St Fergus 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 St Fergus Terminal in response to the IED. This regulatory submission has been prepared to enable Ofgem to make that decision.

As one of the highest utilisation compressor sites on the National Transmission System (NTS), St Fergus enables UK Continental Shelf (UKCS) and Norwegian gas supplies entry onto the NTS. Compression is required to raise the pressure of the gas supplied via the North Sea Mid Stream Partners (NSMP) sub-terminal to NTS pressure. NSMP acquired the sub-terminal in 2015 from Total at a reported cost of £583m. Peak flow through this sub-terminal is ca. 75 mcm/d, which represents over 20% of supplies on a winter day. The only route for this gas to reach consumers is via the compression facility at St Fergus, there is no other physical substitute available.

The site comprises three compressor plants with ten berths and nine units: two variable speed drive electric units (VSDs), five Avon gas powered units and two RB211 gas powered units. The site is one of the highest polluting sites on the NTS and is impacted by the requirements of the Industrial Emissions Directive (IED), which incorporates both the Integrated Pollution Prevention and Control (IPPC) directive and the Large Combustion Plant (LCP) directive.

To ensure minimum compliance with IPPC, this needs case evaluates replacement or emissions abatement of at least one of the five Avon units. To meet the requirements of LCP, the two RB211 units (currently operating under the Limited Lifetime Derogation (LLD)) are evaluated to establish whether replacement, emissions abatement or decommissioning is the optimum solution.

Following an initial detailed analysis of all options available, which was presented as part of the May 2018 reopener, it was recommended to provide emission compliant capability comparable to one Avon and one RB211 unit by December 2023. Based on this recommendation the options were further developed and market tested. Three suppliers provided new unit solutions for the specified duty at St Fergus. We conducted a Best Available Technique (BAT) assessment of the proposed solutions and identified candidate BAT options, which consisted of single and two unit solutions.

The candidate BAT solutions were then subject to a Cost Benefit Assessment (CBA), with the single unit solution defined as the counterfactual, which had two variants to comply with the 2030 requirements of the Medium Combustion Plant (MCP) Directive. 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 costs, asset health investment and commercial costs, the most economical solution was evaluated as the two unit Delta solution, undertaking the works for both units concurrently. This option maintains a high level of reliability at this critical site and results in significant emissions reduction compared to the current position and the other options.

The Delta two unit solution 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 £80.4m, with a forecast spend profile as shown in the table below.

£m (18/19 prices)	Prior Years	2018-19	2019-20	2020-21	2021 -22	2022-23	2023-24	2024-25	Total
Delta option	0.5	0.6	14.6	9.3	21.4	18.4	14.6	1.0	80.4
Decommission RB211		0.0	0.0	0.0	0.0	0.7	1.7	0.0	2.5

Table 1: St Fergus forecast spend profile

The proposed solution will deliver an output of IED (LCP and IPPC) emissions compliance at St Fergus.

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

2. Introduction

This regulatory submission is made to enable Ofgem to make a decision on the need case and outputs at St Fergus Terminal in response to the IED legislation.

The strategy to comply with the IED legislation at St Fergus 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 St Fergus Terminal.

In developing the solution at St Fergus Terminal, we have followed our internal Network Development Process (NDP) as outlined below:

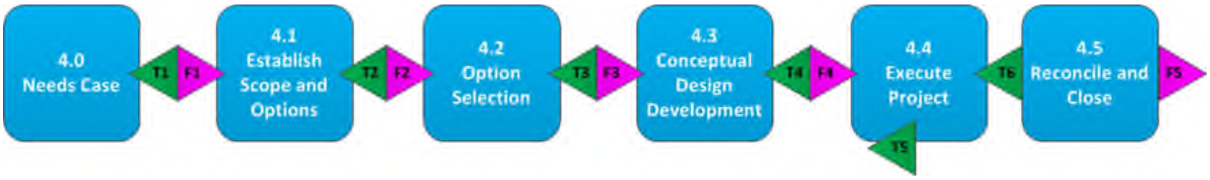

Figure 1: Network Development Process

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

The compressors at St Fergus have some of the highest run hours of the NTS compressor fleet. The compressors support the flows from the NSMP sub terminal, rather than providing compression for the general operation of the NTS, and are required to raise the pressure of the gas supplied via the NSMP sub-terminal to a pressure suitable for the gas to flow into the NTS. In contrast with all other compressors on the NTS, which are typically embedded in the network, St Fergus does not have an extended upstream pipe network so it must be able to respond to changes in the NSMP flow requirements on an almost immediate basis. It also requires any necessary resilience to be fully located on site rather than relying on alternative site back up.

Gas flows from the NSMP sub-terminal and enters the St Fergus terminal at a pressure of approximately 40 barg. The gas then flows through scrubbers and meter streams before passing through the compression plants where the gas pressure is raised. Depending on network conditions this is typically to between 60 barg and 65 barg, although often up to the maximum allowable system pressure for this part of the network of 70 barg. The gas is then cooled in the aftercoolers to remove the heat of compression before being blended with gas from the Apache and Shell sub-terminals. The gas is supplied into the NTS down the five pipelines towards Aberdeen and further south.

In terms of configuration, the St Fergus compressor assets are divided into three separate plants: Plant 1, Plant 2 and Plant 3 with a total of 10 berths. Plant 1 and 2 were built as part of the original site, commissioned in 1978, with Plant 3 commissioned in 2015.

Plant 1 comprises four gas turbine driven compressors. All four are Rolls Royce (now Siemens) Avon units.

Plant 2 comprises three gas turbine driven compressors plus one empty berth. There is one Rolls Royce Avon unit and two Rolls Royce (Siemens) RB211 units.

Plant 3 comprises two electric variable speed drive (VSD) compressors.

Individual Avon units can support a nominal flow of 15 mcm/d, whilst individual RB211s and the VSDs can support flows of up to 30 mcm/d.

Plants 1 and 2 offer flexibility; they can operate independently but are generally operated together. The supporting assets – scrubbers and after-coolers – are nominally assigned to the individual plants but can also be cross connected. Plant 3 provides baseload compression and is designed to operate in conjunction with Plant 1 and/or Plant 2 as these provide the necessary scrubbing, metering and after cooling.

For over 40 years of operation (circa mid-1970s to 2012) two RB211 driven compressor sets provided primary compression capacity at the St Fergus site, run in conjunction with the five Avon compressor sets. This provided successful operation for many years. A significant change occurred when the Plant 3 electrically powered VSD units were introduced, and since this point the VSDs and Avons have provided the main compressor capacity, with the RB211 units being used as backup to the VSDs.

The VSDs provide bulk compression capability, effectively mimicking the capability of the RB211s. In order to effectively map the entire operating envelope of the site, the smaller Avon gas units continue to be required for when flows are:

- below the minimum turndown capacity of a single VSD;
- mid-range i.e. greater than a single VSD but less than two VSDs at minimum turndown capacity; or
- very high i.e. greater than two VSDs in parallel.

In addition, there is a requirement for gas turbine driven compressors to provide back up in the event of loss of the incoming electrical power supply or unavailability of the VSDs as a consequence of maintenance or failure. The site operates 24 hours a day, 365 days a year.

The primary means of achieving the required flexibility is by selecting a combination of compressors of appropriate capacity with further flexibility achieved by exploiting the range of individual compressors. A load share controller ensures that the compression duty is shared evenly between the online compressors. Further flexibility in operation can be achieved by recycling gas via the plant recycle line but this is both noisy and inefficient and is thus minimised.

From an operational perspective, flows through St Fergus have always shown a high degree of variability. As shown by the red bars on the chart below, in the mid-2000s, typical daily flows through NSMP's sub terminal were in excess of 50 mcm/d. However, from 2009 flows were significantly lower and with the decline in UKCS gas, flows of 10-20 mcm/d were more common. In 2016 with a change of ownership at the sub-terminal and new supplies coming on from West of Shetland, there was a marked change in flows. Typical flows at the sub-terminal increased up to the region of 30-40 mcm/d and then in October 2016 there was another significant increase up to 50-60 mcm/d. On two days in January 2017 flows exceeded 60 mcm/d. NSMP has indicated that flows are likely to be around the 50 mcm/d level for the foreseeable future and potentially higher. In 2018/19 flows have receded to some extent from the highs seen in 2017.

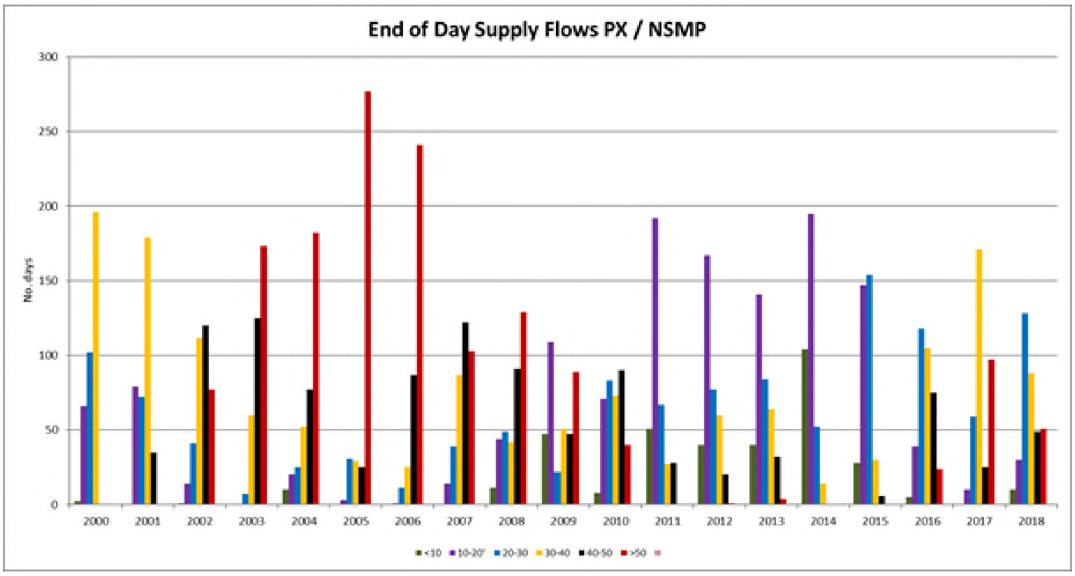

Figure 2: NSMP flows

The consequence of these changes was a 30% increase in compressor run hours between 2015/16 and 2016/17. The chart below shows the station's operation over the last 5 years overlaid with the typical capability of the units on site.

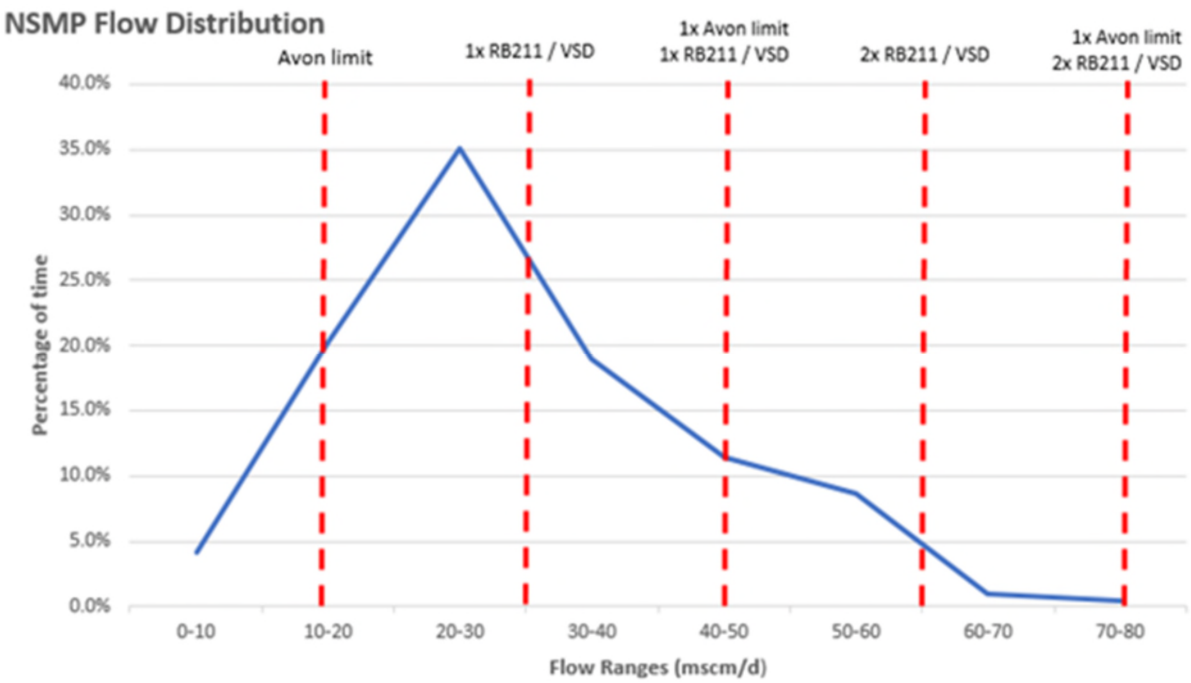

Figure 3: NSMP Flow Ranges and Unit Capability

The running hours and emissions for each individual compressor unit over the past five years are shown below:

	Individual Unit Running Hours *(financial year)*				
	2014/15	**2015/16**	**2016/17**	**2017/18**	**2018/19**
Unit 1A	2,482	942	281	518	93
Unit 1B	25	632	339	447	0
Unit 1C	2,407	1,214	1,353	939	4
Unit 1D	1,371	776	1,458	465	0
Unit 2A	1,756	1,709	1,006	2726	688
Unit 2B	253	1,337	7	77	840
Unit 2D	1,131	152	740	1365	1235
Unit 3A	N/A	618	4800	2211	3605
Unit 3B	N/A	3001	4182	5420	4268
Total	**9,425**	**10,381**	**14,166**	**14,168**	**10,733**

Table 2: Running Hours - as reported in the Regulatory Reporting Pack

NOx (tonnes)	Individual Unit Emissions *(financial year)*				
	2014/15	2015/16	2016/17	2017/18	2018/19
Unit 1A	27	11	3	5	1
Unit 1B	0	6	3	4	0
Unit 1C	20	11	12	8	0
Unit 1D	13	9	14	3	0
Unit 2A	68	58	46	107	24
Unit 2B	3	15	0	1	8
Unit 2D	36	6	31	56	43
Unit 3A	N/A	N/A	N/A	N/A	0
Unit 3B	N/A	N/A	N/A	N/A	0
Total	167	116	109	184	76

Table 3: NOx emissions - as reported in the Regulatory Reporting Pack

Plant 1 and 2 are still seeing significant service supporting the VSD units on Plant 3. Whilst the VSD units were commissioned relatively recently in 2015, the majority of the compressor related assets at St Fergus terminal have been in situ since 1977, reaching 40 years of service in 2017. Consequently through duty and condition, there are significant asset health issues that need to be addressed to ensure continued safety, operational reliability and environmental compliance at the site. The cost and effectiveness of the various maintenance, repair and replacement options for the compressor assets impact the large items that make up the machinery train (gas turbine, power turbine, gas compressor) but also the wet gas seals and the auxiliary systems such as the cab ventilation, cab structure, exhaust stack and control systems.

To facilitate some of the necessary asset health work, Plant 2 was taken out of service (for the first time in almost forty years) during the summer of 2016 and Plant 1 was taken out of service during the summer of 2018, hence the low run hours during 2018/19. This places additional demands on the remaining operational plant to provide supplementary and back up capability to the VSDs. Further plant outages are likely to be required in support of future construction or upgrade projects e.g. to facilitate the removal and replacement of the 40+ year old unit isolation and emergency shutdown valves.

