Final Option Selection Report

Uncertainty Mechanism Submission

St Fergus Gas Terminal

January 2023

nationalgrid

Executive Summary

Project Snapshot

Our compressor fleet is subject to the Industrial Emissions Directive (IED) and Medium Combustion Plant Directive (MCPD) which regulate pollutant emissions from the combustion of fuels in combustion plants. These directives impact our assets as they provide limits on emissions of Sulphur Dioxides (SO_2), Nitrogen Oxide (NOx) and Carbon Monoxide (CO) to the environment. More detail on all relevant emissions legislation is provided in the overarching, accompanying Compressor Emissions – Asset Management Plan (CE-AMP).

St Fergus Gas Terminal has five Siemens (formerly Rolls-Royce) Avon gas compressors; three of which are currently operational with plans to return a fourth to operation in 2023/24. These units are not compliant with MCPD legislation, which requires that our existing compressor fleet must not exceed 150mg/m³ NOx from 1 January 2030. The site also has two Siemens (formerly Rolls-Royce) RB211 gas compressors; one of which is operational. These are derogated under the Large Combustion Plant Directive (LCPD) legislation and must cease operation by 31 December 2023. These compressors support the flows from the NSMP sub-terminal. Significant intervention is required to ensure compliance with the legislation and to maintain the required level of capability and network resilience for our customers.

St Fergus is the highest utilisation compressor site on the National Transmission System (NTS), and is required to operate 24 hours a day, 365 days a year. The terminal plays a critical role in ensuring UK Continental Shelf (UKCS) and Norwegian gas supplies can enter the NTS, with the site typically meeting over 25% of the average national demand.

This Final Option Selection Report (FOSR) provides a summary of all the work performed to date to evaluate, cost and analyse the full suite of feasible options available. These options need to achieve emissions legislation compliance, ensuring the right levels of network capability and availability are maintained for our customers and continue to provide value for consumers. We have developed an extensive list of all potential options which have considered both commercial (contractual) options as well as physical investment options.

Following a detailed and in-depth option selection process, including an extensive stakeholder consultation programme, we have determined that St Fergus requires four compliant units across Plant 1 and Plant 2 by 2030. Four units provides the required capability to be able to manage a range of differing network flows, whilst having these units split across two Plants provides the necessary resilience should there be planned or unplanned circumstances that render some of the units unavailable.

We have been working collaboratively with [redacted] to progress a prototype of Dry Low Emissions (DLE). Subject to the results of ongoing testing, we are proposing to DLE retrofit one existing St Fergus Avon unit to further test the suitability of this technology on the NTS. St Fergus would allow testing of DLE retrofit on a high utilisation site, with reduced risk if failure occurs. If the DLE retrofit unit proves unsuccessful we will reassess the options to achieve a fourth compliant unit.

Our preferred option of four unrestricted units (three new units and one DLE retrofit trial unit) represents the optimum solution for both achieving emissions compliance, ensuring the long-term Security of Supply of the UK and delivering value for consumers. The indicative total project value is [redacted] (2018/19) +/- 30%.

This project aligns with our RIIO-T2 stakeholder priorities “I want you to care for the environment and communities” and “I want to take gas on and off the transmission system where and when I want”. Our overarching strategy is set out within the Compressor Emissions Asset Management Plan (CE-AMP) which accompanies, and gives an updated view of, our Compressor Emissions Compliance Strategy (CECS) that was released in 2019 as part of our RIIO-T2 submission. CE-AMP focuses on the impact of MCPD on our compressor fleet, while including other ongoing Industrial Emissions Directive investments. CE-AMP will further develop into the Compressor Asset Management Plan to be released in support of our RIIO-T3 Business Plan.

Summary Boxes:

- Blue summary boxes are inserted throughout the document to highlight the key points within a section and help the reader understand and navigate the many interdependencies within the FOSR.

Introduction

1. The purpose of this Final Option Selection Report (FOSR) is to seek Ofgem's approval of National Grid Gas Transmission's (NGGT) final preferred option for the St Fergus Gas Terminal to comply with the Industrial Emissions Directive (IED) and Medium Combustion Plant Directive (MCPD) emissions legislation and to ensure suitable levels of resilience for customers out to 2050. The report provides a detailed view of the project, its associated timings and presents the different options that have been considered.
2. This submission builds upon our December 2019 RIIO-T2 Business Plan, where we described the options available to us to comply with emissions legislation. Our preferred solution at that time was the construction of three new compressor units on a redeveloped Plant 2, asset health work on Plant 1 to enable operation until 2030 and the subsequent decommissioning of Plant 1 once the new Plant 2 became operational.
3. Whilst Ofgem agreed with the overall requirement to develop options for MCPD compliance, due to some uncertainty surrounding the option, it was requested that this project be progressed through the Uncertainty Mechanism (UM) process. Rather than a single Re-opener window covering a project in full, Ofgem proposed a two-step process whereby we submit the FOSR and then a subsequent cost submission once the project has gone through a full Front-End Engineering and Design (FEED) and tender process. NGGT were awarded £21.22m (2018/19) baseline funding to progress the option selection process.
4. This report is submitted in accordance with the Gas Transporter Licence Special Condition 3.11 Compressor Emissions Re-opener and Price Control Deliverable, Part C, and as per Price Control Deliverable Reporting Requirements and Methodology Document and RIIO-T2 Re-opener Guidance and Application Requirements Document. We have provided further detail on how this FOSR submission complies with these requirements in Appendix P – Mapping of Ofgem Requirements. This comprises the St Fergus specific requirements including the potential impact of investment on charges, which specifically is covered in Appendix C – Charging Methodology.

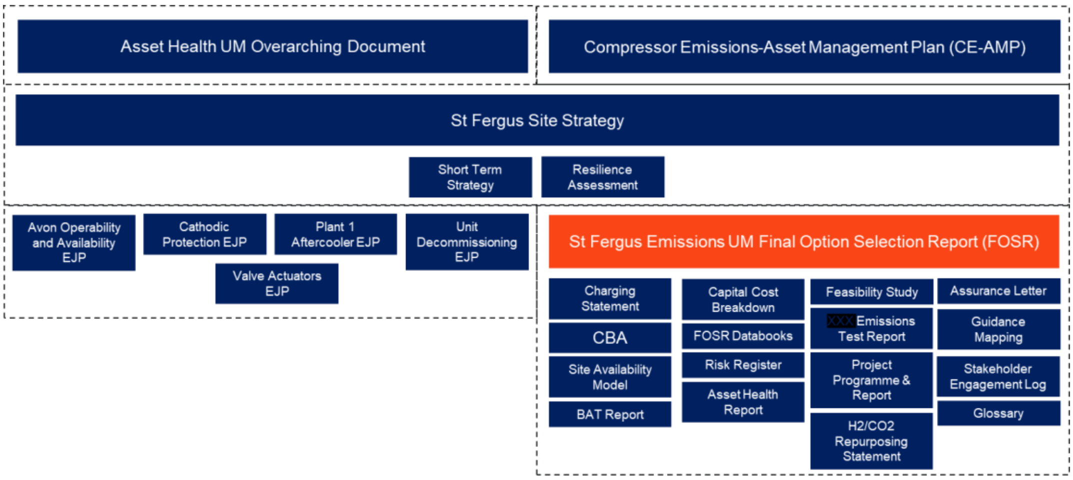

Figure 1 – St Fergus Submission Documents Structure

5. Figure 1 shows the hierarchy of UM submission documents which relate to St Fergus with this FOSR document highlighted in red. Appendix A - Compressor Emissions – Asset Management Plan (CE-AMP), in support of this FOSR, details our approach for how the whole of our compressor fleet will comply with

emissions legislation, maintain the network's resilience, and meet our customers' needs while ensuring value for consumers.

6. The St Fergus Site Strategy document introduces the St Fergus gas terminal, its purpose and layout, its criticality to the network, the strategies we have developed to guide our investments and a summary of all the investments we are proposing. It also includes our Resilience Assessment as an appendix which assesses the potential for rationalisation across the site to optimise our proposed capex and long-term opex. Both the Site Strategy and the CE-AMP provide crucial background information to understand the FOSR in context.

7. At RIIO-T2 final determination, subsidence at St Fergus Terminal was included in the Emissions Uncertainty Mechanism as it had possible implications for the long-term operation of the Terminal. As part of the Feasibility process, we have determined that there is not a site wide issue that will affect future operation. There is evidence of localised occurrences of subsidence, therefore we plan to request upfront funding for detailed survey and optioneering through the next Asset Health UM Submission window of June 2023. This will then provide the basis for a baseline funding request in our RIIO-T3 submission.

8. In progressing the FOSR, we have refined the options considered and amended our proposal. We propose to build three new compressor units across both Plants 1 and 2 and carry out a Dry Low Emissions (DLE) retrofit trial on one of the existing Avons (Option 14). To support this option, we will also need to carry out asset health works across Plants 1 and 2 to enable operation until 2030 and decommission surplus units; however, the majority of our planned Asset Health investment is to support broader operation of the entire site. Five of our proposed Asset Health investments are captured as part of the January Asset Health UM Submission and around 20 others will follow in the June submission. Decommissioning proposals for redundant Avons will be submitted once the new units are operationally proven.

9. This final preferred option reflects three years of development of this investment proposal, during which our understanding of the need to maintain gas-driven compression across two separate plants has increased. For more information on the resilience requirement at St Fergus, see the Resilience Assessment appendix within the St Fergus Site Strategy.

Investment Drivers

10. The St Fergus gas terminal is one of the most strategically important sites on the NTS. It regularly supplies over 25% of the UK's gas supplies and is an entry point to the system for gas from three sub-terminals, currently owned by Ancala, Shell and North Sea Midstream Partners (NSMP). It provides Security of Supply and access to gas from the UK Continental Shelf (UKCS) and from Norway, helping to minimise gas prices. The access to UKCS gas also allows access to oil production, with any restriction of gas supplies into St Fergus having a significant financial and environmental impact on customers' ability to produce oil. This is because gas is produced as a by-product of oil production either being flared or provided to gas consumers via St Fergus. Oil production can be reduced if gas transportation is compromised. As a result, St Fergus is the highest utilisation compressor site on the National Transmission System (NTS), and is required to operate 24 hours a day, 365 days a year.

11. The 2021 Future Energy Scenarios (FES) shows that there is an enduring need for the site until at least 2050 and St Fergus remains critical in facilitating our customers' current and future plans. There is continued investment in the North Sea sector, with new discoveries of natural gas coming on stream, particularly west of Shetland. There have also been some substantial acquisitions of existing gas fields by new operators showing a long-term investment plan for the area. Some of the North Sea gas production is connected only to St Fergus, and so production would be stranded without unrestricted access to the St Fergus terminal (for example the Frigg UK Association (FUKA) pipeline route).

12. This commitment to increased energy independence through domestic energy supply investment has been further strengthened, considering current global geopolitical and economic conditions, with the

government confirming its support for a new oil and gas licensing round that is expected to offer over 100 new licenses, launched by the North Sea Transition Authority (NSTA) in October 2022[1]. The logic for maintaining or expanding production in UKCS is also motivated by wider European energy security and market opportunity. Even in a scenario where UK demand for gas materially decreases, the UK NTS will be a crucial conduit for UKCS gas, Norwegian gas and global LNG to be exported to continental Europe.

13. The St Fergus terminal has been in continuous operation for over 40 years. Even with careful maintenance, the design life of most assets is between 15-40 years, therefore, it requires significant investment to re-life many of these assets.

14. Due to its continuous running, the St Fergus terminal has some of the highest emissions on the NTS. NGGT is committed to reducing the impact of its activities on the environment while operating with the required network resilience and capability. Critical to fulfilling this commitment is ensuring that our compressor fleet meets emissions limits as set out in the LCPD and MCPD.

15. In 2014 we declared our route for compliance with LCPD, entering Units 2A and 2D at St Fergus into Limited Lifetime Derogation. Thus, these units cannot operate past 31 December 2023; Unit 2D subsequently ceased operation in 2020.

16. The MCPD requires that our existing compressor fleet, between 1 MW and 50 MW net thermal input, must not exceed Nitrogen Oxide (NOx) emission levels of 150mg/m³ by 1 January 2030. The site currently includes five Avon gas powered units which are non-compliant with MCPD. Three of these units are currently operational, however a separate funding request is being submitted in the Asset Health UM in order to return a fourth Avon to operation by the end of 2023. This will ensure sufficient capability after the RB211 Unit 2A ceases operation in compliance with LCPD.

17. NGGT is legally obligated to comply with the MCPD and failure to act would result in the need to restrict or cease the operation of these units. Restricting or ceasing use of the units would not provide the necessary site capability and required service for our customers and would have significant implications for the Security of Supply to the UK.

18. In addition to ensuring legislative compliance, NGGT must also ensure the right level of network capability and resilience is maintained to fulfil our customers' current and future needs, and to meet our operational requirements. This ensures we efficiently minimise network constraints, meet the peak demand of a 1-in-20 scenario and help provide Security of Supply to the UK.

19. 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 1977, with Plant 3 commissioned in 2015 to house two new Variable Speed Drives (VSDs). 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. Plants 1 and 2 can operate independently or be operated together, which provides the flexibility and resilience required to manage varying flow patterns, maintenance activities and unforeseen events such as unplanned outages. Rationalisation of the number of compression plants was considered through the Resilience Assessment, attached to the St Fergus Site Strategy, but we determined that it would significantly increase the risk of loss of compression with little associated cost savings.

20. The five Avon compressors on Plants 1 and 2 support the flows from the NSMP sub-terminal, rather than providing compression for the general operation of the NTS. They 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

[1] https://www.nstauthority.co.uk/licensing-consents/licensing-rounds/offshore-petroleum-licensing-rounds/#tabs

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 means that any necessary resilience must be fully located on site rather than relying on compression back up from other sites.

21. The further work we have conducted in developing and evaluating our options has determined that we must retain four units across two separate Plants to continue to provide the level of capability and resilience required at the site. For more information on the resilience requirement at St Fergus, see the Resilience Assessment appendix within the St Fergus Site Strategy.

22. The operational requirement to run 24/7, 365 days/year combined with the difficulties in securing outages at the site and the compliance deadline of 2030, has meant that an investment decision delay is not deemed viable. The 2030 MCPD deadline also places substantial time constraint on the delivery of the solution hence a solution must be agreed at pace.

Investment Drivers Key Points:

- The St Fergus gas terminal is one of the most strategically important sites on the NTS and there is an enduring need for the site until at least 2050.
- The site is one of the highest emitting sites on the network and has assets that are over 40 years old - intervention is required to comply with environmental legislation and to re-life ageing assets.
- Four units split across two plants are needed to maintain the required level of site capability and resilience.
- Investment decision delay is not feasible given the 2030 MCPD compliance deadline.

Optioneering

23. We have considered a full suite of solutions to enable St Fergus to comply with emissions legislation. This has included commercial and regulatory options that were an alternative to investing in compression. Through further evaluation and consulting with stakeholders, the commercial options were discounted and more information on this engagement is available in Appendix Q – Stakeholder Engagement Log.

24. During Phase 1 of the optioneering, a workshop was undertaken by NGGT with our feasibility consultant [redacted] to identify potentially suitable technologies.

25. The feasibility study went through a process of option identification, option development and, lastly, option selection. The initial screening process identified 22 technologies. Those which fell in to the following four broad categories were discounted for the reasons provided later in Section 5 – Option Selection.

    - Turbine choices/modifications to recycle lines (Electric, Steam)
    - Hydrogen and Hydrogen Blend driven turbines
    - Replacing drive units only (new or used) and retaining compressor
    - Modifying existing drives with emissions reduction technology – Selective Catalytic Reduction (SCR)

26. Following this reduction in technologies four remaining broad technology categories were combined in different configurations. These four technology categories are:

    - Derogation – Minimum investment to continue site operation on restricted hours (counterfactual), where the Avon units are limited to average 500 hours per year usage post 2030

- Control system changes – Derate output to ensure emissions do not breach MCPD limits (such as Control System Restricted Performance (CSRP))
- Abatement – Retrofitting the existing Avon units with abatement technology (such as DLE)
- New units – Building new low-emission, high-efficiency compressors (gas-driven) on either a brownfield (sites that have had previous development on them) or greenfield (undeveloped sites) site

27. Through a process of engagement internally and with Ofgem, a comprehensive list of 18 discrete options was created, detailed in Table 1 below. Each option assumes associated decommissioning equal to the number of new units proposed. This list includes some options which were not considered likely to meet requirements but were included to demonstrate the outer bounds of what capability is needed.

28. If units were replaced on a like-by-like basis in line with the original site design, this would require six new 15 MW units. However, our analysis shows low constraints with four units and therefore no options with greater than four units were included to reduce the cost to consumers.

Option Ref	Option Summary
0	Counterfactual (Do Nothing). Derogate four Avons to 500 hours per unit per year after 2030.
1	3 x New 15 MW GTs at existing Plant 1 and Plant 2 location
2	3 x New 15 MW GTs in a new Greenfield location within site perimeter
3	2 x New 23 MW GTs at existing Plant 1 and Plant 2 location
4	2 x New 23 MW GTs in a new Greenfield location within site perimeter
5	2 x New 15 MW GTs and 1 x 23 MW GT at existing Plant 1 and Plant 2 location
6	2 x New 15 MW GTs and 1 x 23 MW GT in a new Greenfield location within site perimeter
7	4 x New 15 MW GTs at existing Plant 1 and Plant 2 location
8	4 x existing Avon 1533s derated (CSRP)
9	3 x existing Avon 1533s derated (CSRP)
10	4 x existing Avon 1533s with DLE modification
11	3 x existing Avon 1533s with DLE modification
12	2 x new 15 MW GTs at existing Plant 1 and Plant 2 location with 2 existing Avon 1533s with DLE modification
13	1 x new 15 MW GT at existing Plant 1 and Plant 2 location with 3 existing Avon 1533s with DLE modification
14	3 x new 15 MW GTs at existing Plant 1 and Plant 2 location and 1 existing Avon 1533 with DLE modification
15	1 x New 15 MW GT and 1 x 23 MW at existing Plant 1 and Plant 2 location
16	2 x new 15 MW GTs with 1 existing Avon 1533s with DLE modification at existing Plant 1 and Plant 2 location
17	1 x new 15 MW GT with 2 existing Avon 1533s with DLE modification at existing Plant 1 and Plant 2 location
18	2 x New 15 MW GTs at existing Plant 1 and Plant 2 location

Table 1 – Shortlisted Options

29. Stakeholders were consulted on the potential needs case solutions using a detailed evaluation process where they were taken through to further development. Asset investment analysis was completed on these 18 options with the support of a Best Available Techniques (BAT) Consultant, [redacted] ([redacted]), and Feasibility Consultant,. [redacted]

30. The DLE retrofit emissions abatement technology is in development, with a dedicated external study and ongoing performance trials to support our assessment. Control System Restricted Performance (CSRP) technology has completed its performance trials and is now proceeding to permit trials. More information on these technologies and the results of the trials are available in CE-AMP.

31. These options underwent a level 4[2] (+/-30%) Cost Estimating process to enable internal Cost Benefit Analysis (CBA). 18 options were qualitatively assessed using Best Available Technique Assessment (BAT) evaluation criteria and 10 were taken through to full BAT assessment.

Optioneering Key Points:

- We have considered a full suite of solutions to enable St Fergus to comply with emissions legislation - this includes commercial and asset investment solutions.
- Given the criticality of the St Fergus Gas Terminal, commercial and regulatory options cannot offer a more cost-effective alternative to physical site investment.
- Like for like replacement of five or six units has been discounted as offering greater capability than necessary thus options with four or fewer units offers the greatest value to consumers.
- A shortlist of 18 options were developed and taken forward for further evaluation.

Evaluation Criteria

32. We use a wide range of models to help evaluate options and aid decision making. The key option evaluation inputs that we consider are summarised in Figure 2.

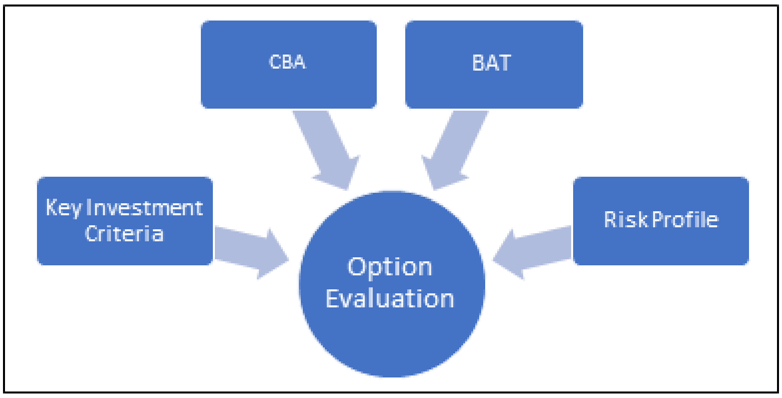

Figure 2 – Option Evaluation Inputs

33. The CBA Tool combines +/-30% cost estimates, option capability, availability and forecast run hours until 2050 to arrive at the lowest overall cost to consumers.

34. A BAT assessment has also been conducted. This is an environmental and technological CBA, which assesses options in terms of their environmental performance and operational attributes. We are required to use BAT as a selection mechanism for all new and substantially modified compressor machinery trains. This means that when we are looking at solutions for achieving compressor emissions compliance, BAT assessment assists with the decision-making process hand in hand with the CBA. For further detail, the full BAT assessment can be found in Appendix J – BAT Report Summary.

35. Several key investment considerations also influence option evaluation. These investment considerations cannot easily be represented in numerical modelling and serve as narrative reinforcement for the investment case. They include:

- Impact on UK Security of Supply, long term gas price and UK economy of disrupting supply or demand
- Wider consumer and industry impact

[2] Infrastructure and Projects Authority, UK Government

- Balancing the risk of trailing innovative solutions on a critical site against the benefits to future compressor fleet decisions

36. Finally, the risk and opportunity profile for each option also feeds into the overall evaluation process to help determine the final preferred option for this investment.

Evaluation Criteria Key Points:

- We use a wide range of models to help evaluate options and aid decision making including CBA and BAT.
- In the main FOSR document we also include narrative to explain key investment considerations which cannot be easily quantified such as UK economic impact of disrupting supply/demand.

Assumptions

37. This FOSR has used the 2021 FES data. FES 2022 was published on 18 July 2022, but elements of our analysis had already commenced and therefore we have progressed the FOSR using FES 2021. This also maintains consistency with the Stakeholder Consultation that was carried out and other FOSR submissions being progressed at this time. The FES 2022 framework is consistent with 2021 but due to concerns with how heat has been decarbonised in the Falling Short (previously Steady Progression) scenario and the potential source of Hydrogen in the System Transformation scenarios, we have made the decision to continue with FES 2021 for this year's planning cycle. Full details of the review and differences are detailed in CE-AMP Section 3.

38. All FES 2021 scenarios have been considered for this FOSR and given equal weight in our analysis. However, assessment of the actual changes seen over the last few years shows that annual gas demand has not declined below that forecast for System Transformation. For more information refer to CE-AMP[3].

39. It is our view that until key policy decision and incentives are put in place, gas demand will remain within the Steady Progression to System Transformation range until at least 2030. This is supported by the recent ED2[4] Ofgem decision to base investment on the System Transformation scenario "because this relatively conservative Future Energy Scenario will ensure that consumers do not speculatively fund work that may not be required".

Assumptions Key Points:

- The FOSR has used 2021 FES data - all FES 2021 scenarios have been considered and given equal weight in our analysis.
- Based on our assessment, we believe that gas demand will remain within the Steady Progression to System Transformation range until at least 2030.
- Ofgem's recent ED2 decision to base investment on the System Transformation scenario supports our assumption that gas demand will remain in the Steady Progression or System Transformation range until at least 2030.

[3] See Compressor Emissions - Asset Management Plan 2022

[4] ED2 Ofgem Decision - [RIIO-ED2 Draft Determinations | Ofgem]

Option Evaluation and Final Recommendation

40. We have used the high-level decision tree presented in Figure 3 to support our evaluation and final option selection. As described previously, Commercial Options were ruled out as being not feasible; this would fall under the shown Capability Requirements stage.

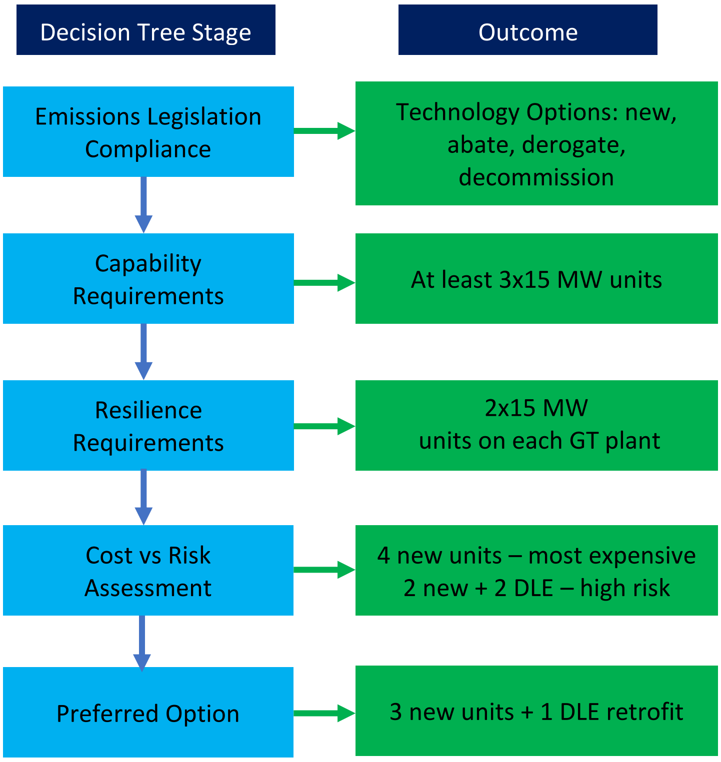

Figure 3 – High-Level Decision Tree

41. Following this process, the outcome for each of the considered options at each stage is shown in Table 2.

Option Description	Emissions Compliance	Capability Requirements	Resilience Requirements	Cost vs Risk Assessment	Preferred Option
0 - Retain 4*Avons on 500 hours					
1 - A1 (Brownfield) - 3 x new 15MW GTs					
2 - A1 (Greenfield) - 3 x new 15MW GTs					
3 - A2 (Brownfield) 2 x new 23MW GTs					
4 - A2 (Greenfield) 2 x new 23MW GTs					
5 - A3 (Brownfield) 2 x new 15MW and 1 x new 23MW GTs					
6 - A3 (Greenfield) 2 x new 15MW and 1 x new 23MW GTs					
7 - A4 (Brownfield) 4 x new 15MW GTs					
8 - E1 4 x Existing Avon 1533 15MW derated					
9 - E2 3 x Existing Avon 1533 15MW derated					
10 - D1 4 x Existing Avon 1533 15MW with DLE modification					
11 - D2 3 x Existing Avon 1533 15MW with DLE modification					
12 - AD1 2 x new 15MW GTs (Brownfield) and 2 x Avon 1533 (15MW) with DLE modification					
13 - AD2 1 x new 15MW GTs (Brownfield) and 3 x Avon 1533 (15MW) with DLE modification					
14 - 3 x new 15MW GTs (Brownfield) and 1 x Avon 1533 (15MW) with DLE modification					
15 - 1 x 23 MW + 1 x 15MW (Brownfield)					
16 - 2 x 15MW +1 Avon 1533 (15MW) with DLE modification					
17 - 1 x 15MW + 2 Avon 1533 (15MW) with DLE modification					
18 - 2 x 15MW (Brownfield)					

Table 2 – Decision Tree Outcome for 18 Options

42. The decision tree is supported in more detail by assessing key criteria such as NOx emissions and NPV. The results of this assessment of the 18 options are shown in Table 21 in Section 8, assigning a relative assessment status ranging between positive and negative against each option for each criteria. All options had a positive Net Present Value (NPV) compared to the counterfactual, with the constraint costs outweighing the lower investment costs of that option.

43. The results of the assessment indicate that Option 14 (three new 15 MW units and one DLE retrofit) performs well against the majority of criteria. In comparison to four new units it only has slightly higher carbon emissions and slightly smaller NPV but this is offset by a lower total installed cost. The only other options that perform similarly or better are those that include additional DLE retrofit units, as these options use existing assets and therefore lower the total installed cost.

44. If this DLE retrofit on the fourth unit is implemented immediately as an additional trial, it could, depending on results and performance, fast-track our ability to prove the technology thus making it a possible candidate for the remaining twelve MCPD non-compliant units across the NTS[5].

45. As described previously, DLE retrofit remains an unproven technology and options that include multiple DLE retrofit units would be considered too much of a risk at a site as critical as St Fergus. However, it is considered feasible to accommodate a single DLE retrofit trial at St Fergus. This is because, if DLE retrofit is proven unfeasible, the presence of multiple other units on site provides mitigating capability while a decision is made on the best way to meet the requirement for four compliant units.

46. Our selected Option 14 (three new units plus one DLE retrofit unit) scores within the top three options in the CBA. It minimises constraints, fuel usage and emissions by ensuring the bulk of primary duty and back-up uses the cleaner and more reliable new units. By proposing to trial DLE on an existing unit, this option is also in line with the guidance set out in Ofgem's Supplementary Re-opener Requirements document, which encourages us to explore opportunities to repurpose and retrofit non-compliant units to minimise capital costs.

47. Our BAT assessment was also supportive of Option 14 (three new 15 MW units and one DLE retrofit) from an operational and environmental perspective. The assessment featured qualitative scoring of all options against key technical and environmental criteria, as well as whole life emissions and costs.

48. Option 14 (three new 15 MW units and one DLE retrofit) scored the joint second highest when compared to all other options in terms of ability to meet compression requirements (versatility), maintenance complexity and availability of spares (ownership), future resilience against tightening of energy efficiency and emissions limits (future proofing) and environmental control (hazard). Regarding emissions reduction, three new units plus one DLE retrofit (alongside SCR) ranked as the leading solution for emissions reduction through improved efficiency and fuel consumption. Overall scores assuming one VSD is available can be seen in Table 19 for the 10 options taken to full BAT Assessment with full details in Appendix J – Preliminary BAT Report Summary.

49. We have considered the results of the option evaluation to arrive at an optimum solution for both achieving emissions compliance and ensuring the long-term Security of Supply of the UK. Through our analysis we have determined that St Fergus requires four compliant units across Plant 1 and Plant 2 by 2030. This report recommends the installation of three new units and one DLE retrofit unit to fulfil this requirement (Option 14 - three new 15 MW units and one DLE retrofit) at an efficient cost to consumers.

