St Fergus NSMP Sub-terminal:

Consultation on the preferred investment option to meet the future needs of the site

September 2022

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Executive Summary

Why are we consulting?

This consultation has been written by National Grid Gas (NGG) in its role as owner and operator of the National Transmission System (NTS) in Great Britain. It follows on from the Autumn 2021 consultation on the range of future charging and commercial solutions at the St Fergus North Sea Midstream Partners (NSMP) sub-terminal.

In the previous consultation you told us that we were on the right track in terms of our approach and that there is a recognised need for capability at St Fergus. However, some stakeholders felt some further commercial options i.e. non-investment options should be explored and that charging i.e. cost recovery topics should be discussed in more detail. The latter was taken to the NTS Charging Methodology Forums.

In addition, we've continued to engage with you to understand the impacts of potential charging options on our customers and are presenting indicative charges for some cost recovery options based on investment data. We have listened to your feedback and in this consultation we show how commercial options are not an efficient solution and ask for stakeholder input on the following:

- The needs case for investment
- The results of our feasibility studies on investment options and our preferred option including the underlying assumptions we've used
- Next steps for charging options

The consultation questions are provided in Section 7 and embedded in this Executive Summary.

Background to St Fergus Gas Terminal

The St Fergus gas terminal, which accepts gas from three sub-terminals, is currently one of the highest utilised sites on the NTS. It is a site of fundamental importance to the UK as it provides security of supply and access to gas from the UK Continental Shelf (UKCS) and from Norway helping to minimise gas prices. Additionally, uninhibited transportation routes for UKCS gas at St Fergus enables offshore oil production, another benefit to the UK economy.

The terminal has been in continuous operation for over 40 years and requires a level of investment to both re-life a number of assets on the terminal and to make the compressors that receive gas from the NSMP sub-terminal compliant with environmental legislation[1]

The Investment Needs Case

The needs case for investment has been presented using independent supply/demand data from the 2021 Future Energy Scenarios (FES). We have not used 2022 FES data because the data was not published in time for analysis to be completed for this consultation. Based on previous years we do not anticipate the use of 2022 FES having a marked impact on our analysis.

The data presented on the low and high case scenarios shows that even with a low case scenario (i.e. just based on connected flows at the NSMP sub-terminal and a low demand case under the Consumer Transformation FES) there is a strong case for compression out to 2040 and beyond. By overlaying the expected additional flows from Norway in the high case

[1] Industrial Emissions Directive https://ec.europa.eu/environment/industry/stationary/ied/legislation.htm, and Medium Combustion Plant Directive https://ec.europa.eu/environment/industry/stationary/mcp.htm, see Section 3

and using the higher demand Steady Progression FES this makes the case for flows beyond 2040 even stronger.

We want to hear from you:

1. Have we used the correct independent assumptions for supply/demand for the investment needs case? Please give reasoning for your answer.
   For more detail, please see Section 2

Commercial Options

In our consultation in Autumn 2021 we set out commercial options that were alternatives to investing in compression. Stakeholders told us that those options weren't feasible but did ask us to look at other alternatives such as asset sharing with adjacent sub-terminals. After discussions with the sub-terminal parties this has also been ruled out for physical and commercial reasons. A summary of all commercial options considered and the rationale for discounting them are presented in Appendix B.

Investment Options

Screening

The feasibility study for options has been through a process of option identification, option development and finally option selection.

This has resulted in 22 technologies being narrowed down to 4 with 14 discrete options being taken forward to the assessment phase.

The four technologies and their combinations shortlisted are:

- **Derogation** – running the existing Gas Turbines (GT) for less than 500 hours/year to keep within emissions legislation.
- **Control System Restricted Performance (CSRP)** – controls the compressor unit's power in relation to Exhaust Cone Temperature, to prevent NO_x emissions from exceeding the legal limit.
- **Dry Low Emissions (DLE)** – DLE emissions abatement technology injects air into the combustion chamber to create a lean air fuel ratio, which lowers the combustion temperature and reduces NO_x production.
- **New Gas Turbine units** – in an existing brownfield location or new greenfield location.
- **Combination** – combination of new Gas Turbine units and DLE retrofit or CSRP.

Assessment

The 14 discrete options have been put through a Cost Benefit Analysis (CBA) process and assessed against criteria and the counterfactual option of derogating the existing units. The assessment criteria are:

- **NO_x emissions** – The MCPD sets a definitive limit on NO_x of 150mg/Nm3. It is also important to note that NO_x is circa 300 times more damaging than CO_2, although it has no monetary value.
- **Carbon Emissions –** tonnes, a carbon cost per tonne is applied to each option based upon the BEIS framework.

- **Total installed cost** – Total installed cost is the total cost to design, purchase, fabricate, install and commission the relevant option.
- **Relative NPV –** The NPVs of each option for the System Transformation FES are shown against the counterfactual option (as described in Section 4).
- **Constraint costs –** These are the relative constraint costs against the counterfactual option (as described in Section 4).
- **Resilience –** The assessment is based on plant availability. Newer compressor units and options with more compressor units will have greater plant availability. A detailed RAM study (Reliability, Availability and Maintainability) has been completed as part of the study works to identify the most suitable options.
- **Technical score** – The technical (Best Available Techniques "BAT" scoring) is completed in line with National Grid Specification ENV/21 and assesses each tabled option independently. Data including Cost, Emissions and Availability is considered as part of this assessment and so provides a summary technical score.

Wider market impacts have not been included at this stage. Whilst the wider market factors, such as those listed below, have been considered in a qualitative way, no financial assessment has been included:

- supporting Scottish security of supply (maintaining offtake pressure in Winter)
- providing energy security through regional gas (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

Accounting for these additional market factors would only strengthen the case and we believe the current criteria provides a strong enough justification for an investment needs case.

Preferred Option

The results of the assessment including a High/Medium/Low status of the 14 options are shown in the Assessment Table below. Throughout the document references are made to brownfield and greenfield location - when referring to brownfield we mean new GT units to be built on the existing plinths replacing old GT units and greenfield we mean new GT units to be built on new plinths within the site boundary.

The results indicate that there is a clear need for new compressor units either in a brownfield or a greenfield location, the preferred option being the installation of 3 new Gas Turbine (GT) units on a brownfield location (Option 1) closely followed by 3 new GT units on a greenfield location, 3 new GT units (one large) on a brownfield location and the four units either as new GT units or a combination option of 3 new GT units and one compressor unit with retrofit DLE technology.

In the long term we believe we will need the resilience that would be provided by four units, either as new units or as a combination of three new GT units and a retrofit technology or a derogated compressor unit but providing three for now leaves flexibility to choose the best method of getting capability once DLE trials are complete and the supply demand forecasts are updated each year.

The options with standalone CSRP or DLE technologies do not perform well in the assessment as both have high NO_x and carbon emissions, and low relative NPV, resilience and technical scores.

In our analysis no weighting has been given to any of the FES scenarios. The preferred options show good relative NPV performance across all of the FES scenarios so could be said to be futureproofed across all the future scenarios described by FES.

In addition, we have engaged manufacturers to discuss scope to accommodate methane and hydrogen and we are confident that the preferred options will be future proof.

In terms of constraints, when the required compression is not available there would not be sufficient capability to meet flows. The constraint is the volume of gas which cannot be accommodated, for which the owner of the capacity is compensated. In the case of St Fergus this compensation is based on Section I of the Uniform Network Code (UNC) as the restriction impacts a specific sub-terminal rather than a whole ASEP, these costs are based on the cost of capacity and not energy prices. The calculations are based on the expected flows in each of the scenarios as described in Section 2.

Assessment Table

Options			Relative Assessment							
Option #	Option type	Option description	emissions (tonnes NOx)	emissions ('000s tonnes carbon)	total installed cost	relative NPV	relative constraint costs	Resilience	Technical Score (BAT)	Preferred Option
0	Derogate	Counterfactual, derogate existing units	1046	2466	£90m	£0m	£0m			
1	New units	3 x new GT brownfield	561	1832	£148m	£396m	-£635m			1
2		3 x new GT greenfield	561	1832	£174m	£376m	-£635m			
3		2 x large new GT brownfield	482	1592	£127m	£289m	-£307m			
4		2 x large new GT greenfield	482	1592	£145m	£275m	-£307m			
5		3 x new GT (1 large) brownfield	500	1948	£157m	£374m	-£627m			
6		3 x new GT (1 large) greenfield	500	1948	£189m	£348m	-£627m			
7		4 x new GT brownfield	561	1832	£193m	£366m	-£655m			
8	Derated (CSRP)	4 x CSRP	1046	2466	£97m	£334m	-£641m			
9		3 x CSRP	1046	2466	£80m	£321m	-£592m			
10	DLE	4 x Avon 1533 DLE	561	2466	£112m	£316m	-£628m			
11		3 x Avon 1533 DLE	561	2466	£78m	£311m	-£560m			
12	Combination (new + DLE)	2 x new GT + 2 x Avon 1533 DLE	561	1990	£200m	£330m	-£648m			
13		1 x new GT + 3 x Avon 1533 DLE	561	2070	£162m	£342m	-£640m			
14		3 x new GT + 1 x Avon 1533 DLE	561	1885	£172m	£371m	-£653m			

We want to hear from you:

2. For the purposes of making long term investment decisions on critical national infrastructure do you believe there should be a weighting of FES demand scenarios? if so, what do you believe is best?
3. Have we used the appropriate assumptions for calculation of constraint costs? Please give reasoning for your answer
4. Having focussed on gas consumer value in our analysis do you think our omission of wider market factors is appropriate? Please give reasoning for your answer
5. Do you agree with our proposed preferred investment option? Please give reasoning for your answer

Charging Considerations

During the consultation in Autumn 2021 we received feedback which differed on whether cost recovery should be targeted or socialised, and on when any charges should start. At that time, we provided indicative charges based on the investment option in our 2019 Business Plan. Since then, having arrived at a preferred investment option we would like to update these indicative charges.

Based on the "Installed Costs" for Option 1, shown in the table in Section 5 - Preferred Option within this document, and using a very simple set of assumptions which are detailed in Section 6 - Charging Methodology Considerations of this document, two scenarios, selected to provide the outer extremities of a range rather than to express any preference, are shown in the table below. These figures should be considered as guidance and are not indicative of any potential rates.

Scenario	Entry Rate p/kWh	Exit Rate p/kWh	Charging Base	Entry	Exit
A Pre-Modification	0.0004	0.0004	Costs split across Entry & Exit 50:50	Socialised Costs	Socialised Costs
A Post-Modification	0.0241	N/A	Entry Only	Targeted to NSMP	N/A
B	0.0003	0.0003	Costs split across Entry & Exit 50:50	Socialised Costs	Socialised Costs

Table detailing potential Entry and Exit Rates in p/kWh:

For context, the latest published Transmission Services Entry Rates, for Gas Year 2022/23 are set at 0.0851 p/kWh and the latest published Transmission Services Exit Rates, for Gas Year 2022/23 are set at 0.0218 p/kWh. For the same period, the latest St Fergus Compression Charge is set at 0.0514 p/kWh.

