Hatton IED Needs Case

June 2019

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1. Executive Summary

As part of Ofgem's Decision on National Grid Gas Transmission's, hereafter referred to as National Grid, Industrial Emissions Directive (IED) reopener submission in May 2018, Ofgem provided the opportunity for National Grid to seek approval of the proposed solution at the Hatton compressor station in response to the IED. This regulatory submission has been prepared to enable Ofgem to make that decision.

Hatton compressor station is located in the east of the UK and has a pivotal role in the operation of the NTS. With nine connecting pipelines, Hatton is used across a wide range of scenarios. The station is used to facilitate gas flows from terminals to the north, to support the operation of storage sites in the North West, to provide demand support in the south east and to support the interconnector flows at Bacton.

Hatton is a critical station, and is required for compliance with the 1-in-20 obligation, which forms part of our Gas Transporter's Licence. The 1-in-20 obligation in effect ensures that there is sufficient network capability and resilience to meet consumer demand on the worst winter experienced in 20 years. Without Hatton compressor station there would be a shortfall of capability in the South East of ca. 30 mcm/d under peak demand conditions, this is equivalent to the load of approximately 2 million consumers.

Hatton compressor station is currently equipped with three Rolls Royce RB211-24 25 MW gas turbine driven compressor units (Units A, B and C) and an additional 35 MW electrically powered Variable Speed Drive (VSD) unit (Unit D) that was commissioned in 2016. Unit D is the station lead unit, the other three units can be operated either individually or in parallel. The compressor station has the capability to compress over 100 mcm/d, which is equivalent to over 25% of supplies on a winter day.

Hatton Units A, B and C are all impacted by the IED legislation. Unit A was put on the Emergency Use Derogation (EUD), which limited running hours to 500 hours per year in perpetuity. Units B and C are operated under the Limited Life Derogation (LLD) which allows for a maximum of 17,500 hours operation per unit or until the 31st December 2023 (whichever comes first) after which the units must be decommissioned.

Following an initial detailed analysis of all options available at Hatton compressor station and interacting stations, which was presented as part of the May 2018 reopener, it was recommended to provide emission compliant capability equivalent to one large unit of similar size to the current VSD by December 2023. Based on this recommendation a range of options in different configurations were further developed and market tested. Three suppliers provided new unit solutions for the specified duty at Hatton. We conducted a Best Available Technique (BAT) assessment on the proposed solutions and identified three candidate BAT options.

The three candidate BAT solutions were then subject to a Cost Benefit Assessment (CBA), with a counterfactual of no investment in additional compression capability, but using contractual solutions to meet the 1-in-20 requirement instead. The CBA tested the need case over a 25 year period considering alternative supply forecasts and other sensitivities. Taking all factors into account, including upfront Capex, fuel and emission cost, asset health investment and commercial costs, the most economical solution was evaluated as the Theta option. This option maintains a high level of reliability at this critical site and provides the greatest emissions reduction compared to the other options.

The Theta option was proposed to and approved by the Gas Transmission Investment Committee on 29 May 2019, subject to Ofgem's agreement of this need case.

The estimated cost of this solution is £90.8m, with a forecast spend profile as shown in the table below. Also shown in the table are the decommissioning costs for the RB211s.

£m (18/19 prices)	Prior Years	2018-19	2019-20	2020-21	2021 -22	2022-23	2023-24	2024-25	Total
Theta option	0.2	0.5	16.1	10.1	24.1	21.5	17.0	1.2	90.8
Decommission two RB211		0.0	0.0	0.0	0.0	1.5	3.5	0.0	5.0

Table 1: Hatton forecast spend profile

The proposed solution will deliver an output of IED Large Combustion Plant (LCP) emissions compliance at Hatton, with no further emission related expenditure forecast based on existing emission legislation.

Ofgem are invited to approve this need case and provide written notification.

2. Introduction

This regulatory submission is made to enable Ofgem to decide on the need case and outputs at Hatton compressor station in response to the IED legislation.

The strategy to comply with the IED emission legislation at Hatton has been under development for a number of years. Funding was initially sought within National Grid's RIIO-T1 submission and subsequently in the reopener windows in May 2015 and May 2018. As part of Ofgem's decision in 2018 they provided the opportunity for National Grid to seek approval of the proposed solution at Hatton compressor station.

In developing the solution at Hatton compressor station, we have followed our internal Network Development Process (NDP) as outlined below:

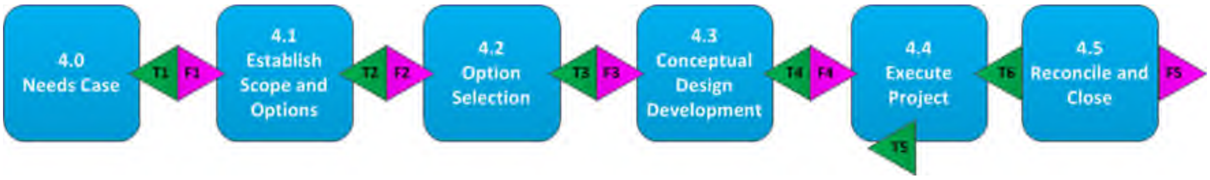


Figure 1: Network Development Process

The project has passed through the relevant stages up to and including the approval to start Stage 4.3, which was provided on 29 May 2019. National Grid keeps all projects under review and revisits earlier stages if key assumptions, such as supply and demand forecasts change. This submission reflects the analysis performed in compiling the 2018 reopener submission and passing through the requisite NDP stage gates. Where appropriate, in response to Ofgem feedback or new information, we have updated our analysis.

The following sections explain; the site and operation, the impact of the legislation, the future site requirements, the assessment of options and the chosen solution.

3. The Site: Assets and Operation

Hatton is located on the main bulk north to south transmission route and is one of the largest combined multi-junction and compressor sites on the NTS. The compressor units at Hatton are some of the most highly utilised units in the fleet. The site is critical in providing operational flexibility and is ideally suited to support a variety of supply and demand patterns and gas flow volumes. The three significant factors influencing the utilisation of Hatton are the location of the site on the network, its connectivity to a number of different pipelines and its wide range of operating configurations.

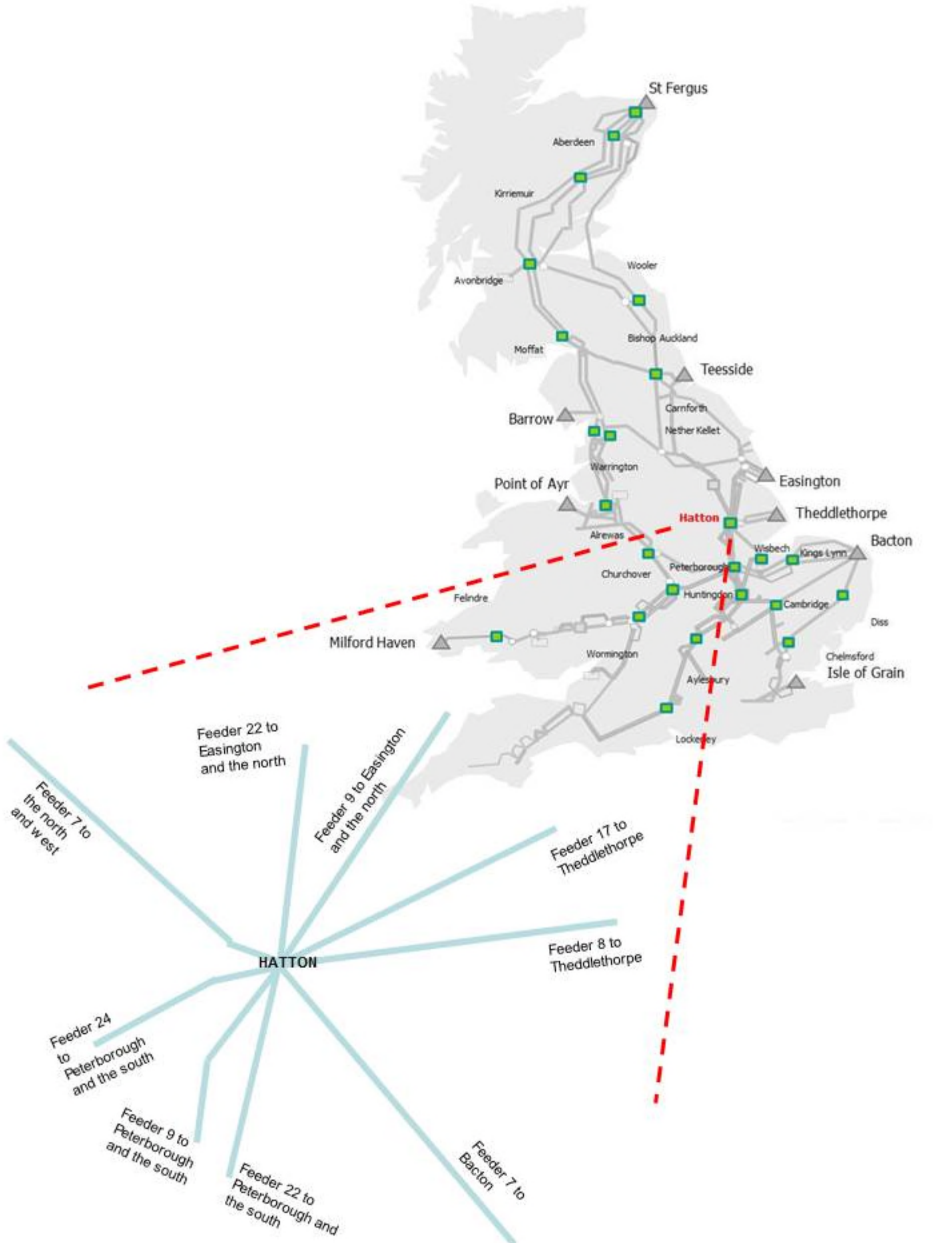


Figure 2: Hatton feeder connectivity

The compressor station was originally constructed over a four year period from 1988 through to 1992. At that time, the station consisted of three Rolls Royce RB211-24 25 MW gas turbine driven compressor units, Units A, B and C. These units could be configured to run as single units, or as any two units in parallel. Each unit had a maximum flow of 65 mcm/d and the site was designed to transmit a maximum gas flow of 93 mcm/d at a maximum discharge pressure of 75 barg.

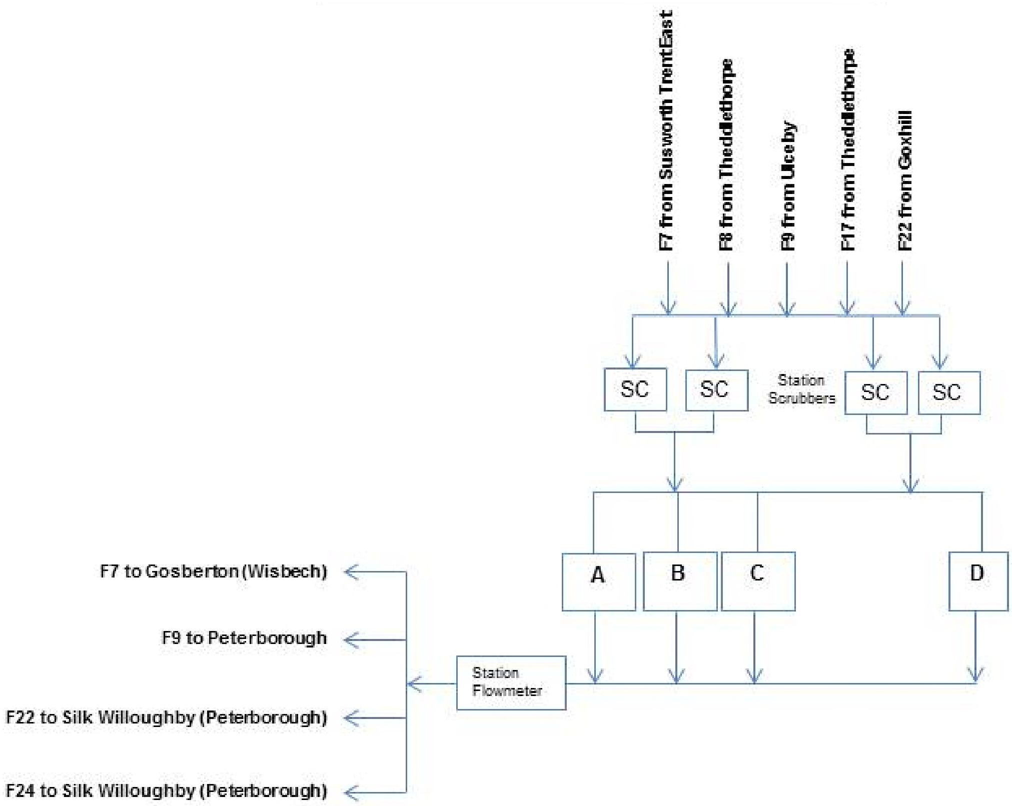


Figure 3: Site schematic layout

A significant operational change occurred in 2016, when a new electric VSD compressor, Unit D was commissioned to comply with Integrated Pollution Prevention and Control (IPPC) Directive Phase 2 requirements. This unit provides the base load compression, and with a maximum flow rate of 93 mcm/d, acts as the lead operational unit at the site. The station capability increased to a maximum flow of 130 mcm/d, with one RB211 unit running in parallel with the electric drive unit. In December 2017, the compressor rotor sustained serious damage which resulted in Unit D being taken out of service. The unit is due to commence recommissioning on 10 June 2019, with expected operations to resume on 23 June 2019.

The running hours and associated emissions of the four units can be seen below.

	Individual Unit Running Hours *(financial year)*				
	2014/15	2015/16	2016/17	2017/18	2018/19
Unit A	1063	363	200	88	215
Unit B	495	2014	1743	3466	423
Unit C	1353	1440	896	2047	174
Unit D	N/A	4	2549	1147	27
Total	**2911**	**3821**	**5388**	**6748**	**839**

Table 2: Run hours summary

NOx (tonnes)	Individual Unit Emissions *(financial year)*				
	2014/15	2015/16	2016/17	2017/18	2018/19
Unit A	31	15	8	4	8
Unit B	13	74	73	163	16
Unit C	42	47	40	87	6
Unit D	N/A	N/A	N/A	N/A	N/A
Total	**86**	**136**	**121**	**254**	**30**

Table 3: NOx summary

In 2018/19 due to the unavailability of Unit D and the limited running hours available on the remaining units a new operating strategy, utilising West coast compression instead of Hatton, was adopted with the aim of preserving hours on the units. This new strategy combined with favourable supply patterns, including significant LNG flows at the Isle of Grain, and a mild winter resulted in a marked decrease in operating hours.

Considering the station's operation between 2013/14 and 2017/18, the flow range profile through Hatton is shown on the chart below.

