Stage 02: Combined Workgroup Report

At what stage is this document in the process?

01 Modification
02 Workgroup Report
03 Draft Modification Report
04 Final Modification Report

0498:

Amendment to Gas Quality NTS Entry Specification at BP Teesside System Entry Point

0502:

Amendment to Gas Quality NTS Entry Specification at the px Teesside System Entry Point

0498: This modification will facilitate a change to the current contractual Carbon Dioxide limit at the BP Teesside System Entry Point, through modification of a Network Entry Provision contained within the Network Entry Agreement (NEA) between National Grid plc and Amoco (UK) Exploration Company LLC in respect of the CATS Terminal (BP Teesside).

0502: This modification will facilitate a change to the current contractual Carbon Dioxide limit at the px Teesside System Entry Point, through modification of a Network Entry Provision contained within the Network Entry Agreement (NEA) between National Grid Gas and px (TGPP) Limited in respect of the px Teesside System Entry Point.

Since these modifications are identical in nature, differing only in the impacted NEA, the Modification Panel requested a single report encompassing both. For simplicity, information in this report has been presented once but applies equally to both 0498 and 0502.

The Workgroup recommends that these modifications should now proceed to consultation.

Medium Impact: Transporters, Shippers and Consumers

Contents

About this document:

This combined report will be presented to the Panel on 16 July 2015.

The Panel will consider whether these modifications should proceed to consultation or be returned to the Workgroup for further assessment.

The Workgroup recommends the following timetable:	
Initial consideration by Workgroup	01 May 2014
Workgroup Report v1 presented to Panel	21 May 2015
Report returned for further Assessment	21 May 2015
Workgroup Report v2 presented to Panel	16 July 2015
Draft Modification Report issued for Consultation	16 July 2015
Consultation Close-out for representations	07 August 2015
Final Modification Report published for Panel	10 August 2015
UNC Modification Panel decision	20 August 2015

Any questions?

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1 Summary

Are these Self-Governance Modifications?

The Modification Panel determined that these are not self-governance modifications because they are likely to have an impact on Shippers, Transporters or consumers of gas conveyed through pipes.
The Workgroup agreed with the Modification Panel's determination on self-governance as these modifications may impact Shippers, Transporters or consumers of gas conveyed through pipes, as they potentially change the CO_2 limits at specific entry points to the NTS.

Why Change?

0498 - The current carbon dioxide limit at BP Teesside System Entry Point of 2.9 mol% is incompatible with the anticipated gas quality specification of some potential new offshore developments. While the inclusion of processing and treatment solutions to remove the excess carbon dioxide are being considered upstream of the National Transmission System (NTS), these would require significant investment and/or operating costs, reducing the economic delivery of those developments. Hence, this modification seeks to establish whether a change of one of the existing Network Entry Agreement (NEA) parameters would be a more efficient and economic approach to facilitate delivery of potential new supplies to the System, subject to ensuring no adverse impact on consumers or on the operation of the pipeline system.

0502 - The px Delivery Facility receives the same composition of commingled gas from the Central Area Transmission System (CATS) pipeline as the BP CATS Facility, and currently has the same carbon dioxide limit within its Network Entry Provisions.

These modifications should be considered as 'enabling', since the changes are to Network Entry Agreements ~~that~~ between National Grid NTS and the sub-terminal operators. UNC TPD Section I 2.2 permits changes to such agreements via the use of an enabling modification.

Solution

Both modifications propose an amendment to a Network Entry Provision, to permit an increase in the CO_2 limit of gas delivered from the respective Entry Points into the NTS.

0498 - This modification, in accordance with UNC TPD I 2.2.3(a), proposes an amendment to a Network Entry Provision within the existing NEA in respect of BP Teesside System Entry Point. This amendment would increase the CO_2 limit of gas delivered from the BP Teesside System Entry Point into the National Transmission System to 4.0 mol% from the current limit of 2.9 mol% from October 2020. The rationale for making this change now is that with the long lead times required for offshore developments early implementation ~~will~~is essential to give the necessary confidence to the field owners that gas can be delivered to the NTS ahead of any key design decisions and consequently to encourage continued investment.

0502 - This modification, in accordance with UNC TPD I 2.2.3(a), proposes an amendment to a Network Entry Provision within the existing NEA in respect of the px Teesside System Entry Point. This amendment would increase the CO_2 limit of gas delivered from the px Teesside System Entry Point into the NTS to 4.0 mol% from the current limit of 2.9 mol% from October 2020.~~.~~ The rationale for making this change now is as per modification 0498.

Relevant Objectives

For both Modifications **0498** and **0502** it is believed that the increase to a higher CO_2 limit will permit economic delivery of additional UK Continental Shelf (UKCS) gas production, increasing GB supply security and reducing reliance on imported gas. This will contribute to the economic and efficient operation of the total system through maintaining a diversified supply base and by continued use of existing capacity.

It will provide greater competition between Shippers and between Suppliers by increasing gas availability in the market and also securing greater supply for consumers.

Implementation costs

No significant implementation costs have been identified with changing the Gas Entry Conditions in respect of BP Teesside System Entry Point or of px Teesside System Entry Point.

Implementation

The Workgroup ~~has not proposed a timescale for implementation of these modifications, but would suggest that they are implemented simultaneously at the earliest practical opportunity.~~suggests that a modification is made at the earliest practical opportunity to increase in the CO_2 limit in respect of BP Teesside System Entry Point and of px Teesside System Entry Point effective from October 2020.

Does this modification impact a Significant Code Review (SCR) or other significant industry change projects, if so, how?

This does not affect the UK Link Replacement Programme delivery or any other change.

2 Why Change?

UNC TPD section I2.2.2 (a) (i) provides that certain Network Entry Provisions that apply in respect of a System Entry Point may not be altered without either:

a) the written consent of all Users that hold NTS Entry Capacity at the relevant Aggregate System Entry Point on a specific date; or

b) by way of a Code Modification

As has been typical of similar situations in the past, option (b) is proposed due to the practical difficulties of obtaining multiple consents from a potentially large number of Users. These modifications are therefore considered as 'enabling'.

0498 - With the increasing maturity of the UKCS as a gas production area, the accessibility of new fields and improved extractability from existing fields increase in importance to the UK. Some current production relies on blending with other fields in order to meet Gas Entry Conditions, and other potential new upstream developments are known to have CO_2 levels that exceed current limits. ~~The current CO_2 limit at Teesside already causes restrictions to production to certain fields on days when insufficient blending gas is available and the current limit would be temporarily exceeded. In addition, B~~by analysing the CO_2 content of future gas production potentially entering the System at Teesside, BP has identified an increasing risk that, especially in summer months and from ~~2019~~ around 2020 onwards, the availability of sufficient blending gas cannot be guaranteed prior to entry into the NTS.

Under the prospect of reduced blending opportunities there would be an increasing risk of interruption of gas flows, which would affect gas production processes. This problem could be addressed by treating the gas for removal of CO_2 at the wellhead or at the terminal, but the investment to bring the quality in line with current specification would be significant, thus increasing materially the risk of making some upstream projects, currently being evaluated, less economic.

To assess the feasibility of a higher CO_2 content, BP has undertaken an analysis of the potential impacts and has engaged with National Grid NTS to understand whether a higher limit would be compatible with network safety and operational efficiency. The preliminary results of National Grid NTS and BP work have so far identified no material increase in risks in the NTS associated with 4.0 mol% carbon dioxide content. In addition, as there are some legacy arrangements in place granting a similar limit at some NTS Entry Points, it seems plausible that gas with higher CO_2 content could be potentially accommodated without impacting NTS integrity and/or consumers and/or cross border trade. It should also be noted that CO_2 is not a defined parameter in the Gas Safety (Management) Regulations 1996, and no amendment of GSMR is required. Similar arguments for change have been put forward under Modification 0502.

0502 - The px Delivery Facility receives the same commingled gas from the CATS pipeline as the BP CATS Facility, and therefore any changes to the commingled gas composition that may affect BP's processing ability, would have the same impact upon the px Delivery Facility. If Modification 0498 is approved and the specification in the pipeline changes as predicted by BP, then without this equivalent Modification 0502 to change the carbon dioxide limit at the px Teesside System Entry Point to align with BP, there is a risk that deliveries from the px Teesside System Entry Point will be curtailed when the CATS pipeline specification reaches the current CO_2 limit, resulting in the interruption of gas flows into the NTS. Therefore, this modification seeks, in the same manner as the BP modification, to use the most efficient and economical method of affecting the change through amending the Network Entry Provisions, assuming no adverse impact on the system or users of the system. E24 understands that National Grid NTS has written to its likely affected customers to informally seek views as part of its response to the BP proposal, and it has considered risk to the NTS system. In addition, as a similar limit is in place at other System Entry Points, it seems plausible that gas with higher CO_2 content could be potentially accommodated without impacting the system or consumers. It should also be noted that CO_2 is not a defined parameter in the Gas Safety (Management) Regulations 1996, and no amendment of GS(M)R is required.

Industry engagement was sought, through this combined Workgroup, to assess more thoroughly the impact of the proposed changes under these modifications, in order to establish whether a higher CO_2 limit at the px Teesside System Entry Point, alongside the same higher limit proposed at the BP Teesside System Entry Point, would be beneficial for the GB market.

3 Solution

UNC (TPD Ref I 2.2.3(a)) states the following:

"2.2.3 Where

(a) the Transporter and the relevant Delivery Facility Operator have agreed (subject to a Code Modification) upon an amendment to any such Network Entry Provisions, such Network Entry Provisions may be amended for the purposes of the Code by way of Code Modification pursuant to the Modification Rules"

Modification 0498

This modification seeks to amend a Network Entry Provision within the existing BP Teesside NEA. This amendment would increase the CO_2 upper limit for gas delivered from the BP Teesside System Entry Point into the NTS to 4.0 mol% from the current limit of 2.9 mol% from 1st October 2020.

Modification 0502

This modification seeks to amend the Network Entry Provision within the existing px (TGPP) Limited NEA. This amendment would increase the CO_2 upper limit for gas delivered from the px Teesside System Entry Point into the NTS to 4.0 mol% from the current limit of 2.9 mol% from 1st October 2020.

User Pays	
Classification of the modification as User Pays, or not, and the justification for such classification.	No User Pays service would be created or amended by implementation of either of these modifications and they are not, therefore, classified as User Pays Modifications.
Identification of Users of the service, the proposed split of the recovery between Gas Transporters and Users for User Pays costs and the justification for such view.	Not applicable
Proposed charge(s) for application of User Pays charges to Shippers.	Not applicable
Proposed charge for inclusion in the Agency Charging Statement (ACS) – to be completed upon receipt of a cost estimate from Xoserve.	Not applicable

4 Relevant Objectives

Impact of the modifications on the **Relevant Objectives:**	
Relevant Objective	Identified impact
a) Efficient and economic operation of the pipe-line system.	**0498** and **0502**: Impacted
b) Coordinated, efficient and economic operation of (i) the combined pipe-line system, and/ or (ii) the pipe-line system of one or more other relevant gas transporters.	None
c) Efficient discharge of the licensee's obligations.	None
d) Securing of effective competition: (i) between relevant shippers; (ii) between relevant suppliers; and/or (iii) between DN operators (who have entered into transportation arrangements with other relevant gas transporters) and relevant shippers.	None
e) Provision of reasonable economic incentives for relevant suppliers to secure that the domestic customer supply security standards… are satisfied as respects the availability of gas to their domestic customers.	None
f) Promotion of efficiency in the implementation and administration of the Code.	None
g) Compliance with the Regulation and any relevant legally	None

binding decisions of the European Commission and/or the Agency for the Co-operation of Energy Regulators.	

The Workgroup concluded that there were impacts to one Relevant Objective:

a) Efficient and economic operation of the pipe-line system

A more efficient and economic operation of the pipeline system can be expected, due to an extended utilisation of the existing NTS assets compared to potential curtailment of feasible supplies entering at Teesside. Some participants believed this represented a non-material impact on Relevant Objective a). National Grid NTS believe that, should these proposals be rejected and the gas flowed into the NTS at other entry points, there is potential that alternative supplies of gas could trigger reinforcement costs elsewhere.

Initial Representations

Initial representations were received from SSE, GrowHow and Tata Steel and are published alongside this report and views from Scotia Gas Networks were included in the minutes of 03 July 2014 Workgroup meeting (available here).

Issues raised in these representations include:

- Our CO_2 emissions increase as the additional CO_2 is emitted from our process in addition to the CO_2 we are generating ourselves (this would presumably take the form of an increased emissions factor on the metered incoming gas), leading to higher costs under EU ETS.
- There would be additional load on our CO_2 removal systems, which are already highly loaded at maximum production rates – so this could become a limit on production rate.
- Calorific value is reduced, so our volume of gas consumed needs to increase, this will increase pressure drop in the distribution pipework (both NG system and customers own distribution system).
- The CO_2 acts a diluent, so where we are trying to achieve high temperatures (e.g. in reformer furnaces) we have more mass to heat, which consumes more energy (minor effect).
- If the added CO_2 displaces a 'high' hydrocarbon the effect on these will be different to the displacement of a 'low' hydrocarbon. A quick calculation suggests that the move from 2.9% to 4%, with a reduction in methane (CH_4), will reduce the CV by about 1% and the Wobbe by 2%.
- Gas turbine combustion dynamics, emissions and operability are impacted by the total level of inerts (principally CO_2 and Nitrogen) contained in the gas. Certain gas turbine Original Equipment Manufacturers (OEMs) stipulate a maximum level of 4% inerts in their fuel gas specifications, operation outside this specification could invalidate the unit's warranty or service agreement. As a result this will prevent operation of the asset and result in lost revenue and less competition in the market for supplying electricity. Where new build is being considered, an increase in CO_2 to 4.0 mol% could restrict the selection of which future gas turbine manufacturer could be used, suppressing market competition.
- Increasing the level of inerts creates the potential for a greater range of gas composition and specification. Varying gas specification within this wider range will lead to a requirement for unpredictable gas turbine re-tuning in order to maintain combustion stability and dynamics within the OEM's specification to avoid warranty and Environment Agency breaches. Currently, re-tuning of gas turbine combustion systems takes around 4 hours, is costly as it requires the services of specialist OEM combustion engineers to retune the combustion system and prevents flexible, load following operation during that period. This lack of flexibility will not only impact on being able to support intermittent generation and security of supply but lead to loss of revenue, the magnitude of which will be dependent upon when the gas composition changes. In addition changes in Gas Quality could result in gas turbine start up and transfer issues. This represents a real risk to the reliability of future operations especially for

stations operating in a cyclic mode with implications for providing support for intermittent generation and hence electricity system security.

- The proposed increase in CO_2 of the gas composition will increase the amount of CO_2 released to the atmosphere and will lead to additional costs for gas turbine operators because they will have to pay for the increase in inherent CO_2 through EU ETS liabilities.

The Workgroup considered these issues as part of their overall assessment.