It should be noted that based on the options presented there is for instance a 16% difference in charges between option 1 and the more resilient four-unit option 14. Under this set of assumptions, rates would increase by this factor should this option be selected over Option 1.

Detailed charging conversations have taken place at the NTS Charging Methodology Forum (NTSCMF) and a consolidated Discussion Pack has been published via the website of the Joint Office of Gas Transporters. These discussions have taken us to the next stage of development but, prior to Ofgem's final decision on investment, we would like Stakeholder input into how costs of investment specifically related to the compression delivered to the NTS by the NSMP sub-terminal could potentially be recovered.

We would like to understand at what stage stakeholders would like to formally engage in development of any potential Uniform Network Code (UNC) Modification.

We want to hear from you:

6. Should any costs incurred following the decision on the Final Option Selection Report (due mid-2023) but prior to Ofgem's final investment decision, (late-2025), be socialised?
7. At what stage in the submission process should we further explore targeting of these charges to ensure a balance between informed debate and expedience?
    a. Feb-2023: Based on the details in the January 2023 FOSR submission
    b. c. Q3-2023: Following publication of an Ofgem decision on the FOSR.
    c. c. Q4-2024: Using a version of the timetable proposed in the NTSCMF discussions which aligns the end of the UNC Modification process, and submission to Ofgem for decision, with the final UM submission to Ofgem.
    d. Another date/time (please state).

Process

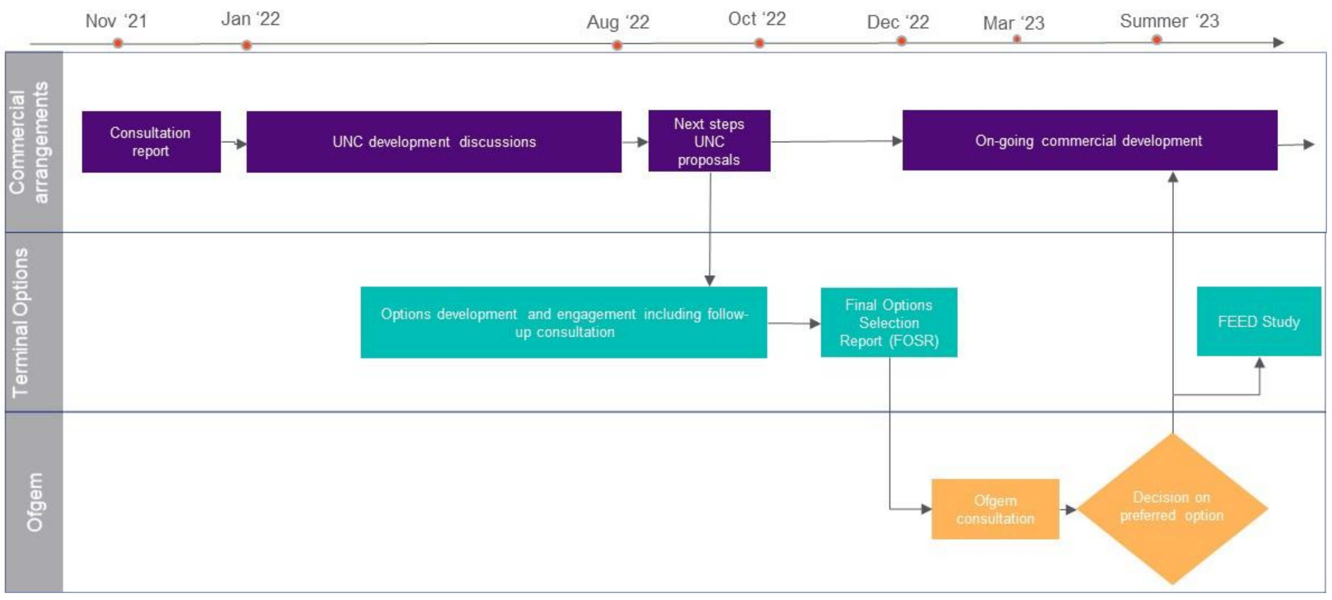
The consultation comes as part of a wider piece of work on our RIIO-2 price control and the need for a re-opener in June 2025 to agree the funding for the capability that is needed at St Fergus for customers and consumers.

As part of this process, we will submit a Final Option Selection Report (FOSR) to Ofgem in January 2023. The outcome of this consultation will form a key part of our FOSR, then the decision will be set out in an Ofgem consultation, which will provide further opportunity for stakeholders, customers and consumers to input into the decision. It is then anticipated that a decision on the final option will be made mid-2023 ahead of a price control reopener in June 2025. The high-level timeline is shown in the schematic below.

We want to hear from you:

8. Do you wish your response to remain confidential (Y/N)?

Schematic showing process going forward



Stakeholder Questions

Through this consultation we are asking for stakeholder input in terms of our approach, assumptions and assessment of options. A summary of the St Fergus stakeholder engagement is included in Appendix D and a summary list of questions for stakeholders to consider is provided in Section 7.

Please email your responses to box.operationalliaison@nationalgrid.com by 12 Oct 2022.

Following this consultation, we will publish a consultation report here that will summarise the responses received, our response to the issues raised and set out our proposed next steps. We will publish all consultation responses that we receive on our website here unless a party specifies that their response or part thereof should be treated confidentially.

We will host an industry webinar to explain our thinking on this topic and answer any questions you may have on 16 Sep 2022 at 09.30 GMT. You may register for this webinar via the following link. If you would like to discuss the content of this consultation on a bilateral basis; please contact mark.freeman1@nationalgrid.com.

1. Introduction

St Fergus Overview

1.1. The St Fergus gas terminal is located on the North-East Coast of Scotland and operates 24 hours a day 365 days a year, regularly supplying in the range of 25% to 50% of the UK's natural gas supplies and currently expected to continue to supply significant quantities of gas for decades to come.

Figure 1: St Fergus Terminal Location

1.2. The terminal receives gas from three sub-terminals (currently owned by Ancala, Shell and North Sea Midstream Partners). It is a site of fundamental importance to the UK in that it currently provides security of supply and supports access to Norwegian gas fields and UK Continental Shelf (UKCS) gas, helping to keep gas prices low. The access to UKCS gas also allows access to oil production, another benefit to the UK economy.

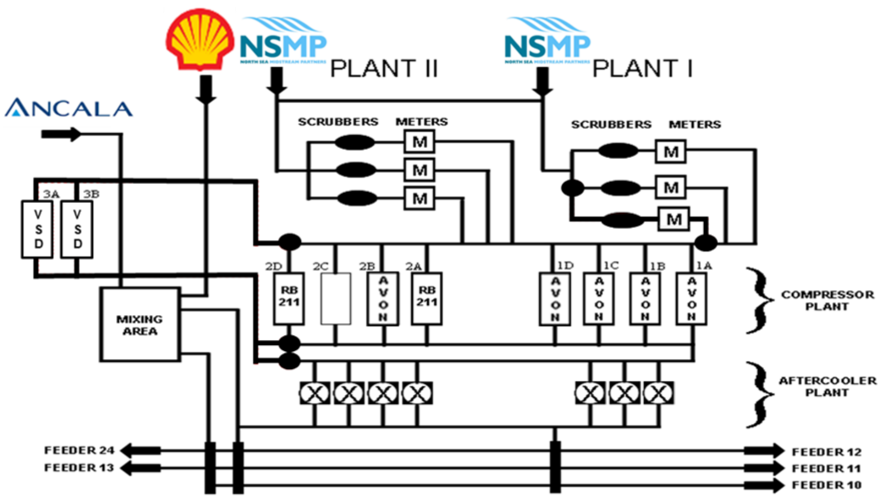


Figure 2: Terminal layout

1.3. NGG provide compression for gas received from the NSMP terminal under the terms of the Network Entry Agreement (NEA), a legacy arrangement dating from when British Gas was privatised.

1.4. The terminal has been in continuous operation for over 40 years and requires a level of investment to both re-life a number of assets on the terminal and to make the compressors that receive gas from the North Sea Midstream Partners (NSMP) sub-terminal compliant with new environmental legislation.

2. Needs Case

Supply and Demand Scenario Discussion and Selection

2.1. We have used the Steady Progression scenario from the 2021 FES as the base scenario for this consultation, with other 2021 FES scenarios considered as sensitivities to this. The 2021 FES is the most recent available data sufficient to be able to update the required network models and associated CBA work in time for this consultation. For information, the most recent FES update was published on 18th July 2022, which was too late to do the analysis work required to inform this consultation. The analysis and associated CBAs used in this consultation are an update to those submitted in our RIIO-2 business plan, which was based on the 2018 FES. Figure 1 Shows St Fergus Peak supply from Gas Ten Year Statement (GTYS) 2021 based on FES 2021 data.

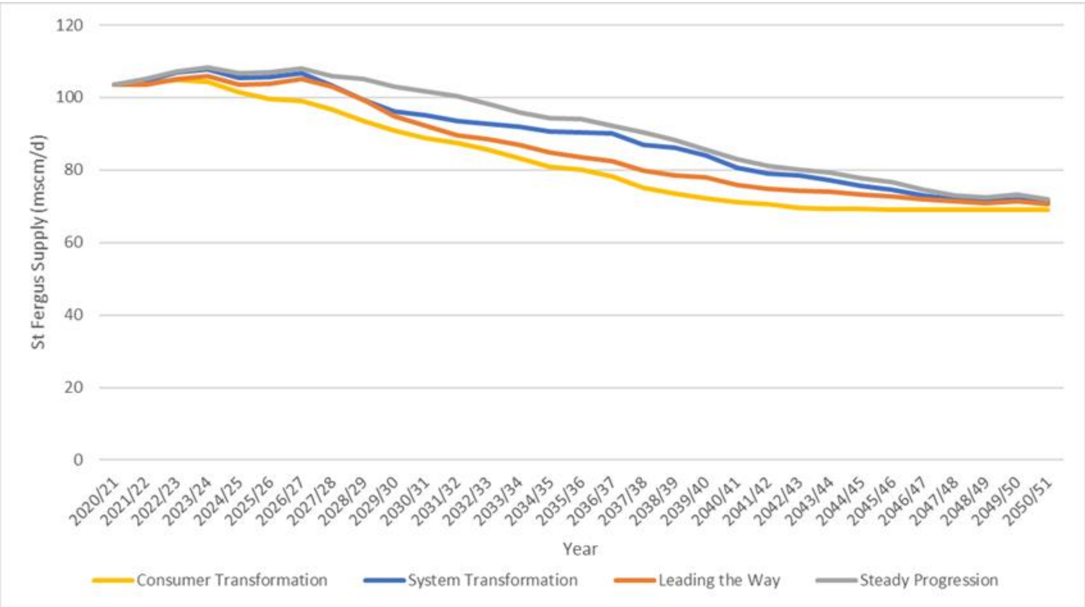


Figure 3: Peak day St Fergus FES 2021

2.2. Figure 3 shows the maximum flows at St Fergus for each of the FES2021 scenarios. Although there is expected to be a fall in the maximum expected flows in all scenarios, the flow levels are still significant. However, the required level of flow required in each of the four scenarios is significantly different as demand drivers vary. Any investment at St Fergus will need to consider the wide range of potential flows that may arise over time.

