consider:

1. Reduce Obligated Baselines

The obligated entry capacity levels at specific entry points inform our decision making around network investment requirements. Where these baselines are significantly higher than the peak physical flows through the supply point, this can create uncertainty in the level of investment required. Reducing the baselines at specific supply points would give greater clarity to the required level of compressor investment to meet customer needs. In 2007, a process to reduce baselines was undertaken. This generated significant industry debate and was highly complicated. However, we are in a different environment today and this may be a less contentious option at certain entry points, as seen in the recent reduction of the Fleetwood baseline.

Case Study – Fleetwood Obligated Entry Capacity Consultation

Review

In November 2016, Ofgem announced that they were reviewing the price control treatment of entry capacity obligation at Fleetwood. They launched a formal consultation process between 31st March 2017 and 26th May 2017 to establish industry views on options they were considering for this National Transmission System (NTS) entry point. Ofgem proposed three options:
Option 1 – Do nothing now – retain the existing obligation of 650GWh/day
Option 2 – Remove the capacity now
Option 3 – Reduce the obligated entry capacity (e.g. to 350GWh/day)

There was an existing obligation of 650GWh/day of entry capacity at Fleetwood which was created following an entry bid by Cantaxx Shipping Limited in 2006. Prior to this bid we were not obliged to offer entry capacity at Fleetwood so a new entry point had to be created to meet Cantaxx's requirement. In 2007, Ofgem approved the release of 650GWh/day of entry capacity and it was included in our gas transporters licence. At the beginning of RIIO-T1 Ofgem provided us with a £277.5m allowance to cover the cost of investment works to meet this entry capability. No works have taken place as the original project which triggered the entry capacity fell through. In March 2016, a shipper bought 350GWh/day at Fleetwood for use in one quarter in 2025, but no other capacity has been purchased to date.

Consultation Responses

Four of the ten respondents supported option 2 and five respondents supported option 1. The industry responses raised concerns that if all of the capacity was removed it might have an impact on long term regulatory confidence.

Ofgem Decision

Following the consultation process Ofgem decided to reduce the capacity obligation at Fleetwood from 650GWh/day to 350GWh/day and to remove the £277.5m allowance provided at the beginning of RIIO-T1. Ofgem also indicated that they may decide to remove all of the capacity at this entry point at a future date if this is in consumer's interests.

2. Turn up and turn down contracts for constraint management

Bi-lateral contract arrangements at either entry or exit points can be used to manage network flows. For example, to help meet the required pressure level at a distribution network offtake, a turn up contract could be negotiated with the relevant gas shippers at a particular entry point. Flows through that entry point are then increased on request by National Grid, boosting local pressures. A turn down contract at a power station can be used in a similar way. As an alternative to asset investment, contracts of this type are likely to be the most effective options when linked to single entry points over the short term.

3. Disaggregation of entry points

This option would allow for capacity buyback mechanisms to be targeted at a single entry point; sub terminal rather than Aggregated System Entry Point (ASEP). This option is applicable at St Fergus terminal where the compression service carried out by National Grid is directly linked to flows through one individual sub-terminal, rather than the ASEP. If the compressor units were unavailable, only gas flows through one sub terminal would be constrained, and hence the capacity buy back mechanism would be targeted at the sub terminal, rather than ASEP level.

Case Study – Splitting the Bacton ASEP

Reasons for the Split

The Network Code on Capacity Allocation Mechanisms (CAM) came into force in November 2013 and required that capacity at Interconnection Points (IPs) should be sold in EU-specific auction types that were consistent across the EU but different to the Uniform Network Code (UNC) auctions that applied to the rest of the UK. The Aggregated System Entry Point at Bacton held a unique position in the UK in that it consisted of two IPs, IUK and BBL, as well as non-IP sub-terminals that facilitated the importation of gas from UK Continental Shelf (UKCS) fields.

Options Considered

The options considered by Ofgem included:

- making the full Bacton capacity release obligation available in both UNC and CAM auctions, with National Grid required to manage any constraints that might arise if flows exceeded network capability;
- releasing the remaining capacity release obligation sequentially into the next available UNC or CAM auction;
- running UNC and CAM auctions simultaneously as competing auctions;
- an ex-ante split of the Bacton capacity release obligation between UNC and CAM auctions, and thereafter running the auctions as distinct processes.

Solution Implemented

Each of these solutions had its own advantages and disadvantages. The only practical solution was to split the capacity release obligation at Bacton between two new entry points, Bacton IP and Bacton UKCS. This was unpopular with shippers, however, who argued that this approach reduced the flexibility of Bacton entry capacity and therefore devalued existing holdings as well as future capacity.

A process was run to allocate existing holdings across the two new entry points. The volume of capacity that shippers wished to allocate to the Bacton UKCS entry point exceeded the capacity available in some calendar quarters, meaning that Bacton UKCS was sold out for these quarters and some shippers had part of their holdings allocated to the Bacton IP entry point instead.

Asset Options

In addition to the commercial and regulatory options, for each site affected by IED there are a number of potential 'asset' options which can be considered either in isolation or in combination:

1) Retain under the Limited Life Derogation
2) Retain under the Emergency Use Derogation
3) Oxidation Catalyst
4) Selective Catalytic Reduction (SCR)
5) Replace with the same capability
6) Replace with different capability
7) Retrofit
8) Mothball
9) Decommission

1. Retain under the Limited Life Derogation

The Limited Life Derogation allows units to continue to operate for a maximum of 17,500 hours from 1st January 2016 to the 31st December 2023, after which time the unit would need to be decommissioned. We currently have six units operating under this derogation. Rather than initiate immediate decommissioning, this option buys time to consider and implement options e.g. replacement.

2. Retain under Emergency Use Derogation

A second option is to use the Emergency Use Derogation. This means affected units can be used for a maximum of 500 hours per year. There are seven units currently operating under this derogation. Applied to the low utilisation units, this option leads to reduced capability (in terms of duration) and therefore a risk management strategy needs to be considered. For units that continue to operate under this derogation, or the limited life derogation, the age of the assets will mean there is an ongoing requirement for asset health investment.

3. Catalytic Converter: Oxidation of CO using an Oxidation Catalyst

One option to meet the required ELVs is to use a catalyst to treat exhaust gases emitted from the compressor flue stack. Catalytic converters can be used to either oxidise the CO or to reduce the NOx.

An oxidation catalyst is used to convert CO and hydrocarbons to carbon dioxide and water vapour. When the CO in the exhaust gases is passed over a catalyst it reacts with the excess oxygen to produce CO_2. This solution requires sufficient physical space to fit the exhaust gas catalyst unit and in some cases continuous monitoring of the exhaust gas to ensure a sufficient degree of abatement (see figure 10). The oxidation catalyst can be used in combination with Selective Catalytic Reduction (SCR) for NOx control. Compressor station overview (without a catalyst fitted)

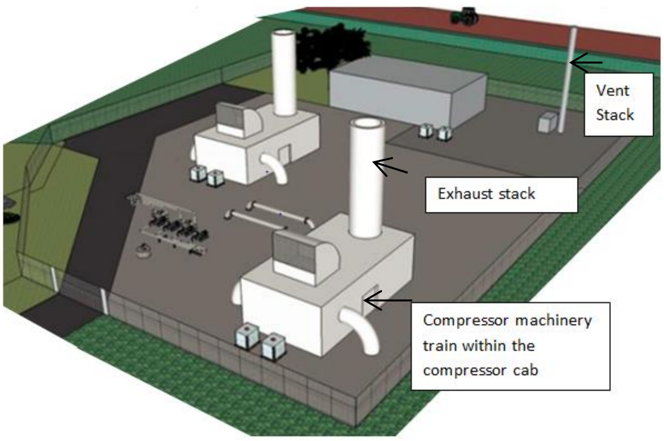

Figure 9: Compressor station overview (without a catalyst fitted)

4. Catalytic Converter: Reduction of NOx with Selective Catalytic Reduction (SCR)

NOx can be reduced to nitrogen and water using SCR. Using this technique, aqueous ammonia is typically used as a reducing agent, and is injected in the exhaust gas upstream of the catalyst to break down NOx into nitrogen and water.

SCR is a more complex process to implement than an oxidation catalyst as it includes the catalyst units, storage of ammonia and process control and monitoring systems (see figure 10).

Figure 10: Compressor cab with SCR fitted

Ammonia is considered hazardous and hence subject to its own specific control conditions under the Control of Substances Hazardous to Health legislation. Whilst this technology has not been applied on the NTS, it has been in use at two operational gas transmission sites in Europe. SCR offers significant reduction in NOx emissions; however a limiting factor could be longevity of the other compressor assets, which will continue to incur ongoing asset health issues. SCR options may therefore need to be accompanied with a range of asset health replacements and equipment re-lifing.

5. Replace with the same capability

Under this option the capability provided by each unit would be replaced with the same capability which would result in no change in risk profile. However due to the significant changes in supply and demand patterns over the last 15 years and the way in which shippers use capacity, this may no longer be an optimal solution. Based on recent engagement in the market, replacement units will have emissions limits which significantly reduce the operating range of the unit, and so cannot be considered like for like in terms of range, flexibility or capability when compared to existing units. This can be addressed by the installation of multiple smaller units to provide the same operating range and capability.

6. Replace with different capability

Under this option, we determine the capability requirement for each site based on forecast flows, operating strategy and legal obligations and replace non-compliant technology with compliant equipment. This enables us to develop solutions that take account of the current and the future needs of the system.

7. Retrofit

A retrofit in this context is the exchange or modification of an aspect of the compressor unit with newer elements which offer lower emissions. Under this option only some of the unit will be upgraded, meaning that the unit as a whole will be limited to its original lifespan. In advance of the 2015 IED compressor reopener submission a detailed study was undertaken to look at options for retrofitting a DLE (Dry Low Emissions) RB211 engine at a NTS compressor site. This study highlighted that a retrofit required quite major and expensive alterations to the cab structure to accommodate the new engine, and also, importantly, a retrofit DLE RB211 engine is significantly overpowered for the existing power turbine, compressor and other site infrastructure. Revised ELVs would apply to the larger retrofit engine, and as the unit would be running at a low turndown it could not meet the required ELVs. So potentially, the environmental performance and total cost of ownership could be less favourable compared with a new low emission package. There has been an ongoing dialogue with the relevant Original Equipment Manufacturer (OEM), however, at present there is no additional information available regarding the retrofit of a RB211 unit. Therefore this option was not considered as part of this reopener submission.

Initially there was no market option for an Avon unit retrofit. However, within the past few months, one OEM has indicated they are looking at the possible development of options that could be suitable for retrofit to an existing machinery train. This work is still in the early stages but subject to successful validation of these options, and assessment of engine power output issues described above, any emerging retrofit solutions will form part of our future optioneering for units impacted by MCP. So whilst none of the available retrofit packages are technically suitable at the current time, the retrofit option will continue to be part of our ongoing discussions with the OEMs.

8. Mothball

Mothballing is an option to preserve a compressor unit which is currently not required in a condition whereby it could be restored and brought back online if required within a prescribed timeframe. To build a new compressor takes up to seven years, so this option retains flexibility in circumstances where the future need for the site is not fully known. However, the environmental permit for the compressor station requires the unit to undergo regular emissions testing. To retain the permit a unit would therefore have to be kept in full working order, maintained in a similar way to a fully operational unit with a test run on a regular basis. If the environmental permit is surrendered or removed, for certain sites it is highly unlikely that a new permit would be granted in the future, consequently removing any advantages of mothballing. Hence this option has not been taken forward.