WORKGROUP ASSESSMENT

The Workgroup identified the issues raised by these modifications and collated them into a number of key themes, as follows:

- **Further Background to the Change**
- **Anticipated Impact on Gas Quality**
- **National Grid NTS' Assessment of their Operational Risks**
- **Impact on Consumers**
- **Impact on Storage Operators**
- **Carbon Cost Assessment**
- **Wider Considerations**
- **Conclusions**

Further Background to the Change

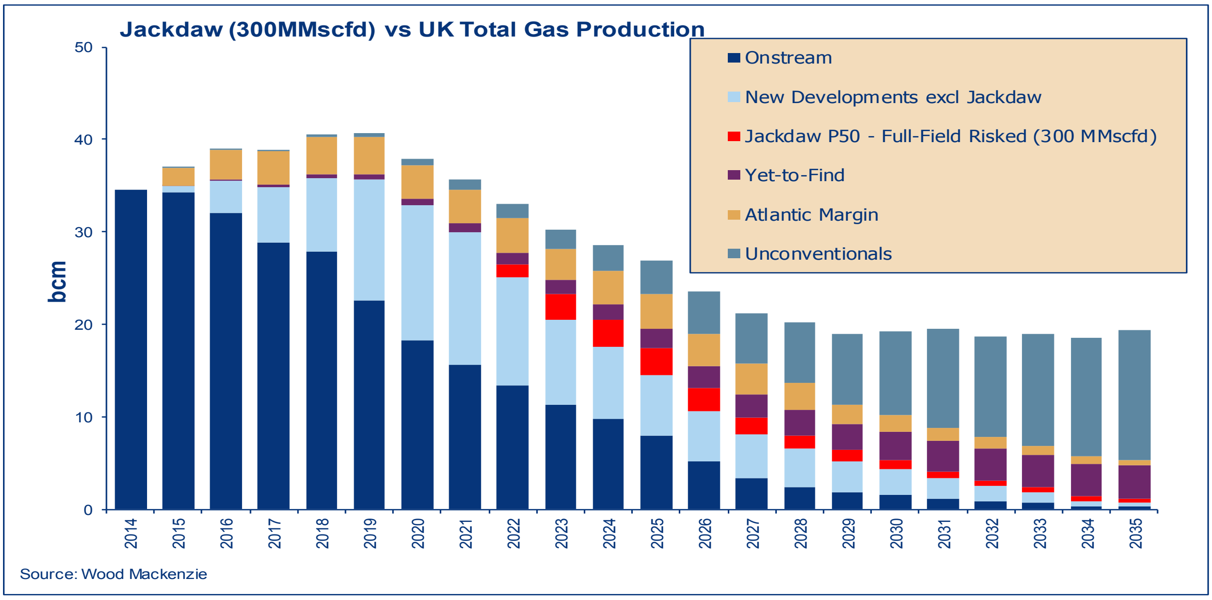
BP and TGPP consider that the current specification for CO_2 at the Teesside entry points is incompatible with the composition of some natural gas from potential upstream developments.~~ BP has observed that the current CO_2 limit is already causing restriction to existing field production on certain days (in 2013 this occurred on 44 days).~~ At least one future development, Jackdaw, in the Central North Sea area defined by the CATS catchment area would benefit from an increase in the NTS entry specification at Teesside from 2.9 mol% to 4.0 mol%. ~~Using Jackdaw as an example, s~~Studies are currently underway to determine the optimal development plan for this~~e~~ ~~Jackdaw development~~discovery. The Jackdaw discovery was made in 2005 and is one of a number of significant gas discoveries in the area. Operated by BG Group plc (BG), the discovery is located in the ultra-High Pressure High Temperature (uHPHT) province of the Central North Sea. Given the uHPHT nature of the reservoir (with pressures above 1,200 bar and temperature above 200 degrees C), development costs for Jackdaw and other developments of the same type are high (estimated to be in the region of £3bn). In order for such projects to be developed it is essential the project costs are minimised; BG confirmed in October 2014 that the Jackdaw project has been delayed[1] while further studies on development options take place and the impact of additional ~~and its final investment decision may take place in 2017. There have been discussions with Government on further~~ tax allowances and incentives ~~that for~~ uHPHT fields ~~like Jackdaw could benefit~~announced in the last Budget are considered. It is anticipated that a final investment decision will take place in 2017. The requirement for CO_2 processing is a key aspect of any decision. As a result, ~~from as well as assessing the most cost effective way of accessing the field. Timing~~ timing of first gas for the Jackdaw development may be expected to be in the early 2020s.

By 2020 DECC forecast UK gas production to be of the order of 30 billion cubic metres with demand at circa 67 billion cubic metres[2]. With reserves of over 16 billion cubic metres and a plateau production rate of circa 2.6 billion cubic metres per year Jackdaw will have the ability to meet about 4% of UK gas demand in the early 2020s, and BG estimates that a development such as Jackdaw will account for up to about 10% of UK

[1] BG Group 2014 Third Quarter Results (28 Oct 2014) http://files.the-group.net/library/bggroup/files/transcript_576.pdf

[2] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/287001/production_projections.pdf

domestic production. The impact of Jackdaw on production from the UKCS as a whole is shown on the following chart:



	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
% of Total UK Gas Production	4%	9%	10%	11%	11%	9%	7%	6%	5%	4%	3%	3%	3%	2%

Chart courtesy of BG Group plc.

The significant size of the find could help underpin UK energy supply for more than a decade but the high cost associated with uHPHT developments makes developing this and other discoveries challenging. It is essential that the initial capital cost is kept as low as possible. The requirement to remove CO_2 from the Jackdaw gas would add to the development cost which may have an impact on a development decision.

Other UK sub-terminals, such as two (of the three) at St Fergus, currently have a firm 4.0 mol% NTS entry specification whilst the CATS and TGPP Network Entry Agreements (NEAs) have Reasonable Endeavours rights for short duration breaches of the 2.9 mol% CO_2 specification up to a maximum of 4.0 mol%. In practice, this right has never been used as the majority of the time CO_2 levels are managed by blending. While the duration available is not specified the general expectation is that the Reasonable Endeavours right is available to manage short, within-day specification breaches. As such, reliance on a third party Reasonable Endeavours service for managing flows over several days ~~is likely to~~will be sub-optimal for operators of new developments.~~BG.~~ BG has noted that while a field such as Jackdaw could seek to manage the level of CO_2 in its export gas stream by means of blending with gas from other fields that also flow through the CATS system,~~.~~ ~~However t~~this approach makes the field reliant on predicted future flows from other fields. Blending with other fields is clearly dependent on those fields actually flowing gas at any given time and is therefore subject to interruption during shut-downs and trips. Such a service could only be offered by the offshore pipeline operator on a Reasonable Endeavours basis. A key concern for BG is that in order to have an economically viable project that will compete successfully for investment funds there has to be a very high degree of confidence that gas can be exported on any given day. This equates to a requirement for a firm transportation and processing service. The provision of such a service requires either the provision of CO_2 removal equipment to ensure that export gas remains within current specifications which is costly and could further impact the economic viability of such a project, or a relaxation of the CO_2 specification at Teesside to mirror that of some of the other sub-terminals which provides a very high degree of certainty that gas can be exported on any given day at the lowest capital cost.

Increasing the current CO_2 specification at the Teesside entry points to 4.0 mol% would result in more efficient utilisation of existing infrastructure capacity and, by facilitating the development of discoveries such as Jackdaw, extend the useful life of existing assets through material contributions to operating cost, reduce occurrences of existing gas field production restrictions and contribute significantly to Maximisation of Economic Recovery of oil and gas from the UK continental shelf (MERUK).[3]

Simplified Technical Explanation of impact of increasing CO_2 on Gas Quality at Teesside

CATS and TGPP adhere strictly to all NEA specifications which includes: Wobbe >48.14 <51.41; ICF <0.48; SI <0.60.

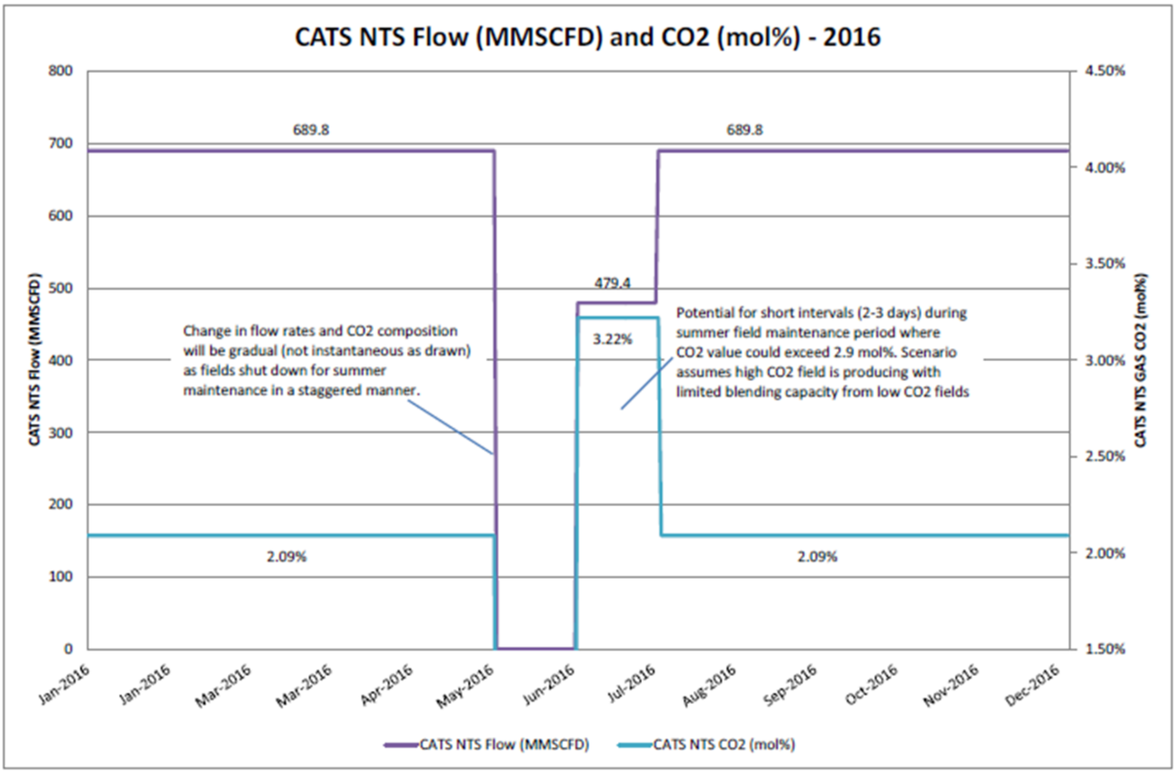
An assessment of the impact of CO_2 content on Calorific Value (CV), Wobbe Index (WI), Soot Index (SI) and Incomplete Combustion Factor (ICF) has been carried out by BP. The assessment is based on daily average flows between 01 January 2013 and 07 July 2014 and correlates CO_2 content of the NTS delivery gas to the parameter noted above. The findings were presented by BP at the Workgroup meeting on 07 August 2014 (http://www.gasgovernance.co.uk/0498/070814). The analysis shows that gas delivered into the NTS from the Teesside entry points will remain well within current NTS specification limits for GCV, Wobbe, ICF and SI even at the maximum requested CO_2 limit of 4.0 mol%. Detailed analysis can be found in Appendix 3.

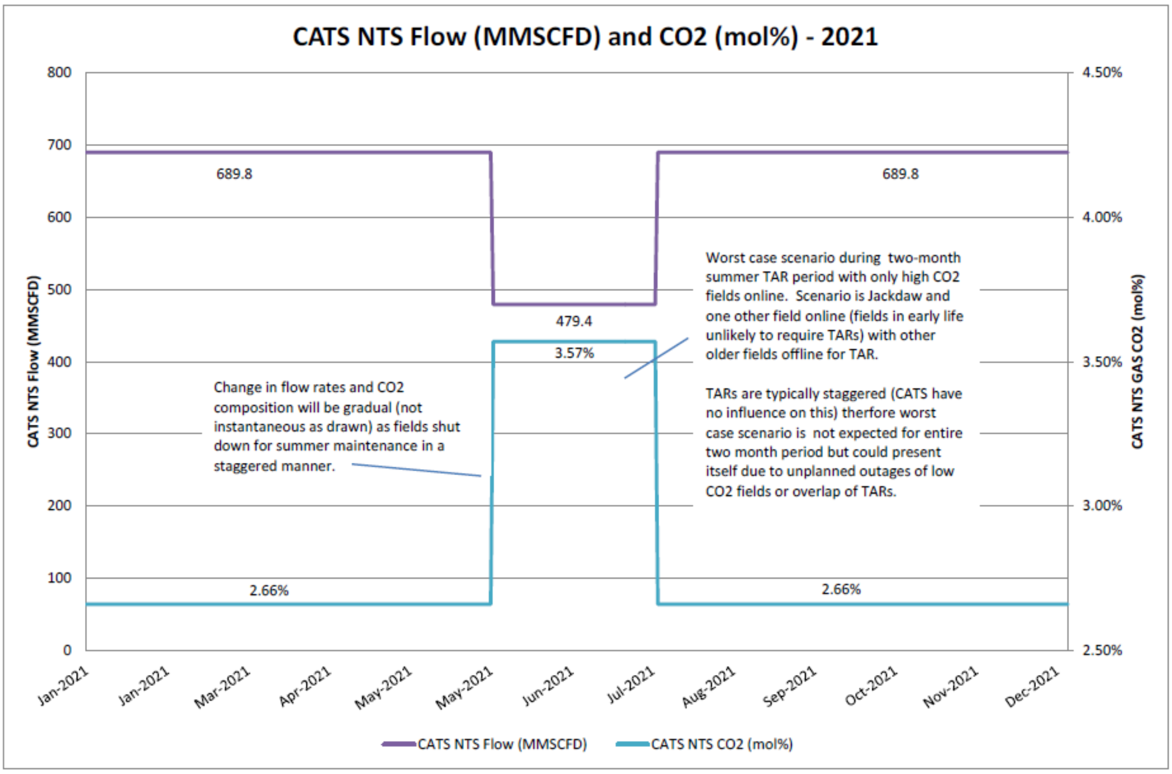
Forecast Levels of CO_2 in gas at Teesside

The average CO_2 content of gas entering the NTS at the px Teesside entry point over the last two years has been 2.18 mol%. Currently, there are days when CO_2 content exceeds the current specification limit and post 2019, there is the potential for development of at least one new field in the CATS catchment containing elevated levels of CO_2 in the produced gas. Analysis by BP and TGPP of forecast future gas production from offshore fields has shown that for the majority of time, the CO_2 content of gas entering the NTS at the Teesside entry points is likely to be similar to historical norms and well below the current 2.9 mol% specification limit. This is achieved through the blending of gas with high CO_2 content with gas low in CO_2 from other fields feeding into the CATS pipeline and being exported in the pipeline as commingled flow. Issues may arise however, when fields are shutdown during summer maintenance periods or during unplanned production upsets at offshore fields when flows of gas in the CATS pipeline are reduced and there is insufficient gas low in CO_2 to blend the high CO_2 gas into specification.

~~BP estimates that up to 2018, CO_2 levels could exceed 2.9 mol% for a maximum of 5% of the year. These are likely to be short durations (circa 2-3 days) during summer maintenance periods. Maximum CO_2 levels during these periods may be up to 4.0 mol% but in practice are likely to be lower. As a result, the overall impact on annual average CO_2 content is forecast to be 0.03 mol%. A representative flow profile for export gas from the CATS plant and the associated CO_2 content (using 2016 as an example) is shown in the chart below.~~

3 http://www.woodreview.co.uk/documents/UKCS%20Maximising%20Recovery%20Review%20FINAL%2072pp%20locked.pdf





With the development of a field such as Jackdaw in the early 2020s~~From 2019 onwards~~, CO_2 levels in CATS/TGPP export gas during the summer months are likely to range between 2.66 mol% and 4.0 mol% with CO_2 levels in non-summer months ranging between 2.66 mol% and 3.57 mol%. A representative example of the gas flow from the CATS plant and the associated CO_2 content of the gas for 2021 is shown in the chart above. This is based on the high CATS pipeline flow rate (all fields producing including Jackdaw) scenario that BP has previously shared with the Workgroup.

Anticipated Impact on Gas Quality

Potential European Standard on Gas Quality

There are currently no regulatory CO_2 limits at cross border points. The European Committee for Standardisation (CEN) issued its draft gas quality standard to national standardising bodies in May 2014. British Standards Institute (BSi) conducted GB's consultation, ending on 31 August 2014, following which the CEN Working Group met in November/December 2014 to consider the consultation responses. Agreement could not be reached on a harmonised range for Wobbe-Index but was for all other components including CO_2.