2.3. Considering the demand information in more detail, the figures below compare the annual average flow for the NSMP terminal, when balanced against demand, against the maximum potential NSMP flows. Two scenarios are considered, Steady Progression (SP) and Consumer Transformation (CT), giving high and low flow scenario data. The potential NSMP flows are broken down into the different supply sources:

- Norway flows
- UKCS flows

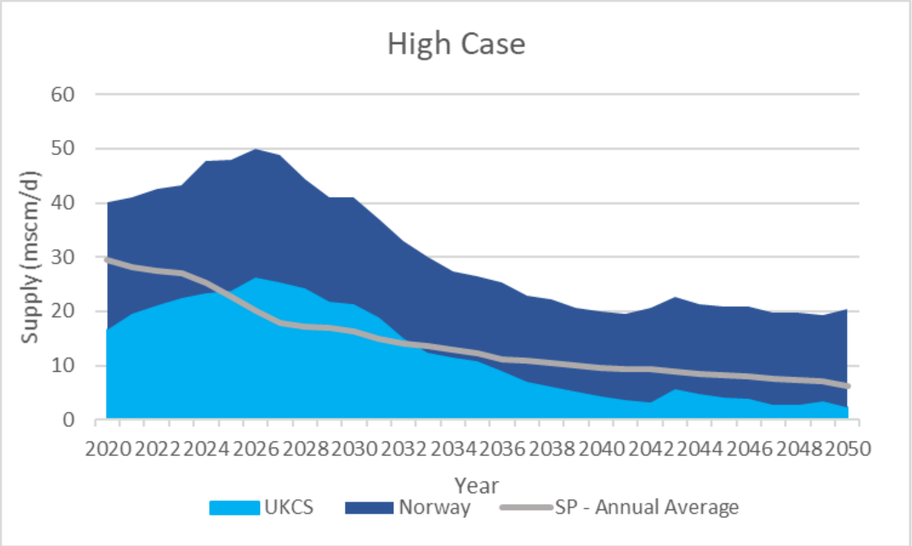


Figure 4: FES 2021 High Case NSMP Flows with Steady Progression

2.4. The High case shows the potential supplies available in the event of high supply availability. Plotted onto this is the SP FES scenario, demonstrating that the overall high case flows are greater than the flows used for SP scenario modelling for flows at the NSMP sub-terminal.

2.5. SP is the High supply case with high UKCS investment leading to more found fields with sizable gas reserves / good incentives for known new fields to move to production and existing producing fields output towards the upper range of expected reserves. SP is the High FES scenario case, which is characterised by a continuing significant role for natural gas to support energy demands.

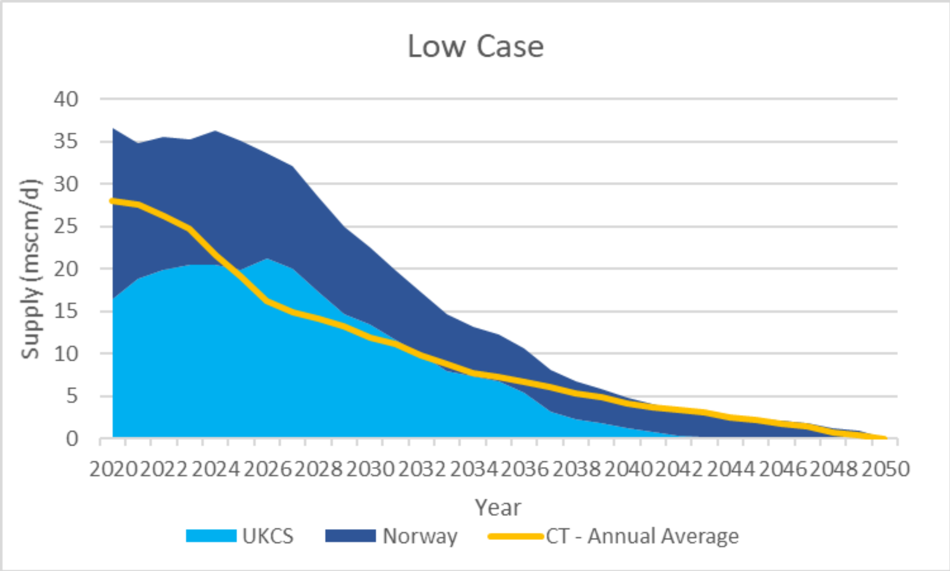


Figure 5: FES 2021 Low Case NSMP Flows with Consumer Transformation

2.6. The Low case in Figure 5 above shows the potential supplies available in the event of low supply availability. Plotted onto this is the CT FES scenario, demonstrating that the overall low case flows are greater than the flows used for CT scenario modelling for flows at the NSMP sub-terminal.

2.7. Low supply case assumes low UKCS investment leading to fewer future fields with sizable gas reserves and less incentives for known new fields to move to production. Those producing fields output towards the lower range of expected reserves. CT is the low FES scenario case, which is characterised by strong electrification of demands and a move toward decentralised energy production reducing the use of natural gas out to 2050.

2.8. The FES 21 High & Low cases provide a good range of possible outcomes and defining characteristics.

2.9. It should be noted that the impact of the April 2022 Energy Security Strategy on North Sea production is not factored in, which could see:

- 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

3. Options Considered

3.1. To deliver the reliable and resilient compression required, we have considered both commercial (non-investment) and physical (investment) options.

Commercial Options

3.2. 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 at the NSMP sub-terminal. However, as demonstrated, all of these options have shortcomings. 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.

3.3. Appendix B lists all of the options 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/resilience is inadequate, were discounted. Given the criticality of the St Fergus sub-terminal and the volume of flows through the site, commercial and regulatory options cannot offer a better, more cost-effective alternative to physical site investment.

Physical Options

3.4. The site uses predominantly electric Variable Speed Drives (VSDs) for compression but VSDs do not cover the whole range of flows and require back up. That back up is necessary for two reasons. Firstly, any outages (planned & unplanned) related to the VSD unit/plant and, secondly, the single point of failure related to electricity supply.

3.5. The back up and capability is currently provided by 4 Avon compressor units at St Fergus.

3.6. However, MCP legislation results in these 4 Avon compressor units being non-compliant. This leads to a significant risk of entry constraint and security of supply if we don't make compression compliant because we would rely solely on VSDs.

3.7. This terminal operates 24/7/365 so levels of resilience and the cost/benefit of this has been considered for all flow scenarios, especially the lower flows not provided for by the VSDs. We have assessed the full range of technologies available and unit combination options to ensure the most cost beneficial solution for consumers is proposed.

3.8. The feasibility study for options has been through a process of option identification, option development and finally option selection. The screening process assessed 22 technologies and those that fell in to the following broad 4 categories were discounted for the following reasons.

Technology Type	Discounting Rationale
Turbine choices/ modifications to recycle lines (Electric, Steam)	High costs and unable to meet resilience and reliability levels.
Hydrogen and Hydrogen Blend driven turbines	No secure hydrogen supply to meet reliability and resilience requirements
Replace drive units only (new or used) and retain compressor	Unable to meet reliability and resilience requirements
Modify existing drives with emission reduction technology (SCR)	Introduces Ammonia to top-tier COMAH site. Anhydrous ammonia is a named dangerous substance in The Control of Major Accident

	Hazards Regulations 2015 (legislation.gov.uk)

Table 1: Discounted Technologies

3.9. This has resulted in 22 technologies being narrowed down to 4 with 14 discrete options being taken through to further development into a level 42 (-15/+30%) Cost Estimate to enable internal Cost Benefit Analysis (CBA) and Best Available Technique Assessment (BAT). The technologies are:

- **Derogation –** running the existing Gas Turbines (GT) for less than 500 hours/year to keep within emissions legislation
- **Control System Restricted Performance (CSRP) –** controls the unit's power in relation to Exhaust Cone Temperature, to prevent NO_x emissions from exceeding the legal limit
- **Dry Low Emissions (DLE) –** DLE emissions abatement technology injects air into the combustion chamber to create a lean air fuel ratio, which lowers the combustion temperature and reduces NO_x production
- **New Gas Turbine units –** in an existing brownfield or greenfield location
- **Combination –** combination of new Gas Turbine units and DLE retrofit or CSRP

3.10. The CBA Assessment is described in the following section 4 and together with a wider assessment against the following criteria:

- Emissions (NO_x and Carbon)
- total installed cost
- relative NPV
- constraint costs
- resilience
- BAT

3.11. The preferred option(s) are described in section 5.

4. Business Case Outline and Discussion

4.1. This section shows the breakdown of costs for each of the 14 options. These costs along with the others detailed in this section are included in the CBA to produce a NPV for each option.

4.2. Wider market impacts have not been included at this stage. Whilst the wider market factors, such as those listed below, have been considered in a qualitative way, no financial assessment has been included as there is no definitive approach to robustly articulate and capture these impacts:

- supporting Scottish security of supply.
- providing energy security through delivering regional gas (reducing import dependency).
- maintaining supply liquidity supressing even higher market prices.

[2] Infrastructure and Projects Authority, UK Government

- value to the oil industry.
- enabling the offshore industry and associated jobs/tax.
- enabling Norwegian supply to freely enter the UK as the market dictates could have been included.

Key Business Case Drivers Description

Cost Breakdown

4.3. The costs are broken down into the upfront cost of the option and the ongoing Asset Health required to maintain the option over the assessment period. The upfront costs are typically higher for new unit solutions compared to retrofit, although this is often outweighed by lower operating costs and fewer constraints due to higher availability.