The VSD units themselves have experienced some availability issues in the period following commissioning. This is most likely to be a function of the bedding in process and it is expected availability levels will pick up once these issues are resolved.

It is important to note that there is a fundamental 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 which makes it uneconomic to carry ‘fleet spare’ machines. Even if a similar motor exists at another location, it would be a costly and time consuming process to modify and relocate the motor to a different location. 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. These types of failures are low probability events but will impact the overall availability of the VSD units.

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 Industrial Emissions Directive (IED) and the effect of this new legislation on our compressor units.

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

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

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

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

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

The Industrial Emissions Directive

(Directive 2010/75/EU)

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

1. The use of permits for installations

The IED specifies that all installations must be operated with a permit. These permits specify the ELVs for polluting substances, which are likely to be emitted from the installation concerned and determines the environmental risk of that installation. This mirrors the specifications set out in the IPPC whereby installations have to comply with the ELVs set out in their permit, which are based on BAT.

2. Establishment of BAT Reference documents

The IED also introduces an increased emphasis on the status of the BAT Reference (BREF) documents. These BREF documents draw conclusions on what the BAT is for each sector to comply with the requirements of IED. In addition to emissions 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 Limited Lifetime Derogation state that from 1st January 2016 to 31st December 2023 combustion plant may be exempted from compliance with the ELVs for installations above 50 MW provided certain conditions are fulfilled:

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

(b) The operator submits each year a record of the number of operating hours since 1st January 2016

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

5. Emergency Use Derogation (EUD)

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

6. 1,500 hours derogation[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 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 31 December 2029. Figure 4 summarises the emissions compliance status of the compressor units on the NTS.

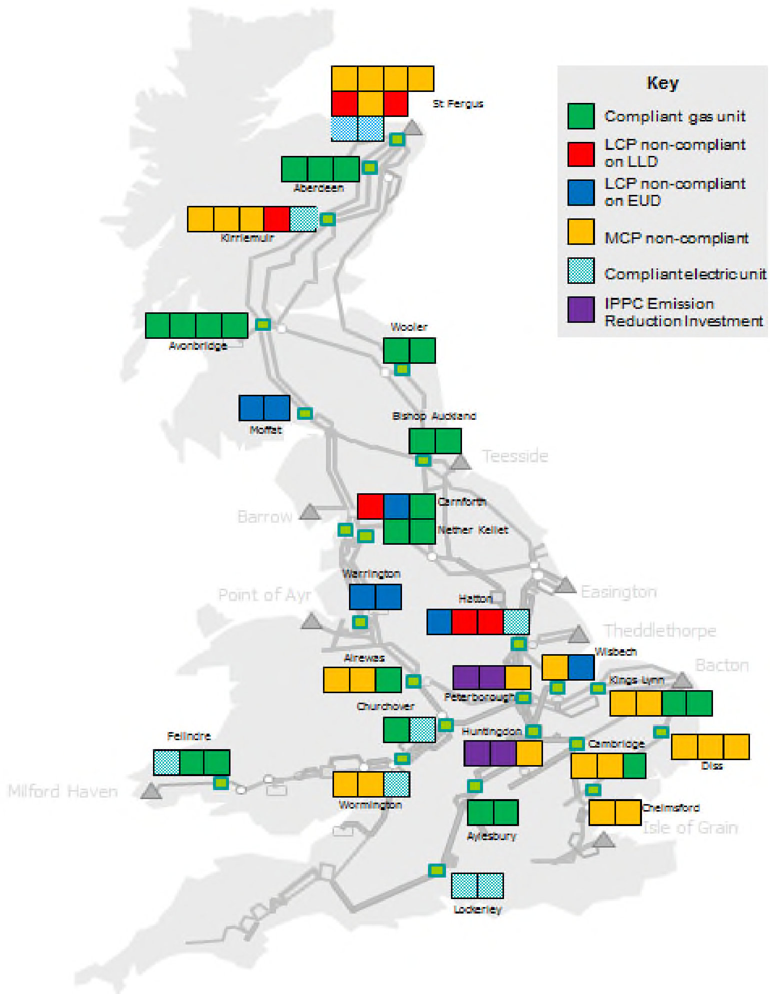

Figure 4: Compressor unit type and compliance with environmental legislation

St Fergus Impact

<u>IED: LCP</u>

Both of the RB211 units, 2A and 2D are impacted by the IED (LCP) requirement – highlighted in red on the diagram below.

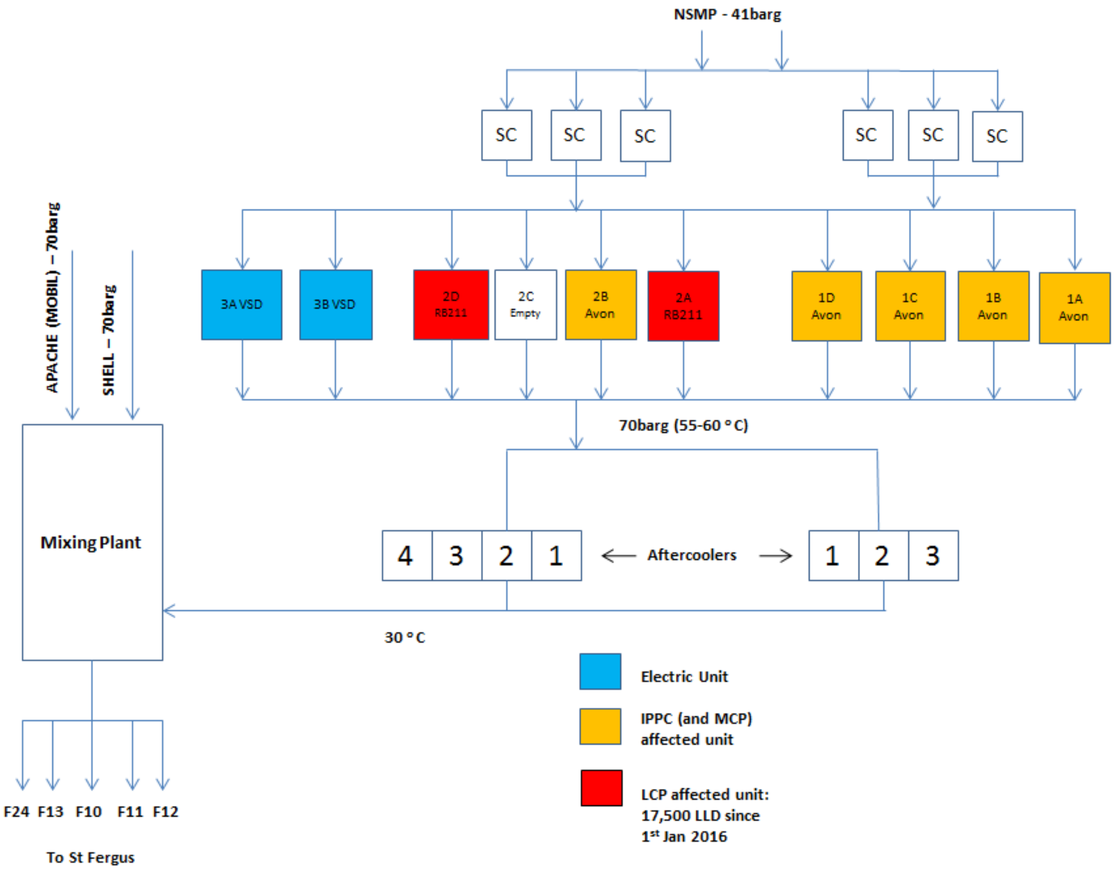

Figure 5: Site schematic

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 regarding the individual affected units, 2A and 2D. The options at this stage were whether to decommission the units immediately, or enter them into either the EUD or LLD. Neither immediate decommissioning nor use of the EUD were considered suitable. The EUD limits running hours to just 500 hours per year, which was not adequate to meet the site requirements, particularly as the VSDs were not operationally proven at that point. In line with the outcome from stakeholder engagement carried out as part of our IED submission in May 2015, units 2A and 2D were put onto the LLD. This allows the units to operate for a maximum of 17,500 hours or until 31st December 2023 whichever is sooner. With the 2023 deadline approaching, the investment decision as part of this submission is to consider whether these units should now be replaced, abated or decommissioned.

IED: IPPC element

The St Fergus compressor site is affected by the requirements of the IPPC element of IED as it is one of the highest run hour sites on the network (see chart below).

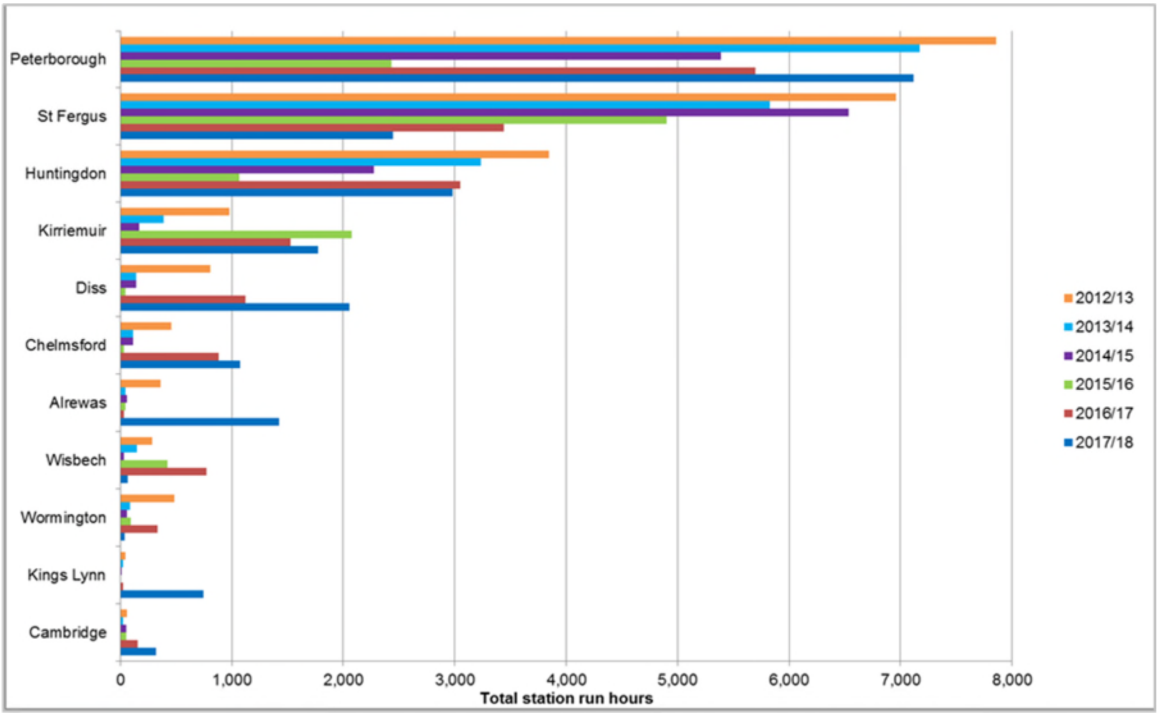

Figure 6: Ranked run hours for IED non-compliant compressor units by station 2012-2018

To reduce our fleet NOx emissions, we have completed two phases of investment as part of our IPPC programme of works. The first phase focused on St Fergus and Kirriemuir with the installation of three new electrically driven compressors, two at St Fergus and one at Kirriemuir. The second phase focused on the installation of an electrically driven compressor at Hatton. All of the units installed as part of IPPC Phase 1 and 2 are now the lead units at these compressor stations.

IPPC Phase 3 was proposed as part of our RIIO-T1 business plan in 2012. This focused on reducing emissions at Peterborough and Huntingdon, the sites with the next highest levels of NOx emissions with the intention of significantly reducing NOx emissions from both sites by 2021.

We provisionally identified Alrewas, Diss and Wormington compressor sites in our RIIO-T1 business plan for inclusion in the IPPC Phase 4 programme of works. These sites were identified based on prevailing and forecast future network flows in 2011/12. Due to a number of uncertainties, baseline funding was not provided for IPPC Phase 4 but funding was provided in RIIO-T1 to develop an integrated plan for IED and IPPC Phase 4.

In 2013/14, we re-assessed the compressor station run hours as part of our IPPC Phase 4 site need case analysis. All three of the provisionally identified stations were found to have declining run hours.

The focus of the IPPC Phase 4 works shifted to other sites with units with higher current and forecast future running hours, this identified remaining units at St Fergus, Huntingdon and Peterborough as priority sites.

The Avon units at St Fergus are used extensively as they have the ability to deal with lower flows through the site - operating for over 2,200 hours per annum and emitting over 20 tonnes of NOx per annum on average since 2016/17. Therefore, investment options on one or more of the Avon units need to be assessed and implemented to comply with IPPC at this site.

In 2014, as part of our May 2015 stakeholder engagement process, we presented the IPPC Phase 4 analysis and our future compressor strategy. We received positive feedback from our stakeholders that St Fergus, Peterborough and Huntingdon were the most appropriate sites to take forward as part of IPPC Phase 4.

<u>MCP Directive</u>

There are five units at St Fergus that will be affected by the MCP directive. These are Avon units 1A, 1B, 1C, 1D and 2B. These units need to be compliant with the MCP directive by the 1st January 2030, without intervention the units will be restricted to 500 operating hours per year as a rolling average over a period of five years. The need case analysis for IED has therefore taken account of the interaction with the MCP legislation.

Summary

The current investment decision looks to review the two units currently operating under the LCP derogation; whether to replace, abate or decommission Units 2A and 2D by the end of 2023. The St Fergus investment decision also considers options to achieve compliance with IPPC; replacement or abatement of one or more Avon units. Consideration is given to the future requirements of the MCP directive, as the Avon units will all be captured under this legislation from 2030. Due to the interaction between the different units at St Fergus, a holistic evaluation must be undertaken in order to determine the optimum solution.

A summary of the current status of all units is given in the table below.

	IED LCP and MCP Summary	IPPC Summary	Allowed Operating Hours	Year Applicable from	Legislative year of closure
Unit 1A	Captured under MCP from 2030	Evaluation for IPPC Phase 4	N/A	2030	TBD
Unit 1B	Captured under MCP from 2030	Evaluation for IPPC Phase 4	N/A	2030	TBD
Unit 1C	Captured under MCP from 2030	Evaluation for IPPC Phase 4	N/A	2030	TBD
Unit 1D	Captured under MCP from 2030	Evaluation for IPPC Phase 4	N/A	2030	TBD
Unit 2B	Captured under MCP from 2030	Evaluation for IPPC Phase 4	N/A	2030	TBD
Unit 2A	LCP Limited Life Derogation	-	17500hrs total until 2023	2016	2023
Unit 2D	LCP Limited Life Derogation	-	17500hrs total until 2023	2016	2023
Unit 3A	Compliant	IPPC Phase 1	N/A	N/A	N/A
Unit 3B	Compliant	IPPC Phase 1	N/A	N/A	N/A

Table 4: IPPC, LCP and MCP unit summary

5. The Future Requirements

The gas landscape has changed considerably in the last 20 years. With the continued decline of 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, the full details can be found in the main FES document.