9. Decommissioning

Decommissioning is the option of permanently removing assets from service. Where an option refers to unit decommissioning this would include dismantling and disposal of the compressor train, removal of all associated balance of plant equipment and systems and demolition of the compressor cab. We use the term decommissioning to ‘plinth level’ to encompass these activities. Where units have experienced significant asset health issues, and are no longer fit for operation and have been isolated from the site prior to decommissioning, the term ‘disconnection’ has been used.

Where an option includes decommissioning of the compressor station, this also includes work on pipework on the above ground installation to isolate the site from network feeders, demolition of buildings, and other civil works. It would not be acceptable under our safety or environmental obligations for site infrastructure to continue to remain in–situ once a station is disconnected from the NTS. We use the term ‘station decommissioning’ to encompass these activities.

IED investment to date

Since the introduction of IPPC, LCP and then the combined requirements of IED, we have received funding for six sites to ensure compliance with the legislation.

As part of IPPC Phase 1, prior to RIIO-T1 baseline funding was agreed for works at St Fergus for two electric VSD (variable speed drive) units 3A and 3B, which were operationally accepted in June 2015. Also funded under IPPC Phase 1 was the VSD Unit E at Kirriemuir. IPPC Phase 2 then established funding for Hatton Unit D, an electric unit which achieved operational acceptance in February 2016.

IPPC Phase 3 was agreed with funding at the start of RIIO-T1 for one unit at both Peterborough and Huntingdon. The early stages of the Front End Engineering Design (FEED) study concluded that the option of electrically driven compressors was not viable at Peterborough, but remained a possibility for the Huntingdon site. The tender process for Huntingdon included the option for suppliers to offer an electrically driven compressor option and a number of bids were received. The BAT assessment of the tender submissions, combined with further information on the availability and costs of a high voltage electrical supply to site concluded that the electric drives do not represent BAT. As a result of the assessment, the unit selected to reduce emissions at both sites is a 15.3 MW gas turbine unit. Construction works began in 2017. At both sites, it will be necessary to retain all three existing units until the new units have been operationally proven.

Aylesbury falls under the LCP element of the IED and upfront funding received under RIIO-T1 was to fund works on two units at this site. The existing engines at Aylesbury are prototype versions of an upgraded Rolls Royce Avon engine fitted with DLE technology to reduce emissions. These are the only engines of this type that we have within our fleet. Analysis of the performance of the Aylesbury engines showed that whilst they are able to achieve the required NOx limits within their operating range, they are unable to achieve the required ELV for CO. It was established through work with Rolls Royce that the CO ELV could be achieved by the addition of a CO oxidation catalyst in the exhaust stack. The construction phase of the catalyst installation was completed in the last quarter of 2016. Unit B was successfully commissioned to Operational Acceptance stage in early 2017. Unit A achieved operational acceptance in April 2018.

The timeline presented below summarises the key actions and decision points for this reopener. Looking forward to the next phases of work, under IED IPPC Phase 4 we have considered investment options and have begun further investment at St Fergus, Peterborough and Huntingdon to ensure compliance. Under IED LCP we are considering commercial and investment options at seven sites: Wisbech, Carnforth, Hatton, St Fergus, Moffat, Warrington and Kirriemuir.

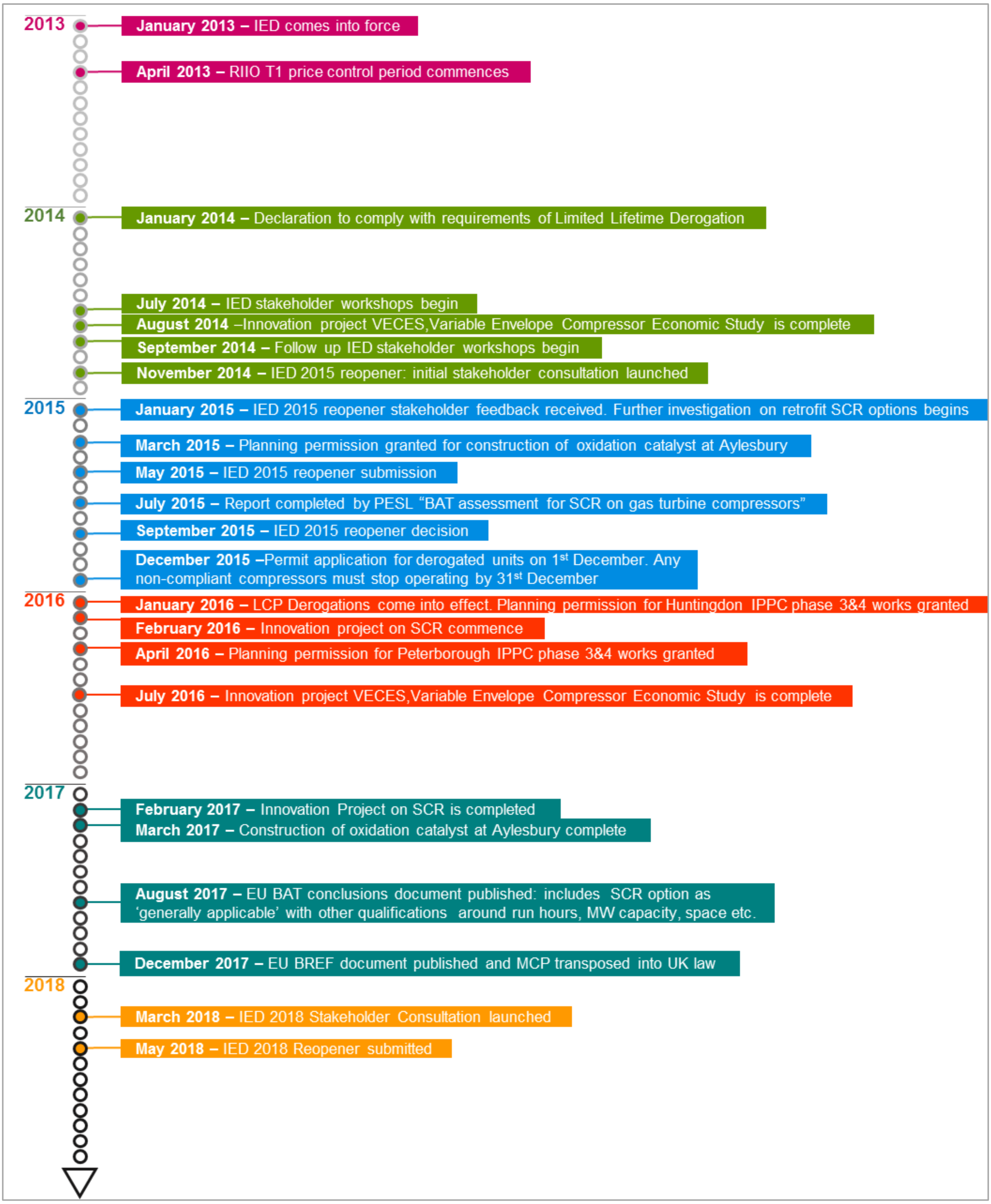

Figure 11: IED Timeline: key actions and decisions

Stakeholder engagement

Stakeholder engagement is of fundamental importance to us. We have listened to our stakeholders' views and acted on what they told us. As we work to meet environmental legislation and replace ageing assets it is crucial that we are transparent and clear about the tasks ahead, and that we work with our stakeholders to produce an integrated plan that meets their requirements**.**

In April 2014 we began our initial period of stakeholder engagement. We also publicised the start of the engagement through our Connecting website and a project specific website under the Talking Networks umbrella. We commissioned a video to provide an overview of the IED legislation and its impact on our network and its users.

Then, in July 2014 based on feedback, stakeholder consultations began with an initial workshop and subsequent workshops in September 2014, November 2014 and March 2015. Attendance (22 different attendees across all workshops), represented a wide range of industry participants including shippers, Gas Distribution Networks (GDNs) and trade associations.

In the first workshop to get a better understanding of stakeholders' requirements delegates completed a Gas Transmission Network Strategy scorecard, to identify the network capability criteria that are most important to them and why (Figure 12). This formed the basis for the development of a range of site options. On the 17th November 2014 we published the *IED Investments: Initial Consultation* document. In this consultation we asked for stakeholders views on a range of questions including the range of available options for compliance at each affected site.

The *IED Investments: Initial Consultation Stakeholder Feedback* document was then published on 16th January 2015 outlining what stakeholders told us in the responses and what we would do as a result, including providing more information on the different elements of legislation.

In February 2015 we presented at the Transmission Workgroup and we also held a number of bilateral discussions to address particular concerns for individual parties including all four GDNs. On the 13th March 2015 we published the *IED Investments: Proposals Consultation*. This was a development of the initial consultation document in light of stakeholder feedback received. It also provided a recommended option to achieve compliance at each site. The consultation received responses from Centrica, RWE, Total, National Grid Distribution and Energy UK.

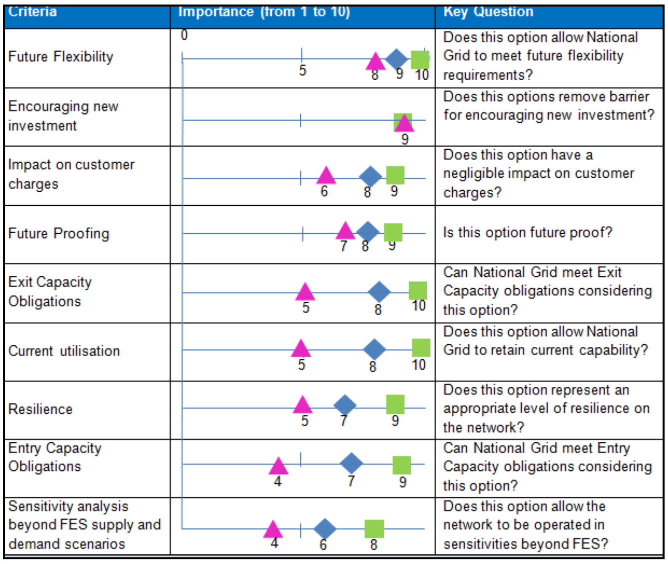

Figure 12: Overview of the network strategy scorecard

In their responses stakeholders broadly agreed with our recommendations. Ultimately this formed the basis for our IED reopener submission to Ofgem in May 2015. Ofgem, whilst positive about the stakeholder engagement process we had undertaken asked for the submission to be resubmitted in May 2018 with further work on costed options. In preparation for the May 2018 reopener we looked to build on the positive response from our 2015 stakeholder engagement, developing the factors stakeholders consider important with a robust Cost Benefit Analysis (CBA) methodology for the options presented.

The first events held as part of our second period of stakeholder engagement were three workshops held in London, Edinburgh and Warwick in October 2017. These events attended by a range of stakeholders, have re-introduced the background to the legislation and provided an updated view on the impact on the compressor fleet. These workshops have also provided insight into the most effective way to continue stakeholder engagement in this second phase.

