Consultation

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St Fergus Compressor Emissions – Final Preferred Option

Subject	Details
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We are consulting on our Final Preferred Option for investment at the St Fergus Gas Terminal to ensure compliance with the Medium Combustion Plant Directive. We are seeking views from all interested stakeholders in particular, network companies, gas shippers, consumer groups, environmental groups, and the public. This document sets out our proposed Final Preferred Option and seeks responses to several specific questions. The responses we receive will be considered before our final decision is issued.

We want our consultations process to be transparent. So, we intend publishing the non-confidential responses received on our website at Ofgem.gov.uk/consultations along-side our decision. If you want your response – in whole or in part – to be considered confidential, please tell us and explain why. Please clearly mark the parts of your response that you consider to be confidential, and if possible, put the confidential material in separate appendices to your response.

Contents

Executive summary

St Fergus Compressor Emissions - Final Preferred Option

In our RIIO-T2 Final Determinations we accepted the 'needs case' for investment at the St Fergus Gas Terminal to ensure compliance with the Medium Combustion Plant Directive. The Directive requires that by 1 January 2030 the Nitrogen Oxide (NOx) emissions of all gas turbines with a net thermal input of between 1MW and 50MW, do not exceed 150mg/m^3.

However, given the level of uncertainty at the time with respect to both the 'preferred option' and the level of funding required, we decided that this project, alongside similar Compressor Emissions projects, should be funded through our Gas Transmission Project Assessment Process. This two stage process is set out in Special Condition 3.11 Compressor Emissions Re-opener and Price Control Deliverable.

At Final Determinations we provided £20.08m (2018/19 prices) of baseline funding in the form of a Price Control Deliverable for the St Fergus Compressor Emissions project. The required deliverables were a Final Option Selection Report in January 2023 followed by a Re-opener application seeking a funding Direction in June 2025. The Final Option Selection Report must contain a Final Preferred Option along with supporting evidence necessary for the Authority to either accept the Final Preferred Option or approve an alternative as the Final Preferred Option, reject the Final Preferred Option on the basis that no further work should go ahead or ask for more information. The Re-opener application must be based on the Final Preferred Option approved by the Authority.

In compliance with Special Condition 3.11, National Gas Transmission submitted a Final Option Selection Report in January 2023. Nineteen options including the counterfactual 'do nothing' were shortlisted with the Final Preferred Option being identified as the installation of three new 15MW gas turbine driven compressor units and the retention of one existing Avon unit modified with Dry Low Emissions (DLE) technology. All the new units to be installed on existing plinths. The Final Preferred Option was identified using various decision making tools including Cost Benefit Analysis and Best Available Technology assessment.

Having considered the evidence presented in the Final Option Selection Report we propose accepting the Final Preferred Options identified by National Gas Transmission. Our proposed Final Preferred Option includes the installation of three new gas turbine driven compressor units of approximately 15MW which will be commissioned by 2030. The new units will be

installed in existing Plant 1 and Plant 2 locations. In addition, one of the existing Avon units will be retained with significant asset health investment to improve unit availability. There is no preference as to which of the existing Avon units will be retained. The option contains a cost for decommissioning any remaining Avon unit, which will be subject to the detailed delivery plan and commissioning requirements.

Next Steps

We welcome responses to our consultation, in particular, to the specific questions we have included in Chapters 4 and 5. Please send your response to: graham.craig@ofgem.gov.uk by 28 July 2023. We expect to publish our decision on the Final Preferred Option no later than 3 November 2023.

1. Introduction

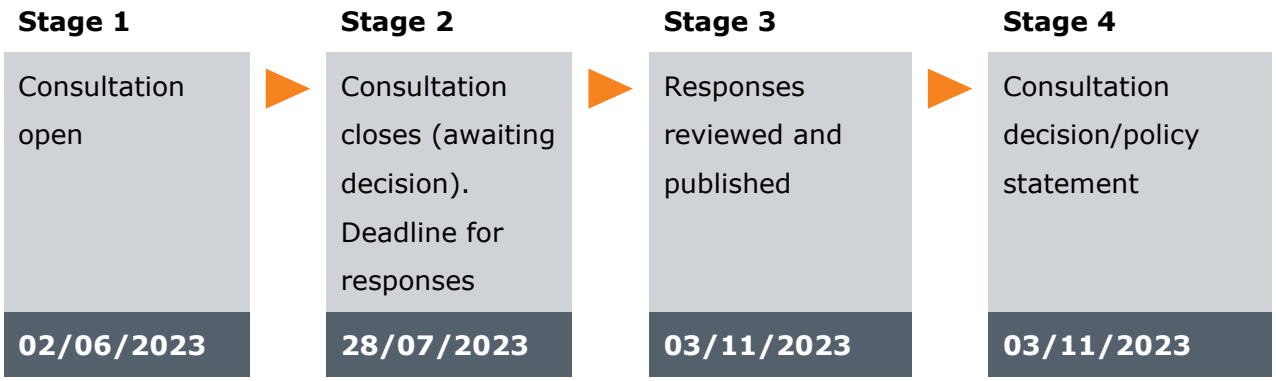
What are we consulting on?

1.1. This consultation sets out our minded to position on the Final Preferred Option identified by National Gas Transmission in the St Fergus Compressor Emissions Final Option Selection Report.

1.2. This consultation sets out our assessment of the evidence presented in the Final Option Selection Report and the various factors we have considered when reaching our minded to position. We are seeking views from interested stakeholders on our assessment of the evidence and our minded to position as to the Final Preferred Option.

Consultation Process

1.3. Figure 1 shows the stages of this consultation process:



How to respond

1.4. We want to hear from anyone interested in this consultation. Please send your response to the person or team named on this document's front page. We have asked for your feedback in each of the questions throughout. Please respond to each one as fully as you can. We will publish non-confidential responses on our website at www.ofgem.gov.uk/consultations.

Your response, data and confidentiality

1.5. You can ask us to keep your response, or parts of your response, confidential. We will respect this, subject to obligations to disclose information, for example, under the Freedom of Information Act 2000, the Environmental Information Regulations 2004, statutory directions,

court orders, government regulations or where you give us explicit permission to disclose. If you do want us to keep your response confidential, please clearly mark this on your response and explain why.

1.6. If you wish us to keep part of your response confidential, please clearly mark those parts of your response that you *do* wish to be kept confidential and those that you *do not* wish to be kept confidential. Please put the confidential material in a separate appendix to your response. If necessary, we will contact you to discuss which parts of the information in your response should be kept confidential, and which can be published. We might ask for reasons why.

1.7. If the information you give in your response contains personal data under the General Data Protection Regulation (Regulation (EU) 2016/679) as retained in domestic law following the UK's withdrawal from the European Union ("UK GDPR"), the Gas and Electricity Markets Authority will be the data controller for the purposes of GDPR. Ofgem uses the information in responses in performing its statutory functions and in accordance with section 105 of the Utilities Act 2000. Please refer to our Privacy Notice on consultations, see Appendix 4.

1.8. If you wish to respond confidentially, we will keep your response itself confidential, but we will publish the number (but not the names) of confidential responses we receive. We will not link responses to respondents if we publish a summary of responses, and we will evaluate each response on its own merits without undermining your right to confidentiality.