[5] These twelve units are: Kirriemuir (A and B), Alrewas (A and B), Wisbech (B), Cambridge (A and B), Chelmsford (A, B and C) and Diss (A, B and C).

50. Option 14 (three new 15 MW units and one DLE retrofit) is supported by the outputs from extensive stakeholder engagement. Through the Autumn 2022 stakeholder consultation a preference was indicated for four units, with at least three of them being new units.

51. This recommendation is subject to positive results from the DLE prototype testing. If the DLE retrofit unit proves unsuccessful we will reassess the options to achieve a fourth compliant unit.

Option Evaluation and Final Recommendation Key Points:

- To fulfil the requirement of providing emissions compliance and continued site capability and resilience, this report recommends the installation of three new units across Plants 1 and 2 and one DLE retrofit unit (Option 14 - three new 15 MW units and one DLE retrofit).
- This decision is supported by the results of the CBA and BAT analysis with Option 14 (three new 15 MW units and one DLE retrofit) scoring the second highest NPV score in the CBA, and the joint second-best total score for BAT.
- The decision is also supported by the outputs from extensive stakeholder consultation which indicated a preference for four units, at least three of them being new units.
- DLE remains an unproven technology and options that include multiple DLE retrofit units would be considered too much of a risk at a site as critical as St Fergus.
- Implementing a DLE trial at St Fergus facilitates the demonstration of this technology to utilise it across the wider NTS.
- If the DLE retrofit unit proves unsuccessful we will reassess the options to achieve a fourth compliant

Conclusion and Next Steps

52. In line with the requirements set out in the RIIO-T2 Final Determination document, the question of who should pay for compressor capital costs at St Fergus has been taken forward and will be addressed further in 2023. See Appendix C – Charging Methodology for further information.

53. Ofgem are invited to assess and approve the proposed final preferred option for the St Fergus gas terminal in line with Special Condition 3.11, Part C, 3.11.9. Following Ofgem's decision on the final preferred option, NGGT will use the received Baseline allowances to develop our preferred option further and submit a Re-opener application in line with Special Condition 3.11, part D and Appendix B – CE-AMP for Ofgem's consideration in June 2025.

54. We have welcomed engagement with Ofgem throughout the option selection process and intend to keep engaging with the regulator at all relevant project development stages. This will ensure Ofgem remain informed throughout and ensure we successfully deliver our proposed solution at the St Fergus gas terminal.

Conclusion and Next Steps Key Points:

- Ofgem are invited to assess and approve the proposed final preferred option for the St Fergus gas terminal in line with Special Condition 3.11, Part C, 3.11.9.
- The final preferred option is installation of three new units across Plants 1 and 2 and one retrofit DLE unit.
- The question of who should pay for investment has been taken forward and will be addressed further in 2023.

Contents

1. Summary Table

Name of Project	T2_Emissions_2021_St Fergus Future Operating Strategy		
Scheme Reference	PAC1050309		
Primary Investment Driver	Compliance with MCPD legislation		
Project Initiation Year	2019		
Project Close Out Year	2031		
Project Spend to Date (£)	[redacted] (until end of December 2022)		
Total Indicative Project Spend	[redacted] +/-30%		
Total Installed Cost Estimate (£)	£168.943m (3 new units and 1 DLE retrofit unit - does **not** include spend to date)		
Cost Estimate Accuracy (%)	+/-30%		
Price Base	2018/19		
Current Project Stage Gate	4.2 – Option Selection		
Reporting Table Ref	RRP Table 6.2 (Projects) and Table 6.1 (Capex Summary)		
Outputs included in RIIO-T1	No		
Outputs included in RIIO-T2	<u>Compressor Emissions Price Control Deliverable (PCD):</u> PCD to ensure NGGT delivers a Final Options Selection Report, long lead items and Re-opener submission[6]. Final Option Selection Report: January 2023 Re-opener application window: June 2025 Baseline allowances: £21.22m (excl. RPEs)		
Spend Apportionment	**RIIO-T1**	**RIIO-T2**	**RIIO-T3**[7]
	[redacted]	[redacted]	[redacted]
Applicable Future Energy Scenario (FES) Edition	2021		

Table 3 – FOSR Summary Table

[6] Detailed in Special Condition 3.11 Compressor emissions Re-opener and Price Control Deliverable

[7] As per project spend profile – Option 14 (three new 15 MW units and one DLE retrofit); See Section 6.3 – Project Spend Profile and including spend to date

2. Project Status and Request Summary

Overview

55. NGGT requires its compressor fleet to achieve compliance with the MCPD legislation from 1 January 2030. As part of our RIIO-T2 submission in December 2019, we proposed to install three new gas driven compressor units at St Fergus Gas Terminal by 2030. Once the new units received operational acceptance, decommissioning of the five existing non-MCPD compliant Avons would take place.

56. As part of Final Determinations, Ofgem determined that there was still uncertainty around the final solution, providing funding to complete the options selection (including engineering assessments) within this Final Option Selection Report (FOSR) and to complete a Re-opener submission in June 2025 (cost submission) once the project has gone through a full Front End Engineering and Design (FEED) and tender process for the final preferred option.

57. This FOSR has been developed using our Option Selection process (Stage 4.2 of the Network Development Process (NDP); an overview of which is available in CE-AMP) to assess credible options aimed at meeting MCPD legislative compliance while meeting customer and stakeholder needs.

Project Status

58. In 2021, NGGT selected [redacted] as Feasibility Consultant to support in further evaluating the available options to achieve MCPD compliance by 2030. All options proposed as part of the RIIO-T2 submission have been further evaluated, along with new emission abatement technology options.

59. A preliminary BAT assessment, undertaken by [redacted], supports the CBA and feeds into the decision-making process. BAT analysis is an assessment of the available techniques best placed to prevent or minimise emissions and impacts on the environment. Options that have been considered in the preliminary BAT assessment are aligned to those described in Section 5 – Option Selection. These include new abatement options identified since the previous assessments included in our 2019 RIIO-T2 business plans. The preliminary BAT Assessment report can be found in Appendix J – Preliminary BAT Report Summary.

60. The required initial and ongoing Asset Health expenditure applicable for each of the shortlisted options has been investigated, see Appendix I – Asset Health Report, and used along with operational running costs within the CBA.

61. A qualitative risk assessment has been undertaken across all options. As part of the risk assessment process, significant areas of risk requiring onward management and opportunities to be further investigated as part of value engineering have also been identified. Risks and Opportunities relating to options can be found within Appendix H – Project Risk Register and Report.

62. All four of the 2021 Future Energy Scenarios (FES) and new Network Capability modelled flow data has been used in the CBA.

63. The inability to accept gas from the NSMP sub-terminal at the St Fergus Gas Terminal (because of unit unavailability and planned or unplanned outages), could result in high constraint costs being passed onto UK consumers. These have been assessed and included in the CBA.

Request Summary

64. To achieve MCPD legislative compliance at the St Fergus Gas Terminal, NGGT's final preferred option is to install three new gas-driven compressors at St Fergus by 2030 and implement a DLE retrofit trial on one of the existing Avons, with an associated cost of [redacted] (2018/19) funded through the Re-opener submission by June 2025. Funding to decommission any non-MCPD compliant units whose removal is required to achieve the proposed solution has been included in this total cost. Complete decommissioning

of any units remaining after the proposed solution is complete will be considered after operational acceptance of the new units, and not included within the Re-opener funding request. The total project cost also includes the already received Baseline funding of £21.22m (2018/19, excl. Real Price Effects (RPEs)). The Baseline funding will be subject to true up following our Re-opener submission.

65. Our final preferred option is supported by a wide quantitative and qualitative assessment of the specific needs of the site including a CBA and BAT assessment which have considered investment costs for compressors, the constraints and contracts, and compressor running costs. The increase in availability that three new units plus a DLE retrofit Avon provide, will minimise network constraints associated with supply flows from UKCS and Norway through the NSMP sub-terminal. Increasing availability and minimising network constraints is supported by stakeholders and customers. Further information on this can be found in CE-AMP. Furthermore, implementation of a DLE retrofit trial supports the development of this technology for potential use on up to twelve MCPD non-compliant units across the NTS.

66. The final preferred option is the most cost efficient for consumers when considering the technology readiness of abatement options and the associated risks. It minimises constraint costs, provides the right level of network capability, delivers a significant reduction in greenhouse gas emissions and is proven to be the most cost beneficial with a short payback time. It also reduces the total number of units at the site, reducing our ongoing maintenance costs and resulting in fewer, more available units. This option has been selected from a complete range of potential options that have been analysed and developed extensively to ensure a robust decision is presented.

67. Ofgem are invited to assess and approve our proposed final preferred option at St Fergus in line with Special Condition 3.11, Part C, 3.11.9. NGGT's view is that the PCD should be viewed as fully delivered once we have submitted our Re-opener application at which point the PCD will be revised to reflect the outputs and allowances related to the delivery of our preferred option. NGGT is reporting on our PCD progress and spend as part of the annual Regulatory Reporting Pack (RRP).

68. Following Ofgem's decision on the final preferred option, NGGT will use the received Baseline allowances to develop our preferred option further, order long lead items and submit a Re-opener application in line with Special Condition 3.11, part D and Appendix B – CE-AMP for Ofgem's consideration by June 2025. We welcome engagement with Ofgem throughout the Option Selection process and intend to keep engaging with them at relevant project development stages, so they remain informed throughout and ensure we successfully deliver our proposed solution at St Fergus Gas Terminal.

Project Status and Request Summary Key Points:

- In line with Ofgem's Final Determinations, we have used Baseline allowances to progress the St Fergus FOSR.
- We have conducted a robust option assessment process that includes feasibility study, CBA, BAT assessment and qualitative risk assessment to support our option evaluation and selection.
- Our analysis supports our request to build three new compressor units and retrofit one DLE unit at St Fergus with an indicative total project cost of [redacted].

3. Problem/Opportunity Statement

Why are we doing this work and what happens if we do nothing?

69. The St Fergus terminal has been in continuous operation for over 40 years and is the highest utilisation compressor site on the National Transmission System (NTS). It is required to operate 24 hours a day, 365 days a year. Even with careful maintenance, the design life of most assets is between 15-40 years, therefore, it requires significant investment to re-life many of these assets.

70. Due to its continuous running, the St Fergus terminal also has some of the highest emissions on the NTS. NGGT is committed to reducing the impact of its activities on the environment while operating with the required network resilience and capability.

71. NGGT is legally obligated to have its compressor fleet compliant with MCPD legislation from the deadline of 1 January 2030. Five of the nine compressors present at the St Fergus Terminal (Units 1A, 1B, 1C, 1D and 2B) fall within the MCPD category and can breach the NOx limits imposed. Therefore, these units require intervention to ensure the site remains legally compliant. At its minimum, this intervention would involve the derogation or decommissioning of these units, which are assessed as part of this process. In addition to this, two units (Units 2A and 2D) are derogated under IED legislation and must cease operation by 31 December 2023 (or when they reach 17,500 hours since entering the derogation).

72. The compressors at St Fergus are configured across three operational plants. Plants 1 and 2 contain a mixture of Siemens (formerly Rolls-Royce) Avon's and RB211s. Plant 3 contains two electric driven Siemens Variable Speed Drives (VSDs); Units 3A and 3B. See Figure 4Figure 4 for a site overview.

[redacted]

Figure 4 – St Fergus Gas Terminal Site Overview

73. Units 3A and 3B are the lead units on site, with the remaining gas compressors providing resilience when the VSDs are not available, either due to planned or unplanned outages. The GTs also have the required capability to support flows outside the range of the VSDs. This utilisation of the different capabilities is

shown later in Figure 9. More information on the role of St Fergus compression can be found in the overarching St Fergus Site Strategy (Appendix A).

74. The St Fergus gas terminal is one of the most strategically important sites on the NTS. It regularly supplies over 25% of the UK's gas supplies and is an entry point to the system for gas from three sub-terminals, currently owned by Ancala, Shell and NSMP. It provides access to gas from the UK Continental Shelf (UKCS) and from Norway, the cheapest sources of natural gas into the UK. The access to UKCS gas also allows access to oil production, with any restriction of gas supplies into St Fergus having a significant financial and environmental impact on customers' ability to produce oil. This is because gas is produced as a by-product of oil production either being flared, or oil production reduced if gas transportation is compromised. Therefore, St Fergus is critical in supporting UK Security of Supply and ensuring customers will be able to take gas on and off the system where and when they want providing the necessary energy needs for domestic, commercial, and industrial use at lowest available cost.

75. The 2021 Future Energy Scenarios (FES) shows that there is an enduring need for the site until at least 2050 and St Fergus remains critical in facilitating our customers' current and future plans. There is continued investment in the North Sea sector, with new discoveries of natural gas coming on stream, particularly west of Shetland. There have also been some substantial acquisitions of existing gas fields by new operators showing a long-term investment plan for the area. Some of the North Sea gas production is connected only to St Fergus, and so production would be stranded without access to the St Fergus terminal (for example the Frigg UK Association (FUKA) pipeline route).

76. This commitment to energy independence through domestic energy supply investment has been further strengthened, considering current global geopolitical and economic conditions, with the government confirming its support for a new oil and gas licensing round, launched by the North Sea Transition Authority (NSTA) in October 2022[8]. The logic for maintaining or expanding production in UKCS is also motivated by wider European energy security and market opportunity. Even in a scenario where UK demand for gas materially decreases, the UK NTS will be a crucial conduit for UKCS gas, Norwegian gas and global LNG to be exported to continental Europe.

77. The option of 'Do nothing' for this project, is defined as the 'Counterfactual' within this FOSR. This is where no action is taken, other than asset health works, and Units 1A,1B, 1D and 2B are operated under Emergency Use Derogations (EUD). Unit 1C is currently non-operational and therefore not considered in the counterfactual option or availability model. Derogation would limit the units to 500 run hours per year over a five-year rolling average, with no reduction in emissions from the units during their operation. For the rest of this report, this will be referred to simply as a restriction of hours.

78. Limiting the available run hours of these units will impact the ability to maintain network capability, preventing us from meeting our customers' requirements and disrupting the UK's Security of Supply by increasing our dependence of imports from either Europe or via LNG.

79. Commercial contracts would not be cost effective in minimising the impact of constraints to the consumers. We discuss the wider viability of commercial options in Section 5, where we demonstrate that commercial options do not provide a feasible alternative to physical investment.

80. This FOSR has considered and compared multiple options, to ensure that the final preferred option (replacing the existing gas units with three new units and carrying out a DLE retrofit trial on one of the existing Avons) meets the MCPD requirements and accommodates the wide range of potential flows at the St Fergus NSMP sub-terminal to provide the most cost-effective option for our customers and the UK's gas consumers.

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[8] https://www.nstauthority.co.uk/licensing-consents/licensing-rounds/offshore-petroleum-licensing-rounds/#tabs

Under what circumstances would the need or option change for this project?

81. The final preferred option of three new units and a DLE retrofit trial by 2030 is further reinforced with any delay to the Future Energy Scenarios' stated speed of UK electrification, as detailed in CE-AMP.

82. Changes in system operation or supply/demand scenarios which could alter the final preferred option:

- Significant changes in supply and demand patterns which dramatically increase or decrease UKCS and Norwegian gas supplies into St Fergus beyond the scope of any current projections.
- DLE site trials prove that retrofitting DLE to Avon units is an unviable option
- Changes in offshore operating models of new discoveries that increase or decrease UKCS and Norwegian gas supplies into St Fergus.
- Clarity on the impact on the gas industry of the net-zero target for 2050 and the development of Hydrogen use.

83. Any changes in legislation could impact the preferred option for three new units and a DLE retrofit trial. Below is a list of changes that could impact the final preferred option:

- Unilateral change in the UK environmental legislation to rescind or alter the conditions of MCPD. For example, lowering the required NOx levels and/or including CO limits would favour new, more efficient units over existing units that just meet the current legislative levels.
- Introduction of legislation that defines the required energy efficiency of our compressors would favour new units.

84. Any other changes that could impact the preferred option for three new units and one DLE retrofit trial, are listed below:

- Increasing energy costs would favour new units that are more efficient than the existing ones.
- Increasing material costs is less favourable to new units due to the larger material quantities required when compared with retrofit options.
- Access to skills in the St Fergus area when competing with the offshore industry. We've already taken this into account based on our RIIO-T1 experience, but if the situation changed significantly it could result in higher or lower costs.
- Unforeseen maintenance and/or failure of the existing Avons resulting in increased Asset Health costs would favour new units.
- Reduction in the availability of spares for the existing Avons could result in increased down time, favouring new units.
- Reduction in third party support for the existing Avons would favour new units.
- Any changes to the contractual obligation for compression for the NSMP sub-terminal.
- Preference of FES faster electrification scenarios are less favourable to new units due to the low demand and constraints.
- Preference of FES which include a slower pace of electrification are more favourable to new units due to high demand and constraints.

What are we going to do with this project?

85. To achieve MCPD compliance at the St Fergus Gas Terminal, NGGT's final preferred option is to install three new gas-driven compressor units before the MCPD deadline of the 1 January 2030 and carry out a DLE retrofit trial on one of the existing Avons. Once these new units have been commissioned and are operationally accepted, the remaining Avons (which will be a subset of the following: Units 1A, 1B, 1C, 1D and 2B) will be considered for decommissioning.

86. This recommendation is subject to positive results from the DLE prototype testing. If the DLE unit proves unsuccessful we will reassess the options to achieve a fourth compliant unit.

87. More detail on our final preferred option can be found within Section 8.1 – Preferred Option for the Request.

Problem/Opportunity Statement Key Points:

- The St Fergus gas terminal is one of the most strategically important sites on the NTS and there is an enduring need for the site until at least 2050.
- The site is one of the most polluting sites on the network and has assets that are over 40 years old - intervention is required to comply with environmental legislation and to re-life ageing assets.
- NGGT is legally obligated to ensure the five Avons at St Fergus are compliant with MCPD legislation from the deadline of 1 January 2030
- Derogation limits the available run hours of these units and would impact the ability to maintain network capability, preventing us from meeting our customers' requirements and disrupting the UK's security of supply.
- Commercial contracts would not be cost effective in minimising the impact of constraints to the consumers.

What makes this project difficult?

88. Construction of new units on our network takes approximately six years from confirmation of preferred option to operational acceptance. To ensure that the final preferred option of three new units and one DLE are operationally accepted by the 2030 deadline, construction cannot be delayed. For the Option 14 (three new 15 MW units and one DLE retrofit) Level 2 programme, please see Section 8.2 – Option Programme. Construction of three new units and implementation of the DLE trial at St Fergus Terminal will require multiple outages, careful management of simultaneous operations and complex stakeholder engagement to ensure that the site continues to flow gas.

89. The St Fergus Gas Terminal is in a geographically isolated part of the United Kingdom which increases the costs of supplying material and personnel to site. In addition, the human resources and skill sets required to carry out gas transmission construction projects are in high demand by the rest of the North Sea Oil and Gas Industry and onshore and offshore renewables. This can create highly competitive market conditions for these resources that may affect cost and programme.

90. Due to St Fergus's critical location on the network, any maintenance and/or down time on the existing units will reduce capability to accommodate supplies from the NSMP sub-terminal, potentially leading to constraints. Construction of the new units on existing plant locations should minimise the impact on the existing units, maintaining the current level of availability and capability during construction. However, this sequencing will be developed further in FEED.

91. The current national and international geopolitical situation is creating significant uncertainty in prices and availability of materials and labour which makes estimating project delivery costs more challenging. This will need to be a consideration when finalising the delivery strategy after confirmation/approval of the preferred option. A sensitivity has been included within the CBA which considers the impact of increasing capex costs.

92. Risks and opportunities associated with the preferred option can be found in Section 8.3 – Option Risks and Opportunities and details of risks and opportunities of all shortlisted options can be found in Appendix H – Project Risk Register and Report.

Problem/Opportunity Statement Key Points:

- To ensure that new units are operationally accepted by the 2030 deadline, construction cannot be delayed, as it takes approximately six years from confirmation of preferred option to operational acceptance. Therefore, investment decision delay is not feasible.
- Construction of new units will endeavour to avoid outages which reduce capability to accommodate supplies from PX, as this could lead to constraints.

What are the key milestone dates for project delivery?

93. The project aims to have the three new units commissioned in 2029, allowing time for them to become operationally accepted prior to the 2030 deadline. Milestone dates have been informed by scheduling of this project against other planned investment work. This has identified that the opportune time to begin the design and build phase at St Fergus is in 2025 with operational acceptance and project closure in 2030 as summarised in Table 4.

94. The DLE trial will be implemented as soon as possible to provide results that can feed into wider network decisions that will support our RIIO-T3 business plan.

ND500 – Network Development Stage Gates and Key Milestones			
ND500 Phase	**Key Activities**	**Sanction**	**Indicative**
4.0 **Needs Case**	• Identification of Needs case • Define strategic approach and outputs required to deliver	**T0**	N/A
4.1 **Establish Scope and**	• F1 Sanction - Optioneering	**T1**	January 2021
		F1	January 2021
		T2	April 2021
		F2	April 2021
4.2 **Option Selection**	• F2 Sanction- Feasibility • BAT Assessment and Compressor Machinery Train Selection • Final Option Selection Report Submission • Agreement to Proceed to Conceptual Design • F3 Sanction -Conceptual Design and Long Lead Items	**T3**	January 2024
		F3	January 2024
4.3 **Concept Design and Development**	• UM Cost Re-opener Submission • Scope Freeze	**T4**	August 2025
		F4	August 2025
4.4 **Project Execution**	• F4 Sanction – Detailed Design and Build • DDS Challenge, Review and Sign Off • Maintenance Requirements Identified	**T5**	November 2026
		T6	December 2029
4.5 **Project Acceptance**	• Post Commissioning Handover to GT • Operational Acceptance • Project Closure	**F5**	December 2030

Table 4 – Key Project Milestones

95. The stage gates within our Network Development Process ensure minimum requirements are met for each phase of investment development.

96. Decommissioning of any remaining Avons will be carried out after the outcome of the DLE trial is known and the operational acceptance of the new units has taken place.

How will we understand if the project has been successful?

97. Overall project success will be confirmed by operational acceptance of the preferred option, meeting customer demands throughout the construction period, compliance with MCPD requirements whilst retaining the required level of site resilience, as well as the project completed safely and to time, quality and cost.

98. Additionally, the DLE retrofit trial will be deemed a success when a successful review and inspection has been carried out at [redacted], at which point the concept could be considered as a prime candidate for other sites.

99. For this Option Selection stage, the project will be deemed a success if the Price Control Deliverable (PCD) set out in Special Condition 3.11 will be deemed as fully delivered. The PCD entails the FOSR being submitted to Ofgem by January 2023 and the Re-opener submission by June 2025 following Ofgem's review of the preferred option that provides the best value for consumers.

Problem/Opportunity Statement Key Points:

- The optimum time to begin the design and build phase at St Fergus is in 2025, with operational acceptance and project closure in 2029.
- The DLE retrofit trial will be implemented as soon as possible to provide results that can feed into wider network decisions that will support our RIIO-T3 business plan.
- Decommissioning of any remaining Avons will be carried out after the outcome of the DLE retrofit trial is known and the operational acceptance of the new units has taken place.

3.1. Related Projects

100. There are key interactions with other significant investments, both at St Fergus and across the NTS:

- St Fergus station and unit control system replacements are planned for 2024/25 and 2025/26 delivery.
- Funding has been granted through the RIIO-T2 Redundant Assets theme to remove a variety of redundant assets across the site which are not required in any future scenario. There may be potential for bundling of this work with other investments for more efficient delivery.
- Funding has been granted through the RIIO-T2 Asset Health theme across a variety of assets (such as drainage, ducting, fuel gas skids). Some of these are fully funded but others will require additional funding and this is being requested for further Asset Health works, as set out in our Asset Health Uncertainty Mechanism submission. This will aid in maintaining the availability of the units, minimising constraints until our final preferred option is implemented by 2030.
- Potential for resource challenges (e.g. contractor capacity) when delivering multiple MCPD compliance projects across multiple sites. However, there is also the potential for cost-saving through multi-buy discounts and knowledge sharing across all in flight MCP schemes.

101. To increase the options available to comply with MCPD legislation, we are trialling emissions abatement technologies to determine their viability and legal acceptance. These technologies are:

- Control System Restricted Performance (CSRP) - This involves permanently derating or reducing the power output of an Avon through modification of the control system. A CSRP proof-of-concept trial was conducted at Huntingdon and Chelmsford Compressor Stations in winter 2021. It successfully confirmed a correlation between Exhaust Cone Temperature and NOx emissions. Further information is provided in a dedicated CSRP report which can be found in CE-AMP.
- DLE - An Avon DLE retrofit modifies the combustion system within the Avon engine so that air and fuel are premixed before combustion. This reduces the peak combustion temperature, which in turn reduces the amount of NOx produced. NGGT have funded development of a DLE retrofit 1533 Avon in partnership with [redacted], beginning with combustor can trials in early 2022. A full engine test bed performance trial to determine NOx reduction, and operational trial on an NTS

unit to determine unit availability has been planned. As the performance trials are ongoing, an interim summary report is provided within CE-AMP.

102.To support our Option Section process we have developed a detailed Reliability Availability Maintainability (RAM) model which has evaluated unit availability across the entire NGGT fleet. This study was developed in collaboration with [redacted]. An overview of the RAM model and how it has been applied and used in the CBA can be found in CE-AMP. See Section 4 – Project Definition for more detail on Annual Network Capability Assessment Report (ANCAR) 2022.

3.2. Project Boundaries

103.The scope of this project is delivery of emissions compliant compression which meets forecast network capability requirements. For St Fergus, these are costs associated with construction of three new gas-driven compressor units and undertaking a retrofit DLE trial. Other costs such as ongoing asset health costs, decommissioning of redundant compressor units required to facilitate the proposed option and operational running costs for the existing units and site are included in the CBA, although we will not request funding for these until the planned Re-opener submission by June 2025.

104.Decommissioning costs for redundant compressor units not associated with option delivery are not included within this Final Option Selection Report. A request for decommissioning funding of these redundant units will not be included within the Cost Re-opener as decommissioning investment will be delivered once the new units have been operationally accepted and requested as part of future decommissioning business plans.

105.As detailed within Section 3.1 – Related Projects, investments which are already funded as part of our RIIO-T2 business plan are not included within this report. These include asset health, station and unit control system replacements and decommissioning of redundant assets. This report also does not include unfunded asset health investments which are being submitted through the Asset Health Uncertainty Mechanism Submission.

Problem/Opportunity Statement Key Points:

- The St Fergus FOSR project has some interactions with other NGGT investments. These include St Fergus station and unit control system replacements, RIIO-T2 Redundant Assets and RIIO-T2 Asset Health.
- To increase the options available to comply with MCPD legislation, we also have inflight projects trialling CSRP and DLE emissions abatement technologies.
- The scope of the St Fergus FOSR is restricted to costs associated with construction of three new gas-driven compressor units and undertaking a retrofit DLE trial. Other costs, such as ongoing asset health costs, are included in the CBA but we will not request funding for these until the planned Re-opener submission in June 2025.

4. Project Definition

4.1. Expected Flows and Site Operation

106. The details in the following section are based on the analysis undertaken in support of our 2019 RIIO-T2 business plan submission to Ofgem, and associated Annex A24.16 St Fergus Plant 2 Redevelopment Justification Report December 2019. The details have been updated and refined to support the FOSR.

107. The Needs Case was established in our RIIO-T2 Business Plan to consider the options at St Fergus to comply with MCPD legislation and future flow expectations. In the RIIO-T2 Final Determination, Ofgem accepted the need in RIIO-T2 to consider options for investment to meet MCPD compliance and to come up with a long-term plan which also considered required asset health work. Therefore, a separate Needs Case document has not been issued. This FOSR has been funded as a Price Control Deliverable (PCD), proposing a final solution determined by feasibility study.

Supply and Demand Scenario Discussion and Selection

108. An assessment of the flows at the NSMP sub-terminal was completed together with the capability of our proposed options. The output from this was used in a risk and constraint assessment to define the associated constraint costs.

109. This FOSR has used the 2021 FES data. FES 2022 was published on 18 July 2022, but elements of our analysis had already commenced and therefore we have progressed the FOSR using FES 2021. This also maintains consistency with the Stakeholder Consultation that was carried out and other FOSR submissions being progressed at this time. The FES 2022 framework is consistent with 2021 but due to concerns with how heat has been decarbonised in the Falling Short (previously Steady Progression) scenario and the potential source of Hydrogen in the System Transformation scenarios, we have made the decision to continue with FES 2021 for this year's planning cycle. Full details of the review and differences are detailed in CE-AMP Section 3.

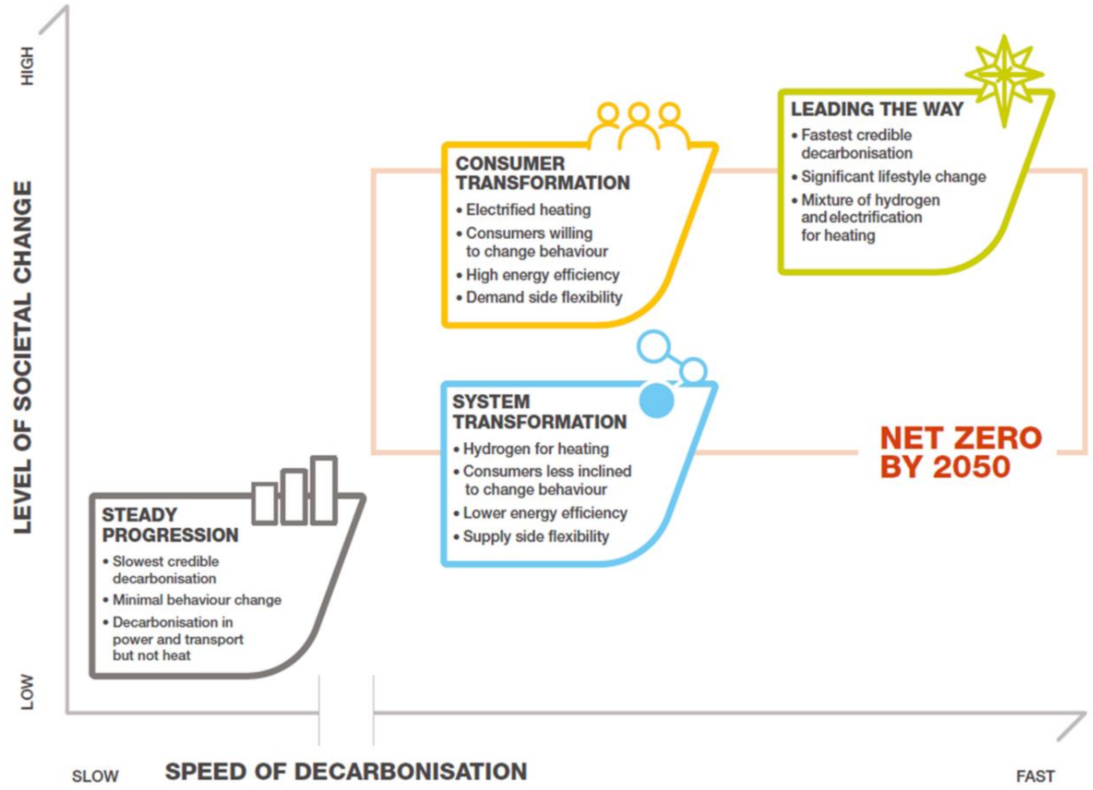

Figure 5 – 2021 Scenario Framework

110. The four FES scenarios, as described in the National Grid ESO Future Energy Scenarios[9], provide different potential pathways to a net zero future. These range from the Steady Progression (SP) scenario, that falls just short of the net zero target, to Leading the Way (LW) which achieves net zero ahead of 2050. Each scenario is dependent to varying degrees on a series of changes to; government policy and legislation, energy delivery and consumption, consumer behaviour, technological change and government incentives and investment. In many ways these different pathways, also represent different potential extremes of energy industry change. As such, FES on its own provides no validation of the most appropriate investment option, instead it provides a broad envelope of energy backgrounds against which the merit of alternative investments may be appraised.