A key message from stakeholders was that views shared in the May 2015 reopener process are still very relevant and the themes identified are still appropriate. Having shared the key inputs with the stakeholder groups in November, many of the possible inputs have been captured appropriately in the CBA tool. Where stakeholders identified other factors, we have sought to either include these in the CBA tool, or to capture these within the stakeholder section within each site assessment. These additional factors are grouped under three themes, consolidated from the stakeholder themes from the 2015 reopener process:

- Future Flexibility: delivering a network fit for the future
- Impact on our Customers: minimal effect on consumers and our direct customers
- Resilience: maintaining network access and operation

In some cases the relevant information under each theme will be assessed qualitatively, whilst in other cases financial figures will be presented.

Since the workshops in October we have conducted several bi–lateral meeting with interested parties and have incorporated their views. In January and February 2018 there were two presentations at the Transmission Working Group, sharing the analysis and taking questions from stakeholders.

A formal consultation was launched on 14th March 2018. A stakeholder document contained a description of the options assessment for each site and was made available on our website and advertised through the Energy Networks Association. The consultation contained 12 questions, and four responses were received, two by written responses and two by online survey.

We received informal feedback from some shippers that they were unable to respond to our consultation due to the workload associated with other consultations. They told us that their feedback from the 2015 consultation – that flexibility in the network is important and should be maintained at a reasonable cost – was still valid, and indicated an intention to respond to subsequent consultations carried out by Ofgem.

We asked respondents whether they agreed with our approach to estimating the costs of the various options that we had considered, and whether we had given them enough information about our cost assumptions. There was broad agreement with the CBA approach. Some respondents noted the wide range given for the costs of new compressors and emissions abatement, and indicated a preference for new units if the whole life costs of each option was very close. One respondent noted that the cost to producers of constraints at St Fergus was likely to exceed the UNC costs that we had assumed.

We asked respondents whether they agreed with our specific proposals for each compressor site. Two respondents only expressed an opinion about our proposals at St Fergus; both stressed the importance of maintaining compression capability at this important location, but suggested that the wide cost ranges made it difficult to assess whether these were the best options.

Those respondents that expressed an opinion on our proposals at other sites generally agreed with our proposals. For Moffat and Warrington, the outcome of the CBA was to decommission compression capability at both sites. In our consultation document we presented this information, but also noted that these sites gave benefits in terms of capability, resilience and flexibility that we had been unable to quantify, and asked stakeholders for their view on the merits of retaining compression capability at these sites. One respondent indicated that compression capability should be decommissioned, and the other was not sure.

In summary, our stakeholder engagement process has built on the comprehensive activities undertaken in 2015. Our proposals have been well received, with consistent key messages on flexibility and cost.

Development of an integrated plan

In response to feedback from our 2015 proposals, and in order to strike a better balance between holistic (whole-network) and site-by-site analysis, we have adopted a two-step approach to our analysis to form an integrated plan. An overview is provided below, and the results can be found in the Integrated Plan chapter.

Four of the sites with limited interactions are considered standalone. The remaining sites are assessed at an individual site level and then combined in a Cluster analysis. The Cluster analysis focusses on the interactions between compressors on the east and west coast routes and validates the recommendations made at individual site level as being the optimum holistic solution for the network and our customers.

St Fergus

This is our most complex site, with the highest utilisation and the largest number of units, which are affected by the LCP and IPPC elements of the IED directive and MCP. St Fergus performs a different role to the other sites in the network and is therefore considered standalone.

Kirriemuir

This site includes a unit that is non-compliant with LCP. The affected unit was put on the 500-hour Emergency Use Derogation in January 2016, however since then asset health issues were identified which were uneconomic to resolve and so the unit has been disconnected. This business case has been considered standalone.

Huntingdon and Peterborough

These are two of our highest utilisation sites and both are critical during periods of high demand. The units at these sites are affected by both the IPPC element of IED and MCP. The primary focus of the analysis for these sites is determining the most appropriate option to reduce emissions at these high use sites. The capability at Peterborough and Huntingdon is included within the Cluster analysis

Wisbech

As a relatively low utilisation site, Wisbech is impacted by the LCP element of the IED. The site interacts strongly with Peterborough and Huntingdon, and is therefore included as part of the Cluster.

Hatton and Carnforth-Nether Kellet

The interactions between compressors on the east and west coast routes are analysed through the Cluster analysis. A range of emission compliant options are considered to assess the impact on network capability, resilience, emissions and fuel costs at a holistic network level.

Moffat and Warrington

These sites include units that are non-compliant with LCP. The affected units were put on the 500-hour Emergency Use Derogation in January 2016 because our future utilisation of these sites was forecast to be low. This also gave us greater flexibility to respond should our forecasts for network conditions change. The key focus of the analysis at these sites is to establish whether it is justified to retain compression capability. There is an interaction between Moffat and Warrington in terms of the network resilience they provide during periods of outage in Scotland and at Carnforth-Nether Kellet. Therefore the options considered at both sites were assessed together with the options proposed at Carnforth-Nether Kellet to ensure network resilience was not compromised.

Overarching Approach

We have taken the following high-level approach to our analysis:

Establish the Counterfactual

The 'Counterfactual' is defined for each site to act as a starting point for decision-making. It represents the current network with minimum interventions to meet the legislative requirements. We keep existing compressor units, unless we have already committed to decommission them (e.g. if they have a Limited Life Derogation).

Develop the options

We developed an extensive list of all potential options which ensure we meet our environmental legislative obligations in the most economic and efficient manner. We then developed detailed assessments on a short list of options including:

- Investment costs
- Decommissioning costs
- Asset health costs
- Operating costs
- Fuel costs
- Constraint costs
- Contracting costs
- Emissions damage costs

The costs associated with each of the options were incorporated into our Cost Benefit Analysis (CBA) model, which is explained in more detail in the next section. The CBA considers a range of supply and demand scenarios, together with uncertainty modelling through Monte Carlo analysis to develop Net Present Value (NPV) estimates and distributions for each option.

Proposals

The output of the CBA identifies the option or options which have the most favourable NPV. These are presented relative to the Counterfactual. If more than one option has a comparable NPV we may propose taking more than one option forward to the next stage of our network planning process for more detailed costing.

We also include some qualitative assessments to these options to incorporate factors that are more difficult to quantify, such as benefits in handling within-day changes in supply or demand or associated risks such as the possibility that our forecasts of the future may change or that assumptions about the availability of existing assets may change.

Cost Benefit Analysis (CBA)

In order to quantify the relative benefits of each option, we have built a Cost Benefit Analysis (CBA) tool. The CBA is a mathematical decision support tool, which, based on Ofgem feedback has been developed to quantitatively assess and compare a range of options in order to inform the optimal solution. The evaluation includes the costs of implementing each option and the relative advantages of doing so. In developing the CBA tool, an independent review was completed by an external party.

The tool generates a Net Present Value (NPV) of the options, and includes optimal timing analysis. The assessment includes costs of maintaining and replacing assets, fuel usage, emissions costs, site operating costs, the costs of managing constraints and where relevant, the cost of commercial and regulatory options. These costs are spread across the full assessment period in order to represent the impact on consumer bills and to reflect the cost of capital investments, the regulated weighted cost of capital is applied. To allow for comparison between costs occurring over different time periods, future values are discounted using standard rates.

With the long time horizon of the model, out to 2050, most of these inputs have an associated uncertainty. The CBA tool uses a range of supply and demand scenarios and Monte-Carlo modelling in order to account for these uncertainties and simulate the potential range of possible outputs. For every variable within the tool, an uncertainty distribution is applied to account for its potential range of values in the future. The Monte Carlo simulation will pick values for every variable based on defined probability distributions. This process produces an expected final NPV with an associated range representing the 5th and 95th percentile.

The NPV for each option is then compared against a counterfactual option to produce a relative NPV. The counterfactual option is the option which is closest to the current compressor operations while being compliant with all the relevant elements of IPPC and IED. The relative NPV will inform which of the options provides the greatest benefit to the consumer.

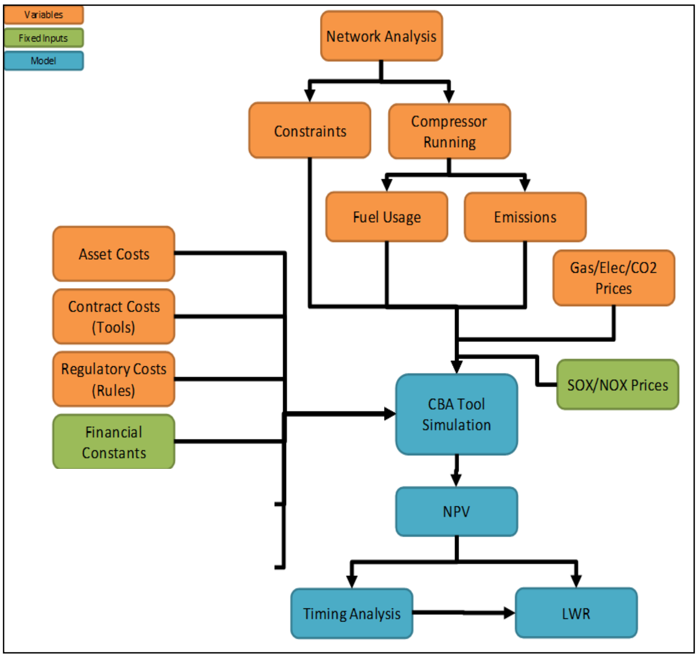

Figure 13: Overview of CBA tool

The Integrated Plan

A specific output within the RIIO-T1 framework is the development of an integrated plan. This was defined in the RIIO-T1 final proposals as follows

“We require NGGT to use the baseline expenditure related to the emissions abatement optioneering to develop an integrated plan of investment to comply with IPPCD Phase 4 and IED Phase 2. This plan will need to demonstrate comprehensive cost-benefit analysis of all the engineering and commercial options available to NGGT. The plan will need to consider compression requirements on the network as a whole, not just at individual sites, as well as performance against other incentives such as venting. It will also take into account any guidance on IED issued by the EA and SEPA, as well as finalised IPPCD Phase 4 requirements. We will evaluate the proposals included in this plan and adjust the relevant part of the baselines upwards or downwards if necessary.”

The appendices to this document set out the individual business cases for each compressor. This chapter considers each individual solution and tests their interactivity with other compressor sites to ensure investment is optimised across the fleet to deliver emissions compliance and value to customers. This in part has been an interactive process, between individual business cases and the wider network considerations. The table below sets out the relevant interactions between the sites and how this has been considered.

Site	Interaction	Assessment Approach
St Fergus	No network interactions	Standalone
Huntingdon	Interacts with Hatton and Carnforth Nether-Kellet on both east and west coast routes	Cluster
Peterborough	Interacts with Hatton and Carnforth Nether-Kellet on both east and west coast routes	Cluster
Hatton	Interacts with Peterborough and Huntingdon on the east coast route	Cluster
Carnforth-Nether Kellet	Interacts with Peterborough, Huntingdon on the west coast route	Cluster
Moffat	Interacts with Warrington	Assessed with Warrington
Warrington	Interacts with Moffat	Assessed with Moffat
Wisbech	Interacts with Peterborough	Cluster
Kirriemuir	No interaction with other IED impacted sites	Standalone

Table 4: Recommended Options

From the table above, it can be seen that a group of stations down the west coast interact with those down the east. Therefore solutions for these stations have been considered together within a ‘Cluster’ approach. St Fergus remains standalone as does Kirriemuir. Warrington was initially considered within the Cluster but even in the most challenging scenarios was not required. Warrington and Moffat have therefore been validated against each other from a resilience perspective.