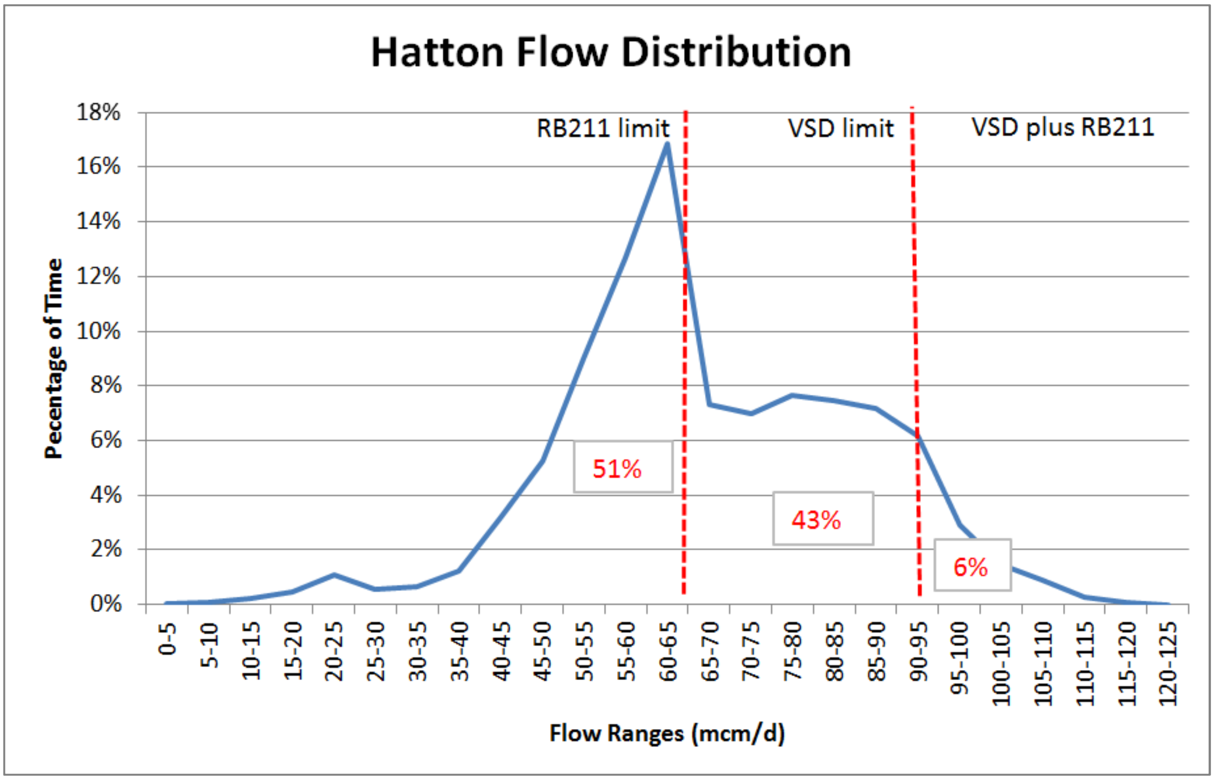


Figure 4: Hatton flow distribution

The VSD unit can cover flows up to 93 mcm/d, above which typically one RB211 unit would be run in parallel with the VSD. The percentage of operating time within the limits of one RB211 is 51%. A further 43% is met by the higher capability VSD unit. 6% of the time flows are beyond that of the VSD, whereby two units will be run in parallel.

It can be seen from the chart below, network supply and demand conditions have led to Hatton operating in a parallel configuration for a significant proportion of time.

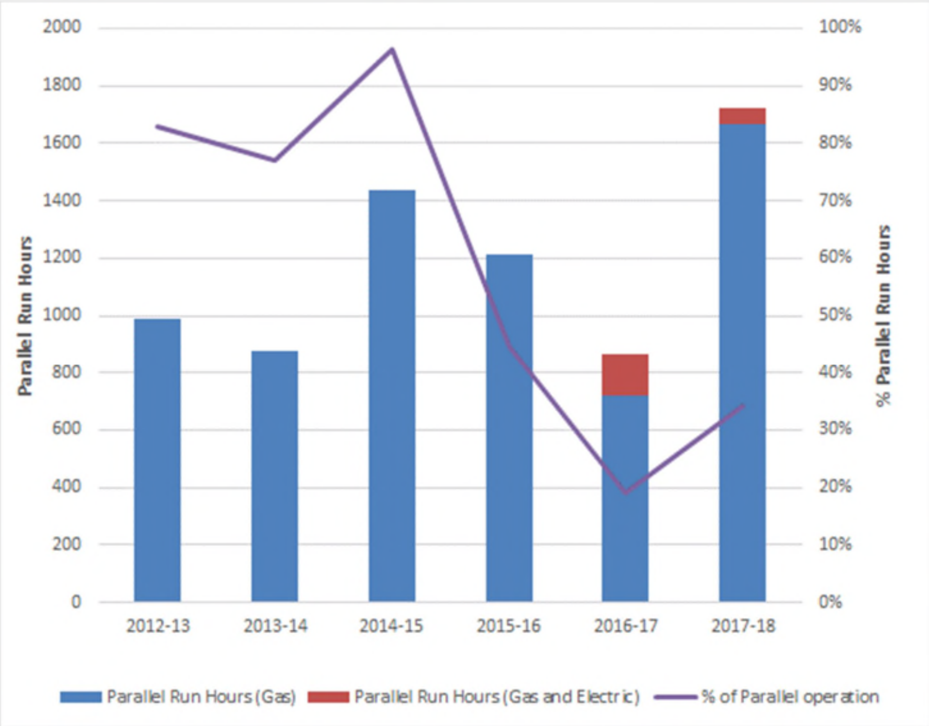


Figure 5: Hatton parallel operation

The operational acceptance of Unit D has clearly changed the percentage of time parallel operation is required. However, the required run hours to operate in parallel are still over 800 hours per year and in the event of any unplanned outage on Unit D, one RB211 unit can only cover the flow through the site 51% of the time. It is important to note, there is a key difference between the electric and gas turbine driven compressor machinery trains. For an electric drive compressor, any significant mechanical or electrical failure of the motor is likely to result in an extended outage whilst the motor is returned to the OEM for repair (typically 6 months). The motors are effectively bespoke to each application and even where there is a similar motor in another location, it would be very time consuming and difficult to relocate even if this is operationally possible. By contrast, a failed gas turbine can be replaced within typically 3 – 5 days utilising a fleet spare, an OEM exchange engine or an engine borrowed from a low utilisation site. Any significant failure of a motor driven compressor is therefore likely to require the use of the gas turbine back-up for an extended period (a period typically greater 500 hours).

4. Emission Legislation Background

Environmental legislation has developed over recent years with the introduction of 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 oxides (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 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 ELVs 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 LLD or the EUD. 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 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 determines the environmental risk of that installation. This mirrors the specifications set out in the IPPC whereby installations must 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. In addition to emission levels, the LCP BREF sets out BAT for mechanical energy efficiency levels, in the case of new units the minimum level is 36.5%. 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;

Carbon Monoxide (CO) – 100 mg/Nm^3

Nitrogen Oxide (NOx) – 75 mg/Nm^3 for existing installations

Nitrogen Oxide (NOx) – 50 mg/Nm^3 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 LLD 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 several 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 LLD, this derogation has been applicable from 1st January 2016 and several of our operating units have been entered into this derogation.

6. 1,500 hours derogation[1]

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/Nm^3, with the limit for CO remaining at 100 mg/Nm^3.

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 1 MW 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.

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

[1] However, our compressor units produce more NOx than the limit specified in this derogation and therefore this does not represent a viable option.

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 IED-LCP 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. Figure 6 summarises the emissions compliance status of the compressor units on the NTS.

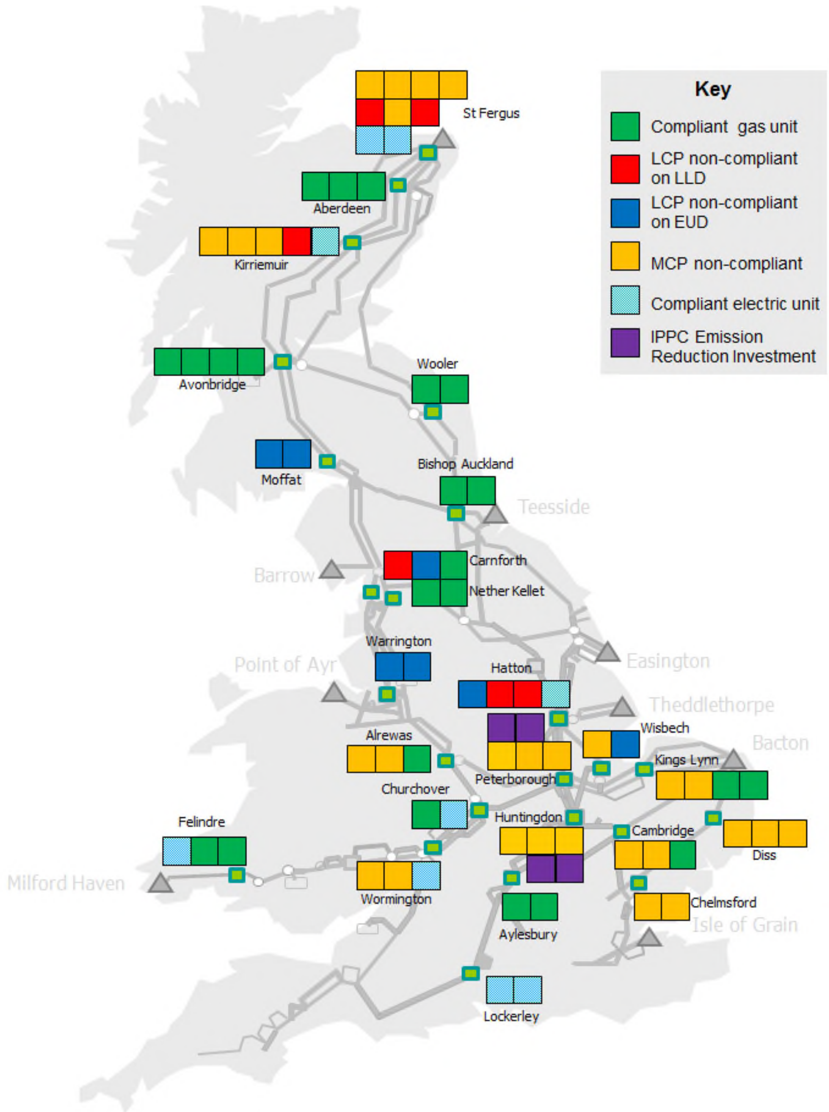


Figure 6: Compressor unit type and compliance with environmental legislation

Hatton Impact

In terms of units at Hatton, which are all above 50 MW, the deadline for compliance with the legislation associated with the LCP element of IED came into force on 1st January 2016 and in December 2015 a decision was made for the three individual units. The options at this stage were to operate under either the EUD or LLD. In line with the outcome from stakeholder engagement carried out as part of our IED submission in May 2015, Units B and C were put onto the LLD. At this point Unit D had not been operationally accepted, so the 17,500 hours in total under the LLD would ensure there were sufficient hours available to run the station in the period prior to Unit D becoming the lead unit. The EUD was used on Unit A. This limits the running hours to 500 hours per year in perpetuity, securing future optionality for the unit. The diagram below illustrates the current emission compliance position at the site.

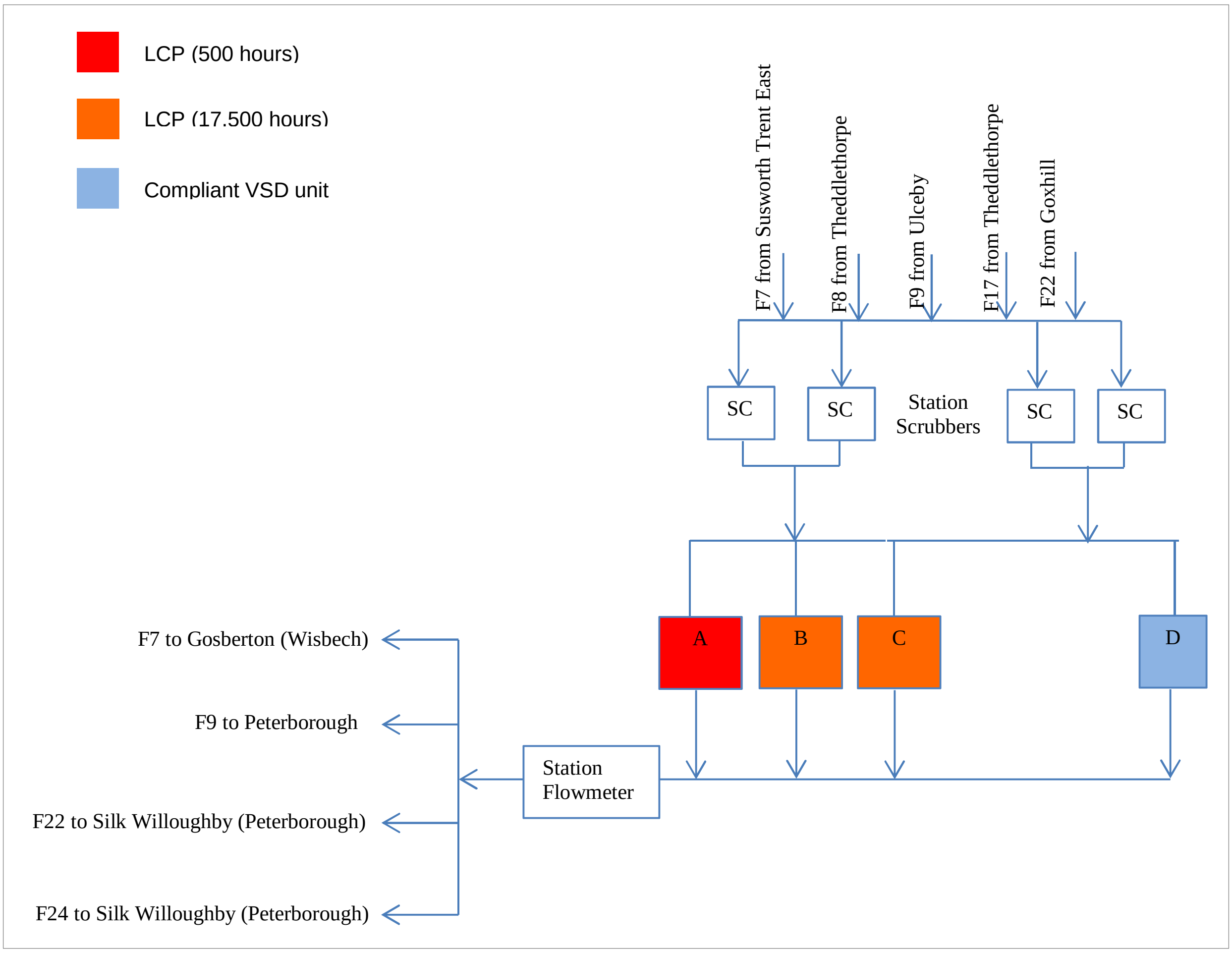


Figure 7: Site schematic

5. The Future Requirements

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). We create these scenarios by drawing on our own analysis and input from stakeholders across the energy industry.

In 2018 we created a new framework for our scenarios. It retains a 2 x 2 matrix with four scenarios but these are now aligned to axes of 'speed of decarbonisation' and 'level of decentralisation'. The speed of decarbonisation axis is driven by policy, economics and consumer attitudes. The level of decentralisation axis shows how close the production and management of energy is to the end consumer. Two scenarios, Community Renewables and Two Degrees, meet the UK's 2050 carbon reduction target. In all scenarios gas will remain crucial for both heating and electricity generation for the coming decades. The figure below shows some of the key characteristics of the four scenarios. It is a selective summary for illustrative purposes and the full details can be found in the main FES document.