General feedback

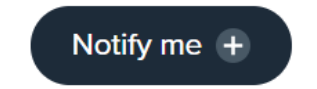
1.9. We believe that consultation is at the heart of good policy development. We welcome any comments about how we have run this consultation. We would also like to get your answers to these questions:

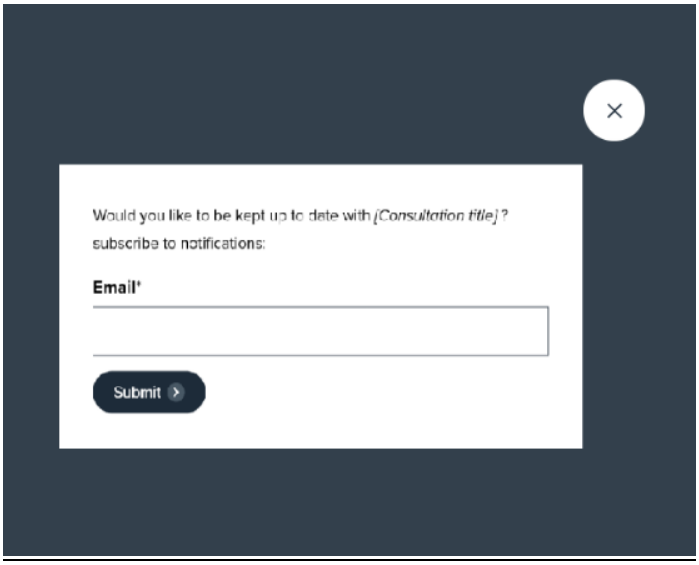
1. Do you have any comments about the overall process of this consultation?
2. Do you have any comments about its tone and content?
3. Was it easy to read and understand? Or could it have been better written?
4. Were its conclusions balanced?
5. Did it make reasoned recommendations for improvement?
6. Any further comments?

Please send any general feedback comments to stakeholders@ofgem.gov.uk

How to track the progress of the consultation

You can track the progress of a consultation from upcoming to decision status using the 'notify me' function on a consultation page when published on our website. Ofgem.gov.uk/consultations.





Once subscribed to the notifications for a particular consultation, you will receive an email to notify you when it has changed status. Our consultation stages are:

Upcoming ▶	Open ▶	Closed (Awaiting decision) ▶	Closed (With decision)

2. Compressor emissions Re-opener and Price Control Deliverable mechanism

Section summary

This Chapter gives an overview of the RIIO-2 Re-opener mechanism and our assessment process.

Overview of the RIIO-2 Re-Opener mechanism

2.1. The gas transmission network in Great Britain is owned and operated by National Gas Transmission. Economic regulation of the network follows the RIIO (Revenue = Incentives + Innovation + Outputs) price control framework. The current RIIO-T2 price control period will last five years from 1 April 2021 to 31 March 2026. Prior to commencement of the price control period, we set out in our Final Determinations[1] our policy on the economic regulation of the network during the period. These policy decisions were given effect by new Special Conditions in Part C of the National Gas Transmission gas transporter licence, which came into force on 1 April 2021.

2.2. In our RIIO-T2 Final Determinations we accepted the 'needs case' for investment at several sites on the network, including St Fergus Gas Terminal, to ensure compliance with the Medium Combustion Plant Directive. The Directive requires that by 1 January 2030 the Nitrogen Oxide (NOx) emissions of all gas turbines with a net thermal input of between 1MW and 50MW, do not exceed 150mg/m^3.

2.3. However, given the level of uncertainty at the time with respect to both the 'preferred option' and the level of funding required, we decided that this and other similar Compressor Emissions projects, should be funded through our Gas Transmission Project Assessment Process. This two stage process is set out in Special Condition 3.11 Compressor Emissions Re-opener and Price Control Deliverable.

[1] Final_Determinations_-_NGGT_Annex_Revised (10).pdf

2.4. At Final Determinations we provided £20.08m (2018/19 prices) of baseline funding in the form of a Price Control Deliverable for the St Fergus Compressor Emissions project. The required deliverables were a Final Option Selection Report in January 2023 followed by a Re-opener application seeking a funding Direction in June 2025. The Final Option Selection Report must contain a Final Preferred Option along with supporting evidence necessary for the Authority to either accept the Final Preferred Option, or approve an alternative as the Final Preferred Option, reject the Final Preferred Option on the basis that no further work should go ahead or ask for more information. The Re-opener application must be based on the Final Preferred Option approved by the Authority.

2.5. Special Condition 9.4 requires that all Re-opener applications must be prepared in accordance with our Re-opener Guidance and Application Requirements Document.[2] This includes guidance on the preparation of Engineering Justification Papers and Cost Benefit Analysis which are the key tools we expect to be used in the identification of a 'preferred option'.

2.6. In addition, we have published an Indicative Re-opener Application Assessment Process.[3] This working document sets out the assessment process we follow when reaching our RIIO-2 Re-opener decisions.

2.7. In compliance with Special Condition 3.11, in January 2023, National Gas Transmission submitted a Final Option Selection Report for investment at St Fergus Gas Terminal to ensure compliance with the Medium Combustion Plant Directive. In accordance with our indicative application assessment process, having determined that a valid submission had been submitted, we proceeded to a detailed assessment of the Final Option Selection Report and the Final Preferred Option. We made our determination on the validity of National Gas Transmission's submission because it was:[4]

- Compliant with the requirements set out in Special Condition 3.11.8;
- Compliant with the requirement set out in Special Condition 9.4.3 to prepare the submission in accordance with our Re-opener Guidance and Application Requirements Document;

[2] RIIO2 Re-opener Guidance and Application Requirements Version 2.0 | Ofgem
[3] RIIO-2 indicative Re-opener application assessment process: working document | Ofgem
[4] St Fergus Compressor Emissions FOSR submission in January 2023 - Appendix P – Mapping of Ofgem Requirements

- Compliant with the requirement set out in our Price Control Deliverable Reporting Requirements and Methodology Document (Appendix 5);[5]
- Published on the National Gas Transmission website within five working days of submission with any redactions in line with our Re-opener Guidance and Application Requirements Document;[6]
- Accompanied by a letter of assurance that met the requirements set out in our Re-opener Guidance and Application Requirements Document.[7]

[5] Price Control Deliverable Reporting Requirements and Methodology Document | Ofgem
[6] Our RIIO-2 re-opener applications (2021-2026) | National Gas Transmission
[7] St Fergus Compressor Emissions FOSR submission in January 2023 - Appendix O Assurance Letter

3. St Fergus Compressor Emissions Final Option Selection Report

Section summary

This chapter summarises the option selection process set out in the Final Option Selection Report submitted by National Gas Transmission.

Context

3.1. The Medium Combustion Plant Directive requires that by 1 January 2030, any gas turbines with a net thermal input between 1MW and 50MW must not exceed a Nitrogen Oxide (NOx) emissions limit of 150mg/m³.

3.2. St Fergus Gas Terminal is one of the most strategically important sites on the National Transmission System, with the combined flows through its three sub-terminals regularly accounting for over 25% of the UK's gas supply. Gas from the UK Continental Shelf and Norway enters the site through the three sub-terminals owned and operated by Ancala, Shell and North Sea Midstream Partners. Gas from the UK Continental Shelf is a by-product of oil production, consequently constraints at St Fergus Gas Terminal will have a negative impact on oil production in the North Sea.

3.3. Continuous compression is required at the St Fergus Gas Terminal for one of the three sub terminals which gives it the highest level of utilisation on the National Transmission System. All Future Energy Scenarios indicated that the St Fergus Gas Terminal will continue to be the principal source of gas entering the National Transmission System. The Government has confirmed its commitment to continued exploitation of indigenous oil and gas production. The St Fergus Gas Terminal and the associated National Gas Transmission compressors are expected to remain a key component of the UK's long term energy security.

3.4. By 2030 the St Fergus Gas Terminal will operate four Avon gas turbine driven compressor units that are not compliant with the Medium Combustion Plant Directive. The terminal will also have two electric drive compressors. A decision is required as to how best to provide the required level of compression post 1 January 2030.

3.5. The Final Option Selection Report provides a summary of all the work performed to date to evaluate, cost, analyse and justify the full suite of feasible options available to achieve compliance with the Directive while ensuring the right levels of network capability and availability are maintained for network users. The Final Option Selection Report aligns with National Gas Transmission's Compressor Emissions Asset Management Plan (CE-AMP).

St Fergus Gas Terminal[8]

3.6. Gas from the North Sea enters the St Fergus Gas Terminal through three separate sub-terminals owned and operated by Ancala, Shell and North Sea Midstream Partners. Gas supplied through the Ancala and Shell sub-terminals enters the National Transmission System without further compression being required.