The Cluster

From an operational perspective, the sites within the Cluster interact with each other and therefore the Cluster analysis looks to optimise investment based on this interaction. The Cluster approach accommodates scenarios where more than one of the sites is unavailable (due to planned or unplanned outages), considers options for capability and back up and develops the case for where the best place is within the Cluster to make an investment.

The Cluster approach encompasses the IED impacted sites; Hatton, Carnforth, Peterborough, Huntingdon, Wisbech and also Alrewas. Alrewas interacts with Carnforth-Nether Kellet to the north and Peterborough to the south. So although Alrewas is not impacted by the IED, the units there will be impacted by MCP from 2030 onwards, and so different capability options at Alrewas are modelled within the Cluster.

At a high level, appraisal of the Cluster compares the merits of a compressor investment strategy placing resilience on the west coast route (via Carnforth-Nether Kellet) with the east coast route (via Hatton). The compressors at Hatton, Peterborough and Huntingdon are in a chain along the eastern side of the NTS and therefore there is some interchangeability in the use of these sites dependent on the supply and demand pattern. Carnforth-Nether Kellet and Alrewas together can be used as an alternative, west coast route.

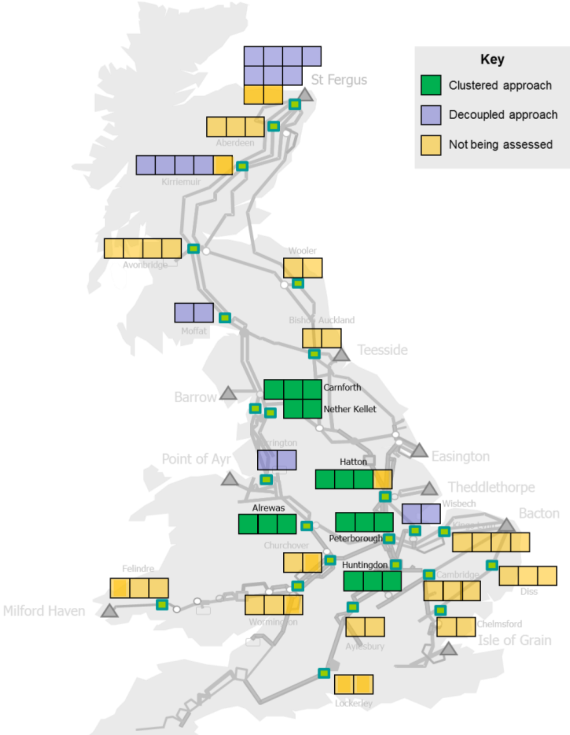

Figure 14 Sites within the Cluster

Huntingdon and Peterborough are high-utilisation compressors that are required for the onward route of the gas to meet system requirements at times of moderate or high demand. The decision at these sites is assumed as a three unit capability at both sites.

Wisbech has a two unit capability assumed which is based on the business case whereby no additional investment is planned at this site apart from an engine overhaul.

Commercial and regulatory options are considered within the Cluster and the appropriate options are built into the matrix of options e.g. low asset capability options may include a turn up contract cost where required. This is particularly important as Hatton is required for 1-in-20 demand, the coldest weather conditions with exceptional demand on a winter day which statistically occurs once every 20 years.

The Cluster therefore analyses the relative benefits of investing in an east coast strategy versus a west coast strategy whilst considering availability of the interacting compressor units, investment and asset health costs, emissions, timing of the various routes and commercial and regulatory cost implications.

Options

Option Selection

The detailed description of the asset options considered for each individual site within the Cluster can be found in the individual business cases.

These options cover a range of site capabilities including investment in new units, emissions abatement and retaining units on the EUD. In order to take forward a representative selection of the options to the Cluster, the investment, asset health and OPEX related costs for each site were calculated and used to develop a short list of options. At this stage the assessment did not include contracting costs. The selected options include the counterfactual as well as high, medium and low capabilities. In general, unless there were any overriding factors, where two options had the same capability, the lower cost option would be selected. For Hatton we also consider a high sensitivity option in order to test the range of the results. These capability levels are then used to determine the required level of commercial contracts for each option.

For Carnforth–Nether Kellet, the counterfactual option was the minimum intervention option, whilst Option 1 included common station pressure tier and offers greater resilience and lower ongoing asset health costs. The high capability option selected is emissions abatement on one unit, so in total three options are taken forward to the Cluster analysis.

Option	Description	Cluster
0	Decommission Unit A (RB211) immediately; retain Unit B (RB211) on 500 hrs EUD; keep Unit C and Nether- Kellet Units A and B as is.	Counterfactual
1	Station reconfiguration: Decommission Units A and B (RB211) immediately; keep Unit C (DLE) as is and reconfigure site pipework with Nether- Kellet (Units A and B) including common pressure tier.	Low
2	Decommission Unit A (RB211) immediately; Emissions abatement (SCR + OxyCat) on Unit B; keep Unit C (DLE) and Nether- Kellet Units A and B as is.	High

Table 5 Carnforth–Nether Kellet options

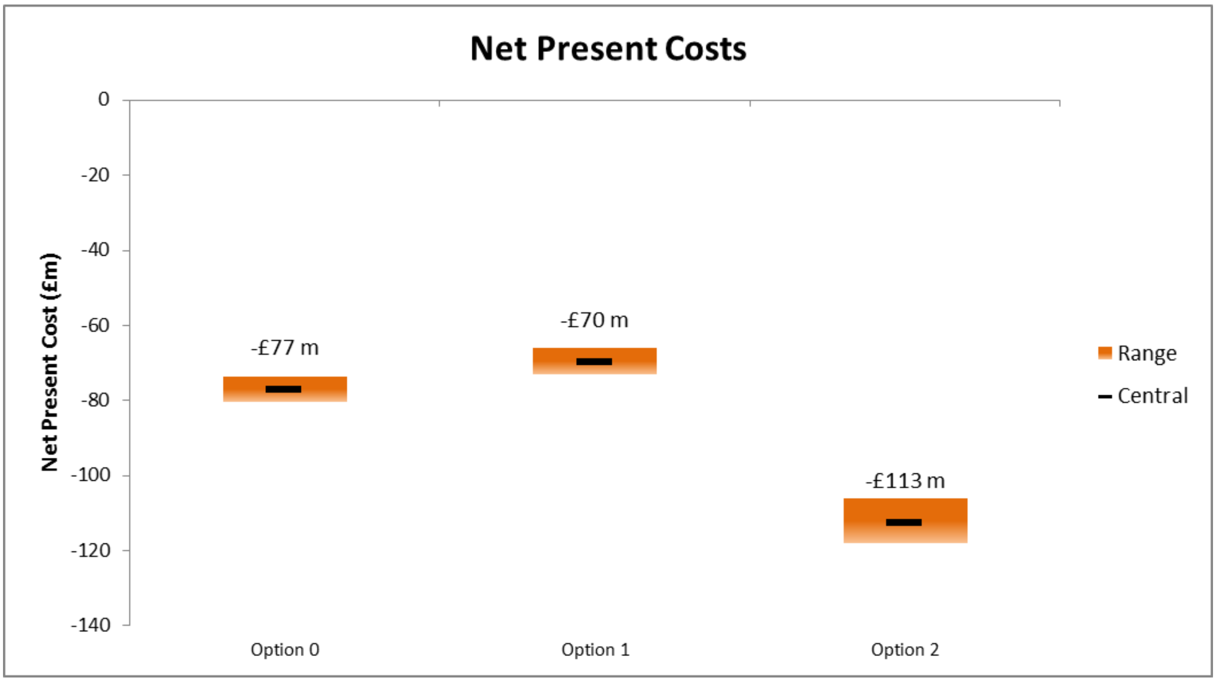

Figure 15: Carnforth-Nether Kellet initial NPV (assesses costs only)

For Hatton the counterfactual and one low, one medium and two high capability options were selected. Option 1 is the low capability option, Option 2 is the medium capability option and Option 4 is the high capability option. Option 7b which demonstrated a favourable NPV in the initial CBA is taken forward as a high capability sensitivity. Five options in total were selected for the Cluster analysis.

Option	Description	Cluster
0	Retain Unit A (RB211) on 500 hrs EUD, retain Unit D (VSD) as is (i.e. lead unit) and decommission Units B and C (RB211s) post 2023.	Counterfactual
1	Keep Unit D (VSD) as is and decommission the RB211s (Unit A immediately and Units B and C post 2023).	Low
2	Retain Unit A (RB211) on 500 hrs EUD. Decommission one RB211 unit post 2023 and invest in emissions abatement (SCR + OxyCat) on other RB211 unit; retain Unit D as is.	Medium
4	Emissions abatement (SCR + OxyCat) two RB211 units; retain the Unit D (VSD) as is. Decommission one RB211 post 2023.	High
7b	Retain Unit A (RB211) on 500 hrs EUD. One large new GT (30MW) on greenfield site. Retain the Unit D (VSD) as is.	High

Table 6: Hatton options

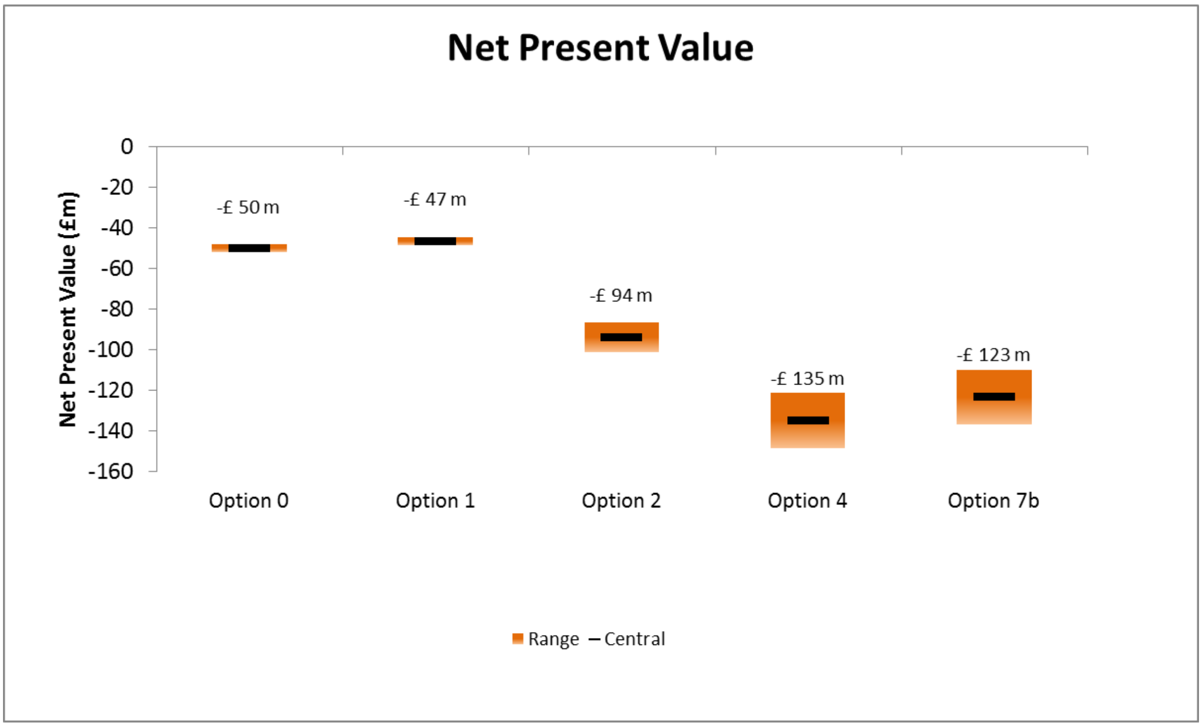

Figure 16: Hatton initial NPV (assesses costs only)

As previously mentioned, Alrewas is not captured by IPPC or LCP elements of the IED directive. However, the west coast transmission route involves interaction between Carnforth–Nether Kellet and Alrewas hence differing levels of capability and required investment are considered as part of the Cluster. Alrewas has three units; Unit C is a gas DLE unit and Units A and B are both Avon units and will be impacted by MCP in 2030. Two different capability options are taken forward to the Cluster.