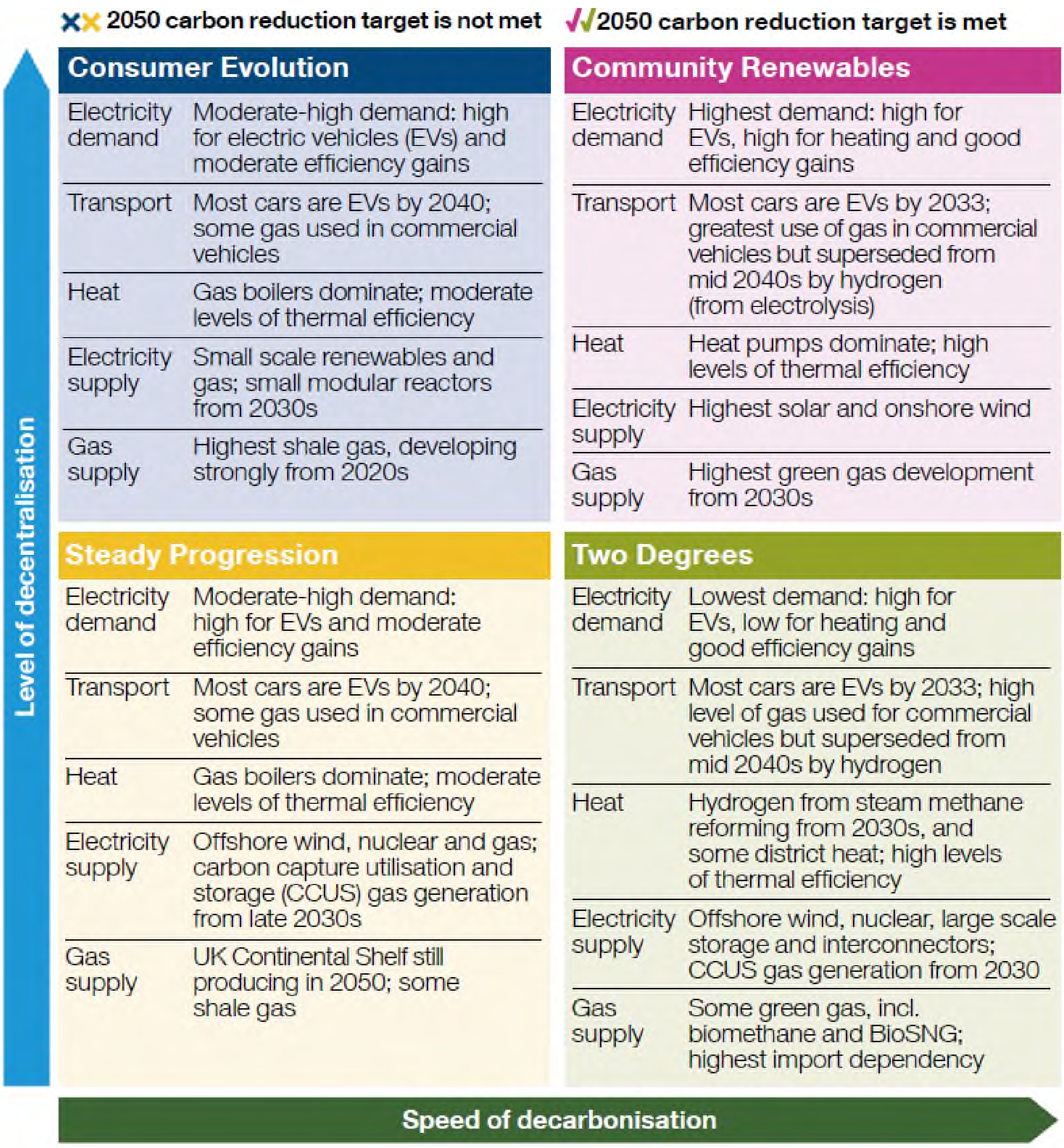


Figure 8: FES 2018- Scenarios

The FES scenarios are extensively utilised to evaluate the need cases. Steady Progression is our core scenario and sensitivity analysis is performed for different scenarios.

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 95 bcm in 2000 to 35 bcm 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. Figure 9 illustrates how future levels of annual UKCS supply and gas import dependency could change depending on the energy pathway taken.

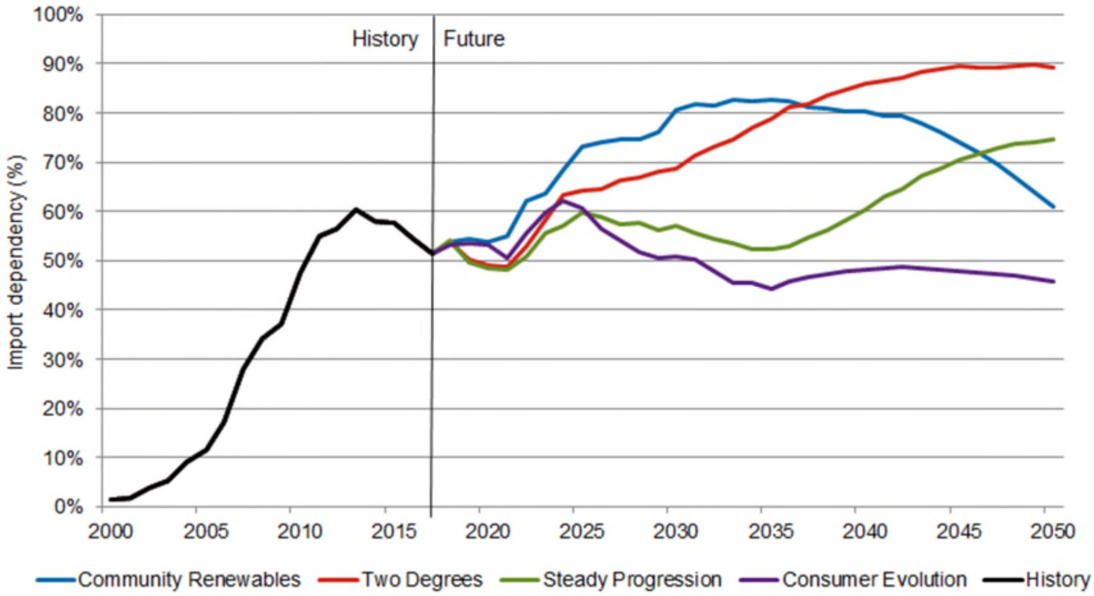


Figure 9: Gas supply import dependency

All scenarios show continued high levels of import dependency, with significant increases in two of the scenarios. This 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 Evolution. Gas demand is instead met by a significant increase in UK shale. The Bowland region (highlighted in red in the figure below) represents the most likely location for shale recovery in Great Britain. However, with shale gas, it is not clear whether development will be successful and in what quantities.

Figure 10: Bowland region where shale gas production is most likely

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.

Today, gas fired generation is critical in maintaining energy security and affordability. In 2017, around 40% 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.

Maintaining compressor optionality

Our FES 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 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 customers' needs.

Hatton Future Requirements

Hatton is a critical NTS compressor stations which is required for peak 1-in-20 and to support bulk transportation of gas from north to south. The site also supports IUK and North West storage flows. The following sections detail the factors used to assess the future requirements of the site within the overall FES context. Considerations include:

Peak 1-in-20

National Grid has an obligation to meet the 1-in-20 demand level, which is defined in the Uniform Network Code (UNC) and forms part of our Gas Transporters Licence. In accordance with our licence obligation, contracts must be considered essential (as specified in the Security Standard (Standard Special Condition A9)) if the physical onsite capability and back up is not sufficient to meet the 1-in-20 demand level. Contracts of this type have not typically been a core part of our compressor strategy so inherently this will introduce more uncertainty than asset based solutions. Hatton compressor station is required to meet our 1-in-20 obligation. The compression capability can be met primarily by Unit D but reliable and effective back up is required.

Bulk Transportation

Due to location and site connectivity, Hatton is used for the bulk transmission of gas down the east coast towards Peterborough and the south. Hatton is connected to six feeders, three of which predominantly support flows from the north. Under high northern flow conditions, Hatton will pull gas from northern entry points down Feeders 7, 9 and 22 to the large demand centres in the south.

Gas flows from the north, can be routed via either the west coast (Carnforth-Nether Kellet, Warrington and Alrewas) or via the east coast using Hatton. The route via Hatton is the shortest, quickest, most efficient way to move gas from north to south. The east coast route is 463km shorter than the west coast route, and requires fewer units, and therefore lower emissions and fuel usage.

Hatton is used to move gas away from Easington area to maximize the supply capability in the area. The total capacity obligation within the Easington area is 201 mcm/d. The available entry capability in the Easington area with Hatton Unit D running is 185 mcm/d. With Hatton D and a second unit running in parallel the capability further increases to 189 mcm/d. If Unit D was unavailable and there was no back-up to cover the capability, the available Easington area entry capability falls to 166 mcm/d, which is below the level of capacity sold for 2023.

The figures below indicate how network flows change when Hatton is not operating. Only a small volume of gas can flow without compression through the Hatton multi junction and the level of capability on the east coast to move gas down from Easington is significantly reduced.

Figure 11: East and west coast flows with Hatton

Figure 12: East and west coast flows without Hatton

With high gas flows from St Fergus and Easington, the preferred route is demonstrated with the dark red arrow through Hatton onwards to Peterborough. If Hatton is not operating, the dark red arrow on Figure 11 seen down the east coast is significantly reduced. To compensate, the flows on the west coast are reversed and gas flows across to Carnforth – Nether Kellet and then south onto the suction of Peterborough compressor via Feeder 4 from Alrewas. Gas travelling this west coast route travels an additional 463km and is not able to provide Peterborough with as high an inlet pressure as Hatton, which can impact the onward transmission of gas to demand centres in the south. Under this configuration, it is also harder to maintain the Assured Operating Pressure (AOP) at Audley North West offtake as compression capability can be impacted by bi-directional storage flows in the north west region.

High IUK export

Hatton is used to push gas towards Peterborough and onwards to Bacton to help increase pressures for IUK export using all four Feeders – 7, 9, 22 and 24. This capability is particularly important when supplies in the south through Isle of Grain LNG terminal are low.

As part of the contract agreement with IUK, National Grid is required to provide a "Normal Offtake Pressure" of 45 barg or such higher pressure, not exceeding 55 barg. On the day, IUK may request a higher offtake pressure which is agreed on a reasonable endeavours basis. Compression is primarily provided by Kings Lynn compressor station, however Hatton is required to provide the necessary suction pressures on Kings Lynn inlet. The future reverse flows through the BBL interconnector at Bacton would further increase this requirement.

Within day fluctuations

The multi-junction at Hatton gives a great deal of flexibility to support a range of other supply and demand patterns. The figure below shows a simplified view of the multi-junction and compressor and gives an indication of the flexibility available when operating the site.

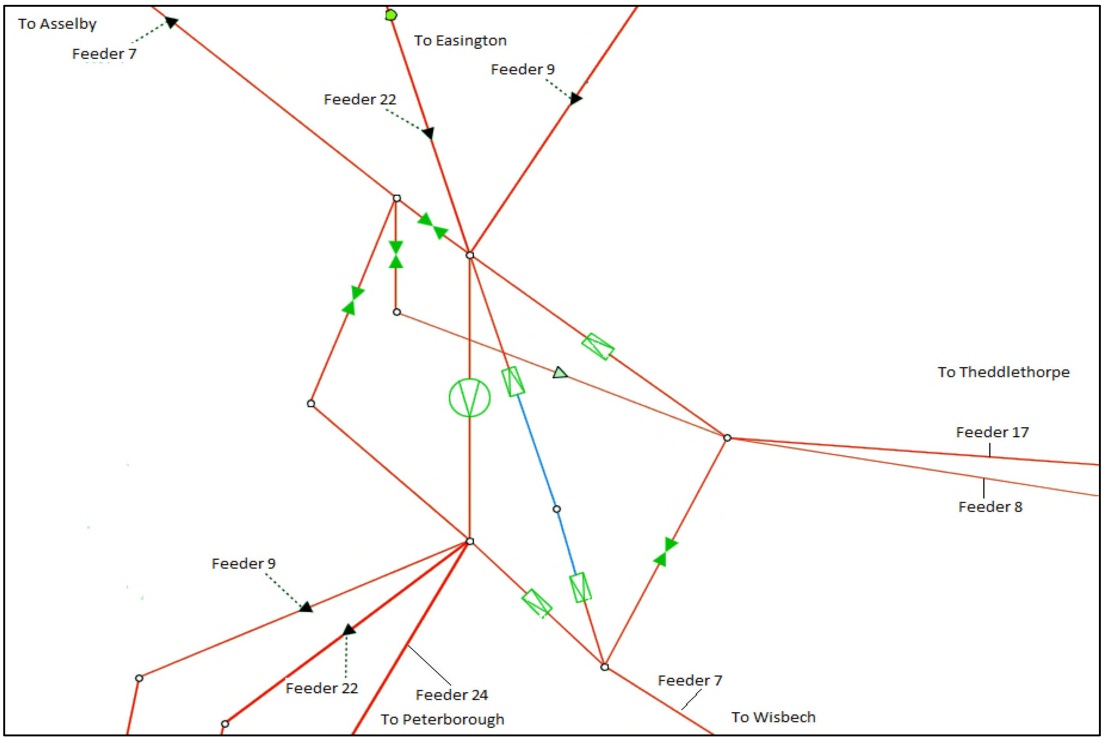


Figure 13: Hatton multi-junction

Geographically, Hatton is perfectly situated to support the whole of the south of the system with multiple configurations available to support different supply and demand patterns. The alternative compression that is required if Hatton is not available is either located near to the north west storage sites or is towards the extremities of the system. This leaves the network vulnerable to changes in flows that result in multiple reconfigurations of the network and leaves the extremities of the system more vulnerable to compressor trips. For example, demand typically peaks in the first half of the day and supply is often back-loaded towards the end of the day. This can result in the network becoming unbalanced with supply entering away from the demand centres in the South. Hatton is a key station used to return the network to a balanced position ready for the start of the next gas day. Looking to the future, changes to the supply mix and changing gas and electricity interactions are likely to make these within day fluctuations more common and more extreme; the magnitude of within-day gas system stock swings has almost doubled over the past two decades. The average linepack swing in 2016/17 was 11.5 mcm/d compared to only 6.5 mcm/d in 2001/02 and there is a notable trend for more commercially responsive customers to reconcile their positions later in the gas day.

Hatton future requirements summary

In line with the factors outlined in the previous sections, the associated run hours forecast for Hatton continue to be high, between 3,000 and 5,000 hours.

Key considerations based on future operating needs and the impact of the IED are as follows:

- Unit D can meet the majority of bulk transportation, IUK exit and North West storage flows.
- One of the RB211 units (A, B or C) can support at lower flows or can be run in parallel with Unit D during very high flow periods.
- Once Units B and C reach the end of the LLD period, Unit A on 500 hours would be considered ring fenced for peak 1 in 20 flows.
- Once Units B and C reach the end of the LLD period, there needs to be appropriate on site back up for Unit D, and for parallel operation at the higher flows.