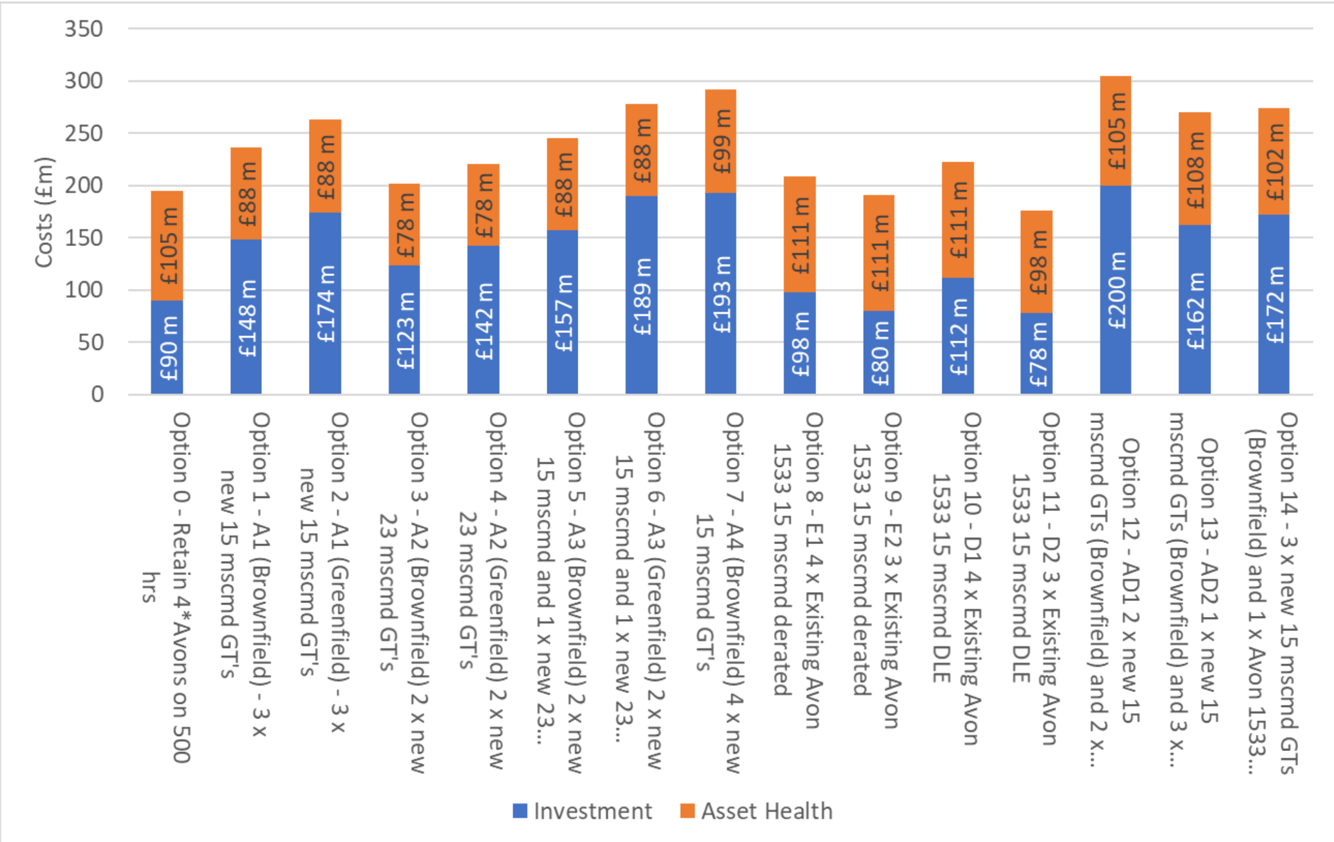


Figure 6: Cost Breakdown

Constraint Costs

4.4. Constraints are calculated based on the expected flows in each of the scenarios as described in Section 2. These will dictate how often the compressor units on site are required to operate based on the capability of the various units. Figure 7 below shows how the VSDs and Avon compressors cover the flow ranges.

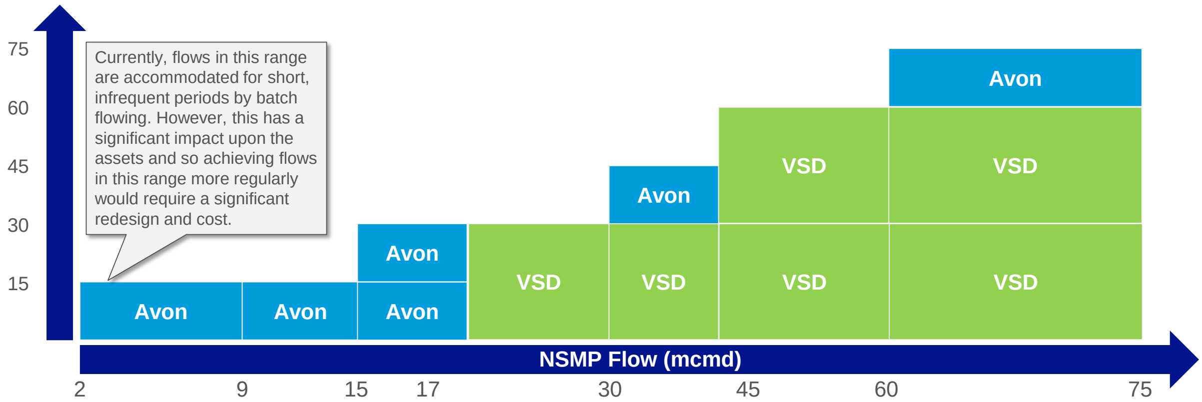


Figure 7: VSD and Avon operation to cover required duty at NSMP sub-terminal

4.5. These factors allow us to calculate which compressor combinations are required to support the expected flows. For each option we define the availability of these capabilities based on the unit availabilities. Typically, new compressor units are be expected to be more available than older ones with improvements in technology and predictive maintenance yielding significant improvements in this area.

4.6. When the required compression is not available there would not be sufficient capability to meet flows. The constraint is the volume of gas which cannot be accommodated, for which the owner of the capacity is compensated. In the case of St Fergus this compensation is based on Section I of the UNC . These costs are calculated based on the cost of the capacity and are not linked to energy prices.

4.7. Constraints are shown relative to Option 1 – three new units. As can be seen in Figure 8 below most options have a similar level of constraints. The counterfactual and options with only 23 mcm/d units have significantly more constraints, in both cases these options are unable to meet the required duty for a significant proportion of the time. This results in constraints way above the current levels.

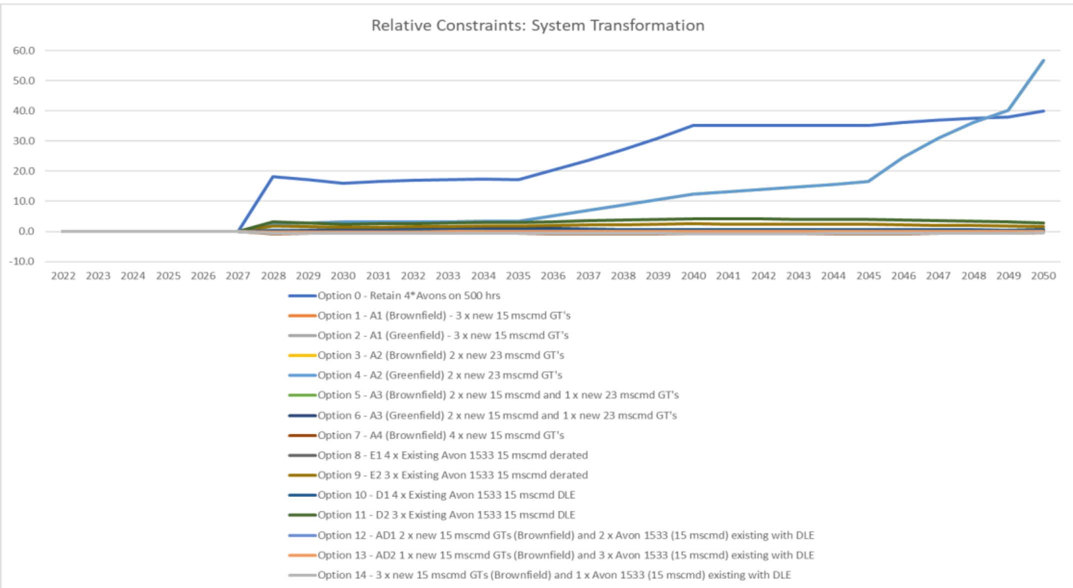


Figure 8: Relative Constraints System Transformation

4.8. If we exclude these options, it allows us to better compare the remaining options under consideration. Options 9 & 11 which both rely on 3 retrofitted compressor units have significantly more constraints than Option 1 with the retrofitted units having a lower availability. Options 5 and 6 – One 15 mcm/d new compressor unit + one 23 mcm/d new compressor unit have slightly higher constraints as this does not offer as much resilience at lower flows. Of the options with four units only Option 10 – 4*DLE results in higher constraints, the others would all slightly reduce these compared to Option 1.

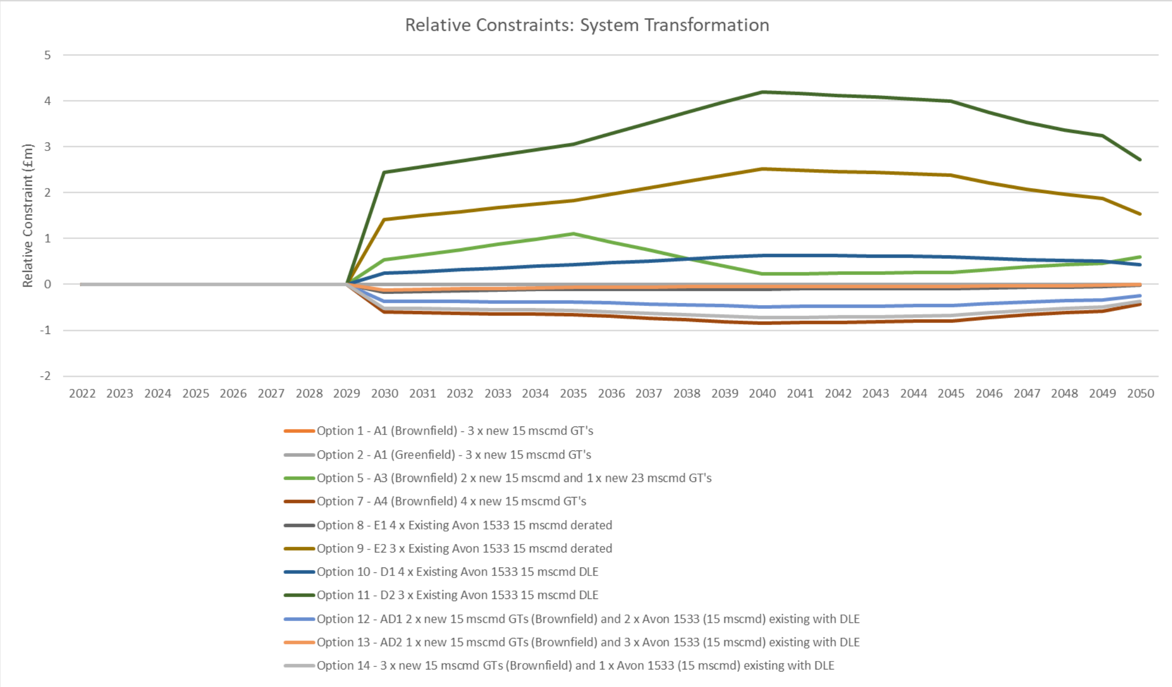


Figure 9: Relative Constraints System Transformation selected options

Operational Costs

4.9. Given the high utilisation of the compression at St Fergus fuel and emissions costs can be significant. New compressor units offer significant benefits in fuel efficiency over Avon compressors, including retrofits, this not only reduces fuel costs but also reduces CO_2 emissions. With the high running of these compressors this makes a significant difference in the costs as can be seen in Figure 10 below.