3.7. Gas supplied through the North Sea Midstream Partners sub-terminal requires compression (from 40barg to between 60 and 65barg) before entry into the National Transmission System. This unique arrangement is set out in the Network Entry Agreement between National Gas Transmission and the owners of the North Sea Midstream Partners sub-terminal. Shippers delivering gas at the sub-terminal are required to pay the St Fergus Compression Charge to recover the additional variable costs (compressor fuel and carbon emission credits) incurred by National Gas Transmission in providing the compression service. But it does not recover any capital, asset health or site operation costs incurred in providing the compression and associated services (scrubbing, metering and cooling[9]).

3.8. Compressor assets at the St Fergus Gas Terminal are configured into three separate operating plants. Plant 3 comprising two electric Variable Speed Drive compressor units was commissioned in 2015 and provides baseload compression. The original Plants 1 and 2, comprising three Avon and one RB211 gas turbine driven compressor units provide support to Plant 3. The existing RB211 unit will cease operations on 31 December 2023 in compliance with the Large Combustion Plant Directive. This is due to be replaced by the re-lifing one of two Avon units connected nbu not currently operational. All gas supplied through the North

[8] St Fergus Compressor Emissions FOSR submission in January 2023 - Appendix A Site Strategy
[9] National Gas Transmission submitted an Asset Health Funding request to upgrade this equipment with a value of £44.6m

Sea Midstream Partners sub-terminal is scrubbed, metered and cooled following compression by equipment attached to Plants 1 and 2.

3.9. The maximum end of day flow is 75 mscm/d, as defined in the Network Entry Agreement, though in recent years the highest flow rate measured is 60 mscm/d. Individual Avon compressor units can support a nominal flow of up to 15 mscm/d whilst a Variable Speed Drive (VSD) compressor can support flows of between 20 and 30 mscm/d. The Avon units perform two separate roles:

- Matching the level of compression available to the nominal flow rate through the North Sea Midstream Partners sub-terminal; and
- Providing back-up during periods of VSD outage.

3.10. Figure 1 below illustrates how the Avon and VSD compressor units can be utilised once the RB211 unit has ceased operating.

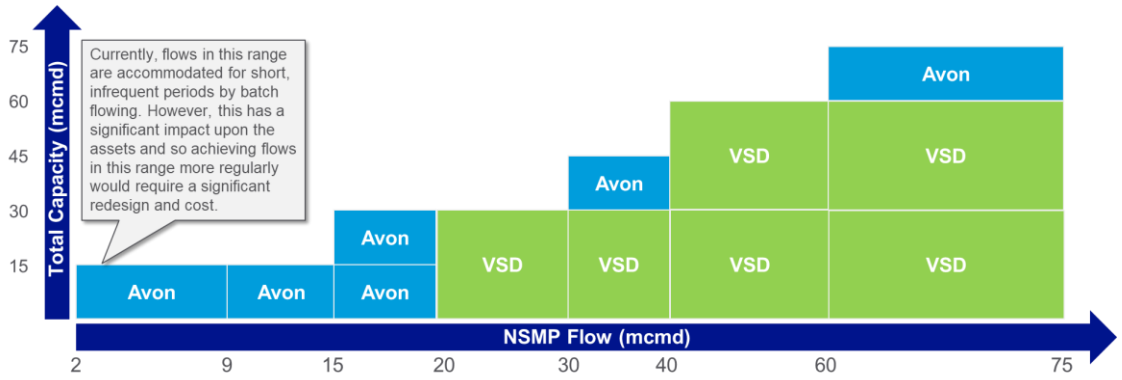


Figure 1 – St Fergus Gas Terminal Compressor Utilisation

Option Selection Process & Cost Benefit Analysis

3.11. National Gas Transmission considered a complete suite of solutions to enable the St Fergus Gas Terminal to comply with the Directive. The high-level options considered included:

- Doing nothing to reduce emissions from the non-compliant Avon units (counterfactual) with the units operated under the Emergency Use Derogation (EUD) i.e. limited to 500 run hours per year beyond 2030;

- Retrofitting of the non-compliant Avon units with emissions abatement technology, Control System Restricted Performance (CSRP) and Dry Low Emissions (DLE);[10]
- Replacement of the non-compliant Avon units with a new low-emission high efficiency gas turbine driven units.

3.12. Table 1 below summarises the shortlisted options considered in the Final Option Selection Report.

[10] St Fergus Compressor Emissions FOSR submission in January 2023 - CSRP Performance Testing Report, Power Avon DLE Test Report

Option	Description	Existing Avon	New 15 MW GT	New 23 MW GT	Plants 1 & 2 / Greenfield
0	Counterfactual -4 x Existing Avon on 500 hrs	4 X EUD			
1	(Brownfield) - 3 x new 15 mscmd GT's		3		
2	(Greenfield) - 3 x new 15 mscmd GT's		3		Greenfield
3	(Brownfield) 2 x new 23 mscmd GT's			2	
4	(Greenfield) 2 x new 23 mscmd GT's			2	Greenfield
5	(Brownfield) 2 x new 15 mscmd and 1 x new 23 mscmd GT's		2	1	
6	(Greenfield) 2 x new 15 mscmd and 1 x new 23 mscmd GT's		2	1	Greenfield
7	(Brownfield) 4 x new 15 mscmd GT's		4		
8	4 x Existing Avon 15 mscmd derated	4 x CSRP			
9	3 x Existing Avon 15 mscmd derated	3 x CSRP			
10	4 x Existing Avon 15 mscmd DLE	4 x DLE			
11	3 x Existing Avon 15 mscmd DLE	3 x DLE			
12	2 x new 15 mscmd GTs and 2 x Existing Avon 15 mscmd + DLE	2 X DLE	2		
13	1 x new 15 mscmd GTs and 3 x Existing Avon 15 mscmd + DLE	3 x DLE	1		
14	3 x new 15 mscmd GTs and 1 x Existing Avon 15 mscmd + DLE	1 x DLE	3		
15	(Brownfield) 1 x new 15 mscmd and 1 x new 23 mscmd GT's		1	1	
16	2 x new 15 mscmd GTs and 1 x Existing Avon 15 mscmd + DLE	1 x DLE	2		
17	1 x new 15 mscmd GTs and 2 x Existing Avon 15 mscmd + DLE	2 x DLE	1		
18	(Brownfield) 2 x new 15 mscmd GT's		2		

Table 1 – Individual site Options summary

3.13. Table 2 below provides a breakdown of the various costs that were included in the Cost Benefit Analysis.

Cost Comparison £m (2018-19 prices)		Non-FES	FES Related Opex	
		Capital, Asset Health, Decommissioning + Site Operation	Compressor Fuel + Carbon Emissions	Constraint Management
0	4 x Existing Avon on 500 hrs	89.95	246 - 318	937 - 2,294
1	(Brownfield) - 3 x new 15 mscmd GT's	195.71	520 - 840	14- 55
2	(Greenfield) - 3 x new 15 mscmd GT's	250.34	520 - 840	14 - 55
3	(Brownfield) 2 x new 23 mscmd GT's	153.46	232 - 703	1,763 - 2,434
4	(Greenfield) 2 x new 23 mscmd GT's	190.48	232 - 703	1,763 - 2,434
5	(Brownfield) 2 x new 15 mscmd and 1 x new 23 mscmd GT's	208.53	525 - 865	47 - 99
6	(Greenfield) 2 x new 15 mscmd and 1 x new 23 mscmd GT's	270.39	525 - 865	47 - 99
7	(Brownfield) 4 x new 15 mscmd GT's	251.41	520 - 840	3 - 20
8	4 x Existing Avon 15 mscmd derated	96.07	690 - 1,101	16 - 57
9	3 x Existing Avon 15 mscmd derated	75.98	690 - 1,101	61 - 188
10	4 x Existing Avon 15 mscmd DLE	120.71	690 - 1,101	31 - 96
11	3 x Existing Avon 15 mscmd DLE	94.48	690 - 1,101	100 - 283
12	2 x new 15 mscmd GTs and 2 x Existing Avon 15 mscmd + DLE	191.43	526 - 856	8 - 38
13	1 x new 15 mscmd GTs and 3 x Existing Avon 15 mscmd + DLE	158.07	558 - 931	16 - 59
14	3 x new 15 mscmd GTs and 1 x Existing Avon 15 mscmd + DLE	225.15	521 - 842	5 - 26
15	(Brownfield) 1 x new 15 mscmd and 1 x new 23 mscmd GT's	144.37	616 - 1,115	328 - 576
16	2 x new 15 mscmd GTs and 1 x Existing Avon 15 mscmd + DLE	166.72	541 - 878	44 - 150
17	1 x new 15 mscmd GTs and 2 x Existing Avon 15 mscmd + DLE	134.27	558 - 931	70 - 224
18	(Brownfield) 2 x new 15 mscmd GT's	136.25	520 - 840	106 - 350

Table 2 - Options Cost Data

3.14. Non-FES costs have a cost confidence interval of +/- 30% and vary between options. These costs include installation costs and ongoing Asset Health and Site Operation costs. Cost estimates for the installation of new compressor units are based on the output from engineering design studies, supplier quotes and National Gas Transmission project

experience.[11] While Asset Health costs are based on a site specific scoping exercise[12] and unit costs from the RIIO-2 Final Determinations.