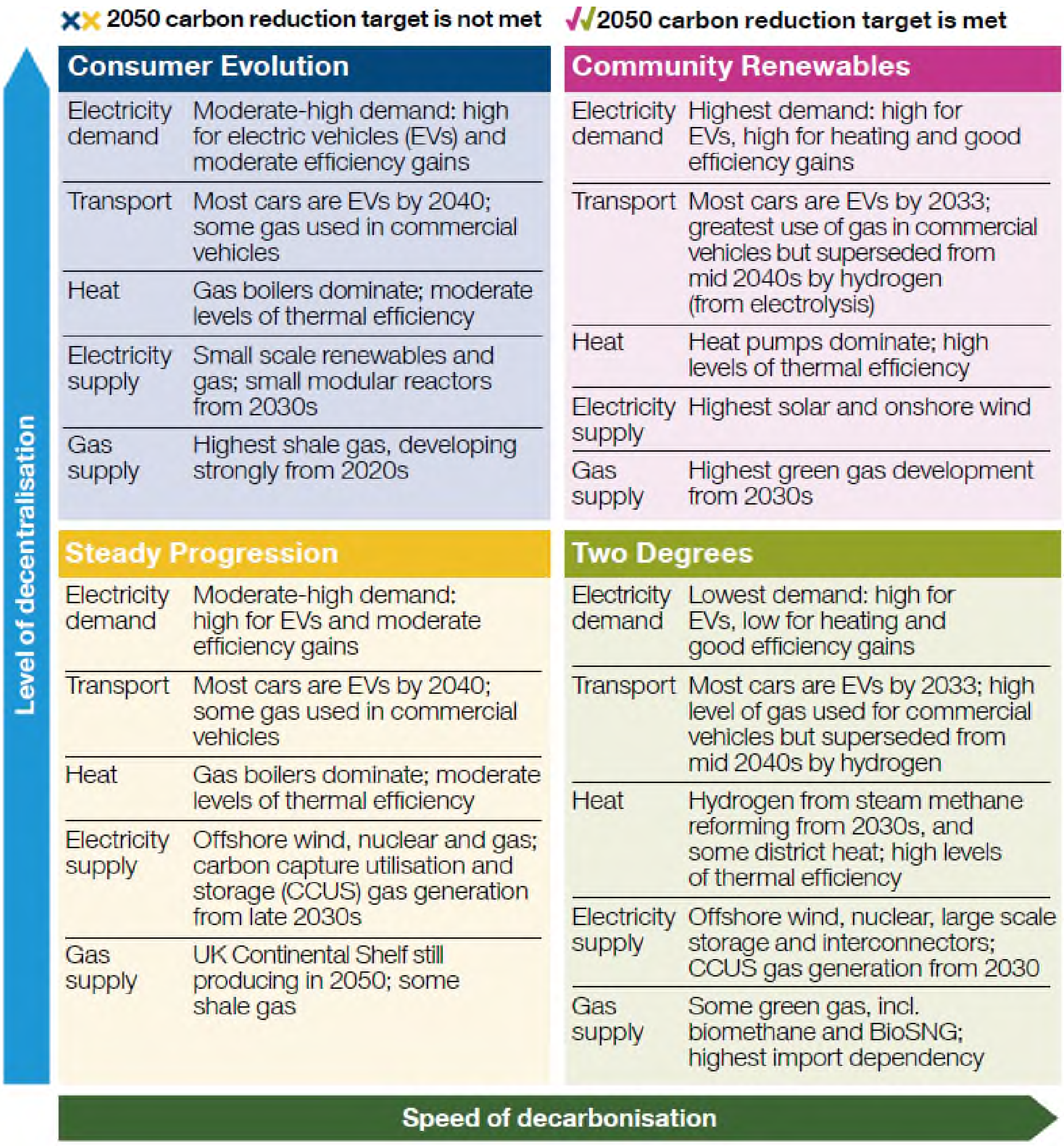

Figure 7: FES 2018 - Scenarios

With the wide-ranging impact of IED on the compressor units at St Fergus, a number of different sources have been used to validate future requirements of the site in addition to FES. Considerations include the obligated baseline entry capacity, the Network Entry Agreement (NEA) and standby requirements.

Obligated Baseline Entry Capacity

The obligated entry level at the St Fergus Aggregated System Entry Point (ASEP) is 154.22 mcm/d. This is the total entry for all three sub-terminals, Apache, Shell and NSMP together and it is not broken down to sub-terminal level. The compression requirement at St Fergus relates to the NSMP flows only.

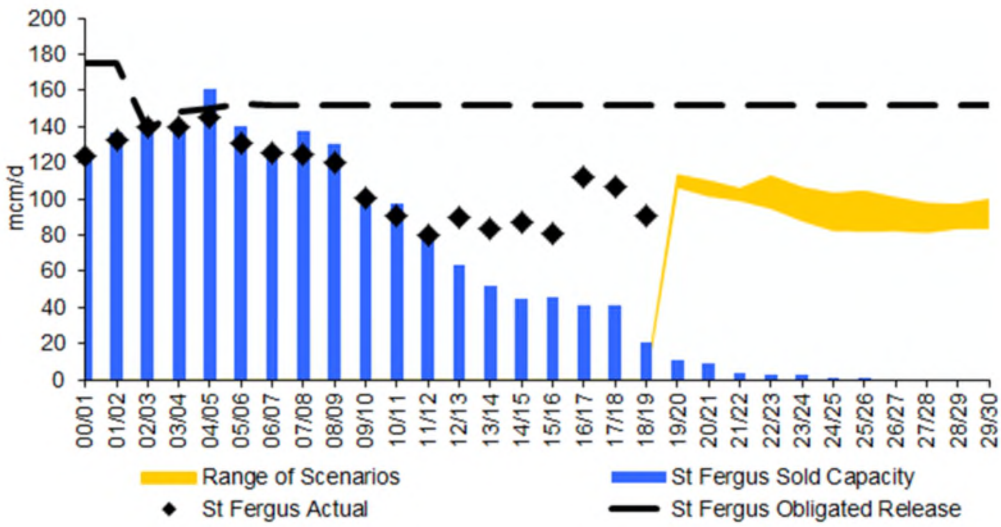

Figure 8: St Fergus capacity and flow - GTYS 2018

The chart above shows the level of capacity sold at St Fergus since 2000. The sold levels are well below the entry baseline for the ASEP with shippers deciding to wait to obtain capacity on the day for free as opposed to paying the entry charges. Therefore, sold levels cannot be taken as a guide to the likely physical flows through the ASEP into the future.

Requirements under FES and forecast run hours

Looking to the future, the analysis carried out as part of FES 2018 indicates there is a capability requirement at St Fergus out to 2040 and beyond. The forecast flow range for NSMP is large, between 10 mcm/d and 68 mcm/d across the four different scenarios. Overall, the predicted flows show a slight decline over the next 10 years. There is an increase in flows from 2024/25 as new fields connect in at the West of Shetland. The recent change in ownership at NSMP, and the associated change in strategy for their upstream assets are likely to push actual supplies towards the top of the range in the chart below.

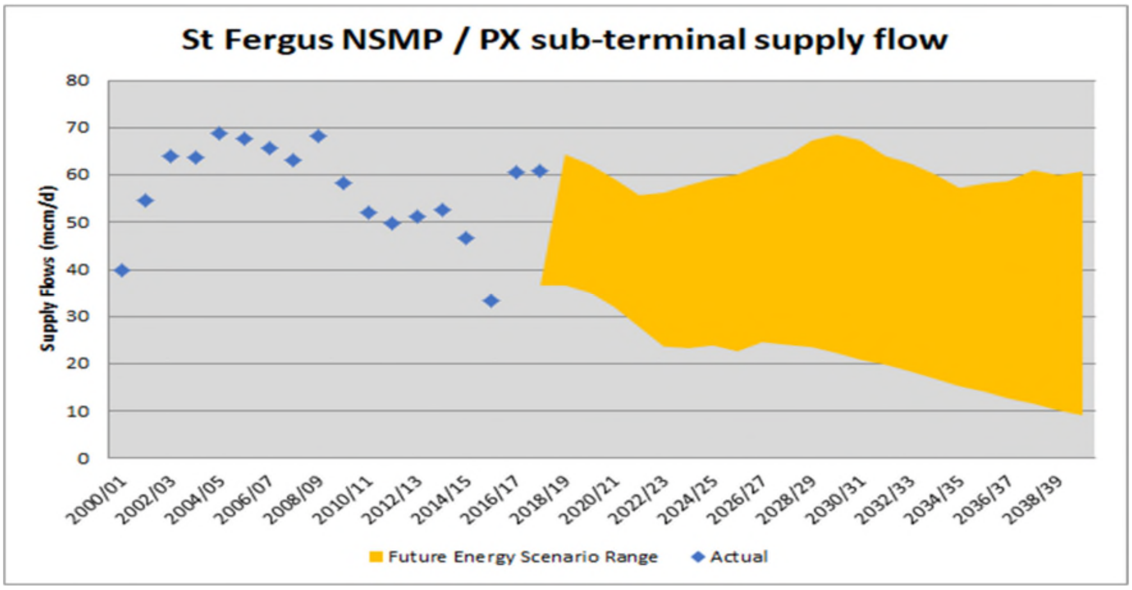

Figure 9: St Fergus NSMP sub-terminal flow – GTYS 2018

The Network Entry Agreement

NSMP acquired the former Total Oil and Marine (TOM) sub-terminal in August 2015. It is operated on their behalf by PX Limited. PX Limited signed an accession Network Entry Agreement (NEA) contract on the 15th March 2016. Contractually, the NEA specifies the pressure of the gas supplied (between 41 and 44 barg), and although there is a metering limit of 81.6 mcm/d per plant stream, this cannot be used as an indication for flow and compression requirements. However, it should be noted that we understand the assumed peak capability of the upstream NSMP Ltd pipelines is ca. 75 mcm/d, which in effect creates an upper limit.

Standby requirements

The compression at St Fergus is used to provide a sub-terminal specific pressure service, not bulk transmission, hence there is no viable Operating Margins (OM) alternative or ability to provide any back up at other compressor sites. The level of stand-by compression needs to be balanced with the expected availability of units as part of the CBA. The Transmission Planning Code (TPC) sets out what should be assessed when considering compressor standby. The investment decision therefore considers the required transmission capability, forecast compressor run hours, economic and efficient system operation, maintenance and fuel security (electricity and/or gas).

Future Requirements Summary

This assessment of the site's future requirements is a key factor in the St Fergus options assessment and analysis in the next section. Taking into consideration the four sources outlined above it is clear there are multiple indicators to inform the maximum level and also the potential range of compression required going forward. The two key values for the maximum flow are:

- 68 mcm/d – The highest peak flow from the 2018 FES;
- 75 mcm/d – The assumed peak capability of the upstream NSMP Ltd pipelines;

The supply range across the 4 scenarios, shown in Figure 9, is used to inform the decision. The options for the LCP impacted units 2A and 2D (replacement, emissions abatement or decommissioning) and the options for the Avon units (replacement or emissions abatement) to ensure compliance with IPPC are critical in ensuring we have sufficient flexibility in the compressor capability at the site to meet the flows across the full flow range required.

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 are 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 of changes to our forecasts of the future or assumptions about the availability of existing assets.

7. Cost Benefit Analysis (CBA)

In order 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 in order to inform the optimal solution. The evaluation includes the costs of implementing each option and the relative advantages of doing so. In developing the CBA tool, an independent review was completed by Pöyry.

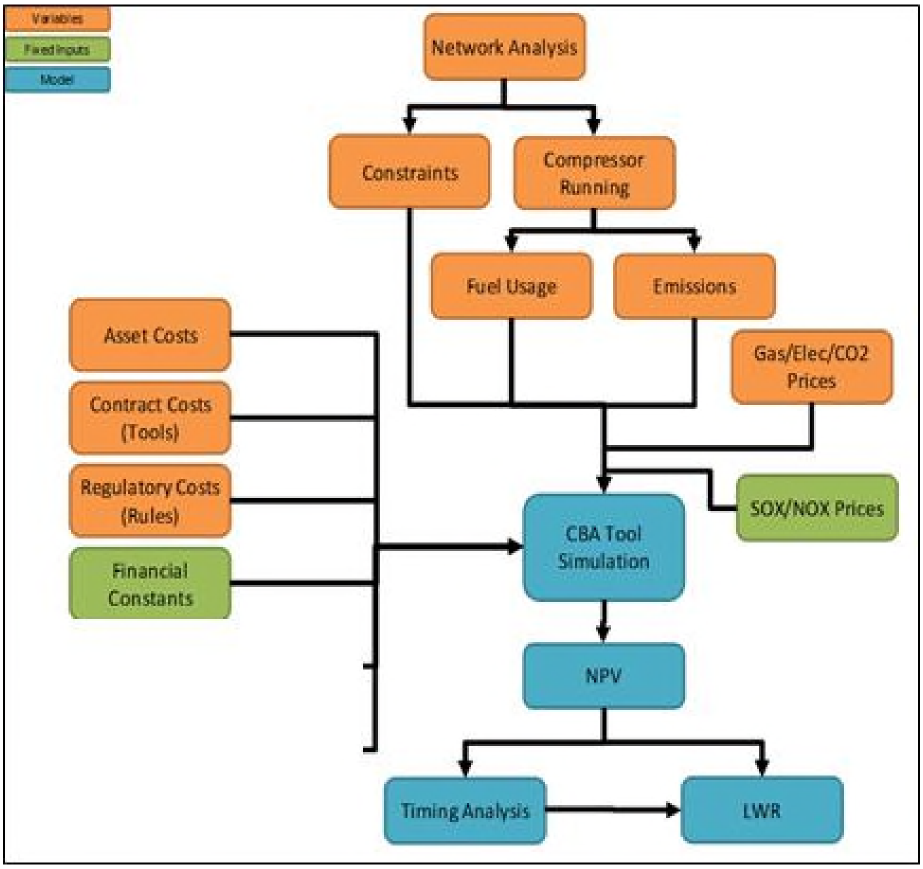

Figure 10: Overview of CBA tool

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

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

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

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 and validation was undertaken at Stage 4.2.

The Counterfactual

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

The counterfactual option is to decommission the currently unused unit in berth 2C and immediately construct one new Avon-sized[2] unit on the footprint of berth 2C to satisfy IPPC requirements. For compliance with LCP, the LLD in place on the two existing RB211 units 2A and 2D, would be utilised with the effect that they both cease operation in December 2023 or after 17,500 hours of operation (from 1st January 2016), whichever is sooner and then be decommissioned. The EUD would be utilised on all the existing Avon units 1A, 1B, 1C, 1D and 2B, and operate less than 500 operating hours per year from 1st January 2030 in perpetuity.

Under this option, it is assumed that the most economical solution for compliance with LCP is to decommission both RB211 units, which does offer certain advantages: minimal site interfaces, limiting operational working constraints and outages etc. However, this option loses flexibility across the wide envelope of site operation that an RB211 unit can provide, and after the RB211 units are decommissioned in 2023, there would also be uneven capability between the three plants which could result in operational issues.

To evaluate the true economic case for the counterfactual, a number of other commercial and physical options were assessed for the purposes of comparison. These options were 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. For the physical options, a CBA was undertaken demonstrating a clear and robust comparison of 14 different unit and ancillary system configurations for the St Fergus terminal. Within the CBA, all of the costs and benefits were calculated for the first 30 years, and then discounted using 45 years through the RAV (Regulatory Asset Value). The assessment was therefore over a 45-year period and the price base for the St Fergus CBA at stage 4.1 was 2016/17.

Commercial Options

The commercial assessment of options to meet the St Fergus terminal compression requirements included both contractual and regulatory code alternatives. The relevant commercial options were those which reduced emissions from one Avon unit (IPPC

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[2] "avon-size" means a gas turbine driven compressor machinery train suitably sized to handle the process duty currently handled by an Avon

compliance) or offered benefits above decommissioning the two RB211s (counterfactual position for LCP compliance).