The draft CEN standard (expected to be published before the end of 2015) currently states:

> "At network entry points and cross border points the maximum mole fraction of carbon dioxide shall be no more than 2.5%. However, where the gas can be demonstrated to not flow to installations sensitive to higher levels of carbon dioxide, e.g. underground storage systems, a higher limit of up to 4% may be applied."

The European Commission has stated its aspiration to see the eventual standard implemented by all Member States.

Gas Quality at NTS System Exit Points

Gas quality at a particular NTS System Exit Point (SEP) is dependent on:

i. the quality of gas at SEPs
ii. which supply sources flow to the exit point on the network (relevant SEPs), and
iii. the degree to which different streams of gas co-mingle within the NTS between the relevant SEPs and the exit point in question.

Thus, typically, the gas quality at SEPs such as Teesside would be expected to be an influence on the gas quality at a particular NTS System Exit Point, but it would unlikely be the sole influence. Approval of these modification proposals would support a change to the permitted level of CO_2 entering the NTS at Teesside but they would have only marginal influence on the other two dependencies. The supply sources that reach a particular exit point has complex dependencies on the variable pattern of NTS supply and demand, and these variations may happen on long term, seasonal, daily and within day time horizons.

National Grid NTS' Assessment of its Operational Risks

National Grid NTS has completed an exercise, supported by network analysis, to assess the possible NTS operational risks arising from higher CO_2 levels. National Grid NTS has assessed the risks (which are discussed further below) in terms of:

- **Safety**
- **Operations**
- **Contractual obligations and cross border flows**
- **Pre-engagement with parties downstream of the NTS.**

Safety

There is no prescribed regulatory limit for CO_2 in GB, and parts of the NTS (e.g. two of the St Fergus sub terminals) have had 4.0 mol% legacy contractual CO_2 limits for many years with no known evidence of additional corrosion (as expected from the "dry gas" NTS system). CO_2 levels in the NTS in Scotland are typically higher than in southern parts of the network, e.g. September 2013 to August 2014 – average from St Fergus ASEP of 2.0% CO_2, compared to average 1.1% CO_2 in Norfolk. See Appendix 1 for more information.

Operations

Risks assessment of engineering operations is similar in character to that of safety, i.e. there are no known issues arising from flows near entry points with 4.0 mol% CO_2 limits. Commercially the lower CV expected from higher CO_2 gas has been assessed with CV shrinkage modelling and was shown to be not material by National Grid NTS. Impact on CO_2 emissions from National Grid NTS' gas fired compressors is likely to be small and not material in the context of all the other variables that affect this.

Contractual obligations and cross border flows - considerations

The Workgroup also considered other, existing, relevant contractual obligations, which are noted below for reference only:

- IUK has an entry condition (exit from NTS) of 2.5% CO_2 (driven by Belgian limits[4]) but otherwise there are no CO_2 contractual obligations at NTS offtakes. Network analysis based on the range of scenarios indicated in the 2013 Gas Ten Year Statement (derived from Future Energy Scenarios) shows that gas from Teesside would expect to be little or no proportion of the flow offtaken at Bacton (IUK).
- Offtake of gas at Moffat to Ireland is in a part of the NTS that has had higher legacy CO_2 limits (than for Teesside) for more than a decade. Again Teesside gas would not typically be expected to be a substantial part of the flow at Moffat.

Pre-engagement with parties downstream of the NTS

Prior to these modification proposals being published National Grid NTS wrote out inviting comments from potentially impacted parties. National Grid NTS received 9 responses provided on a private basis and all[5] substantive points have since been discussed in the Workgroup. National Grid NTS's network analysis also enabled publication via this Workgroup of maps (high demand and low demand) showing where Teesside gas is modelled to make up a proportion of 25% or more of the flow at NTS offtakes. These maps are shown in Appendix 2.

During the course of the development phase National Grid NTS has written out again encouraging potentially impacted parties to bring their views to this Workgroup.

Impact on consumers

Combined Cycle Gas Turbines (CCGTs)

CCGTs can only tolerate limited changes in gas composition (referenced as WI and/or Heating Value), dependent on the Original Equipment Manufacturer (OEM) and control systems. Each CCGT must be tuned to operate in a particular narrow band of gas composition to maximise efficiency and remain within environmental emissions limits.

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[4] http://www.fluxys.com/belgium/en/Services/Transmission/Contract/~/media/Files/Services/Transmission/ServicesAndModels/fluxys_operatingconditions_qualityrequirements.ashx

[5] At as 12th January 2015, a DN is considering whether or not a point is substantive and relevant.

The proposed increase to the level of inerts creates the potential for a greater range of gas composition. Within this wider range, the potential then exists for larger fuel composition variation. This can have a negative impact on CCGT operation despite the gas being within that range allowed by the Gas Safety (Management) Regulations (GSMR) and OEM specifications. Varying gas specification within this wider range will lead to a requirement for unpredictable gas turbine re-tuning in order to maintain combustion stability and dynamics to avoid Environment Agency breaches. If this is not possible the plant will trip to be protected from further damage, although the trip event is undesirable due to asset life reduction, loss of revenue, cash out and penalty regimes:

- The asset life will be reduced as a trip counts towards operating hours. A set number of operating hours are allowed before requiring major maintenance outages.
- In addition, the thermal shock of a forced outage trip, stresses metals and degrades performance, shortening asset life.
- The loss of revenue arising from a trip comes from the loss of generation of electricity.
- The cashout penalty derives from the portfolio now being short following a trip on its nominated position.
- The penalty regime refers to the Capacity Market Payments that will need to be repaid if plant is not available to generate when required.

The sensitivity of CCGTs to gas quality is more fully described in the document shared with the Workgroup in September 2014. The paper summarises the issue as follows:

> Modern low emissions gas turbines are sensitive to variations in natural gas composition. As variations have typically been relatively small and slow this has not historically caused major problems. Throughout Europe, the increasing dependence on natural gas imports is leading to increased gas composition variation within the distribution system. Due to the increasing diversification of natural gas supply, variations in gas quality have the potential to be very rapid, e.g. a rate of change in Wobbe Index of 1%/minute has caused issues at one E.ON site. It is anticipated that fuel variability will be an increasing issue in the future.
>
> Evaluation of operating data for a range of gas turbines within E.ON's UK gas turbine fleet has shown clear trends in pollutant emissions and combustion dynamics with changing fuel composition. These changes can result in forced reductions in power output. Rapid changes in composition have also resulted in emergency shutdowns due to control issues, which have an adverse impact on revenues and component life.

This paper presents real examples of the above findings for a range of gas turbines from most major manufacturers. It also discusses how these findings may inform our understanding of the risks associated with increased fuel composition variation.

It concludes:

> Manufacturers are increasing the fuel flexibility of new GTs and developing retrofit solutions to mitigate the risks associated with fuel composition variation. Operators need to be aware of these developments to ensure that the risks from future fuel variations are properly considered.
>
> The examples described show that operators also need to be aware of these issues to ensure existing turbines are appropriately tuned.
>
> It is clear from the examples that fuel composition variation can impact on GT operation despite being within that allowed in the National Transmission System and manufacturers' specifications. Such examples are becoming more common as the variability in gas composition has increased and are likely to become more significant as fuel imports and international gas trading increase and specifications widen. The examples in this paper are predominantly from E.ON's UK gas turbine fleet but these issues are becoming more common throughout E.ON's European fleet.

Mitigation measures exist to protect GTs against fuel quality variations. However, some of these measures have been developed in recent years and are not yet widespread. More experience with these techniques is required to fully assess their effectiveness at mitigating the increasing variability of gas quality around Europe. The mitigation measures that have been developed may not be sufficient to deal with gas containing significant levels of hydrogen.

H_2 injection into natural gas grids for energy storage purposes may have significant benefits, but this will provide some challenges for the power generation fleet. The impact on individual gas turbines will need to be assessed and appropriate mitigation measures taken.

Although Wobbe Index is an important and useful parameter it does not fully characterise the fuel. This deficiency will be even greater if significant amounts of hydrogen are introduced into natural gas supplies. Reliable parameters to describe the combustion behaviour of natural gas (including the effects of added hydrogen) need to be developed to allow more robust and reliable fuel specifications to be established.

It should be noted that references to Hydrogen in this paper are not relevant for these modification proposals.

The full paper can be found here:

http://www.gasgovernance.co.uk/sites/default/files/Impact of Natural Gas Composition - Paper_0.pdf.

Currently, re-tuning of gas turbine combustion systems takes around 4 hours, it is costly as it requires the services of specialist OEM combustion engineers to retune the combustion system and prevents flexible, load following operation during that period. This lack of flexibility will not only impact on being able to support intermittent generation and subsequent security of supply but lead to loss of revenue, the magnitude of which will be dependent upon when the gas composition changes.

Estimated costs for fitting auto-tune capability to existing CCGTs to compensate for fuel quality changes.

To fit this technology an upgrade of the GT compressor is required.

Cost of compressor upgrade is £450k per GT

Cost of auto-tune technology is £302k for the first GT then £230k for subsequent GTs

Total for site with 2 GTs £1.662m.

Linking CCGT Trips to Changes in Gas Quality

A limited number of examples have been provided of times when plant has tripped (see Appendix 3).

Workgroup participants considered the material and observed that only 3 plant trips (in the sample of 9 dates in 2011/12) could be observed to have happened after a change in gas quality at the associated NTS Offtake.

It was felt that there was insufficient evidence to draw a firm conclusion, either to a direct linkage between gas quality variation and plant trips or for the wider propagation of such trips.

Effect of Increased Carbon Emissions

The proposed increase in CO_2 of the gas composition will increase the amount of CO_2 released to the atmosphere and will lead to additional costs for gas turbine operators because they will have to pay for the increase in inherent CO_2 through EU ETS liabilities.[6] An estimate of this is included in the Carbon Cost Assessment.

[6] http://ec.europa.eu/clima/policies/ets/monitoring/docs/gd1_guidance_installations_en.pdf (p80/81)

Technical Complexity

The significance of WI is that for given fuel supply and combustor conditions (temperature and pressure) and given control valve positions, two gases with different compositions, but the same WI, will give the same energy input to the combustion system. Thus the greater the change in WI the greater the degree of flexibility in the control and combustion systems needed to achieve the design heat input. In addition to the WI, manufacturers also often specify limits on the Heating Value and other bulk properties of the fuel. GT manufacturers typically specify that their turbines are capable of operating over a range of WI and Heating Value. For some GTs a range as low as ±2% of the WI has been specified. The detailed composition also affects combustion performance including flame stability, emissions, flashback, and ignition properties. Manufacturers' specifications account for such compositional changes in different ways, but typically specify maximum levels of higher hydrocarbons (ethane, propane, butane etc), minimum methane and/or maximum inerts. These specifications aim to ensure that the fuel gas is predominantly methane, and that gases which contain both high levels of inerts and higher hydrocarbons, but are still within WI limits, are not allowed.

Flame Stability

To ensure flame stability, fuel injection is widely distributed and an air/fuel mixing zone is provided to ensure even mixing of the fuel and air. High quality mixing is essential to ensure an even temperature within the flame which leads to low NOX emissions when operating under lean conditions. Variable fuel composition and WI can affect the combustion and flame dynamics. The swirling flow tends to enhance mixing and generate the correct aerodynamic conditions for flame stabilisation in the combustor. The design must generate acceptable combustion performance by ensuring:

1. The flame stabilises at the burner exit at the upstream end of the combustor without propagating upstream into the mixing zone (flashback) or lifting from the burner and blowing-out.
2. Excessive combustion dynamics are not produced.
3. Flame temperature and temperature distribution do not deviate significantly from design values (to prevent component overheating or excessive thermal stresses).
4. Low levels of pollutant emissions.

Combustion dynamics (acoustic pressure fluctuations within the combustor) can occur in any combustion device, but lean premix GT combustors are particularly susceptible. Combustion dynamics occur due to the coupling of acoustic pressure oscillations in the combustion system with the energy release within the flame. These oscillations can reach high amplitudes and induce vibration in the combustor components. This leads to increased wear, reduced component life or in extreme cases catastrophic component failure. Instances of component failure can occur particularly when the characteristic combustion dynamics frequency couples with the structural response of the system. The fuel composition together with the air fuel ratio, flow properties (e.g. flow speed, turbulence etc), fuel placement and mixing quality all have a significant influence on flame behaviour (flashback, blow-out, dynamics and emissions). The details of how these effects influence combustion performance depend on the details of the combustion system design and this is why different GT manufacturers have different fuel specifications and use a range of parameters to specify acceptable fuel quality.

Direct Costs for CCGT Trips/Retuning

Energy UK, on behalf of their member organisations who operate CCGTs, have indicated the following costs:

Re-tuning	£22k
Trips	£140k to £180k

Note: these are approximations based upon real examples, but are sensitive to gas prices, spark spread and electricity cashout costs.

Warranty Impacts

The Workgroup considered the potential CCGT warranty impacts as highlighted by SSE's initial representation. SSE provided the following extract from a technical report provided by their equipment supplier and confirmed that there were no residual concerns with respect to warranties:

> The 'standard' fuel specification of this turbine supplier as part of the offer is relatively limiting when compared to other manufacturer specifications. In particular, an upper limit of 98% methane content (as a percentage of combustibles) and a 'preferred' maximum limit of 4.0 mol% inerts (nitrogen and CO_2) results in a large section of the UK GS(M)R specification being unacceptable.
>
> However, written assurances have been given that the gas turbine combustion system can operate over a wider range of gases than stated in their standard specification.
>
> There are two areas of the GS(M)R specification that would be expected to cause combustion issues with the combustion system. These areas include very lean gases (low higher1 hydrocarbon and high inerts content) and very rich gases (high higher hydrocarbon content). From gas property calculations and prior experience of typical gases on the UK gas network it is considered highly unlikely that these types of gases would be received.
>
> The GT is therefore considered to be low risk in terms of combustion behaviour with regards to gas quality variations. However, it should always be noted that premixed combustion as employed for all large GTs, irrespective of manufacturer, will always have the risk of combustion instabilities.

Electricity Capacity Market

The electricity capacity market aims to bring forward new investment while maximising current generation capabilities. Generators who are successful in the auction will benefit from a steady, predictable revenue stream (capacity payments) that encourages them to invest in new generation or to keep existing generation available. In the event of a stress event on the electricity market, generators who hold a capacity obligation and that do not provide energy will incur a penalty. For the first delivery year, 2018/19, capacity awarded to CCGTs constitutes 45% of the total awarded capacity. Any risks associated with changes to the gas composition and/or to the variability of CO_2 flows into CCGTs may not have been considered within the context of the electricity capacity market. For further information please see this National Grid Electricity Transmission report:

https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/T-4%202014%20Final%20Auction%20Results%20Report.pdf

Downstream Consumers – impact on CO_2 Removal Systems

The Workgroup considered the initial representation provided by GrowHow Ltd and sought to quantify the issue. GrowHow confirmed:

- Its primary use of gas is as feedstock. The feedstock is converted to hydrogen and CO_2 by steam reforming and the water gas shift reaction. The CO_2 formed from feedstock is then captured by absorption in circulating solution and released when the solution is heated and lowered in pressure
- Its current CO_2 emissions were approximately 950,000 tonnes in a normal year.
- If the CO_2 content of the incoming gas increases from 2.0 mol% to 4.0 mol% all year round, then it estimates an increase in CO_2 emissions of 13,000 tonnes.
- This represents a direct additional EU ETS cost, which would obviously be dependent on the carbon price.