3.15. FES related Opex costs are derived using a probability-based forecasting model. They vary between options and between Future Energy Scenarios 2021. The four Future Energy Scenarios as described in the National Grid ESO FES[13] provide different pathways to a net zero future. These range from Steady Progression, which falls short of the net zero target, to Leading the Way which achieves net zero ahead of 2050. Each scenario is dependent on assumptions about changes to, government policy and legislation, energy delivery and consumption, consumer behaviour, technological change, and government incentives and investment. The Future Energy Scenarios provide a broad envelope of energy backgrounds against which the merits of alternative investments may be appraised.

3.16. The two lower natural gas usage scenarios (Customer Transformation and Leading the Way) meet carbon reduction targets via electrification with changes in consumer behaviour and large improvements in energy efficiency. The use of hydrogen is considered in Leading the Way and System Transformation. Hydrogen is produced entirely using renewable electricity in Leading the Way whereas in System Transformation gas continues to be used to produce blue hydrogen.

3.17. Compressor Fuel and Carbon Emission volumes are determined by forecast running hours (Table 9) and combined with forecast unit cost (Table 8) to derive four total cost estimates for each option, one for each Future Energy Scenario.

3.18. Constraint management costs, capacity buy backs and locational balancing arise because of the commercial actions the gas system operator takes to match the requirements of network users with the physical capabilities of the network. Constraint management cost volumes are forecast using network capability analysis model developed by National Gas Transmission to define the capability of the National Transmission System. Further details are given in the Gas Ten Year Statement (GTYS)[14] and Annual Network Capacity Assessment

[11] St Fergus Compressor Emissions FOSR submission in January 2023 – Appendix K Feasibility Optioneering Report
[12] St Fergus Compressor Emissions FOSR submission in January 2023 – Appendix I Asset Health Report
[13] Future Energy Scenarios 2022 | National Grid ESO
[14] Gas Ten Year Statement (GTYS) | National Gas Transmission

Report (ANCAR).[15] The North Sea Midstream Partners sub-terminal is subject to specific commercial arrangements set out in Section I of the Uniform Network Code.

3.19. A key factor in assessing network capability is compressor availability. Availability is a measure of how ready a given component in a system is to operate on demand. Typically measured over an extended period to smooth out the effects of day-to-day maintenance and faults. An overview of how this availability value is assessed and how it is used when assessing network capability is set out in the Compressor Emissions – Asset Management Plan.[16]

3.20. National Gas Transmission has commissioned the development of a Reliability Availability Maintainability (RAM) model[17]. This assessed availability across the entire compressor fleet and evaluated the impact of specific asset heath interventions on compressor availability. In addition, a site-specific availability model was developed for the St Fergus Gas Terminal.[18] The results of the availability modelling undertaken for the site is one of the important inputs to the Cost Benefit Analysis model and can often drive the conclusions of the analysis.

3.21. Table 3 below sets out the output from the Cost Benefit Analysis. The option with the highest Net Present Value (in this case the lowest negative) is the one that delivers compliance with the Directive at least cost over the assessment period. The lead option is Option 12 (2 New 15MW GTs + 2 Avon units retrofitted with DLE) under all Future Energy Scenarios except for Leading the Way where Option 13 has a marginally higher Net Present Value.

[15] Network Capability | National Gas Transmission
'[16] St Fergus Compressor Emissions FOSR submission in January 2023 – Appendix B Compressor Emissions – Asset Management Plan
[17] St Fergus Compressor Emissions FOSR submission in January 2023- DNV RAM Study
[18] St Fergus Compressor Emissions FOSR submission in January 2023- Appendix E – Site Availability Model

Option	NPV £m (2018 - 19 prices)	Steady Progression	Consumer Transformation	Leading the Way	System Transformation
0	4 x Existing Avon on 500 hrs	-£1,302 m	-£850 m	-£771 m	-£1,313 m
1	(Brownfield) - 3 x new 15 mscmd GT's	-£589 m	-£451 m	-£435 m	-£587 m
2	(Greenfield) - 3 x new 15 mscmd GT's	-£632 m	-£494 m	-£477 m	-£630 m
3	(Brownfield) 2 x new 23 mscmd GT's	-£1,306 m	-£1,484 m	-£1,536 m	-£1,214 m
4	(Greenfield) 2 x new 23 mscmd GT's	-£1,335 m	-£1,513 m	-£1,565 m	-£1,243 m
5	(Brownfield) 2 x new 15 mscmd and 1 x new 23 mscmd GT's	-£650 m	-£484 m	-£468 m	-£638 m
6	(Greenfield) 2 x new 15 mscmd and 1 x new 23 mscmd GT's	-£698 m	-£532 m	-£516 m	-£686 m
7	(Brownfield) 4 x new 15 mscmd GT's	-£610 m	-£483 m	-£468 m	-£607 m
8	4 x Existing Avon 15 mscmd derated	-£633 m	-£467 m	-£447 m	-£634 m
9	3 x Existing Avon 15 mscmd derated	-£683 m	-£489 m	-£462 m	-£689 m
10	4 x Existing Avon 15 mscmd DLE	-£672 m	-£497 m	-£475 m	-£674 m
11	3 x Existing Avon 15 mscmd DLE	-£743 m	-£530 m	-£499 m	-£752 m
12	2 x new 15 mscmd GTs and 2 x Existing Avon 15 mscmd + DLE	-£580 m	-£445 m	-£428 m	-£579 m
13	1 x new 15 mscmd GTs and 3 x Existing Avon 15 mscmd + DLE	-£599 m	-£446 m	-£426 m	-£602 m
14	3 x new 15 mscmd GTs and 1 x Existing Avon 15 mscmd + DLE	-£594 m	-£464 m	-£449 m	-£592 m
15	(Brownfield) 1 x new 15 mscmd and 1 x new 23 mscmd GT's	-£990 m	-£664 m	-£633 m	-£937 m
16	2 x new 15 mscmd GTs and 1 x Existing Avon 15 mscmd + DLE	-£637 m	-£465 m	-£444 m	-£638 m
17	1 x new 15 mscmd GTs and 2 x Existing Avon 15 mscmd + DLE	-£670 m	-£472 m	-£444 m	-£677 m
18	(Brownfield) 2 x new 15 mscmd GT's	-£690 m	-£480 m	-£450 m	-£701 m

Table 3 - Cost Benefit Analysis Outputs

3.22. To help quantify the full life cycle environmental impact of each option and in compliance with the Industrial Emissions Directive, a Best Available Technology assessment[19] was carried out. The assessment featured both quantitative and qualitative scoring of shortlisted options against key technical and environmental criteria, as well as whole life cycle emissions and costs. The ten options considered for Best Available Technology assessment gave the broadest review of the available options. Table 4 below sets out the scores for each

[19] St Fergus Compressor Emissions FOSR submission in January 2023 - Appendix J – Preliminary BAT Report Summary

option assesses assuming one of the two VSD's at St Fergus is unavailable. Assessments assuming both VSDs are either available or unavailable resulted in very similar scores.