6. Option Assessment Approach

Our high-level approach to determine the optimum solution at each compressor site is set out below.

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 LLD).

Develop the options

We develop an extensive list of all potential options which ensures we meet our environmental legislative obligations in the most economic and efficient manner. We then develop 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 is incorporated into our 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.

7. Cost Benefit Analysis (CBA)

To quantify the relative benefits of each option, we have built a 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 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 Pöyry.

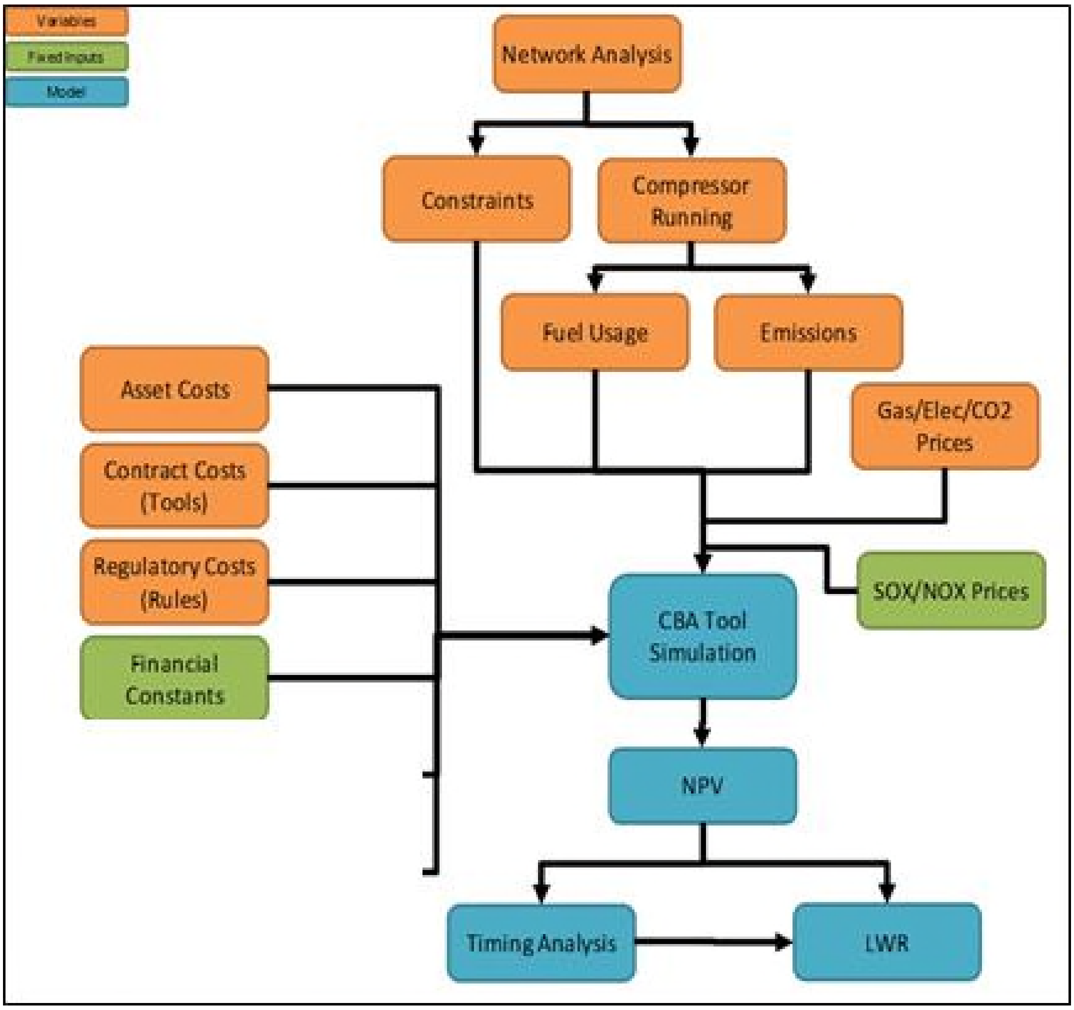


Figure 14: Overview of CBA tool

The tool generates a 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 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 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.

8. NDP Stage 4.1: Establish Scope and Options

The process described below was applied at Stage 4.1 of our Network Development Process, to short list potential solutions. The analysis was undertaken in 2017/18 and utilised the 2017 FES. Further refinement, a BAT assessment, an updated CBA using FES 2018 and validation was undertaken at Stage 4.2.

To determine the optimum solution at Hatton to comply with the IED legislation, we considered the site's interactivity with other neighbouring compressor stations, to assess the merit of options at each compressor station – we termed this as a Cluster approach. The Cluster for Hatton encompassed, Carnforth, Peterborough, Huntingdon and Alrewas.

At a high level, appraisal of the Cluster compared 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).

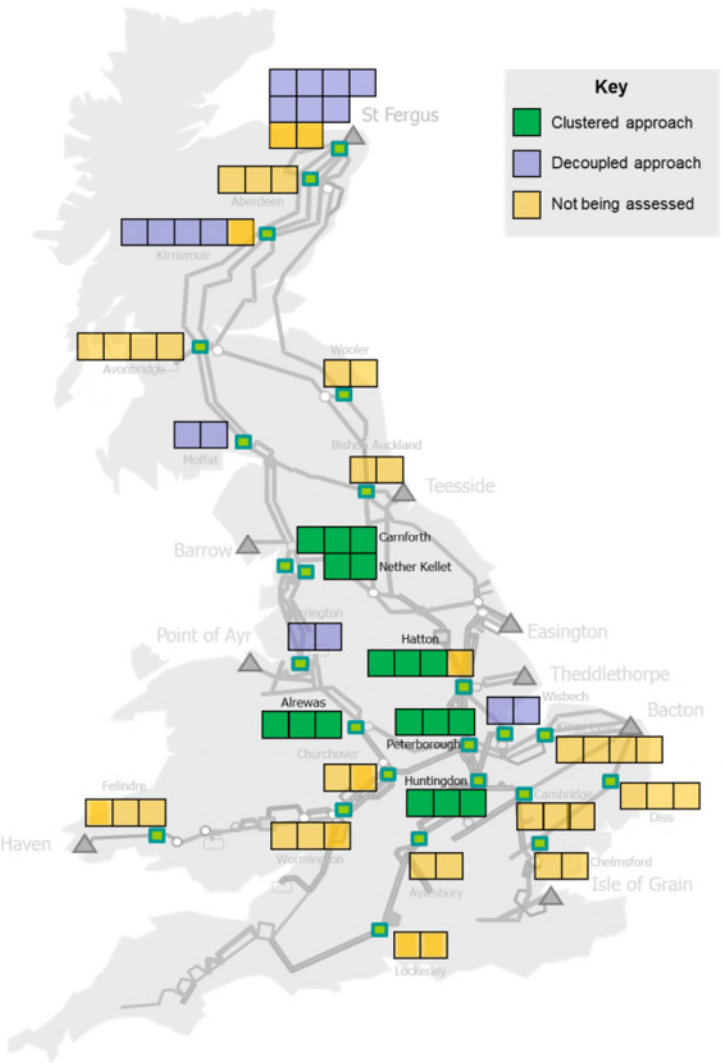


Figure 15: Sites within the Cluster

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.

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.

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.

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.

Cluster Options

The range of options initially considered and the options that are progressed for the three sites flexed within the cluster analysis are set out below.

Hatton

<u>The Counterfactual</u>

Based on the likely future usage of the site, a counterfactual option was defined. This option is the closest to business as usual and is compliant with all the relevant elements of IED.

The counterfactual option (Option 0) is to continue with Unit D, the electric drive unit as the lead operational unit. Unit A would continue to be operated under the EUD, with the associated limit of 500 hours per year in perpetuity. Units B and C would continue to operate under the LLD which requires that the units cease operation after 17,500 operating hours or the 31st December 2023, whichever comes soonest. These units would subsequently be decommissioned post 2023. To comply with our 1-in-20 obligations, Unit A on 500 hours per year should be considered ‘ring fenced’ for those peak requirements. This option would need to be supported by commercial contracts.

To evaluate the true economic case for the counterfactual, several other commercial and physical options have been assessed for the purposes of comparison. These options have been developed through a process of stakeholder engagement including previous feedback generated for the May 2015 reopener, site asset and operational assessments and investigation and assessment of new technology. The new units considered are both medium (15MW) and large (30MW) sized units.

Physical Options

Looking at the standalone options for Hatton seven options in addition to the counterfactual are considered. Please note that in the initial option definition stage sub-options i.e. 7a and 7b were also analysed, the most favourable of which were then progressed to assessment.

Option 1

Under this option, Unit D remains the lead unit and all three Units A, B and C are decommissioned post 2023. Under this option assessment back up and resilience are provided via commercial contracts and from other stations.

Option 2

This option continues to provide lead operational capability from Unit D, and Unit A operates under the 500 hour limit of EUD. Unit B is decommissioned post 2023. Emissions abatement technology is fitted to Unit C, which then operates without the restrictions of the EUD. Due to the limitations of the unit operating under EUD, and only investing in one unit with emissions abatement, commercial contracts will also be required under this option.

Option 3b

Under this option, Unit D continues to be the lead unit and Unit A runs under the EUD until the new units are available. Two new 15MW units (Units E and F) are installed on a greenfield location. Units A, B and C are decommissioned post 2023.

Option 4

Under this option, Unit D continues to operate as the lead unit. Emissions abatement technology is fitted to Units A and B. Unit C operates under LLD until 2023, after which it is decommissioned.

Option 5b

Under this option three new 15MW units (Units E, F and G) are installed on a greenfield location. Following the commissioning of new units, Unit A is decommissioned. Units B and C are decommissioned post 2023. Unit D is retained as is.

Option 6

Under this option, the VSD Unit D is kept as is. Units A, B and C are all fitted with emission abatement technology.

Option 7b

Under this option the VSD Unit D is kept as the lead unit. Unit A is retained under 500 hrs on EUD and one new unit (30MW) is installed on a greenfield site. Units B and C are decommissioned post 2023.

The options cover a wide range of capability, and as presented in the table below, three of the options require commercial contracts for us to meet our obligations under 1-in-20 and other system requirements.

	VSD 93mcm/d	RB211 on EUD 65mcm/d for 500 hours	Unrestricted RB211 65mcm/d	New Medium Unit 30mcm/d	New Large Unit 93mcm/d	Total inc 500 hours restriction*	Contracts Required	Capability
Current	93	65	130	0	0	288	No	Very High
Option 0	93	65	0	0	0	158*	Yes	Low
Option 1	93	0	0	0	0	93	Yes	Low
Option 2	93	65	65	0	0	223*	Yes	Medium
Option 3	93	0	0	60	0	153	No	Medium
Option 4	93	0	130	0	0	223	No	High
Option 5	93	0	0	90	0	183	No	Very High
Option 6	93	0	195	0	0	288	No	Very High
Option 7	93	65	0	0	93	251*	No	High

Table 4: Option capability

<u>Shortlisting</u>

The counterfactual plus the seven other options are compared within an initial CBA, including investment costs, asset health costs and Opex, but not contract costs – as contract costs can only be effectively evaluated as part of the overall cluster. This initial CBA provides the basis for selection of a short list of options to take forward to the Cluster analysis. A second CBA is generated as part of the Cluster considering a matrix of different capability levels at all the relevant sites. These capability levels are then used to determine the required level of commercial contracts. The contract costs are then included in the Cluster CBA.

The NPVs for the eight Hatton options are presented below. The values range from -£47m to -£180m, based on investment costs, asset health costs and Opex. Option 1 had the most favourable NPV, -£47m, with the counterfactual NPV similar at -£50m. Option 2 had a NPV of -£94m. These options would all require contracts to support the station requirements, including the 1-in-20 obligation.

Of the options not requiring contract, Option 7b looked most favourable at -£123m, which is close to Option 4 (-£135m). Option 3b and the two very high capability Options 5b and 6 are -£165m, -£180m and -£161m respectively.