Workgroup participants noted that GrowHow had calculated its increase in carbon emissions based on an enduring increase in CO_2 to 4.0 mol%. Using the assumption of 30 days of >2.9 mol% of CO_2 (see 'Carbon Cost' section below) flows at Teesside, increased emissions at GrowHow would be c. 588 tonnes per year or 0.06%.

With respect to its CO_2 removal system:

> Its CO_2 removal system captures approximately 2/3 of the total CO_2 emission figure (the remainder is combustion CO_2). This system does run heavily loaded when running at maximum production rate. At times this could restrict production*, by up to 2.0 mol% for an increase in CO_2 content from 2.0 mol % to 4.0 mol %. On average the reduction in production from this cause would probably be around 1%. The cost of expanding the CO_2 removal capacity to address this rate restriction would be much greater than the production loss would justify.
>
> However, GrowHow has a greater concern that the additional CO_2 would increase the required flowrate and hence pressure drop through the plant. This is because CO_2 acts as an inert in the feed-gas. The process requires a fixed amount of hydrogen for any given production rate. Any additional CO_2 is a direct additional flowrate through the process from the gas supply pipe to the CO_2 removal section. As the plant runs to a pressure limit, they estimate that an increase in CO_2 content from 2.0 mol % to 4.0 mol % would result in the requirement to reduce production rate by approximately 2.8%.
>
> Increase in CO_2 content in the feedgas from 2.0 mol % to 4.0 mol % would require an increase of 2.1% in feed gas flowrate.
>
> This could cost GrowHow in excess of £1m p.a. in lost production.

Again, Workgroup participants considered this forecast using the assumption of 30 days of higher-level CO_2, believing the production impact to be closer to £45k per year.

* The primary restriction on this system is the CO_2 absorption capacity. CO_2 can start to slip through the absorber if too heavily loaded. The load is determined by throughput primarily and gas composition. Additional CO_2 in the feedstock directly adds to the amount of CO_2 that needs to be removed by absorption.

Impact on Storage Operators

The principal concern for Gas Storage Operators Group (GSOG) members relates to increases in the absolute levels of CO_2 in gas on the NTS, rather than speed of gas quality change, because of the increased risk of corrosion from higher CO_2 gas. This risk arises because higher CO_2 results in higher carbonic acid levels in the aqueous condensate. Increased carbonic acid increases the rate of corrosion in the underground pipework.

Should the changes at Teesside result in higher levels of CO_2, particularly for extended periods during the summer when storage sites are often injecting gas from the NTS, storage operators will need to increase corrosion monitoring and mitigation activities. The level of CO_2 will depend to some degree on the particular site, however GSOG members have noted that sustained levels of gas with greater than 1.7 mol% CO_2 will require them to reassess their carbonic acid monitoring and treatment programme. Others have noted that the 2.5 mol% level could create significant challenges for storage systems.

GSOG members have estimated that increased corrosion inspections and treatment cost could add a significant amount to the operating costs of affected storage facilities. By way of example, an increase in CO_2 levels by around 1 to 1.5mol% could add in the order of £225,000 per annum in operating costs. The exact cost will vary by facility, and will also depend on the volume of higher CO_2 that is ultimately injected into the facility. The higher the volume and CO_2 content, the greater the need for corrosion monitoring and mitigation activities.

GSOG members consider that the estimated costs of the £225,000 per annum is potentially conservative, and that Gas Storage System Operators (SSOs) may face additional costs even if average CO_2 levels are below the 1 to 1.5% specified. The effects of CO_2 levels and the need for monitoring the implications of the potential changes in gas quality may arise even if the actual number of high CO_2 days from Teesside is low. The implications cannot be fully assessed without Front End Engineering Design (FEED) studies at those storage sites likely to receive gas from Teesside. GSOG considers that the party seeking to land the high CO_2 spec gas should fund such studies, as they are the only party benefitting from the proposed change.

GSOG does not see the relevance of expressing this cost as a proportion of operation expenditure. The fact is that these are additional, material costs that SSOs may incur should the UNC modification be approved. Further, GSOG members do not expect any offsetting benefits (i.e. higher revenues due to an increase in spreads or volatility).

In addition to the risk associated with carbonic acid, increasing the CO_2 of gas also results in higher costs for storage operators because it means that higher volumes of gas needs to be injected into storage facilities in order to inject the same calorific value of the gas. This means that the storage operators will need to use more energy to get gas into and out of store. The increased use of fuel to move the gas will require more EU ETS permits.

GSOG notes that there are a number of storage facilities in the catchment area of Teesside gas. However, it is difficult for storage operators to provide an estimate of the likelihood that they will incur significant additional cost associated with Teesside gas given the information provided to the working group. As discussed at the working group, GSOG members are concerned that any such amendment to the CO_2 limit at Teesside may set a precedent for other system entry points on the network to seek higher CO_2 limits which could increase the likelihood of Storage Operators incurring additional corrosion-related costs.

Workgroup participants considered the views presented by GSOG, with some participants considering that the impacts have not been fully evidenced, that the FEED study (and its funding) is a question for future Consultation responses.

Carbon Cost Assessment

Options for addressing elevated levels of CO_2 in gas at Teesside

The options for addressing the possible increases in CO_2 levels in export gas are to either allow such gas to flow directly into the NTS up to an agreed level (4.0 mol%) or to remove the excess CO_2 above the current allowable specification using CO_2 removal technology. The CO_2 emissions and associated cost of such emissions are estimated in the Carbon Cost Assessment (see below).

If the CO_2 entry specification was not increased on Teesside then current excursions in CO_2 concentration in NTS export gas would be dealt with under the current specifications within the TGPP and CATS NEAs. This may lead to continued occasional short-term shut-in of certain fields as previously noted by the CATS Owner as the cost of providing CO_2 removal would not be cost effective. For new developments such as Jackdaw, the development owners would need to take a view on whether the provision of CO_2 removal technology is a cost effective solution. Other options could be to continue the field development accepting that flows could be restricted under certain circumstances or indeed not to develop the discovery at all. In terms of the former, while the decision will ultimately lie with the asset owners, it is TGPP's experience that having to commit substantial (>£3Bn) amounts of capital for a development on the scale of say, Jackdaw, the owners will require a high level of certainty that gas will flow to market in order to secure the projected cash flows. The potential for flow restrictions could lead to capital being deployed elsewhere on projects with a higher level of certainty of deliverability. This is unlikely to be in the UK. Not developing a discovery will have broader impacts on the UK economy in terms of reduction in security of supply (by importing additional gas to replace that which could have been produced domestically), balance of payments, taxation revenues from the field production and ultimately Maximum Economic Recovery of UK oil and gas (MERUK) as laid out in the Wood Report (http://www.woodreview.co.uk/).

See also Appendix 4 for the underlying detail.

Options for addressing increases in CO_2 Levels as detailed in the Carbon Cost Assessment

Option 1 - Flow gas up to 4.0 mol% CO_2 into the NTS

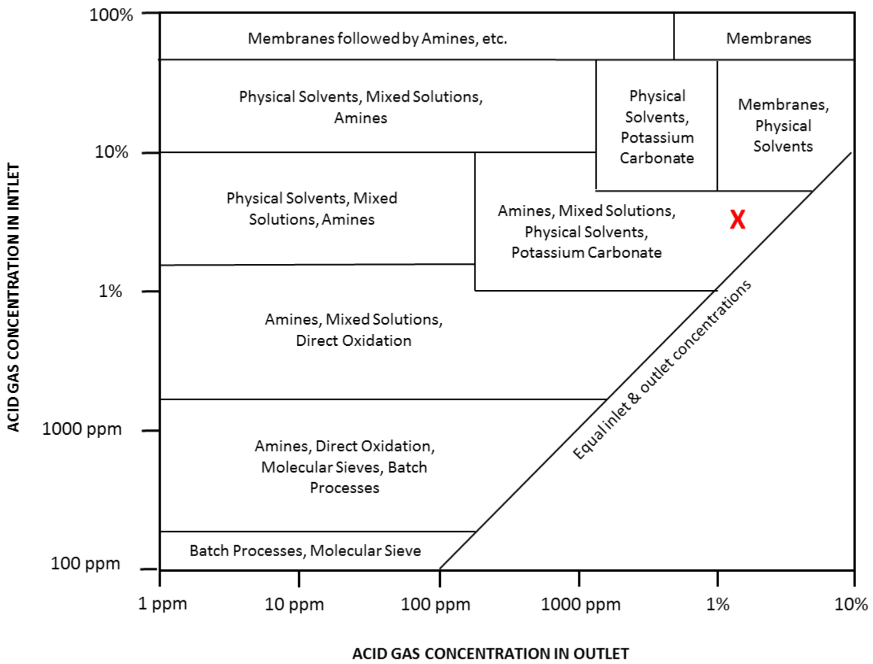
As noted above, flowing gas in excess of the current specification of 2.9 mol% is not expected to be for extended periods of time as it is anticipated that under normal operating conditions gas from any fields with gas of high CO_2 content would be blended in the offshore pipeline to ensure current delivery specifications are met. High CO_2 gas could result from maintenance of offshore fields during summer months or unplanned field operational outages when flows of gas into the CATS pipeline could be reduced and the capacity to blend high CO_2 gas reduced. The advantages to the upstream producers and the gas terminal operators is the removal of the need for significant capital expenditure and increased operating cost from the installation of CO_2 removal equipment which may be used for only a few days/weeks per year. This option would also prevent significant additional CO_2 being released to atmosphere from the use of process heat associated with the CO_2 removal technology.

Removal of CO_2 above 2.9 mol% at the upstream platform or onshore at the terminals

Blend gas cannot be provided for the periods when concentrations of CO_2 exceed the current specification, as these periods will coincide with limited low CO_2 gas flowing in the CATS Pipeline. Storage of gas for blending during these periods cannot be provided for both technical and commercial reasons. The Proposers believe that the provision of physical storage is impractical due to the volume required, space constraints and cost, while the commercial provision of such gas would effectively require the creation of a small-scale gas storage business upstream of the terminal.

The most practical solution alternative to Option 1 outlined above is to remove the additional CO_2 in the gas before entry into the NTS at the Teesside entry points. This could be accomplished either offshore at the field or onshore at the terminal reception facilities at the landfall of the CATS Pipeline on Teesside.

In the technical study work for CO_2 removal at CATS, all feasible technologies were examined.
In general CO2 removal (and H2S removal) technologies rely on either solution reaction (amine or other physical solvents) or pressure drop (membrane or molecular sieve technology). Technologies become optimal in different circumstances relating to the concentration (partial pressure) of CO2 in the inlet stream against that required in the outlet stream (see chart). The red X shows the approximate concentrations of the CATS gas scenario under consideration.



Molecular sieve technology is typically used for removing trace contaminants from gas streams and very low outlet concentrations can be achieved. The loading of CO_2 on molecular sieve is relatively low, and the high feed gas CO_2 content in this case, will result in a physically large system with high regeneration requirements and correspondingly high capital and operating costs when compared to alternative technologies.

CO_2 can also be separated from natural gas using semi-permeable membranes. Membrane processes are best suited to "bulk removal", typically from high levels of 10 mol% or higher, rather than removal at relatively low levels. Given the forecast levels of concentration there would be additional complexities relating to hydrocarbon losses and relatively "rich" dense phase gas as found in the CATS pipeline could cause fouling of the membrane.

The Proposers do not believe that either of the above processes would be suitable for the duty envisaged nor is any cost saving anticipated.

Physical solvents use chemicals other than amine but the adsorption process is similar. Most physical solvent processes have been applied in bulk removal applications from relatively high levels but their CO_2 loading capacity is low and for this duty we would expect that circulation rates could be up to three times that required by amine processes. This increases relative equipment sizes. Other technologies such as hot Potassium Carbonates or caustic washes are not considered suitable.

Hot Potassium Carbonates tend to require a large amount of feed heating and some processes use arsenic based additives, which are considered a safety hazard. Caustic solutions combine with CO_2 to form a non-re-generable product (sodium carbonate solution), which has to be discarded. This leads to high caustic consumption and disposal issues for the spent solution.

Given the likely concentration of CO_2 in the inlet gas a solution reaction technology is the optimal technology for CO_2 extraction and as noted, amine plants are tried and tested in the upstream industry. However, a Formulated Amine Process using proprietary amine technology that allows higher solvent concentrations and CO_2 loadings than commodity amines provide an optimisation of this technology. This provides lower circulation rates and more effective/smaller equipment and lower operating cost. In addition there is often an advantage of reduced corrosion rates compared to commodity amines.

The Formulated Amine Process consists of an absorber column and regeneration unit. A proprietary amine solution (formulated to optimise CO_2 removal) flows against the gas stream in an absorber column. CO_2 is absorbed producing a sweetened gas stream and CO_2 rich amine solution. Rich amine is routed to the regeneration unit where it is flashed to low pressure and heated producing a CO_2 stream for venting and lean solvent routed back to the absorber. Electrical power is required to drive pumps and control systems, whilst significant heat input is required to regenerate the amine and also to regenerate the TEG/MEG used to dehydrate the gas after passing through the amine unit. Heat is usually supplied by a hot oil system heated by natural gas - this generates further CO_2 emissions in addition to the CO_2 extracted from the natural gas. The process also releases a stream of Volatile Organic Compounds (VOC) such as benzene. These cannot be sent to atmosphere so further heat is required to ensure that any VOCs in the vented CO_2 stream are burnt before entering the atmosphere.

Option 2 – Installation of an amine unit on the offshore facility

In order to ensure that discoveries such as Jackdaw can be economically developed, it is essential that capital and operating costs be minimised. The fully installed cost of an offshore amine unit is likely to be in the order of £180m (£~~129M~~ 107m when discounted at a 10% discount rate as per the CO_2 Impact Assessment (see Appendix 6)~~NPV~~), which would be borne by the field owners while the additional equipment would increase the annual operating cost of the facilities (power, maintenance, etc). This cost could be higher if the production platform is required to be increased in size/weight to accommodate an amine unit.

The provision of an amine unit on a facility such as Jackdaw would allow the export of gas into the CATS pipeline that meets the CATS pipeline gas delivery specification for CO_2 at less than 2.9 mol%. As a result, it is likely that the CO_2 content of gas exported into the NTS from the Px Teesside and CATS entry points would remain unchanged from the current ranges observed.

It is possible that the requirement to provide an amine unit for removal of CO_2 on a facility such as Jackdaw could make the development project sub-economic for the field owners and development could be either delayed or postponed.

Option 3 – Installation of amine unit(s) onshore at the TGPP and CATS Facilities

If CO_2 removal facilities were not installed offshore, then in order to ensure that CO_2 levels remain within the NTS entry specifications it would be necessary to install an amine unit or units at the terminals. CO_2 removal facilities would need to be installed at the lower pressure (circa 65 bar) exit points of the terminals as the pipeline and terminal entry points operate at high pressure (circa 105 bar). The cost of installation of an amine unit at a Teesside processing facility is c. £200m (£~~147M~~ 122m when discounted at a 10% discount rate (see above)~~NPV~~). The additional cost over an offshore unit is due to the requirement to process larger volumes of gas from the commingled pipeline stream. As with the offshore unit, the operating costs of the terminal facilities would increase through additional maintenance, the cost of which would be passed through to the user of the equipment.

It is anticipated that the amine unit (or units) would only be operated during those periods when the CO_2 content of the gas exported from the terminals exceeded 2.9 mol%. At present TGPP are discussing the operating parameters of amine units with the vendors to investigate if year round operation would be required or whether a unit could be put into “standby” when not in use. It is the view of the TGPP and CATS terminal operators that in general equipment subject to heat are more reliable when the heat is constant. Continued heating and cooling (as would be required if an amine unit were maintained on standby) tends to cause rapid degradation of equipment due continued thermal expansion and contraction leading to unreliability. This would be unacceptable for an amine unit as export gas would have to be curtailed if CO_2 spec could not be met. Continuous operation would add significantly to the CO_2 footprint due to the heat required. Having said that, we have considered a case where the amine unit could be put onto “standby” when not required. This would require storing the amine in a tank at about 20^oC. This allows process emissions resulting from operation of the unit(s) to be reduced but the requirement to maintain the amine tank at about 20°C when the fluid is not in use, which BP and TGPP estimate requires about 3.6MW of process heat.