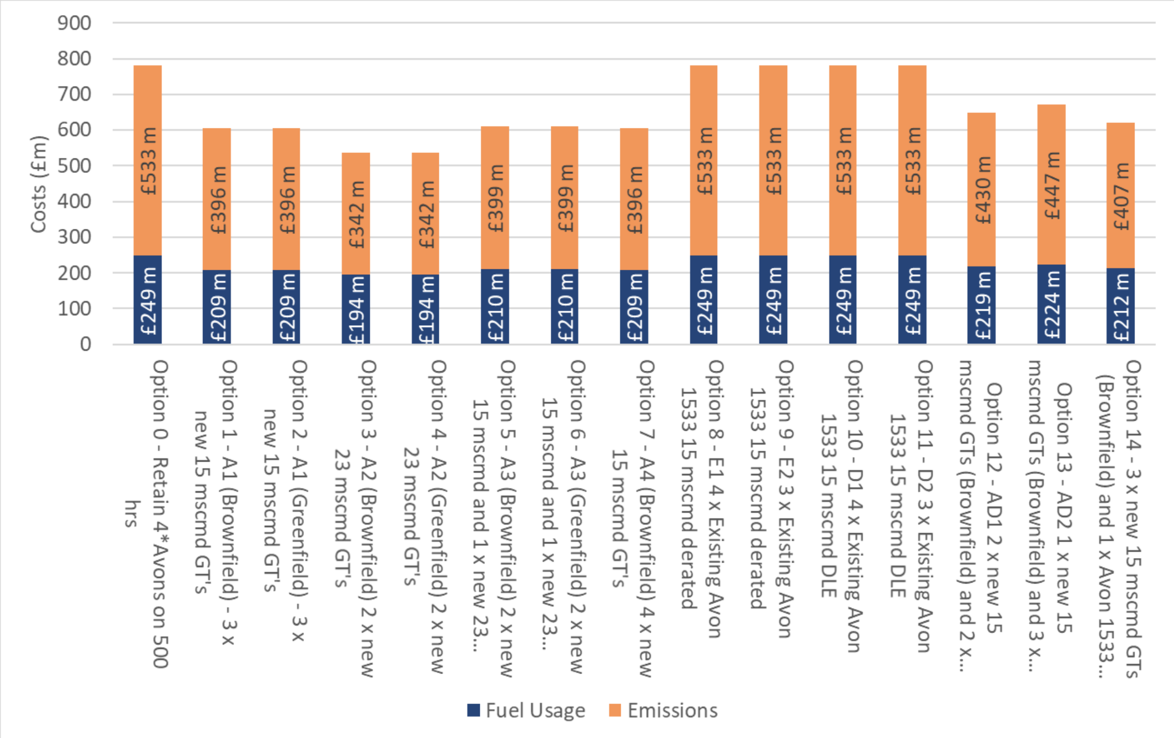


Figure 10: Fuel and Emissions Costs System Transformation

CBA Assessment

4.10. The relative NPVs of the option can be seen in Table 2 below. The best performing option across our scenarios is Option 1 – 3 x new 15 mscmd GTs. Options 2, 7 and 14 have also been highlighted as these also performed strongly in our assessment and across all four scenarios.

Option	Steady Progression	Consumer Transformation	Leading the Way	System Transformation
Option 0 - Retain 4*Avons on 500 hrs	£0 m	£0 m	£0 m	£0 m
Option 1 - A1 (Brownfield) - 3 x new 15 mscmd GT's	£406 m	£292 m	£262 m	£396 m
Option 2 - A1 (Greenfield) - 3 x new 15 mscmd GT's	£386 m	£272 m	£242 m	£376 m
Option 3 - A2 (Brownfield) 2 x new 23 mscmd GT's	£264 m	£88 m	£39 m	£289 m
Option 4 - A2 (Greenfield) 2 x new 23 mscmd GT's	£249 m	£74 m	£24 m	£275 m
Option 5 - A3 (Brownfield) 2 x new 15 mscmd and 1 x new 23 mscmd GT's	£372 m	£275 m	£244 m	£374 m
Option 6 - A3 (Greenfield) 2 x new 15 mscmd and 1 x new 23 mscmd GT's	£347 m	£249 m	£218 m	£348 m
Option 7 - A4 (Brownfield) 4 x new 15 mscmd GT's	£375 m	£257 m	£227 m	£366 m
Option 8 - E1 4 x Existing Avon 1533 15 mscmd derated	£345 m	£247 m	£221 m	£334 m
Option 9 - E2 3 x Existing Avon 1533 15 mscmd derated	£333 m	£246 m	£222 m	£321 m
Option 10 - D1 4 x Existing Avon 1533 15 mscmd DLE	£327 m	£232 m	£206 m	£316 m
Option 11 - D2 3 x Existing Avon 1533 15 mscmd DLE	£324 m	£243 m	£221 m	£311 m
Option 12 - AD1 2 x new 15 mscmd GTs (Brownfield) and 2 x Avon 1533 (15 mscmd) existing with DLE	£340 m	£228 m	£198 m	£330 m
Option 13 - AD2 1 x new 15 mscmd GTs (Brownfield) and 3 x Avon 1533 (15 mscmd) existing with DLE	£352 m	£244 m	£216 m	£342 m
Option 14 - 3 x new 15 mscmd GTs (Brownfield) and 1 x Avon 1533 (15 mscmd) existing with DLE	£381 m	£265 m	£235 m	£371 m

Table 2: Relative NPV

4.11. Given the importance of St Fergus the constraints increase rapidly beyond 2030 if our ability to meet the required duty on site is restricted, as would be the case in our counterfactual of limiting the Avon compressors to 500 hours operation.

4.12. Figure 10 below shows how the NPV develops over time compared to the counterfactual. When it moves above the dotted line that indicates the options NPV is positive when compared to the counterfactual. As can be seen below for all these options that point occurs in the early 2030s, as they all avoid restricting the operation of the Avon compressors to 500 hours in 2030.

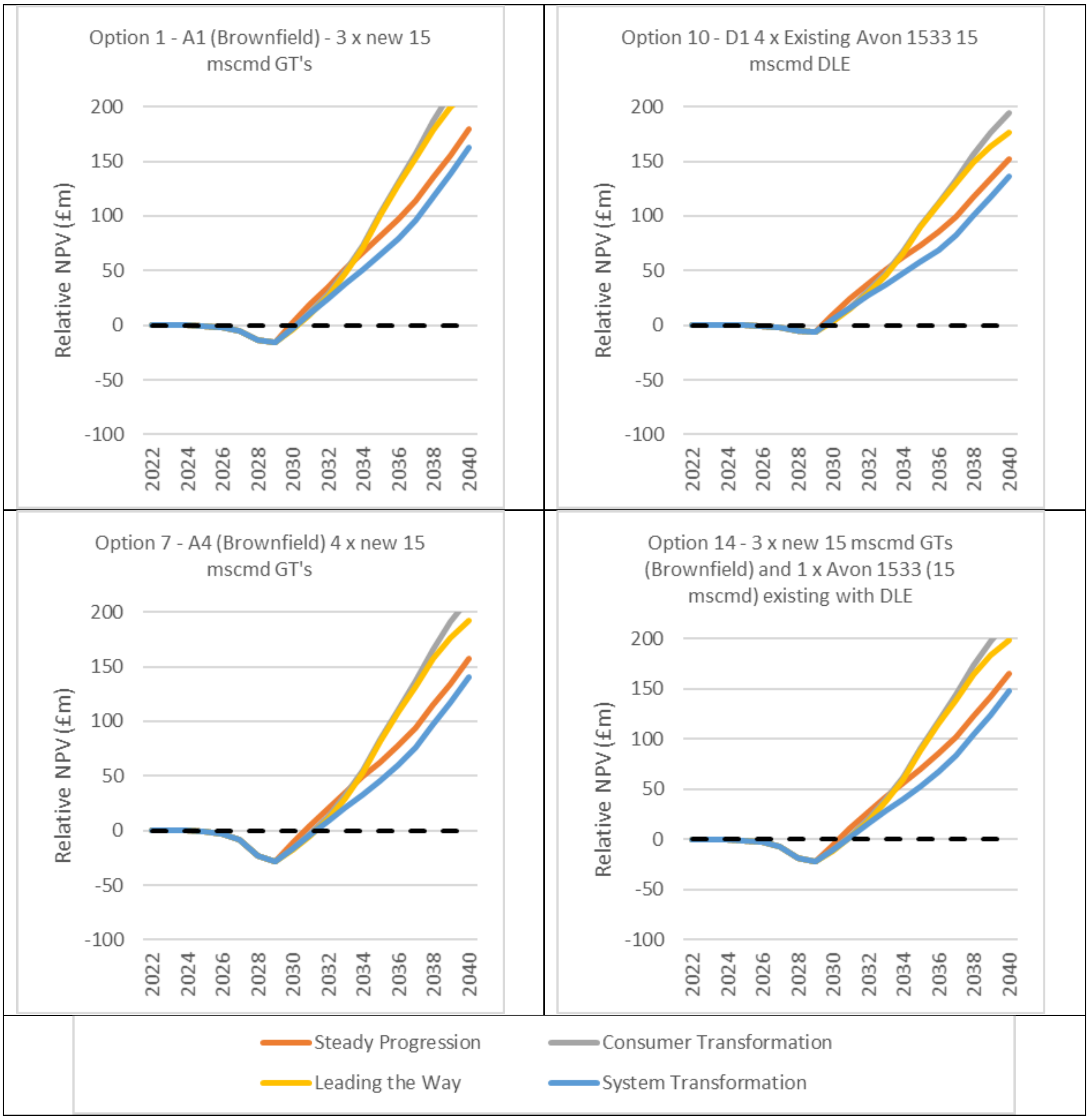


Figure 11: Relative NPVs Selected Options

Sensitivities

4.13. To test the sensitivity of the analysis to uncertainties we have completed a number of sensitivities.

4.14. To ensure we have considered the full range of options we will be testing some additional combinations of two new unit solutions.