Best Availability Technology assessment (1 VSD Available)		Technical / Environmental Score (based on qualitative assessment)	Environmental Score (based on quantitative assessment)	Total Score
0	4 x Existing Avon on 500 hrs	26%	17%	43%
1	(Brownfield) – 3 x new 15 mscmd GT's	55%	28%	83%
5	(Brownfield) 2 x new 15 mscmd and 1 x new 23 mscmd GT's	44%	30%	74%
7	(Brownfield) 4 x new 15 mscmd GT's	61%	28%	89%
8	4 x Existing Avon 15 mscmd derated	53%	17%	70%
10	4 x Existing Avon 15 mscmd DLE	57%	26%	83%
12	2 x new 15 mscmd GTs and 2 x Existing Avon 15 mscmd + DLE	57%	28%	84%
13	1 x new 15 mscmd GTs and 3 x Existing Avon 15 mscmd + DLE	52%	28%	80%
14	3 x new 15 mscmd GTs and 1 x Existing Avon 15 mscmd + DLE	57%	28%	84%
18	(Brownfield) 2 x new 15 mscmd GT's	46%	28%	74%
Maximum Weighted Score Available		70%	30%	100%

Table 4 – BAT Assessment Scores – (1 VSD Available)

Sensitivity Analysis

3.23. The outputs of the Cost Benefit Analysis (Table 3) assume that Constraint Management costs reflect the cost of gas. However, experience from previous constraint periods (July 2006 when prices reached up to 300p/therm equal to 8.5 times the prevailing gas price) indicates that this might not be the case. National Gas Transmission has argued that there are two structural explanations for these high prices:

- Gas supplies to the North Sea Midstream Partners sub-terminal are linked to oil production which means that the gas price does not provide a true reflection of the commercial impact of constraints on offshore producers;
- The commercial arrangements mean that commercial actions cannot be targeted on shippers at North Sea Midstream Partners sub-terminal alone.

3.24. Table 5 below sets out the output from a Cost Benefit Analysis assuming Constraint Management costs in line with those observed during the previous constraint period, July 2006. The lead option is Option 12 (2 New 15 MW GTs + 2 Avon units retrofitted with DLE) under the two low gas Future Energy Scenarios (Customer Transformation Leading the Way) While under the two high gas scenarios (Steady Progression and System Transformation) it is Option 14 (3 New 15 MW GTs + 1 Avon retrofitted with DLE). The differences between these options however are marginal.

Option	NPV £m (2018 - 19 prices)	Steady Progression	Consumer Transformation	Leading the Way	System Transformation
0	4 x Existing Avon on 500 hrs	-£5,286 m	-£3,311 m	-£2,933 m	-£5,339 m
1	(Brownfield) - 3 x new 15 mscmd GT's	-£710 m	-£494 m	-£468 m	-£699 m
2	(Greenfield) - 3 x new 15 mscmd GT's	-£753 m	-£537 m	-£511 m	-£742 m
3	(Brownfield) 2 x new 23 mscmd GT's	-£4,310 m	-£5,876 m	-£6,235 m	-£3,885 m
4	(Greenfield) 2 x new 23 mscmd GT's	-£4,339 m	-£5,905 m	-£6,264 m	-£3,914 m
5	(Brownfield) 2 x new 15 mscmd and 1 x new 23 mscmd GT's	-£851 m	-£596 m	-£573 m	-£833 m
6	(Greenfield) 2 x new 15 mscmd and 1 x new 23 mscmd GT's	-£899 m	-£644 m	-£621 m	-£882 m
7	(Brownfield) 4 x new 15 mscmd GT's	-£661 m	-£491 m	-£475 m	-£644 m
8	4 x Existing Avon 15 mscmd derated	-£756 m	-£514 m	-£484 m	-£748 m
9	3 x Existing Avon 15 mscmd derated	-£1,038 m	-£662 m	-£604 m	-£1,054 m
10	4 x Existing Avon 15 mscmd DLE	-£865 m	-£584 m	-£546 m	-£865 m
11	3 x Existing Avon 15 mscmd DLE	-£1,266 m	-£805 m	-£728 m	-£1,296 m
12	2 x new 15 mscmd GTs and 2 x Existing Avon 15 mscmd + DLE	-£667 m	-£471 m	-£449 m	-£653 m
13	1 x new 15 mscmd GTs and 3 x Existing Avon 15 mscmd + DLE	-£727 m	-£495 m	-£464 m	-£722 m
14	3 x new 15 mscmd GTs and 1 x Existing Avon 15 mscmd + DLE	-£657 m	-£479 m	-£461 m	-£641 m
15	(Brownfield) 1 x new 15 mscmd and 1 x new 23 mscmd GT's	-£2,162 m	-£1,383 m	-£1,320 m	-£1,982 m
16	2 x new 15 mscmd GTs and 1 x Existing Avon 15 mscmd + DLE	-£957 m	-£597 m	-£554 m	-£952 m
17	1 x new 15 mscmd GTs and 2 x Existing Avon 15 mscmd + DLE	-£1,118 m	-£675 m	-£613 m	-£1,131 m
18	(Brownfield) 2 x new 15 mscmd GT's	-£1,351 m	-£795 m	-£705 m	-£1,392 m

Table 5 - Cost Benefit Analysis Outputs (High Constraint Costs)

Final Preferred Option

3.25. In the Final Option Selection Report, National Gas Transmission identified Option 14 as the Final Preferred Option for approval by the Authority in compliance with Special Condition 3.11.8.

3.26. The Final Preferred Option involves the installation of three new gas turbine driven compressor unit approximately 15MW which will be commissioned by 2030. The new units will be installed inn existing Plant 1 and Plant 2 locations. In addition one of the existing Avon units at Plants 1 and 2 will be retained and retrofitted with Dry Low Emissions technology. There is no preference as to which of the existing Avon units will be retained. The option contains a cost for decommissioning any remaining Avon unit, which will be subject to the detailed delivery plan and commissioning requirements.

4. Our assessment and proposed Final Preferred Option

Section summary

In this chapter we offer for consideration our assessment of the evidence set out in the Final Option Selection Report and the reasons for our proposed Final Preferred Option

Questions

Question 4.1: Do respondents agree with our assessment of the evidence presented in the Final Option Selection Report?

Question 4.2: Do respondents agree with our decision that compressor fuel and carbon credit costs should be included in the Cost Benefit Analysis?

Question 4.3: Do respondents agree with our assessment that the Cost Benefit Analysis might be conservative in the estimation of Constraint Management Costs and that the Sensitivity Analysis should be given substantive weight in the selection of the Final Preferred Option?

Question 4.4: Do respondents have any views on National Gas Transmission's proposal to trial Dry Low Emissions technology on one of the existing Avon compressor units at St Fergus Gas Terminal during the RIIO-2 price control period?

Our assessment of the 'needs case'

4.1. In our RIIO-T2 Final Determinations, we accepted the 'needs case' for investment at the St Fergus Gas Terminal to ensure compliance with the Directive. The Final Option Selection Report aligns with National Gas Transmission's Compressor Emissions Asset Management Plan (CE-AMP), which has been updated since Final Determinations and continues to demonstrate the need for compliance-related investment at St Fergus Gas Terminal.

Our assessment of options considered and shortlisted

4.2. Our assessment is that the Final Option Selection Report considered a complete range of available options and shortlisted only those options which would provide a viable solution, given the operational requirements at St Fergus Gas Terminal. Information on the option evaluation methodology was clearly articulated and applied in a consistent and logical manner.[20] The shortlisted options included the counterfactual 'do nothing' option, against which all other shortlisted options were assessed. While the shortlist of options assessed in the Cost Benefit Analysis does not include a market-based solution, constraint management payments, which are the commercial alternative to providing compressor services at St Fergus Gas Terminal, are central to the assessment of each option in the Cost Benefit Analysis. In autumn 2021 National Gas Transmission consulted on several alternative charging and commercial solutions at the North Sea Midstream Partners sub-terminal. This was followed in September 2022 by a further consultation on specific investment options at St Fergus. The topic of cost recovery is being explored further at the NTS Charging Methodology Forums.[21]

4.3. In making our assessment we noted that while both brownfield and greenfield options we considered none of the brownfield options considered consolidating Plants 1 and 2 into a single plant. Having sought further information we are content that pursing a consolidation option would not bring additional value. The current configuration of St Fergus Gas Terminal means that consolidation of Plants 1 and 2 would result in single points of failure in the compression of gas from the North Sea Midstream Partners sub-terminal. Removing these would be complex and the increased installation cost would outweigh any potential reduction in operating expenditure. In any case the inclusion of greenfield options provides a rough proxy for brownfield options involving the consolidation of Plants 1 and 2.