Consideration was initially given to the renegotiation of the Network Entry Agreement (NEA) with a view to remove the compression requirement from being a National Grid provided service. National Grid cannot unilaterally change the NEA and so approached NSMP for early engagement. It was determined that the other party had no appetite for contract negotiations and under their current model, could not make an economic case to do so. This option was therefore discounted.

Capacity buy-back mechanisms can also be considered as a commercial option to reduce absolute compression through the site. Typically used as a way to manage a physical constraint risk on the NTS, entry capacity is only sold at the ASEP level rather than the sub-terminal level. Capacity buy-backs can therefore only economically address a constraint at an ASEP level. This means at St Fergus, there is no effective means of targeting capacity buy-backs at the specific shippers who are unable to flow gas through the affected sub-terminal, as opposed to the broader portfolio of shippers in possession of entry capacity at the ASEP. In this case only the shippers at NSMP would be impacted by the lack of compression, not those flowing through the other two sub terminals.

There is a precedent for splitting an ASEP. Following European legislation, designed to harmonise transparent and non-discriminatory access to transmission capacity at interconnection points across the European Union, it was necessary to split the Bacton ASEP. This necessitated different arrangements and processes for the European Interconnectors (BBL and IUK) than for the other Bacton sub-terminals bringing in gas from the UKCS. The process was longwinded and complex, driven by the need for legislative change. It was not broadly supported by industry, as a split of the ASEP reduces the optionality for shippers looking to trade their flows between different sub-terminals. Based on this experience, a split of the St Fergus ASEP was not taken forward.

As capacity buy back mechanisms are not appropriate we have also considered the use of alternative flow based contractual arrangements. These would be designed to reduce peak flows at the sub terminal and therefore minimise investment in compression capability. Feedback indicates that entering into a turn down contract where compression is needed is contradictory to the agreement we have to provide pressures to accommodate flow onto the network from the sub-terminal. In addition, the price of such a contract would be very high given consequential impact of calling off flows at any time, impacting multiple shippers. Also feedback through stakeholder engagement clearly indicated that fundamentally stakeholders want to flow gas onto the network – they do not want National Grid to have to restrict flow even with financial compensations.

Another commercial option considered changes to the Uniform Network Code (UNC). Under UNC Section Y, National Grid is entitled to levy a compression charge to shippers to recover compressor fuel costs where compression is needed to increase the pressure of gas delivered from the NSMP sub-terminal. One alternative code change considered was the option to modify the UNC (Section Y) whereby National Grid can levy a charge for the cost of investment in the compressor assets as well as the fuel usage for the compression. This option was discounted as although it would change the proportion of the investment cost picked up by relevant shippers – it would not alter the total cost of investment – and would be subject to a code review process.

In summary, these options, whilst designed to either reduce absolute compression at the site or pay compensation where back up is inadequate, were discounted. Given the criticality of the St Fergus sub-terminal and the volume of flows through the site, commercial and regulatory options could not offer a better alternative to the counterfactual.

Physical Options

Options Overview

The physical options were created through a process of evaluating the site's future requirements across a range of three main potential investment solutions: no further investment, emissions abatement and investment in new units. A number of secondary factors associated with the three main solutions were then assessed including combinations of green field and brown field sites, new Avon sized units, new VSD compressors, use of emission abatement technology to achieve ELVs (SCR (Selective Catalytic Reduction to reduce NOx emissions) and Oxidation Catalysts ('OxyCat' to reduce CO emissions)), use of existing ancillary assets, and the enduring use of the Emergency Use Derogation.

This option development was carried out in conjunction with the factors highlighted as important during our stakeholder feedback such as:

- Does this option allow National Grid to meet future flexibility requirements?
- Does this option have a negligible impact on customer charges?
- Is this option future proof?
- Does this option remove barriers for encouraging new investment?

As discussed, Option 0 is the counterfactual - the option against which all of the other options have been assessed. This represents the Do Minimum option which ensures that we are compliant with legislation. For St Fergus terminal, Option 0 is designed to reduce site NOx emissions under IED-IPPC and to ensure compliance with the two units impacted by IED-LPC. This is achieved through the installation of one new Avon size unit and decommissioning the RB211s after 2023.

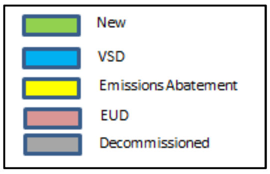
The CBA assessment for St Fergus includes the investment costs, asset health costs, site operating expenditure, compressor fuel usage and the liabilities for each of the options.

The list of options analysed under the CBA are summarised in the table below.

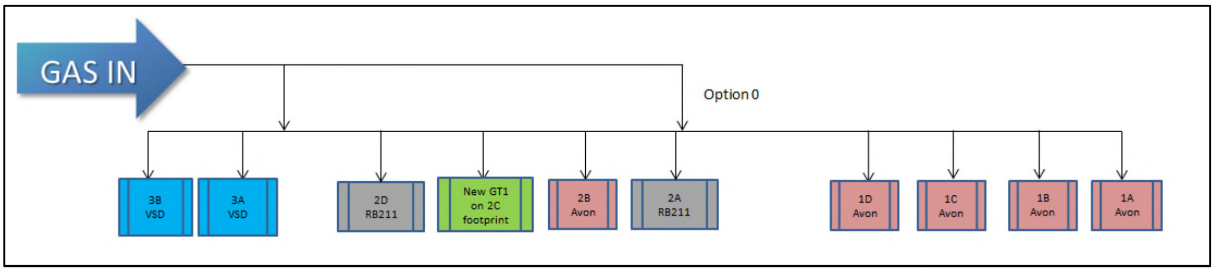
Option Number and description	Existing VSD	New VSD	AVON UNITS			RB211 UNITS		Existing plinths	Greenfield/ Brownfield	Plant Balance
			Number of New Units	Number of SCR Units	Number of Old Units (on limited running hours post 2030)	Number of Units with emissions abatement	Number of Old Units (decommissioned post 2023)			
0 – One new unit on brownfield	2	0	1	0	5	0	2	Yes	B	No
8 - One new unit on greenfield	2	0	1	0	5	0	2	No	G	No
8a – Emissions abatement on one Avon	2	0	0	1	5	0	2	Yes	B	No
9 – Two new units on greenfield	2	0	2	0	4	0	2	No	G	No
9a – Emissions abatement on two Avon units	2	0	0	2	4	0	2	Yes	B	No
9b - Emissions abatement on two Avon units with timing offset	2	0	0	2	4	0	2	Yes	B	No
9c - Two new units on brownfield	2	0	2	0	4	0	2	No	B	Yes
10 - Emissions abatement on one RB211 and one new unit on greenfield	2	0	1	0	5	1	1	No	G/B	No
10a - Emissions abatement on one RB211 and on one Avon unit	2	0	0	1	5	1	1	Yes	B	No
10b - Emissions abatement on one RB211 and one new unit on brownfield	2	0	1	0	5	1	1	Yes	B	Yes
11 - Emissions abatement on one RB211 and two new units on greenfield	2	0	2	0	4	1	1	Yes	G/B	No
11a - Emissions abatement on one RB211 and on two Avon units	2	0	0	2	4	1	1	Yes	B	No

Table 5: Option summary

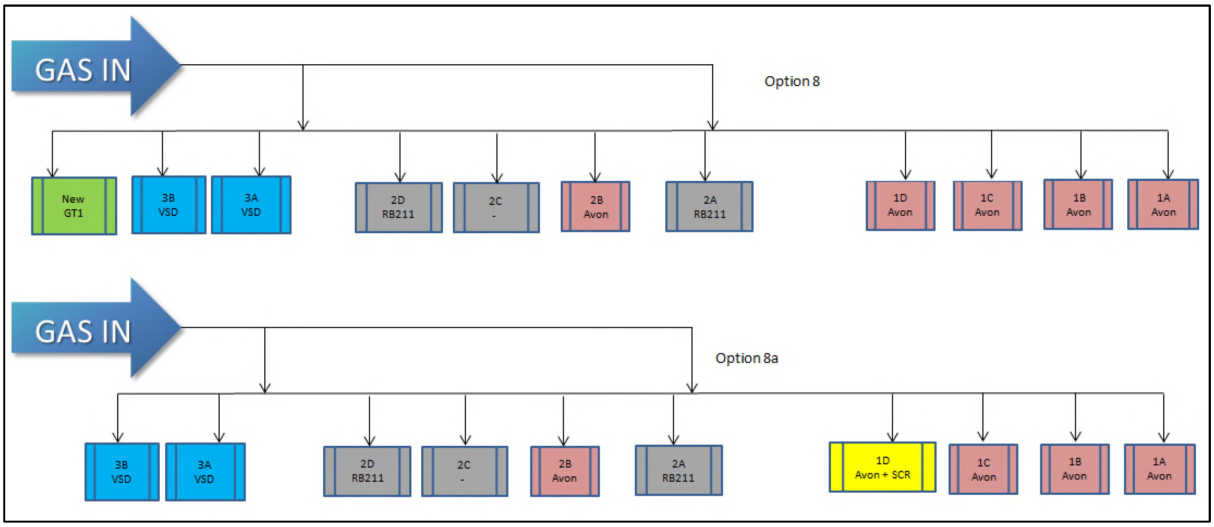
The options were designed to contrast and evaluate different characteristics. Options 8 and 8a have similar capability to Option 0 but delivered through SCR technology rather than a new unit, and existing rather than new plinths. Options 9, 10 and 11 have increasing levels of capability with the various sub options including new Avon sized units and emissions abatement technology on both the Avon and RB211 units. These options are presented in the diagrams below with the following key:



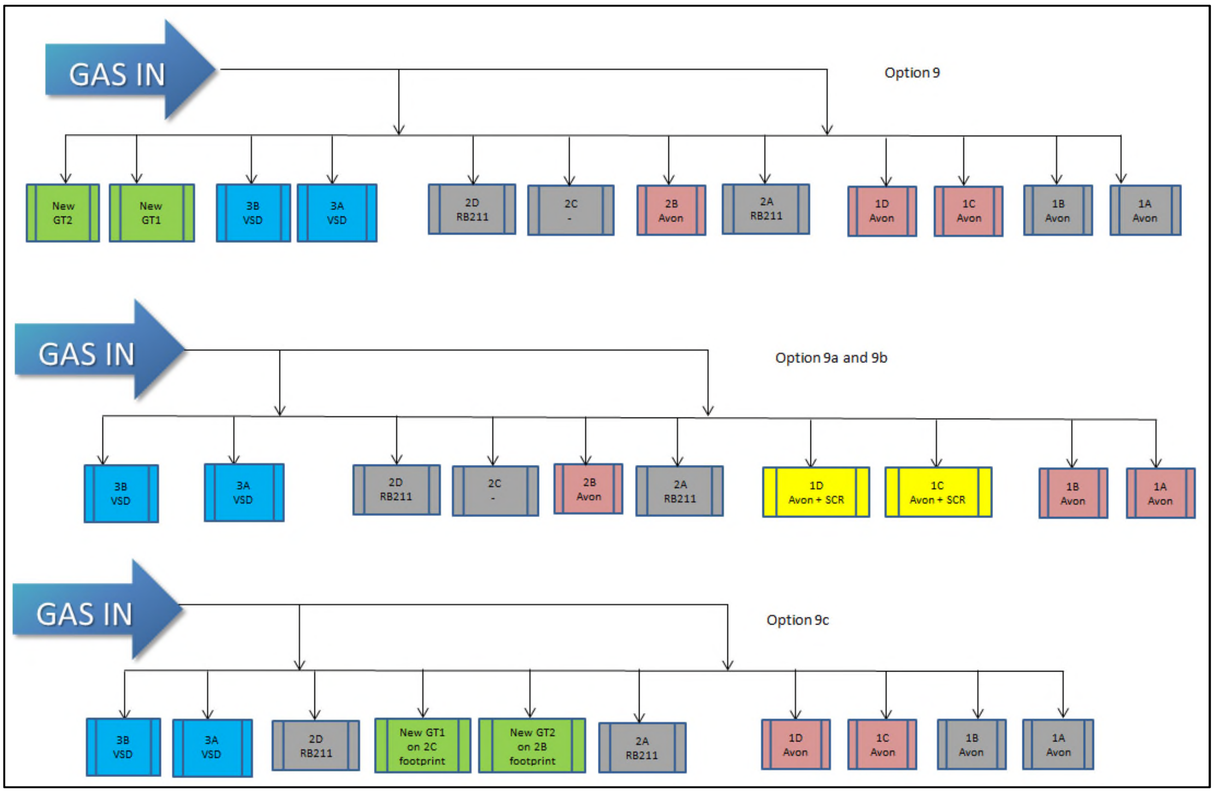
The site layout for **Option 0** is represented in the table below, with the new gas unit on plant 2 highlighted in green.



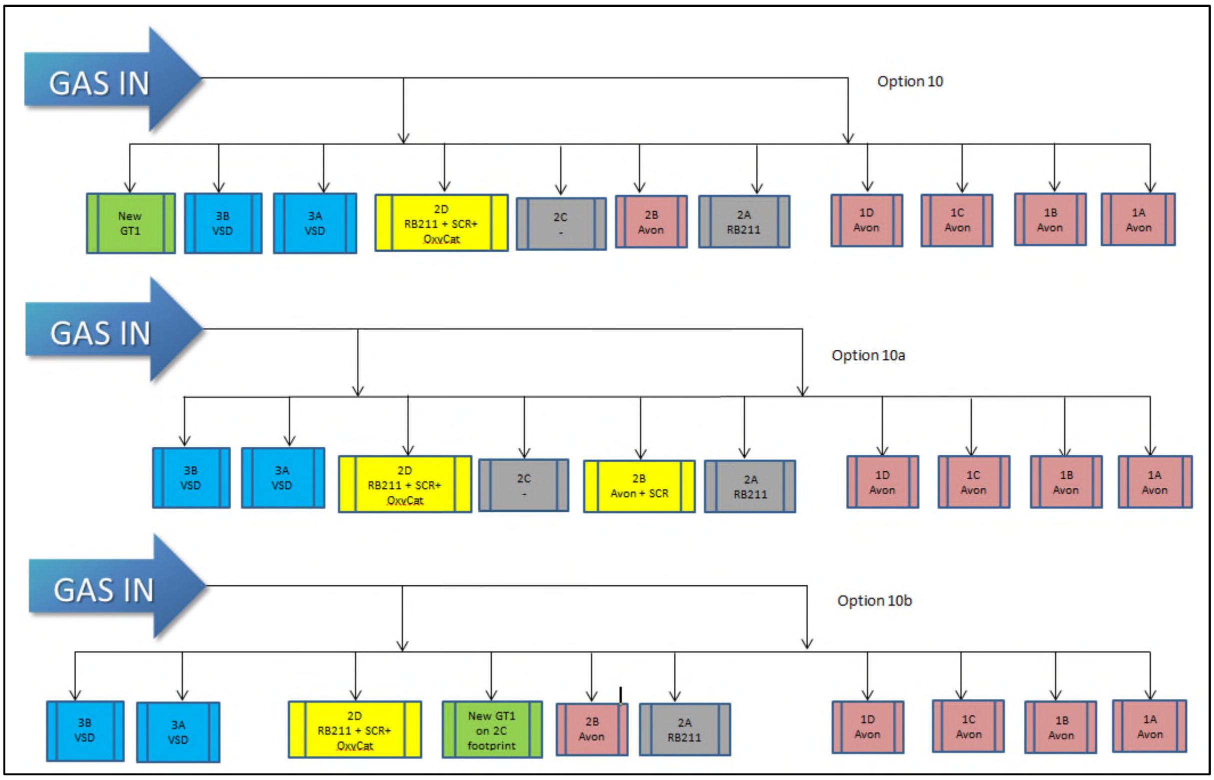
Options 8 and 8a include investment in one Avon sized unit, either a new unit or the existing unit fitted with SCR.