Option	Description	Initial NPV (£m)	Cluster
0	Option 0 (Counterfactual): Retain Avon units A and B on 500 hrs EUD post 2030; and the DLE unit C as is	-63.86	Counterfactual
2	Option 2: Emissions abatement (SCR) on two Avon Units A and B; retain the Unit C (DLE) as is	-101.05	High

Table 7: Alrewas options

Peterborough, Huntingdon and Wisbech capabilities also form part of the analysis. These are fixed as three unit capability at Peterborough and Huntingdon and as two unit capability at Wisbech.

Analysis

In order to understand the operational and commercial implications of the various option choices, network analysis was undertaken focussing on the alternative east coast or west coast routes to transmit gas from north to south.

The network analysis considers a wide range of compressor availability; considering additional compression requirements when two or more of Alrewas, Hatton, Peterborough, Huntingdon and Carnforth-Nether Kellet stations were unavailable. The following table summarises the combinations analysed:

Hatton	Carnforth-Nether Kellet	Alrewas	Peterborough	Huntingdon
√	√	√	X	X
X	√	√	√	X
X	√	X	√	√
X	√	√	X	√
X	X	√	√	√
√	X	X	√	√
X	X	X	√	√

√ available **X unavailable**

Table 8 Compressor availability matrix

The analysis demonstrated several key factors, in particular, the criticality of Hatton and the east coast route versus the limitations of the alternative west coast route in NTS operation. For example, under 1-in-20 conditions, if Hatton is not available it is not possible to maintain Assured Operating Pressures (AOPs) in the South East. Under these scenarios, suitable contracts would need to be in place to guarantee either turn-up or turn-down of supply or demand in the impacted areas.

Constraints can be seen in over twenty high demand scenarios, across a range of supply and demand patterns. In particular in scenarios with high supplies from UKCS, Norwegian and Interconnectors ('High Continental Supply'), the North West, West Midlands and South East areas all experience constraints. Under scenarios with low supplies from UKCS, Norwegian and interconnectors ('Low Continental Supply') constraints are mainly within the South East with some pressure cover failures in the South West. The loss of compression at Hatton causes a reduction in the inlet pressure at Peterborough. Located at the centre of the network, Peterborough is designed for large flows with a relatively low lift so any reduction in the inlet pressure results in a drop in the outlet pressure. The effect of this at Peterborough has a ripple effect through the system, consequently reducing pressures at system extremities and causing constraints.

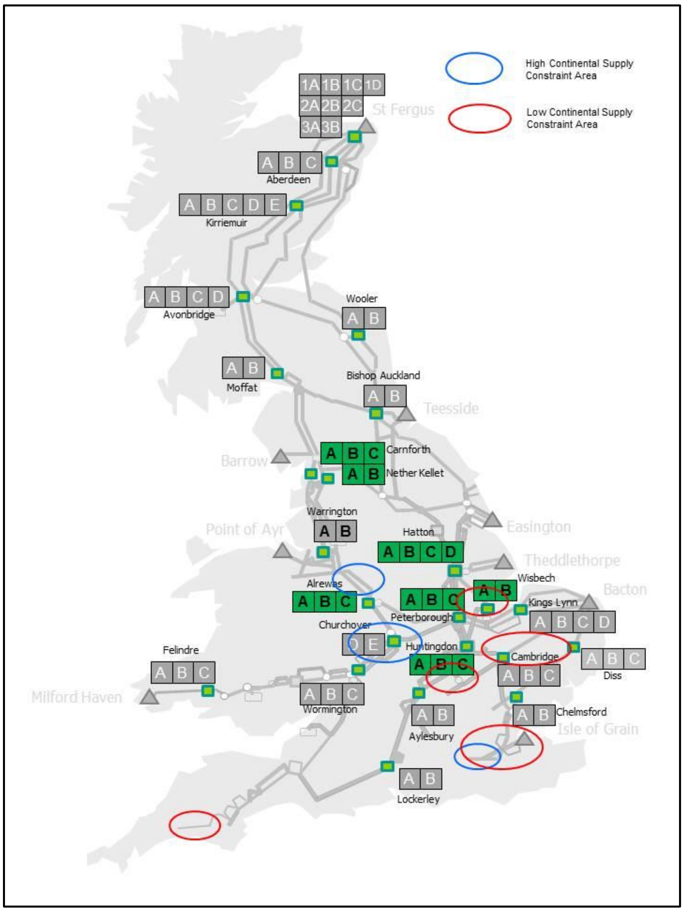

Figure 17 Constraint Map

The network analysis indicates operational inefficiency occurs on the west coast route scenarios through compressors running in a loop configuration. This involves recycling gas through the compression train to boost pressures, which is an inefficient way to operate the network. A compressor loop at Alrewas was used extensively in scenarios when Hatton was not available to support pressures in the North West and West Midlands.

In summary, the analysis demonstrates there are certain benefits associated with the east coast route over the west coast route for transmission of gas north to south. Hatton in particular, plays a key role in meeting the required system pressures and operating the system efficiently.

Commercial Options

Three different commercial and regulatory options have also been considered as part of the Cluster:

- Turn-up and turn-down contracts at a LNG terminal, storage sites, power stations and/or direct connects
- Renegotiation of Assured Operating Pressures (AOPs)
- Reduction of Assumed Normal Operating Pressures (ANOPs)

Turn-Up and Turn down Contracts

Bi-lateral contractual arrangements at either entry or exit points can be used to manage network flows to prevent constraints. This option is considered viable for the Cluster sites where a reduction in capability is proposed. Hatton in particular is required for 1-in-20 compliance; hence contracts must be considered essential as specified in the Security Standard (Standard Special Condition A9 of the License) in all of the low and medium capability options.

The majority of constraints are within the South East, West Midlands and North West of the network. We already have existing services in place at the Isle of Grain and at storage sites in the North West to increase gas supply as part of the annual Operating Margins (OM) tender. So it is therefore considered credible that additional volumes could be booked as part of the annual contracts at these sites. There is also the option of longer term turn up contracts, with sufficient confidence that they could be relied upon under 1-in-20 conditions. On this basis these contracts have been built into the Cluster options depending on the level of compressor availability at each site for each option.

The level of contract (low, medium, high) has been determined by the probability of the maximum volume required.

- High: utilised where analysis indicates significant constraints in both the South East and North West.
- Medium: required to manage significant constraints that are only in South East.
- Low: used to manage minor issues in South East.

Prices are based on current Operating Margin (OM) tenders with the higher volumes requiring higher prices and so the OM tender prices have been uplifted. The prices used are up to 3.5p/kWh

The higher prices are applied to the medium and high contracts as the greater volumes would have a more significant impact on the operation of the contracting partner site so are likely to require higher prices.

Renegotiation of Assured Operating Pressure (AOPs)

Hatton and Carnforth capability impacts a large number of different Distribution Network (DN) offtakes. In order to accept any reduction in AOPs, DNs are likely to have to upgrade the relevant offtake, potentially with some requiring pipeline reinforcement With over twelve different offtakes impacted, this is not taken forward as a suitable option.

Reduction of Assumed Normal Operating Pressures (ANOPs)

These pressures are agreed and detailed within the Network Exit Agreements for each directly connected site. Within these agreements, if it is believed that the pressure can no longer be maintained, notification periods of two or three years can be instigated to negotiate a change in the assumed normal operating pressure. Within the Cluster analysis, under certain scenarios there is an indication that this could be relevant for some direct connects post 2030. So under certain options, this would require a future re-negotiation although no cost is assigned to this as part of the Cluster CBA.

In summary, the option of turn up contracts is carried forward and costed as part of the Cluster CBA. The option to renegotiate AOPs is not taken forward and it is assumed that a reduction of ANOPs is negotiated where required.

The Cluster CBA

The Cluster Options

An initial matrix of options for the Cluster analysis was developed involving the combinations of the low, medium and high capabilities for each site. This was further refined based on an initial CBA to create a short list of the seven options presented below. The options matrix is designed to test the limits of the east coast versus west coast investment, considering the key benefits and disadvantages from the various investment choices.

Option Name*	Carnforth-Nether Kellet	Hatton	Alrewas	Comments
All Counterfactual	Counterfactual	Counterfactual	Counterfactual	
All Low	Option 1: Low	Option 1: Low	Counterfactual	Low overall investment. Contracts and constraints are a key factor.
High West Coast	Option 2: High	Option 1: Low	Option 2: High	High west coast capability
High East Coast (4)	Option 1: Low	Option 4: High	Counterfactual	High east coast capability.
All High	Option 2: High	Option 4: High	Option 2: High	High overall investment
Medium East Coast	Option 1: Low	Option 2: Medium	Counterfactual	Medium east coast capability and low west coast.
High East Coast (7b)	Option 1: Low	Option 7b: High Sensitivity	Counterfactual	Alternative high east coast capability.

Table 9: Cluster options

*The number in brackets represents the Hatton option number, to help differentiate between the two High East Coast options

Results

The NPV for all the Cluster options is presented on the chart below. The values range from -£426m to -£553m. Broadly the high east coast capability options rank higher than the high west coast, with three options ranking higher than the counterfactual, High East Coast (4) with investment in two SCR units at Hatton, Medium East Coast (2) with investment in one SCR unit at Hatton and High East Coast (7b), investment in one large unit at Hatton. All these options include investment as per the low capability, Option 1 at Carnforth-Nether Kellet, which validates the recommended option in the Carnforth-Nether Kellet business case, and the counterfactual at Alrewas.