See Appendix 5 for a schematic of the likely layout.

Alternative options for powering onshore amine unit

Following discussion in the Workgroup, a number of options to provide power for the amine units have been assessed to establish whether there are any viable alternative sources of power generation other than fuel gas which could lower the CO_2 emissions of the onshore CO_2 removal option. However, all the alternative power options considered either introduce undesirable levels of additional complexity at the CATS reception facilities or are simply not feasible as an alternative power solution. Other options such as wind turbine or ground source or water sourced heat were not considered. Self-generation wind turbine cannot be achieved due to safety concerns related to the gas processing plants being top tier COMAH[7] sites while ground source or water sourced heat are unlikely to be ~~due to their unreliability in being~~ able to provide sufficient power on demand. The options considered and the issues attached to these are summarised in the following table.

Alternative options for powering onshore amine unit	
Hot Oil:	Existing hot oil heaters are at capacity. CO2 removal study indicated that a separate hot oil heater / system would be required for the amine unit. Hot oil is the option considered in the CO2 impact assessment (appendix 6)
	Any hot oil duty will be generated by burning fuel gas as this results in better thermal efficiency (>80%) than heating hot oil with electricity supplied from grid (<50%).
	Hot oil could provide heat in both duty and standby mode.
Electric Heater:	Standby mode: 3.5 MW duty for standby is considered to be a high duty for an electric heater application. The extra electrical load required would be supplied from the grid and would result in a lower thermal efficiency than heating with hot oil.
	Duty mode: The 14 MW required whilst on load is too high a duty for an electrical heater.
	CO2 emissions at source generation need to be considered in overall CO2 emissions. Higher overall CO2 emissions are anticipated if electric heating used vs hot oil.
Steam:	There is currently no steam on the CATS site and no waste heat at high enough temperatures to generate steam.
	Any steam generation would require a boiler to be installed, with steam generated from fuel gas.
	There is no desire to introduce steam generation to the CATS site due to the extra water treatment utilities required and increased complexity.
Direct Fired Heater:	Not feasible / recommended at amine temperatures required.
Low Level Heat:	Upto 1.4 MW low level heat available at high throughput – insufficient for standby duty alone. Heat available decreases with decreased plant througput.
	Would require installation of new heat exchangers at increased capital cost to hot oil option (14MW hot oil heater still required for duty operation)
	Electric heater or increased hot oil duty required for deficit (with associated CO2 generation)

[7] Control of Major Accidents and Hazards

Tabulation of Advantages/Disadvantages for CO_2 options

CO_2 Option	Cost (£M)	Advantages	Disadvantages
Option 1 Flow gas at up to 4.0 mol% CO_2 into NTS	No equipment cost	**Producers** • Lowest cost option for high pressure/high temperature fields with high development costs • High CO_2 gas blended with other CATS gas for most of year • Flow of high CO_2 gas for limited periods (Field maintenance, unplanned outages) • Lower CO_2 emissions overall – no CO_2 released from process heat required for CO_2 removal • No VOCs combusted **~~End~~ Gas Consumers:** • Development of domestic gas sources gives improved security of supply compared to gas imports/LNG	**~~End~~ Gas Consumers:** • Higher CO_2 content gas enters NTS on some days (modelled as a max of 30 days) **EU ETS Consumers:** ~~•~~ Potential for elevated emissions charges for consumers of gas from Teesside entry points that has not been fully diluted in NTS but ~~.~~ • l~~L~~imited impact on sites calculating annual CO2 emissions from regional emissions factors or site specific calculated emissions factors rather than direct measurement of CO_2 emissions
Option 2 CO_2 Removal Offshore at source	c. £180M (£~~129M~~ 107M as a discounted Net Present Value at 10%) (NPV10)	**Gas Consumers** • Removes additional CO_2 from specific high CO_2 gas before entering CATS Pipeline • Allows CATS pipeline gas to remain within current specification • CO_2 content of NTS gas remains within current specification **~~End Consumers:~~** • Emission levels remain within current ranges	**Producers** • Additional capex cost to specific project and increases in annual operating costs may make specific project sub-economic at assumed commodity prices • Specific project may be delayed or not developed • Amine unit operational year round • Additional CO_2 emissions from the use of process heat in addition to that removed from the gas • Additional VOCs combusted during venting of CO_2 extracted from gas • Increased emissions charges • Ultimate recovery of oil and gas from UKCS is impacted **~~End~~ Gas Consumers:** • Reduced security of supply if domestic project not developed and gas replaced by imports/LNG
Option 3 CO_2 Removal Onshore at CATS Pipeline Reception Facilities	Up to £200M (£~~147M~~ 122M as a discounted Net Present Value at 10%) (NPV10)	**Gas Consumers** • High CO_2 content gas can be blended with low CO_2 content gas in the CATS pipeline for most of the year • Most of year CO_2 content of NTS gas remains within current specification without specific action • CO_2 removal equipment provides backstop if current CO_2 specification is exceeded **~~EU ETS Consumers:~~** • Emission levels remain within current ranges	**Producers** • Additional capex cost to specific project and increases in annual operating costs may make specific project sub-economic at assumed commodity prices • Specific project delayed or not developed. Costly equipment only required for short durations when blend gas unavailable • Additional CO_2 released through process heat when operational and requirement to ensure amine maintained at 20^oC when not in use • May be required to operate continually to ensure continued reliability • Increased emissions charges • Ultimate recovery of oil and gas from UKCS is impacted **~~End~~ Gas Consumers:** • Reduced security of supply if domestic project not developed and gas replaced by imports/LNG

Carbon Cost

A carbon cost assessment has been completed. The impact assessment compares the tonnage of CO_2 released in order for the forecast gas landed at Teesside to meet the current 2.9 mol% CO_2 NTS entry specification and the cost of this CO_2 mitigation to the tonnages that would be released by downstream consumers if the Teesside NTS entry specification were to be raised to 4 mol% and such gas were not diluted by other NTS flows.

A carbon cost assessment has been calculated for each of the CO_2 options:

Scenario 1 – Non-removal of CO_2;

Scenario 2 – Removal Offshore; and,

Scenario 3 – Removal Onshore.

The detailed carbon cost assessment and assumptions are included in Appendix 6. All financial values are calendar year and on a pre-tax basis. The annual operating costs of onshore and offshore amine units have not been fully evaluated and therefore have not been included in the model. Were such costs to be considered, this would of course increase the cost of any CO_2 removal.

Whilst it is recognised that currently there are certain circumstances when the CATS operator has curtailed or suspended flows from certain existing fields, these occurrences are difficult to model. In order to simplify the model the carbon impact assessment has been made for the period ~~2019~~ 2021 to 2030, ~~2019~~ 2021 being the earliest a field with elevated CO_2 levels such as Jackdaw might be anticipated to start.

For Scenarios 1 and 3, it is recognised (as noted above) that for the majority of time the CO_2 levels are likely to be below the current CO_2 limit with CO_2 content above 2.9 mol% being possible during summer maintenance campaigns or for short periods of unplanned outages when gas with high CO_2 content cannot be blended in the CATS pipeline with gas with low CO_2 content. For the purposes of modelling the CO_2 impact assessment, the proposers have assumed that only Jackdaw would flow (using a representative flow profile) and that this period would be 30 days per year. As a result, for this period the CO_2 content of CATS gas has been assumed to be a maximum of 4.0 mol%. In reality this would be expected to be a worst case scenario. It is unlikely that Jackdaw would flow entirely on its own so some blending is likely to occur and therefore there a likely to be fewer days per year when CO_2 content is at the maximum assumed 4 mol%.

Estimated Incremental CO_2 Emissions above Current Specification ~~2019~~2021-~~2030~~2032

The table below is a summary of the total estimated overall CO_2 emitted under the three modelled scenarios during the period ~~2019~~2021-~~2030~~2032:

Assessment of CO_2 Impact from Teesside Gas (2021-2032)	Scenario 1 NTS Delivery at 4 mol % CO_2	Scenario 2 Offshore CO_2 Reduction	Scenario 3 Onshore CO_2 Reduction
CO_2 Removed by Amine unit (4 mol% to 2.9 mol%) (te)	0	462,881	38,045
CO_2 in fuel gas consumed by Amine unit (te)	0	213,510	87,497
CO_2 above 2.9 mol% emitted by consumers (te)	38,045	0	0
Total additional CO_2 emissions (te)	**38,045**	**676,391**	**125,542**

The removal of CO_2 offshore results in the greatest level of CO_2 emissions over the period (676 kte) as there is a requirement to treat the entire gas stream being exported from the production platform.

Removing CO_2 above the current 2.9 mol% limit at the terminals results in lower CO_2 emissions (125 kte) than an offshore solution as gas with high levels of CO_2 is blended with low CO_2 gas for most of the time and treatment may only be required for short periods. It has been assumed that an amine unit at the terminal/terminals would remain non-operational for much of the year but there is a requirement to maintain the amine tank at about 20^{o}C when the fluid is not in use. As a result, during the period of assessment, there is over 2.3 times more CO_2 released from process heat than is required to be removed from the gas to meet the current 2.9 mol% CO_2 limit for NTS gas. These emissions could increase if, following further work with the equipment vendor, the unit was required to be run continuously to ensure reliability and avoid stressing the system through thermal cycling.

The lowest level of incremental emissions over the period would result from allowing the gas with higher CO_2 content to flow onto the NTS. The model estimates that the direct flow of gas with higher CO_2 content onto the NTS results in a total additional 38 kte of emissions between ~~2019~~ 2021 and ~~2030~~2032. On an annual basis the modelled maximum annual incremental emissions above the current allowable specification in this case would be circa 4,600 te/yr (see Appendix 6) against a total UK forecast annual emissions total of over 300 million tonnes. By way of further comparison a single 1,000MW CCGT power station will emit circa 1,000,000 te of CO_2 per year based on a 30% load factor.

Estimated Cost of Incremental CO_2 Emissions above Current Specification ~~2019~~2021-~~2030~~2032

In terms of cost of abatement of the CO_2 generated above the current 2.9 mol% limit, it should be noted that there is no true abatement as the CO_2 associated with the gas above the 2.9 mol% limit will (if developed) be emitted at some stage. However, it is possible to consider abatement as the prevention of such CO_2 from entering the NTS but it should be noted from the table above that any prevention of the additional CO_2 entering the NTS results in the emission of significantly more CO_2 due to the operation of the CO_2 removal equipment.

The estimated cost of the emitted CO_2 for the three alternative scenarios are summarised in the table below. For consistency, these data are shown on a Net Present Value (NPV) basis discounted to 1/1/15 using a discount rate of 10% (NPV10). A discount rate of 10% has been used in this case as a surrogate for the cost of capital available to a gas production organisation or terminal operator. In reality the cost of capital for individual organisations could be higher.

Cost Assessment of CO_2 from Teesside Gas (2021-2032) (£ NVP10 1/1/15, Pre-tax basis)	Scenario 1 NTS Delivery at 4 mol % CO_2	Scenario 2 Offshore CO_2 Reduction	Scenario 3 Onshore CO_2 Reduction
CO_2 Total ETS Traded Cost	£23,416	£1,601,154	£299,936
CO_2 Total Traded Cost with Carbon Price Support	£158,001		
Total CO_2 Cost (Traded & Price Support)	**£181,417**	**£1,601,154**	**£299,936**
CO_2 Total Non-Traded Cost (£/yr) (non-ETS consumption)	£478,416	£0	£0
Total Estimated Emissions Cost	**£659,832**	**£1,601,154**	**£299,936**
Estimated Fully Installed Cost of Amine Unit		£106,685,573	£121,644,132
Estimated Abatement Cost for additional CO_2 prior to NTS entry		**£108,286,727**	**£121,944,068**
Cost per tonne (Emissions Cost/Total Additional Emssions)*	**£17**	**£160**	**£971**

* Includes capital costs for amine units

In terms of ETS traded costs where CO_2 emissions costs are measured against market prices, the highest cost option (NPV10 £1.60m~~69m)~~) would be removal of CO_2 offshore as this option results in the largest volume of CO_2 emitted due to the requirement to operate an amine unit all year round in order for export gas to meet the offshore pipeline entry specification. The cost of removal of CO_2 onshore at the terminals is also significant (NPV10 £~~304k~~300k) due to the substantial amount of CO_2 emitted through process heat from operation of the onshore amine unit. The emissions cost is not as great as offshore removal as the model assumes that any onshore removal unit would only be operated when gas with high CO_2 content could not be blended into specification although there would be additional emissions associated with process heat during operation of the amine unit and also for additional heating to prevent degradation of the amine when not in use.

Delivery of gas with 4.0 mol% CO_2 content onto the NTS is impacted by the requirement for power generators to pay substantially higher charges for emitted CO_2 due to the Carbon Price Support scheme. However at NPV10 £~~186k~~ 158k this is the lowest cost option given the forecast small number of days per year when such gas is being produced at the terminals.

It can be argued that the calculated emissions cost for delivery of high CO_2 gas onto the NTS (Scenario 1) are at the high end of a range as many ETS registered installations calculate CO_2 emissions using regional emissions factors or installation specific CO_2 emissions factors, (based on the average composition of the gas being consumed), regional emissions factors are annual averages and site specific factors may be annual, monthly or weekly. Given that any gas with elevated CO_2 content entering the NTS from Teesside is likely to be blended with other NTS gas before reaching consumers, such gas will only have a limited impact on the emissions costs paid by many consumers as the regional annual average assumptions for CO_2 content (and therefore regional emissions factors and installation specific emissions factors) will remain unaffected by the small amount of additional CO_2 once diluted.

If the impact of consumption of gas by non-ETS paying consumers is considered (using the DECC pricing assumption for Non Traded CO_2 emissions), the CO_2 emissions cost of NTS delivery of 4.0 mol% CO_2 gas increases to £~~745k~~660k.

If it is considered that the provision of CO_2 removal equipment either offshore or onshore is to “abate” the CO_2 entering the NTS then the total cost of providing that “abatement “ needs to be considered. While the capex figures used here are high level estimates and would be refined with further design work it is estimated that the fully installed cost of an amine unit on an offshore platform would be in the region of £180m and the cost of an onshore unit would be of the order of £200m. If required, the installation decision would be made at the same time as an investment decision for the offshore field. If a 2017 date for an investment decision these values equate to ~~(~~discounted ~~at~~ NPV10 ~~, these values equate to £129m~~ of £107m and £122~~47~~m~~m~~ respectively~~)~~. The lower cost for the offshore unit is due to the smaller size and lower pressure rating however it is possible that following further analysis this would be offset by~~e~~ the additional complexity of installing on a platform with limited space.

Including the cost of the amine units brings the total NPV of mitigating the increased CO_2 – which may be ~~in~~ only in excess of the current 2.9 mol% for 30 days per year and most likely less – to between £~~130m~~ 108m and £122~~147~~m~~m~~. In the worst case this is ~~almost~~ about ~~200~~ 180 times more costly than the £660k~~745k~~ estimate if the CO_2 were delivered onto the NTS.