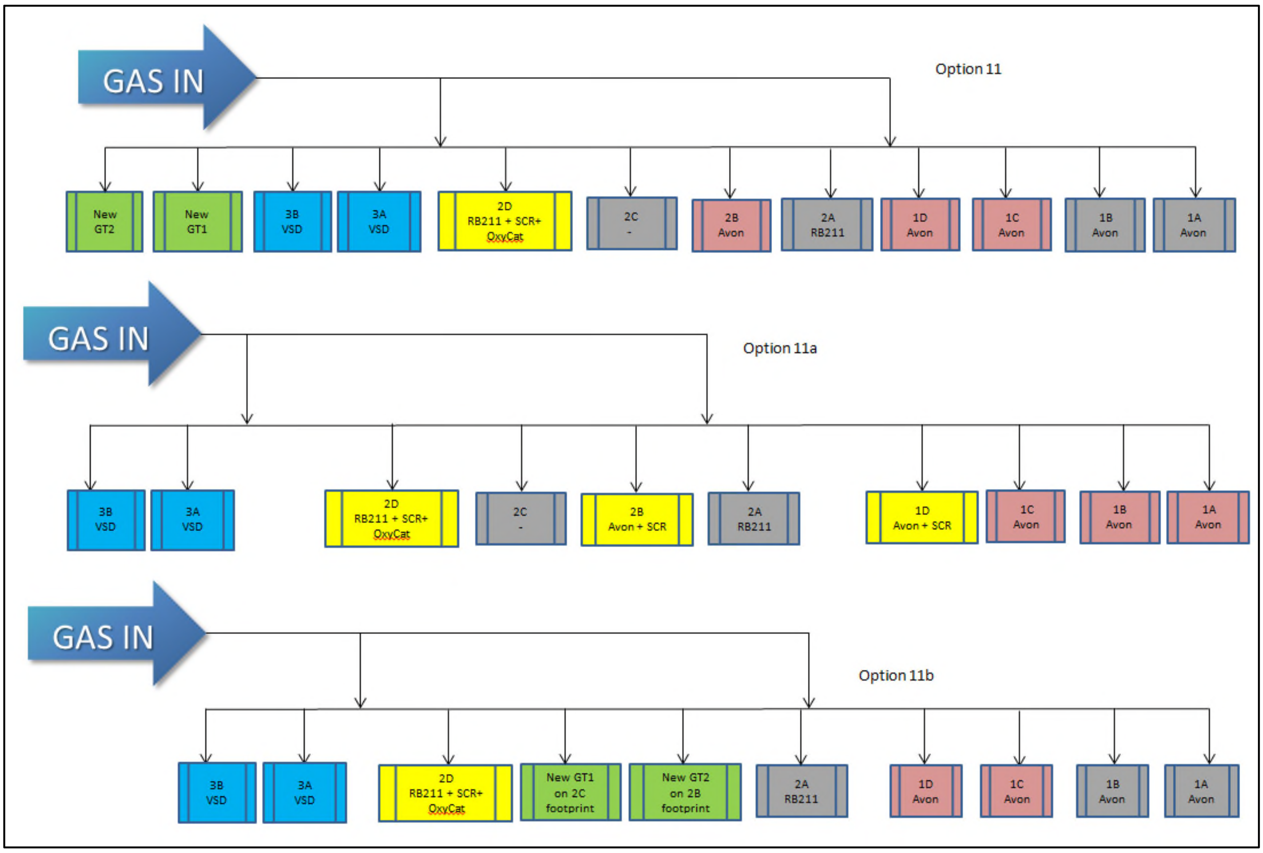
Options 9, 9a, 9b and 9c all involve variants of two Avon sized unit alternatives, either new units or fitted with SCR. Option 9b is a timing variant of 9a, whereby one unit is installed first, followed by the next. Under Option 9 and 9c, two existing Avons 1A and 1B are decommissioned as soon as possible after new units are installed and proven in use.



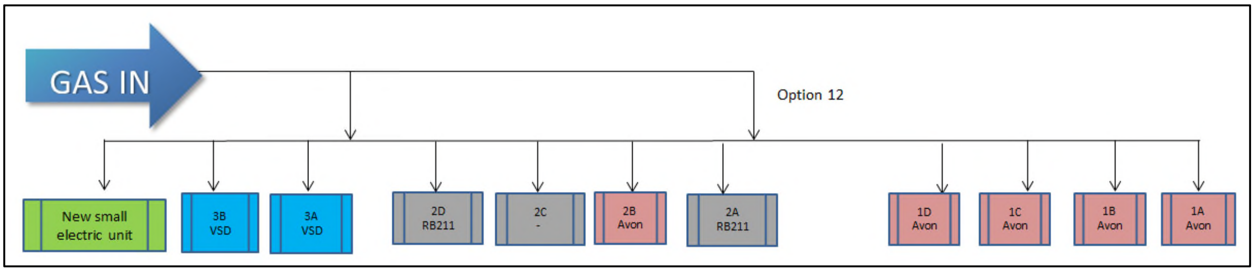
Options 10, 10a and 10b include investment in one RB211 unit as well as one Avon sized units. Emissions abatement on the RB211 unit requires both SCR and OxyCat.



Options 11, 11a and 11b comprise of investment in one RB211 and two Avon sized units. The RB211 investment option comprises of SCR with OxyCat technologies, whilst the Avon sized options include SCR and new units.



Option 12 is one new VSD.



Cost Benefit Analysis

With Option 0 defined as the counterfactual, each of the other 13 options was compared to Option 0 to give a Relative NPV (Net Present Value). The CBA assessment showed a wide range of relative NPVs. The most positive was produced by Option 10b at £54m, with the least positive produced by Option 12 at -£158m. The absolute NPVs ranged from -£839m (Option 12) to -£626m (Option 10b) with a few options (Options 8,9,10 and 11) clustered between -£700m and -£640m. The range within each option is primarily driven by fuel costs and investment costs. The fuel cost range was fairly similar across all of the options, whilst the high capability options, such as the Options 11, 11a and 11b had a higher investment cost range. The lower capability options, such as the counterfactual and Options 8 and 8a had a higher range on liability costs.

The most favourable options were taken forward, these are presented below. Option 8a provides the same capability (in terms of station throughput) as the counterfactual but at a lower cost. All other options identified provide additional capability, resulting in both lower liability costs and greater emission savings. Option 10b, with the highest NPV, represented the optimum investment based on the CBA results.

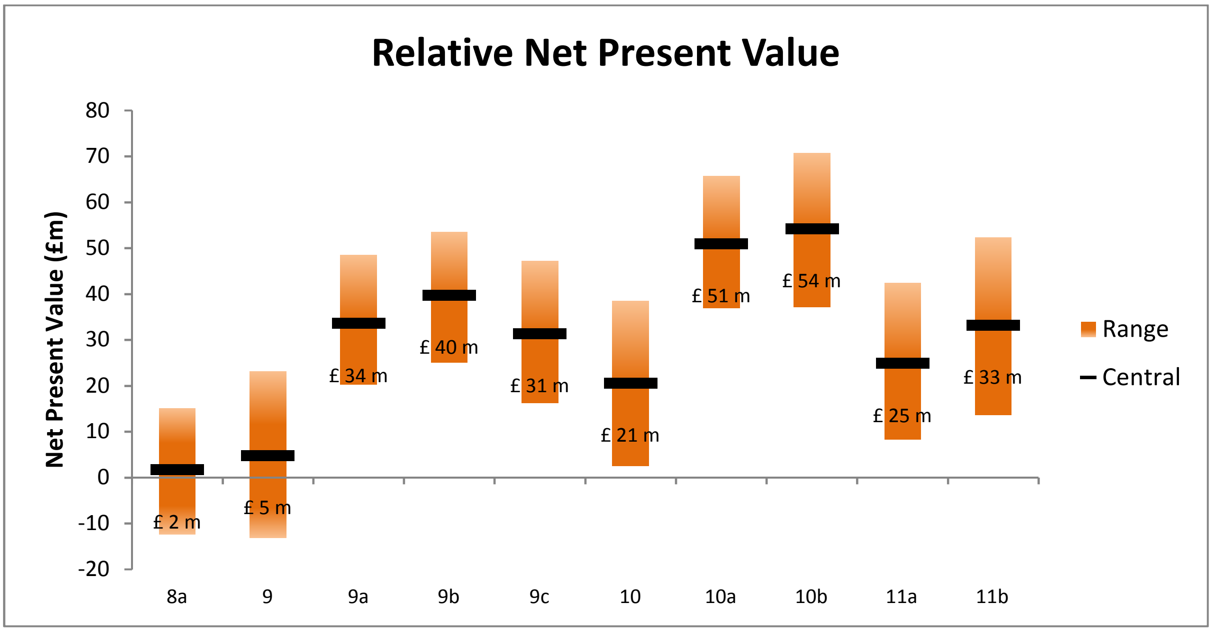


Figure 11: Relative NPV

The charts below show a more detailed breakdown of costs for the lead options. Many of the options show similar levels of initial investment and constraints.

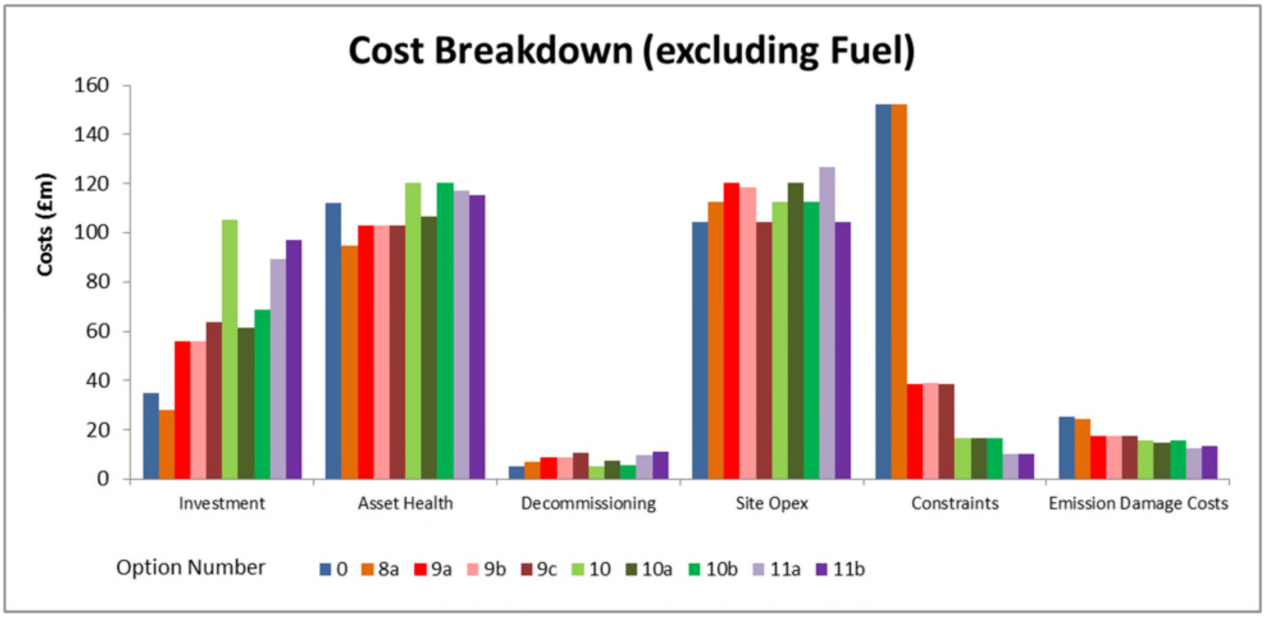


Figure 12: Cost breakdown excluding fuel

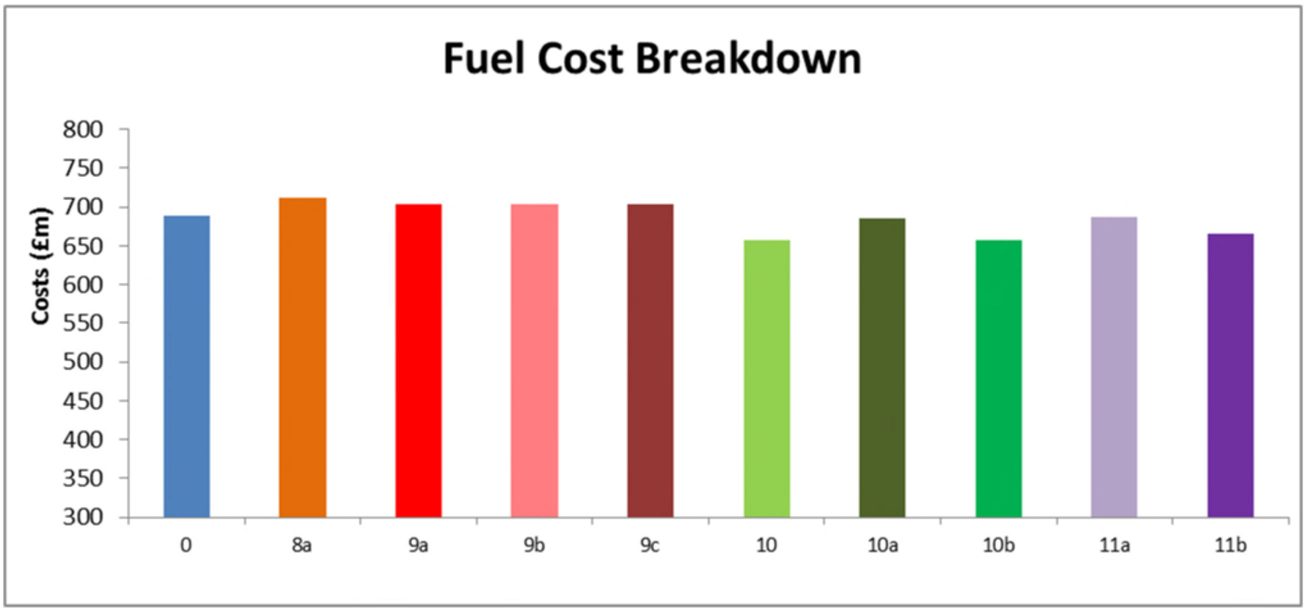


Figure 13: Fuel cost breakdown

Option 8a had the lowest investment costs, which is to be expected given it involves only SCR on one Avon unit. However it had by far the highest constraint costs of the options in the short list, which given its lower capability was to be expected. Options 11a and 11b had the highest investment costs but also the lowest constraint costs. This was to be expected as these options involve investment in two Avon units and one RB211. The higher upfront costs being partly offset by lower liability costs due to the higher capability.

Options 9a, 9b, 9c, 10a and 10b all had similar investment costs as they all address emissions on two of the engines, either two Avon units or one Avon and one RB211. The optimum combination however was offered with options 10a and 10b due to the comparatively lower liability costs for the greater capability offered by the RB211 compared to an Avon.

Considering liabilities in more detail, it can be seen how the options accrue costs differently over time. Liability costs do not play a particularly key role in the short term and they tend to be far more significant after 2030 than before, due to the 500 hour limitation applied to Avon units under MCP. However, most of the investments will occur in the shorter term, over a broadly similar time period regardless of which option.

As seen on the chart below, Options 9a, 9b and 9c have similar capability and so have near identical liability costs. The same is true for Options 10 and Options 11. Whilst there are some constraints before 2030, under all options these costs do not become sizeable until after the impact of MCP. Post 2030, when any remaining unabated units are placed on EUD (500 hours per year) the overall capability of the site will be significantly reduced once these hours are used up. In Option 8a this loss of capability is particularly significant as there are less units not subject to the 500 hour limit.