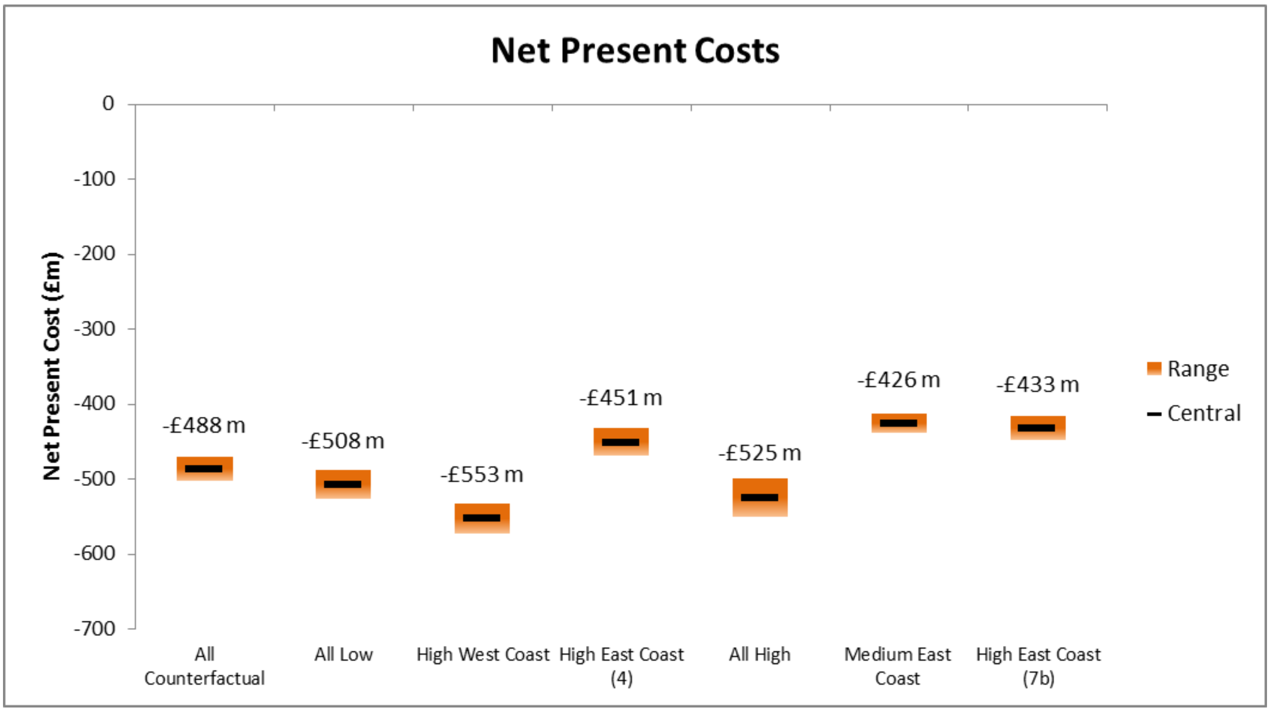

Figure 19: Cluster options NPV

The table below demonstrates the relative NPV position of all the options. Both options with a low capability at Hatton (i.e. Unit D only) result in a negative NPV relative to the counterfactual, between -£66m and -£20m. The loss of capability at Hatton under these options results in increased constraints and requires significant contractual action. The High West Coast option evaluates higher investment at Carnforth-Nether Kellet and Alrewas as an alternative to Hatton but the capability is not sufficiently comparable and does not significantly reduce the risk or requirement for commercial actions. The All High option saw investment at all three sites, and whilst this results in the lowest constraint risk and no requirement for contracts, the high investment costs offset these benefits. High East Coast (7b) and Medium East Coast (2) both have a NPV significantly higher than the counterfactual; £55m and £61m respectively; indicating a balanced approach between investment and constraints.

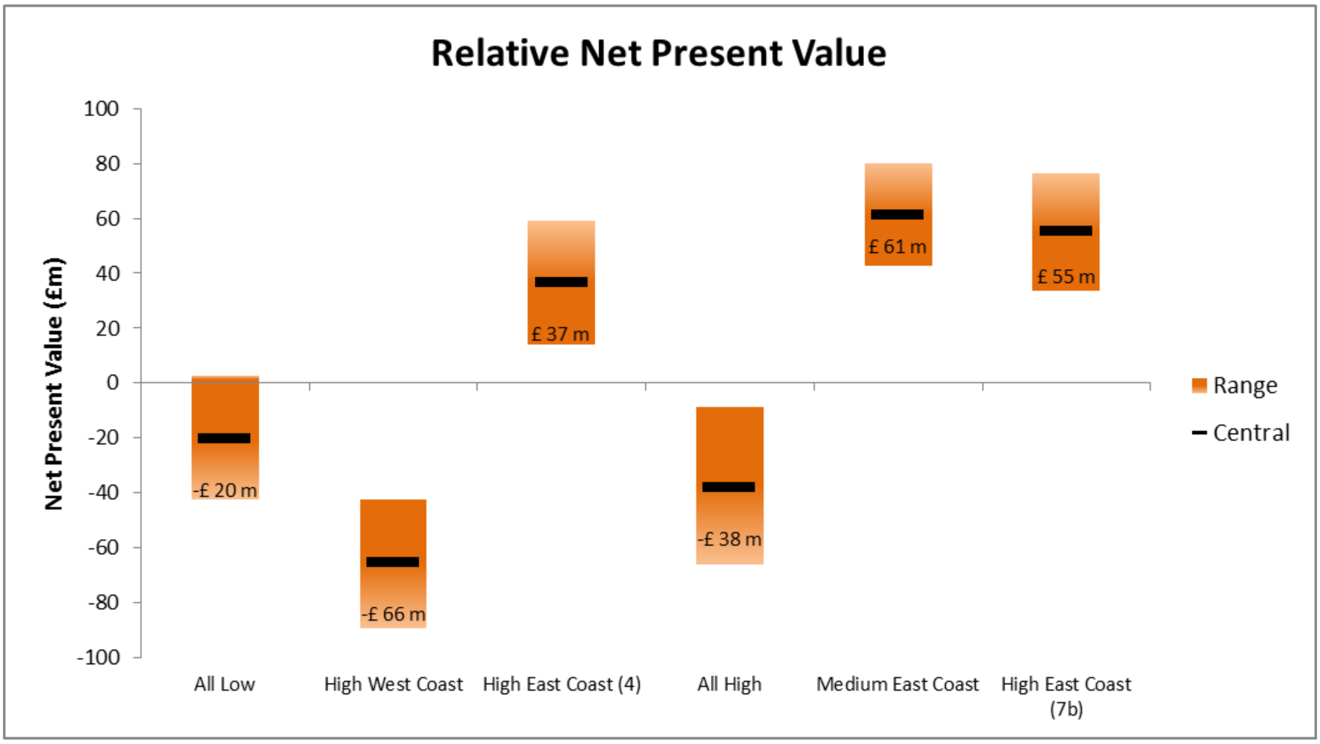

Figure 20: Cluster options relative NPV

Fuel costs are significant for all options; typically between 35-45% of the total option costs. Contracting costs are also considerable for options with low Hatton capability, making up around 20% of the total of the Counterfactual, All Low and High West Coast options. The investment costs accounted for 8% of the total costs on average, with the highest investment cost option under the All High option-£134m accounting for 18% of the total option cost. High East Coast (7b) and Medium East Coast (2) have the most positive NPV, and their respective uncertainty ranges are overlapping.

Net Present Value (£m)	P5	Central	P95
Medium East Coast (2)	42.9	61.0	80.3
High East Coast (7b)	33.7	55.4	76.7

Table 10: NPV uncertainty ranges

Both these two options involve investment at Hatton (in either one emissions abated unit or one larger (30MW) new unit, in addition to the VSD unit and one RB211 on the EUD), and limited investment at Carnforth (a pipework reconfiguration with Nether Kellet in order to provide back up, and Units A and B decommissioned). The key difference is that the lower investment costs in Medium East Coast (2) are offset by contracting costs (£15m under this option). Although High East Coast (7b) has higher investment costs, there are no contract costs associated with this option due to the higher capability of the larger new unit.

The risk around contracting is particularly critical at Hatton which is required for peak 1 in 20 flows. As part of the CBA, a sensitivity, whereby the contract costs associated with all options is doubled across the assessment period is tested. Whilst this is a significant increase, it is expected that if contracts of this type were called upon frequently and disrupted the contracting partner operations (e.g. a LNG ship was diverted) this could be a foreseeable consequence. Under this sensitivity, the difference between the two options becomes much less (£2m) and High East Coast (7b) looks marginally favourable.

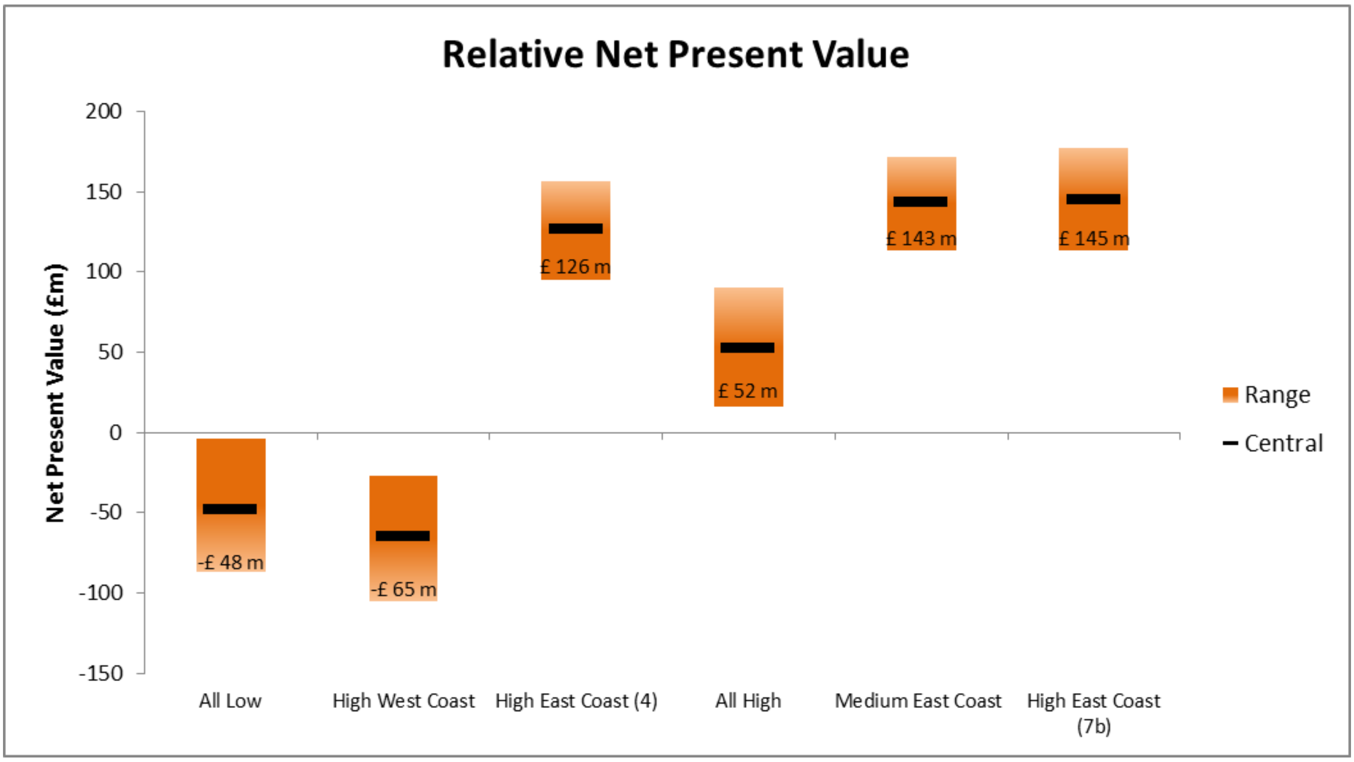

Figure 22: Relative NPV

Emissions

The emissions impact of all the options can be seen on the chart below. All the options considered would result in a significant reduction in NOx emissions compared to current levels. The combined NOx was 136 tonnes / year across the three sites in the Cluster in 2017, Alrewas, Carnforth-Nether Kellet and Hatton. The counterfactual reduces this to fifteen tonnes. The emissions under the counterfactual are primarily associated with Hatton, and to a lesser degree, Alrewas with running hours on existing (unabated) units operating under the EUD. The All Low and High West Coast options only use the VSD unit at Hatton, hence no associated NOx.