111. The two low natural gas scenarios are Customer Transformation (CT) and Leading the Way (LW). These scenarios meet the net zero targets via electrification either at a transmission or distribution level and involve changes in consumer behaviour and high improvements in energy efficiency. The use of Hydrogen is considered in LW and System Transformation (ST) scenarios. In LW, Hydrogen is produced mainly from green sources (with a small amount from methane reformation with carbon capture), and in ST from a combination of green and blue sources, which is the reason for the high long term natural gas need for ST. In many ways, ST is the most balanced scenario with a mixture of electrification, conversion to Hydrogen and increased energy efficiency and demand led consumption. The CT scenario features a supply led consumption. With ST, there is less consumer behaviour change and lower energy efficiency with hydrogen providing significant space heating energy.

112. Current market trends and levels of actual supply/demand indicate that Customer Transformation and Leading the Way scenarios can be considered ambitious and that a strong reliance on gas is likely beyond 2030, as detailed in CE-AMP (Section 3). All FES 2021 scenarios have been considered for this FOSR and

[9] https://www.nationalgrideso.com/future-energy/future-energy-scenarios

given equal weight in our analysis. However, assessment of the actual changes seen over the last few years shows that annual gas demand has not declined below that forecast for ST as discussed in CE-AMP. It is our view that until key policy decision and incentives are put in place gas demand will remain within the SP or ST range until at least 2030. Meaning that any decision made based on the assumed reductions seen in CT and LW would result in the network having insufficient network capability and resilience. This is further supported in the recent ED2 decision by Ofgem to base investment on the ST scenario.

Supply and Demand Scenario Key Points:

- FES 2021 has been used for this FOSR document.
- All FES 2021 scenarios have been considered and given equal weight. However, current market trends and levels of actual supply/demand indicate that gas demand will remain within the Steady Progression to System Transformation range until at least 2030.
- This is further supported in the recent ED2 decision by Ofgem to base investment on the ST scenario.

Key Flows and Boundaries

113. In addition to analysis of the FES data flows, we have also undertaken stakeholder engagement with NSMP[10], who own the sub-terminal, to determine the rationale behind their expected flows and to corroborate the flows expected through their sub-terminal. Following detailed discussions with NSMP it has been determined that the likely flow range for the sub-terminal out to 2041 will be in the range 8 to 75 mcm/d; this full flow range will need to be accommodated by the compression available at St Fergus, and so a range of compression capability will be required to deal with the range of expected flows from low to high.

114. The findings of the engagement with NSMP have been summarised in a report, details of which can be found in Appendix Q – Stakeholder Engagement Log. Figure 6 provides a breakdown of the flows from UKCS sources and those from the flexible Norwegian pipeline. This flexibility further drives the need to ensure we are able to meet the capability and resilience across the full range of potential flows.

[10] See Appendix Q – Stakeholder Engagement Log

[redacted]

Figure 6 - NSMP Peak flow projections

115. In early consultation with Ofgem and NSMP flows below 8 mcm/d were considered as a sensitivity to the main Feasibility Study. The findings of the assessment resulted in the requirement being discarded. Full details of the assessment can be found in Section 5.4.

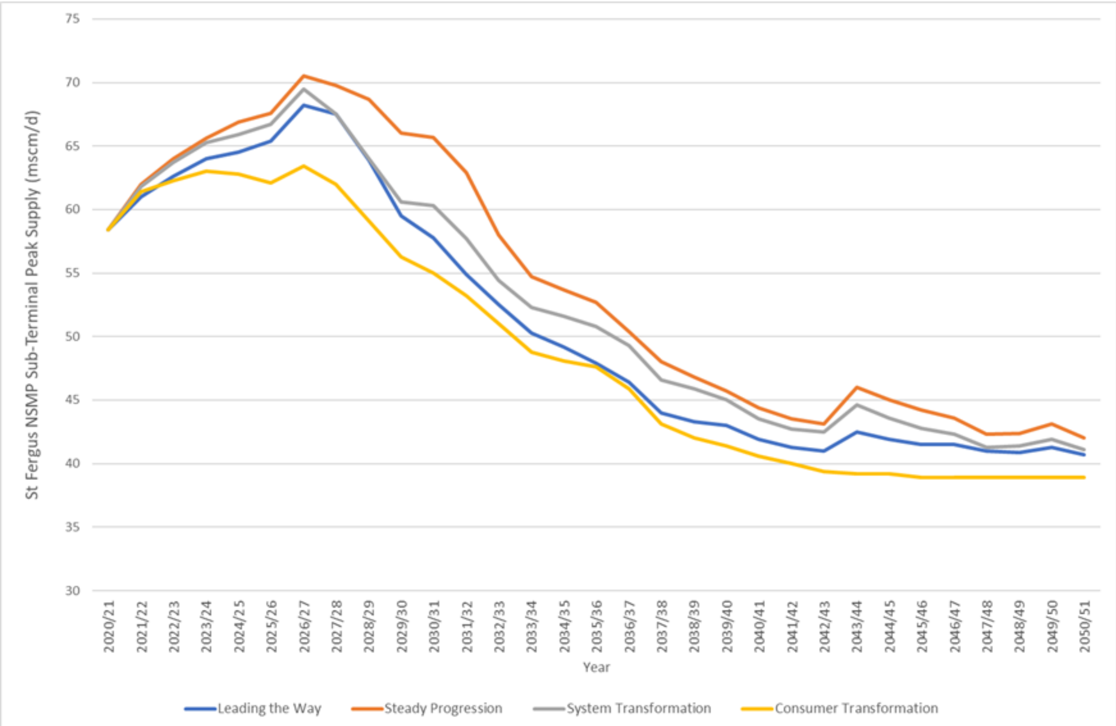

Figure 7 – Peak day St Fergus NSMP Sub-Terminal Supply FES 2021

116. Figure 7 shows the maximum supply flows at St Fergus for each of the FES 2021 scenarios. Although there is expected to be a fall in peak supply level in all scenarios, the supply levels are still significant, demonstrating the continuing need for capability at St Fergus out to and beyond 2050. Any investment at St Fergus will need to consider the wide range of potential flows that may arise over time, from low to high.

117. The peaks calculated by the FES process (Figure 7) are conservative when compared to the view provided by NSMP (Figure 6) which is informed by the producers who utilise the terminal. This view has maximum flows remaining at around 75 mcm into the early 2030s and declining at a slower rate. This supports using FES 21 to set a conservative high case while still providing a sensible low case to model the likely future compression requirements.

118. The FES 2021 High and Low cases provide a good range of possible outcomes and defining characteristics and are supportive of the predicted flows in ST and CT scenarios.

119. It should be noted that the impact of the April 2022 Energy Security Strategy to increase indigenous supplies and reduce our import dependence, has not been factored into the current predictions for North Sea production. This could lead to:

- New licensing round could provide upside for fields that have yet to be found
- Accelerated development of planned fields
- Good levels of North Sea investment due to general interest in greater Security of Supply

Key Flows and Boundaries Key Points:

- Following detailed discussions with NSMP it has been determined that the likely flow range for the sub-terminal out to 2041 will be in the range of 8 to 75 mcm/d. This flow range will need to be accommodated by the compression available at St Fergus.
- The maximum expected supplies at St Fergus remains high in all FES scenarios demonstrating the continued need for capability at St Fergus out to and beyond 2050.

Current Operation

120.The current operation of the site is detailed in the St Fergus Site Strategy. The compression assets on site specifically facilitate the supply of gas from the NSMP sub-terminal, as shown in Figure 8.

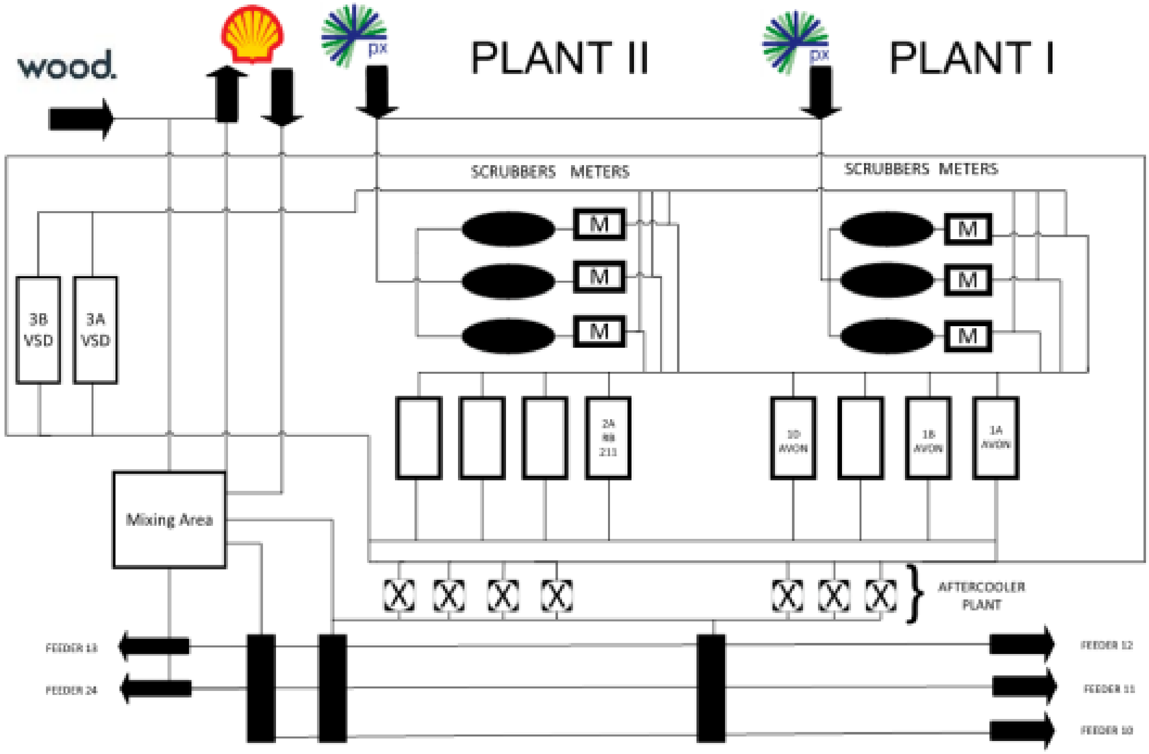

Figure 8 – St Fergus Terminal Schematic Layout

121.Plants 1 and 2 offer flexibility; they can operate independently but are usually operated together. The supporting assets – scrubbers and Aftercoolers – 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.

122.Rationalisation of the number of compression plants was considered through the Resilience Assessment, attached to the St Fergus Site Strategy, but we determined that it would significantly increase the risk of loss of compression with little associated cost savings.

123.Furthermore, utilising the space offered by both Plants 1 and 2 makes it possible to design a future solution with full Class 4 minimum separation distance compliance. The existing compressors on Plants 1 and 2 are 20m apart, with the two plants 34m apart; this was compliant with guidance at the time it was constructed. However, any construction of new units should comply with the current recommendations which requires greater distance between units.

124.Therefore, any use of GTs (new, derogated or abated) across the existing Plants into the future should make use of both Plants 1 and 2 to ensure sufficient resilience and separation between units.

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

126.The VSDs provide bulk compression capability, effectively mimicking the capability of the RB211s. To effectively map the entire operating envelope of the site, the smaller Avon gas units continue to be required, as shown in Figure 9, for when flows are:

- below the minimum turndown capacity of a single VSD (below 20 mcmd)

- mid-range i.e. greater than a single VSD but less than two VSDs at minimum turndown capacity (30 – 40 mcmd)
- very high i.e. greater than two VSDs in parallel (above 60 mcmd)

127.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 because of black-outs, outages or maintenance.

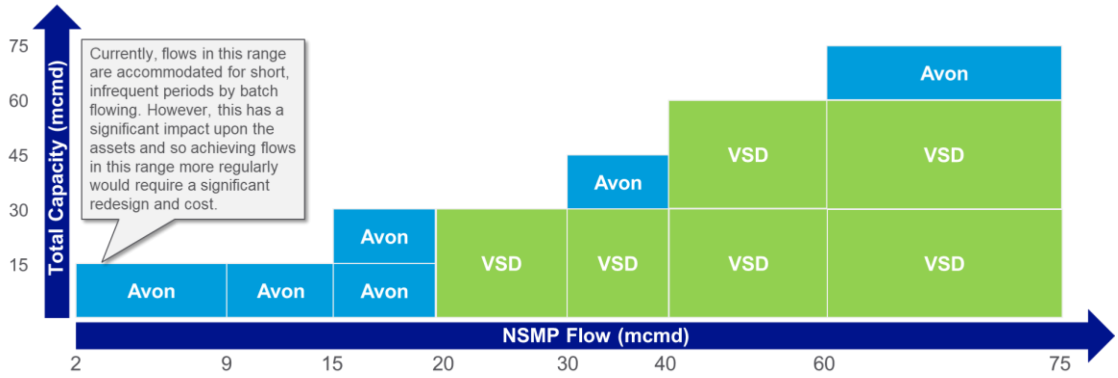

Figure 9 – St Fergus Unit Capabilities

128.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 short-term by recycling gas via the plant recycle line but this is an inefficient use of fuel which places great strain upon the assets and is thus minimised.

129. Figure 9 demonstrates the need to ensure that future compression capability can cover the full range of flows, from low to high. In addition, suitable levels of backup will also be required covering the full range of potential flow bands. This is demonstrated in Figure 10 and Figure 11 where the 15 MW units step in to cover the duty of a missing VSD.

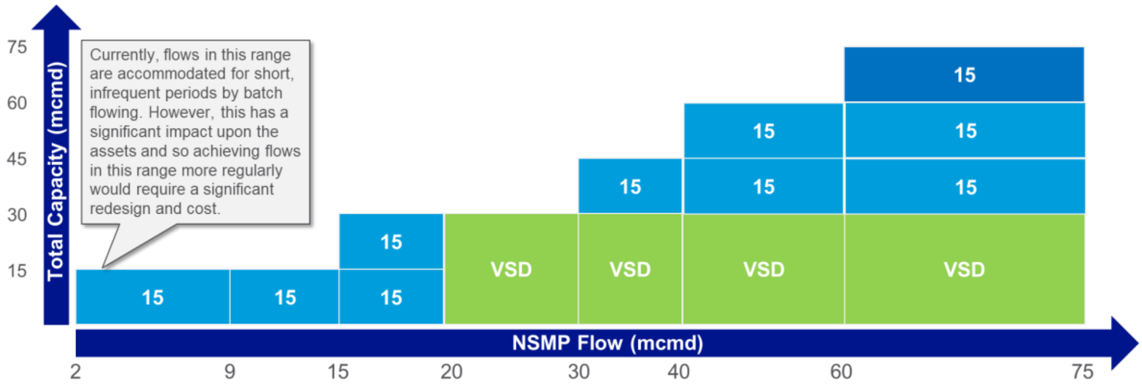

Figure 10 – St Fergus Unit Capabilities with one VSD unavailable

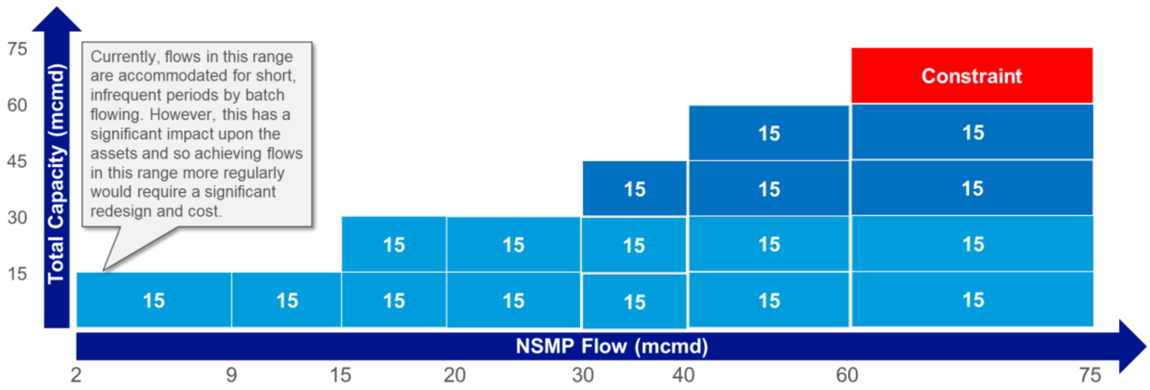

Figure 11 – St Fergus Unit Capabilities with two VSDs unavailable

130.From an operational perspective, flows through St Fergus have always shown a high degree of variability. The heat map in Figure 12 below is of the NSMP sub-terminal flows from 2010 to date. It can be seen that in recent times there has been a wide range of flows, from close to zero up to around 60mcm/d. The range of flows occurs over a wide range of NTS demand ranging from around 100mcm/d to above 400mcm/d. The green and red zones of the heat map are concentrated around average flows on the NTS, as expected, and show typical NSMP flows to be in the region of 20mcm/d, which as discussed above, is at the lower limit of the VSD units' capability. This demonstrates the importance of the smaller Avon units, ensuring flexibility in the operation of the NSMP sub-terminal by dealing with flows at the lower but frequent end of the flow range.

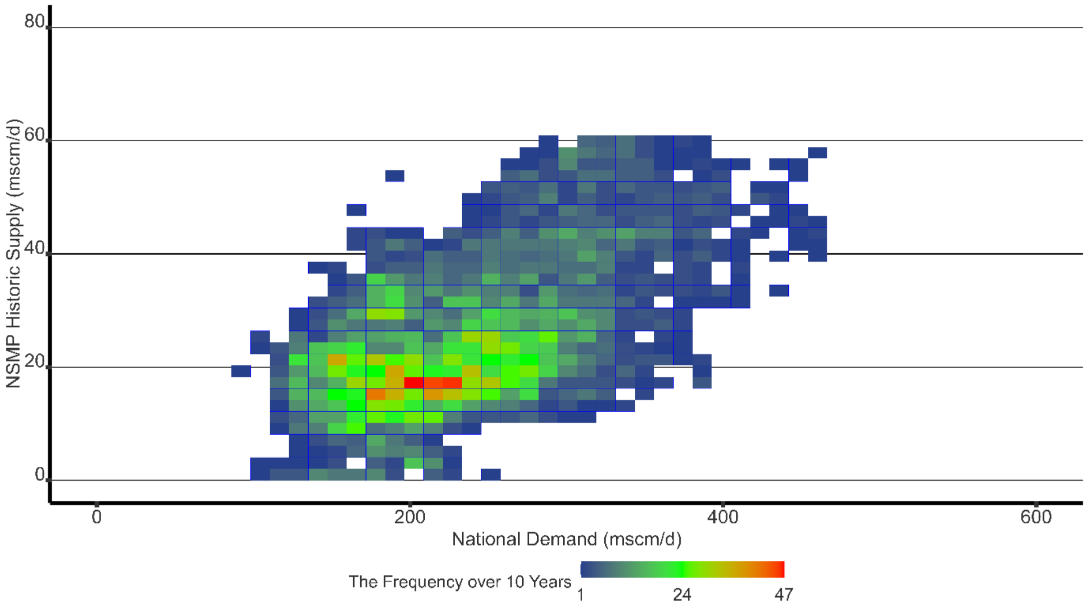

Figure 12 – Heat Map of NSMP Historic Flows 2010 to Date

Compressor Utilisation

131.The compressors at St Fergus have the combined highest running hours of the NTS compressor fleet (29% of 2020/21 total).

132.The running hours of the compressor units by financial year are shown in Figure 13. There are differences in run hours from year to year, with no definitive trend, averaging in the region of 11,200 running hours for the site per year. Usually, where a unit shows no run hours it is due to an extended outage to resolve

Asset Health issues. Units 3A and 3B were commissioned in 2015 and therefore have no run hours prior to this.

	Individual Unit Running Hours (financial year)									
	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23 YTD
St. Fergus Unit 1A	3263	2482	942	281	518	92	237	3585	1274	881
St. Fergus Unit 1B	175	25	632	339	447	0	0	300	606	139
St. Fergus Unit 1C	1497	2407	1214	1353	939	4	389	388	0	0
St. Fergus Unit 1D	833	1371	776	1458	465	0	595	3248	2898	839
St. Fergus Unit 2A	477	1756	1709	1006	2726	688	1077	1053	460	1960
St. Fergus Unit 2B	60	253	1337	7	77	840	159	0	0	0
St. Fergus Unit 2D	4592	1131	152	740	1365	1236	994	0	0	0
St. Fergus Unit 3A	0	0	618	4800	2211	3605	2326	2195	1273	1763
St. Fergus Unit 3B	0	0	3001	4182	5420	4268	3791	1504	3648	1979
Total	10897	9425	10381	14166	14168	10733	9568	12273	10159	7561

Figure 13 – Compressor Run Hours from Regulatory Reporting Packs (RRP) 2013/14 to 2022/23 YTD (End Dec)

133. The variation in flows demonstrates the need for a range of units able to deal with uncertainty and changes in flow patterns over time, with both VSD and Avon units being critical to meeting the wide range of flow patterns.

Current Operation and Utilisation Key Points:

- Plants 1 and 2 provide the necessary site flexibility with Avon units being needed to support flows outside the capability of the VSDs.
- GTs split across two plants are needed to maintain the required level of site capability and resilience.
- The Avon GT units also provide backup if the electric VSDs are unavailable.
- The variation in flows demonstrates the need for a range of units able to deal with uncertainty and changes in flow patterns over time, with both VSD and Avon units being critical to meeting the wide range of flow patterns.

4.2. Capability and Availability

Network Capability

134. An assessment of the potential FES flows has been carried out based on our capability analysis process which has been developed to assist in defining the capability of the NTS. Part of this process uses a statistical assessment to give a visual representation of FES potential flows, colour coded by expected frequency. The results are shown in the form of 'Flame Charts' in Figure 14below. Further details of the creation of the Flame Charts are given in our annual publication Gas Ten Year Statement (GTYS) 2021, and in our annual ANCAR statement.

135. The Flame Charts contain dots plotted onto the chart where one dot is associated with one day in that year, and for every day there are 7840[11] alternative supply and demand patterns across the four FES

[11] For each FES scenario there are 980 supply / demand flows considered, for both high and low LNG import cases. This gives 7840 possible supply/demand patterns per day equating to 2,861,600 possibilities per year. These are mapped as points onto our flame charts as dots colour coded to reflect frequency range at a location on the charts. Refer to our annual ANCAR publication for more information.

scenarios and associated high and low LNG sensitivities[12]. The frequency of a particular flow point is represented by the colouring on the chart, as defined in the chart key. Charts are shown for years 2030 and 2040 showing how we expect supply and demand patterns to change over time, covering the period of focus for the CBA analysis.

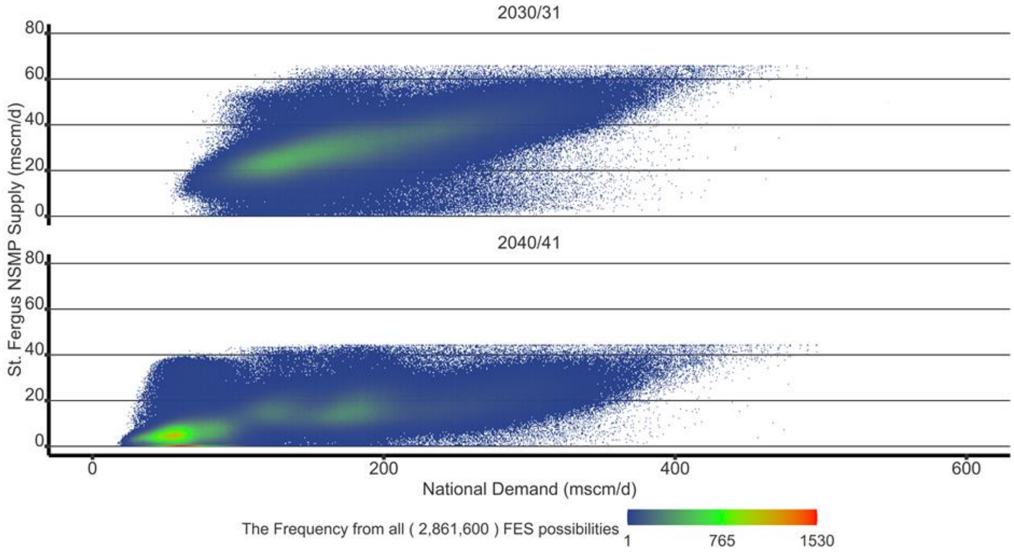

Figure 14 – St Fergus NSMP Sub-Terminal Entry Flame Chart for 2030/31 and 2040/41

136. The flame chart shows the range of potential flows across all FES scenarios for the years 2030/31 and 2040/41. It can be seen there is the potential for a wide range of flows ranging from relatively low to high, with the range of potential flows decreasing in 2040 compared to those for 2030.

137. To facilitate our wider stakeholder needs to take gas on and off the system as and when they want, and to aid UK Security of Supply, it is necessary to be able to accommodate a wide range of flows. This will require a range of operational units to be available that can be used in a range of permutations, providing capability across the full range of possible flows, with a tendency towards the lower flow ranges in later years.

Security of Supply

138. St Fergus is a critical site to support UKCS and Norway supplies, which are the UK's lowest cost sources of gas. The governments April 2022 Energy Security Strategy is to reduce reliance on more expensive imports, such as LNG or European imports. Compression capability and resilience at St Fergus is key to facilitate the indigenous UKCS gas into the UK, as well as support the flexible Norwegian imports as and when required. Failure to provide the right level of capability and resilience will result in higher costs to consumers. The potential magnitude of increased costs arising from supply constraints at St Fergus is covered in detail in Section 7.1.

Compressor Availability

139. The compressor availability used in our assessment, shown in Table 5, has been based on the RAM model developed in collaboration with [redacted]. An overview of the RAM model and how it has been applied and used in the CBA can be found in CE-AMP.

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[12] Within each FES scenario, sensitivities for high continental and high LNG imports are also included, and these are included in the flame charts in this section.

Unit Availability	Train Type	Availability used in CBA	Aligns with RAM scenario
VSD enhanced availability	VSD	86.6%	V1
Avon with 500 hours - enhanced	Avon	79.5%	A3
Avon CSRP	Avon	79.5%	A3
Avon DLE	Avon	74.5%	A3
New Units	tbc	90%	N/A

Table 5 – Unit Availability

140.Availability for St Fergus emissions is based on the likely scenarios from the RAM study that represents the interim investments that would be made for the proposed option.

141.[redacted]

142.The CSRP option uses the same scenario and investments (A3) as this is limiting peak temperature and NOx emissions on the same unit so expect no operational reduction.

143.Avon DLE assumes a 5% reduction on the same A3 scenario reducing availability to 74.5%. It would undertake the same investments, but the technology is unproven in operation and is likely to see commissioning and design issues in the short to medium term. The p10 of the range for the A3 scenario is 69% so this is comfortably within the lower range for the scenario.

144.For each option the site availability is defined based on the compressors required to meet the required capability and the availability of the compressors on site for that option. This availability is then adjusted to account for any 500 hour restrictions which may apply, these are calculated for each scenario every five years. These are detailed further in Appendix B – CE-AMP.

145.New Unit availability (90%) is based on the average availabilities for the two Felindre Gas driven units ('B' and 'C'), which represent the highest availability of a modern gas driven compressor train on the network. This was rounded up to zero decimal places. Their availability is consistent with the RAM model p10 value for the scenario with the highest availability, S4, representing a re-lifed and supported DLE unit.

Predicted Running

146.Based on the availabilities and flows described above we have estimated average compressor usage to enable us to calculate the expected fuel usage and CO_2 for each option. Given the amount of running seen at St Fergus, and expected in the future, these elements can have a significant impact on our economic modelling. Given the combinations of compressors at St Fergus this is shown at unit type and for selected years.

147.The VSDs are the primary unit when flows and availability allow. Given these are consistent between the options, the expected hours do not vary across the options.

148.The New GTs, both the 23 MW and 15 MW, will be the next choice depending on flows and the configuration of the option. The Avon units, whether limited to 500 hours or with DLE or CSRP will be the last choice as these units are less fuel efficient and emit more emissions than the new GTs or VSDs.