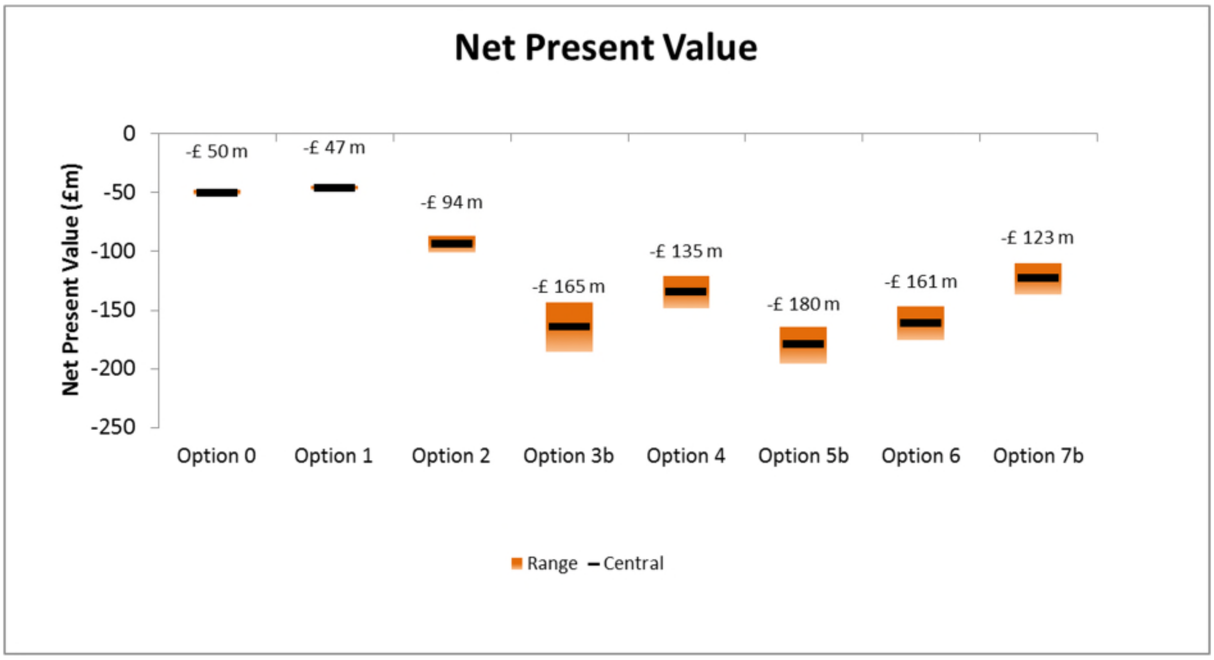


Figure 16: NPV for Hatton options

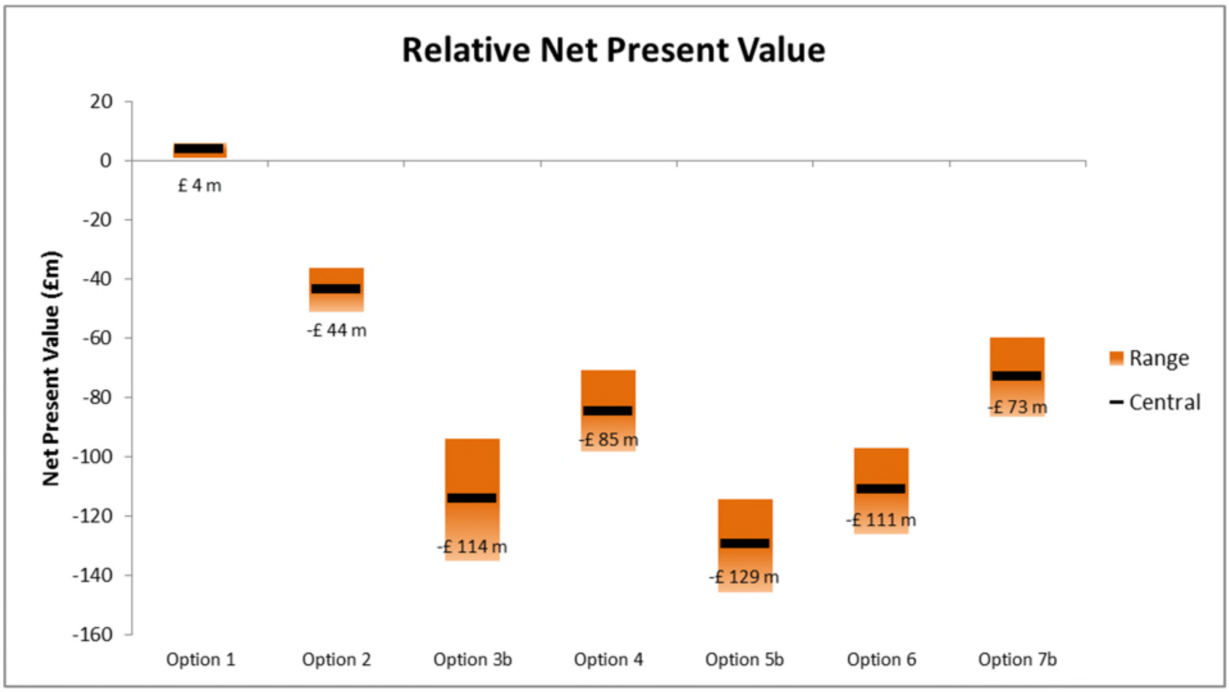


Figure 17: Relative NPV

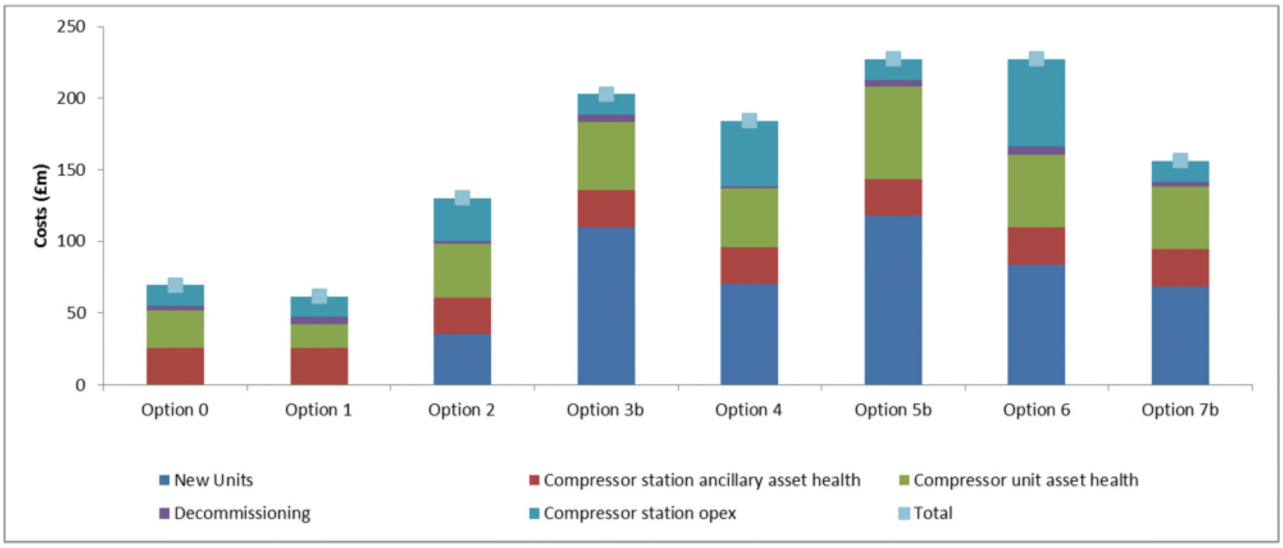


Figure 18: Option cost breakdown over 25 years, non discounted

In summary, Option 0 and Option 1 had the lowest NPV with relatively low investment and asset health costs. Option 2 with investment and ongoing Opex associated with emissions abatement on one unit was the next most favourable. Although not costed in at this stage all these options would require contracts in addition to the physical capability to meet the 1-in-20 requirements. Option 7b was the third most favourable option with investment in one large new unit, and would not require contracts. As a high capability option, this option looked particularly favourable particularly when compared to the additional investment and Opex costs associated with the two SCR units under Option 4. Options 3b, 5b and 6, which require investment in two new units and three new or abated units, were the least favourable.

The counterfactual, Option 0 was automatically taken forward to the Cluster analysis. Option 1 had the lowest costs and was taken forward as the low capability option and Option 2 was taken forward as the medium capability option. Both Options 4 and 7b were taken forward as high capability options. None of the very high capability options were selected so in total five options were taken forward.

Carnforth-Nether Kellet

Carnforth has three compressors units, with units A and B impacted by IED (LCP), unit C is compliant with IED (LCP). Key actions have had to be taken already to ensure compliance with the IED legislation, with unit A being placed on LLD and unit B on EUD. Nether Kellet has two compressor units compliant with MCP. The two stations are in close proximity and for all intents and purposes the two stations are operated as one site.

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 was emissions abatement on one unit.

Option	Description	Capability
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

Based on investment costs, asset health costs and Opex, see figure below, Option 1 was the most favourable, with the high capability option the least favourable. All three options were taken forward to the Cluster analysis.

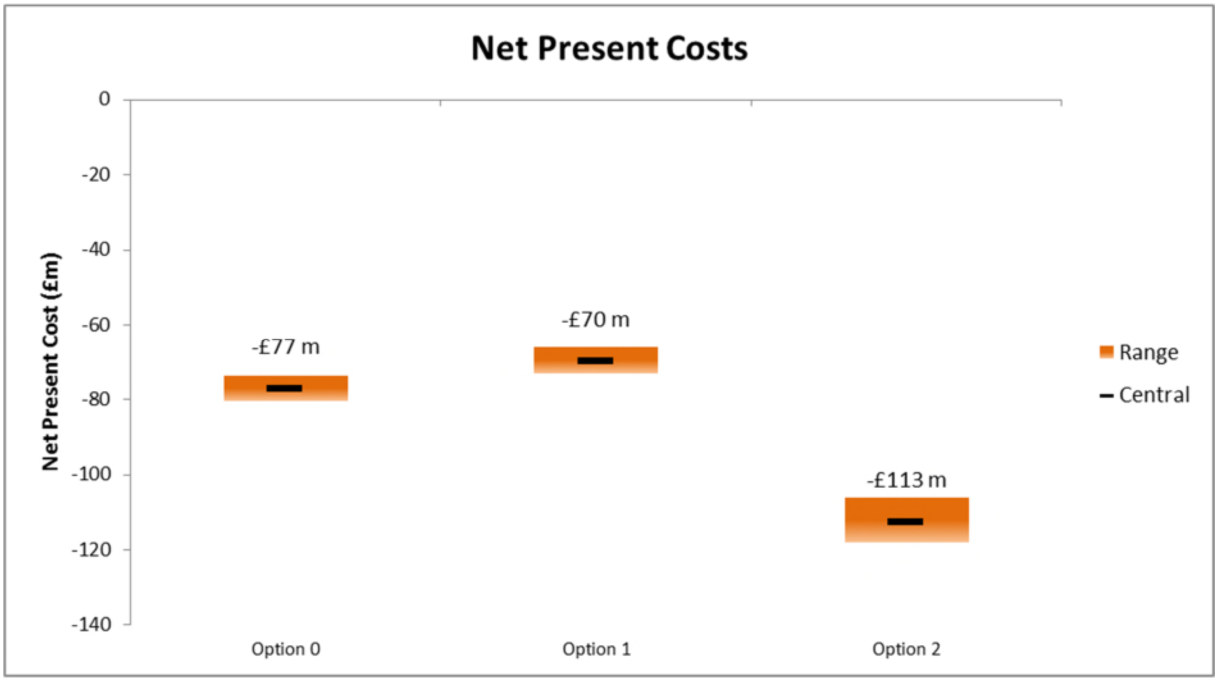


Figure 19: Carnforth-Nether Kellet initial NPV (assesses costs only)

Alrewas

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 were taken forward to the Cluster analysis. Based on investment costs, asset health costs and Opex, see table below, the Counterfactual option was the most favourable

Option	Description	Initial NPV (£m)	Capability

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 6: Alrewas options

Cluster Analysis

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 considered 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 were identified 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 at Choakford 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 throughout the system, consequently reducing pressures at system extremities and causing constraints.

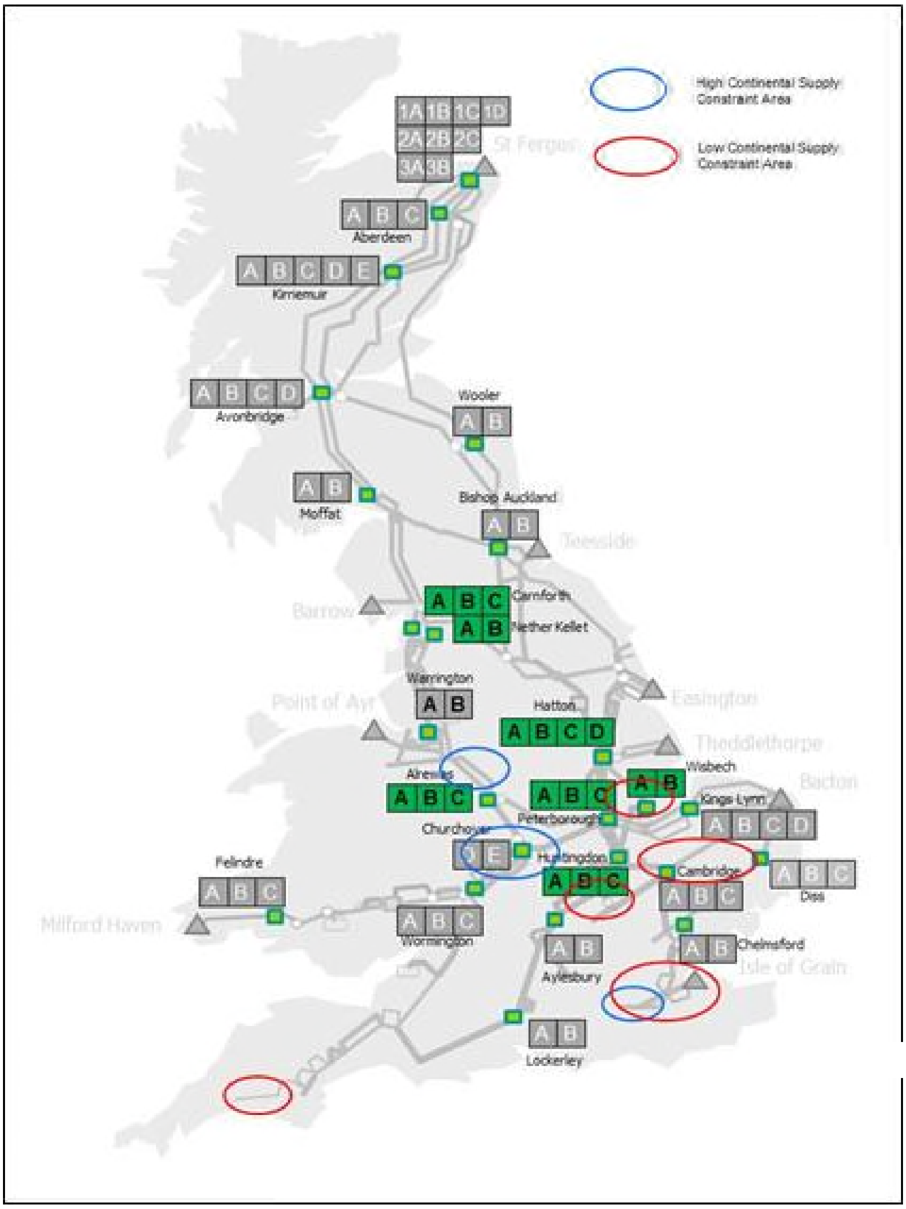


Figure 20: Constraint areas

Tatsfield offtake is located on a system extremity in the South East of the network. Without Hatton, the pressure at Tatsfield falls to almost the level of the end of day Assured Operating Pressure (AOP). Where Hatton is still available, but Peterborough and Huntingdon are not, the pressure at Tatsfield is over 6 barg higher demonstrating the critical nature of Hatton in supporting the demands in the South East. This shows the importance of Hatton to retain stock in the extremities of the system.

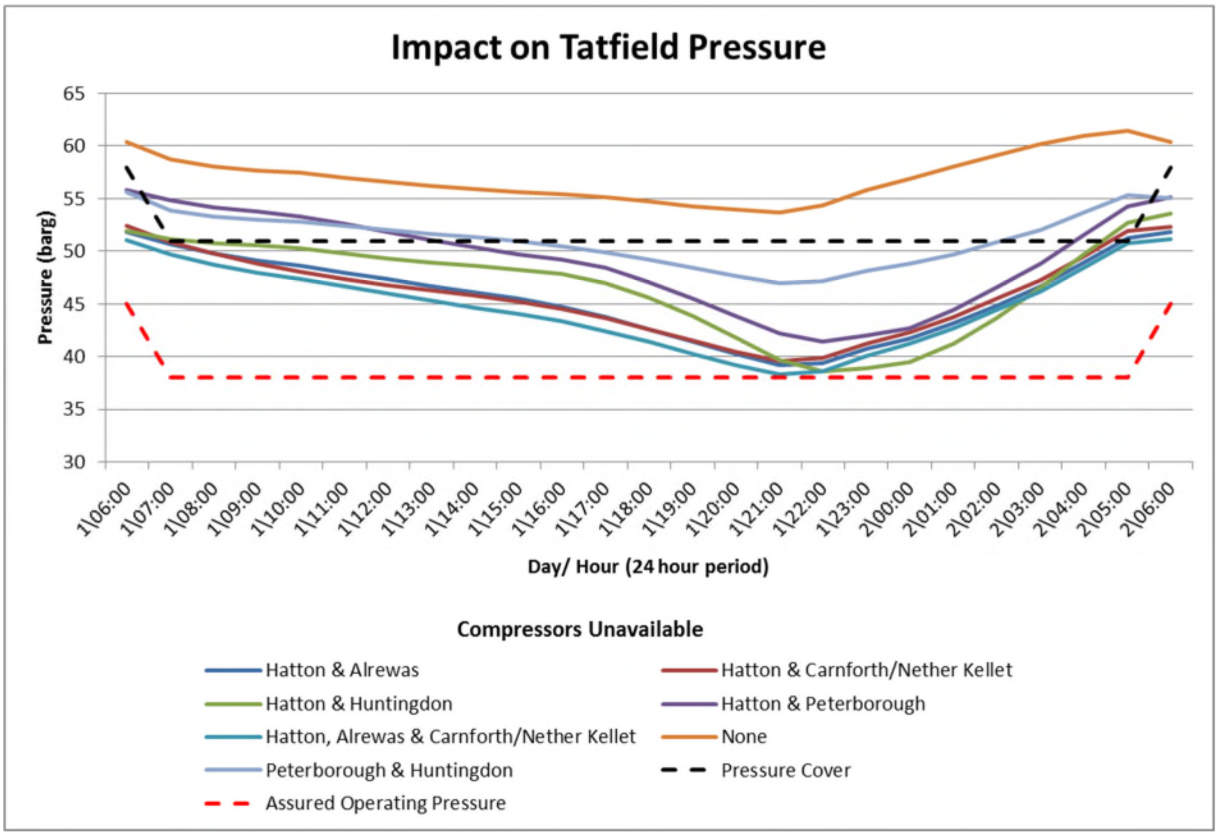


Figure 21: Tatsfield offtake pressure and compressor availability

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 demonstrated that there are significant 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 were considered as part of the Cluster analysis:

- 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 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 Licence) in all the low and medium capability options.