Wider Considerations

Maximising Economic Recovery

In the short briefing note submitted on 26 November 2014, Oil and Gas UK anticipated the announcement in the Autumn Statement of the new high-pressure, high-temperature (HPHT) Cluster Area Allowance to promote the development of HPHT resources, including the known reserves of natural gas in the central North Sea which underpin Modifications 0498 and 0502.

http://www.gasgovernance.co.uk/sites/default/files/Mod%200498-0502%20Action%201106%20Oil%20&%20Gas%20UK.pdf

In the Autumn Statement of 03 December 2014, the Chancellor confirmed the introduction of the new Cluster Area Allowance and set the rate at 62.5% of the qualifying capital expenditure at fields which meet the minimum pressure and temperature thresholds (690 bar/10,000 psi and 1490 C/3000 F). The new allowance allows an amount equivalent to 62.5% of total capital spending to be offset against future Supplementary Charge (SC) levied at 30% and paid on top of Ring-Fence Corporation Tax (RFCT) of 30%. Details of the new allowance can be found in the HM Treasury publication 'Maximising Economic Recovery: Consultation on a Cluster Area Allowance' released in December.

The new fiscal allowance is one of several measures announced to maximise economic recovery of UKCS resources and was designed specifically after extensive consultation to promote additional investment in the technically challenging uHPHT projects in the central North Sea. The government has taken further measures in the Budget in March 2015 in order to restore the international competitiveness of the UKCS for upstream investors.

The Proposers believe that Modifications 0498 and 0502 are entirely consistent with the government's objectives in that they will lower the capital cost of development of uHPHT fields with high CO_2 content, promote greater energy security and bring wider economic benefits to the UK economy.

Risk of setting precedent

The Workgroup considered whether any decisions taken for Modification 0498 and 0502 set precedent for any other, future, requests at entry points. Participants concluded that there was such a risk, but that each request would be subject to an equivalent assessment under the UNC Modification Rules and then a decision taken by Ofgem based upon the merits of the individual case. On the basis of this individual objective assessment, the proposals were not believed to be discriminatory.

Conclusions

No clear conclusions have been achieved. Workgroup participants differed in their view of these changes, depending on the impacts they believed were most relevant to them. This report seeks only to document the arguments to inform further consideration within the UNC modification process (which assesses against the Relevant Objectives). Participants believed that there are other considerations, such as the wider UK interest and UK Government Policy, which are beyond the vires of a UNC modification. [requires further discussion on basis of modifications]

5 Implementation

No direct costs have been identified and no implementation date is proposed. Implementation could be completed immediately following approval from Ofgem, through a bilateral agreement to amend the NEA, and is envisaged that this would be done simultaneously for 0498 and 0502.

~~*The Proposers have recommended that these modifications be implemented simultaneously no later than 01 December 2015 to support timely investment decisions by developer/s. Other participants believed that implementation could be later, and no earlier than 01 January 2017 should first gas for Jackdaw be expected in 2021, or even on the first gas date of 01 January 2021.*~~

6 Impacts

Does this modification impact a Significant Code Review (SCR) or other significant industry change projects, if so, how?

This does not affect the UK Link Replacement Programme delivery or any other change.

7 Legal Text

No changes to the UNC are proposed under either Modification 0498 or 0502.

Suggested text to modify the Network Entry Provisions contained within the relevant NEA has been provided by each Proposer.

No issues were raised by the Workgroup regarding either content.

Suggested Text - Modification 0498

Given the relative simplicity of the legal change, the following legal text is suggested to modify the Network Entry Provisions contained within the NEA.

2.3 Gas tendered for delivery by System Users to the System at the System Entry Point shall not contain any solid, liquid or gaseous material which would interfere with the integrity or operation of the System or any pipeline connected to such System or any appliance which a consumer might reasonably be expected to have connected to the System. In addition, all gas delivered to the System at the System Entry Point shall be in accordance with the following values:

[…]

(k) Carbon Dioxide Not More than 2.9% before 1 October 20~~17~~20 and not more than~~2.9%~~ 4.0 mol% from 1 October 20~~17~~20

Suggested Text - Modification 0502

The following legal text is suggested to modify the Network Entry Provisions contained within the NEA:

2.3 (k) Carbon Dioxide not more than 2.9% before 1 October 20~~17~~ 20 and not more than~~2.9%~~ 4.0 mol% from 1 October 20~~17~~20~~2.9 4.0 mol%~~

8 Recommendation

The Workgroup invites the Panel to:

- AGREE that these modifications should be submitted for consultation.

1. Respondents are requested to quantify any additional costs they would incur as a result of an isolated CO_2 excursion to 4.0 mol%.
2. Respondents are requested to quantify any wider benefits/dis-benefits for the UK economy that might be derived from these proposals.
3. Respondents are requested to quantify the security of electricity supply risk to CCGTs. It would be useful to know how many CCGTs could be affected, when they might be impacted and what flexibility there is elsewhere in the system to accommodate.

9 Appendices

1 CO_2 Levels at Entry Points

2 Teesside Flow Maps

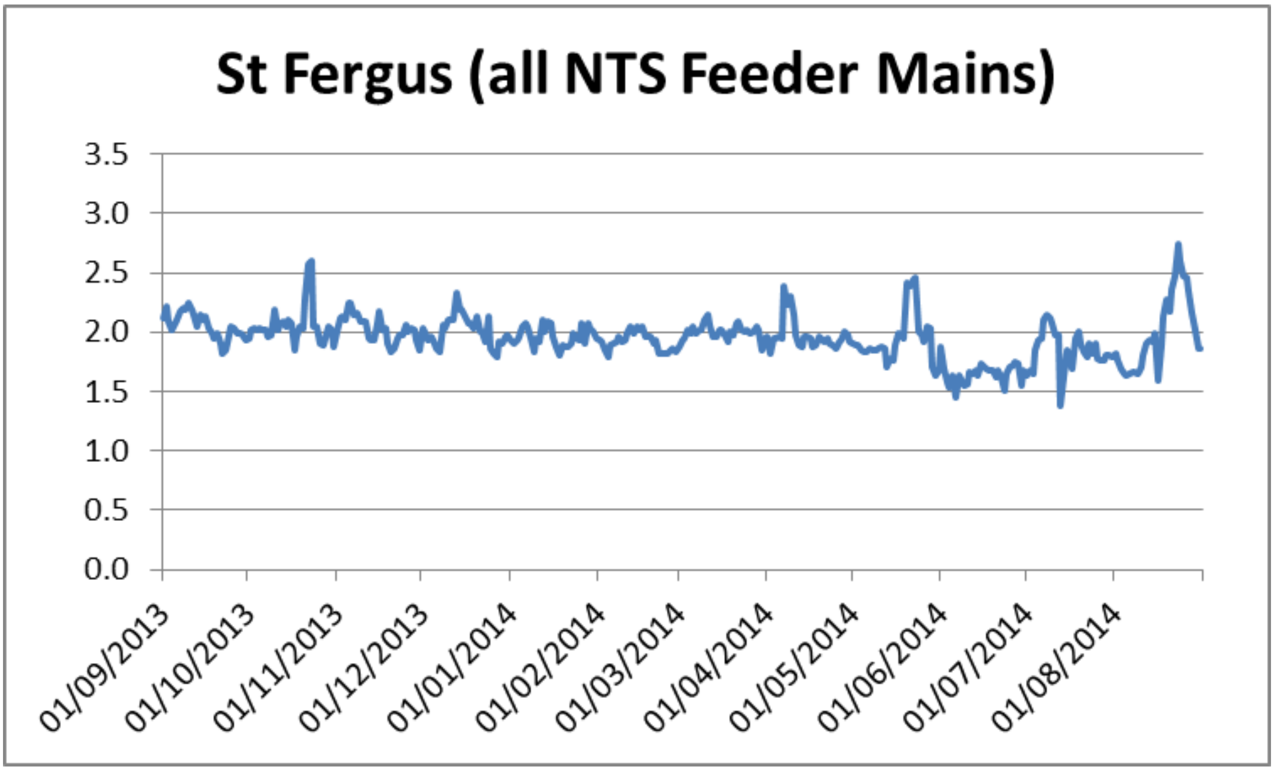
3 Plant trips at one CCGT located in the East of England

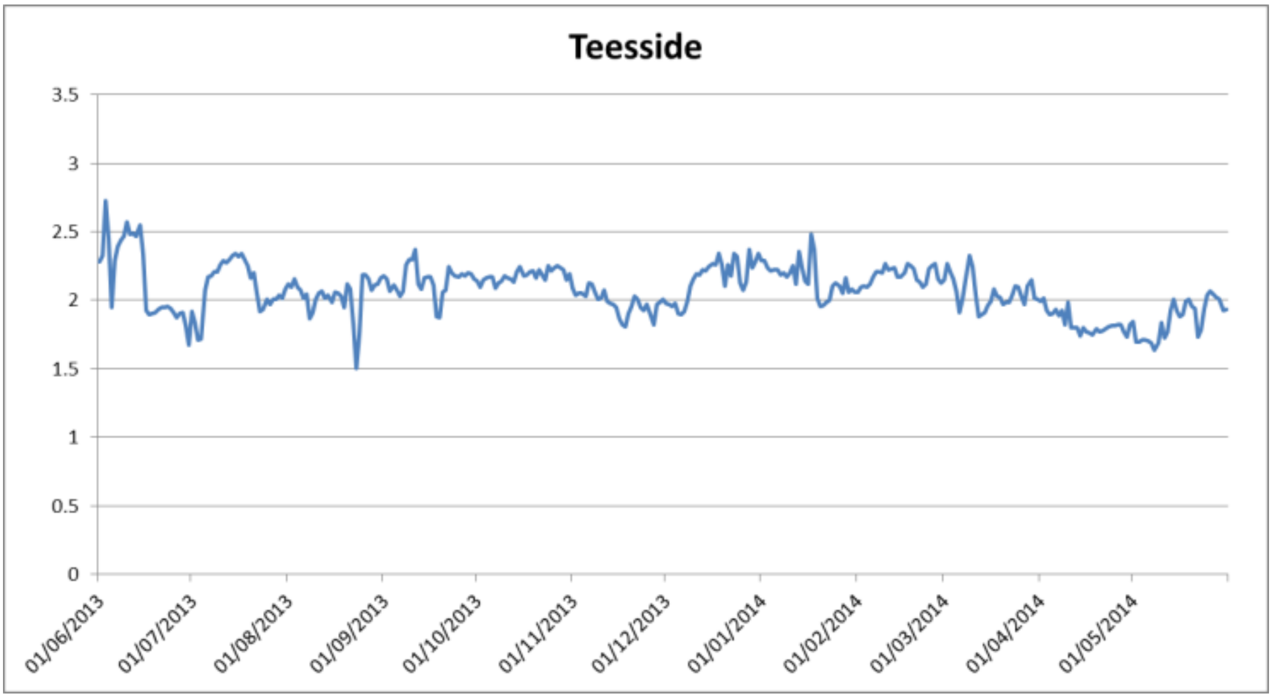
4 Detailed analysis of the impact of increasing CO_2 on Gas Quality at Teesside

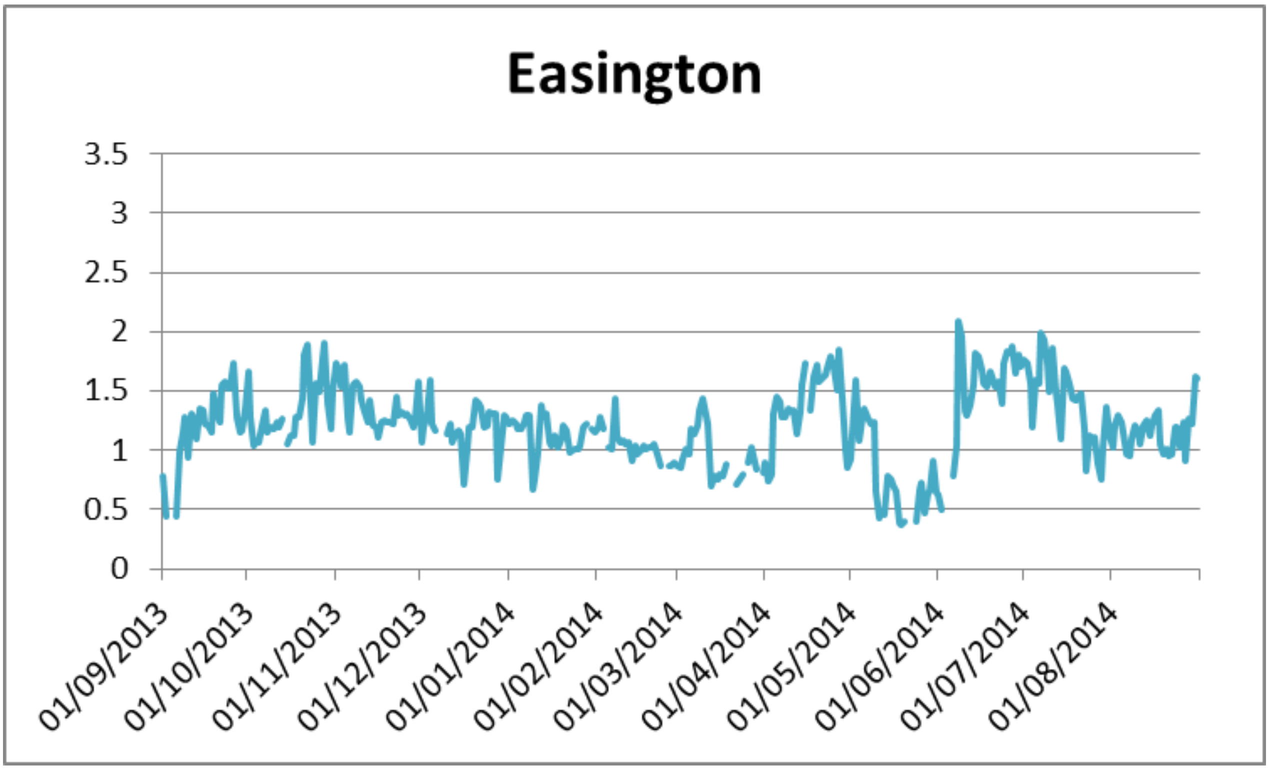
5 Teesside Schematic

6 CO_2 Impact Assessment

Appendix 1 - CO_2 Levels at Entry Points (plot is mol%)






Easington
3.5
3
2.5
2
1.5
1
0.5
0
01/09/2013
01/10/2013
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01/12/2013
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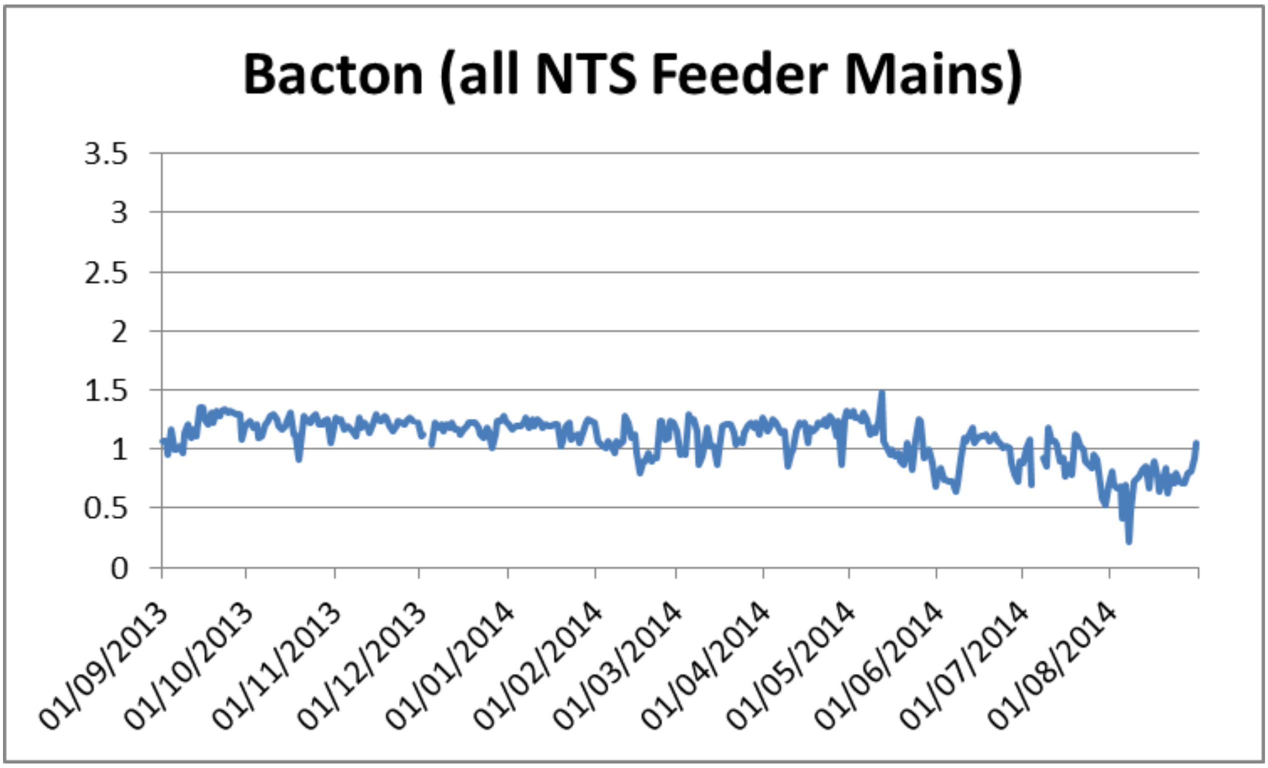
01/08/2014