Option	VSD		23 MW GT		15 MW GT		Avon-500hrs/DLE/CSRP	
	2030	2040	2030	2040	2030	2040	2030	2040
Option 0 - Retain 4*Avons on 500 hrs	8677	2132	0	0	0	0	2000	2000
Option 1 - A1 (Brownfield) - 3 x new 15 mscmd GT's	8677	2132	0	0	7213	10339	0	0
Option 2 - A1 (Greenfield) - 3 x new 15 mscmd GT's	8677	2132	0	0	7213	10339	0	0
Option 3 - A2 (Brownfield) 2 x new 23 mscmd GT's	8677	2132	5468	3723	47	1753	0	0
Option 4 - A2 (Greenfield) 2 x new 23 mscmd GT's	8677	2132	5468	3723	47	1753	0	0
Option 5 - A3 (Brownfield) 2 x new 15 mscmd and 1 x new 23 mscmd GT's	8677	2132	4921	3351	1234	3818	0	0
Option 6 - A3 (Greenfield) 2 x new 15 mscmd and 1 x new 23 mscmd GT's	8677	2132	4921	3351	1234	3818	0	0
Option 7 - A4 (Brownfield) 4 x new 15 mscmd GT's	8677	2132	0	0	7213	10339	0	0
Option 8 - E1 4 x Existing Avon 1533 15 mscmd derated	8677	2132	0	0	0	0	7213	10339
Option 9 - E2 3 x Existing Avon 1533 15 mscmd derated	8677	2132	0	0	0	0	7213	10339
Option 10 - D1 4 x Existing Avon 1533 15 mscmd DLE	8677	2132	0	0	0	0	7213	10339
Option 11 - D2 3 x Existing Avon 1533 15 mscmd DLE	8677	2132	0	0	0	0	7213	10339
Option 12 - AD1 2 x new 15 mscmd GTs (Brownfield) and 2 x Avon 1533 (15 mscmd) existing with DLE	8677	2132	0	0	6839	9569	374	770
Option 13 - AD2 1 x new 15 mscmd GTs (Brownfield) and 3 x Avon 1533 (15 mscmd) existing with DLE	8677	2132	0	0	5048	6117	2165	4223
Option 14 - 3 x new 15 mscmd GTs (Brownfield) and 1 x Avon 1533 (15 mscmd) existing with DLE	8677	2132	0	0	7161	10230	52	109
Option 15 - 1 x 23 MW + 1 x 15MW (Brownfield)	8677	2132	5515	5476	4004	3253	0	0
Option 16 - 2 x 15MW (Plant 2) +1 DLE (Plant 1)	8677	2132	0	0	6218	8700	996	1640
Option 17 - 1 x 15MW (Plant 1) + 2DLE (Plant 2)	8677	2132	0	0	5048	6117	2165	4223
Option 18 - 2 x 15MW (Brownfield)	8677	2132	0	0	7213	10339	0	0

Figure 15 – Predicted Running Hours by type (System Transformation)

149. It should be noted that for Option 0 (Retaining 4 Avons on 500 hours), the 500 hour derogation significantly limits running which results in reduced running hours compared to the other options. This results in significant constraints for this option.

150. The variation in the other options is a result of the larger 23 MW units performing the duty of two Avons, which reduces hours. But for Options 3 (2 new GTs – Brownfield) and 4 (2 new GTs – Greenfield) where no 15 MW units are available running is further limited as no compressors on site are able to meet certain duty points, again resulting in significant constraints.

151. It should be noted this analysis is based on the average simulations of the probabilistic data described in the Network section. This is sufficient to calculate expected running to calculate fuel/emissions but does not identify the risks associated with limiting compressor running to 500 hours.

FES Flows and Availability Key Points:

- The FES 2021 scenarios show a wide range of potential flows across the four scenarios.
- St Fergus is a critical site to support UKCS and Norway supplies, which are lower cost sources of gas supply for the UK. Therefore, St Fergus is a critical site in supporting UK security of supply.
- If St Fergus capability is curtailed, the flame charts demonstrate this will lead to network constraints, resulting in higher gas prices and a reduction in security of supply.
- A range of operational units will be required to ensure compression capability and resilience.

4.3. Project Scope Summary

152. Our final preferred option is for three new units and a DLE retrofit trial at St Fergus to achieve emissions compliance, optimal resilience, long-term site availability and support to a wide range of UKCS and Norwegian gas flows. Table 6 provides a summary of the project scope.

Final Preferred Option	3 New Gas Driven Compressor Units and 1 Dry Low Emissions Modification to Existing Avon 1533.			
Location	Existing Plant 1 and Plant 2 Location.			
Unit Investment Details	Unit 1	Unit 2	Unit 3	Existing Avon 1533
Investment Action	New Build	New Build	New Build	DLE modification to existing Avon Engine
Year of Commission	2030	2030	2030	TBC (Selected Unit Dependent)
Size of Unit	~15 MW	~15 MW	~15 MW	12.34 MW
Type of Unit	GT	GT	GT	GT
Scope Boundaries	The scope of this project is for costs associated with the implementation of MCPD emissions compliance. At St Fergus these costs are associated with building three new units within the existing Plant 1 and Plant 2 location and modifying an existing Avon 1533 unit with Dry Low Emissions. Decommissioning of the remaining Avon units will be considered once the new units and DLE are fully operational.			
Station Discharge Pressure	70 Barg			
Station Suction Trip Pressure	34 Barg			
Availability Required	The optimum level of availability is determined by the Cost Benefit Analysis.			
Supply and Demand Scenario	All four supply and demand scenarios, FES 2021, were detailed as part of the scope to examine the effectiveness of each investment option against a wide envelope of future energy backgrounds.			

Table 6 – St Fergus Project Scope Summary

5. Optioneering

5.1. Options Considered

Introduction

153. This section focuses on the engineering options and commercial rules and tools available to solve the problem described in Section 3, Problem/Opportunity Statement, and uses the project scope in Section 4, Project Definition, to generate plausible engineering solutions.

154. The options selection process included a review of those solutions we considered as part of the NGGT RIIO-T2 Business Plan submission.

155. This section focuses on the engineering options and commercial rules and tools available to solve the problem described in Section 3, Problem/Opportunity Statement, and uses the project scope in Section 4, Project Definition, to generate plausible engineering solutions. This section will describe the option selection process used to identify the final preferred option for this investment, starting from option identification, through option development to option selection. Figure 16 below serves to identify the various stages involved in a typical option selection process.

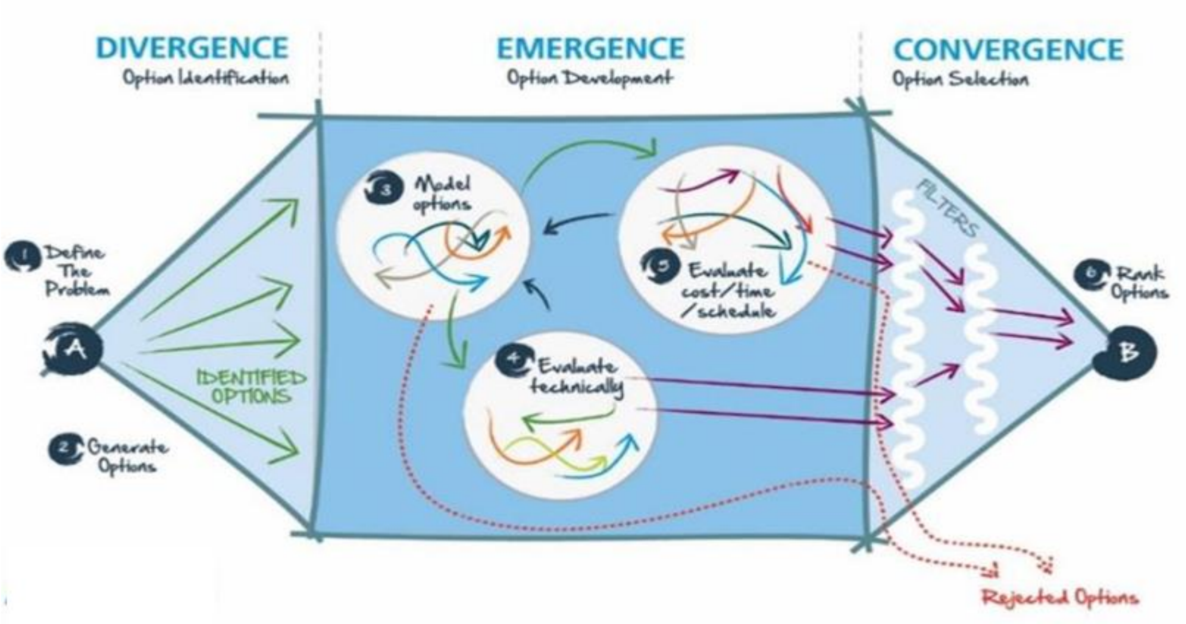

Figure 16 – Options Selection Process

Options Interaction with CBA and BAT

156. The options considered for MCPD compliance have been evaluated in a CBA and via BAT assessment.

157. The BAT assessment, [redacted], was undertaken separately from the CBA using a different methodology; it does however incorporate common assumptions on cost (incl. constraint costs) and future gas supply predictions. For more information on the BAT process undertaken for St Fergus and the results, see Appendix J – Preliminary BAT Report Summary.

Commercial Options Considered

158. As part of the Autumn 2021 consultation, we summarised the commercial options that had been considered at that stage to potentially obviate the need for investment. These included capacity

buybacks, turndown arrangements and renegotiation of the Network Entry Agreement (NEA) at the NSMP sub-terminal. However, as demonstrated, all these options have shortcomings.

159.Stakeholders did ask us to look at some further options including potential asset sharing with adjacent sub-terminals or the use of User Commitment as a way of targeting investment at St Fergus.

160. The Autumn 2022 consultation listed the options being considered and the rationale for ruling them out. These options, whilst designed to either reduce absolute compression at the site or pay compensation where back up or resilience is inadequate, were discounted.

161.Given the criticality of the St Fergus Gas Terminal and the volume of flows through the site, commercial and regulatory options cannot offer a better, more cost-effective alternative to physical site investment.

Options Considered Key Points:

- We have considered a full suite of solutions to enable St Fergus to comply with emissions legislation - this includes commercial and asset investment solutions.
- Given the criticality of the St Fergus Gas Terminal, commercial and regulatory options cannot offer a more cost-effective alternative to physical site investment.
- Options considered for MCPD compliance have been evaluated in a CBA and via BAT assessment.

5.2. Initial Technology Selection and Justification

162.In November 2021, NGGT selected a Feasibility Consultant, [redacted], to support us in quantifying and evaluating the feasibility of our potential investment solutions. In consultation with [redacted], NGGT have considered the full suite of available technologies to enable St Fergus to comply with latest emissions legislation.

163. NGGT led an assessment of the full range of technologies via an engineering study undertaken by [redacted] and supported by other specialist contractors. The complete list of all investment solutions considered is provided in

Investment Solutions	Assessed	Final Option Reference or Option Discounting Justification
Derogation *500 hours Derogation*	✓	Option 0. The 'not doing anything' option provides very low availability, not a fully compliant system, a dead band around 17mscmd a limited operation time at low flow rates (only covered by the Avons)
Emissions Abatement/Derating of Units *Control System Restricted Performance (CSRP)*	✓	Options 8 and 9. Offers a high availability, two independent energy sources however output within MCPD compliance is not currently a tested solution. There is also not a reduction to NOx Emissions with this solution as it is a restriction to performance.
Emissions Abatement *Selective Catalytic Reduction (SCR)*	X	Discounted at initial technology selection due to the need to introduce Ammonia to the St Fergus site this being a COMAH Tier 1 location. Also, high capex cost has ruled this option out with the need to maintain ageing Avon units.
Emissions Abatement *Dry Low Emissions (DLE) technology retrofitted to Avons*	✓	Options 10, 11, 12, 13, 14, 16 and 17.
Decommissioning	✓	Options 1- 18 inclusive. Decommissioning has been reviewed on an option-by-option basis.

Investment Solutions	Assessed	Final Option Reference or Option Discounting Justification
Disconnect and Decommission Avon once alternative solutions are commissioned		
Deferral *Option Deferral*	X	Deferral was not considered as an option for St Fergus due to the 24/7, 365 days/year operating nature of the St Fergus terminal, the operating parameters experienced and the achievability of meeting the 2030 emissions deadline.
Greenfield Site Build *Total Site Units*	X	Traditional 'Greenfield Site Build' i.e. Total standalone new equipment at a new site location has not been considered as part of these works due to large capex costs and impracticalities with build and greenfield location availability. Refer to options 2,4, and 6 which are 'Greenfield' within existing site perimeter.
New Gas Turbine (GT) Compressors on existing plant locations. *Remaining redundant Avon 1533 Gas Turbines to be decommissioned and removed once new units are operational. One or more new units available over Plant 1 and Plant 2.*	✓	Options 1, 3, 5, 7, 15 and 18. Offers high availability, two independent energy sources, new units provide full backup, short repair time for new GTs, they can cover the deadband with individual recycle, flexible and accommodate flow changes, offer a fully compliant system with mature technology.
VSD Modification *VSD Re-Wheel*	X	Re-wheel alone would not have addressed the redundancy issue required at St Fergus, hence focus was put on the Plant 1 and Plant 2 Compression. Discounted at initial technology stage due to the need to have Plant 3 offline for an extended period to achieve this.
Hybrid Option *Combination of New Units and DLE on existing Avons*	✓	Options 12, 13, 14, 16 and 17.
Hydrogen (and Hydrogen Blend) Turbines	X	Discounted at initial technology selection due to the requirement to transport natural for the foreseeable future. During conceptual design, options to increase hydrogen resilience will be explored to ensure greater future resilience at low cost. There is a deadband around the 17mscmd flow and are not a mature technology.
Steam Turbines	X	Discounted at initial technology selection due to high initial capex outlay, high risk of fire and explosion, major plant modifications required to implement the solution and very poor low flow band performance. They also offer less flexibility compared to other options and there is a deadband around the 17mscmd flow.
New Compressors at alternative location within site boundary. *One or more new units.*	✓	Options 2, 4 and 6.
Hold Spare VSD Motor	✓	Allowed for within the Greenfield Build options.
Improve Existing Recycle lines	X	Discounted due to poor availability. Discounted at initial technology stage.
Reuse of other fleet units	X	Discarded due to the works required to bring these units to an operationally suitable level.

Investment Solutions	Assessed	Final Option Reference or Option Discounting Justification
Re-wheel the existing Avon Gas Turbine Compressors	X	Discounted due to poor availability and capex costs.
Flows under 8mscmd	X	Refer to section 5.1 of this report for additional details of low flow considerations and sensitivities.
Fixed Speed Motor	X	Difficult to meet required throughput / operating condition changes
Compressor Hire	X	No vendors identified for the range of required flowrates
Redundancy of Power Supply	X	Recent work undertaken by NGGT already provides redundancy in transmission lines and substations.

164.Table 7. This table includes detail on both the solutions which have been discounted from further investigation and the solutions that have been shortlisted. The discounted options were screened out based on engineering or cost limitations in the first phase of the feasibility study using [redacted] internal review and scoring template.

165.Technologies were screened out using a technical and constructability scoring review. Technologies were scored against a scoresheet agreed between key project stakeholders.

166.The potential solutions were assessed to provide a preliminary technical and economic assessment with enough detail to allow an options screening. The following assessments were performed:

Process review – Review available technologies and process options, determine operating envelope and limitations of existing units, quantify CO_2 emissions, establish process flow schematics and heat and material balances for each option.

Mechanical review – Prepare mechanical datasheets, identify potential vendors, liaise with vendors to confirm feasibility, obtain preliminary estimates of dimensions and procurement costs, contact OEM to review work underway for DLE retrofit on the existing GTs.

Piping/layout review – Review space constraints using St Fergus [redacted] model, identify potential locations for new units or packages, identify available greenfield space.

Electrical review – Review existing infrastructure including recent work performed on St Fergus, review electrical requirements for the options.

RAM analysis – Develop a RAM model to determine the plant availability for current configuration and for the various options.

Safety review – Perform a qualitative review of key safety and environmental risks for each option.

Cost estimate –Develop a -50/+50% total installed cost (TIC) estimate for each option.

Pros-cons and risk analysis – For each option, key advantages, drawbacks, and risks were identified. A cost-benefit analysis was performed based on capex required vs benefits (e.g. reduced penalties associated with plant total outage).

167.Full internal stakeholder engagement and agreement was employed to undertake this screening. More information on the option evaluation methodology used is available in Appendix K – Feasibility Optioneering Report.

Investment Solutions	Assessed	Final Option Reference or Option Discounting Justification
Derogation *500 hours Derogation*	✓	Option 0. The 'not doing anything' option provides very low availability, not a fully compliant system, a dead band around 17mscmd a limited operation time at low flow rates (only covered by the Avons)

Investment Solutions	Assessed	Final Option Reference or Option Discounting Justification
Emissions Abatement/Derating of Units *Control System Restricted Performance (CSRP)*	✓	Options 8 and 9. Offers a high availability, two independent energy sources however output within MCPD compliance is not currently a tested solution. There is also not a reduction to NOx Emissions with this solution as it is a restriction to performance.
Emissions Abatement *Selective Catalytic Reduction (SCR)*	X	Discounted at initial technology selection due to the need to introduce Ammonia to the St Fergus site this being a COMAH Tier 1 location. Also, high capex cost has ruled this option out with the need to maintain ageing Avon units.
Emissions Abatement *Dry Low Emissions (DLE) technology retrofitted to Avons*	✓	Options 10, 11, 12, 13, 14, 16 and 17.
Decommissioning *Disconnect and Decommission Avon once alternative solutions are commissioned*	✓	Options 1- 18 inclusive. Decommissioning has been reviewed on an option-by-option basis.
Deferral *Option Deferral*	X	Deferral was not considered as an option for St Fergus due to the 24/7, 365 days/year operating nature of the St Fergus terminal, the operating parameters experienced and the achievability of meeting the 2030 emissions deadline.
Greenfield Site Build *Total Site Units*	X	Traditional 'Greenfield Site Build' i.e. Total standalone new equipment at a new site location has not been considered as part of these works due to large capex costs and impracticalities with build and greenfield location availability. Refer to options 2,4, and 6 which are 'Greenfield' within existing site perimeter.
New Gas Turbine (GT) Compressors on existing plant locations. *Remaining redundant Avon 1533 Gas Turbines to be decommissioned and removed once new units are operational. One or more new units available over Plant 1 and Plant 2.*	✓	Options 1, 3, 5, 7, 15 and 18. Offers high availability, two independent energy sources, new units provide full backup, short repair time for new GTs, they can cover the deadband with individual recycle, flexible and accommodate flow changes, offer a fully compliant system with mature technology.
VSD Modification *VSD Re-Wheel*	X	Re-wheel alone would not have addressed the redundancy issue required at St Fergus, hence focus was put on the Plant 1 and Plant 2 Compression. Discounted at initial technology stage due to the need to have Plant 3 offline for an extended period to achieve this.
Hybrid Option *Combination of New Units and DLE on existing Avons*	✓	Options 12, 13, 14, 16 and 17.
Hydrogen (and Hydrogen Blend) Turbines	X	Discounted at initial technology selection due to the requirement to transport natural for the foreseeable future. During conceptual design, options to increase hydrogen resilience will be explored to ensure greater future resilience at low cost. There is a deadband around the 17mscmd flow and are not a mature technology.
Steam Turbines	X	Discounted at initial technology selection due to high initial capex outlay, high risk of fire and explosion,

Investment Solutions	Assessed	Final Option Reference or Option Discounting Justification
		major plant modifications required to implement the solution and very poor low flow band performance. They also offer less flexibility compared to other options and there is a deadband around the 17mscmd flow.
New Compressors at alternative location within site boundary. *One or more new units.*	✓	Options 2, 4 and 6.
Hold Spare VSD Motor	✓	Allowed for within the Greenfield Build options.
Improve Existing Recycle lines	X	Discounted due to poor availability. Discounted at initial technology stage.
Reuse of other fleet units	X	Discarded due to the works required to bring these units to an operationally suitable level.
Re-wheel the existing Avon Gas Turbine Compressors	X	Discounted due to poor availability and capex costs.
Flows under 8mscmd	X	Refer to section 5.1 of this report for additional details of low flow considerations and sensitivities.
Fixed Speed Motor	X	Difficult to meet required throughput / operating condition changes
Compressor Hire	X	No vendors identified for the range of required flowrates
Redundancy of Power Supply	X	Recent work undertaken by NGGT already provides redundancy in transmission lines and substations.

Table 7 – Full List of Investment Solutions

168.Post screening the technologies progressed to the next stage of optioneering as potential solutions were:

- New Units
- DLE Retrofit
- Derating (Control System Restricted Performance)
- CSRP

169.To evaluate the impact of no further capital investment at St Fergus, NGGT have included the "counterfactual" or "do nothing" investment option in our CBA [Option 0 (retain 4 Avons); Table 8]. It should be noted that while the counterfactual option considers no additional capital investment to achieve emissions legislative compliance, asset health investment is still necessary to ensure reliable unit operability beyond 2030. These units are no longer supported by the Original Equipment Manufacturer (OEM) and therefore long-term usage of Avons is dependent upon the ongoing support from third parties. Should no investment be made to achieve MCPD compliance by 1 January 2030, Units 1A, 1B, 1D and 2B will fall into Emergency Use Derogation (EUD) where their running hours will be restricted.

170.Existing unit disconnection or decommissioning is considered across several options. For the purpose of CBA and BAT assessment, decommissioning costs have been included where existing Avon locations are to be reused for new Gas Turbine (GT) equipment.

171.At this time no allowance has been made for delay to an investment decision due to the nature of the St Fergus site and its operation requirement of 24/7, 365 days/year. As it's difficult to secure outages at St Fergus, the compressor build will need to be phased to allow continued operation of the site during build. This constrains the programme significantly and delayed investment is not considered viable whilst achieving timely legislative compliance. The 2030 MCPD deadline requirements also places substantial time constraints on the delivery of the solution hence an agreed solution must be made at pace.

172. We have considered several emissions abatement innovation technologies, which can be used in isolation or in combination with new build units, to reduce NOx emissions. CSRP and DLE emissions abatement technologies are being investigated through dedicated external studies and performance trials. More information is available on these in CE-AMP.

Inclusion of DLE at St Fergus

173. If DLE units were to be implemented immediately as an additional trial at St Fergus, it could fast-track our ability to prove the technology because the Avons at St Fergus see some of the highest running hours across the entire fleet. Over the last 9 years, an individual St Fergus Avon saw up to 3,585 run hours in a single year compared to a maximum at Kirriemuir of 1,234. DLE retrofit trials consisting of around [redacted] hours is required before DLE installation can be considered on high utilisation units. Therefore, using St Fergus as a trial site could result in an accumulation of [redacted] hours prior to other locations on the NTS.

174. This would in turn make it a possible solution for the remaining MCPD non-compliant units across the NTS. If DLE retrofit is proven as an appropriate MCPD solution, it can then be considered for the remaining non-MCPD compliant units across the NTS, along with the other options of new unit(s), emissions abatement, derogation and decommissioning.

175. There would be risks associated with running a DLE retrofit trial at St Fergus as it could limit the capability of the site, particularly if an issue were encountered. If a trial unit failed catastrophically, it would likely result in the immediate cessation of all trial units while an investigation was undertaken to identify and solve the root cause; this could take up to a year. The greater the number of trial units at St Fergus, the greater the impact would be if such a failure occurred. Therefore, any use of DLE trial units must take this low probability, high impact event into account.

176. Following completion of the trial, it is considered possible to return the trial unit to its original state as long as specific parts are retained and the unit has not encountered a catastrophic failure. This work would take approximately 10 days. Therefore, implementation of a DLE retrofit trial is unlikely to rule out the possibility of utilising the Avon as a 500-hour derogated unit in the future if that were deemed appropriate.

177. It is estimated that a DLE retrofit trial could be operational at St Fergus by the end of 2024, based upon a manufacture time of 9 months. However, this would be increased if multiple DLE retrofit units were required, delaying completion to 2025. Based upon planned submission timelines for our RIIO-T3 business plan, this would reduce the benefit of the trial in informing our wider NTS compressor fleet decisions.

5.3. Option Short-Listing

178. Following on from the initial analysis performed on the full list of investment technologies, a list of options was derived where each of the main solutions (derogation, abatement, new build, etc.) is represented. Initially this created a list of 14 options which was shared in the Autumn 2022 consultation. The final list of 18 options was developed in response to the consultation and through engagement with Ofgem to allow for all aspects to be considered even if they did not provide the full solution to the stated needs case. These options and detail on which units they have been applied across can be seen in Table 8.

179. With multiple technical options available in a variety of quantities, it is not feasible to run analysis on every possible combination. Therefore, we took a prioritised approach to analyse a subset of combinations which demonstrates the value of significantly different combinations. This is outlined in Figure 17.

180. It is based on an underlying assumption that the technical options are ranked (best to worst) as follows based on reliability and capability: new unit, DLE retrofit, CSRP, derogated unit. This then means that if analysis of a particular quantity of the best technical option (e.g. two 15MW new units) is demonstrated

to be significantly worse than other combinations, all the options below that in the ranking can be automatically discounted (e.g. two DLE, two CSRP and two derogated can all be ruled out once two small new units is deemed insufficient to meet the site requirements).

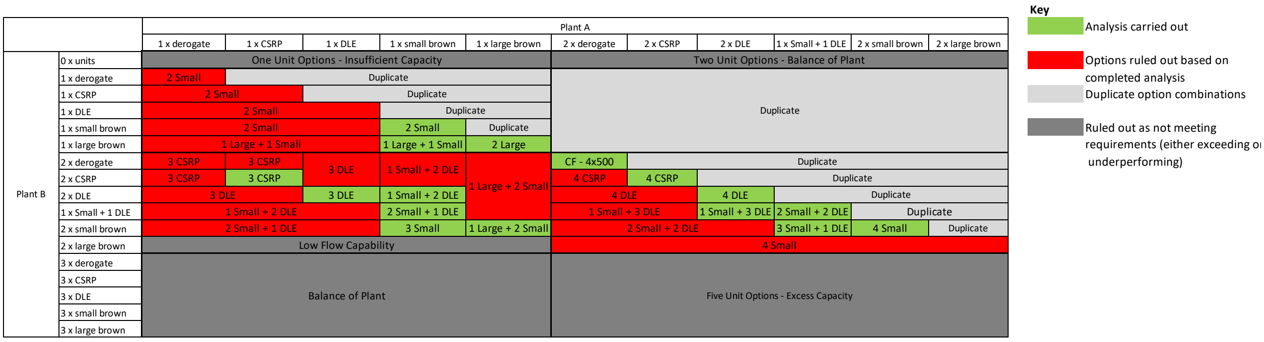

Figure 17 – Matrix of Options Considered and those included in analysis

181. If units were replaced on a like-by-like basis in line with the original site design, this would require six new 15 MW units. However, our analysis shows low constraints with four units and therefore no options with greater than four units were included to reduce the cost to consumers.

182. The full list of options taken through to CBA can be viewed in Table 8. Additional sensitivities were assessed as part of the CBA and are described in Section 7.3 – Supply and Demand Scenario Sensitivities.

Option Ref	Option Summary
0	Counterfactual (Do Nothing). Derogate to 500 hours per unit after 2030.
1	3 x New 15 MW GTs at existing Plant 1 and Plant 2 location
2	3 x New 15 MW GTs in a new Greenfield location within site perimeter
3	2 x New 23 MW GTs at existing Plant 1 and Plant 2 location
4	2 x New 23 MW GTs in a new Greenfield location within site perimeter
5	2 x New 15 MW GTs and 1 x 23 MW GT at existing Plant 1 and Plant 2 location
6	2 x New 15 MW GTs and 1 x 23 MW GT in a new Greenfield location within site perimeter
7	4 x New 15 MW GTs at existing Plant 1 and Plant 2 location
8	4 x existing Avon 1533s derated (CSRP)
9	3 x existing Avon 1533s derated (CSRP)
10	4 x existing Avon 1533s with DLE modification
11	3 x existing Avon 1533s with DLE modification
12	2 x new 15 MW GTs at existing Plant 1 and Plant 2 location with 2 existing Avon 1533s with DLE modification
13	1 x new 15 MW GT at existing Plant 1 and Plant 2 location with 3 existing Avon 1533s with DLE modification
14	3 x new 15 MW GTs at existing Plant 1 and Plant 2 location and 1 existing Avon 1533 with DLE modification
15	1 x New 15 MW GT and 1 x 23 MW at existing Plant 1 and Plant 2 location
16	2 x new 15 MW GTs with 1 existing Avon 1533s with DLE modification at existing Plant 1 and Plant 2 location
17	1 x new 15 MW GT with 2 existing Avon 1533s with DLE modification at existing Plant 1 and Plant 2 location
18	2 x New 15 MW GTs at existing Plant 1 and Plant 2 location

Table 8 – Options Shortlist

183. These 18 options underwent a qualitative BAT assessment and a quantitative assessment was completed for 10 options taken through to BAT assessment.

Technology Selection and Option Short-Listing Key Points:

- Like for like replacement of five or six units has been discounted as offering greater capability than necessary thus options with four or fewer units offer the greatest value to consumers.
- Implementing a DLE retrofit trial at St Fergus facilitates the demonstration of this technology to utilise it across the wider NTS; particularly due to the high running hours of Avons at St Fergus.
- DLE retrofit trial units could be forced to cease operation if catastrophic failure of any trial unit occurred but if this did not occur then it would be possible to revert a trial unit to its original Avon state.
- It is estimated that a DLE retrofit trial unit could be operational at St Fergus by the end of 2024.
- A list of 14 options was consulted upon and developed into a final shortlist of 18 options which were taken forward for further evaluation.

5.4. Low Flow Sensitivity Options

Low Flow Operation Sensitivities

184. The low flow range was identified during early consultation with NSMP and was considered as a sensitivity to the main Feasibility Study, [redacted] assessed the impact on selected technologies and equipment for the low flow band 2 to 8 mscmd. The outcome of this assessment is detailed in Table 9. This table shows the low flow review findings and identifies what is practical to be taken forwards and what can be discarded from the outset. It must be noted that at this time this is a preliminary assessment and is not part of the core flow range of 8-45 mscmd which the St Fergus FOSR is based upon.

185. In order to achieve the sub 2mscmd flowrates a standalone technology to complement the existing compression arrangement would be required which at this stage has not been considered as part of this emissions investment core requirements.

186. On the basis that FES scenarios show relatively high flows for 10+ years, and that the addition of low flow capability would not be required to meet MCPD compliance, the selected option does not include the addition of this capability. It is recommended that low flows are explored further as part of conceptual design and presented as a separate investment case in RIIO-3 if viable. Table 9 highlights options which have been considered as potential low flow solutions. Those which are identified as viable solutions have been retained and those deemed at this stage to be not suitable have been discarded with reasoning detailed in the table below.

Option	Description	Retained/ Discarded	Associated Reason
Q	Use existing plant recycles	Retained	Existing works are already in place by NG to replace the Plant 1 and 2 recycle valves. Through hydraulic calculation, it has been determined the minimum of 2 mscmd could be achieved with either of the Plant 1 & 2 recycles following recycle valve replacement
R	New coolers on individual compressor recycles	Discarded	The requirement for individual compressor recycle improvements, with the addition of recycle coolers, has been discarded as being more complex than using the existing plant recycle (Option Q).
S	New small capacity units	Retained	A new dedicated compressor for low flow operation is retained. It will provide more efficient operation compared to the plant recycle option (Option Q).
T	Compressor re-wheel	Retained	Modification (re-wheel) of an existing compressor for low flow operation is retained as it would provide more efficient operation compared to the plant recycle option (Option Q).
U	Adjust inlet pressure	Discarded	Reducing the inlet pressure of the site to achieve a lower throughput is technically not feasible and therefore discarded
V	Batch operation with new buffer volume	Discarded	Conversion to batch operation while at low flows is not practical due to large buffer volume required and potential to operate for extended periods of time at low flows. This option has been discarded.