Most 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 we could rely upon these 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 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 many different Distribution Network (DN) offtakes. To accept any reduction in AOPs, DNs are likely to have to upgrade the relevant offtake, potentially with some requiring pipeline reinforcement. As an example, discussions were held with Cadent about Audley North West offtake and a possible pressure reduction there. Although the AOP at this site has historically been agreed at a lower level on the day, Cadent confirmed that without the existing AOP, in a 1-in-20 situation their network would not be compliant and so to accept a reduced pressure would require the upgrade of their offtake. 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 ANOP. 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 was 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	Option 1: Low	Option 4: High	Counterfactual	High east coast capability.

(4)				
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 8: 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 and the counterfactual at Alrewas.

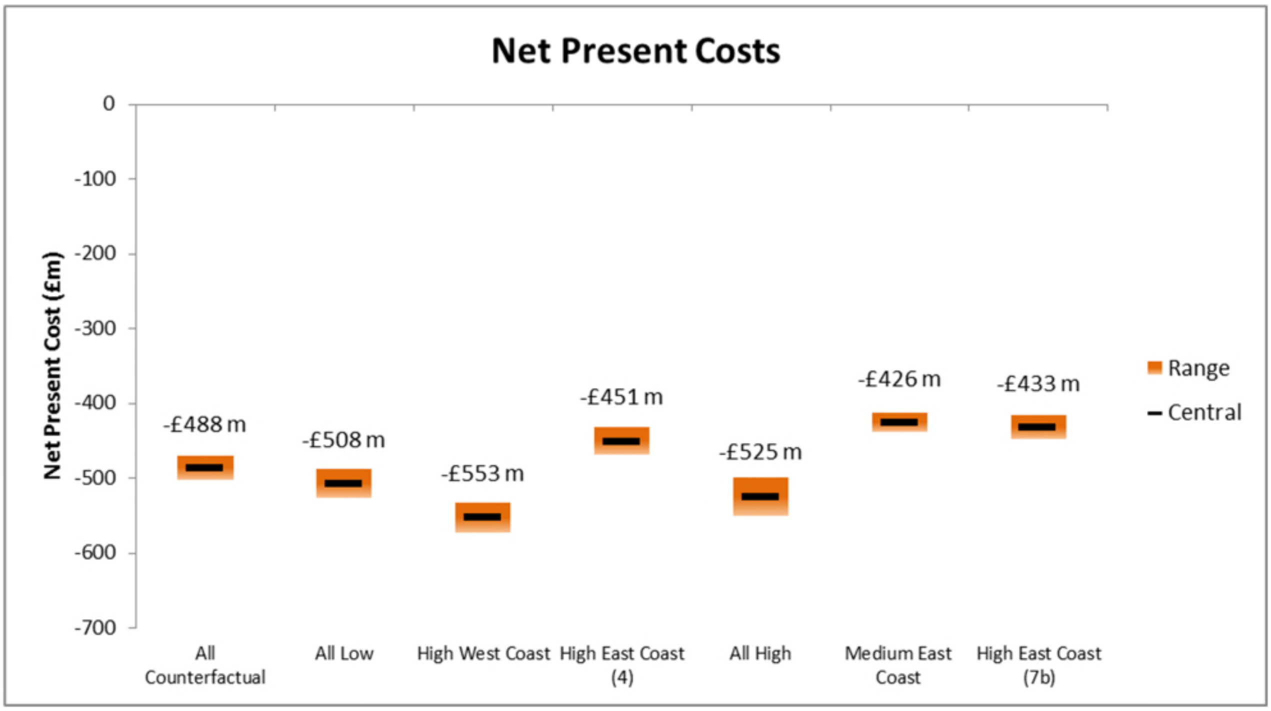


Figure 22: Cluster options NPV

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.

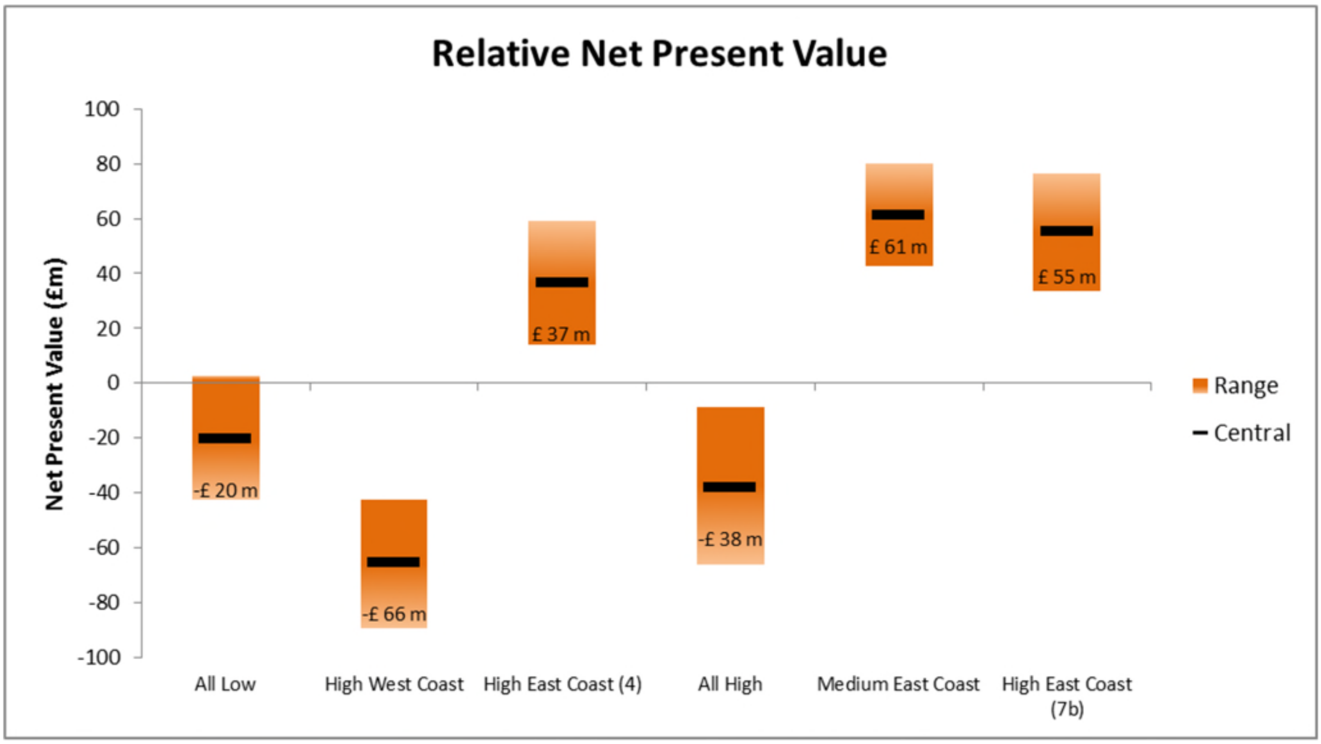


Figure 23: Cluster options relative NPV

The chart below gives a more detailed breakdown of the option costs.

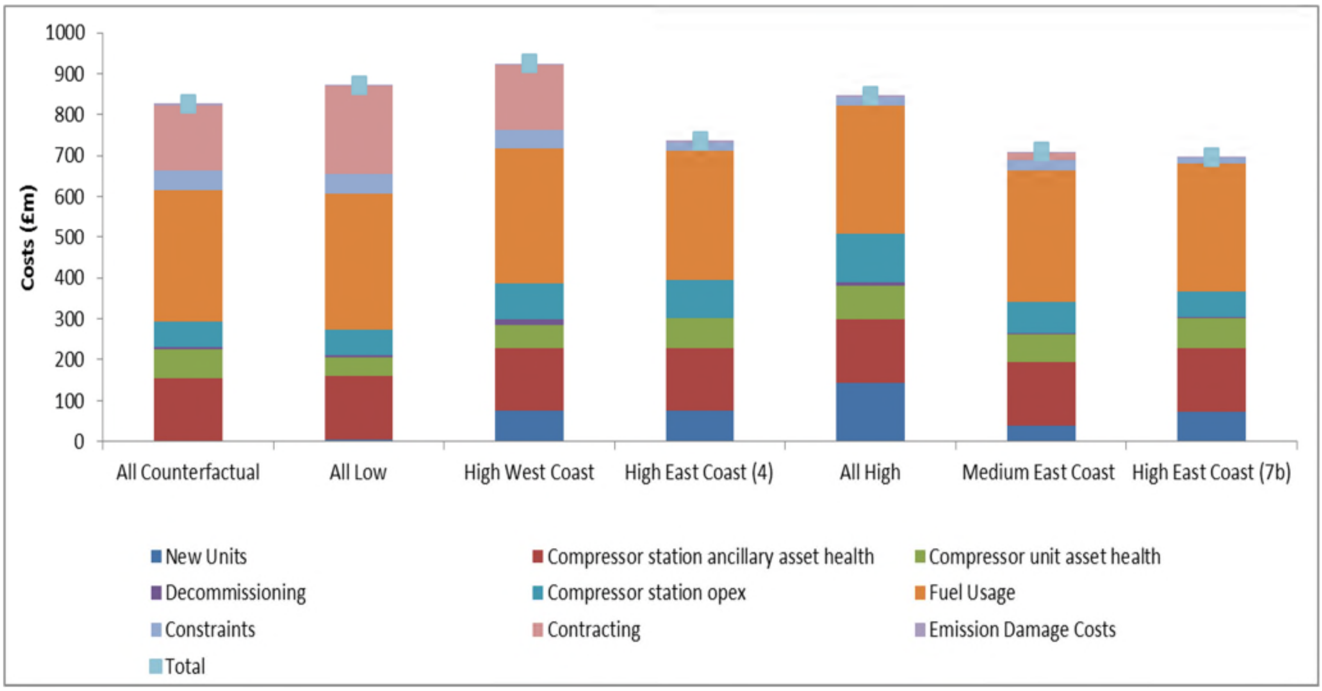


Figure 24: Option breakdown, over a 25 year period, non-discounted

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 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 was doubled across the assessment period was 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.

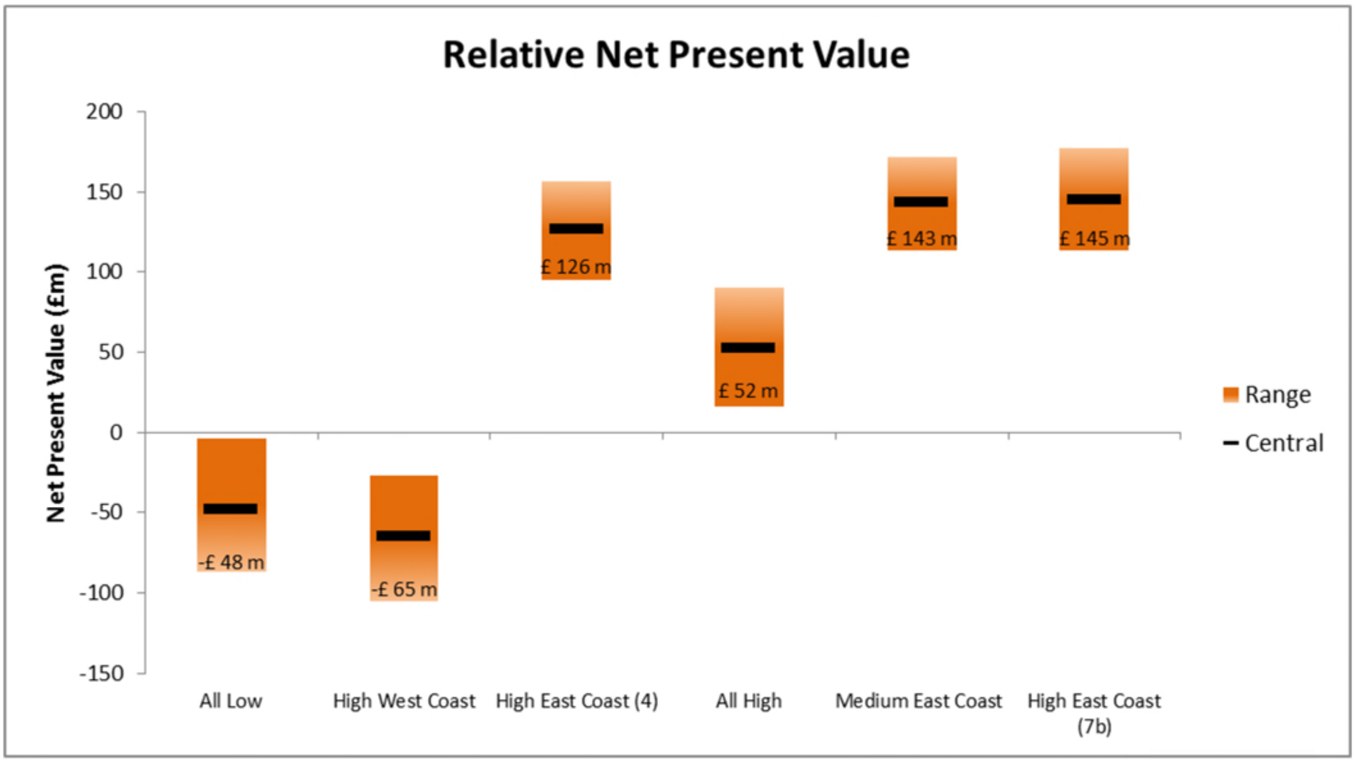


Figure 25: Relative NPV

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.