Bacton (all NTS Feeder Mains)
3.5
3
2.5
2
1.5
1
0.5
0
01/09/2013
01/10/2013
01/11/2013
01/12/2013
01/01/2014
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01/05/2014
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01/07/2014
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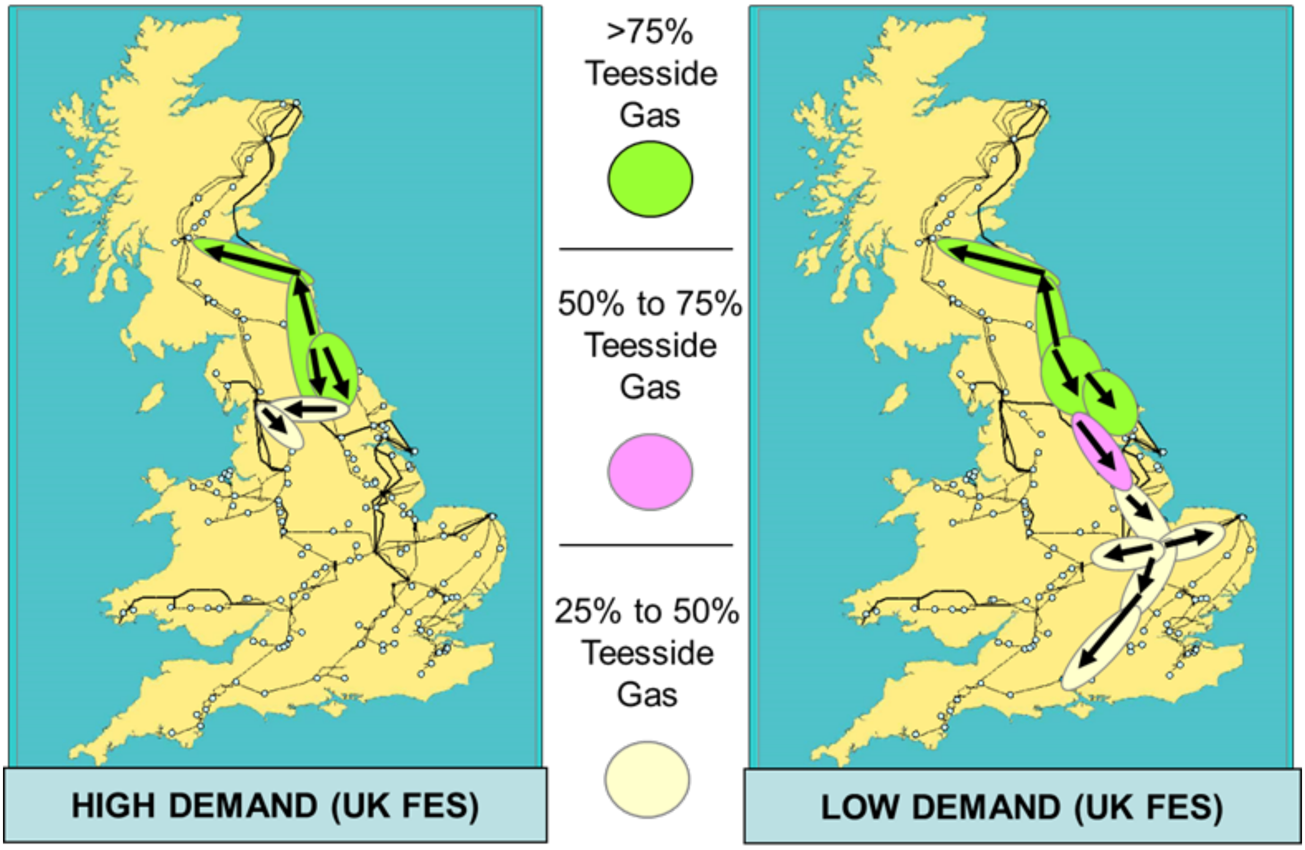
Appendix 2 - Teesside Flow Maps

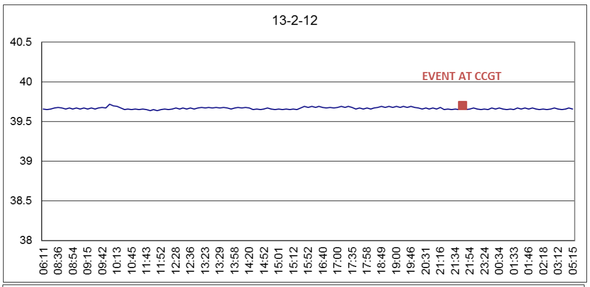


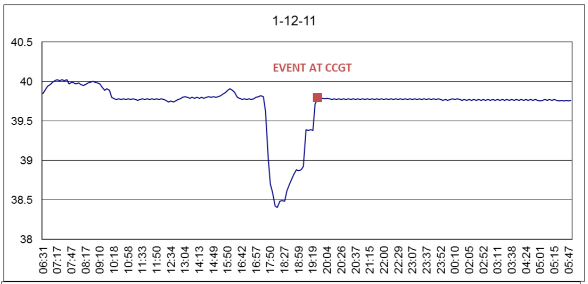
Appendix 3 – Plant trips at one CCGT located in the East of England

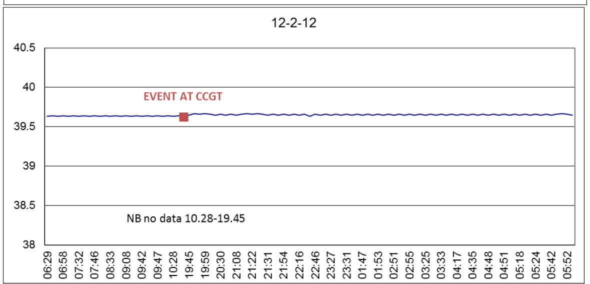
Data provided via Energy UK:

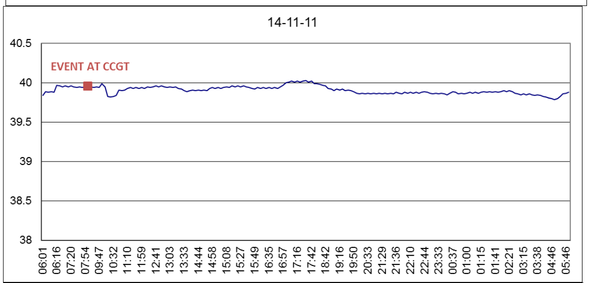
Date	Event	Wobbe Index, MJ/Sm^3	CO_2 (mol%)
13/02/2012 21:36	Trip during shutdown - Loss of Flame	50.2	1.5
12/02/2012 19:30	Trip during shutdown - Loss of Flame	50.2	1.5
12/02/2012 03:57	Trip during shutdown - Loss of Flame	50.2	1.5
18/01/2012 22:29	Trip during shutdown - Loss of Flame	50.6	0.8
19/12/2011 19:02	Trip during shutdown - Loss of Flame	50.8	0.8
14/12/2011 21:06	Trip during shutdown - Loss of Flame	No data Next day value was 50.8	0.9
01/12/2011 19:27	Trip during shutdown - Loss of Flame	50.4	1.3
14/11/2011 08:02	Failure to Ignite	50.6	1.5
28/09/2011 14:01	Trip on start-up - Unable to increase speed	No data Next day value was 50	2.5
28/09/2011 12:18	Trip on start-up - Unable to increase speed	No data Next day value was 50	2.5
23/08/2011 18:04	Trip during shutdown - Loss of Flame	50.2	2

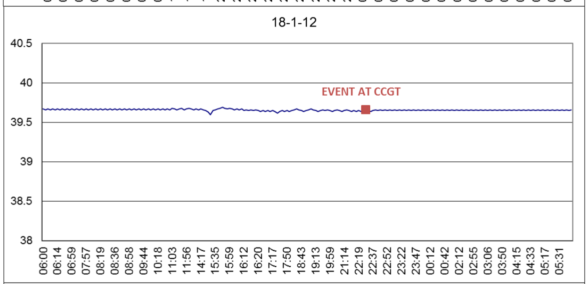
Within Day variation of CV at NTS offtake and CCGT trip events at a location in the East of England:

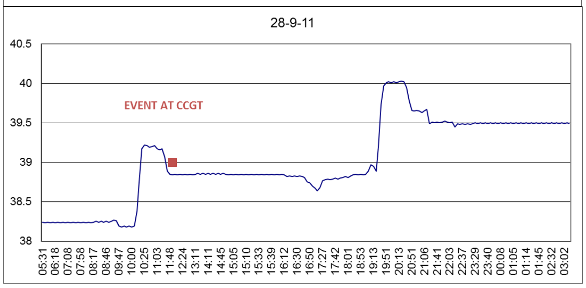


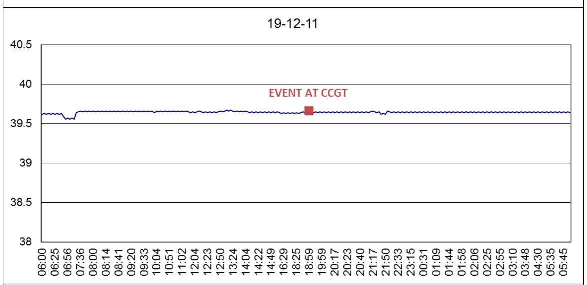


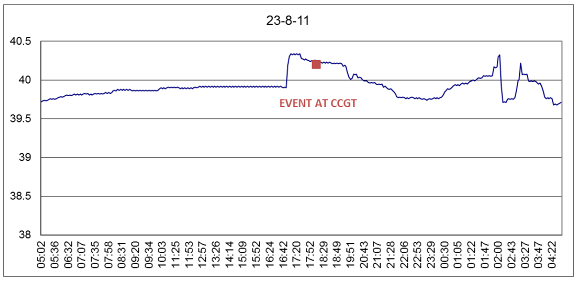


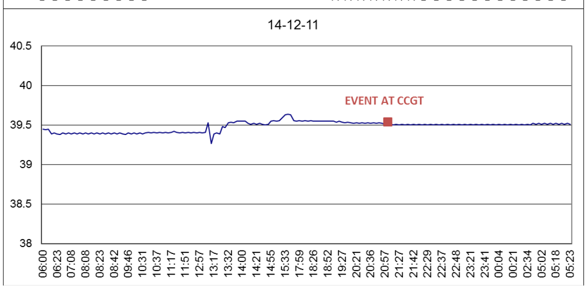










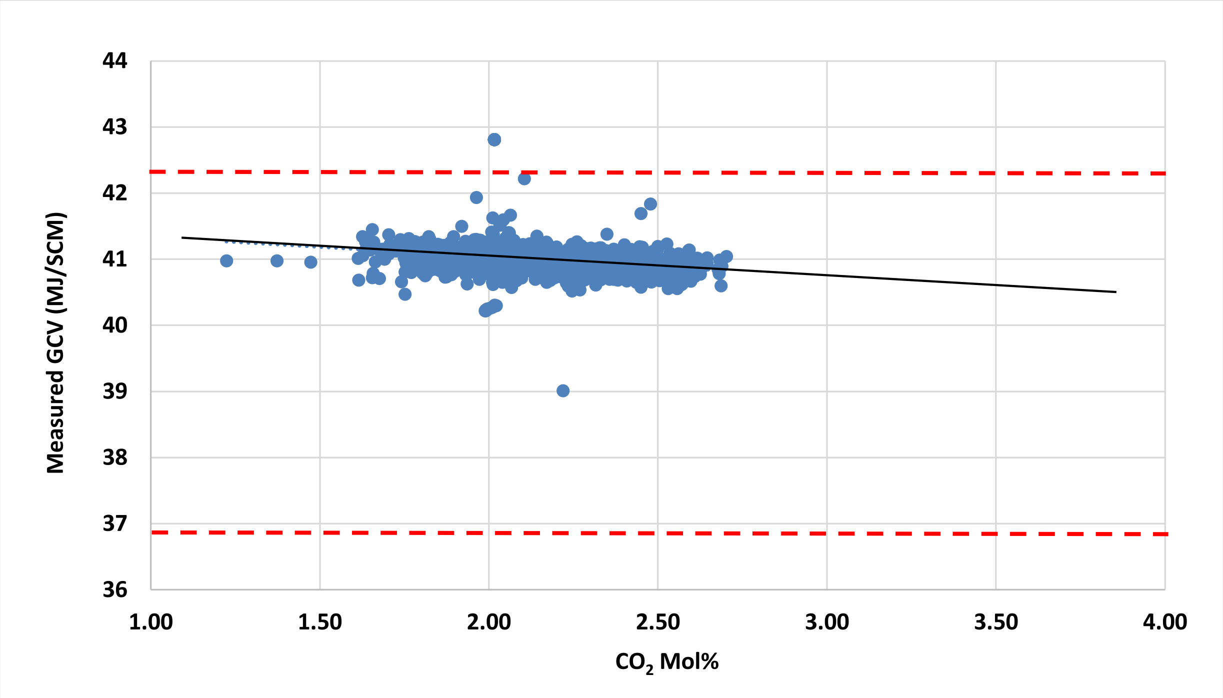


Appendix 4 – Detailed analysis of the impact of increasing CO_2 on Gas Quality at Teesside

Analysis of the impact of ~~Increasing~~ increasing CO_2 on gas quality at Teesside has been carried out by BP. The impact of the varying CO_2 content of CATS gas was analysed for its effect on Wobbe, Gross Calorific Value (GCV), Soot Index (SI) and Incomplete Combustion Factor (ICF) over a period of 42 months from January 2011 to June 2014 using daily average data. The findings were summarised in a presentation made to the Workgroup on 7th of August 2014 available here.