Table 9 – Low Flow Options Summary Table

Low Flow Options Conclusion

187. Three low flow options have been initially identified in the sensitivity flow area of 2 to 8 mscmd as potential solutions for further review and development should the below 8mscmd sensitivity become a requirement:

- Option Q – Use existing plant recycle. This option has the following pros and cons:
    - Can achieve very low flows (2 mscmd or smaller)
    - High availability retained
    - No capex required
    - However, it is not energy efficient, as large amount of flow would need to be recycled to achieve very low flows
- Option S – New small capacity GT units. Option S considers adding an additional compressor (circa 8 mscmd nominal capacity) to cover low flows. The capacity of the compressor has been selected to cover the low flow range (2 – 8 mscmd) which will prevent a dead band between the lowest flow the 15 mscmd (or Avon) compressors can achieve and the new smaller compressor nominal capacity. This option has the following pros and cons:
    - Can be used with any of the main options selected for the large compressors
    - High Availability retained
    - More efficient than Option Q as the compressor is designed for low flows
    - If a single 8 MW compressor is installed, very low flows of 2 mscmd would require some plant recycle. The number and size of the small compressors should be further evaluated considering the more realistic FES scenarios for low flows. If low flows are predicted to be as low as 2 mscmd, then it may be more valuable to install 2 x 4 MW compressors rather than 1 x 8 MW compressor to prevent continuous plant recycle
    - High capex cost
- Option T – Compressor re-wheel. This option considers re-wheeling an existing compressor to operate at a better efficiency point for low flows. A new 15 mscmd capacity compressor or an existing Avon driven compressor could be re-wheeled. It is expected that the following upgrades are required: - Remove 15 mscmd compressor bundle - Install new small capacity compressor bundle - Upgrade the compressor anti-surge valve to suit new performance curves. This option has the following pros and cons:
    - Lower capex in comparison to Option S
    - Higher Efficiency and less dependency on plant recycle compared to Option Q
    - Higher availability returned
    - Expected to be a challenging solution for existing Avon compressors
    - Cannot achieve very low flows of 2 mscmd without some plant recycle.

Option Selection Key Points:

- The low flow section of the FOSR is currently detailed as a sensitivity only.
- Three low flow options have been initially identified for low flow operations (under 8 mscmd):
    - Option Q - Use existing plant recycle
    - Option S - New smaller compressor
    - Option T – Compressor Re-wheel
- Further development work needs to be undertaken as part of the FEED should the less than 8mscmd requirement become a realistic flow requirement.

6. Cost Definition

6.1. Cost Estimate Methodology

188. As the project has developed since our 2019 RIIO-T2 Business Plan submission, the accuracy of the scope of works and the estimate has improved. The current level of cost confidence (+/-30%) is consistent with other projects at a similar stage and reflects the inherent uncertainties due to further engineering work required to finalise the scope of works; detailed design; and the completion of tendering processes, engineering, procurement and construction. The level of cost certainty in our estimates is aligned with an AACE Class estimates which the classification system defines as appropriate for project screening, feasibility, concept evaluation and preliminary budget approval. The Infrastructure Projects Association (IPA) published cost estimate guidance[13] classifies a +/-30% cost estimate as suitable for "Outline Business Case".

189. The cost estimates, which are consistent between options, are appropriate to inform the option selection process, including CBA and BAT assessment. As detailed in the PCD guidance, the cost Re-opener submission by 2025 will be based on a finalised scope of works, Conceptual Design and Build, Main Works Contractor (MWC) tendered prices and order values for long lead items.

Estimate Scope

190. We have developed estimates of Total Installed Cost (TIC) for all 18 shortlisted options. We then determined approximate spend profiles for the preferred option (see Section 6.3 – Project Spend Profile). All our estimates have been developed based on an assumed standard Engineering, Procurement and Construction (EPC) delivery strategy consisting of the following main contracts: pre-FEED, FEED, EPC and compressor machinery train equipment.

191. The total installed cost estimates are based on the following main cost elements:

- Installation of new build Compressor Machinery Train equipment, including acoustic enclosure
- Tie-in of new equipment to existing station piping; control and protection systems, electrical and utilities connections, process vent where applicable
- Asset Health scope for existing Avons to be retained considering planned interventions already funded via our RIIO-T2 business plans (see Appendix I – Asset Health Report)
- Retrofit emissions abatement modifications to existing Avon driven compressor trains (DLE, CSRP)
- Engine upgrades for applicable retrofit options
- Decommissioning of redundant compressor units affected by the relevant options only. Any residual compression not part of the relevant option will not be included within the cost build up.

192. Whole life cost estimates also include estimated ongoing asset health spend for new and existing GTs until 2050. These costs include asset refurbishment and replacements based on our asset management policies, procedures and specifications and they are consistent with asset health plans approved as part of our 2019 RIIO-T2 business plans.

193. Other recurring costs in our whole life cost estimates include opex, fuel consumption, reagent use and network constraint cost.

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

Base Data

Compressor Machinery Train Equipment

194. For new build options, [redacted] identified suitable compressor machinery train equipment following review of process requirements and initial engagement with original equipment manufacturers (OEMs) on our compressor machinery train supply framework. We then based equipment costs on budget prices provided by OEMs, and contract costs from recent compressor projects.

195. The St Fergus Gas Terminal, as with many of our sites, is in an area of low background noise meaning compressor noise must be mitigated by using low noise compressor acoustic enclosures. Costs for these enclosures are included in the compressor machinery train equipment cost estimates and are based on costs for similar equipment purchased for other sites.

Tie-in of New Equipment

196. New compressor machinery train equipment will be installed on a Brownfield location on existing Plant 1 and Plant 2 Berths based on a layout developed by [redacted] as described in Appendix K – [redacted] FEED Report. Tie-in of new assets into existing site infrastructure has been priced based on Material Take Offs (MTOs) produced in house using [redacted] drawings with the following allowances applied:

- **Technical Allowance** covers design development (e.g., Equipment specifications, changes in size and valve specifications) and to allow for the options containing 23 MW compressors.
- **Growth** covers increase in size or complexity of the project as engineering definition develops (e.g. plot layout definition increase due to additional small bore piping, valves, non-tagged minor equipment)
- **Cut and Waste** covers bulk material off-cuts, overages and waste.
- **MTO Allowance –** margin to cater for items not included MTOs (e.g., small bore piping and valves, bolts and gaskets, minor electrical and instrumentation material etc).

197. Procurement costs are based on in-house material cost data and fabrication and installation costs are based on in-house labour rates. Given the prevailing national and international geopolitical conditions, labour and material rates present a risk to the project, particularly for new build options involving larger scope.

Asset Health Interventions

198. The scope of Asset Health interventions required on the existing Avon compressor trains and associated equipment is defined in Appendix I – Asset Health Report. Our RIIO-T2 Asset Health plans were based on retaining the existing Avons at St Fergus until 2030 when they would be replaced with new units as part of our preferred option for MCPD compliance.

199. Asset health costs are based on unit costs agreed as part of our RIIO-T2 business plans where available. These costs are total installed cost and therefore no additional cost factors or Unallocated Provision (UAP) has been applied.

Decommissioning

200. We have included the cost for decommissioning existing Avon compressor units where they will be replaced with new units. These costs are based on confirmed allowances for decommissioning of similar units at other sites. However, the investment decision on decommissioning scope for the other existing Avon units will be made as part of an NTS wide decommissioning plan and will not form part of the MCPD cost Re-opener.

201.A funding request is being submitted through the Asset Health Reopener for the immediate demolition of Units 2C and 2D. If any new units are constructed in the previous location of those units, there will be a cost reduction for the Emissions investment as funding will not requested a second time for that decommissioning. This will be captured in the Cost Reopener by June 2025.

Remaining Project Costs

202. All remaining project costs were estimated based on cost factors taken from in-house cost data. These costs include the following:

- Engineering design including FEED, Detailed Design, surveys and third-party consultancy
- Client and contractor project management during design and construction
- Other client costs (overhead)
- Freight
- Certification and Documentation
- Commissioning and operational spares
- Insurance
- Vendor representatives
- Third Party inspection
- First Fills
- Royalties

Unallocated Provision

203.Unallocated provisions are included in the estimate to account for unidentified growth and/or uncertainties in rates, etc. A 30% Unallocated Provision (UAP) factor has been applied to the base cost for all options excluding asset health and decommissioning spend. If all the assumptions on which the base estimate was made turn out to have been valid, then the base cost estimate should represent the expected cost or 50/50 estimate (i.e., cost at which there is a 50% chance of a higher final cost and 50% chance of a lower final cost). This provision is not a management reserve or budget contingency; instead, it is an unallocated provision for project risks, based on the current maturity of data and scope definition.

204.There are many potential sources of over-run for a project of this type, such as schedule delays, labour disputes, supplier problems, etc. There will be many such risks on the project risk register, many of which will not occur. However, as they all have a finite chance of happening, some will occur and have a cost impact, others might require mitigation to be put in place, at a cost, to ensure that either they do not occur, or they can be dealt with.

205. Moreover, not all assumptions made in the study design premise will turn out to be valid. Some will have been based on early available information, but there is no allowance in the base estimate for wrong assumptions. There may also be considerable uncertainty in the estimate because of work yet to be performed or finalised, e.g., flow assurance, weather or contracting strategy. Any one of these could have a significant impact on the cost estimate.

206.UAP does not cover force majeure, major changes, political upheaval, major location change, capacity changes >10%, major / national strikes, major legislation change, major cost inflation change, major industrial disputes, bankruptcy major contractor, major exchange rate fluctuations and natural disasters.

6.2. Option Cost Estimate Details

207.Capex estimates for each option are provided per the breakdown requested in the 2019 Engineering Justification Paper (EJP) guidance document. Asset health costs are included separately as they are based on RIIO-T2 unit costs. All costs are provided in 2018/19 price base year and should be considered accurate to +/-30%; an unallocated provision of 30% is included.

208. A detailed cost breakdown can be seen in Table 10 below for the options which ensure four GTs; the same breakdown can be seen for all options in Appendix F – Capital Cost Breakdown Detail.

Cost Element	Description	Option 7 A4 (Brownfield) 4 x new 15 MW GTs	Option 12 AD1 2 x new 15 MW GTs (Brownfield) and 2 x Avon 1533 (15 MW) with DLE modification	Option 14 3 x new 15 MW GTs (Brownfield) and 1 x Avon 1533 (15 MW) with DLE modification
Engineering Design	Detail costs for studies/FEED/Detailed design as appropriate.	[redacted]	[redacted]	[redacted]
Project Management	Element of project costs attributed to project management, not direct or indirect company costs.	[redacted]	[redacted]	[redacted]
Materials	Bulk materials, DLE Material breakdown preferred	[redacted]	[redacted]	[redacted]
Main Works Contractor	Project construction contractor costs.	[redacted]	[redacted]	[redacted]
Vendor Package Costs	Costs of packages purchased for project.	[redacted]	[redacted]	[redacted]
Direct Company Costs	Refer to Regulatory Instructions and Guidance for definition of direct company costs.	[redacted]	[redacted]	[redacted]
Indirect Company Cost	Refer to Regulatory Instructions and Guidance for definition of indirect company costs.	[redacted]	[redacted]	[redacted]
Total Installed Cost (TIC)		[redacted]	[redacted]	[redacted]
UAP 30%	Forecast total project cost including contingency. Sum of all elements noted above.	[redacted]	[redacted]	[redacted]
Decommissioning	Refers to the removal of existing Avon units and replaced with new GT Solar units.	[redacted]	[redacted]	[redacted]
Total Cost		[redacted]	[redacted]	[redacted]
Total Cost (2018/19)		[redacted]	[redacted]	[redacted]
Overall Total Costs (2018/19)		XXXXXX	XXXXXXX	XXXXXXX
Cost Estimate Accuracy	This is an important element to give confidence that the engineering is mature, and the costs can be relied upon.	+30 -30	+30 -30	+30 -30

Table 10 – Detailed Cost Breakdown (£m, 2022/23 unless stated otherwise) - Options 7, 12 and 14

6.3. Project Spend Profile

209.The capex spend profile below, refers to the preferred Option 14 (three new 15 MW units and one DLE retrofit). The spend profile **only** includes Total Installed Cost (TIC) and Decommissioning cost. Asset Health and Relife capex costs are excluded.

[redacted]

Table 11 – Spend Profile (£m, 2018/19) for Option 14 (3x15 MW + 1 DLE)

[redacted]

Figure 18 – Spend Profile (£m, 2018/19) Graph for Option 14 (3x15 MW + 1 DLE)

Cost Definition Key Points:

- The current level of cost confidence (+/-30%) is consistent with other projects at a similar stage and reflects the inherent uncertainties due to further engineering work required to finalise the scope of works.
- We have included the cost for decommissioning existing Avon compressor units where they will be replaced with new units. However, the investment decision on decommissioning scope for the other existing Avon units will be made as part of an NTS wide decommissioning plan and will not form part of the MCPD cost Re-opener.

7. Option Evaluation and Final Recommendation

210. This section details the various forms of analysis undertaken to assess the shortlist of 18 options in order to come to a final preferred option.

7.1. Cost Benefit Analysis

Key Cost Benefit Analysis Drivers

Constraints

211. As the constraints impact a particular sub-terminal these would need to be costed based on Section I of the Uniform Network Code (UNC). The method for calculating the cost of these constraints is based on the higher of two main elements. These being either the cost of capacity at St Fergus or the price for any Buy Backs either at St Fergus or elsewhere on the network on the day of the constraint.

212. In the event of a constraint NGGT would seek to resolve this using our commercial tools, such as Buy Backs and Locational actions. It should be expected that the price of these actions would be commensurate with any costs incurred by the shippers as a result of being unable to flow the gas. These should be in line with the value of gas but could also potentially include the costs of any associated oil production along with any penalty clauses. Based on previous Buy Back actions at St Fergus in 2006 prices increased to around 8.5 times the market prices at the time. These reached a peak of almost [redacted], as can be seen in Figure 19.

[redacted]

Figure 19 – SAP Price and Bid Price during 2006 Buy Back event

213. In a buy back situation, Shippers will make Entry Capacity buy back offers at the ASEP. These offers must be accepted in price order (lowest first). Shippers at all 3 St Fergus sub-terminals could potentially make offers yet only those provided by NSMP Shippers would actually alleviate the constraint. This has the effect of inflating the overall cost of each buyback event as any surplus capacity at the neighbouring sub-terminals would likely be in the bid stack. In simple terms, we cannot target the buy back to NSMP shippers only and this will inflate the cost. In a buy back situation, Shippers will make Entry Capacity buy back offers at the ASEP. These offers ust be accepted in price order (lowest first). Shippers at all 3 St Fergus sub-terminals could potentially make offers yet only those provided by NSMP Shippers would

actually alleviate the constraint. This has the effect of inflating the overall cost of each buyback event as any surplus capacity at the neighbouring sub-terminals would likely be in the bid stack. In simple terms, we cannot target the buy back to NSMP shippers only and this will inflate the cost.

214. For our central case we have costed the constraints at the BEIS long term price, this is a conservative assumption and in line with the minimum costs that shippers would likely incur – the cost of the lost gas. It is likely actual costs could be higher than this as any locational actions and buy backs would be assumed to occur at a significant premium to the prevailing prices at the time. To understand the potential impacts of higher prices we have included several sensitivities in section 7.2. For transparency the Section I cost and additional cost are included on separate lines in the CBA files.

215. We see significant constraints in Option 0 (Counterfactual) throughout the period as the required duty for all the Avons is above the 500-hour limit. This would severely limit the operation of the site and result in frequent disruptions to supplies.

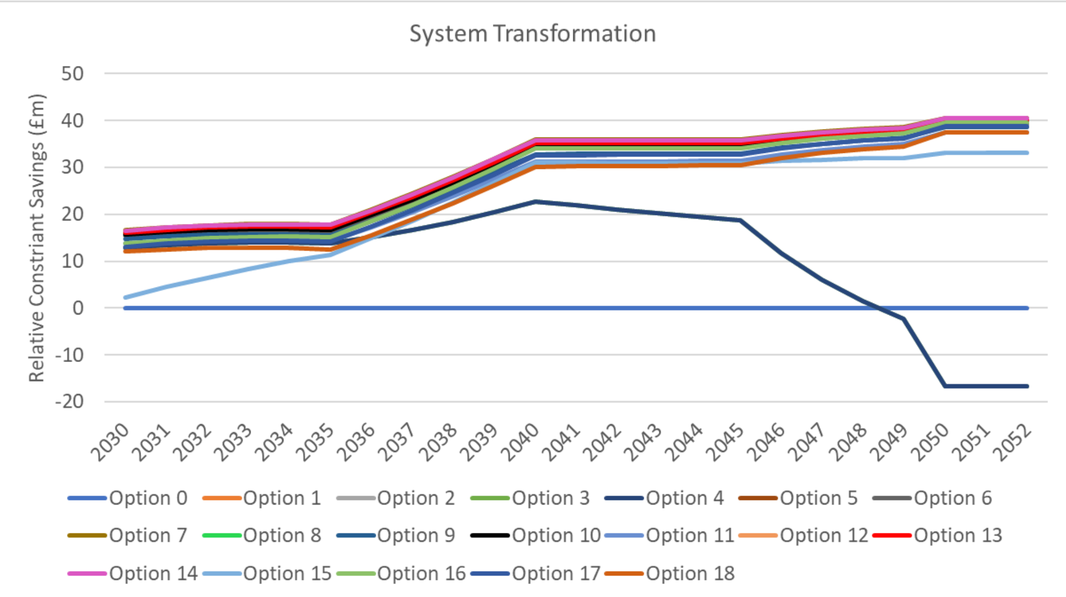


Figure 20 – Constraint savings relative to counterfactual – System Transformation

216. Several options severely restrict the operation of the site resulting in very high constraints. These can make it difficult to see the differences between the options which can cover the main site duty and provide resilience for the bulk of the required duty. To help compare the options Figure 21 has removed the options with the highest constraints to show the relative position of the leading options in the CBA.

217. The lowest level of constraints are achieved in Option 7 (four new 15 MW units), this is closely followed by our recommended Option 14 (three new 15 MW units and one DLE retrofit). Both of these options ensure we are able to retain balance of plant at the site and the primary duty is taken by the more reliable new units.

218. Most of the options constraints follow a similar path, with the level determined by the reliability of the units. The outliers are Options 5 and 6 (two new 15 MW and one 23 MW unit, Brownfield and Greenfield versions respectively) as the 23 MW cannot meet the full site duty. This results in constraints varying compared to other options based on the flow patterns and the frequency of flows outside the duty of the 23 MW unit.

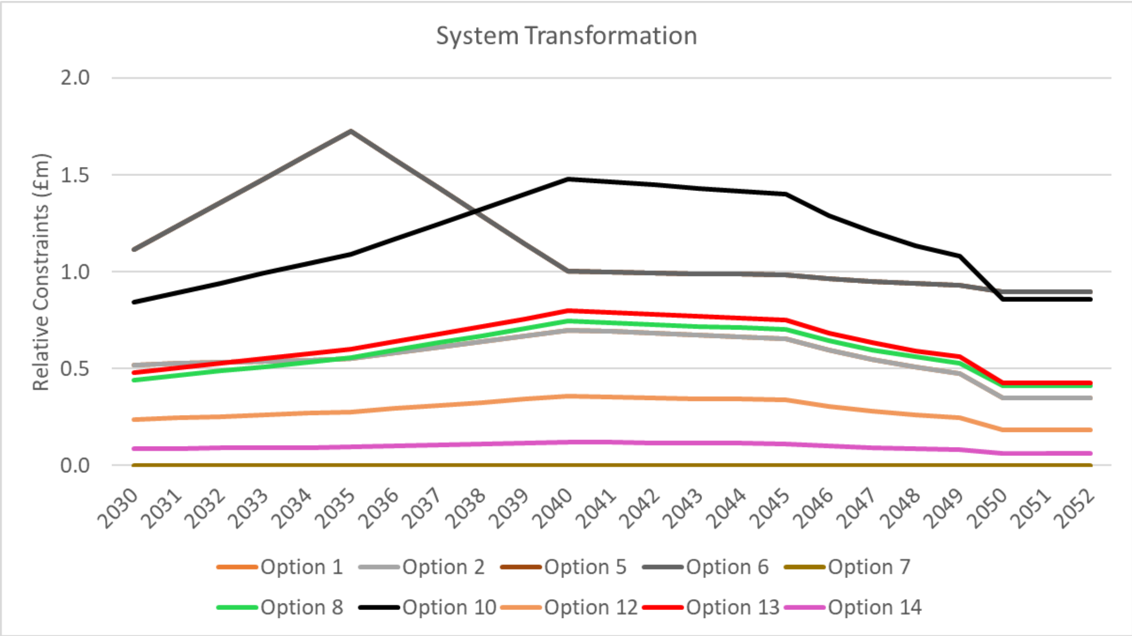


Figure 21 – Relative Constraints to Option 7 – Selected Options

CBA Drivers Key Points:

- Constraints have been calculated based on the gas cost for consistency with BEIS long term price, however this significantly risks undervaluing the cost of a constraint event and therefore Section I costs are also displayed for transparency
- We see significant constraints in Option 0 (Counterfactual) throughout the period as the required duty for all the Avons is above the 500-hour limit. This would severely limit the operation of the site and result in frequent disruptions to supplies.
- The lowest level of constraints are achieved in Option 7 (four new 15 MW units), closely followed by our recommended Option 14 (three new 15 MW units and one DLE retrofit).

Cost Breakdown

219. This section shows the breakdown of costs for each option which are included in the CBA to produce a NPV for each option. The breakdown of costs is covered in more detail in Section 6 – Cost Definition.

220. Figure 22 and Figure 23 show the breakdown of the costs included in the CBA, split into the investment costs and compressor running costs. This allows a comparison of the relative costs in each of the options.

221. The lowest cost options, as expected, are those which rely on either retrofitted or derogated Avons. However, these tend to result in very high constraints and/or high emissions and fuel usage.

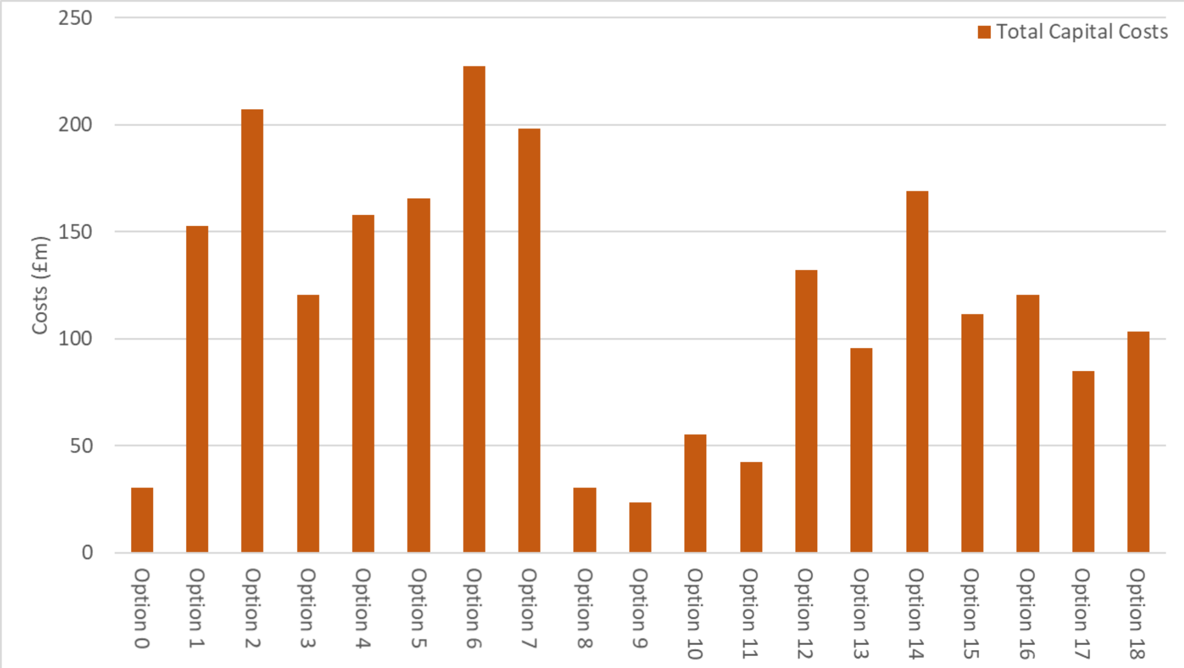


Figure 22 – Asset Costs Included in CBA

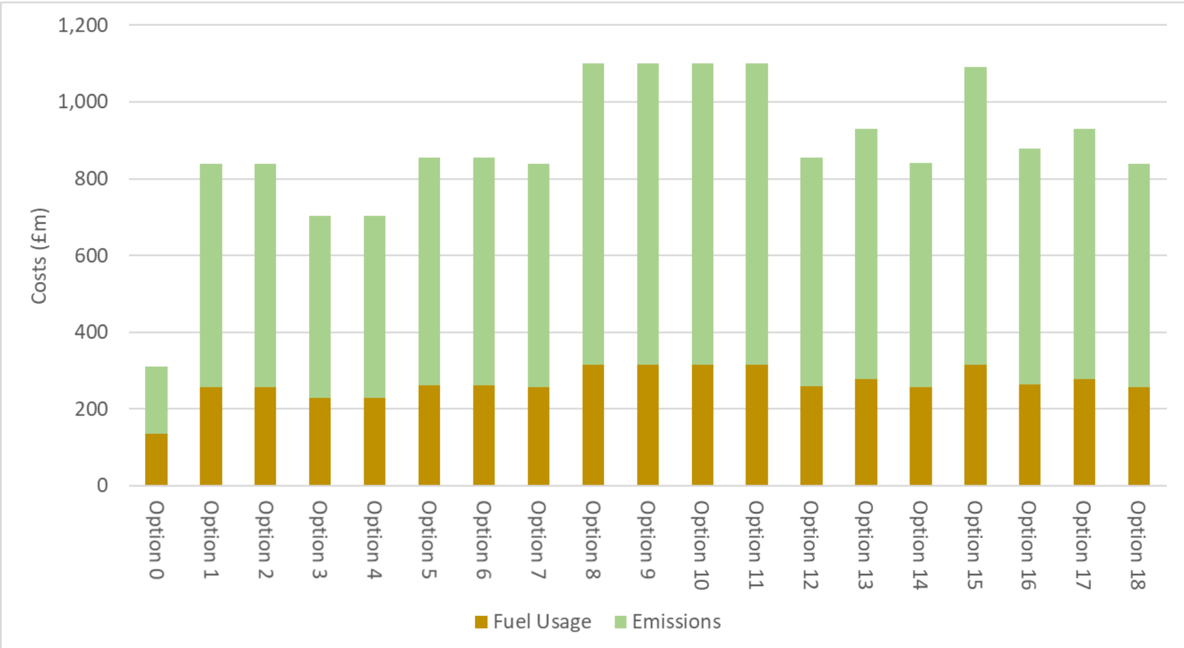


Figure 23 – Operational Costs included in the CBA (System Transformation)

222. Given the high running hours, the fuel and emissions costs are significant at St Fergus, as shown in Figure 23. The Counterfactual appears to be the option where these are lowest, despite this option having no reduction in the emission rate of the GT units. This is because the units are limited to 500 hours, limiting the emissions but resulting in significant constraints and market disruption.

223. Option 7 (four new 15 MW units) is the lowest emission option as all the required GT duty is taken by new units, which offer the best fuel efficiency and lowest rates of emissions. Our preferred Option 14 (three new 15 MW units and one DLE retrofit) results in similar fuel and emission costs as the bulk of the GT duty would be performed by new units, with the added benefit of a lower required investment.

CBA Cost Breakdown Key Points:

- We see significant constraints in Option 0 (Counterfactual) throughout the period as the required duty for all the Avons is above the 500-hour limit. This would severely limit the operation of the site and result in frequent disruptions to supplies.
- Options which rely on either retrofitted or derogated Avons have the lowest investment cost. However, these tend to result in very high constraints and/or high emissions and fuel usage.
- Our preferred Option 14 (three new 15 MW units and one DLE retrofit) results in similar fuel and emissions costs as Option 7 (four new 15 MW units) with the benefit of a lower required investment.

CBA Assessment

224.Table 12 shows the results of our CBA using the System Transformation scenario. All options had a positive NPV compared to the counterfactual, with the constraint costs outweighing the lower investment costs of this option.

Option	Relative NPV	Absolute NPV	Rank
Option 0 - Retain 4*Avons on 500 hours	0	[redacted]	19
Option 1 - A1 (Brownfield) - 3 x new 15MW GTs	725	[redacted]	2
Option 2 - A1 (Greenfield) - 3 x new 15MW GTs	682	[redacted]	6
Option 3 - A2 (Brownfield) 2 x new 23MW GTs	99	[redacted]	17
Option 4 - A2 (Greenfield) 2 x new 23MW GTs	70	[redacted]	18
Option 5 - A3 (Brownfield) 2 x new 15MW and 1 x new 23MW GTs	675	[redacted]	8
Option 6 - A3 (Greenfield) 2 x new 15MW and 1 x new 23MW GTs	627	[redacted]	12
Option 7 - A4 (Brownfield) 4 x new 15MW GTs	705	[redacted]	5
Option 8 - E1 4 x Existing Avon 1533 15MW derated	678	[redacted]	7
Option 9 - E2 3 x Existing Avon 1533 15MW derated	623	[redacted]	13
Option 10 - D1 4 x Existing Avon 1533 15MW with DLE modification	638	[redacted]	10
Option 11 - D2 3 x Existing Avon 1533 15MW with DLE modification	560	[redacted]	15
Option 12 - AD1 2 x new 15MW GTs (Brownfield) and 2 x Avon 1533 (15MW) with DLE modification	734	[redacted]	1
Option 13 - AD2 1 x new 15MW GTs (Brownfield) and 3 x Avon 1533 (15MW) with DLE modification	710	[redacted]	4
Option 14 - 3 x new 15MW GTs (Brownfield) and 1 x Avon 1533 (15MW) with DLE modification	721	[redacted]	3
Option 15 - 1 x 23 MW + 1 x 15MW (Brownfield)	375	[redacted]	16
Option 16 - 2 x 15MW + 1 Avon 1533 (15MW) with DLE modification	675	[redacted]	8
Option 17 - 1 x 15MW + 2 Avon 1533 (15MW) with DLE modification	636	[redacted]	11
Option 18 - 2 x 15MW (Brownfield)	612	[redacted]	14

Table 12 – NPV (£m) System Transformation

225.Options 1, 7, 12, 13 and 14 all show strong positive NPVs. These options minimise the constraints while ensuring the bulk of the running is with new, clean and efficient units which minimise fuel costs and emissions.