4.15. To test against a variety of supply and demand scenarios the analysis has been undertaken against all four FES scenarios.

4.16. Given uncertainty in energy prices the analysis will be run against several price scenarios. These will include the BEIS high case for prices along with assessing the impact of the levels seen over the last 12 months.

4.17. In addition to these we will also test the impact of increasing both the investment and ongoing asset health costs to find the level at which the option would change.

Business Case Summary

4.18. All of the options assessed offer benefits when compared to the counterfactual. However, the options with at least 3 new GT units installed showed a more favourable NPV than the other options. These options also performed well against our other assessment criteria, as is detailed further in the Preferred Option section below.

4.19. These options ensure that most of the duty can be met with clean and reliable units. This minimises the constraints, running costs and emissions at St Fergus and overall offer the best value for the consumer.

5. Preferred Option

5.1. The results of the assessment process of the 14 discrete options against the Cost Benefit Analysis (CBA) detailed in Section 4 and ENV 213 (BAT) and the other key criteria are shown in the table below as a relative High, Medium and Low status.

Assessment Table

Options			Relative Assessment							
Option #	Option type	Option description	emissions (tonnes NOx)	emissions ('000s tonnes carbon)	total installed cost	relative NPV	relative constraint costs	Resilience	Technical Score (BAT)	Preferred Option
0	Derogate	Counterfactual, derogate existing units	1046	2466	£90m	£0m	£0m			
1	New units	3 x new GT brownfield	561	1832	£148m	£396m	-£635m			1
2		3 x new GT greenfield	561	1832	£174m	£376m	-£635m			
3		2 x large new GT brownfield	482	1592	£127m	£289m	-£307m			
4		2 x large new GT greenfield	482	1592	£145m	£275m	-£307m			
5		3 x new GT (1 large) brownfield	500	1948	£157m	£374m	-£627m			
6		3 x new GT (1 large) greenfield	500	1948	£189m	£348m	-£627m			
7		4 x new GT brownfield	561	1832	£193m	£366m	-£655m			
8	Derated (CSRP)	4 x CSRP	1046	2466	£97m	£334m	-£641m			
9		3 x CSRP	1046	2466	£80m	£321m	-£592m			
10	DLE	4 x Avon 1533 DLE	561	2466	£112m	£316m	-£628m			
11		3 x Avon 1533 DLE	561	2466	£78m	£311m	-£560m			
12	Combination (new + DLE)	2 x new GT + 2 x Avon 1533 DLE	561	1990	£200m	£330m	-£648m			
13		1 x new GT + 3 x Avon 1533 DLE	561	2070	£162m	£342m	-£640m			
14		3 x new GT + 1 x Avon 1533 DLE	561	1885	£172m	£371m	-£653m			

5.2. The criteria are:

- **NO_x emissions** – The MCP directive sets a definitive limit on NO_x of 150mg/Nm3. However, it is also important to note that NO_x is circa 300 times more damaging than CO2, although has no monetary value.
- **Carbon Emissions** – tonnes, a carbon cost per tonne is applied to each option based upon the BEIS framework.
- **Total installed cost** – Total installed cost is the total cost to design, purchase, fabricate, install, and commission the relevant option.
- **Relative NPV** – the NPVs of each option for the System Transformation FES shown against the counterfactual option (as described in Section 4).
- **Constraint costs** – these are the relative constraint costs against the counterfactual option (as described in Section 4).
- **Resilience –** the assessment is based on plant availability, newer units and options with more units will have greater plant availability. A detailed RAM study (Reliability, Availability and Maintainability) has been completed as part of the study works to identify the most suitable options.
- **Technical score** – The technical (BAT scoring) is completed in line with National Grid Specification ENV/21 and assesses each tabled option independently. Data including Cost, Emissions and Availability is considered as part of this assessment.

5.3. The results show the preferred option is the installation of 3 new Gas Turbine units on a brownfield location (Option 1) closely followed by 3 new Gas Turbine units on a greenfield location, 3 new Gas turbine units (one large on a brownfield location and

[3] Our specification T/SP/ENV/21 provides guidance on carrying out an assessment of Best Available Techniques (BAT) for compressor machinery train projects. BAT is a legal requirement applying to all current and future gas compressor installations which are permitted as combustion installations under statute implementing the Industrial Emission Directive (IED).

four units either as new GT units or a combination option of 3 new GT units and one unit with retrofit DLE technology.

5.4. The benefits of installing new units are summarised in the table below:

Benefit	Advantage
Availability	The new units will be more reliable than the existing ageing Avon units. Therefore, the overall availability achieved will be higher than current setup allows whilst continuing to provide back up and the ability to meet all predicted low and high flow combinations.
OPEX	The new units will require a smaller OPEX compared to Options which re-uses the existing Avon units albeit derated.
Brownfield Work	Minimum pipework tie-ins required for the new units, as existing lines and headers can be re-used. In addition, Units 2C/ 2D will be destructed by NG, therefore minimising brownfield work for this option.
Green House Gas Emissions (GHG)	The new compressor units will have a higher efficiency compared to existing Avon driven units, therefore leading to lower GHG emissions due to a reduction in fuel gas consumption. In addition, new compressors will have dry gas seals, leading to lower GHG emissions compared to wet seals (on the existing Avon units) due to lower leakage rates from the seals.
Future Proofing	The new compressor packages can be purchased with as many capital and operational spare parts as required. This improves on the current scenario of having to seek spare parts from redundant packages in the NGG fleet, due to ever-dwindling supplies in the market. New packages will also have access to a superior catalogue of available spare parts in the market. In addition, both Solar and Siemens can provide ongoing operational and maintenance support which can be engaged on a contractual basis and may already be in place for existing units. With the inclusion of DLE for these packages, NO_x and other emissions are significantly reduced, therefore future proofing against additional restrictions that could potentially be imposed by the UK government. However, CO2 emissions are not reduced to zero and so this may need to be addressed if Net Zero targets apply from 2050 onwards. In addition, we have engaged manufacturers to discuss scope to accommodate methane and hydrogen and we are confident that the preferred options will be future proof.
Safety Risks	New units are more reliable than existing ageing Avon units, therefore have a reduced risk of failure which could lead to a major accident hazard.

Table 3: Benefits of New Gas Turbine Units

5.5. The options with CSRP retrofit technology (Options 8 and 9) do not perform well in the assessment. Although they have benefits in terms of lower installed cost they have shortcomings in terms of emissions, technical score and relative NPV.

5.6. The options with DLE retrofit technology (Options 10 and 11) also do not perform well for similar reasons to those for CSRP. These effects can be mitigated to a certain extent where a unit with DLE fitted is in combination with new GT units and this is borne in out in the good performance assessment for Option 14 (3 new GT units plus one unit fitted with DLE).

5.7. The results indicate that there is a clear need for new compressor units. In the long term we believe we will need the capability for four compressor units, either as new compressor units or as a combination of three new compressor units and a retrofit technology or a derogated unit but providing three for now leaves flexibility to choose the best method of getting capability once DLE trials are complete and the supply demand forecasts are updated each year.

5.8. For the FOSR submission in January 2023 this analysis will be updated with the latest cost information but given the clear distinction between those options with at least 3 new GT units and those without we do not expect our conclusions to change.

6. Charging Methodology Considerations

6.1. In the Final Determination[4], Ofgem agreed on the need for NGG to develop options for emissions compliance at St Fergus. A baseline allowance (c. £20m) for the option selection process was proposed and these costs are currently being fed into the allowed revenue. As these values are included in the Transmission Operator (TO) Allowed Revenues, these costs are socialised across all users through Transmission Services Entry and Exit charges.

6.2. Ofgem also stated in the determination that they were considering the issue of who should pay for compressor capital costs at St Fergus, given that the assets provide compression to NTS appropriate pressures for the NSMP terminal only.

6.3. There has been constructive engagement between Ofgem and NGG around the issue of who pays for compressor capital works at St Fergus, this resulted in an expectation from Ofgem for NGG to take “reasonable steps within its powers to ensure that an appropriate solution representing a fair balance between consumers and terminal users is in place before an application under the St Fergus reopener mechanism is submitted to Ofgem”.

6.4. As part of the process, Ofgem expected NGG to consider a range of solutions, including putting forward and progressing a modification to the UNC charging provisions if it were considered appropriate.

6.5. Following the Final Determination, NGG released a consultation[5] building upon the extensive feedback we had from our stakeholders during the RIIO-2 discussions. This kicked off a wider piece of work to establish both the most appropriate level of future entry capability at the St Fergus gas terminal and the most appropriate charging regime.

6.6. The feedback from this consultation was fed into a series of discussions held at the monthly NTS Charging Methodology Forums (NTSCMF). We focused on five key topics which arose in the feedback to the consultation, giving opportunities for further discussion on potential charging arrangements. Those five topics were: Scope of Charges, Allowances, Cost Recovery, Under/Over Recovery Process, Timescales.

6.7. During this process, discussions have been explorative rather than definitive. This was primarily due to the lack of certainty, at that early stage of the process, around the final preferred option, and the lack of clarity on the expected costs and the spending profile. Without knowing the details of the expected solution and the potential cost implications, Users have had difficulty in expressing firm opinions.

6.8. Users recognise that this is a unique set of circumstances, which warrant further discussion, but were also concerned about setting precedents for the targeting of charges which could potentially read across to future changes, such as the charging of Hydrogen, blending and de-blending.

6.9. A reference pack[6] providing all the background information used in these discussions can be found via the website of the Joint Office of Gas Transporters[7]. Minutes of the meetings are also available via the NTSCMF pages on the Joint Office website.

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[4] RIIO-2 Final Determinations for Transmission and Gas Distribution network companies and the Electricity System Operator | Ofgem

[5] St Fergus Consultation | National Grid Gas

[6] St Fergus Consolidated Discussion Pack

[7] Joint Office of Gas Transporters

6.10. In parallel with these discussions, further talks have been held with Ofgem regarding the Uncertainty Mechanism (UM) process. As a result of both the industry engagement and the Ofgem discussions we have revised the expectations around the timescales for any potential UNC Modification.

6.11. As part of the process Ofgem expected NGG to consider putting forward and progressing a modification to the UNC charging provisions once a range of solutions had been considered. However, rather than including a UNC proposal alongside this Final Option Selection Report (FOSR), we feel it would be prudent to delay.