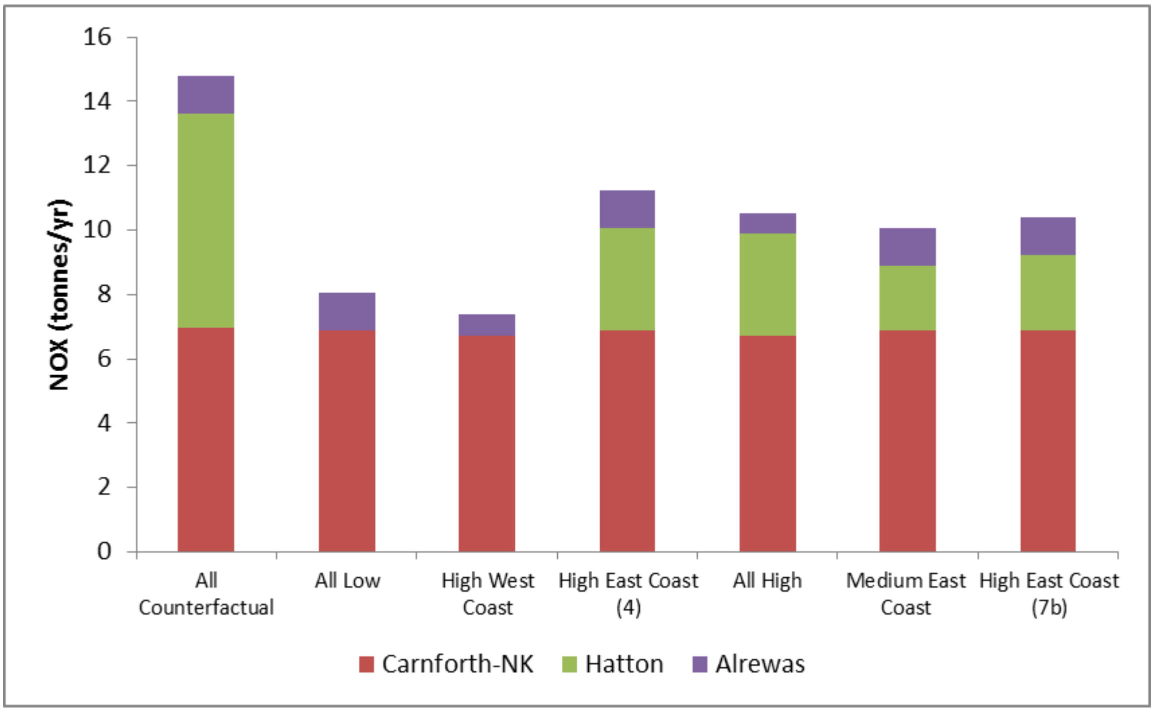

Figure 23: NOx emissions

Additional considerations

Compressors provide the main means by which within-day perturbations can be managed; effectively by moving gas to where it is most needed (or away from areas where pressures are building up). However, the value of any particular compressor in this context is a function of its position on the NTS and the associated network configurability. Hatton is particularly important in this regard. It is used to provide flexibility and manage issues within day.

The Cluster network analysis however is based on 'slow moving' gas dynamics, where the rate of change with time is limited – e.g. a back-loaded supply profile that varies slowly throughout the day. The analysis does not capture the 'fast moving' dynamics which typically arise within day, such as a major power station suddenly switching on, or a compressor failing during operation.

The gas in the NTS travels at an average speed of about 25 – 30 miles per hour. The historic compressor run hours demonstrate a preference with current network operation to using the East coast and the use of Hatton as opposed to using the West coast and Carnforth-Nether Kellet and Alrewas. If we consider the flow of gas from St Fergus towards the south east, then the journey down the west side (i.e. via Carnforth) takes 3 hours longer than the route down the east side (i.e. via Hatton). In fact, the analysis shows that by applying this simple 'time of travel' approach to key demand concentrations on the network, then on average the journey time from supply to demand via Hatton is shorter than via Carnforth.

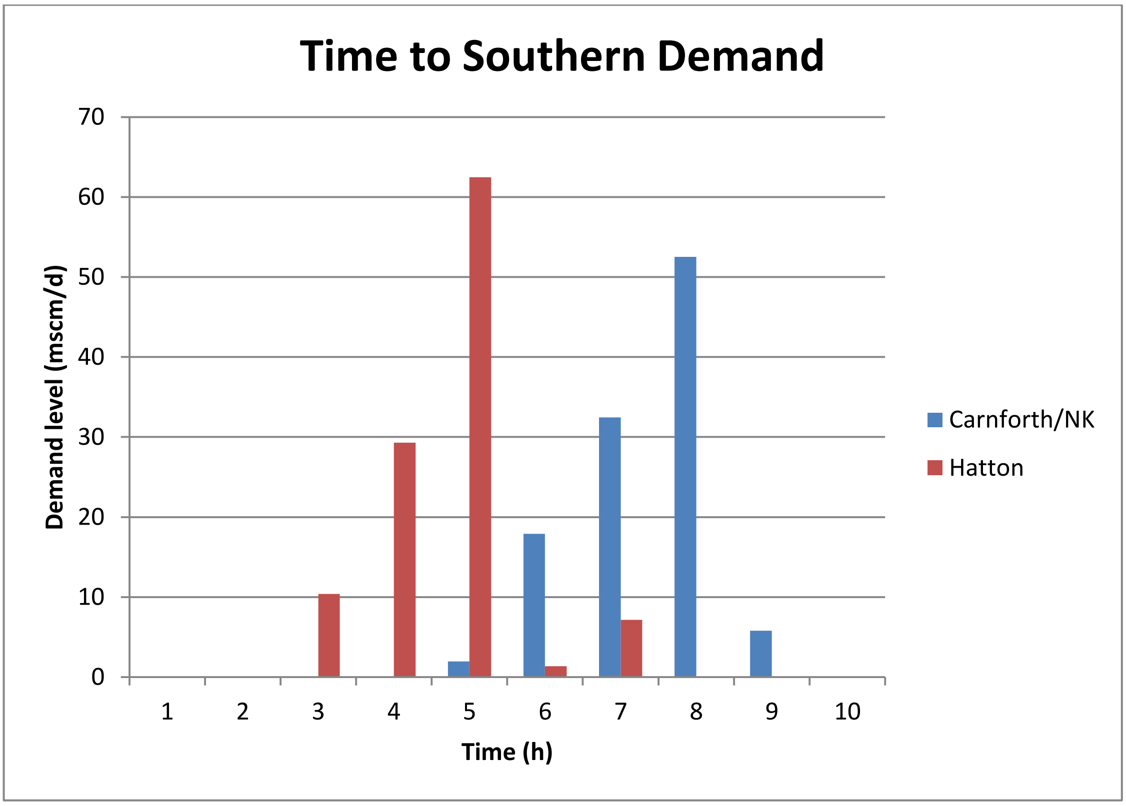

Figure 24: Time to Southern demand

So whilst the Cluster has shown that one of the key benefits of using Hatton is the additional pressure it provides Peterborough compressor station and the subsequent increase in extremity pressures, a benefit that is not shown through the analysis is the level of flexibility given by Hatton due to its proximity to the extremity points in the South of the network. If there is a supply loss or power station turn-up in the south of the network, the best compressor to respond is Hatton.

Although this is not an important distinction in a steady-state network, it can be critical in a network with a major within-day perturbation that results in significant line pack depletion. Hence, on a relative scale,

Hatton - due to its highly configurable multi-junction and proximity to Peterborough compressor station (a major ‘distribution centre’ on the NTS) and the south east - is more valuable in terms of within-day issues than Carnforth-Nether Kellet.
This within day utilisation cannot be fully captured within the Cluster analysis or the CBA, but it is a key factor when comparing these options; the east coast versus west coast investment does not give completely comparable flexibility.

Recommendation

The Cluster analysis and CBA demonstrate the benefits of an east coast route for gas transmission versus the West coast.

The recommendation from the Carnforth–Nether Kellet business case, Option 1; decommission Units A and B and partially merge with Nether Kellet is validated through the Cluster analysis. Both of the highest ranking options in the Cluster, Medium East Coast (2) and High East Coast (7b) support this decision. So Carnforth-Nether Kellet Option 1 is the recommended option.

The benefits of physical investment at Hatton, rather than significant reliance on contracts to support network requirements are demonstrated through the Cluster. The Counterfactual and the low capability options for Hatton are therefore discounted. The medium capability option, Medium East Coast (2) is slightly lower cost (-£55m) than the high capability option, High East Coast (7b) (-£66m). However, the medium capability option does still require contracts to meet a range of likely scenarios. The current contract price assumptions are based on existing OM tender prices. The use of contracts under a wider range of network conditions will introduce a higher level of risk that prices rise sharply once these contracts are called upon, and also that the required changes in flow are not seen when called upon. At a network critical station like Hatton, the Medium East Coast option introduces further risk with the use of emissions abatement which is an innovative technology and not yet proven on the NTS.

We therefore recommend taking forward Hatton Option 7b which is the proposal under the High East Coast (7b) Cluster option. Although this option cost circa £6m more than Hatton Option 2, the cost ranges overlap significantly, and this expenditure would provide capability certainty at a critical station, without the additional year on year contractual risk.

The integrated plan summary

Based on the Cluster analysis, the individual business cases and the assessment of other interactions, our integrated plan proposal to comply with the IED is set out below:

Site	Legislation Compliance	Output	Programme Cost Range (£m)
St Fergus	IPPC Phase 4	Emissions reduction on one Avon unit and emissions compliance on one RB211 unit at St Fergus.	20-40
	LCP	RIIO-T1 activities: Completion of FEED incorporating recommended option. OEM contract awarded and unit design and FAT complete. EPC contract awarded and detailed design commenced.	20-40
	LCP	RIIO-T2: Decommission one RB211 in accordance with IED (LCP) requirements.	<10
Huntingdon	IPPC Phase 4	To install one new unit at Huntingdon by the end of RIIO-T1 in accordance with IPPC Phase 4 requirements.	20-40
Peterborough	IPPC Phase 4	To install one new unit at Peterborough by the end of RIIO-T1 in accordance with IPPC Phase 4 requirements.	20-40
Carnforth-Nether Kellet	LCP	Decommission two units at Carnforth–Nether Kellet compressor station and provide partial integration across the station by the end of RIIO-T1.	<10
Hatton	LCP	IED (LCP) emissions compliance at Hatton equivalent to one large unit. RIIO-T1 activities: Completion of FEED incorporating recommended option. OEM contract awarded and unit design and FAT complete. EPC contract awarded and detailed design commenced.	40-60
Moffat	LCP	To undertake asset health works at Moffat to maintain the RB211s on 500 hours EUD to ensure ongoing compliance with the IED legislation.	10-20
Warrington	LCP	To decommission the compressor station at Warrington by the end of RIIO-T1.	<10
Wisbech	LCP	To convert the Maxi-Avon to an Avon and undertake asset health works to maintain the existing compressor units to ensure ongoing compliance with the IED legislation.	<10
Kirriemuir	LCP	Decommission Unit D at Kirriemuir compressor station by the end of RIIO-T1.	<10
Total			**191.8**

Table 11: The integrated plan (2009/10 price base)

In summary, through listening to our stakeholders, intensely challenging the need and adopting innovative solutions, we have been able to deliver an integrated plan of compressor investments that meet the emissions legislation and deliver value for money to consumers.