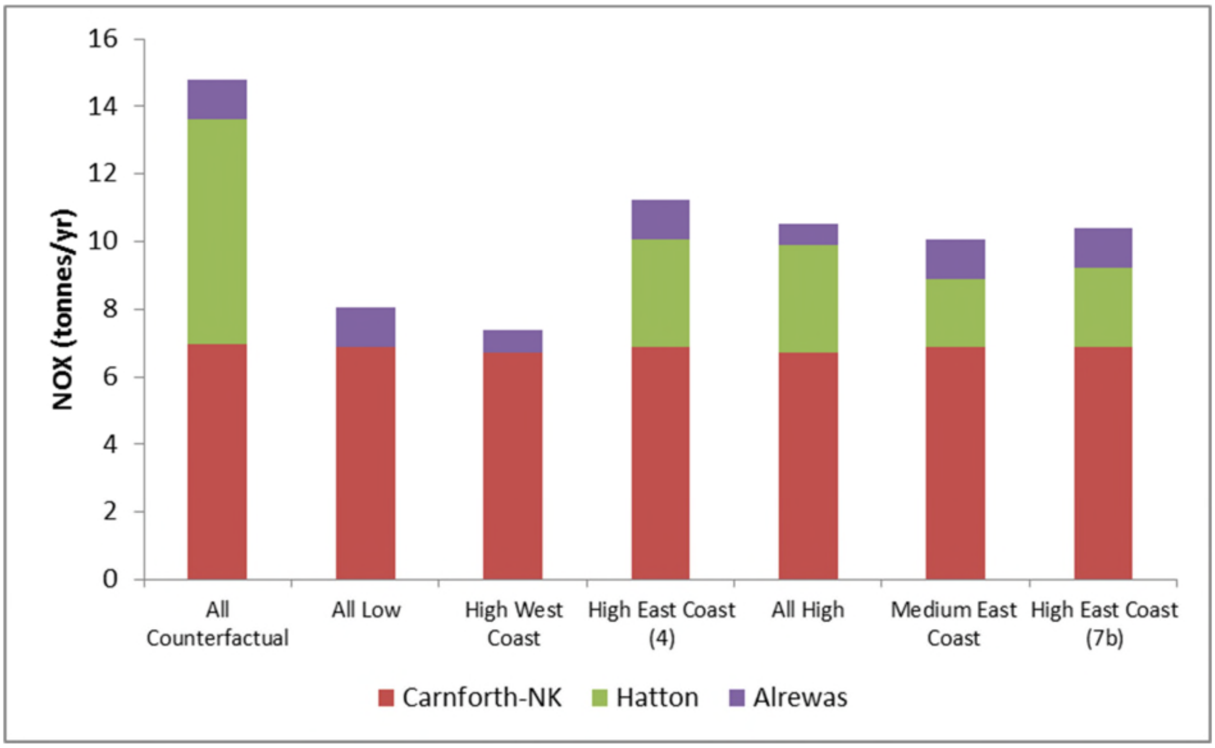


Figure 26: NOx emissions

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 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 use the East coast route and Hatton as opposed to using the West coast route 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.

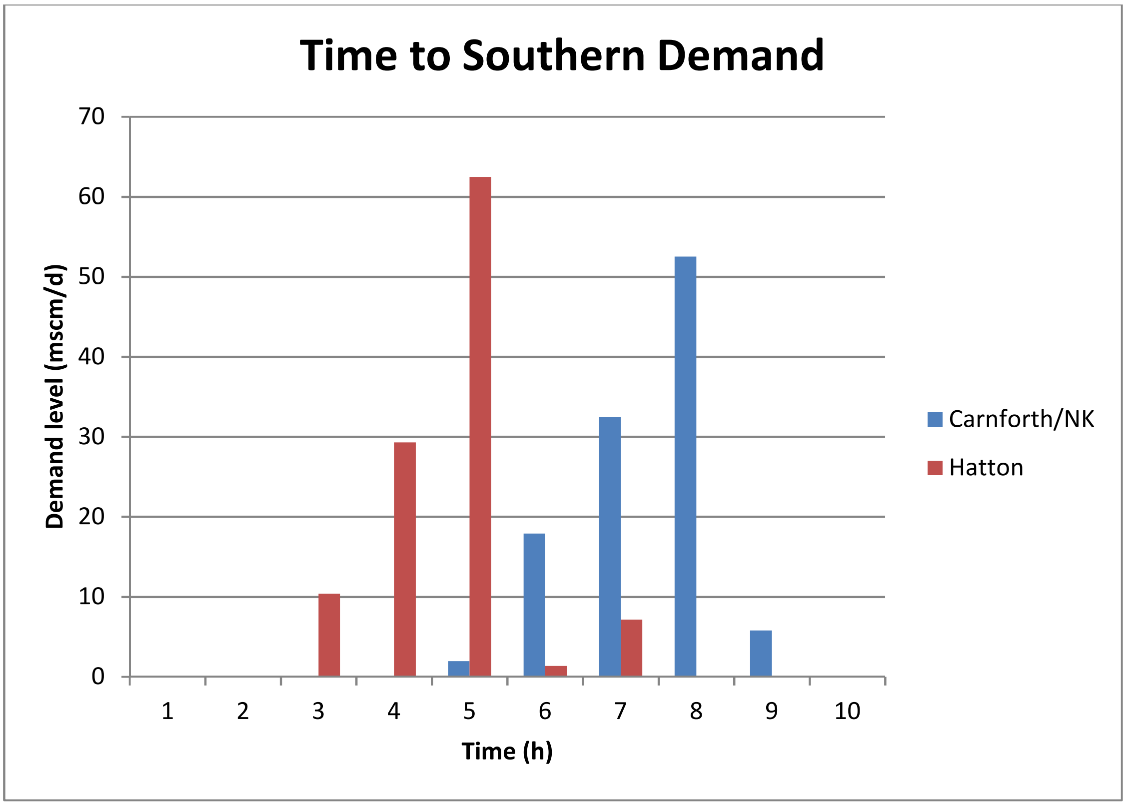


Figure 27: Time to Southern demand

So, whilst the Cluster analysis showed 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 placed 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.

Cluster Hatton Recommendation

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

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 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.

It was therefore recommended at Stage 4.1 to take forward to Stage 4.2 Hatton Option 7b, which is the proposal under the High East Coast (7b) Cluster option, providing emission compliant capability equivalent to one large unit of similar size to the current VSD by December 2023. A comprehensive programme of stakeholder engagement and consultation was undertaken in support of the May 2015 and 2018 reopeners. There were no concerns raised regarding the Hatton options, analysis and proposed recommendation.

9. NDP Stage 4.2: Key Activities

During Stage 4.2 the Basis of Design Document (BoDD) was developed and the final solution was determined. Key activities included:

- Finalisation of the Process Duty Specification (PDS) Study; which sets out the compressor capabilities required for the tender – based on the selected option from Stage 4.1.
- Formal Environmental Assessment (FEA) Study; which includes amongst other items; noise reports, ecological constraints, flood appraisal
- Initial site records review and non-intrusive surveys; to determine key parameters e.g. condition of affected units, space availability and proximity distances
- Preliminary outage planning; determining the sequencing of any works alongside works at interacting compressor sites
- BAT discussions with the Environment Agencies; which clarified that any solution at Hatton would need to meet the prescribed emission limits and the efficiency levels for new units.
- OEM tender; based on the PDS points, emissions and efficiency limits
- Tender for the Conceptual FEED to select a design consultant to support Stage 4.3
- BAT assessment of OEM tender returns
- CBA re-run of candidate BAT options

The following chapters summarise the Procurement approach, the BAT assessment and the outcome of the CBA.

It is worth highlighting that the BAT efficiency requirements presented a significant challenge to the viability of the solutions that use abatement technology, which had not been fully taken into account at Stage 4.1. The RB211s at Hatton typically have mechanical efficiencies of ca. 32%. For an abatement solution to be considered BAT it would need to achieve a mechanical efficiency of 36.5%, which considering abatement reduces efficiency by a few percentage points, appeared to largely rule out abatement technologies fitted to existing units. However, the tender event kept the option open to ensure that the widest array of potential solutions could be considered.

10. Procurement

Due to the similarities in scope and programme for the St Fergus and Hatton IED investments a combine procurement strategy was developed. The purpose of this section is to outline the joint procurement process that has been undertaken for the purchase, installation testing and commissioning of gas turbine solutions and associated equipment at both St Fergus and Hatton.

The section outlines National Grid's procurement approach for the following:

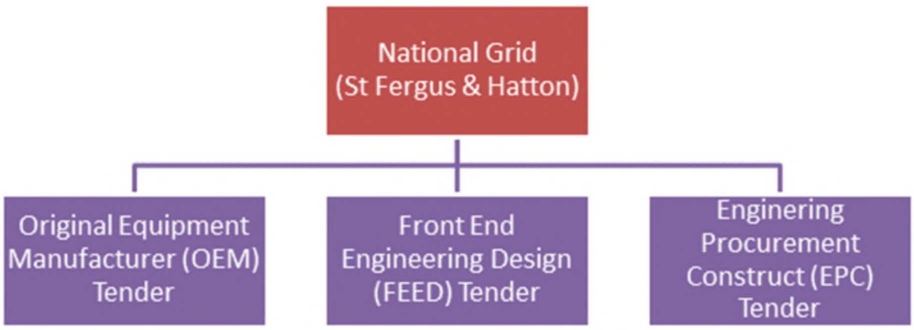
1. **Procurement Strategy Overview**
   This section documents the extensive internal analysis and market engagement that was undertaken to define a procurement strategy that will result in a demonstrable value for money solution.

2. **Procurement Tender Process**
   This section details the procurement tender process that was being employed to execute the strategy.

Procurement Strategy Overview

The procurement strategy for this event was developed based on the delivery strategy implemented for the most recent compressor investments at Peterborough and Huntingdon compressor stations. Lessons learnt from these and other recent investments and an extended period of market engagement, industry benchmarking and supplier forums were utilised to develop a strategy that would result in a timely and cost-effective delivery of solutions for each site.

The procurement strategy is based around three separate tender events per the below diagram.



Three key themes to be implemented through the individual tender events were determined following strategy development:

<u>Modularity</u>

Turbine manufacturers have made great advances in developing modularised compressor units. Whereby more fabrication, pre-assembly and integration testing of assembled sub-systems is conducted in the controlled environment of a manufacturing facility. The benefit of this approach compared to a more traditional approach is reduced on-site construction and commissioning duration, cost and risk. This is particularly relevant to Hatton and St Fergus projects which involve working within operational sites.

All the major Original Equipment Manufacturers (OEM) of compressor machinery train equipment have developed 'modular' compressor solutions and highlighted reference projects where the modularised design was successfully installed.

Opportunities for a modular build approach to balance of plant equipment will be reviewed through the FEED stage.

Specifications

In the drive to deliver new compressor machinery train packages more efficiently, National Grid has recently undertaken an activity to challenge and review our technical specifications associated with the design and build of compressor machinery train packages.

All suppliers currently qualified on National Grid's 'Supply of Compressor Machinery Train Equipment' framework have been engaged in the activity. The key aim was to understand and fully justify any additional National Grid technical requirements which were above and beyond the supplier's standard solutions. This activity has enabled National Grid to better align our requirements with international standards and the supplier's standard solutions, hence minimising bespoke designs and so reducing the cost of future compressor machinery investments. This work is ongoing, with further opportunities for cost reduction being explored during the tendering events for new equipment.

This activity ensured that OEM's could supply their standard package and reduce any cost incurring amendments.

Catalytic Abatement

Following the recommendation of catalytic abatement options at the conclusion of Stage 4.1 various procurement strategies were reviewed and a period of engagement with the potential supply chain undertaken.

The main procurement options reviewed were based on the supply of catalytic abatement equipment via: the EPC provider; the compressor OEM framework suppliers, or a separate specialist catalytic equipment supplier. National Grid determined the most effective delivery strategy would be to utilise the compressor OEM framework to provide an integrated compressor machinery train solution. The key benefits of this option are, robust performance guarantees, direct contract with key equipment suppliers, and reduced contractual interfaces, which together provided significant whole life benefits over alternative procurement strategies.

In parallel to the development of the procurement strategy National Grid Procurement and Engineering Teams worked with the supply chain to develop technical specifications and tender documentation to ensure technically and commercially viable catalytic abatement solutions could be proposed by compressor OEMs and evaluated against new unit solutions.

Procurement Tender Process

With the strategy defined the tender process was designed to execute the strategy through a fair, transparent and competitive tender process.

OEM Tender

The OEM tender is a competitive process amongst the suppliers that are on National Grid's Supply of Compressor Machinery Train Equipment framework. In 2014, as part of the Peterborough and Huntingdon compressor upgrade projects, National Grid went out to market to implement this framework. The framework is the primary compliant route to market for new compressor machinery train equipment and associated technologies. As the turbomachinery products that the OEM's manufacture have already been technically assessed and approved by National Grid's internal technical team and terms and conditions reviewed with OEMs – it provides an efficient route to market.

As the procurement event progressed we revised our approach to Lotting, which originally consisted of a single Lot. Following review of initial tender returns from the initial request for proposal requirements and discussions with OEMs, additional lots were created to ensure that a full range of solutions could be considered.

Candidate BAT options were selected for each lot based on pre-defined assessment criteria, tender prices and derived remaining CAPEX and OPEX by National Grid's in house estimating department, Ehub. The final contract award decision from the candidate BAT options is determined by the CBA process as described in Section 12 of this document following negotiations.

FEED Tender

The Front End Engineering Design (FEED) is required to develop an engineering design to an appropriate level of detail to support the development of a ±15% CAPEX estimate and a sufficiently detailed scope of work for the EPC phase to be tendered on a fixed price or target cost basis.

The Negotiated Procedure option of the Utilities Contract Regulations 2016 is being utilised to award this package of works. The successful tenderer will develop the FEED for use by the EPC for installing and commissioning the selected solution for both sites.

EPC Tender

Equipment procured via the compressor OEM tender will be free issued to a contractor selected via the EPC tender event who will be responsible for, detailed design, procurement of balance of plant materials and equipment, and all on site installation, testing and commissioning works. Should the timelines allow, the intention is to split the tender into two lots with a separate lot for each site and the option for a variant bid whereby tenderers can suggest potential efficiencies should they be awarded both lots. This approach will be reviewed through FEED as the scope and overall delivery programmes are further developed.

The Negotiated Procedure option of the Utilities Contract Regulations 2016 is being utilised to award this package of works.

In designing the tender structure for all of these packages of work, National Grid has sought to maintain a fair, transparent and competitive tender process to award the most economically advantageous tender solution.

11. BAT Assessment

All of National Grid's gas turbine driven compressor stations are subject to regulation under the Environmental Permitting (England & Wales) / Pollution Prevention and Control (Scotland) Regulations, as amended. These Regulations place obligations on operators of permitted processes to apply BAT to the way in which an installation is designed, built, maintained, operated and decommissioned.

BAT assessment is the primary selection mechanism for all new and substantially modified or retrofitted compressor machinery trains.

A detailed justification of any investment decision and how it meets the requirements of BAT is required to support an application to the relevant environmental regulator to operate a new or vary an existing facility. Following a successful determination of the application, a legally binding permit will be issued.

National Grid developed a BAT evaluation approach which supports the Compressor Machinery Train selection process for new compressor investment projects, and ensures that the relevant considerations relating to potential environmental impact, whole life costs and operating efficiency are taken into account. It also ensures that the selection is consistent with National Grid's corporate objective of ensuring that every project delivers Whole Life Value (WLV).

This process takes place during the project Feasibility Phase. The approach, which is supported by a BAT Evaluation Toolkit, utilises comparative performance and design information on candidate Compressor Machinery Train packages supplied by the OEMs.

BAT Process

The UK environmental regulators have set out an outline stepwise approach for the assessment of BAT. This requires that an operator should:

- Review the market to identify possible technical options that are available (candidate BAT techniques).
- Consider the potential environmental impacts of these options to determine which represents the Best Environmental Option (BEO).
- If the BEO is not acceptable on cost grounds, the environmental performance and costs of the other options should be compared.