4.4. In making our assessment we also sought further information from National Gas Transmission on a modified version of one of the longlisted options, the re-wheel of the VSDs at Plant 3, that was not subsequently shortlisted. Data on predicted run hours (Table 7)

[20] St Fergus Compressor Emissions FOSR submission in January 2023 - Appendix K Feasibility Optioneering Report
[21] St Fergus Compressor Emissions FOSR submission in January 2023 - Appendix C Charging Statement and Appendix Q Stakeholder Engagement Log

shows that beyond 2040 in all Future Energy Scenarios the VSDs will be underutilised and will not contribute to site resilience or capability. Re-wheeling[22] the VSDs to lower the minimum gas flow they can support would allow their continued utilisation. Initial discussions between National Gas Transmission and the OEM suggest that such a re-wheel is achievable without extensive modification to the existing equipment.

4.5. To understand if re-wheeling the VSDs in the late 2030s would alter the ranking of options. National Gas Transmission produced a modified Cost Benefit Analysis for Option 14 and Option 16) under the System Transformation Future Energy Scenario. It was assumed that a re-wheel was completed in 2040 at an estimated cost of £14m. There was a marginal improvement in Net Present Value of both options but it did not alter their relative performance.

4.6. Based on this analysis and given the uncertainty about future gas supplies at the North Sea Midstream Partners sub-terminal we are content that a VSD re-wheel should not form part of this option selection. However, given the potential benefits in reduced carbon emissions and additional resilience that a re-wheel could deliver once gas supplies at the North Sea Midstream Partners sub-terminal decline the technical and economic viability of this option should remain under active review.

Our assessment of key Cost Benefit Analysis parameters

Base Assumptions

4.7. Our assessment is that all the key parameters used in the construction of the Cost Benefit Analysis as set out in Table 6 below are appropriate, with a sound rationale, having been taken from the existing regulatory framework or published Government guidance. National Gas Transmission has clarified that the methodology used to calculate Constraint Management Costs within the Cost Benefit Analysis is akin to the use of locational balancing

[22] Re-wheeling a compressor changes the capacity range without the need to replace the entire unit. It requires much lowe investment than building a new unit but does require an extended outage.

actions at other System Entry Points. This is an appropriate representation of the actual commercial arrangements set out in Section I of the Uniform Network Code. Uncertainty about the unit cost of Constraint Management under Section I arrangements is reflected in the sensitivity analysis provided (Table 5).

Category	Assumption	Base Assumption	Rationale
CBA parameters	WACC	2.81%	Defined in RIIO-T2
	Social Time Preference Rate	3.5% (Years 0 – 30) / 3.0 % (30+)	Defined in Green Book
	Regulated Asset Life	45 years	Defined in RIIO-T2
	Assessment Period	25 years	Based on lifetime of asset
	Depreciation	SOTYD	Defined in RIIO-T2
	Capitalisation	75.00%	Defined in RIIO-T2
Constraints and Fuel	Gas Price	Annual price 50 – 64 p/th	BEIS reference scenario
	Compressor Fuel Costs	Gas Price	
	Constraint management pricing	BEIS Gas Price	As defined by Commercial Constraint Price Methodology
	Constraint management method	UNC Section I	Reflective of tools available to manage constraints
Emissions	CO2 cost	Annual price 241 – 378 £/tonne	BEIS Valuation of greenhouse gas emissions: for policy appraisal and evaluation: Central Case
	NOx price	£6,199 £/tonne	DEFRA damage costs

Table 6 - Cost Benefit Analysis Assumptions

Capital Expenditure & Asset Health Cost Estimates

4.8. Our assessment is that the Capex, Asset Health (including Retrofit), Decommissioning and Ongoing Site Operation cost estimates, included in the Cost Benefit Analysis, have been arrived at using appropriate data sources and assumptions. The level of cost confidence to

which these estimates have been made is appropriate for a project at this stage of development and is in line with guidance published by the Infrastructure and Project Authority.23

Constraint Management, Compressor Fuel & Carbon Emission Cost Estimates

4.9. Our assessment is that constraint management, compressor fuel and carbon emission cost estimates have been derived using the established probabilistic network capability forecasting methodology that underpins both the Gas Ten Year Statement (GTYS) and Annual Network Capacity Assessment Report (ANCAR). It is outside the scope of this consultation to review this methodology.

4.10. The model generates predicted flows of gas through the North Sea Midstream Partners sub-terminal on an hourly basis using a complex supply and demand model. A set of simple logical rules are then used to determine the total number of hours during which the various compressor units operate under a single unit or parallel running configurations. Total running hours are therefore determined by the Future Energy Scenario being considered, whereas the allocation between compressor units is influenced by the shortlisted option.

4.11. In making our assessment, we sought further information on running hours under each Future Energy Scenario. Table 7 below sets out predicted running hours for the shortlisted Options. Despite all Future Energy Scenarios showing a significant reduction in gas supplies over time, total running hours do not exhibit the same decline. National Gas Transmission confirmed that total running hours depend heavily on daily throughput. Flows below the VSD minimum operating capacity typically result in two smaller 15MW gas turbines being utilised. Thus, as flows decline the higher capacity VSD units are replaced by lower capacity gas turbine units requiring higher running hours to compress a lower volume of gas.

4.12. National Gas Transmission confirmed that fuel efficiency of individual compressor units was reflected in compressor fuel and emission forecasts.

[23] IPA_Cost_Estimating_Guidance.pdf (publishing.service.gov.uk)

Predicted Running Hours		Steady Progression	Customer Transformation	Leading the Wat	System Transformation
Electric VSD All Options	2030	9,500	6,250	6,014	8,677
	2040	1,919	176	174	2,132
	2050	1,568	133	136	769
Gas Turbines All Option (excluding 0,3,4,5,6,7,15)	2030	7,733	6,835	6,726	7,213
	2040	10,022	8,007	6,848	10,339
	2050	8,679	1,524	3,125	9,443
Gas Turbines Option 0 4 x Existing Avon on 500 hrs	2030	2,000	2,000	2,000	2,000
	2040	2,000	2,000	2,000	2,000
	2050	2,000	2,000	2,000	2,000
Gas Turbines Option 3 and 4 2 x new 23 mscmd GT's	2030	6,077	4,328	4,136	5,515
	2040	5,162	790	279	5,476
	2050	2,541	152	161	2,994
Gas Turbines Option 5 and 6 2 x new 15 mscmd and 1 x new 23 mscmd GT's	2030	6,765	4,930	4,735	6,155
	2040	7,535	7,833	6,774	7,168
	2050	7,418	1,447	3,048	8,023
Gas Turbines Option 5 and 6 1 x new 15 mscmd and 1 x new 23 mscmd GT's	2030	10,663	6,540	6,111	9,519
	2040	9,578	8,392	6,945	8,729
	2050	8,346	1,499	3,109	9,260

Table 7 – Predicted Running Hours for each Option and Future Energy Scenario

4.13. As compressor fuel and carbon credit costs are recovered directly from shippers delivering gas to North Sea Midstream Partners sub-terminal through a specific St Fergus Compression Charge. It might be argued that these costs should be excluded from the Cost Benefit Analysis. We believe that these costs should continue to be included as the majority of them are likely to be funded by consumers through wholesale gas prices. In any case, the majority of costs relating to compressor fuel usage relate to the non market social cost of carbon emissions that are not included in the St Fergus Compression Charge.

Compressor Availability

4.14. Our assessment is that the approach taken to modelling site availability is appropriate and the models have been through a Quality Assurance procedure and been approved by

competent professionals. Table 8 below sets out the availability assumptions, following proposed interventions[24] used in the construction of the Cost Benefit Analysis.