Financial summary

Funding Request

The table below summarises the requested allowance for each station.

Site	Legislation Compliance	Programme Cost Range (£m)	RIIO-T1 Percentage	RIIO-T2 Percentage
St Fergus	IPPC Phase 4	20-40	44	56
	LCP	20-40	44	56
	LCP	<10	0	100
Huntingdon	IPPC Phase 4	20-40	100	0
Peterborough	IPPC Phase 4	20-40	100	0
Carnforth-Nether Kellet	LCP	<10	100	0
Hatton	LCP	40-60	35	65
Moffat	LCP	10-20	100	0
Warrington	LCP	<10	100	0
Wisbech	LCP	<10	100	0
Kirriemuir	LCP	<10	100	0
Total*		**191.8**	**123.4**	**68.4**

*Please note for commercial confidentiality reasons, the costs of the projects has been presented in a range for this public document.

Table 12: Funding request (£m, 2009/10 price base)

The total allowance request for the recommended options is £192m of which £123m is within RIIO-T1. With the complete programme necessary to achieve legislative compliance, where site works cross over into RIIO-T2 at Hatton and St Fergus we have defined an output associated with the complete delivery of our recommended option. We also identify activities which would be undertaken prior to 2021.

The table below sets out the proposed adjustment based on the ex-ante allowance and this reopener request:

£m	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	Total
Ex-ante allowance	0.0	1.6	16.2	49.1	66.3	66.6	46.9	33.9	280.5
RIIO-T1 cost	0.3	4.2	5.5	3.5	13.7	25.3	43.3	27.5	123.4
Relevant adjustment	0.3	2.6	-10.6	-45.6	-52.6	-41.2	-3.6	-6.4	-157.1

Table 14: RIIO-T1/T2 funding, (£m, 2009/10 price base)

Customer Bill Impact

The impact of this programme on customer bills is return of 52p as a maximum change in one year.

Conclusion

Our integrated programme, developed through stakeholder engagement and a robust approach to options assessment, represents a significant return to customers of £157m against the RIIO-T1 allowance. The programme delivers an optimised set of investments to deliver the network that will best meet users' needs today and tomorrow.

Glossary

Above Ground Installation (AGI) = above ground gas assets (including, but not limited to; pipework, valves, pigtraps, meters and regulators) located within a fence line for the safe operation and maintenance of the National Transmission System

Aggregated System Entry Point (ASEP) = a system entry point where there is more than one, or adjacent connected delivery facility; the term is of the used to refer to gas supply terminals.

Anticipated Normal Operating Pressure (ANOP) = a pressure that we may make available at an offtake to a large consumer connected to the NTS under normal operating conditions.

Assured Offtake Pressure (AOP) = a minimum pressure at an offtake from the NTS to a DN that is required to support the downstream network.

Avon unit = a small Rolls Royce (Siemens) gas turbine engine which forms part of the compressor machinery train.

Best Available Technique (BAT) = the most effective and advanced stage in the development of activities and their methods of operation which indicates the practical suitability of particular techniques 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.

BAT Reference Documents (BRef) = a series of reference documents covering, as far as is practicable, the industrial activities listed in Annex 1 of the EU's IPPC Directive. They provide descriptions of a range of industrial processes and their respective operating conditions and emission rates. EU Member States are required to take these documents into account when determining best available techniques generally or in specific cases under the Directive.

Brownfield = construction of new units on land that is already occupied by existing assets / infrastructure. Under the brownfield option, this existing infrastructure would need to be demolished or renovated.

Buyback = National Grid may request to buyback Firm capacity rights to manage a constraint on the NTS after any Interruptible/Off-peak capacity has been scaled back.

Capability = the physical limit of the NTS to flow a volume of gas under a given set of conditions; this may be higher or lower than the capacity rights at a given exit or entry point.

Capacity

Entry Capacity = holdings give NTS users the right to bring gas onto the NTS 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. Each NTS Entry point has an allocated Baseline which represents a level of Capacity that National Grid is obligated to make available for delivery against on every day of the year.

Exit Capacity = holdings give NTS users the right to take gas off the NTS 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. Each NTS Exit point has an allocated Baseline which represents a level of Capacity that National Grid is obligated to make available for offtake on every day of the year.

Carbon Monoxide (CO) = a colourless, odourless and tasteless gas produced from the partial oxidation of carbon-containing compounds. It forms when there is not enough oxygen to produce carbon dioxide (CO_2), such as when operating an internal combustion engine in an enclosed space.

Carbon Dioxide (CO_2) = a naturally occurring chemical compound composed of 2 oxygen atoms and a single carbon atom. If there is not enough oxygen to produce CO_2, carbon monoxide is formed.

Cluster Analysis = an integrated approach to developing options that consider interacting sites together, thereby accommodating scenarios where more than one of the sites is unavailable.

Compressor Unit = comprises of the gas generator, gas turbine and gas compressor.

Control of Substances Hazardous to Health (COSHH) = the law that requires employers to control substances that are hazardous to health.

Cost Benefit Analysis (CBA) = a mathematical decision support tool to quantify the relative benefits of each site option.

Counterfactual = the counterfactual option represents current network with minimum interventions to comply with emissions legislation.

Distribution Network (DN) = an administrative unit responsible for the operation and maintenance of the local transmission system and <7barg distribution networks within a defined geographical boundary.

Dry Low Emissions (DLE) = a technology that reduces NOx emissions when producing power with gas turbines.

Environment Agency (EA) = a non-departmental public body, sponsored by DEFRA, with responsibilities relating to the protection and enhancement of the environment in England.

Emergency Use Derogation (EUD) = derogation provided under the IED for equipment used in emergencies and less than 500 hours per year.

Emission Limit Values (ELV) = limits set for industrial installations by the LCP directive and IPPC under the umbrella of the IED.

Front End Engineering Design (FEED) = the FEED is basic engineering which comes after the conceptual design or feasibility study. The FEED design process focusses on the technical requirements as well as an approximate budget investment cost for the project.

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

Gas Distribution Networks = GDN

Greenfield = construction of new units on land that has never been used, where there is no need to demolish or rebuild any existing structures.

High Voltage (HV) = electrical energy above a particular threshold.

Industrial Emissions Directive (IED) = an EU directive that came into force in January 2011. It combined 7 existing directives including the LCP directive and IPPC detailed below.

Integrated Pollutions Prevention and Control (IPPC) = an EU directive which requires industrial installations to have a permit containing emission limit values and other conditions based on the application of Best Available Techniques (BAT). It is set to minimise emissions of pollutants likely to be emitted in significant quantities to air, water or land.

Interconnector UK (IUK) = the pipeline transporting gas between Bacton and Zeebrugge. It is capable of flowing gas in either direction and provides a strategic energy link between the UK and continental Europe.

Intrusive Outage = significant outage works impacting the whole station and where the station cannot be returned to service until the scheduled works are completed.

Large Combustion Plant (LCP) = an EU directive to reduce emissions from combustion plants with a thermal output of 50 MW or more. Combustion plant must meet the emission limit values (ELVs) given in the LCP directive for NOx, CO, SO2, and particles.

Limited Lifetime Derogation (LLD) = derogation under the IED that a combustion plant may be exempted from compliance with the ELVs for installations above 50 MW provided certain conditions are fulfilled, including the plant is not operated for more than 17,500 operating hours within the derogation period.

Linepack = the stock of gas within the gas transmission system.

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

Local Distribution Zone (LDZ) = a geographic area supplied by one or more NTS Offtakes, consisting of local transmission and distribution system pipelines.

Medium Combustion Plant (MCP) Directive = a directive to reduce emissions from combustion plants with a net thermal input between 1-50 MW.

Mg/Nm^3 = a measurement of milligrams per normal meter cubed.

Mega Watt (MW) = a unit of power equal to one million watts.

Maximum Operating Pressure (MOP) = Maximum pressure at which a system can be operated continuously under normal operating conditions.

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

Network Development Process (NDP) = the process by which National Grid identifies and implements physical investment on the NTS.

Network Review = the Network Review process allows National Grid to identify the key environmental priorities with regard to ongoing operation of the compressor fleet and agree National Grid's Network Environmental Investment and Regulatory Strategy with both the EA and SEPA.

Nitrogen Oxide (NO_x) = a molecule with chemical formula NO and is a by-product of combustion of substances in the air, such as gas turbine compressors.

Net Present Value (NPV) = is the difference between the present value of cash inflows and the present value of cash outflows over a period of time.

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

Operating Envelope = All NTS compressors have been designed to operate within a certain range of parameters, namely maximum and minimum gas flow rates and maximum and minimum engine speeds. The limits of these ranges define the performance of a compressor and are referred to as the operating envelope.

Operationally Proven = A unit is operationally proven when it can be shown to be operating reliably and post commissioning / early life issues have been resolved.

Operations Margin (OM) Contracts = Operating Margins (OM) relate to how we use gas to manage short-term impacts of operational stresses (e.g. supply loss) where the market response is not sufficient, or during a gas system emergency. OM gas can be provided under contract by a number of operators: storage and LNG facility operators, offers for a guaranteed level of supply increase or offtake reduction (or combination thereof) from a shipper's portfolio; and offers for a site to be available for supply increase or offtake reduction.

Proximity Outage = significant works on a site for which safety precautions must be put in place which make the station unavailable, but the station is capable of being returned to service in a few hours if required as the works taking place are not intrusive to the operation of the station.

Replacement = installing a new unit to replace the capability provided; this may not be a like-for-like replacement.

RIIO (Revenue = Incentives + Innovation + Outputs) = the new regulatory framework set out by OFGEM, building on the previous RPI-X regime. RIIO-T1 is the first transmission price control review to reflect the framework; it sets out what the transmission network companies are expected to deliver and details of the regulatory framework that supports both effective and efficient delivery for energy consumers over the eight years from 2013 – 2021. RIIO-T2 will be the second price control review.

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

RB211 unit = a medium sized Rolls Royce (Siemens) gas turbine engine which forms part of the compressor machinery unit.

Selective Catalytic Reduction (SCR) = a means of converting nitrogen oxides (NO_x) with the aid of a catalyst into diatomic nitrogen, N_2, and water, H_2O. A gaseous reductant, typically anhydrous ammonia, aqueous ammonia or urea, is added to a stream of flue or exhaust gas and is adsorbed onto a catalyst. Carbon dioxide (CO_2) is a reaction product when urea is used as the reductant.

Scottish Environment Protection Agency (SEPA) = Scotland's environmental regulator and flood warning authority.

Shipper = a company with a Shipper Licence that is able to buy gas from a producer, sell it to a supplier and employ a transporter to convey gas to consumers.

System Flexibility = the ability of the gas transmission network to cater for the rate of change in the supply and demand levels which results in changes in the direction and level of gas flow through pipes and compressors and which may require rapid changes in the flow direction in which compressors operate.

Talking Networks = National Grid's dedicated stakeholder website for Transmission stakeholders. Talking Networks was developed as part of National Grid's price control and business plan development for stakeholder engagement.

Unit Outage = significant outage works impacting a single or only some of the units on a compressor station, the unit cannot be returned to service until the scheduled unit works are completed, however, the station can still operate with other available units.

United Kingdom Continental Shelf (UKCS) = the region of waters surrounding the United Kingdom, in which the country claims mineral rights.

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