Given the unique nature of the gas NTS, this approach has been refined to ensure that the particular operational requirements are considered, including safety, availability, reliability and flexibility and that the selection can be conducted within the constraints of a tendering exercise subject to legally binding EU procurement rules.

The combined BAT assessment and tender evaluation process is a formalised decision making mechanism conducted by National Grid to facilitate the selection of one (or more) compressor machinery train packages from one (or more) OEM. This approach has been shared and is supported by the UK Environmental Regulators.

Hatton BAT Assessment

Detailed below are the tendered options for the four Lots specified. All tendered solutions except Gamma and Delta were compliant bids.

- Alpha
- Beta
- Gamma
- Delta
- Epsilon
- Zeta
- Theta
- Kappa

Zeta and Theta solutions had the highest technical and environmental scores with very little difference between them, therefore both of these options are considered candidate BAT. Epsilon, offered a significant potential whole life cost advantage – therefore this was also considered candidate BAT.

The output of the BAT assessment was presented to the EA on the 9 May 2019. The EA in principle supported the conclusion that the three options represented BAT.

12. Updated CBA

Based on the outcome of the BAT assessment, the three candidate BAT options were evaluated within an updated CBA, which included the original counterfactual of retaining the VSD and RB211 on 500 hours and decommissioning Units B and C. The table below summarises the four options assessed.

Option	Description
0	Retain VSD Unit D and RB211 Unit A on 500 hours. Decommission RB211 units B and C post 2023. **(counterfactual)**
Theta	Retain VSD Unit D and RB211 Unit A on 500 hours. Install new unit(s) by December 2023. Decommission RB211 units B and C post 2023
Zeta	Retain VSD Unit D and RB211 Unit A on 500 hours. Install new unit(s) by December 2023. Decommission RB211 units B and C post 2023
Epsilon	Retain VSD Unit D and RB211 Unit A on 500 hours. Install new unit(s) by December 2023. Decommission RB211 units B and C post 2023

Table 10: CBA Options

The chart below shows the NPV of the four options. Based on this Theta and Zeta Options are favoured.

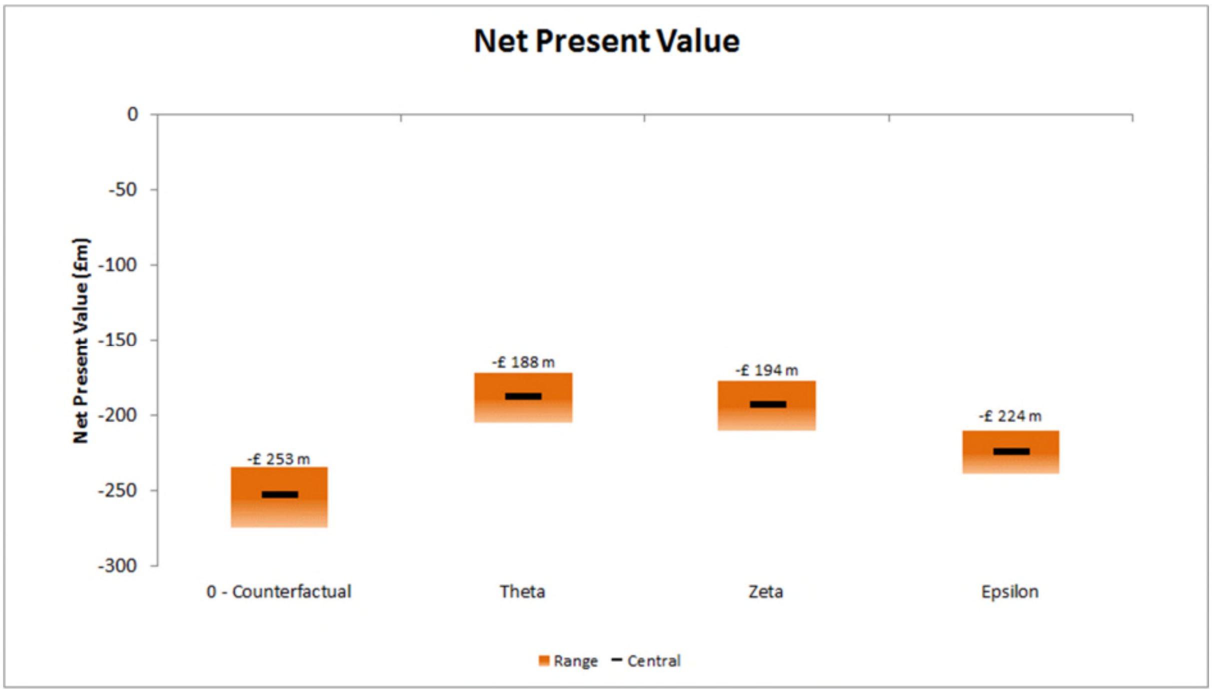


Figure 28: NPV of CBA Options

The following chart shows for each option the cost components of the NPV. It can be seen that in terms of the counterfactual (Option 0) not investing in additional compression capability post 2023 results in high contracting costs. Epsilon also has significant contracting costs which therefore favours Theta and Zeta Options, with Theta showing an NPV improvement of £6m over Zeta. Theta performs better than Zeta in terms of on-going costs for fuel, asset health (overhauls) and emissions, but has higher upfront capital cost.

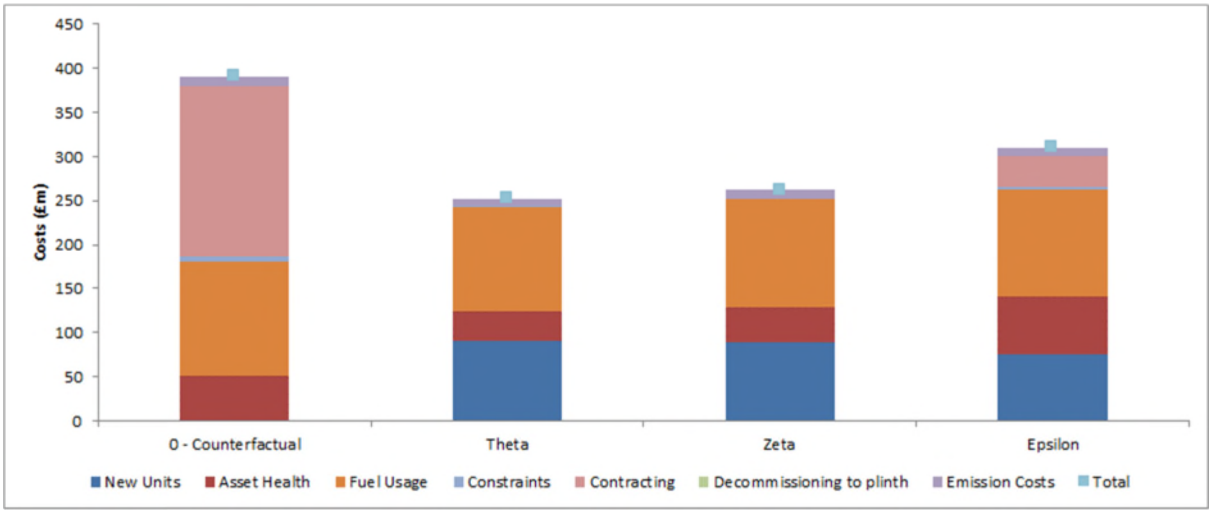


Figure 29: Cost Breakdown

In addition to the financial analysis the figure below shows the relative NOx performance of each of the options. It is clear that Theta offers significant benefits over Option 0 and Option Epsilon. There is also a notable benefit compared to Zeta

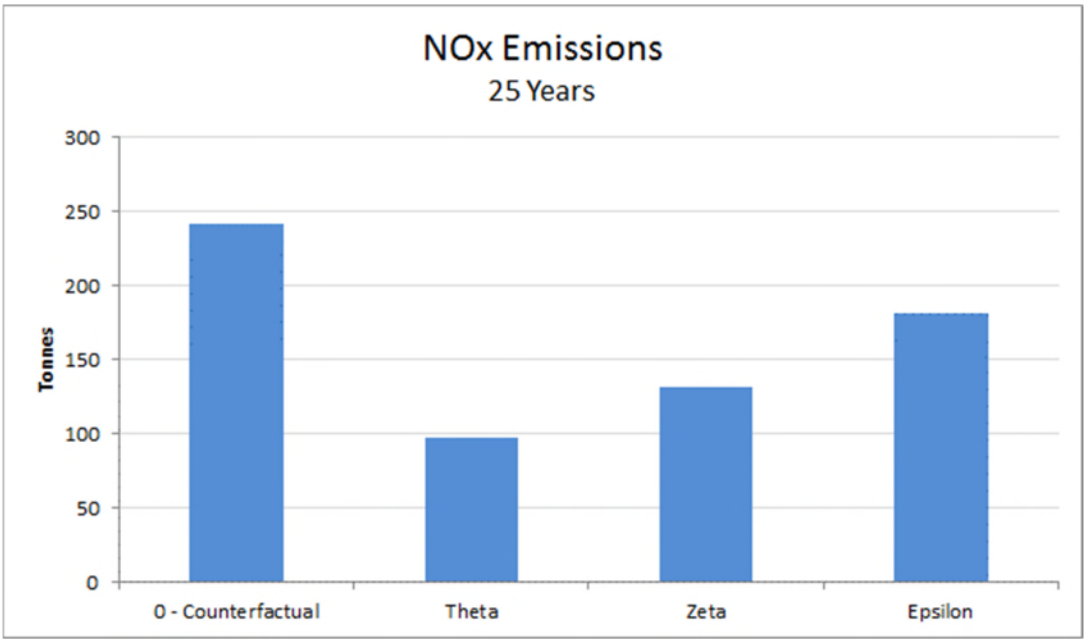


Figure 30: NOx emissions

As mentioned previously our CBA tool factors in uncertainty on various parameter, for example capital costs. However, in addition we have undertaken two sensitivities, firstly we have tested the result against the Two Degrees FES scenario and secondly against lower VSD unit availability, in recognition of the recent problems. The table below shows the NPVs for each of these sensitivities.

Option	NPV Core scenario (£m)	NPV Two degrees (£m)	VSD Availability - 68% (£m)
0	-253	-144	-275
Theta	-188	-178	-193
Zeta	-194	-183	-201
Epsilon	-224	-201	-231

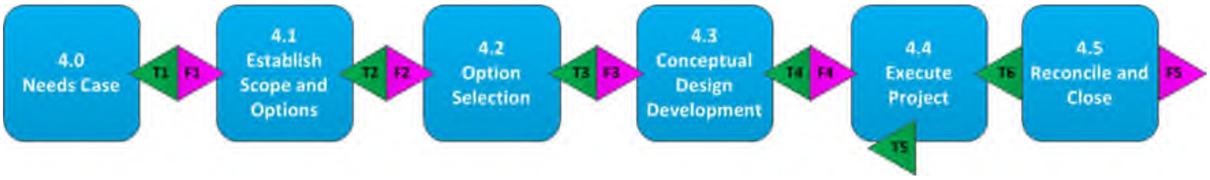
Table 11: Option NPVs Sensitivity Analysis

It can be seen from the sensitivity analysis that the outcome would change if demand levels were significantly lower as characterised by the Two Degrees scenario, with the counterfactual becoming the preferred option. Reducing VSD availability increases the positive differential between Theta and the counterfactual, compared to the core scenario.

The conclusion of the CBA assessment is to progress with the Theta Option, which offers significant financial benefit under our core central scenario compared to the counterfactual and Epsilon. Our core scenario is based on the Steady Progression FES, which we believe is more credible than Two Degrees. This view was broadly shared by the Gas Distribution Networks during the recent Energy Network Association work on a common scenario for RIIO-2. The Theta Option is also favoured over Zeta due to lower ongoing costs and improved environmental performance.

13. Governance

As described within the introduction section, the development of the solution at Hatton has followed National Grid's Network Development Process, shown below.



Pre-Works Sanction (F1) – August 2016

The first sanction (F1) for Hatton compressor station was approved in August 2016, following the acceptance of the needs case in May 2015. The sanction allowed for the initiation of a Basis of Design Document and the production of PDS points. The P50 cost for this stage was approved at £0.085m with the F2 sanction planned for October 2016.

Pre-Works Re-sanction (F1) – February 2017

The F1 for Hatton compressor station was re-sanctioned in February 2017. The re-sanction brought forward elements of work from Stage 4.2, such as procurement and consenting activities, whilst further work was undertaken on the solution development following the outcome of the May 2015 reopener. The P50 cost for this stage was approved at £0.180m with the F2 sanction planned for April 2017.

Pre-Works Re-sanction (F1) – February 2018

The F1 for Hatton compressor station was re-sanctioned in February 2018. The re-sanction brought forward further elements of work from Stage 4.2 to provide the best opportunity to achieve a commissioning date of the replacement capability at the site before 1 January 2024, whilst further work was undertaken on the solution development, including the appraisal of SCR technology. The P50 cost for this stage was approved at £0.485m with the F2 sanction planned for May 2018.

Full Sanction (F2) – May 2018

The F2 for Hatton compressor station was sanctioned in May 2018. The sanction covered feasibility and BAT studies to identify the preferred solution, based on the Needs Case / CBA outputs previously described. The P50 cost for this stage was approved at £1.531m with the F3 sanction planned for May 2019.

Full Sanction (F3) – May 2019

The F3 for Hatton compressor station was sanctioned in May 2019. The sanction covered the letting of the FEED contract and the procurement of the machinery train, subject to needs case acceptance by Ofgem. The P50 cost for this stage was approved at £40.9m with the F4 sanction planned for December 2020.

14. Finance

The cost of the BAT solution at Hatton is forecast to be £90.8m, with a spend profile as per the table below.

£m (18/19 prices)	Prior Years	2018-19	2019-20	2020-21	2021 -22	2022-23	2023-24	2024-25	Total
Theta option	0.2	0.5	16.1	10.1	24.1	21.5	17.0	1.2	90.8
Decommission two RB211		0.0	0.0	0.0	0.0	1.5	3.5	0.0	5.0

Table 12: Hatton forecast spend profile

15. Summary

Based on a detailed assessment of the options available to comply with IED, followed by a BAT and CBA assessment, National Grid is proposing to install and commission new unit(s) by 31 December 2023. In addition, we will decommission the RB211 Units B and C.

The proposed solution will deliver an output of IED (LCP) emissions compliance at Hatton, with no further emission related expenditure forecast based on existing emission legislation.

Ofgem are invited to approve this need case and provide written notification.

Appendix 1: Glossary

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 compressor machinery train driven by a Rolls Royce (now Siemens) gas turbine.

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.

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

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.

DEFRA = Department for Environment, Food and Rural Affairs

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.

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.

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

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.

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 total rated thermal input of 50 MW or more. Combustion plant must meet the emission limit values (ELVs) given in the LCP directive for NOx, CO, SO_2, 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.

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.

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 regarding ongoing operation of the compressor fleet and agree National Grid's Network Environmental Investment and Regulatory Strategy with both the EA and SEPA.

Nitrogen Oxides (NO_x) = gases composed of nitrogen and oxygen, which are a by-product of combustion of substances in air.

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 pressures 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.

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 several 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.

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.