Train Type	Availability
New Gas Turbine	90.00%
Avon 500 Hour EUD	79.50%
Avon CSRP	79.50%
Avon DLE	74.50%
VSD Electric Drive	86.60%

Table 8 – Compressor Availability Assumptions

4.15. A penalty of 5% has been applied to interventions that include a Dry Low Emissions technology retrofit to account for the immaturity of the technology. A reduction to the availability of the unproven technology is fair in the analysis but we believe it would be excessive to apply this penalty for the duration of the assessment period as experience should see it dissipate over time.

4.16. The availability figure for a new Gas Turbine is based on observed performance of new gas turbine compressors installed at other compressor stations such as Felindre. We believe the availability value used for the new unit is appropriate for this analysis.

4.17. In making our assessment we sought specific information from National Gas Transmission on the performance of the compressor units at St Fergus Gas Terminal. Although individual unit run hours are higher than elsewhere on the National Transmission System the number of starts is similar. As the number of starts is the main determinant of availability we accept that there is no material difference between the availability of compressor units at St Fergus Terminal and the network as a whole.

4.18. We also sought further information on the supply of electricity to the two VSD units and are satisfied that the current system is as robust as it can be without having back-up onsite power generation.

[24] Both Asset Health and Control Systems, the cost of the former is included in the Cost Benefit Analysis however the latter is excluded as it is associated with an unrelated system wide upgrade.

Future Energy Scenarios

4.19. Our assessment is that the appropriate Future Energy Scenarios have been used in the Cost Benefit Analysis. In making this assessment we sought further information from National Gas Transmission on forecast supplies through the North Sea Midstream Partners sub-terminal. In particular, the assumed maximum end of day flow of 75 mscm/d. National Gas Transmission confirmed that 75 mscm/d can be achieved with a single gas turbine unit working alongside two VSDs. Therefore, meeting this maximum daily flow is not a key determining factor for any of the options and operational availability of compression through the year drives more value in the Cost Benefit Analysis. National Gas Transmission also confirmed that although the design capability of compression at St Fergus Gas Terminal is between 8 and 75 mscm/d. The majority of modelled compressor run hours occur between 8 and 45 mcm/d driving the majority of value in the Cost Benefit Analysis. The Best Available Technology assessment has also been based on this restricted flow range.

4.20. We note that a sensitivity analysis identified three viable options should daily flows fall to between 2 and 8 mscm/d. However, these options were not included in the option selection process. This sensitivity analysis is preliminary and was not part of the option selection process. Daily flows under 2 mscm/d were not considered as part of the sensitivity analysis. We are content with this approach.

4.21. In making our assessment we also consulted the North Sea Transition Authority to better understand the broad range of forecast gas supplies that could be expected to be delivered to the St Fergus Gas Terminal. Aggregated supply profiles for all three sub-terminals were provided and compared to Future Energy Scenario data provided by National Gas Transmission. No significant difference between the two data sources was found. We continue to believe that Future Energy Scenarios provide an appropriate basis for this investment decision.

4.22. We also sought further information from National Gas Transmission with respect to the offshore production facilities that utilise the North Sea Midstream Partners sub-terminal. National Gas Transmission confirmed that they had limited visibility on this issue and that they relied upon information provided by the owners of the sub terminal.

Our Assessment of Best Available Technology

4.23. Our assessment is that the Best Availability Technology methodology used by National Gas Transmission is appropriate for this stage of the project. All shortlisted options except the counterfactual (do nothing) are assessed as being Best Available Techgnology.

Our Assessment of Project Risk Register[25] and Project Programme[26]

4.24. Our assessment is that an appropriate Risk Register has been established and maintained. The majority of risks are routine for a project of this type with acceptable mitigations proposed. We have however identified two unique and high impact risks:

- Control System Restricted Performance (CSRP) may not be considered by the Environment Agency as complying with Best Available Technology requirements, resulting in the necessary environmental permits being withheld;
- Avon Dry Low Emissions (DLE) Retrofit technology effectiveness, cost and availability remains uncertain ahead of the final stages of testing being completed.

4.25. Our assessment is that an appropriate project programme has been developed for each of the shortlisted options. The differences in scope, types of construction/operating risk in particular periods of plant outage between new build and retrofit options have been recognised in the project programme. In making this assessment, National Gas Transmission confirmed that the programme for their Final Preferred Option (Option 14) had been developed further than for other options but we have accepted that all costs provided are within +/-30% as requested.

[25] St Fergus Compressor Emissions FOSR submission in January 2023 - Appendix H – Project Risk Register and Covering Document
‘[26] St Fergus Compressor Emissions FOSR submission in January 2023 - Appendix M – Project and Preferred Option Programmes

Discussion

4.26. Although Cost Benefit Analysis and Best Available Technology assessments are key decision-making tools, they are not the only considerations that should be given weight. In this case we focused on the Cost Benefit Analysis and Sensitivity Analysis. All shortlisted options excepting the counterfactual (do nothing) are assess as representing Best Available Technology. Although nineteen options were shortlisted a number of these can be discounted at this stage:

- Options that include a greenfield site which have a brownfield equivalent. The former has a lower Net Present Value with no non-monetary benefit identified. This removes Options 2, 4 and 6;
- Options that include 23 mscm/d gas turbines. Units of this size do not map to the duty requirements set out in Figure 1 and this is reflected in lower Net Present Value outcomes. This removes Options 3, 5 and 15;
- Options that include modification of existing Avon units with Control System Restricted Performance. There is an unknown level of risk that this approach would not receive approval from the Environment Agency. This removes Options 5 and 9.
- Options that include modification of existing Avon units with Dry Low Emission technology. This technology has not been fully tested and is not currently commercially available. There is also an unknown level of risk that this approach would not receive approval from the Environment Agency. This removes Options 10, 11, 12, 13, 14, 16 and 17. However we retain Options 12 and 14 as the former has the lowest Net Present Value in the Cost Benefit Analysis and the later is the Final Preferred Option identified by National Gas Transmission.

4.27. With the lowest scoring options removed from contention, Table 9 below sets out the outcome of the Cost Benefit Analysis and Sensitivity Analysis for the remaining options.

NPV £m (2018 - 19 prices)		Steady Progression	Consumer Transformation	Leading the Way	System Transformation
Cost Benefit Analysis					
0	4 x Existing Avon on 500 hrs	-£1302 m	-£850 m	-£771 m	-£1313 m
1	(Brownfield) - 3 x new 15 mscmd GT's	-£589 m	-£451 m	-£435 m	-£587 m
7	(Brownfield) 4 x new 15 mscmd GT's	-£610 m	-£483 m	-£468 m	-£607 m
12	2 x new 15 mscmd GTs and 2 x Existing Avon 15 mscmd + DLE	-£580 m	-£445 m	-£428 m	-£579 m
14	3 x new 15 mscmd GTs and 1 x Existing Avon 15 mscmd + DLE	-£594 m	-£464 m	-£449 m	-£592 m
18	(Brownfield) 2 x new 15 mscmd GT's	-£690 m	-£480 m	-£450 m	-£701 m
Sensitivity Analysis					
0	4 x Existing Avon on 500 hrs	-£5,286 m	-£3,311 m	-£2,933 m	-£5,339 m
1	(Brownfield) - 3 x new 15 mscmd GT's	-£710 m	-£494 m	-£468 m	-£699 m
7	(Brownfield) 4 x new 15 mscmd GT's	-£661 m	-£491 m	-£475 m	-£644 m
12	2 x new 15 mscmd GTs and 2 x Existing Avon 15 mscmd + DLE	-£667 m	-£471 m	-£449 m	-£653 m
14	3 x new 15 mscmd GTs and 1 x Existing Avon 15 mscmd + DLE	-£657 m	-£479 m	-£461 m	-£641 m
18	(Brownfield) 2 x new 15 mscmd GT's	-£1,351 m	-£795 m	-£705 m	-£1,392 m

Table 9 – Net Present Value of Lead Options (Cost Benefit and Sensitivity Analysis)

4.28. Based on Net Present Values both Option 0 (counterfactual) and Option 18 can be excluded. This leaves a choice between Option 1 (3 new 15 mscm/d GTs) and Option 7 (4 new 15 mscm/d GTs). The former option leads in all Future Energy Scenarios by between £21m and £33m in the Cost Benefit Analysis. While the latter option leads in all but one Future Energy Scenario by between -£7m and £55m, in the Sensitivity Analysis. The exception being Leading the Way. Taking the Cost Benefit Analysis and Sensitivity Analysis together the difference between the two options is negligible.