6.12. Users have suggested that while avoiding unnecessary socialisation of costs is preferable, they would like a more solid basis on which to judge any proposal, this would include the need for thorough analysis and a greater level of certainty on the potential costs than the wide range of potential impacts shared in the initial St Fergus Charging consultation linked above.

6.13. Based on the conversations held and the feedback received, NGG believe that developing a modification too early in the process would only hamper discussion and impede future development of a workable solution. We will instead, commit to reassessing the need, scope, and timing of any potential modification at regular intervals as we advance through the reopener process.

6.14. As more certainty comes to NGG's preferred option, we will have clearer idea of the costs involved. Publication of a decision from Ofgem following the Final Option Selection Report will give us a firmer basis on which to begin the analysis required to develop a fully formed UNC Modification.

6.15. We expect that our submission will be followed by a formal Ofgem Consultation process giving you a further opportunity to input into their decision process which we would expect to conclude later in 2023.

6.16. Once that decision has been published and confirmation around the preferred option, including the costs and spending profile are known, NGG have the option to begin the siteworks ahead of the final submission process in Jun-2025.

6.17. To fund these works, under the UM proposals in RIIO-2, an annual forecast of spend can be incorporated into the Price Control Financial Model (PCFM) prior to the Final UM Proposal decision, which is expected to follow the scheduled reopener submission in June 2025. These annual forecasts feed into the Allowed Revenues to be accounted for in the Price Setting Process each May, and ultimately flow into the Transmission Services Reserve Prices for each Gas Year.

6.18. Any under or overspend in relation to these forecasts, incurred prior to the Final UM decision, will be trued up in the years following publication. Again, this will be done through the PCFM process which sets the Allowed Revenues for the subsequent Gas Years.

6.19. Any spend prior to implementation of a methodology designed to target these costs would, by default, be socialised across all users.

6.20. A range of approximate timescales detailing the process of agreeing a UNC Modification to implement any proposed changes were included in the NTSCMF material linked above in Paragraph 6.9.

6.21. It is possible, based on the known, fixed points in the charge calculation process and factoring in average process times, that some costs could be socialised as early in the process as Gas Year 2024/25, with the potential for targeted charges to be included from Gas Year 2025/26 or 2026/27 dependant on decision timescales.

6.22. Based on the information provided in Section 5 - Preferred Option of this document, two sets of figures have been created to provide stakeholders with the outer limits of a potential range. They use a very simple set of assumptions and so can only be considered as guidance and not indicative of any potential rates.

- Scenario A assumes a targeted charging regime is in place from the year 2026/27. In this scenario costs are socialised for two years before implementing the most extreme form of targeting, which focuses all potential costs solely at the NSMP terminal. From the point that a Modification is implemented Exit flows across the network and Entry flows at all other points and terminals would no longer contribute to the costs under this scenario.

  This is an updated iteration based the process used for Table 1 - Scenario B provided in the appendix of the previous consultation document.

- Scenario B is a socialised figure applicable from GY 2024/25 onwards. This example rate, applicable to users at both Entry and Exit, uses the overall project costs, assumes a 50:50 Entry to Exit split, and is based on historic flows. This is a simplistic view which doesn't account for any changes in future usage of the network.

  This is similar in process to Table 1 - Scenario D provided in the appendix of the previous consultation document.

6.23. Both options use the Installed costs for Option 1, shown in the table in Paragraph 5.1. Both assume a repayment period of 26 years. A flat, spend profile is used for each period assessed. In the case of Option B, this covers the full 26-year period. For Option A this is split in to two periods: the two, forecasted, socialised years before approval and implementation of a potential targeted charging Modification, and the remainder of the period recovery period with a targeted charge in place.

Scenario	Entry Rate p/kWh	Exit Rate p/kWh	Charging Base	Entry	Exit
A Pre-Modification	0.0004	0.0004	Costs split across Entry & Exit 50:50	Socialised Costs	Socialised Costs
A Post-Modification	0.0241	N/A	Entry Only	Targeted to NSMP	N/A
B	0.0003	0.0003	Costs split across Entry & Exit 50:50	Socialised Costs	Socialised Costs

Table 4: Potential Entry and Exit rates in p/kWh

For context, the latest published Transmission Services Entry Rates, for Gas Year 2022/23 are set at 0.0851 p/kWh and the latest published Transmission Services Exit Rates, for Gas Year 2022/23 are set at 0.0218 p/kWh. For the same period, the latest St Fergus Compression Charge is set at 0.0514 p/kWh.

It should be noted that based on the options presented there is for instance a 16% difference in charges between option 1 and the more resilient four-unit option 14. Under this set of assumptions, rates would increase by this factor should this option be selected over Option 1.

7. Consultation Questions

We want to hear from you:

1. Have we used the correct independent assumptions for supply/demand for the investment needs case?

2. For the purposes of making long term investment decisions on critical national infrastructure do you believe there should be what weighting of FES demand scenarios, if so what do you believe is best?

3. Have we used the appropriate assumptions for calculation of constraint costs?

4. Having focussed on gas consumer value in our analysis do you think our omission of wider market factors is appropriate?

5. Do you agree with our proposal for a preferred investment option?

6. Should any costs incurred following the decision on the Final Option Selection Report (due mid-2023) but prior to Ofgem's final investment decision, (late-2025), be socialised?

7. At what stage in the submission process should we further explore targeting of these charges to ensure a balance between informed debate and expedience?

   For Example:

   a. Feb-2023: Based on the details in NGGTs January 2023 UM FOSR submission
   b. c. Q3-2023: Following publication of an Ofgem decision on the FOSR.
   c. c. Q4-2024: Using a version of the timetable proposed in the NTSCMF discussions which aligns the end of the UNC Modification process, and submission to Ofgem for decision, with the final UM submission to Ofgem.
   d. Another date/time (please state).

8. Do you wish your response to remain confidential (Y/N)?

8. Appendix A – Acronyms

Acronym	Description
ASEP	Aggregated System Entry Point
BAT	Best Available Technology
CBA	Cost Benefit Analysis
BEIS	Department for Business, Energy & Industrial Strategy
COMAH	Control of Major Accident Hazards
CSRP	Control System Restricted Performance
CT	Consumer Transformation FES
DLE	Dry Low Emissions
FES	Future Energy Scenarios
FOSR	Final Option Selection Report
GT	Gas Turbine
GTYS	Gas Ten Year Statement
MCP	Medium Combustion Plant
NEA	Network Entry Agreement
NGG	National Grid Gas
NPV	Net Present Value
NSMP	North Sea Midstream Partners
NTS	National Transmission System
NTSCMF	NTS Charging Methodology Forum
RAM	Reliability, Availability and Maintainability
SCR	Selective Catalytic Reduction
SP	Steady Progression FES
TO	Transmission Operator
UKCS	United Kingdom Continental Shelf
UM	Uncertainty Mechanism
UNC	Uniform Network Code
VSD	Variable Speed Drive

9. Appendix B – Discounted Commercial Options

Type of Commercial Option	Commercial Option	Reason for Discounting
Change Network Entry Agreement (NEA)	Change pressure range in NEA	Requires agreement from NSMP
	Change pressure range in NEA by UNC Modification	Requires agreement by NSMP shippers
	Withdraw from NEA	Requires agreement from NSMP
Asset Transfer	Transfer assets to NSMP	Requires agreement from NSMP
NSMP fund investment	NSMP fund investment	Requires agreement from NSMP
Third party provides compression	Sell/transfer compression service	Unlikely third party interested with current liabilities
Limited investment and derogate compressors to manage runtime less than 500 hours	Buyback capacity at St Fergus	Capacity held at ASEP level, ASEP difficult to split
	Enter into Turndown Arrangements with NSMP shippers	Need arrangement with multiple shippers - complex
	Enter into Turndown Arrangements with NSMP sub-terminal	Requires arrangement with NSMP
	Manage runtime and incur constraint costs	Requires UNC Modification to limit liabilities
Asset Sharing*	Share assets between sub-terminals to offset need for compression at NSMP sub-terminal	Requires agreement between sub-terminal – operational and commercial barriers
User Commitment*	Use of User Commitment principles to provide a signal for investment	More of a cost recovery option, this would involve splitting the ASEP, an unpopular and onerous task. Would also require bespoke User Commitment principles requiring development

*New Options considered since autumn 2021 consultation

10. Appendix C - Charging

10.1. Autumn 2021 Consultation Report Summary[8]

Consultation Question	Stakeholder Feedback	NGG Response and Action
2. Following on from the RIIO-2 process do you agree with our approach to address the requirements of Final Determinations? a. is there anything else we should consider?	There were a range of supporting comments: - strong case to meet the RIIO-2 Final Determination requirement - robust, commendable, elicit appropriate outcome - options should be explored; assets could be shared across the sub-terminals, robust analysis of reduced hours operations - sensitivity to the Future Energy Scenarios should be explored there should be a robust analysis of capacity requirements post-2025 including behaviours of users/shippers - Asset health expenditure should be out of scope - Will the proposed charging mechanism have broader impacts on the structure of the NTS?	For those in support there is clearly a sensitivity around the Future Energy Scenarios, and we will have to look at this in more detail and we take on board comments to other questions in relation to user commitment which, if this can be adopted, may alleviate some of this sensitivity. We take on board the comments in relation to the asset health costs in relation to supporting the compression assets at NSMP sub-terminal and this will be explored further as detailed later in the document.
3. We would be interested in stakeholder views on whether we should include the wider market impact in our assessment and, if so, what robust method could we utilise?	Of the nine responses to this question there was unanimous support for the assessment of wider market impacts, in some shape or form, to be considered.	It is clear from the responses that participants feel wider market impacts are an important area to consider. Whilst we had many useful suggestions on what needs to be considered there was less emphasis on the most suitable method to carry out this analysis
4. Do you support targeted charging where there is demonstrable localised benefits that should be borne by a targeted group of parties / customers? a. Please give your reasoning for your answer	Of those that weren't supportive of targeted charging, the following reasons were given: - It would cut across the single pricing methodology which could result in distortions in the market with unpredictable long-term consequences - No demonstrable benefits - Impinges on NG licence - Less gas and lower security of supply - Consumers ultimately bear the cost - The entry point could become uncompetitive - Barrier to new investment in new fields - Upgrades should be paid by all consumers and daily operations costs should be paid by NSMP shippers Of those that were supportive of targeted charging, the following reasons were given:	Of those that expressed a view opposing cost targeting they were by and large upstream parties. Those that were in favour of targeted charging were two upstream parties that do not use the compression services at St Fergus users of the network or their representatives. The comments against targeted charging are largely centred on concerns that targeted charging will: - make the NSMP sub-terminal less competitive resulting in distortions in the market, - a barrier to investment in new gas fields and lower security of supply. We are conscious of these concerns and will address them as part of the study on wider market impacts. There were also comments that targeted charging will cut across a single pricing methodology and it could impinge on our licence obligations. As part of