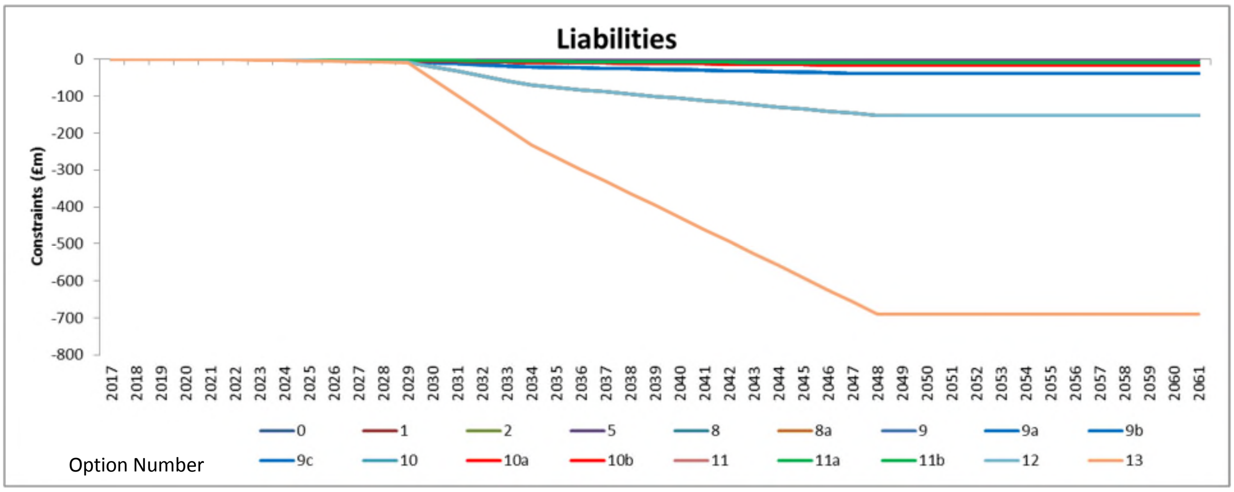


Figure 14: Liability costs

In comparing options over the full timeline of the analysis, higher capability options are valued favourably with the higher investment costs offset by lower liabilities.

The CBA was completed in early 2018 with estimated costs for all options. These costs were updated for the funding request in May 2018.

Sensitivities

Given the uncertainties over the flows at St Fergus a number of sensitivities were explored to test the results of the CBA, in particular the ranking of the options. To test for the impact of lower flows a sensitivity test was run using the Slow Progression FES scenario, which has the lowest flows through St Fergus terminal. This is compared to the Steady State FES scenario with higher St Fergus flows. As expected, the consequence of lower flows was reduced liabilities so this sensitivity reduced the relative benefit of the options with greater capability than the counterfactual.

Another key uncertainty tested was the reliability and availability of the compressors, in particular the VSD units. A sensitivity scenario was created that assumed the availability of these units was only 56%, similar to that seen to that point in time. This significantly increased the liabilities seen across all options, but far less so with those with the greatest capability such as options 11a and 11b.

Relative NPV (£)	Central	Low Availability	Low Flows
	Steady State scenario with 75% availability	Steady State scenario with 75% availability on gas turbines and 56% on VSDs (Position Ranking)	Slow Progression scenario with 75% availability (Position Ranking)
Option 10b	54.3	220.6 (3)	-5.7 (2)
Option 10a	51.0	217.7 (4)	-8.6 (3)
Option 9b	39.7	175.8 (6)	-13.9 (4)

Option 9c	33.6	168.7 (8)	-21.6 (6)
Option 9a	33.2	170.9 (7)	-19.7 (5)
Option 11b	31.4	270.2 (1)	-29.4 (7)
Option 11a	24.9	262.0 (2)	-37.2 (8)
Option 10	20.6	187.5 (5)	-39.4 (9)
Option 8a	1.7	1.8 (9)	1.8 (1)

Table 6: Low availability and low flow sensitivities

CBA Summary

The CBA analysis at Stage 4.1 provided a consolidated short list of options. As well as the counterfactual, the analysis focussed on Options 10a, 10b, 9a, 9b and 9c which did well in overall NPV terms. Options 10a and 10b were consistently ranked highly across the sensitivities. There were however, combinations involving SCR and new units across a range of levels of capability where it was not possible to clearly distinguish the benefits of one option over another. To assist with this, and to validate the results of the CBA a more complex technique involving prescriptive modelling was introduced.

Prescriptive Modelling

The prescriptive modelling technique involves modelling multiple constraints including operational, asset and financial constraints and accounting for asset interdependencies. The model can therefore be used for the St Fergus terminal analysis to calculate the impact of various forecasts or scenarios whilst also taking into account operational constraints. Having used the prescriptive model to incorporate a wider range of input variables and criteria than the CBA, the results were then used iteratively to improve the CBA e.g. inclusion of compressor fuel data.

The absolute NPVs were different between the two techniques due to the different treatment of risk, liabilities and fuel costs in the two tools. The average NPV under the prescriptive modelling is -£711m, compared to -£833m under the CBA. However as shown in the table below, the relative ranking of the NPVs was broadly similar with Options 10a and 10b favourable using either technique.

NPV Position Ranking	CBA	Prescriptive Modelling
1	Option 10b	Option 10b
2	Option 10a	Option 10a
3	Option 9b	Option 10
4	Option 9c	Option 0

5	Option 11b	Option 11a
6	Option 9a	Option 11b
7	Option 11a	Option 11
8	Option 10	Option 8
9	Option 8a	Option 9
10	Option 9	Option 9b
11	Option 0	Option 9a
12	Option 8	Option 8a
13	Option 11	Option 9c
14	Option 12	Option 12

Table 7: NPV position ranking

Primarily, the prescriptive model could more clearly illustrate the benefits of options 10a and 10b - whereby the lowest TOTEX costs are combined with significant emissions reduction (63% less than the counterfactual). Option 11a does offer higher emission reduction but at £30m higher TOTEX over the evaluation period.

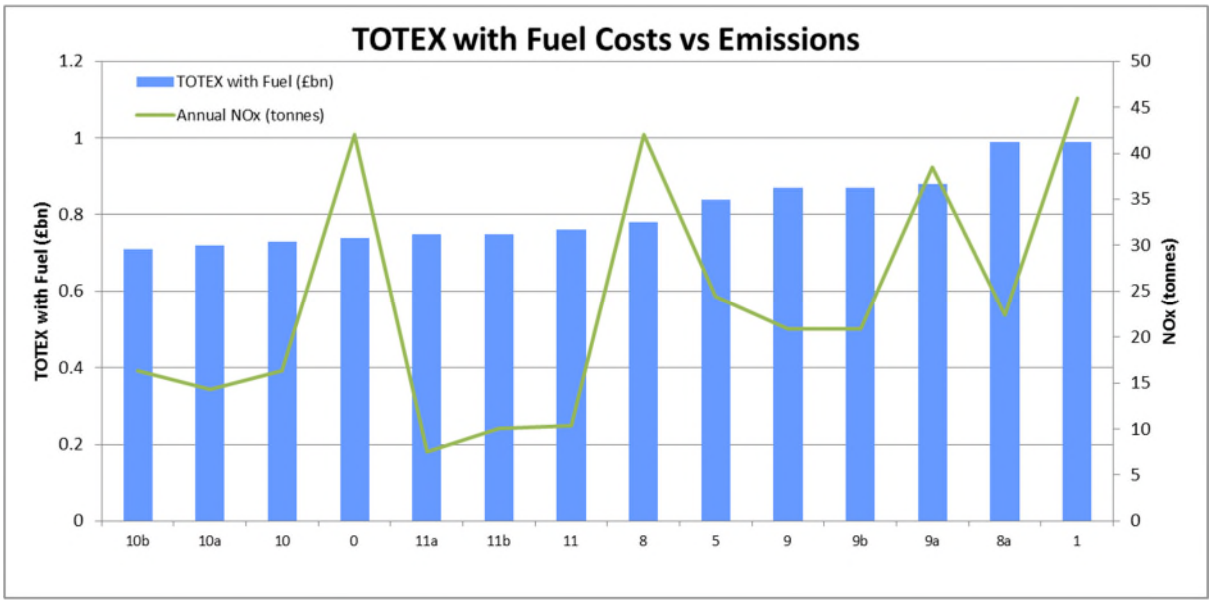


Figure 15: TOTEX with fuel costs vs emissions

The counterfactual (Option 0), Option 8, 8a and 12 all have significantly higher NOx emissions than the other options which is not favourable under the requirements of IPPC. It is noticeable that Options 9a, 9b and 9c were not favourable options using this prescriptive modelling technique (position 9 and lower out of 14), although they were more highly ranked options under the CBA. Option 11 is more strongly favoured. This can be explained by the more complex risk calculations in the prescriptive tool. In general, the option 9 variants, with fewer units overall, have a much higher risk of simultaneous asset failure (as shown in the chart below), with financial penalties associated with end of day shortfall. Although the Option 11s have higher capital and operational costs, this is offset by higher resilience to risk of multiple asset failure.

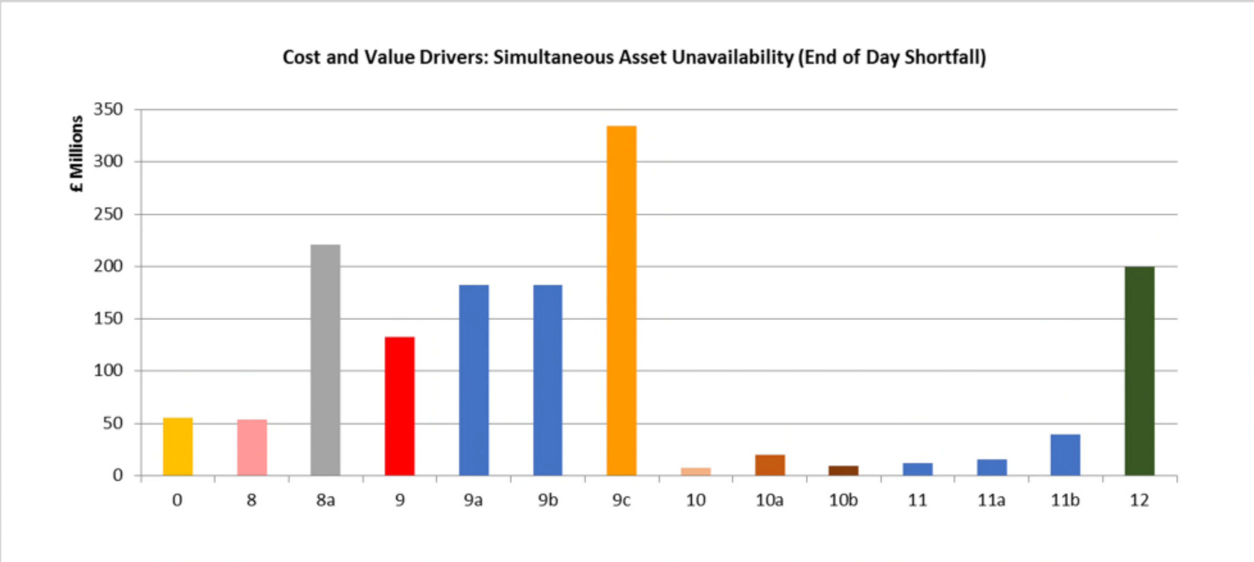


Figure 16: Simultaneous Asset Unavailability

Option 8a with investment in one Avon on Plant 1, ranked less highly in the prescriptive model, than the CBA due to the 'plant balance' and risk of simultaneous asset unavailability. The balance of capability between Plants 1 and 2 is a key operational consideration and whilst the value of this operational aspect is not calculated within the CBA, it is captured within the prescriptive model. Uneven capability between the two plants could result in insufficient back-up to the electric drives should the more capable of either Plant 1 or 2 be on outage. Under Option 8a, the capability is heavily weighted towards Plant 1. The prescriptive model analyses the impact of multiple failure types; simultaneous asset unavailability, single asset unavailability and trip impacts. But specifically the model can derive the financial consequences of the risk of asset failure of one plant, as shown on the chart below. Eight options are vulnerable to this type of asset failure - losing one single plant, with options 8a and all the options 9 showing the highest financial risk.

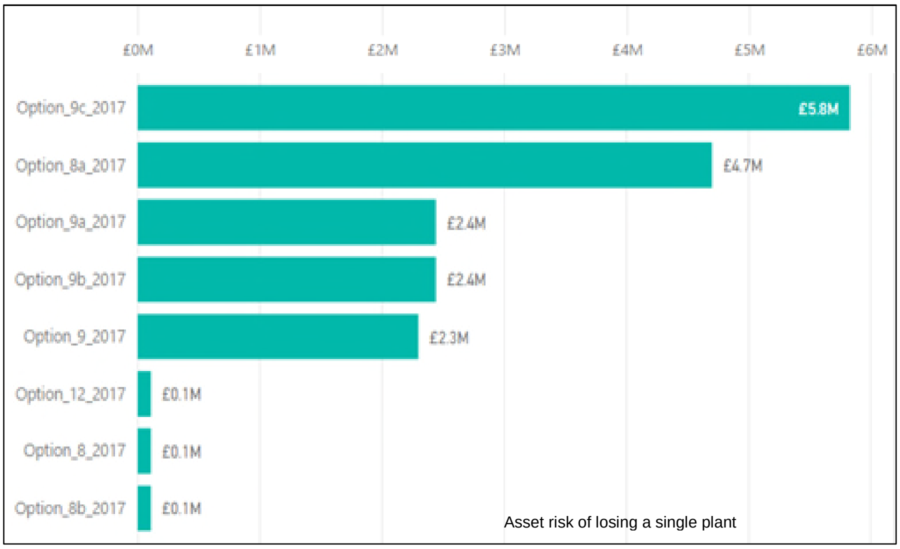


Figure 17: Asset failure risk

In considering all the cost and value drivers for the top five options under the prescriptive model in more detail, although the total investment costs, comprising investment in new assets, asset health and decommissioning costs, for Option 0 are the lowest (£152m), the costs associated with unavailability are significantly higher than under any other option.