4.29. In particular, based on the historical evidence from July 2006 and the arguments presented by National Gas Transmission as to why Constraint Management unit costs might exceed the prevailing gas price, we accept that the Cost Benefit Analysis might be conservative in its estimate of Constraint Management Costs at St Fergus Gas Terminal and that if this was the case substantive weight should be given to the Sensitivity Analysis. However, we remain to be fully convinced by the argument that higher Constraint Management Costs can be attributed to the link between oil and gas production in the North Sea.

4.30. To assess the usage to which a fourth gas turbine driven compressor unit would be put we considered the running hours of the Avon retrofitted with Dry Low Emissions technology in Option 14. As set out in Table 10 below these running hours over the assessment period are set out in Table 10 below. Based on these low running hours we do not believe that a fourth new gas turbine driven compressor unit can be justified and that any fourth unit should be existing Avon operated under the 500 hours per year Emergency Use Derogation.[27]

Predicted Running Hours Option 14		Steady Progression	Customer Transformation	Leading the Wat	System Transformation
Existing Avon 15 mscmd + DLE	2030	52	71	73	52
	2040	88	14	9	109
	2050	49	4	6	54

Table 10 – Predicted Running Hours of Option 14 Existing Avon

4.31. National Gas Transmission however did not include this option in their shortlist. Instead, Option 14 has an existing Avon retrofit with Dry Low Emissions technology. The Net Present Value data set out in Table 9 has Option 14 ahead of Option 7 in both the Cost Benefit and Sensitivity Analysis for all Future Energy Scenarios but behind Option 1 in the Cost Benefit Analysis. The appropriate choice is therefore between Option 1 and Option 14 rather than between Option 1 and Option 7.

4.32. For the reasons set out above it would not be appropriate to choose an option which relied on Dry Low Emissions technology to deliver cost effective compliance. However, in the case of Option 14, the technology will only be fitted to the fourth back up unit which, as shown by Table 10, could deliver the same level of benefit under the Emergency Use Derogation. The Asset Health interventions are required whether the existing Avon is operated under the Emergency Use Derogation or with a Dry Low Emissions retrofit post 2030. This removes the risk of asset stranding should the risks related to the viability of Dry Low Emission technology materialise. Not proceeding with a Dry Low Emissions retrofit will reduce the Non-FES costs for Option 14 as set out in Table 2 by up to £8m improving its performance in the Cost Benefit Analysis.

[27] Calculated on a 5-year rolling average with a maximum of 750 hours in any single year

4.33. We therefore propose that Option 14, which involves the installation of three new gas turbine driven compressor units and the retention of one of the existing Avon units should be the Final Preferred Option.

Avon Dry Low Emissions Technology Trial

4.34. National Gas Transmission has requested that as part of Option 14, the existing Avon unit identified for retention post 2030 should be retrofitted with Dry Low Emission technology during the RIIO-2 price control period. This would allow the technology to be trialled under operational conditions with the potential for significant running hours each year. A successful trial would facilitate acceptance and application of the technology to other Avon units on the National Transmission System.

4.35. National Gas Transmission believe that should the trial be unsuccessful it would be possible to return the trial unit to its original status within 10 days. This would mean it could continue to operate under the Emergency Use Derogation post 2030... The Final Option Selection Report indicates that the additional cost of retrofitting over and above the asset health works associated with the Emergency Use Derogation would be under £5m.

4.36. Avon Dry Low Emissions retrofit turbines are currently not available commercially. However, the technology is undergoing the final stages of testing and qualification by National Gas Transmission. The required changes to Avon turbines are limited and focus on the configuration of the burner and associated control systems and tests on the new burner configurations have already been successfully tested. Given the number of Avon units currently in use around the world, it is anticipated that a sufficiently large market exists to provide an attractive opportunity for providers. It therefore seems reasonable to assume that the technology will become commercially available in time to be installed ahead of 1 January 2030.

4.37. The timing and funding of any trial is outside the scope of this decision. In any case we would need additional information before making any decision. We recognise the potential value of an operational trial of this technology and will therefore continue to engage with National Gas Transmission on this issue.

5. Proposed Final Preferred Option

Section summary

In this chapter we set our proposed Final Preferred Option

Questions

Question 5.1: Do respondents agree with our proposed Final Preferred Option?

Our Proposal

5.1. Based on our assessment of the evidence included in the Final Option Selection Report, in accordance with Special Condition 3.11.9, we propose to accept the option identified by National Gas Transmission as the Final Preferred Option (Option 14).

5.2. Our proposed Final Preferred Option includes the installation of three new gas turbine driven compressor units of approximately 15MW which will be commissioned by 2030. The new units will be installed in existing Plant 1 and Plant 2 locations. In addition, one of the existing Avon units will be retained with significant asset health investment to improve unit availability. There is no preference as to which of the existing Avon units will be retained. The option contains a cost for decommissioning any remaining Avon unit, which will be subject to the detailed delivery plan and commissioning requirements.

Appendix 1 – Privacy notice on consultations

Personal data

The following explains your rights and gives you the information you are entitled to under the General Data Protection Regulation (GDPR).

Note that this section only refers to your personal data (your name address and anything that could be used to identify you personally) not the content of your response to the consultation.

1. The identity of the controller and contact details of our Data Protection Officer

The Gas and Electricity Markets Authority is the controller, (for ease of reference, "Ofgem"). The Data Protection Officer can be contacted at dpo@ofgem.gov.uk

2. Why we are collecting your personal data

Your personal data is being collected as an essential part of the consultation process, so that we can contact you regarding your response and for statistical purposes. We may also use it to contact you about related matters.

3. Our legal basis for processing your personal data

As a public authority, the GDPR makes provision for Ofgem to process personal data as necessary for the effective performance of a task carried out in the public interest. i.e., a consultation.

3. With whom we will be sharing your personal data

(Include here all organisations outside Ofgem who will be given all or some of the data. There is no need to include organisations that will only receive anonymised data. If different organisations see different set of data, then make this clear. Be a specific as possible.)

4. For how long we will keep your personal data, or criteria used to determine the retention period.

Your personal data will be held for ***(be as clear as possible but allow room for changes to programmes or policy. It is acceptable to give a relative time e.g., 'six months after the project is closed')***

5. Your rights

The data we are collecting is your personal data, and you have considerable say over what happens to it. You have the right to:

- know how we use your personal data
- access your personal data
- have personal data corrected if it is inaccurate or incomplete
- ask us to delete personal data when we no longer need it
- ask us to restrict how we process your data
- get your data from us and re-use it across other services
- object to certain ways we use your data
- be safeguarded against risks where decisions based on your data are taken entirely automatically
- tell us if we can share your information with 3rd parties
- tell us your preferred frequency, content, and format of our communications with you
- to lodge a complaint with the independent Information Commissioner (ICO) if you think we are not handling your data fairly or in accordance with the law. You can contact the ICO at https://ico.org.uk/, or telephone 0303 123 1113.

6. Your personal data will not be sent overseas (Note that this cannot be claimed if using Survey Monkey for the consultation as their servers are in the US. In that case use "the Data you provide directly will be stored by Survey Monkey on their servers in the United States. We have taken all necessary precautions to ensure that your rights in term of data protection will not be compromised by this."

7. Your personal data will not be used for any automated decision making.

8. Your personal data will be stored in a secure government IT system. (If using a third-party system such as Survey Monkey to gather the data, you will need to state clearly at which point the data will be moved from there to our internal systems.)

9. More information for more information on how Ofgem processes your data, click on the link to our "Ofgem privacy promise".