226.Our selected Option 14 (three new 15 MW units and one DLE retrofit) minimises constraints, fuel usage and emissions by ensuring the bulk of primary duty and back-up uses the cleaner and more reliable new GTs. This option also utilises the DLE technology to ensure balance of plant and resilience by reducing upfront investment.

CBA Assessment Key Points:

- All options had a positive NPV compared to the counterfactual of derogating the four Avons.
- The options which include four units (7, 12, 13, 14) and the three unit Option 1 (three new GTs) all show strong positive NPVs.
- The selected Option 14 (three new 15 MW units and one DLE retrofit) minimises constraints, fuel usage and emissions. It also utilises DLE retrofit technology to ensure balance of compression across plants and resilience.

7.2. Key assumptions and Sensitivities

Key Assumptions

227.The key assumptions behind the St Fergus case are detailed in Table 13.

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	75.0%	Defined in RIIO-T2
Constraints and Fuel	Gas Price	Annual price 50 – 64 p/th	BEIS reference scenario N/A
	Compressor Fuel Costs	Gas Price	
	Constraint management pricing	Based on BEIS price	See Constraints section
	Constraint management method	Section I	Reflective of tools available to manage constraints
Emissions	CO_2 cost	Annual price 241 – 378 £/tonne	BEIS Valuation of greenhouse gas emissions: for policy appraisal and evaluation Central Case

Table 13 – Key Assumptions

228.Solution design life varies depending on the asset element in question. Figure 24 outlines the design life requirements for each new compressor asset on the NTS. For example, Protection and Control Systems have a design life of 15 years and Gas Generators a life of 20 years. Therefore, replacement will be required, and has been considered, during the CBA period.

229.All other new assets installed as part of the MCPD project will have a design life greater than the CBA period and replacement cost has therefore not been included. Routine maintenance and estimated ad-hoc repairs have also been included in cost estimates included in the CBA.

Asset	Life (years)
Compressors	40
Gas Generators	20
Power Turbines	25
Pipework and Valves	30
Protection and Control Systems	15
Enclosures and Buildings	60

Figure 24 – T/PM/Comp/20 Asset Design Life

Scenario Sensitivities

230. To test the sensitivity of the St Fergus case to different supply and demand scenarios we have tested the case against all four FES scenarios. The relative and absolute NPVs of these can be seen in Table 14 and Table 15 respectively.

231. Our leading NPV across all scenarios except Leading the Way is Option 12 (two new 15 MW units and two DLE) with Options 13 (1 new GT, 3 Avon DLEs) and 14 (3 new GTs and 1 DLE Avon) also performing strongly across all scenarios. These options all have a mix of technologies providing four gas units to ensure we maintain two operational plants, in line with our resilience assessment, with the options with more new units minimising emissions.

Option	Steady Progression	Consumer Transformation	Leading the Way	System Transformation
Option 0 - Retain 4*Avons on 500 hours	£0 m	£0 m	£0 m	£0 m
Option 1 - A1 (Brownfield) - 3 x new 15MW GTs	£713 m	£398 m	£336 m	£725 m
Option 2 - A1 (Greenfield) - 3 x new 15MW GTs	£670 m	£356 m	£293 m	£682 m
Option 3 - A2 (Brownfield) 2 x new 23MW GTs	-£4 m	-£634 m	-£765 m	£99 m
Option 4 - A2 (Greenfield) 2 x new 23MW GTs	-£33 m	-£663 m	-£794 m	£70 m
Option 5 - A3 (Brownfield) 2 x new 15MW and 1 x new 23MW GTs	£652 m	£366 m	£303 m	£675 m
Option 6 - A3 (Greenfield) 2 x new 15MW and 1 x new 23MW GTs	£604 m	£318 m	£255 m	£626 m
Option 7 - A4 (Brownfield) 4 x new 15MW GTs	£692 m	£367 m	£303 m	£705 m
Option 8 - E1 4 x Existing Avon 1533 15MW derated	£668 m	£382 m	£324 m	£678 m
Option 9 - E2 3 x Existing Avon 1533 15MW derated	£618 m	£361 m	£309 m	£623 m
Option 10 - D1 4 x Existing Avon 1533 15MW with DLE modification	£630 m	£352 m	£296 m	£638 m
Option 11 - D2 3 x Existing Avon 1533 15MW with DLE modification	£559 m	£320 m	£271 m	£560 m
Option 12 - AD1 2 x new 15MW GTs (Brownfield) and 2 x Avon 1533 (15MW) with DLE modification	£722 m	£405 m	£342 m	£734 m
Option 13 - AD2 1 x new 15MW GTs (Brownfield) and 3 x Avon 1533 (15MW) with DLE modification	£702 m	£404 m	£345 m	£710 m
Option 14 - 3 x new 15MW GTs (Brownfield) and 1 x Avon 1533 (15MW) with DLE modification	£708 m	£386 m	£322 m	£721 m
Option 15 - 1 x 23 MW + 1 x 15MW (Brownfield)	£311 m	£186 m	£138 m	£375 m
Option 16 - 2 x 15MW + 1 Avon 1533 (15MW) with DLE modification	£664 m	£385 m	£327 m	£675 m
Option 17 - 1 x 15MW + 2 Avon 1533 (15MW) with DLE modification	£632 m	£378 m	£327 m	£636 m
Option 18 - 2 x 15MW (Brownfield)	£611 m	£370 m	£321 m	£612 m

Table 14 – Relative NPVs (£m) all scenarios

Option	Steady Progression	Consumer Transformation	Leading the Way	System Transformation
Option 0 - Retain 4*Avons on 500 hours	[redacted]	[redacted]	[redacted]	[redacted]
Option 1 - A1 (Brownfield) - 3 x new 15MW GTs	[redacted]	[redacted]	[redacted]	[redacted]
Option 2 - A1 (Greenfield) - 3 x new 15MW GTs	[redacted]	[redacted]	[redacted]	[redacted]
Option 3 - A2 (Brownfield) 2 x new 23MW GTs	[redacted]	[redacted]	[redacted]	[redacted]
Option 4 - A2 (Greenfield) 2 x new 23MW GTs	[redacted]	[redacted]	[redacted]	[redacted]
Option 5 - A3 (Brownfield) 2 x new 15MW and 1 x new 23MW GTs	[redacted]	[redacted]	[redacted]	[redacted]
Option 6 - A3 (Greenfield) 2 x new 15MW and 1 x new 23MW GTs	[redacted]	[redacted]	[redacted]	[redacted]
Option 7 - A4 (Brownfield) 4 x new 15MW GTs	[redacted]	[redacted]	[redacted]	[redacted]
Option 8 - E1 4 x Existing Avon 1533 15MW derated	[redacted]	[redacted]	[redacted]	[redacted]
Option 9 - E2 3 x Existing Avon 1533 15MW derated	[redacted]	[redacted]	[redacted]	[redacted]
Option 10 - D1 4 x Existing Avon 1533 15MW with DLE modification	[redacted]	[redacted]	[redacted]	[redacted]
Option 11 - D2 3 x Existing Avon 1533 15MW with DLE modification	[redacted]	[redacted]	[redacted]	[redacted]
Option 12 - AD1 2 x new 15MW GTs (Brownfield) and 2 x Avon 1533 (15MW) with DLE modification	[redacted]	[redacted]	[redacted]	[redacted]
Option 13 - AD2 1 x new 15MW GTs (Brownfield) and 3 x Avon 1533 (15MW) with DLE modification	[redacted]	[redacted]	[redacted]	[redacted]
Option 14 - 3 x new 15MW GTs (Brownfield) and 1 x Avon 1533 (15MW) with DLE modification	[redacted]	[redacted]	[redacted]	[redacted]
Option 15 - 1 x 23 MW + 1 x 15MW (Brownfield)	[redacted]	[redacted]	[redacted]	[redacted]
Option 16 - 2 x 15MW + 1 Avon 1533 (15MW) with DLE modification	[redacted]	[redacted]	[redacted]	[redacted]
Option 17 - 1 x 15MW + 2 Avon 1533 (15MW) with DLE modification	[redacted]	[redacted]	[redacted]	[redacted]
Option 18 - 2 x 15MW (Brownfield)	[redacted]	[redacted]	[redacted]	[redacted]

Table 15 – Absolute NPVs (£m) all scenarios

Market Impacts / Upstream Impacts

232. Through our Autumn 2021 and Autumn 2022 consultations, (referenced in Appendix Q - Stakeholder Engagement) stakeholders have told us that wider market factors are important, including the following:

- supporting Scottish Security of Supply (maintaining offtake pressure in Winter)
- providing energy security through UKCS supply (reducing import dependency)
- maintaining supply liquidity supressing even higher market prices
- value to the oil industry (unrestricted gas flows enabling oil production)
- enabling the offshore industry and associated jobs/tax
- enabling Norwegian supply to freely enter the UK as the market dictates

233. Quantification of these factors would only strengthen an already strong needs case, and we have made some progress in being able to demonstrate this.

234. This can be seen in the constraint costs above where, in reality, these costs could be far more significant as any lost gas from the St Fergus NSMP sub-terminal would have to be replaced by other sources. Given that the replacement would need to be secured from marginal imports this could have a significant impact on wider market prices.

235. In support of our Wormington Emissions proposal, we contracted [redacted] to conduct sensitivity analysis to understand the potential impact on wholesale gas prices when supplies from Milford Haven are interrupted. This sensitivity was against their latest near outlook and considered varying supply loss over a 5-day period across a winter and summer period. Whilst the analysis assumed “perfect market competition” and full availability from all other supply sources, it provides an indication to the potential impacts to the wholesale gas market from disruption to supply. Given the gas provided at St Fergus would usually be expected to provide more baseload supplies, as much of the volumes are linked to oil production, any disruption to these supplies is likely to have a larger impact on wholesale energy markets.

236. The study showed that, in most scenarios explored, for every 1 mcm/d of gas supply removed, the impact to gas prices would result in an additional £1m cost to the wider NBP market (based on [redacted]’s near-term market outlook). This is approximately five times the constraint costs applied in our analysis.

237. The wholesale price impact below is based on current market conditions, and whilst this is subject to change depending on underlying assumptions, it represents the “minimal” expected market impact as it doesn’t factor in any risk premiums or other market distortions that would result from an unexpected supply interruption.

[redacted]

Figure 25 – Potential Market Price Impacts – [redacted]

Market Impact Key Points:

- Stakeholders feel that market impacts are an important factor and should be quantified where possible.
- Any lost gas from St Fergus NSMP would have to be replaced by other sources which could result in a significant impact on market prices.
- Gas provided at St Fergus would usually be expected to provide more baseload supplies, as much of the volumes are linked to oil production. Therefore, any disruption to these supplies is likely to have a more dramatic impact on price than shown by the study done for Wormington.

Constraint Sensitivities

238. As described in the Key Cost Benefit Analysis Drivers section, the cost of constraints have significant uncertainty as a result of how they would be calculated. To test the impact of this we have evaluated a sensitivity based on the upper end of the buy back prices seen during the Buy Back event at St Fergus in 2006.

239. This price of about 300p/th is in line with the National Balancing Point (NBP) price impact outlined above and the pricing seen during much of 2022. This is by no means an upper limit to the potential costs of the constraints but looks to demonstrate the impacts of restricting flows at St Fergus, whether these are in the form of higher gas costs for consumers or high constraint prices.

Option	SP	CT	LW	ST
0 - Retain 4*Avons on 500 hours	£0 m	£0 m	£0 m	£0 m
1 - A1 (Brownfield) - 3 x new 15 MW GT's	£4576 m	£2817 m	£2465 m	£4640 m
2 - A1 (Greenfield) - 3 x new 15 MW GT's	£4533 m	£2774 m	£2422 m	£4597 m
3 - A2 (Brownfield) 2 x new 23 MW GT's	£977 m	-£2565 m	-£3302 m	£1454 m
4 - A2 (Greenfield) 2 x new 23 MW GT's	£948 m	-£2594 m	-£3331 m	£1425 m
5 - A3 (Brownfield) 2 x new 15 MW and 1 x new 23 MW GT's	£4435 m	£2715 m	£2360 m	£4506 m
6 - A3 (Greenfield) 2 x new 15 MW and 1 x new 23 MW GT's	£4387 m	£2667 m	£2311 m	£4457 m
7 - A4 (Brownfield) 4 x new 15 MW GT's	£4625 m	£2819 m	£2458 m	£4695 m
8 - E1 4 x Existing Avon 1533 15 MW derated	£4530 m	£2797 m	£2448 m	£4591 m
9 - E2 3 x Existing Avon 1533 15 MW derated	£4248 m	£2648 m	£2329 m	£4285 m
10 - D1 4 x Existing Avon 1533 15 MW with DLE modification	£4421 m	£2726 m	£2387 m	£4474 m
11 - D2 3 x Existing Avon 1533 15 MW with DLE modification	£4021 m	£2506 m	£2204 m	£4043 m
12 - AD1 2 x new 15 MW GTs (Brownfield) and 2 x Avon 1533 (15MW) with DLE modification	£4620 m	£2840 m	£2484 m	£4686 m
13 - AD2 1 x new 15 MW GTs (Brownfield) and 3 x Avon 1533 (15MW) with DLE modification	£4559 m	£2816 m	£2468 m	£4617 m
14 - 3 x new 15 MW GTs (Brownfield) and 1 x Avon 1533 (15 MW) with DLE modification	£4629 m	£2832 m	£2472 m	£4698 m
15 - 1 x 23 MW + 1 x 15MW (Brownfield)	£3125 m	£1928 m	£1613 m	£3357 m
16 - 2 x 15MW + 1 Avon 1533 (15MW) with DLE modification	£4329 m	£2714 m	£2379 m	£4386 m
17 - 1 x 15MW + 2 Avon 1533 (15MW) with DLE modification	£4169 m	£2636 m	£2320 m	£4208 m
18 - 2 x 15MW (Brownfield)	£3935 m	£2515 m	£2227 m	£3946 m

Table 16 – Relative NPV High Constraint Price

240.In this sensitivity, our preferred option is the lead option in both the Steady Progression and System Transformation scenarios, and the second option in both the Consumer Transformation and Leading the Way scenarios.

7.3. Best Available Techniques Review

241.To further assist the option selection process, a BAT assessment was undertaken in accordance with the requirements of the NGGT Specification ENV/21. This is a cost benefit modelling approach that uses environmental and technical evaluation criteria and whole life costs over a 20-year period to assess option performance.

242.We are required to use BAT as a primary selection mechanism for all new and substantially modified compressor machinery trains. The Pollution Prevention and Control Regulations (Scotland) 2012 require operators to determine BAT for an installation by considering likely costs and benefits of different solutions, to prevent or reduce emissions. This means that when we are looking at solutions for achieving compressor emissions compliance, the BAT assessment supports the chosen option for build solutions.

[redacted]

Figure 26 – St Fergus BAT Process Flow Chart

243.The BAT assessment for St Fergus includes a set of weighted qualitative (six) and quantitative (two) technical and environmental criteria against which each option is scored to assess option performance.

244.Collectively, the qualitative criteria have a weighting of 70% of the total combined technical/environmental score, and the quantitative criteria have weighting of 30%. Assessment criteria, weighting and qualitative scores were determined by representative business stakeholders. Scores are not intended to be used to determine the final preferred option but to support the decision-making process in parallel with CBA.

245.Table 17 identifies the structure and percentage weighting of the technical and environmental criteria.

Technical and Environmental Criteria Description	Weighting
Versatility – Performance and useability of an MCPD emissions compliant compressor envelope	15%
Future proofing – headroom above current emission limit values (ELVs) and performance against anticipated energy efficiency levels which may be contained in a future MCPD BAT Reference Document (BREF)[14]	12%
Ownership - maintenance complexity and availability of spares for the compressor plant	12%
Constructability – ease of construction and likely disruption to existing site operations	11%
Resilience - level of resilience provided by whole gas compression solution	15%
Environmental amenity – potential for visual and noise concerns	5%
Oxides of nitrogen (NOx) – predicted emissions emitted from the operation of the electric and gas-powered compressors for the assumed running hours over the 20 year model period	20%
Carbon Dioxide (CO_2) -– predicted emissions emitted from the operation of the electric and gas-powered compressors for the assumed running hours over the 20 year model period	10%
	100%

Table 17 – Qualitative Assessment Criteria

247.The technical and environmental criteria are defined as follows:

- **Versatility** refers to the performance and usability of the MCPD emissions compliant compressor envelope. This criterion is a combination of unit capability and availability to meet the pre-defined Process Duty Specification (PDS) points.
- **Future Proofing** is defined as the headroom above current emission limits and performance against anticipated energy efficiency levels which may be contained in a future BAT Reference (BREF) 46 Document. Future Proofing for Hydrogen use will be further developed at the next stage of design once the option is selected. As stated in last September's St Fergus NSMP Sub-terminal consultation event, we have engaged manufacturers to discuss scope to accommodate natural gas and hydrogen and we are confident that the preferred options will be future proof. Also, please refer to Appendix N – Hydrogen/CO_2 Repurpose Statement for a more detailed exposition of the current state of NGGT's Hydrogen and Carbon developments.
- **Ownership** refers to maintenance complexity, cost of ownership and the availability of spares for the compressor unit(s).
- **Constructability** refers to the ease of construction and potential for disruption to exiting site operations. Also considers number of outage periods required and risk to customers being able to achieve required flow.

[14] The UK environmental agencies have indicated that any forthcoming BREF for MCDP will contain energy efficiency targets.

- **Resilience** criteria refers to the ability for the site to still operate at its required parameters in the event of a failure or combination of failures.
- **Environmental Amenity** refers to the potential for visual impact and noise concerns, perceived by various stakeholders, resulting from the selected option.
- **Emissions** criteria refers to predicted NOx, CO_2 and CO emissions for each technology solution.

248.[redacted]

Duty	Station Flow (mscmd)	Inlet Pressure (barg)	System Transformation Station Hours (estimated per annum)
P1	[redacted]	[redacted]	[redacted]
P2	[redacted]	[redacted]	[redacted]
P3	[redacted]	[redacted]	[redacted]
P4	[redacted]	[redacted]	[redacted]
P5	[redacted]	[redacted]	[redacted]
P6	[redacted]	[redacted]	[redacted]
P7	[redacted]	[redacted]	[redacted]
P8	[redacted]	[redacted]	[redacted]
P9	[redacted]	[redacted]	[redacted]
P10	[redacted]	[redacted]	[redacted]
P11	[redacted]	[redacted]	[redacted]
P12	[redacted]	[redacted]	[redacted]
Total Estimated Station Hours per annum			[redacted]

Table 18 – St Fergus Process Conditions used for the BAT assessment

249.Annual station running hours were allocated to each PDS point, to estimate the distribution of operation. This is considered to be a representative distribution under the Future Energy Scenario (FES) System Transformation. The BAT Assessment results presented in this report assume the operating conditions set out in Table 18, with total estimated station running of 8,532 hours per annum. No sensitivity analyses were carried out on operating hours in the BAT assessment at this stage. BAT Assessments were conducted on three scenarios; 1 x VSD available, 2 x VSDs available and 0 x VSDs available.

250.The existing two VSDs will be retained as the lead compressor units; these provide compression capability covering the study flow range of 19 to 45 mscmd, covering PDS points P1 to P6. At lower flows, the GTs would provide compression capability, which for the assumed System Transformation operating scenario is an estimated 42% of total hours per annum.

251.Whilst a high availability is assumed for the VSDs (86.6% in the CBA), to assess back-up compression performance of the solution (an operationally critical aspect of the St Fergus operating philosophy) as well as overall technical performance, the BAT assessment was undertaken for multiple VSD available/unavailable scenarios.

252. The most likely scenario at St Fergus regarding VSD availability is the 1 x VSD available scenario. This tests the operationally critical backup compression case under likely real-world scenarios such as when maintenance is required on one of the VSDs. Details of all scenarios can be seen in the full [redacted] BAT report available in Appendix J – Preliminary BAT Report Summary.

BAT Scenario: 1 VSD available – most likely VSD scenario

253. Following evaluation of the feasibility study phase, a total of 18 options incorporating the selected techniques were identified. The CBA assessment was undertaken on these 18 options and a Peer Review was held with NGGT subject matter experts, who evaluated the CBA results and options qualitatively.

254. One of the functions of the St Fergus CBA is to act as a screening funnel into the BAT assessment, due to the high number of options taken through to CBA. This is because the modelling software used for the BAT allows no more than 10 options at any one time. Therefore, the 10 most suitable options which covered the widest spread were taken through to BAT review after stakeholder discussion and agreement. Further details can be seen in the full [redacted] BAT report available in Appendix J – Preliminary BAT Report Summary.

255. A combined technical and emissions score (technical 70% and a qualitative assessment, environmental 30% and a quantitative assessment) across the 10 options scored for BAT assessment can be found in Table 19.

Option Number	Candidate BAT Option Description (1 VSD Available)	Technical / Environmental Score (based on qualitative assessment)	Environmental Score (based on quantitative assessment)	Total Score
0	[redacted]	[redacted]	[redacted]	[redacted]
1	[redacted]	[redacted]	[redacted]	[redacted]
5	[redacted]	[redacted]	[redacted]	[redacted]
7	[redacted]	[redacted]	[redacted]	[redacted]
8	[redacted]	[redacted]	[redacted]	[redacted]
10	[redacted]	[redacted]	[redacted]	[redacted]
12	[redacted]	[redacted]	[redacted]	[redacted]
13	[redacted]	[redacted]	[redacted]	[redacted]
14	[redacted]	[redacted]	[redacted]	[redacted]
18	[redacted]	[redacted]	[redacted]	[redacted]
Maximum Weighted Score Available		[redacted]	[redacted]	[redacted]

Table 19 – Combined Technical and Emissions Review for the 10 Options taken through to BAT

256. Figure 27 illustrates the cost-benefit BAT model results. The Y axis represents the modelled total project cost over a 20-year period; the X axis is the combined technical and environmental score derived by the

BAT model for the options. When one VSD only is available, back-up will be provided by a GT to support the remaining VSD at higher gas flows.

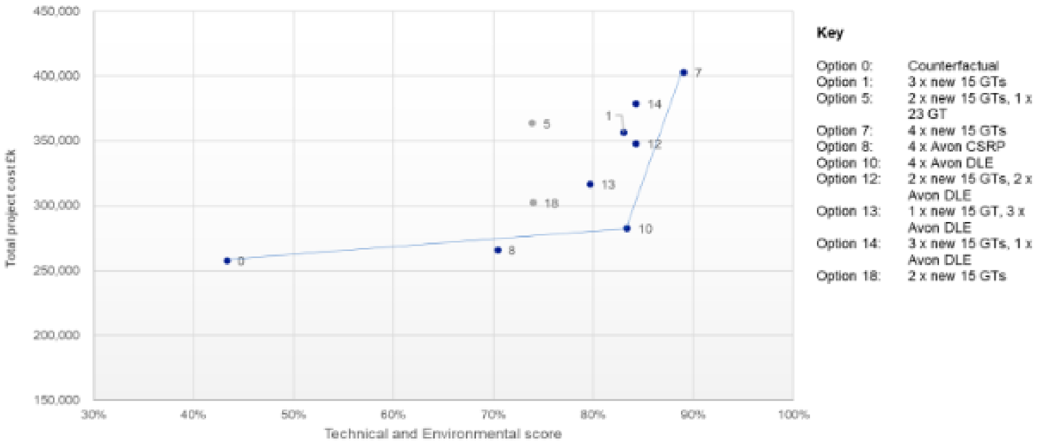


Figure 27 – BAT Chart for the 10 options taken through to BAT assessment with 1 x VSD Available

257.The potential for the candidate BAT options to reduce total mass emissions is presented in Figure 28 and Figure 29. The figures illustrate total tonnes emitted over the 20-year period of the BAT model. It is assumed that the unmitigated Avons in the counterfactual (Option 0 – retain 4 Avons on 500 hours) will run for the total number of hours required to deliver the required site duty (i.e. not capped at 2,000 hours, cumulatively, per annum) to illustrate the potential emissions impact.

258.It should be noted that emission calculations for the Avon DLE modification options assume certain emissions factors provided by the technology provider developing the technique for the 1533 engine model, which is not proven at engine scale and may be subject to future change.

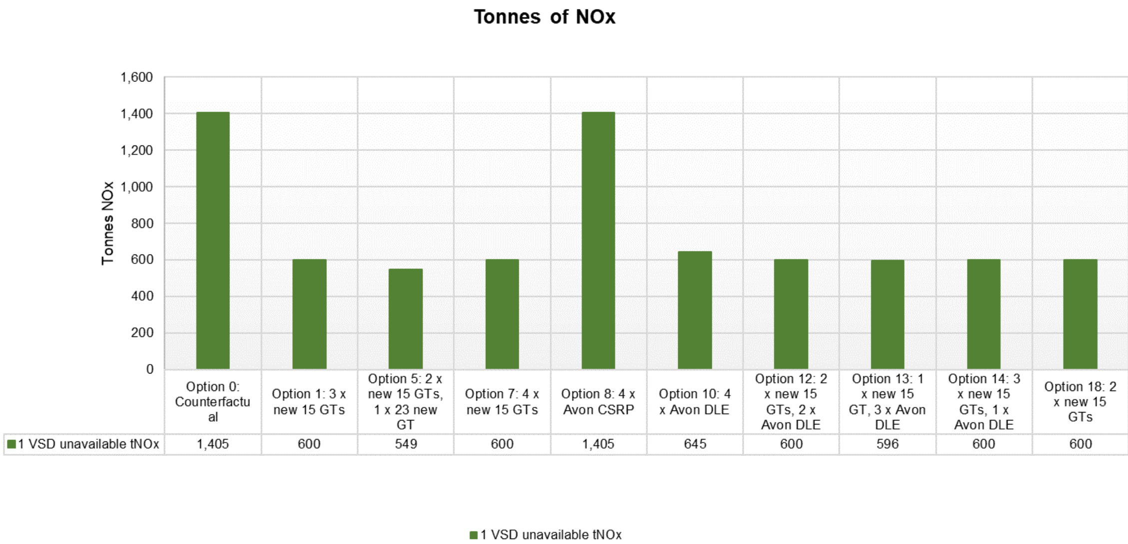


Figure 28 – Options NOx Emissions for 1 VSD Available

259.Figure 28 illustrates that the counterfactual and the Avon CSRP option have the highest NOx levels as they have no emissions abatement technique. The high number of running hours required by the Avon CSRP units to deliver the site duty result in high total emissions.

260.Figure 28 also illustrates that options which include new GTs and Avons with DLE retrofit produce similar NOx emissions, but Option 5 (2x 15MW and 1x 23MW new GTs - Brownfield) utilising a larger GT has the lowest emissions. It should again be noted though that the site would not operate in the back-up configuration over the entire 20-year period in reality, this is a necessary assumption made in conducting a BAT assessment of the back-up scenario, i.e. the realised emissions will depend on the likely percentage availability of the lead units and the need to run the backup configuration.

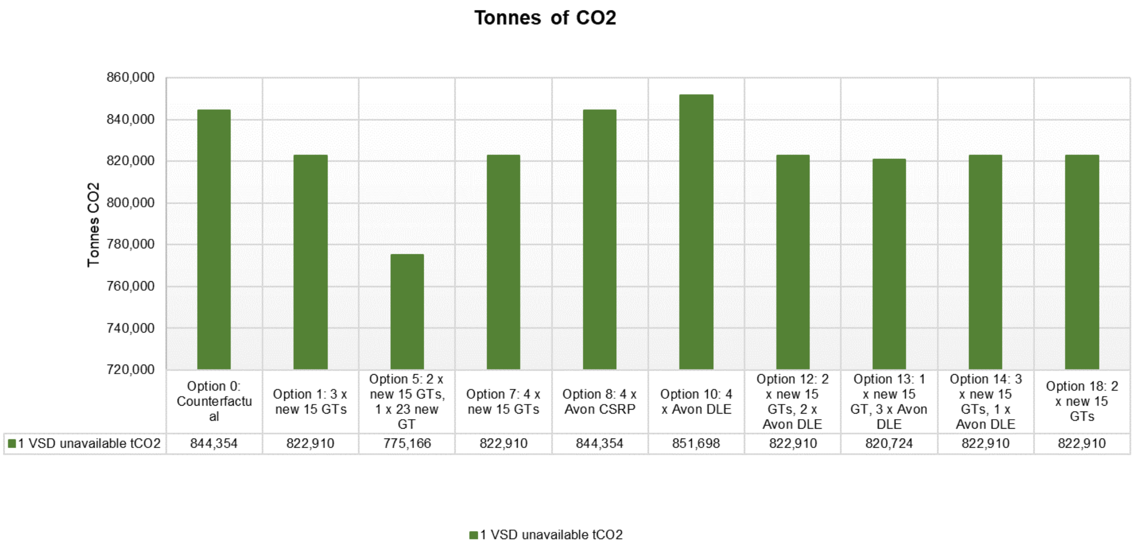


Figure 29 – Options CO_2 Emissions for 1 VSD Available

261. Figure 29 indicates that options using new GTs produce lower overall CO_2 emissions compared to options using existing Avon units. The DLE retrofit has the effect of slightly reducing energy efficiency, resulting in increased fuel consumption, and thus direct CO_2 emissions.

BAT Assessment Summary

262. When only one VSD is available, all candidate BAT options (with the exception of the counterfactual (Option 0) due to its Avon 500 hour running hour restriction) are potentially capable of providing complete back-up compression capability. The larger GT unit (23 MW) in Option 5 (2x 15MW and 1x 23MW new GTs - Brownfield) would need to operate in recycle at flows of 12 mscmd and below, reducing energy efficiency and resulting in avoidable emissions. This reduces the overall versatility of the solution, which would have particular implications should neither VSD be available.

263. Option 8 (4 x Existing Avon 1533 15MW derated) has the second lowest whole life cost but a lower technical/environmental score compared to options utilising Avon DLE retrofit technology or that have investment in a new GT. The Feasibility report suggests that although some power restriction from CSRP is expected, the resulting loss of compression capability is not considered material when four units are available. In spite of this, the Avon CSRP option is not regarded as a BAT solution for St Fergus due to the high NOx emissions associated with the high running hours expected for these units. The ultimate acceptability of CSRP does also remain to be tested with the UK environmental regulators via a formal variation to a site's environmental permit.

264. Options with four units provide good resilience on occasions when two Avon/new GT units are unavailable due to plant failure. Options with two or three Avon/new GT units provide a lower level of resilience.