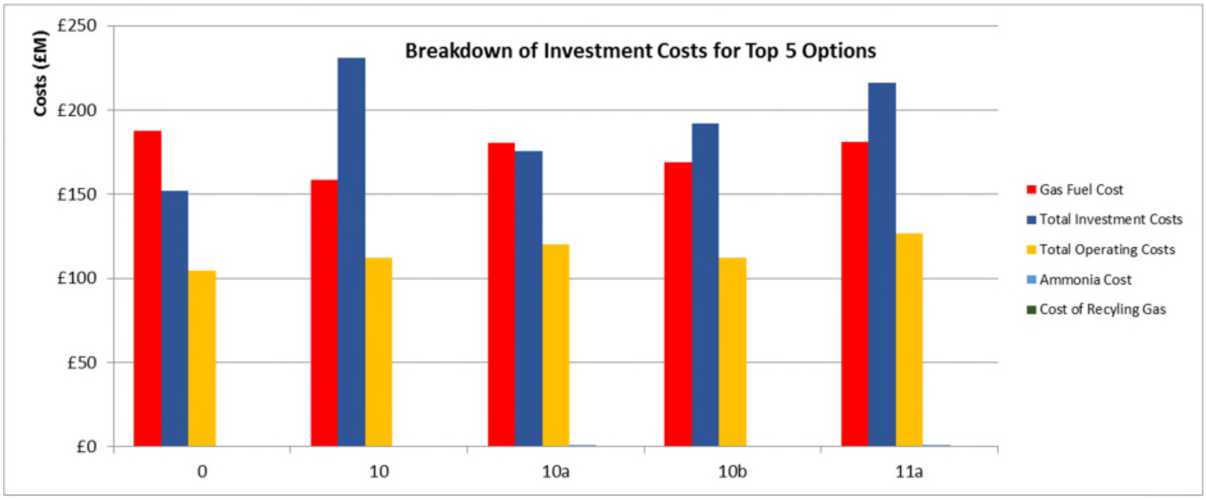
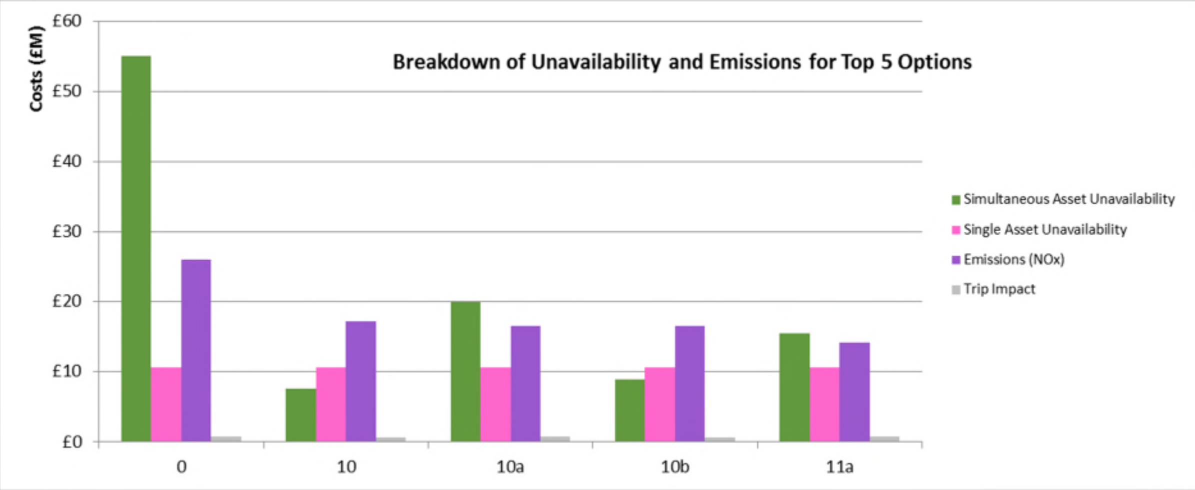


Figure 18: Cost breakdown



Note: Due to scale, electricity costs are not included in the charts above. These costs are very similar across all options, ranging from £415m – £419m

Figure 19: Unavailability and emissions breakdown

Total investment costs are lower under Options 10a and 10b (£176m and £192m respectively), than under Option 10 (which is a greenfield option, £216m). Electricity costs to run the VSD units remain fairly consistent at around £415- £419m across all options. Total operating costs are higher for the higher capability options – Option 11, and also the options including SCR, whereby more regular maintenance overhauls are required. Gas fuel costs are lowest under Options 10 and 10b; both options have new gas units, which have a higher efficiency compared to the SCR options. Comparing the aggregate cost of all investment, operational and unavailability variables across the five options, 10a and 10b have the lowest TOTEX, as per Figure 15.

Emissions: NOx and CO

The prescriptive analytics tool calculates the NOx and CO levels for each of the options. From the chart below it is possible to see emissions impact of each of the options considered. Options 8 and 9 with small units (both new and SCR) show higher levels of NOx and CO. Option 11 with a combination of large and small units shows the lowest levels of NOx. Option 10 sits in a middle rank position. Across all options where a new unit is installed rather than catalytic abatement emissions are higher. This is because the emissions abatement technology will reduce emissions to a value lower than what can be achieved by a compliant new unit.

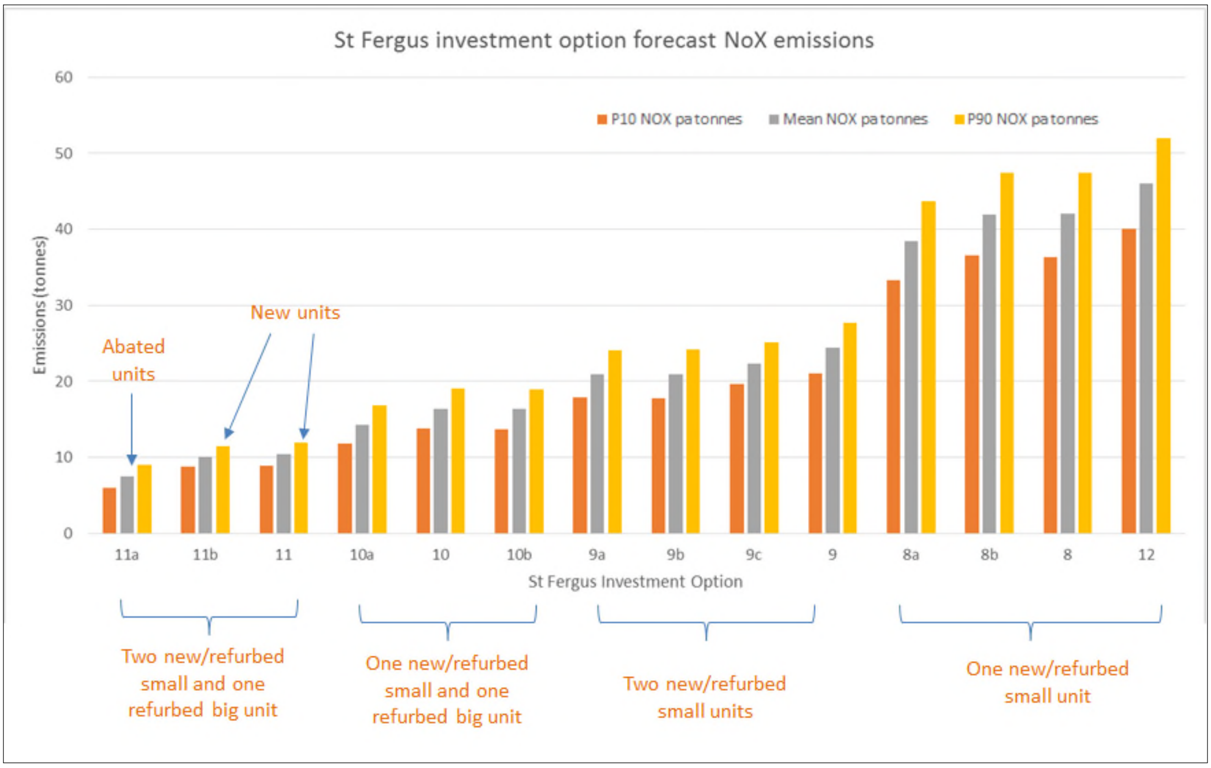


Figure 20: Forecast NOx

Stress Tests

A number of stress tests were designed to examine the consequences of changing key inputs within the prescriptive model. In particular the stress tests considered increasing capital expenditure; even with 90% higher capex, option 10b and 10a remain second and third in the ranking position. Increasing the costs or the emissions associated with SCR technology does not alter the ranking of options 10b and 10a. Changing the model's assumptions around asset failure and the risk of liabilities also does not alter the ranking of options 10b and 10a. These limited changes in position of the top five options provide reassurance around the robustness of the options assessment.

Position Ranking	Base Case	All options 90% higher Capex	SCR Capex plus 10%	Failure rate frequency increased by 90%	Consequence of asset failure increased by 90%	SCR emissions plus 100%	Low Flow Supply from NSMP
1	Option_10b	Option_0	Option_10b	Option_10b	Option_10b	Option_10b	Option_0
2	Option_10a	Option_10b	Option_10a	Option_10	Option_10	Option_10a	Option_10b
3	Option_10	Option_10a	Option_0	Option_11a	Option_10a	Option_10	Option_10a
4	Option_0	Option_10	Option_10	Option_10a	Option_11a	Option_0	Option_10
5	Option_11a	Option_8	Option_11a	Option_11	Option_11	Option_11a	Option_11b
		[Option_11a = 6]		[Option_0 = 6]	[Option_0 = 6]		

Table 8: Option ranking of sensitivities

Stakeholder Engagement

A comprehensive programme of stakeholder engagement has been undertaken since 2015. Most recently in January and February 2018 there were two presentations at the Transmission Working Group, where we shared our analysis and responded to questions from stakeholders.

A formal consultation was held between 14th March 2018 and 13th April 2018. There were several responses relevant to St Fergus; some respondents noted the wide range given for the costs of new compressors and emissions abatement, and indicated a preference for new units if the whole life costs of each option are very close. This view was also supported by informal feedback from Oil and Gas UK. One respondent noted that the cost to producers of constraints at St Fergus was likely to exceed the UNC costs that we had assumed. We asked respondents whether they agreed with our specific proposals for each compressor site. Two respondents expressed an opinion about our proposals at St Fergus; both stressed the importance of maintaining compression capability at this important location, but suggested that the wide cost ranges made it difficult to assess whether these were the best options.

Optionality (Qualitative)

Looking out to the long term impacts of the IED decisions, there are some permanent consequences associated with certain options. The main impact is the loss of capability provided by the RB211s post 2023 for options 8a, 9a, 9b and 9c. Options 10a /10b however retain the RB211 capability, and also retain future options on additional Avon units. This is captured in a non-quantitative way in the chart below:

Option	Total Capability	Retain RB211	Future Capability through existing Avon	Optionality Position Ranking
Option 8a	VSD + 75	No	Yes (5 units)	
Option 9a	VSD + 75	No	Yes (5 units)	
Option 9b	VSD + 75	No	Yes (5 units)	
Option 9c	VSD + 60	No	Yes (4 units)	
Option 10a	VSD + 105	Yes	Yes (5 units)	2
Option 10b	VSD + 120	Yes	Yes (5 units)	1
Option 11a	VSD + 90	Yes	Yes (4 units)	=3
Option 11b	VSD + 90	Yes	Yes (4 units)	=3

Table 9: Optionality

The prescriptive analysis models operating hours as shown on the chart below. This shows Avon units operating in the region of 200-400 hours per year in a central case scenario. 400 hours per year would be approaching very close to the rolling 500 hours derogation limit and from an operational perspective could result in unacceptable risk. Looking forward to the decision around MCP and variability in the long term flow levels through the terminal, keeping options open for the existing Avon units is strategically valuable.

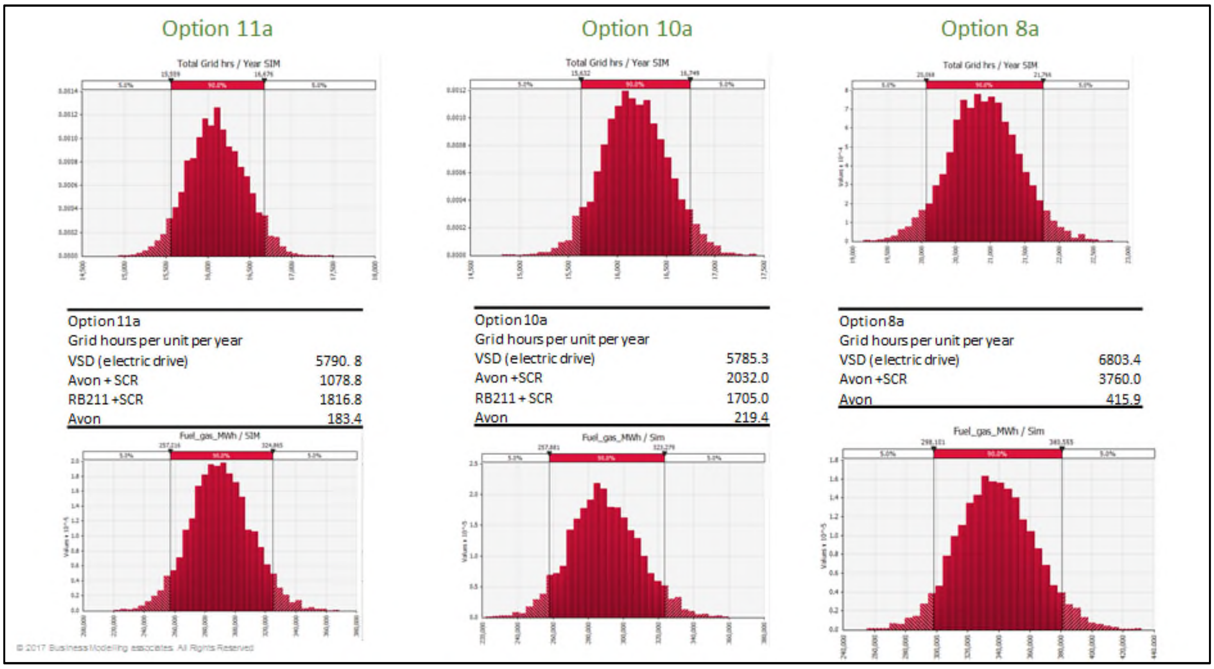


Figure 21: Operating hours

A summary of the top options under each technique and scenario is presented in the table below:

	Core		Sensitivities					
OPTION Place	NPV	Prescriptive Model	Low Availability	Low Flows	Prescriptive Model Stress Tests	Emissions	Plant Balance	Optionality
1	Option 10b	Option 10b	Option 11b	Option 8a	Option 10b	Options 11	=10b	10b
2	Option 10a	Option 10a	Option 11a	Option 10b	Option 10a	Options 1, 2, 5	=10a	10a
3	Option 9b	Option 10	Option 10b	Option 10a	Option 10	Options 10	=10	=11a
4	Option 9a	Option 0	Option 10a	Option 9b	Option 0	Options 9	=11b	=11b
5	Option 11c	Option 11a	Option 10	Option 9a	Option 11a	Options 8, 0	=11a	

Table 10: Recommendation

Based on the CBA and non-monetised aspects, the recommendation at Stage 4.1 was to take forward options 10a and 10b to Stage 4.2, FEED feasibility stage. These options, which provide emission compliant capability comparable to one Avon and one RB211 unit by December 2023, had the highest overall NPV under the CBA, and the underlying risk and cost analysis from the prescriptive tool favoured these two options. 10a and 10b both combine low capital cost and low risk together with flexibility to perform well under key sensitivities and produce lower emissions than the counterfactual.

9. NDP Stage 4.2: Key Activities

During Stage 4.2 a 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 short-listed Options 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 the extensive on-going asset health programme at St Fergus
- BAT discussions with the Environment Agencies; which clarified that any solution at St Fergus 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 and Avons at the St Fergus site typically have mechanical efficiencies of ca. 32%. For an LCP 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 LCP 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 combined 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:

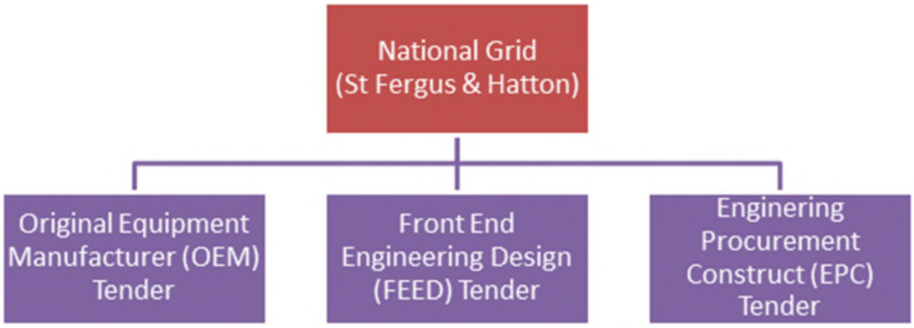
1. **Procurement Strategy Overview**
   This section documents the extensive internal analysis and market engagement that was undertaken to define a procurement strategy that will result in a demonstrable value for money solution.