[8] Shaping the future of the St Fergus Gas terminal - Full Consultation Report

	- If charges are recovered from a wider set of users, then there would be a cross-subsidy because National Grid Gas does not provide this service at other sub-terminals which would also be discriminatory - It would be more cost-reflective - It provides the right market signals - It is aligned with the existing St Fergus compression charge - The existing St Fergus compression charge creates a precedent - Socialising costs creates an unlevel playing field - Without cost targeting the NSMP sub-terminal would enjoy competitive advantage over the other sub-terminals - Principles of user commitment should apply - The Tariff code as now applicable in the UK via retained EU law provides for this at Article 4.4(b). This also provides for Ofgem assessing whether the service provided benefits all network users	discussions going forward, we will explore these points further either with the respondent on a one-to-one basis or in the industry forums. In terms of those that were in favour of targeted charging the reasoning centred around cost reflectivity, alignment with existing St Fergus charging and providing the right market signals and without targeting then there is potentially a competitive advantage for the NSMP terminal, an unlevel playing field and a cross-subsidy where NGG does not provide this service. We are also cognisant of the comments on user commitment and compliance with the EU tariff code and would like to discuss all these points further in industry forums.
5. If you believe the charge should be targeted, to what degree should this targeting take place i.e. users at entry, users at exit, users at NSMP sub-terminal or some distance-related charge?	Three respondents felt there should be no degree of targeting. Two respondents felt that the transmission system, including compression, benefits both entry and exit network users and there is no case for departing from the 50:50 split. Of those who supported the targeted charge they all felt that this should be targeted at those benefiting from the service at the NSMP sub-terminal.	Not surprisingly the responses to this question reflected those in Q4 where those not in favour of targeted charging did not think there should be a departure from the split between entry and exit charges of 50:50. We note that those in favour of targeting believe it should be at the NSMP sub-terminal level.
6. In terms of the costs that should be reflected in the charge, do you think this should cover all of the following or specific categories. Cost categories are emissions driven, asset health, cyber security, physical security and decommissioning of redundant assets? a. Please give your reasoning for your answer, including which categories	Two respondents felt that none of the categories should be targeted. Another felt that the costs associated with emissions was outside of normal business and should be accommodated within the economics of the energy system. Two respondents felt that only the clearly identifiable compression costs should be targeted charges, other categories could be common costs. Another respondent felt any relevant costs, including those related to decommissioning and compressor emissions, should be included. One respondent felt that their initial view is that all categories should be included in the charge.	Of those that supported targeting there is a consensus that the costs to be targeted should at least cover those that are clearly identifiable supporting compression for the NSMP sub-terminal.
7. Do you believe the introduction of a targeted charge will change shipper behaviours such that flows could be redirected to avoid paying the additional charge?	Two respondents felt sure that shipper behaviour would change as Norwegian gas producers have more than one export route. A further five respondents felt there was a possibility of a change in shipper behaviour.	It is interesting that the majority of respondents feel that targeted charging will or possibly will change shipper behaviour by responding to market signals and the flexibility that Norwegian has to flow to other markets.

a. Please give your reasoning for your answer	Another respondent felt that the shipper behaviours might change but this shouldn't be a consideration, other pricing methodology changes haven't considered this. One further respondent supported this statement and asserted this should not be discussed further. One respondent felt that targeted charging won't change behaviour for UKCS gas but will affect the economics of the gas fields. It was recognised that Norwegian gas would be redirected but their intelligence suggested Norwegian imports would increase in future.	It is also interesting to recognise that two respondents felt that any change in shipper behaviour should not be a consideration as this has not been a consideration for other similar pricing methodology changes.
8. Other than the changes to the UNC discussed i.e. cost targeting and limiting liabilities, are there other changes to the UNC that could be made to protect GB consumers?	One respondent felt that it would be up to Ofgem to determine what changes should be made to the UNC as part of their final decision. One respondent felt that it was important to relax the gas specification for entry into the national transmission network as this will help safeguard supply to GB consumers during a period of transition. One respondent believed it was not clear that the GB consumer should be protected against specific costs, based on some assumptions the amortised cost per household is around 28p per year. One respondent wondered if it were possible to change the charging methodology such that NSMP is offered the option of funding this work through user commitment, similar to incremental entry capacity, with an up-front commitment of at least 50%, and targeted charges for the remainder of the investment.	In terms of relaxing gas quality specification to help safeguard supply we feel this is a more general point that could apply to all terminals. The comment regarding the onus being on Ofgem to determine what changes should be made is also a general point and is of course determined by the proposals presented to them. For the example provided on the impact of socialising the cost across all consumer bills, this will be taken forward to the discussions in NTSCMF for industry validation and opinion. The point from the respondent on user commitment will be explored further as a potential commercial option underpinning any investment.
9. Are there any other commercial options i.e. other than capacity buybacks and turndown arrangements that could be used as a solution?	One respondent felt that capacity buybacks would not provide a feasible solution as producers will not wish to shut in production and compensation could be costly to justify the action. Two respondents felt that there were other potential commercial options available including sharing of compression across two or more sub-terminals at St Fergus. One respondent felt that NSMP constructing compression would not be viable as it would not make sense to build brand new compression compared to the upgrade proposed by National Grid. They do not believe that NSMP taking over the terminal site would work as the site provides services to all three sub-terminals and there are likely to be issues around competition and conflict of interest. They do feel there is a possibility of developing a lower cost solution but feel it would not make sense for NSMP to invest in the project due to the likely higher cost of capital when compared to NGG.	We welcome the comments from the three respondents that we have considered all commercial remedies and the respondent that supports our initial view that capacity buybacks or turndown arrangements would not provide an effective solution. In terms of other solutions NGG also welcomes the views that asset-sharing options should be explored, or a new commercial arrangement could be a solution. We will be looking more closely at these options. In terms of the comments regarding the unviability of NSMP constructing compression, taking over the terminal site or providing a lower cost solution we will be taking these discussions forward with the respondent.

10.2. NTSCMF Engagement March 22– July 22

Topic	Key points for Debate	Stakeholder Feedback
Scope of charges	Which works are included in the charges and scope of Targeting: - FEED Study - Cyber Security - Decommissioning - Asset Health - Physical Security - Emissions.	Whilst targeting is not the typical treatment, this investment consideration at St Fergus is not typical and should play into the discussion. The benefits and impacts to the whole system need to be considered. One party raised a concern NGG is not best placed to decide on this investment as we could 'overdevelop'. Are there other solutions? Some believed there are parallels around commitment and cost targeting from PARCAs and User Commitment. Whichever way we progress, this could be precedent setting. We need to avoid unintended consequences and were urged to consider potential crossover with Hydrogen and how any investments may be recovered and from who.

Allowances	Identifying allowances associated with the works:
	- Transmission Services,
	- Non-Transmission Services,
	- Transmission Operator,
	- System Operator,
	- Directly Renumerated Service.
		Generally, Users realise that to do anything other than 'the norm' of socialising through the existing charging framework would require both UNC and licence changes to implement. And one of three drivers will facilitate more focused debate:
		- Knowing the works going ahead,
		- Knowing the likely costs of any works,
		- Any precedent it could set. i.e.
		    o Where else could be open to targeting in future?
		    o Other projects such as H2?

Cost recovery	Options for how charges could be recovered, and which users will be responsible: - Commodity Based - Capacity Based - Standing Charge - Capped or collared total charge - User Commitment.	Users thought it was necessary to understand what the preferred outcome is (investment, no investment, alternative use of infrastructure) to manage the compression at St Fergus into the future before they would be able to provide strong views. Some useful discussion on aspects that will need to be considered when thinking further on charging and or use of User Commitment. This includes: - Differentiating the compression 'service' to investment for capacity and how this plays a part, - Should it be different when thinking about providing compression to other parts of the network that also provide compression but have no bespoke charging or user commitment arrangements, - Should it be a different approach when not increasing the baseline, this investment (if done) will not impact the overall St Fergus baseline, Will have links to Hydrogen so should consider this at the appropriate time.

		There was a question linked to whether St Fergus is different to other parts of the network and whether the rules on GSMR at the NSMP sub terminal were before or after the compressors. The key challenge was on NGG to demonstrate the differences at St Fergus relative to other parts of the network in any targeting justification. The principle of splitting the ASEP was not popular. Bacton Split was not welcomed by many and there was / is still some dissatisfaction on how this was done. The issue of splitting booked capacity was the key item brought up, though this may not be an issue as there is little remaining Long-Term capacity booked at St Fergus.
Under/Over Recovery Process	Reconciliation of recovered charges against costs: - Reconciliation, - RRC within year - K carried over in to following year folded back in to Allowed Revenue and socialised.	Users immediately discounted post-hoc reconciliations. It was advisable to guard against any retrospective charge at the end of the year as Users need to know what they are paying up front, any variance should feed in to market prices in future years. 'K' is the mechanism by which any amount not collected in one year is carried forward to adjust a subsequent year by updating the allowed revenues, which is a core input to Transportation charges. Under the 'do nothing' option there would be no carve-out of the revenue, and it would simply flow through into the next year's K value. A licence change may be needed for any targeted option. In the options where revenue is targeted there may still be some under or over-recovery and this element could be 'socialised'. Impact on the customers needed to be considered carefully. Although the socialised charge is predicted to be relatively small compared with the cost of gas this might change in future.
Timing of charging / recovery	Various potential timelines presented for discussion.	Concerns were raised about the length of time non urgent Modifications were taking, hope was to avoid an Urgent Modification, but three workgroups were not considered long enough to fully assess. Concerns raised around potential knock-on effects if a modification wasn't specific enough in its application that it could bleed into other areas. Magnitude of the change really needs to be known and understood, sooner rather than later.

11. Appendix D –Stakeholder Engagement

11.1. Delivering the right solution for GB consumers relies on understanding the current and future needs of our customers and consumers. We have developed and delivered a comprehensive engagement programme to ensure we gather robust insight to inform our plans.

11.2. We have engaged with the following objectives:

Objective	Engagement
• Stakeholders understand the issue around compression • Stakeholders feel informed and able to engage across full spectrum of topics related to this consultation • We have a robust view of stakeholders preferred option in regards to compression challenges • We understand stakeholder views on recovery of costs for options via charges • Stakeholders feel they've had their voices heard • Stakeholders are advocates for our preferred option • Stakeholders are advocates for suggested funding approach	We engaged via: Webinars, newsletters, 1-1's, consultations, NTS Charging Methodology Forum. We measure our engagement via: • Qualitative and quantitative feedback • Good representation of stakeholders • Consultation responses • Letters of support

For more detail, please see our engagement approach.