265. Options containing Avons with DLE retrofit have a high technical/environmental score. This BAT assessment uses preliminary data provided by the technology provider developing the Avon DLE retrofit technique. The data suggests that emissions performance is very similar to new GTs using DLE technology and is considered unlikely to constrain the Avon's power.

266. It should be noted that the CSRP and Avon DLE retrofit techniques are not proven on the network, with no real-world availability of full-scale engine trial data. Should either or both solutions turn out not to be

viable, or too high a risk based on confidence levels, investment options would need to include new GT solutions.

267. The assessment indicates that Option 10 (4 x Avon with DLE modification) is potentially a BAT solution, providing a good cost-benefit result. It assumes that the Avon DLE retrofit provides technical advantages over an unmitigated Avon, however is unproven as discussed previously. If the assumed Avon DLE performance is not realised, options that contain additional new GTs are more likely to represent a BAT solution. Although the four new GT option does offer the best technical/environmental performance, this is the higher cost solution.

BAT Scenario: 2 VSDs available

268. The BAT assessment was extended to include for when 2 VSDs (Plant 3) are available.

269. From a qualitative assessment, the scores for when 2 VSDs are available remain the same as the one VSD available case for each candidate BAT option.

270. From a quantitative assessment, the availability of two VSDs does however impact on the total emissions for NOx and CO_2 over the 20-year model period as a result of two VSDs running together to deliver PDS points 1 and 2 instead of a gas driven GT.

271. Figure 30 and Figure 31 below, show a comparison between 1 and 2 VSD available and the subsequent CO_2 and NOx emissions levels. This illustrates that the emissions for both parameters are reduced for every candidate BAT option compared to when one VSD is available.

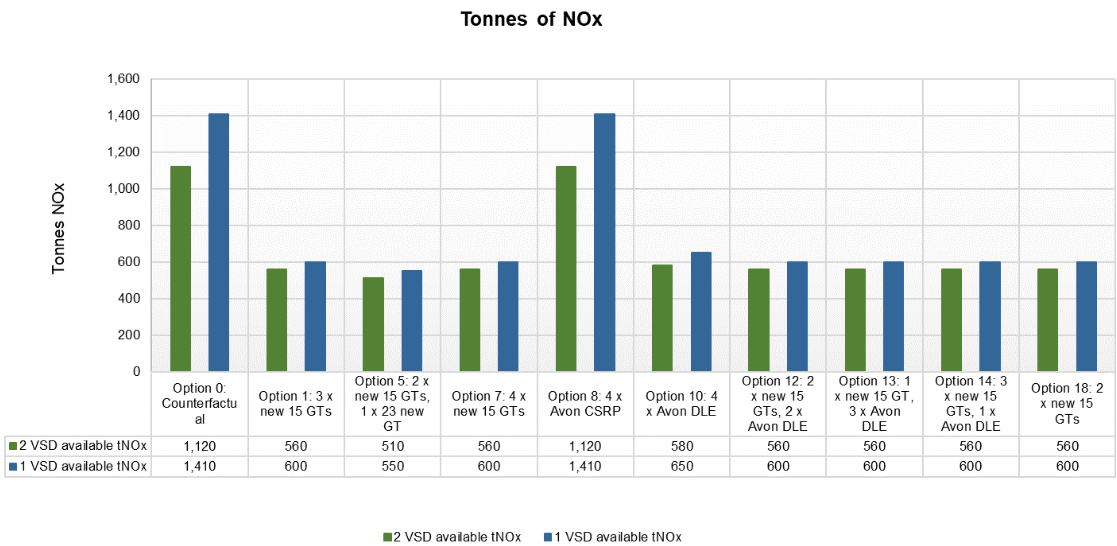
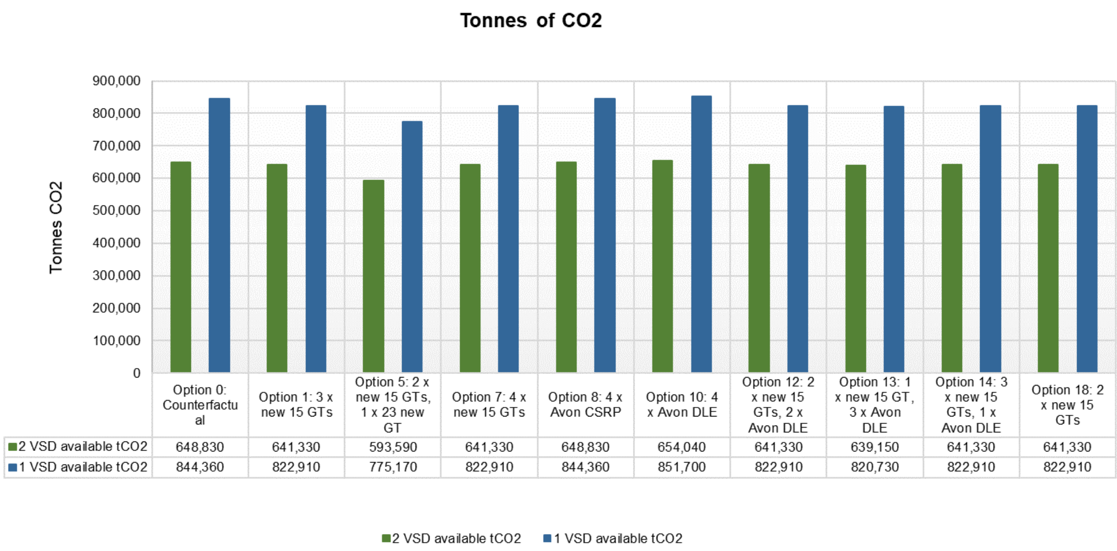


Figure 30 – Options NOx Emissions Comparison for 1 and 2 VSD Available



	Option 0: Counterfactual	Option 1: 3 x new 15 GTs	Option 5: 2 x new 15 GTs, 1 x 23 new GT	Option 7: 4 x new 15 GTs	Option 8: 4 x Avon CSRP	Option 10: 4 x Avon DLE	Option 12: 2 x new 15 GTs, 2 x Avon DLE	Option 13: 1 x new 15 GT, 3 x Avon DLE	Option 14: 3 x new 15 GTs, 1 x Avon DLE	Option 18: 2 x new 15 GTs
2 VSD available tCO2	648,830	641,330	593,590	641,330	648,830	654,040	641,330	639,150	641,330	641,330
1 VSD available tCO2	844,360	822,910	775,170	822,910	844,360	851,700	822,910	820,730	822,910	822,910

Figure 31 – Options CO_2 Emissions Comparison for 1 and 2 VSD Available

272. From a technical and environmental performance perspective, there is a slight improvement in Option 0 (retain 4 x Avons on 500 hours) and Option 8 (4 x Existing Avon 1533 15MW derated) when 2 VSDs are available. This can be seen in Figure 32 and is a result of reduced NOx or CO_2 emissions associated with the greater reliance on VSD running over unabated Avon based solutions.

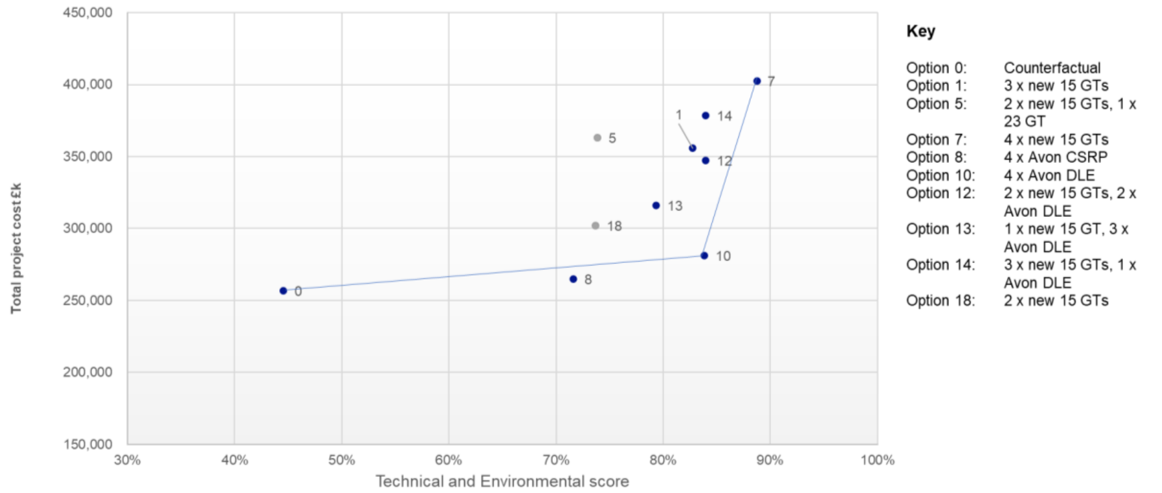


Figure 32 – BAT Chart for the 10 options taken through to BAT assessment with 2 VSD available

273. The performance of the other candidate BAT options remains largely the same. The overall conclusions for the BAT assessment remain the same for when one VSD is available.

BAT Scenario: 0 VSDs available

274. For the two VSD unavailable scenario, it was assumed that when options include a combination of new GTs and retrofitted Avons, the new GTs would be run in preference.

275. From a qualitative perspective, the absence of any operational VSDs has an impact on the versatility of options. For station flows above 30 mscmd (i.e. for PDS points P1 and P2 where the flow is assumed to be 45 mscmd), a total of three 15MW GTs are needed to deliver site compression requirements. Option 18 (2 x new 15MW GTs) is not capable of delivering P1 and P2 and therefore is awarded a score of zero for versatility. The versatility score for CSRP (Option 8 - 4 x Existing Avon 1533 15MW derated) is reduced from 5 (when one VSD is available) to 4 when no VSDs are available. The CSRP technique is expected to

reduce Avon power availability, resulting in the possibility that four Avon CSRP units will be required to deliver capability for P1 and P2. The versatility scores of all other options remain the same as they each have at least three GTs with sufficient power availability.

276. In Option 12 (two new 15 MW units and two Avons with DLE modification), one of the Avon DLE units will be required to deliver P1 and P2. This requirement reduces the future proofing score from 5 to 3, compared with one VSD available.

277. As the VSDs are already constructed, the ownership, constructability and environmental amenity criteria are unaffected by the unavailability of both VSDs.

278. The resilience criteria scores are unaffected as this criterion is driven by resilience of the solution to operate in the intermediate flow band (17-19 mscmd) should there be loss of plant. This flow band is below the surge control line of a VSD therefore the lack of any VSD does not make a candidate BAT option more or less resilient.

279. The unavailability of both VSDs has an impact on total emissions for NOx and CO_2 over the 20-year model period, as a result of all PDS points being delivered by gas-driven GTs. The following figures illustrate that the emissions for both parameters are increased compared to when one VSD is available. This is most marked for the counterfactual (Option 0 - Retain 4 Avons on 500 hours) and CSRP (Option 8 - 4 x Existing Avon 1533 15MW derated), which have no NOx abatement. The CO_2 emission factors for electricity are lower than for gas, reflecting the increased prevalence of renewables in the UK grid mix.

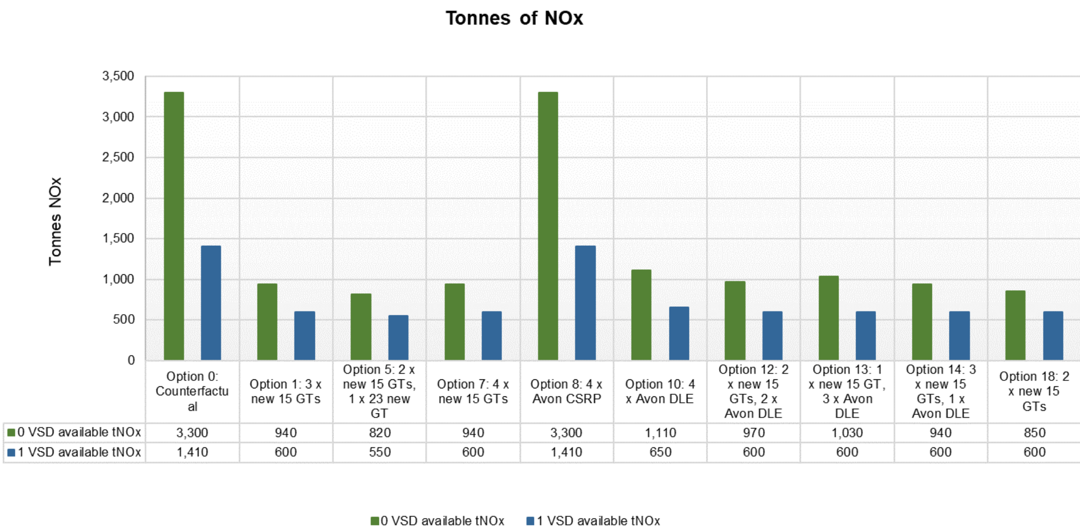
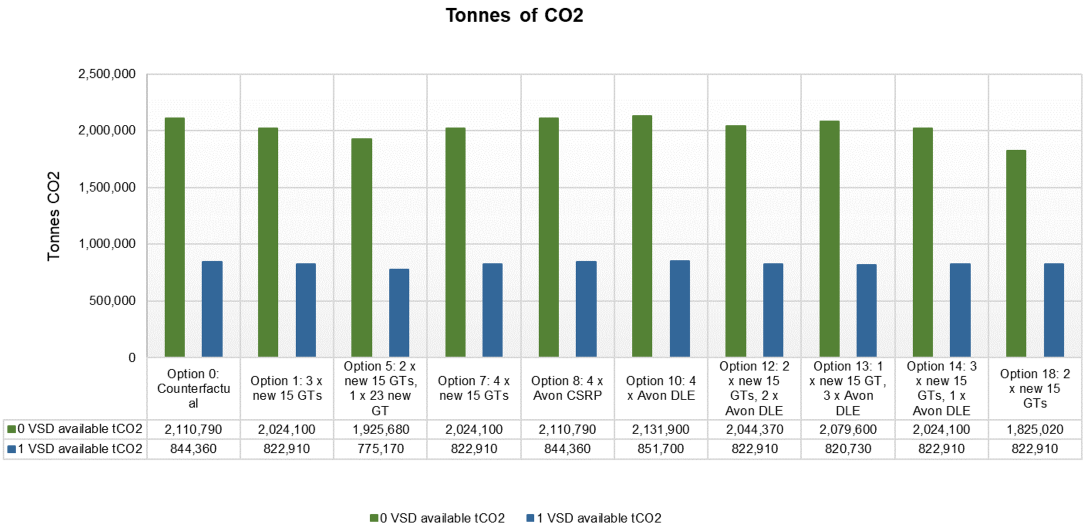


Figure 33 – Option NOx Emissions for 0 VSD Available



	Option 0: Counterfactual	Option 1: 3 x new 15 GTs	Option 5: 2 x new 15 GTs, 1 x 23 new GT	Option 7: 4 x new 15 GTs	Option 8: 4 x Avon CSRP	Option 10: 4 x Avon DLE	Option 12: 2 x new 15 GTs, 2 x Avon DLE	Option 13: 1 x new 15 GT, 3 x Avon DLE	Option 14: 3 x new 15 GTs, 1 x Avon DLE	Option 18: 2 x new 15 GTs
0 VSD available tCO2	2,110,790	2,024,100	1,925,680	2,024,100	2,110,790	2,131,900	2,044,370	2,079,600	2,024,100	1,825,020
1 VSD available tCO2	844,360	822,910	775,170	822,910	844,360	851,700	822,910	820,730	822,910	822,910

Figure 34 – Options CO_2 Emissions for 0 VSD Available

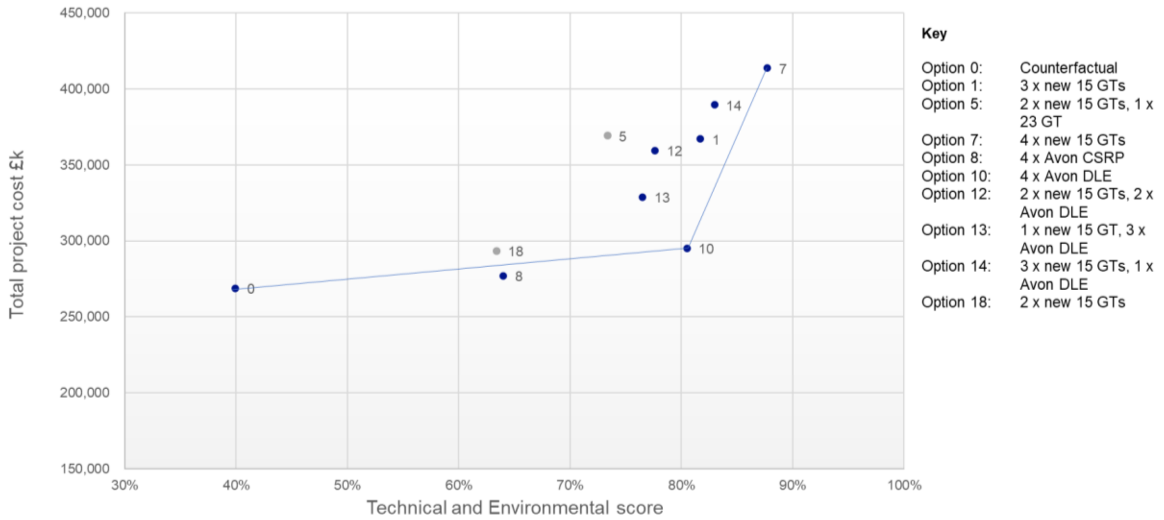


Figure 35 – BAT Chart for the 10 options taken through to BAT assessment with 0 VSD Available

280. NOx emissions are higher for all options compared to when one VSD is available, with the counterfactual and Option 8 (4 x Existing Avon 1533 15MW derated) having the greatest relative increase in NOx since they have no NOx abatement. This is reflected in the lower environmental/technical total scores. Option 18 (2 x new 15MW GTs) performs significantly worse due to zero score for versatility. Option 12 (two new 15 MW units and two Avons with DLE modification) has a slightly lower environmental/technical score as a result of having to run an Avon with DLE retrofit for PDS points 1 and 2; the Avon DLE retrofit is assumed not to run in the one VSD scenario.

281. All options are slightly more expensive compared to when one VSD is available due to fuel costs, as cost of gas used instead of electricity to run VSD is assumed to be higher. The exception to this is Option 18 (2 x new 15MW GTs) which has a lower cost when there are no VSDs. This is because there are reduced fuel costs associated with PDS points 1 and 2 as only 2 x 15 GTs running, noting that these operating points are not fully met. This is an artefact of the modelling approach, as the compression shortfall would have to be met elsewhere on the network (with associated emissions) or via financial measures.

282. Apart from these exceptions, the performance of the other candidate BAT options remains largely the same. The overall conclusions for the BAT assessment remain the same for when one VSD is available.

Key Findings from additional BAT Assessment Sensitivities with 0 and 2 VSDs Available

283. Apart from a few notable differences, the BAT assessment observations for when both or neither of the VSDs are available is very similar, confirming the validity of the conclusions reached for when one VSD is available. Key observations are as follows:

- When both VSDs are available, environmental performance improves for all options as a result of lower NOx and CO_2 emissions.
- Versatility is compromised when neither VSD is available for CSRP (Option 8 - 4 x Existing Avon 1533 15MW derated) and Option 18 (2 x new 15MW GTs).
- Whole life costs increase with increasing use of GTs, as a result of assumed increased cost of gas compared to electricity.

BAT Key Points:

- The Avon CSRP option is not regarded as a BAT solution for St Fergus due to the high NOx emissions associated with the high running hours expected for these units.
- This BAT assessment uses preliminary data which suggests that emissions performance is very similar to new GTs using DLE technology, though this is not proven at engine scale and may be subject to future change.
- Options with four units provide good resilience, on occasions when two Avon/new GT units are unavailable due to plant failure. Options with two or three Avon/new GT units provide a lower level of resilience.
- Although the four new GT option does offer the best technical/environmental performance, this is a higher cost solution.
- Our preferred option 14 (three new 15 MW units and one DLE retrofit) scored the joint second highest when compared to all other options in terms of ability to meet compression requirements (versatility), maintenance complexity and availability of spares (ownership), future resilience against tightening of energy efficiency and emissions limits (future proofing) and environmental control (hazard). Regarding emissions reduction, three new units plus one DLE retrofit ranked as the leading solution for emissions reduction through improved efficiency and fuel consumption.

8. Final Preferred Option

8.1. Option Assessment Summary

Decision Tree

284. We have used the high-level decision tree presented in Figure 36 to support our evaluation and final option selection. As described previously, Commercial Options were ruled out as being not feasible; this would fall under the shown Capability Requirements stage.

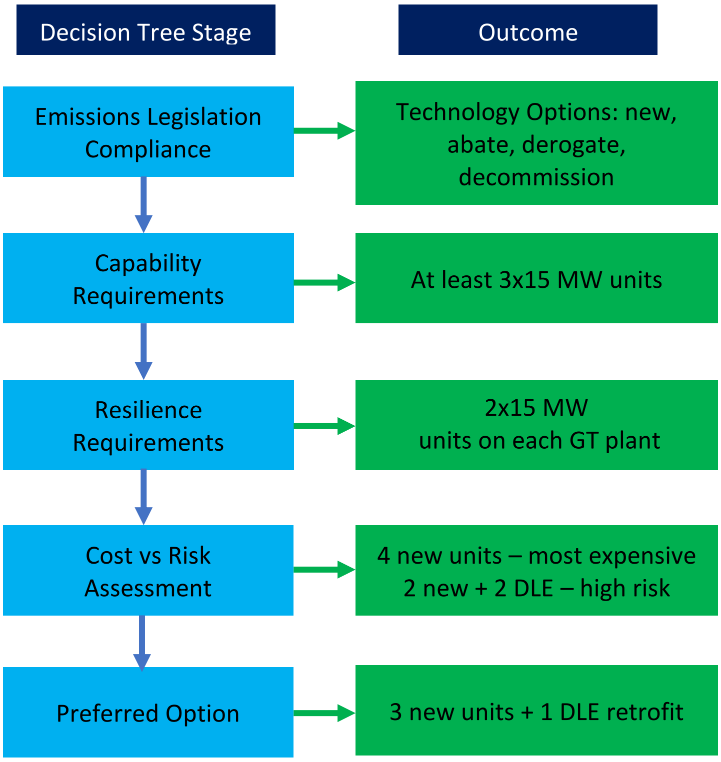


Figure 36 – High-Level Decision Tree

285. Following this process, the outcome for each of the considered options at each stage is shown in Table 20.

Option Description	Emissions Compliance	Capability Requirements	Resilience Requirements	Cost vs Risk Assessment	Preferred Option
0 - Retain 4*Avons on 500 hours					
1 - A1 (Brownfield) - 3 x new 15MW GTs					
2 - A1 (Greenfield) - 3 x new 15MW GTs					
3 - A2 (Brownfield) 2 x new 23MW GTs					
4 - A2 (Greenfield) 2 x new 23MW GTs					
5 - A3 (Brownfield) 2 x new 15MW and 1 x new 23MW GTs					
6 - A3 (Greenfield) 2 x new 15MW and 1 x new 23MW GTs					
7 - A4 (Brownfield) 4 x new 15MW GTs					
8 - E1 4 x Existing Avon 1533 15MW derated					
9 - E2 3 x Existing Avon 1533 15MW derated					
10 - D1 4 x Existing Avon 1533 15MW with DLE modification					
11 - D2 3 x Existing Avon 1533 15MW with DLE modification					
12 - AD1 2 x new 15MW GTs (Brownfield) and 2 x Avon 1533 (15MW) with DLE modification					
13 - AD2 1 x new 15MW GTs (Brownfield) and 3 x Avon 1533 (15MW) with DLE modification					
14 - 3 x new 15MW GTs (Brownfield) and 1 x Avon 1533 (15MW) with DLE modification					
15 - 1 x 23 MW + 1 x 15MW (Brownfield)					
16 - 2 x 15MW +1 Avon 1533 (15MW) with DLE modification					
17 - 1 x 15MW + 2 Avon 1533 (15MW) with DLE modification					
18 - 2 x 15MW (Brownfield)					

Table 20 – Decision Tree Outcomes for 18 Options

Key Assessment Criteria

286.The decision tree is supported in more detail by assessing key criteria such as NOx emissions and NPV. The results of this assessment of the 18 options are shown in Table 21, assigning a relative assessment status ranging between positive and negative against each option for each criteria.

287.All options had a positive NPV compared to the counterfactual, with the constraint costs outweighing the lower investment costs of this option.

[redacted]

Table 21 – Assessment Criteria Status for all 18 Options

288. The results of the assessment indicate that Option 14 (three new 15 MW units and one DLE retrofit) performs well against the majority of criteria. The only other options that perform similarly or better are those that include additional DLE retrofit units, as these options use existing units and therefore lower the total installed cost.

289. Our BAT assessment was also supportive of Option 14 (three new 15 MW units and one DLE retrofit) from an operational and environmental perspective. The assessment featured qualitative scoring of all options against key technical and environmental criteria, as well as whole life emissions and costs.

290. Option 14 (three new 15 MW units and one DLE retrofit) scored the joint second highest when compared to all other options in terms of ability to meet compression requirements (versatility), maintenance complexity and availability of spares (ownership), future resilience against tightening of energy efficiency and emissions limits (future proofing) and environmental control (hazard). Regarding emissions reduction, three new units plus one DLE (alongside SCR) ranked as the leading solution for emissions reduction through improved efficiency and fuel consumption. Overall scores assuming one VSD is available can be seen in Table 19 (10 Options taken to full BAT Assessment), and Appendix J – Preliminary BAT Report Summary.

291. The assessment does not include wider market impacts discussed in Section 7.2. These factors haven't been quantified but would only strengthen the justification for our preferred option. However, we have been able to provide an indication of the impact of market factors, for instance, on constraint costs.

292. This can be seen in the constraint cost analysis in Section 7.1 where, in reality, these costs could be far more significant as any lost gas from St Fergus NSMP would have to be replaced by other sources. Given that the replacement would need to be secured from marginal imports this could have a significant impact on wider market prices.

8.2. Inclusion of DLE

293.As noted previously, if a DLE retrofit unit is implemented immediately as an additional trial, it could fast-track our ability to prove the technology thus making it a possible candidate for the remaining MCPD non-compliant units across the NTS.

294.However, as DLE remains an unproven technology there are risks associated with its inclusion. The size of this risk varies depending upon the number of trial units implemented. The two risks of greatest concern are:

- Impact upon site capability during the trial, especially if major issues are encountered
- Deliverability of an alternative long-term solution if the trial proves the technology unsuitable

295.As outlined in Section 5 – Optioneering, a catastrophic failure of any DLE retrofit trial unit would likely result in all trial units ceasing operation until the cause is identified and resolved; which could take up to a year. Therefore, the greater the number of trial units at St Fergus, the greater the impact would be if such a failure occurred.

296.In 2024, the site will have two operational VSDs and four operational Avons. If one of these Avons were utilised for the trial, any failure would mean that the number of Avons potentially available would reduce to three. However, if two Avons were utilised in the trial then a failure would result in only two operational Avons remaining and any planned or unplanned outage on those units would mean that flows between 15-20mcmd could not be accommodated and there would be insufficient back-up for the VSDs.

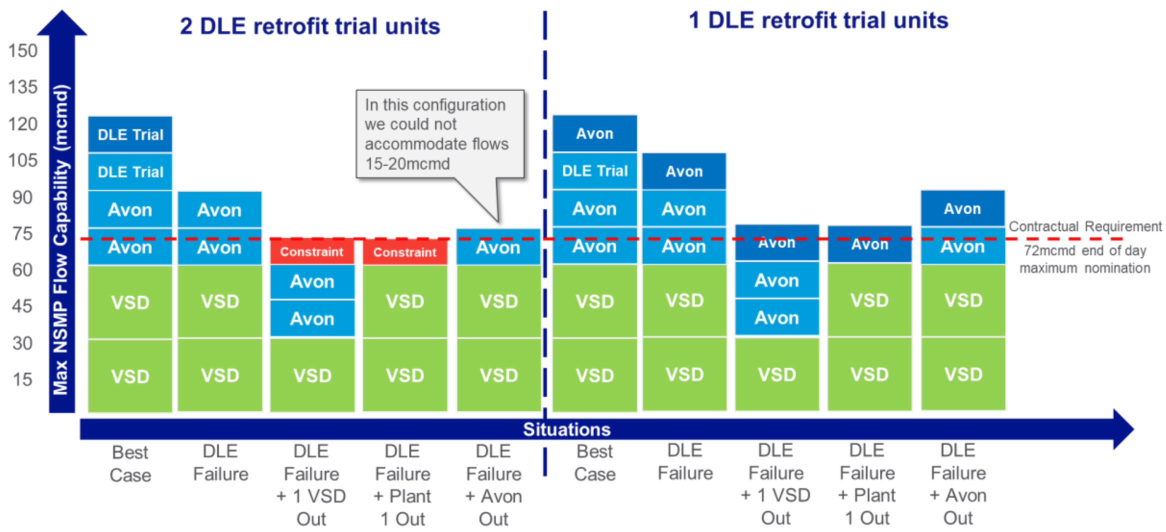


Figure 37 – Site capability under different scenarios with either 1 or 2 DLE retrofit trial units

297.Another consideration is the implementation of a different solution for a fourth compliant unit if the DLE trial proves the technology unsuitable. If it were determined that the DLE trial units needed to be replaced with new units, then the greater the number of trial units the greater the impact of a delayed start to the new builds.

298.If a single DLE trial unit had to be replaced, this could be started after 2030 because the site would already have three new units commissioned which could potentially be supported by up to three Avons on 500 hour derogation as a short-term measure. Whereas, if replacement for two DLE trial units began after 2030 the site would have only two new commissioned units with the support of up to three derogated Avons. The number of derogated Avons available would depend upon the reason for non-implementation of DLE. A catastrophic failure of a DLE unit would mean that it could not then be utilised as a derogated unit subsequently.

299.The fewer the number of new units, the greater the reliance upon derogated units which may mean additional investment to ensure their continued operation past 2030 in addition to the environmental impact. Retaining derogated Avons as a short-term measure while a long-term solution is finalised is not ideal as it also delays our compliance with unit spacing requirements.

300.The different units available in these two scenarios is shown in Figure 38.