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:

Modularity

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 provide significant whole life benefits over alternative procurement strategies.

In parallel to the development of the procurement strategy, we 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 the National Grid 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 tender returns from the initial request for proposal requirements and discussions with OEMs, an additional lot was created to ensure that a full range of solutions could be considered:

- Lot 1A (original): two new unit or catalytic abatement proposals requested to meet specified process duty points based on process duty currently covered by an Avon and an RB211 unit
- Lot 1B – single new unit or catalytic abatement proposals requested to meet specified process duty points based on process duty currently covered by a single Avon unit

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.

FEED Tender

The 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 (the Environment Agency (EA), Scottish Environment Protection Agency (SEPA) or Natural Resources Wales (NRW)) 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 Original Equipment Manufacturers (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.

St Fergus BAT Assessment

All tendered solutions for the two lots were compliant bids.

The chart below shows the overall BAT assessment for both Lots.

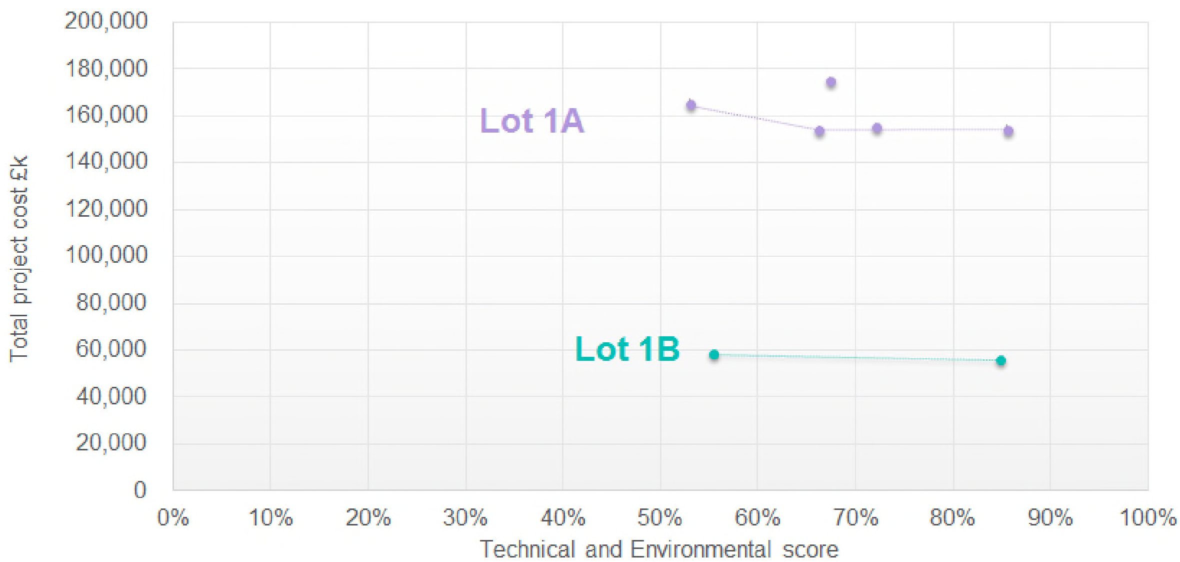


Figure 22: BAT assessment

The BAT options were then subject to a CBA, see next section, to determine the solution which represents the greatest consumer value.

The output of the BAT assessment was presented to SEPA on the 9 May 2019. SEPA in principle supported the conclusion that a two unit solution represented BAT. However, as BAT is assessed at a whole site level they had concerns whether a single unit solution was candidate BAT and requested further information following the conclusion of the CBA analysis.

12. Updated CBA

Based on the outcome of the BAT assessment, the candidate BAT options were evaluated within an updated CBA. A single unit Zeta option was defined as the counterfactual with two variants. The first variant did not include any further investments with all remaining Avon units entered into the 500 hour derogation with the introduction of MCP in 2030. The second variant, Option 10d, included investing and commissioning a second larger unit (consistent with the Delta option) before 2030. The table below summarises the three options assessed.

Option	Description
0	Zeta - Install one new small unit by December 2023. Decommission 2 * RB211. Place all Avons on 500 hour derogation post 2030. **(counterfactual)**
10c	Delta - Install two units by December 2023. Decommission 2 * RB211. Place all Avons on 500 hour derogation post 2030.
10d	Theta - Install one new small unit by December 2023. Decommission 2 * RB211. Install one large unit by 2030. Place all Avons on 500 hour derogation post 2030.

Table 11: CBA Options

The chart below shows the NPV of three options. Based on this Option 10c is favoured.

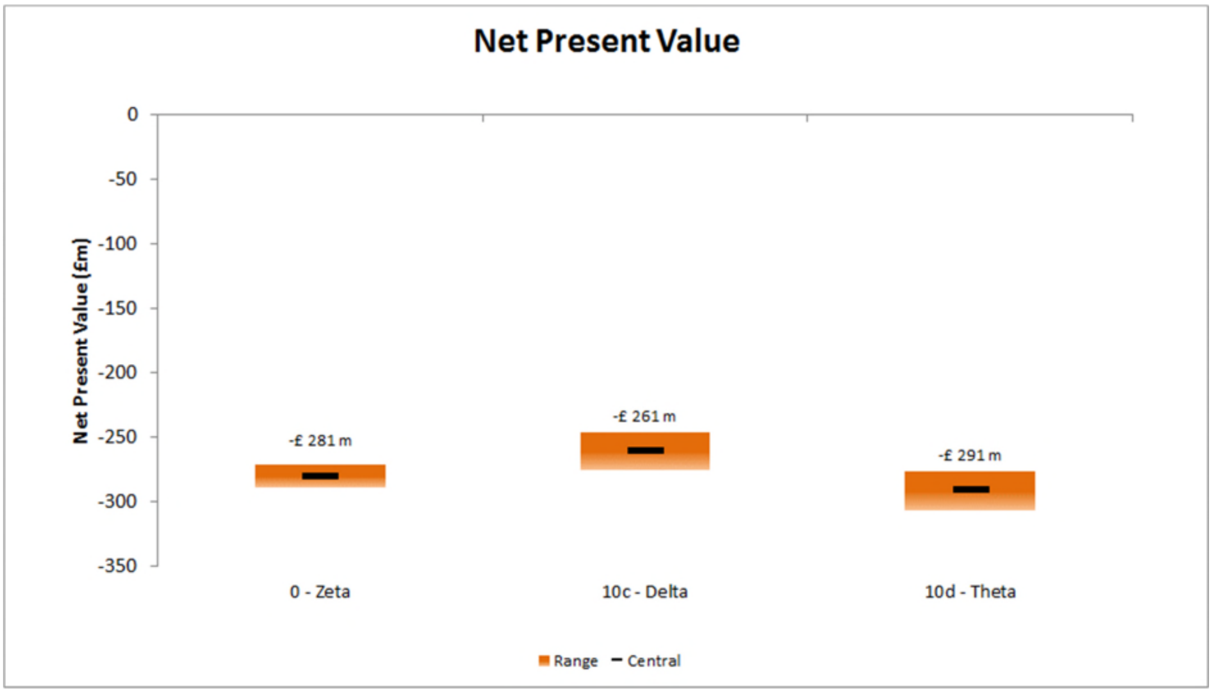


Figure 23: NPV of CBA Options

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 new compression capability post 2023 results in high costs for asset health, liabilities and fuel. Whereas the additional investment and fuel costs compared to Option 10c incurred through waiting to commission the second unit are not outweighed by the associated benefits.

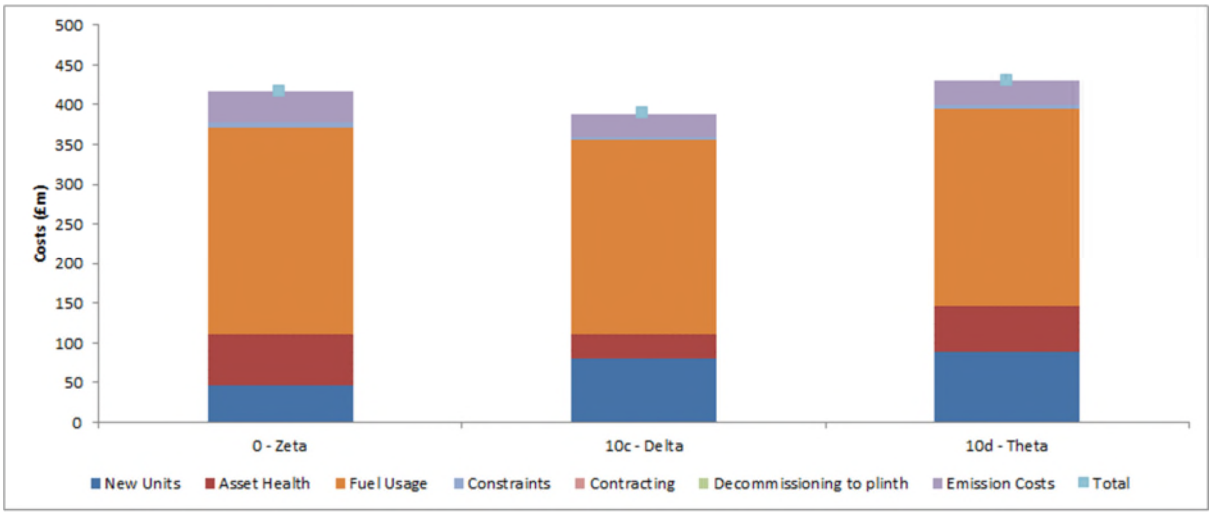


Figure 24: Cost breakdown

In addition to the financial analysis the figure below shows the relative NOx performance of each of the options. It is evident that Option 10c provides a noticeable improvement in NOx emissions, to the benefit of the local environment. In discussions with SEPA, they had questioned whether a single unit would represent BAT for the site overall. Based on the potential NOx emissions this concern is borne out.

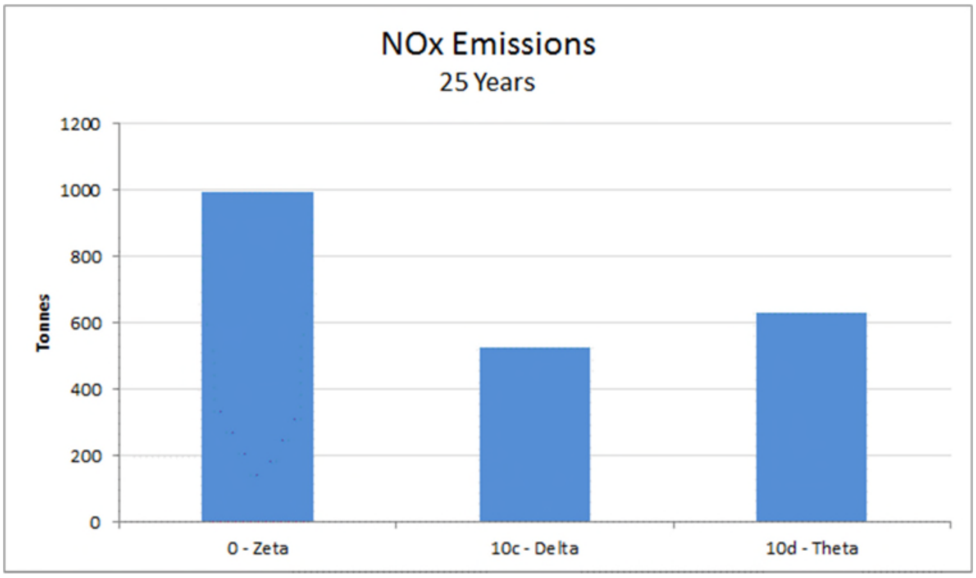


Figure 25: Life time NOx emissions

As mentioned previously our CBA tool factors in uncertainty on various parameters, for example capital costs. However in addition we have undertaken two sensitivities, firstly we have tested the results against the Two Degrees FES scenario and secondly against a lower VSD unit availability (reflecting issues that have been experienced at both St Fergus and Hatton) against the currently modelled 78%. 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	-281	-262	-295
10c	-261	-247	-266
10d	-291	-278	-299

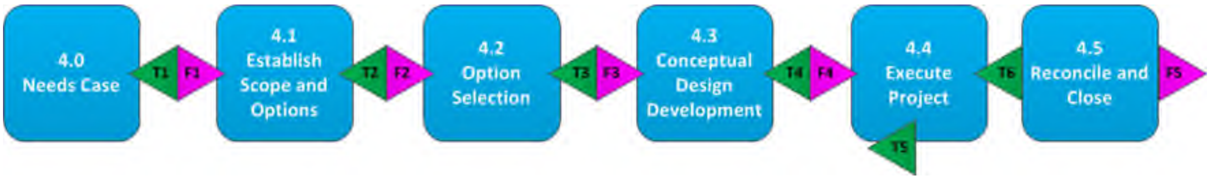
Table 12: Option NPVs Sensitivity Analysis

It can be seen from the sensitivity analysis, that the outcome does not change even if there are lower flows through the sub-terminal, as depicted by the Two Degrees scenario. It should be noted that as St Fergus compression operates 24 hours per day and 365 days per year the impact of lower flow is a change in the running order of the machines, generally the lower flows require more hours of legacy Avon unit running. In terms of unit availability, it can be seen that if the availability of the VSDs reduce, the relative benefits of Option 10c over the counterfactual increase.

The conclusion of the CBA assessment is to progress with Option 10c - Delta, which offers significant financial benefit under our core central scenario compared to the two other options, in addition to the environmental benefits.

13. Governance

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



Pre-Works Sanction (F1) – August 2016

The first sanction (F1) for St Fergus 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 Process Duty Specification Points. The P50 cost for this stage was approved at £0.125m with the F2 sanction planned for October 2016.

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

The F1 for St Fergus 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 £0.222m with the F2 sanction planned for April 2017.

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

The F1 for St Fergus compressor station was re-sanctioned in September 2017. 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, and investigation of flow forecasts. The P50 cost for this stage was approved at £0.830m with the F2 sanction planned for January 2018.

Full Sanction (F2) – December 2017

The F2 for St Fergus compressor station was sanctioned in December 2017. 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 £1.499m with the F3 sanction planned for January 2019.

Full Sanction (F3) – May 2019

The F3 for St Fergus 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

Ofgem's approval of this needs case. The P50 cost for this stage was approved at £38.1m with the F4 sanction planned for December 2020.

14. Finance

The cost of the recommended solution at St Fergus is forecast to be £80.4m, 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
Delta option	0.5	0.6	14.6	9.3	21.4	18.4	14.6	1.0	80.4
Decommission RB211		0.0	0.0	0.0	0.0	0.7	1.7	0.0	2.5

Table 13: Option cost summary

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 the two unit Delta option by 31 December 2023. In addition we will decommission the two existing RB211s on the site.

The proposed solution will deliver an output of IED (LCP and IPPC) emissions compliance at St Fergus.

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

Appendix 1: Glossary

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

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.

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

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

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

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.

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

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.

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.

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.

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

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

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

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

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

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

Large Combustion Plant (LCP) = an EU directive to reduce emissions from combustion plants with a 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.

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

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

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

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

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

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.

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

Operations Margin (OM) Contracts = Operating Margins (OM) relate to how we use gas to manage short-term impacts of operational stresses (e.g. supply loss) where the market response is not sufficient, or during a gas system emergency. OM gas can be provided under contract by 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.

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.

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.