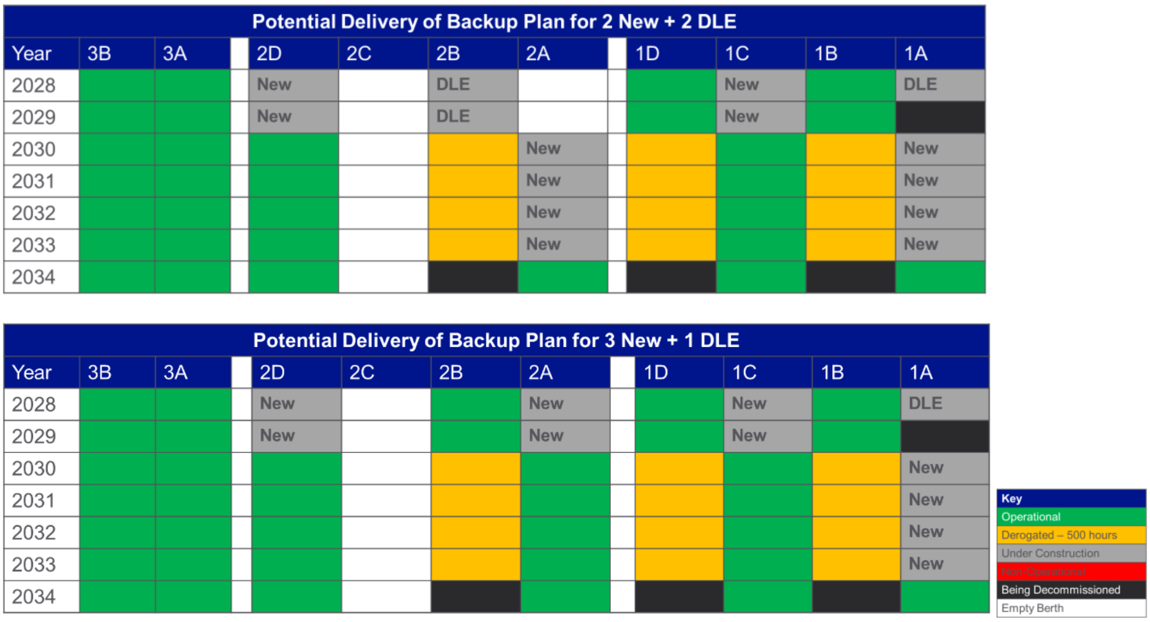


Figure 38 – Comparison of delivery for replacing DLE trial units with new units

301.Therefore, options that include multiple DLE units are considered too much of a risk at a site as critical as St Fergus. However, it is considered feasible to accommodate a single DLE retrofit trial at St Fergus.

302.Our selected Option 14 (three new 15 MW units and one DLE retrofit) scores within the top three options in the CBA. It minimises constraints, fuel usage and emissions by ensuring the bulk of primary duty and back-up uses the cleaner and more reliable new units. By proposing to trial DLE on an existing unit, this option is also in line with the guidance set out in Ofgem's Supplementary Re-opener Requirements document, which encourages us to explore opportunities to repurpose and retrofit non-compliant units to minimise capital costs.

8.3. Conclusion

303.We have considered the results of the option evaluation to arrive at an optimum solution for both achieving emissions compliance and ensuring the long-term Security of Supply of the UK.

304.Through our analysis we have determined that St Fergus requires four compliant units across Plant 1 and Plant 2 by 2030. Of the options which meet our requirements of providing at least four units spread across two plants, our preferred Option 14 (three new 15 MW units and one DLE retrofit) is in the top four options across all sensitivities.

305.Option 14 (three new 15 MW units and one DLE retrofit) is also supported by the outputs from extensive stakeholder engagement. Through the Autumn 2022 stakeholder consultation a preference was indicated for four units, with at least three of them being new units.

306.Option 12 (two new 15 MW units and two DLE) shows the most positive NPV across three of the four scenarios. However, based on the current unproven status of the DLE retrofit technology our preferred option remains Option 14 (three new 15 MW units and one DLE retrofit). This allows us to pursue proving this technology while mitigating the risk posed if it proves unsuitable.

307. Therefore, this report recommends the installation of three new units and one retrofit DLE unit to achieve emissions compliance and ensure long-term Security of Supply of the UK at an efficient cost to consumers. This recommendation is subject to positive results from the DLE prototype testing. If the DLE unit proves unsuccessful we will reassess the options to achieve a fourth compliant unit.

Final Preferred Option Key Points:

- To fulfil the requirement of providing emissions compliance and continued site capability and resilience, this report recommends the installation of three new units across Plants 1 and 2 and one retrofit DLE unit (Option 14).
- This decision is supported by the results of the CBA and BAT analysis with Option 14 (three new 15 MW units and one DLE retrofit) scoring the second highest NPV score in the CBA, and the joint second-best total score for BAT.
- The decision is also supported by the outputs from extensive stakeholder consultation which indicated a preference for four units, at least three of them being new units.
- Stakeholders feel wider market impacts are an important factor, quantification of which will strengthen an already strong needs case
- DLE remains an unproven technology and options that include multiple DLE retrofit units would be considered too much of a risk at a site as critical as St Fergus.
- Implementing a DLE retrofit trial at St Fergus facilitates the demonstration of this technology to utilise it across the wider NTS. If the DLE unit proves unsuccessful we will reassess the options to achieve a fourth compliant unit.

9. Preferred Option Detail

9.1. Preferred Option for the request

What is the Driver for this Investment?

308.The primary driver for future investment at the St Fergus Gas Terminal is to ensure compliance with MCPD emissions legislation. Failure to invest in emissions reduction or replacement with new MCPD compliant units will place the existing Avon Units 1A, 1B, 1D and 2B onto reduced running hours which reduces site availability. The implication of this, given high future compression requirements at St Fergus, is significant constraint costs for shippers, potentially higher gas costs for consumers are passed on and reduced Security of Supply.

309.In addition to ensuring compliance to the emissions legislation, NGGT must also ensure the right level of network capability and resilience is maintained to fulfil our customers' needs and our operational requirements, efficiently minimising network constraints and meeting the 1-in-20 peak day demand. We must ensure that our network is safe, reliable and that it delivers value for our consumers and stakeholders, while minimising impact on the environment.

Our Investment Recommendation

310.The final preferred option for St Fergus Gas Terminal has been driven by a robust selection process where a full range of emissions reduction solutions have been evaluated through a CBA and BAT process. This included derogation of existing units, abatement of existing units through the application of exhaust technology such as DLE retrofit and new build units.

311.The St Fergus CBA utilised +/-30% capex estimates to determine the whole life cost for each short-listed option. Unit capability was assessed using network capability modelling while availability estimates were based on NTS operational data and site-specific RAM models as described in Appendix E - Site Availability Model and CE-AMP. These CBA inputs combined to determine the highest NPV option based on projected network capability requirements outlined across the four Future Energy Scenarios. The BAT assessment, which is an Industrial Emissions Directive requirement, supported decision making through qualitative scoring of options based on an operational and environmental perspective.

312.The BAT review favours options which include new units and therefore points clearly to Option 7 (four new 15 MW units) as being the highest scoring option, but this is also the most expensive option from a capex perspective. The CBA balances installation costs against longer term reductions in constraints and running costs and therefore highlights Option 12 (two new 15 MW units and two Avons with DLE modification) which incorporates a mix of both new and existing units (2 x new 15 MW GTs within a Brownfield location and 2 x Avon with DLE modification) as being the best performing option. However, this option includes two DLE retrofit units which are currently unproven technology.

313.Our recommendation to select Option 14 (three new 15 MW units and one Avon with DLE modification) aims to balance the environmental benefits of installing new, more efficient units against the lower cost of retrofitting existing units with abatement technology, which are a lower capital cost but have fewer environmental benefits and less certainty around availability.

314.Whilst the DLE technology remains unproven, it would not be appropriate to install two DLE retrofit units at the critical St Fergus site. There are however advantages of trialling one DLE retrofit unit at the St Fergus location as it provides the opportunity to test the technology on a unit with high run hours and has a number of other backup units should the DLE retrofit unit fail.

315.NGGT are progressing with the DLE retrofit testing currently planned in for trials at Kirriemuir Compressor Station. We are proposing that these tests are further substantiated and continued at the St Fergus Gas terminal as part of the St Fergus Future Operating Strategy on one of the existing Avon 1533 Machinery Trains.

316.This is based on the outcome of the CBA, BAT assessment and considering the criticality of the St Fergus Gas Terminal to the UK's Security of Supply. The use of both Plants 1 and 2 is to ensure sufficient resilience for the site as outlined in the St Fergus Resilience Assessment attached to the St Fergus Site Strategy. The inclusion of a DLE retrofit unit is for the benefit of the wider fleet in proving the retrofit DLE technology. For cost evaluation purposes, unit size was determined to be approximately 15 MW each but following final preferred option approval, each new unit will be appropriately sized to meet capability requirements.

317.This option provides long-term emissions compliant compression capability that is needed to meet forecast future requirements across the Future Energy Scenarios.

Justification for our Investment Recommendation

318.Through our evaluation and selection of a preferred final option we have endeavoured to balance and meet the varying requirements associated with this investment. Our assessment has determined that four units across two separate Plants provide the optimum level of site capability and resilience. Our BAT analysis determined that new GT units provided the greatest environmental benefit. Our preferred option provides the right balance between providing MCPD emissions legislation compliance, achieving site capability and resilience requirements and minimising costs to consumers.

319.New units are the highest performing solution from an emissions reduction perspective. New GT compressors offer fuel efficient operation, long-term reliability and low emission compression. New units also feature the most up-to-date technology and OEM support packages, which protects this investment from future changes in energy legislation ahead of the UK's aspiration to achieve Net Zero by 2050.

320.New build units incur the highest capital investment cost but the lowest asset health cost.

321.From a BAT assessment perspective where one VSD is available, Option 14 (three new 15 MW units and one DLE retrofit) has a high technical/environmental performance, comparable with option 12 (two new 15 MW units and two DLE) and slightly favourable compared with Option 10 (4 x Avon DLE). The assessment assumes that the Avon DLE retrofit provides technical advantages over an unmitigated Avon but not as much as installation of a new unit, however this technique is relatively new and not proven on the network. If the assumed Avon DLE retrofit performance is not realised, options that contain additional new GTs are a more viable option and will represent a BAT solution.

322.Our preferred option also allows further testing of DLE. Unlike other UM sites there is more mitigation available at St Fergus due to the multiple berths meaning we can spread the risk and leave options open for longer (i.e. if DLE is proven unsuitable there is time to either build an alternative fourth unit or utilise multiple Avons on derogation). St Fergus also offers greater opportunity for high running hours on a DLE test unit, giving more confidence to utilise it across the wider network.

323.Deferral or delay of the investment is not feasible due to the criticality and 24/7/365 nature of the St Fergus site. Derogating the Avon to 500 hours doesn't provide the necessary site resilience.

324.For the preferred option, operational acceptance is forecast for 2029, aligned to our RIIO-T2 and RIIO-T3 outage plans. Decommissioning of the non-compliant units could take place from 2032, once the new units are operational. Decommissioning will not form part of the MCPD Uncertainty Mechanism. An NTS-wide assessment of units to be decommissioned will be undertaken under a separate decommissioning investment plan within our RIIO-T3 submission. This will ensure targeted decommissioning investment can be undertaken to provide maximum value in terms of risk reduction and capability enhancement across the NTS.

9.2. Option Programme

325. Project delivery programmes for all 18 shortlisted investment options have been developed to confirm the feasibility of delivery prior to the 1 January 2030 MCPD legislative deadline and to identify notable schedule related risks. These programmes have not been used to derive any elements of the capex estimates, but they have been used to determine basic spend profiles and delivery capability.

326. Appendix M – Project and Preferred Options Programmes shows the overall construction programme and the preferred option (Option 14 - three new 15 MW units and one DLE retrofit) indicative build programme.

327. The project delivery programme is based on a standard EPC delivery approach including the following main contracts:

- Pre-FEED
- FEED
- Compressor machinery train equipment supply
- Engineering, Procurement, Construction and Commissioning

328. Pre-FEED stage will be initiated immediately following confirmation/approval of the final preferred option via the Ofgem Re-opener, starting at the end of January 2023 and planned for completion by July 2023. During this pre-FEED stage the delivery strategy will be confirmed and tender documentation for the FEED stage produced.

329. During the subsequent FEED phase the selected investment option will be defined to an appropriate level of detail to support the Re-opener to confirm remaining project costs and to allow the EPC phase to be contracted on a lump sum or target price basis.

330. The FEED phase will include development of tender package for the compressor machinery train equipment which will be purchased by NGGT and free issued to the EPC contractor. Site works will commence once detailed design has been sufficiently progressed and three years has been allowed for all site works up to operational acceptance. The proposed brownfield locations will allow a significant amount of site works to be conducted in a separate construction area (known as Construction, Design and Management or CDM Area) segregated from the operational site thus reducing the impact on operations. However, multiple Plant outages will be required to allow tie-in and commissioning of the three new units suction and discharge pipework to existing suction and discharge header pipework.

331. Tie in and commissioning of the three new units and DLE retrofit upgrade on existing Avon engine will be undertaken through a series of outage works. Full details of these will be developed at the next stage of the project.

332. After operational acceptance a winter running period has been allowed to operationally prove the new units and DLE retrofit modification to existing Avon unit prior to the 2030 legislative deadline when any non-compliant units will be removed from service.

9.3. Option Risks and Opportunities

Key Option Risks and Mitigation

333. A key concern with the works proposed at St Fergus is that the site is operational 24/7/365 days a year which present challenges for both securing of long-term outages and physical construction of the works as a whole.

334. The requirements for these outages will be further developed as the project progresses through the FEED detailed design works and a greater understanding of the necessary tie in works required are identified.

335. There is a key risk in relation to planning requirements for new units. Current permitted development allows for stack heights of up to 15m. Liaison with potential OEMs has identified that this may be exceeded with the new units requiring additional planning permissions to potentially be obtained.

336. A key risk is the geographical location of the St Fergus site and the issues with mobilisation of plant, personnel, and materials to site to be able to undertake the works. Given the current global climate, this will continue to be a key risk moving forwards and will have the potential to affect cost and resource availability to complete the works.

337. Progression to the next phase of the project relies on agreement between NGGT and Ofgem on the preferred option. There is a critical risk that alignment will not be gained at the end of the 6-month Re-opener window allowed for in the project delivery programme causing schedule delays. To mitigate this risk we have held regular engagement meetings with Ofgem through the option selection phase. The output of these engagement sessions has informed this option selection process described in this submission.

338. There is a critical risk associated with UK specific and worldwide geopolitical issues which has the potential to impact equipment supply and labour rates and availability leading to capex increase and schedule delay. This risk will be a key focus area during development of the delivery strategy and lessons learnt from other similar projects will be applied appropriately. The other key risk associated with delivery is the MCPD 2030 deadline which will put tight delivery constraints on the project given the multiple concurrent projects likely to be in flight.

339. There is a risk in relation to spacing requirements between plant complying with the NGGT G/37 specification and that this will need to be closely considered during the detailed design phase to avoid potential problems. As part of this the sequence of installation will also need to be closely reviewed and scheduled.

340. There is a risk in relation to the review and condition assessment of the existing plinths to potentially be reused. This will be further reviewed at the next stage of design development.

341. There is a key risk in relation to the interaction of the existing station control system with the new proposed units and this needs to be fully explored at detailed design phase.

342. Condition assessment of existing assets to be interfaced with the new compression proposal needs to be fully realised and understood.

343. There is a critical risk in relation to the construction works being implemented on a ‘live’ gas terminal which in turn will bring its challenges with delivery. In parallel to the construction works will be routine maintenance works and ongoing Asset Health interventions which will further add to the complexity of the delivery.

344. There is a critical risk in the proving of the DLE technology as a viable solution. Proposed trial runs at Kirriemuir are still to be undertaken as the technology is in its infancy stages.

Option Opportunities Identified

345. The inclusion of a DLE trial within the preferred option provides the opportunity to gain additional confidence in that technology which will allow greater use of it across the wider fleet.

346. There is the potential with the preferred option for reuse of existing equipment and tie into existing pipework systems and manifolds. However, there is also an opportunity to review the assets on site and look for opportunities to rationalise in order to reduce ongoing maintenance and associated opex costs.

347.There is also an opportunity to coordinate with other projects and bundle scope to provide potential capex savings across this and other investments. This will be reviewed with the development of the delivery strategy.

348.There is an opportunity to align the design to a future hydrogen strategy will also be reviewed early in the engineering design development process.

349.There is an opportunity to maximise multiple procurement efficiencies with other MCPD schemes in parallel delivery.

9.4. Efficient Cost

350.CBA and BAT assessments are based on -30/+30% capex estimates developed according to the methodology described in Section 6.1 – Cost Estimate Methodology. These cost estimates were based on engineering inputs, including material quantities and equipment lists taken from drawings provided by [redacted] the engineering consultant used for the option selection phase. We applied in-house cost data developed from previous projects to the engineering inputs to produce capex estimates for new build scope. Asset Health costs were based on relevant funding allowances agreed for RIIO-T2.

351.Following confirmation of the final preferred option we will develop the delivery strategy, engineering design and cost estimates through pre-FEED and FEED stages ahead of the cost Re-opener currently forecast for 2025. As part of the development of the preferred option, value engineering and delivery efficiencies will be reviewed including consideration of opportunities identified during the option selection process including:

- Refinement of the preferred option including layout.
- Alignment of project delivery with other planned investments at St Fergus and across the wider NTS. This includes consideration of outage requirements for construction and commissioning and bundling opportunities which provide delivery efficiencies
- Refinement of the project delivery programme alongside the development of the delivery strategy for the project. This will incorporate relevant lessons learnt from the Hatton LCPD and Wormington MCP projects which is being delivered to an accelerated programme using an EPCM contracting strategy.
- Develop an option specific risk register for the preferred option and review of the UAP.

352.Cost efficiencies will be incorporated into the updated cost estimates which will form the basis of the funding allowance request to be submitted in our Cost Re-opener submission in 2025.

353.An investment decision regarding decommissioning of remaining Avon Units (which will include a subset of 1A, 1B, 1C, 1D and 2B at St Fergus will be taken once agreement of the preferred solution is agreed. Further development work on decommissioning costs for the existing Avon units is in flight.

9.5. Outputs and Allowances in RIIO-T2

354.In RIIO-T1, NGGT did not have any outputs related to St Fergus Gas Terminal emissions compliance. As detailed in the summary table, **Table 3**, we spent [redacted] in RIIO-T1, which was to initiate the feasibility study and options selection process as well as the development of our RIIO-T2 business plan submission for MCPD compliance for St Fergus Compressor Station. For further detail on RIIO-T1 outputs related to emissions compliance, please see CE-AMP.

355.In RIIO-T2, NGGT has a Compressor Emissions PCD detailed in Special Condition 3.11 Compressor emissions Re-opener and Price Control Deliverable, Appendix 2. The PCD is to ensure NGGT delivers a Final

Options Selection Report, long lead items and a Re-opener submission for St Fergus Compressor Station. Through pre-application engagement we agreed with Ofgem the most appropriate timing for submission of the Final Option Selection Report is January 2023 to ensure option selection is based upon results from all options under consideration and the Re-opener application window is in June 2025. The received Baseline allowances are [redacted] (excl. RPEs). In the first year of RIIO-T2 we have spent [redacted] of our Baseline allowance. We are reporting on spend and progress against our Baseline allowance and PCD as part of our annual Regulatory Reporting Pack (RRP).

356.The PCD follows the GT Project Assessment Process (GTPAP), which is a two-step process whereby we submit the FOSR as part of the first step, and a cost submission once the project has gone through a full FEED for the preferred option and tender process, as a second step. The outcome of the second step (Re-opener submission in June 2025) will be to amend the licence to incorporate the PCD outputs associated with delivery of the selected option set by Ofgem's Final Determinations in December 2020.

357.Following Ofgem's review and approval of our Proposed Final Option for St Fergus Compressor Station MCPD compliance, we will continue working to develop our preferred option further in readiness for our Cost Re-opener submission at which point we will propose a revised PCD to be included in the Gas Transporter Licence to reflect the delivery of our preferred option.

Outputs and Allowances Key Points:

- Our preferred option is 3 New Units on the existing Plant 1 and Plant 2 location with a DLE modification to one of the existing Avon 1533 Gas Turbines.

10. Conclusions and Next Steps

358.Our final preferred option is the installation of three new compressor units and implementation of a retrofit DLE trial on one of the existing Avon units (Option 14). The inclusion of DLE as part of our preferred option is subject to its successful prototype testing and will aim to further our understanding of the suitability of this technology for the NTS. This recommendation is based on a review of the outcomes of the CBA and BAT assessment in addition to considering the criticality of the St Fergus gas terminal to the UK's Security of Supply.

359.This recommendation represents the optimum solution to comply with MCPD legislation and maintain the capability and resilience that the St Fergus site requires.

360. Our recommendation has been justified following comparison against a variety of key investment metrics:

- Three new units is one of the highest performing solutions from an emissions reduction perspective - this emissions performance is only surpassed by Option 7 (four new 15 MW units), which proposed the installation of four new units. New compressors offer efficient operation, long-term reliability and low emissions compression.
- Option 14 (three new 15 MW units and one DLE retrofit) has a good NPV across all four scenarios and is one of the leading options which satisfies the criteria of providing four units across two plants.
- From a technical perspective, Option 14 (three new 15 MW units and one DLE retrofit) received one of the highest overall technical ratings compared to the alternative investment options. It was only surpassed by Option 7 (four new 15 MW units) which proposed the installation of four new units at the site. New units scored highest in terms of network versatility, future proofing against changes in energy legislation, maintainability and environmental hazard control.

- Reduced unit availability can have a significant impact on site resilience, network capability and continuity of supply on the NTS. Given St Fergus – NSMP's key role in supporting UK supply from both UKCS and Norwegian gas, maximising the resilience on site is vital in minimising the risks to Security of Supply any disruptions would cause.
- The brownfield location of the preferred option provides a significant benefit to St Fergus as it utilises existing assets whilst being possible to deliver without interrupting gas supply. This is achievable because of the existence of Plants 1 and 2, and their ability to support one another in addition to Plant 3.

361.Through the development of our preferred option, and in line with Ofgem's RIIO-T2 Final Determinations, we have progressed the issue of who should pay for compressor investment at St Fergus. Additional detail on this progress can be found in Appendix C – Charging Methodology and will be addressed further in 2023.

362.Following Ofgem's decision on the final preferred option, NGGT will use the remaining baseline allowances confirmed in the Final Determinations document to develop our preferred option up to the cost Re-opener, currently forecast for June 2025. We intend to initiate a pre-FEED stage immediately following preferred option confirmation where the delivery strategy will be confirmed, and tender documentation produced for the FEED stage. During the subsequent FEED phase, the selected investment option will be refined to support the cost Re-opener and confirmation of remaining project cost. The EPC phase will include development of tender package for the compressor machinery train equipment. Site works will commence once detailed design has been sufficiently progressed which allows for a maximum of three years for all site works up to operational acceptance. Construction of the new units on existing berths will minimise the impact on the existing units, maintaining the current level of availability and capability during construction. After operational acceptance in 2029, a partial winter running period is provided for the new units prior to the 2030 legislative deadline when the remaining Avons will be restricted to a maximum of 500 hours operation per year.

363.Ofgem are invited to assess and approve the NGGT preferred option outlined in this FOSR and publish those views as per the RIIO-2 Re-opener Guidance and Application Requirements Document.

Conclusion:

- Ofgem are invited to assess and approve the proposed final preferred option for the St Fergus gas terminal in line with Special Condition 3.11, Part C, 3.11.9.
- The final preferred option is installation of three new units across Plants 1 and 2 and one retrofit DLE unit.
- The question of who should pay for investment has been taken forward and will be addressed further in 2023.

11. Appendices

Appendix A – St Fergus Site Strategy

Appendix B – CE-AMP

Appendix C – Charging Statement

Appendix D – CBA

Appendix E – Site Availability Model

Appendix F – Capital Cost Breakdown Detail

Appendix G – FOSR Databooks

Appendix H – Project Risk Register and Covering Document

Appendix I – Asset Health Report

Appendix J – BAT Report

Appendix K – Feasibility Optioneering Report

Appendix L – [redacted] Emission Testing Report

Appendix M – Project and Preferred Option Programmes

Appendix N – Hydrogen/CO_2 Repurposing Statement

Appendix O – Assurance Letter

Appendix P – Guidance Mapping of Ofgem Requirements

Appendix Q – Stakeholder Engagement Log

Appendix R – Glossary

Appendix R - Glossary

Glossary	
1-in-20	The 1-in-20 peak day demand is the level of demand that, in a long series of winters, with connected load held at the levels appropriate to the winter in question, would be exceeded in one out of 20 winters, with each winter counted only once.
AGI	**Above Ground Installation:** Above ground gas assets (including, but not limited to; pipework, valves, pigtraps, meters and regulators) located within a fence line for the safe operation and maintenance of the National Transmission System
ASEP	**Aggregated System Entry Point:** 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	Rolls Royce (Siemens) gas turbine engine which forms part of the compressor machinery train and is subject to MCPD.
Barg	Bar gauge
BAT	**Best Available Technique:** 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.
BRef	**BAT Reference Documents:** 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 within the existing site perimeter fence.
Buyback	NGGT 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.
CBA	**Cost Benefit Analysis:** A mathematical decision support tool to quantify the relative benefits of each site option.
CE-AMP	Compressor Emission Asset Management Plan
CO	**Carbon Monoxide:** 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.
CO_2	**Carbon Dioxide:** A naturally occurring chemical compound composed of two oxygen atoms and a single carbon atom. If there is not enough oxygen to produce CO_2 during combustion, Carbon Monoxide (CO) is formed.
Compressor Unit	Equipment used to compress gas to high pressure for transport through the NTS. Each compressor station consists of one or more compressor units as well supporting equipment such as meters, filters, valves and pipework. Compressor units can be driven by gas turbines or electric drives.
Counterfactual	The counterfactual option represents current network with minimum interventions to comply with emissions legislation.
CSRP	**Control System Restricted Performance:** Technology that restricts the performance of a gas-driven compressor to limit NO_x emissions.

Glossary	
DLE	**Dry Low Emissions:** An Avon DLE retrofit modifies the combustion system within the Avon engine so that air and fuel are premixed before combustion. This reduces the peak combustion temperature, which in turn reduces the amount of NOx produced
EA	**Environment Agency:** A non-departmental public body, sponsored by DEFRA, with responsibilities relating to the protection and enhancement of the environment in England.
ELV	**Emission Limit Values:** Limits set for industrial installations by the LCP directive and IPPC under the umbrella of the IED and MCPD.
Emissions Abatement	Includes technology that reduces the emissions from a gas-driven compressor.
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 NGGT is obligated to make available for delivery against on every day of the year.
EPC	**Engineering, Procurement and Construction**
EUD	**Emergency Use Derogation:** Derogation provided under the MCPD for equipment used in emergencies and less than 500 hours per year on a rolling 5 year average, with a maximum limit of 750 hours in any one year.
Exit Capacity	Holdings give NTS users the right to take gas off the NTS on any day of the gas year. Capacity rights can be procured in the long term or through shorter term processes, up to the gas day itself. Each NTS Exit point has an allocated Baseline which represents a level of Capacity that NGGT is obligated to make available for offtake on every day of the year.
FEED	**Front End Engineering Design:** The FEED is basic engineering which comes before the detailed design stage. The FEED design process focusses on the technical requirements as well as an approximate budget investment cost for the project.
FES	**Future Energy Scenarios:** 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 ESO and contains their latest scenarios.
FOSR	Final Option Selection Report
GDN	**Gas Distribution Network:** An administrative unit responsible for the operation and maintenance of the local transmission system and <7barg distribution networks within a defined geographical boundary.
Greenfield	Construction on land that is outside of the existing perimeter site boundary, where there is no need to demolish or rebuild any existing structures.
IED	**Industrial Emissions Directive:** An EU directive that came into force in January 2011.
Intrusive Outage	Significant outage works impacting the whole station and where the station cannot be returned to service until the scheduled works are completed.
LCPD	**Large Combustion Plant Directive:** An EU directive to reduce emissions from combustion plants with a thermal output of 50 MW or more. Combustion plant must meet the emission limit values (ELVs) given in the LCP directive for NO_x, CO, SO_2, and particles.

Glossary	
LNG	**Liquefied Natural Gas:** Natural gas that has been cooled to a liquid state (around -162°C) and either stored and/or transported in this liquid form.
MCPD	**Medium Combustion Plant Directive:** A directive to reduce emissions from combustion plants with a net thermal input between 1-50 MW.
MTO	Material Take Offs
MWC	Main Works Contractor
NDP	**Network Development Process:** The process by which NGGT identifies and implements physical investment on the NTS.
NGGT	National Grid Gas Transmission
NO_x	**Nitrogen Oxide:** Oxides of nitrogen which are a by-product of combustion of substances in the air, such as gas turbine compressors.
NPV	**Net Present Value:** NPV is the discounted sum of future cash flows, whether positive or negative, minus any initial investment.
NSMP	North Sea Midstream Partners
NTS	**National Transmission System:** 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.
Ofgem	**Office of Gas and Electricity Markets:** The regulatory agency responsible for regulating Great Britain's gas and electricity markets.
Operating Envelope	All NTS compressors have been designed to operate within a certain range of parameters, namely maximum and minimum gas flow rates and maximum and minimum engine speeds. The limits of these ranges define the performance of a compressor and are referred to as the operating envelope.
Operationally Proven	A unit is operationally proven when it can be shown to be operating reliably and post commissioning / early life issues have been resolved.
PARCA	Planning and Advanced Reservation of Capacity Agreement
Plant	In the context of the Limited Lifetime Derogation, plant refers to an individual compressor unit.
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.
RB211	A Rolls Royce (Siemens) gas turbine engine which forms part of the compressor machinery unit and is subject to LCPD.
Re-opener	Re-openers are a type of RIIO uncertainty mechanism. Depending on their design, they allow Ofgem to adjust a licensee's allowances (in some cases up and in some cases down), outputs and delivery dates in response to changing circumstances during the price control period.
Replacement	Installing a new unit to replace the capability provided; this may not be a like-for-like replacement.
RIIO	**Revenue = Incentives + Innovation + Outputs:** RIIO-T2 is the second 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.

Glossary	
RPE	Real Price Effects
SCR	**Selective Catalytic Reduction:** 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.
SEPA	**Scottish Environment Protection Agency:** Scotland's environmental regulator and flood warning authority.
UAP	Unallocated Provision
UKCS	**United Kingdom Continental Shelf:** The region of waters surrounding the United Kingdom, in which the country claims mineral rights.
UM	**Uncertainty Mechanism:** Uncertainty mechanisms exist to allow price control arrangements to respond to change. They protect both end consumers and licences from unforecastable risk or changes in circumstances.
Unit Outage	Significant outage works impacting one or more compressor 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.