Gross Calorific Value (GCV)

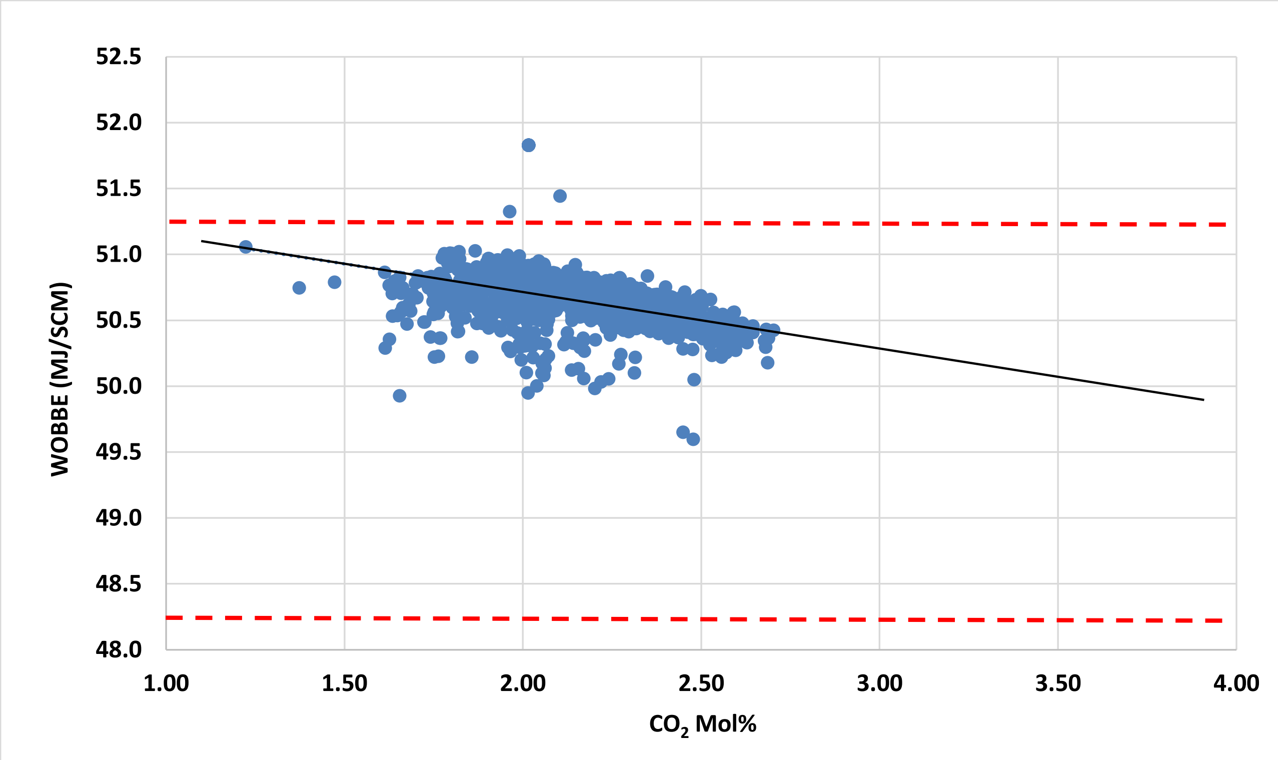
The impact of varying CO_2 on GCV is shown in the chart below. In normal operation, CO_2 varies between 1.6 mol% and 2.7 mol% with very little impact on GCV. Using a best fit line for these data it can be shown at every 1 mol% change in CO_2 content results in about 0.3 MJ/SCM change in GCV.



Extrapolating this to a max of 4 mol% would result in a forecast GCV of 40.4 MJ/SCM or a change of less than 1 MJ/SCM when CO_2 content of the gas is 1 mol%. The analysis shows that this GCV remains significantly within the range of GCV allowable in the NEA.

Wobbe Index (WI)

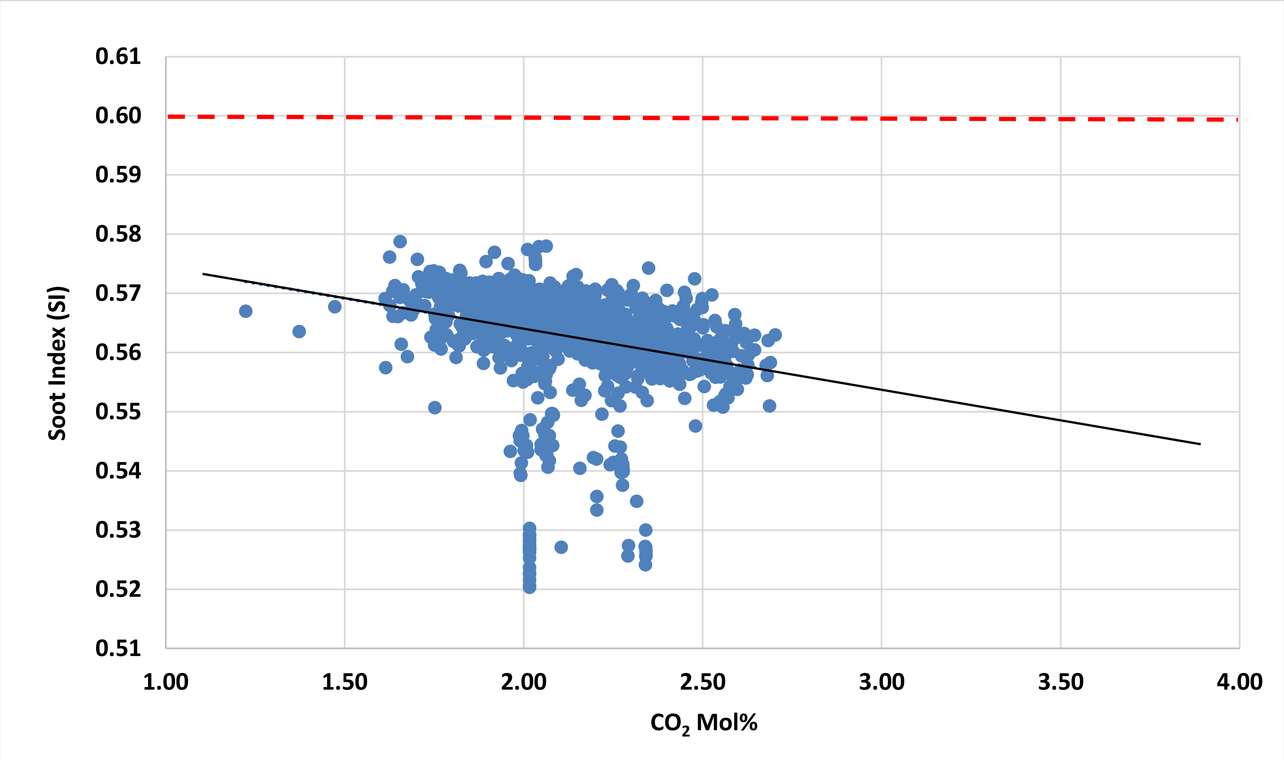
Overall, the data tends to show more scatter than that of GCV in that there a wider range of WI values for any given CO_2 content but this is within normal operating conditions for the Teesside terminals.



The impact on WI at 4 mol% CO_2 content remains well above the mid-point of the WI range allowable in the NTS gas specification. A move from CO_2 content of 2.9 mol% to 4 mol% would result in a decrease in WI of about 0.5 MJ/SCM.

Soot Index (SI)

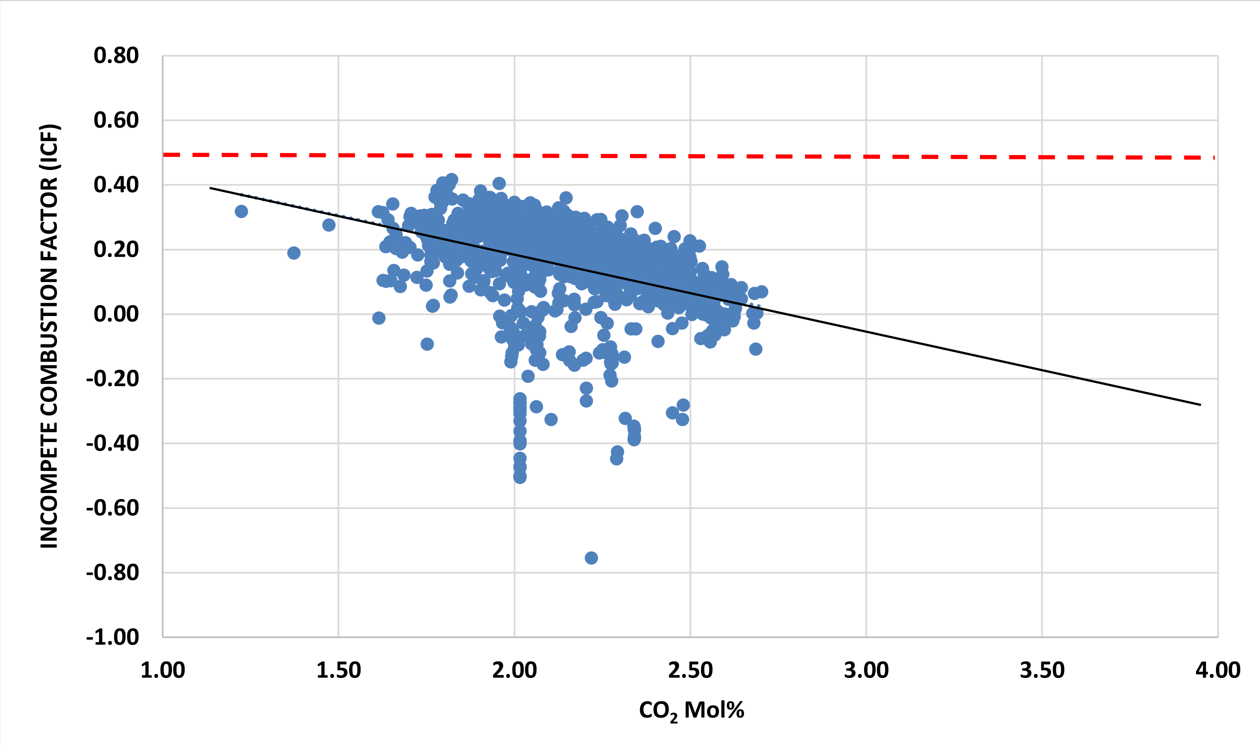
The data show slightly decreasing SI as CO_2 content increases. NTS gas specification has only an upper limit to SI so scatter below the upper limit is acceptable.



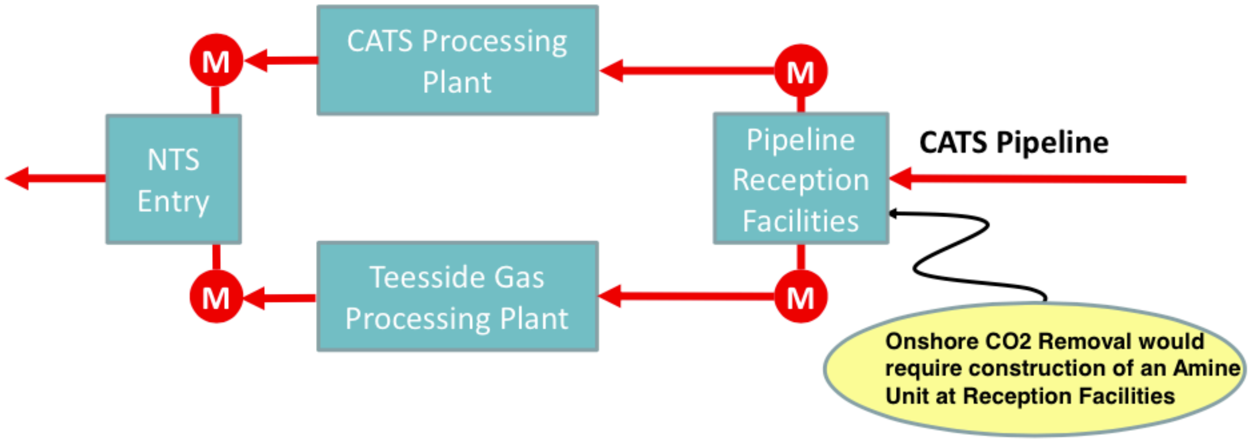
Moving from a CO_2 content of 2.9 mol% to 4 mol % results in a 0.01 reduction in SI.

Incomplete Combustion Factor (ICF)

The data for ICF show a similar scatter to that of SI. At 4 Mol% CO_2 the SI value would remain within the operational range recognised for CATS gas entering the NTS and well below the specification limit for NTS gas.



Appendix 5 - Teesside Schematic



Gas in dense phase is carried from offshore oil and gas fields to Teesside by the CATS Pipeline. The reception facilities contain flow & pressure control equipment, metering and H_2S & Hg guard beds. Gas is then processed in either the CATS terminal of Teesside Gas Processing Plant. Water and NGL is removed and NTS specification gas exported via metering equipment to the NTS entry points

Appendix 6 - CO_2 Impact Assessment

Summary

A carbon cost assessment has been calculated for the proposal. The least impact on CO_2 emissions from bringing gas with up to 4.0 mol% CO_2 content into the CATS system is for such gas to be allowed to flow into the NTS. Significantly more CO_2 is emitted by removing CO_2 from the gas due to the need for process heat to remove CO_2. The cost of installing an amine unit either at specific fields offshore or at the onshore terminals is considerable. Current estimates for the fully installed cost of an offshore amine unit is of the order of £200m (undiscounted). When this is taken into account, the mitigation cost increases significantly when compared to the costs to NTS gas consumers (including non ETS participants). On a tonnage basis the cost to an NTS gas consumer (both ETS and Non-ETS participants) is c. £20/te but the cost to mitigate the higher levels of CO_2 prior to gas entering the NTS could be over £1000/te.

Introduction

A carbon cost assessment has been calculated for the proposal. The impact assessment compares the tonnage of CO_2 released in order for the forecast gas landed at Teesside to meet the current 2.9 mol% CO_2 NTS entry specification and the cost of this CO_2 mitigation to the tonnages that would be released by downstream consumers if the Teesside NTS entry specification were to be raised to 4.0 mol% and such gas was not diluted by other NTS flows.

Three scenarios are therefore considered:

- Scenario 1 – Non-removal of CO_2, allowing flow at 4 mol% CO_2 into NTS when such gas cannot be blended with other CATS gas with lower CO2 content;
- Scenario 2 – Reduction of CO_2 Offshore with an amine unit installed on an offshore production platform to ensure all gas entering the CATS pipeline from the specific field meets the current 2.9 mol% specification; and,
- Scenario 3 – Reduction of CO_2 Onshore with an amine unit installed at the CATS Pipeline reception facilities on Teesside to ensure that gas entering the Teesside Gas Processing Plant or the CATS terminal meeting the current 2.9 mol% specification.

Whilst it is recognised that currently, there are certain circumstances when the CATS operator has curtailed or suspended flows from certain existing fields, these occurrences are difficult to model. In order to simplify the model the carbon impact assessment has been made for the period ~~2019~~ 2021 to ~~2030~~2032, 2019 being the earliest a field with elevated CO_2 levels such as Jackdaw might be anticipated to start.

Where gas with an elevated CO_2 content flows into the CATS pipeline (Scenarios 1 and 3) this gas will be commingled with other gas with lower CO_2 content. As a result, it is expected that for the majority of time the CO_2 content of gas entering the Teesside NTS entry points is likely to be below the current limit. Increases above the current limit are most likely to be during summer maintenance campaigns or for short periods of unplanned outages when field outages means that gas flows at Teesside will be lower than normal and low CO_2 content gas for blending gas may be restricted. For the purposes of modelling the CO_2 impact assessment, we have assumed that only Jackdaw would flow (using a representative flow profile) and that this period would be 30 days per year. As a result, for this period the CO_2 content of CATS gas has been assumed to be a maximum of 4 mol%. In reality we would expect this to be a worst case scenario. It is unlikely that Jackdaw would flow entirely on its own so some blending is likely to occur and therefore there a likely to be fewer days per year when CO_2 content is at the maximum assumed 4 mol%.

CO_2 Impact Assessment - Assumptions

The assumptions for the CO_2 impact assessment are detailed in the following table.

Current maximum CO_2 specification	2.9 mol%
Future maximum CO_2 specification	4 mol%. Commingled CATS flow likely to be lower No account taken of any blending of Teesside sourced gas with other gas of low CO_2 content in the NTS
Assessment period	~~2019~~ 2021 to ~~2030~~2032
Assessment basis	Calendar Year
Annual requirement for CO_2 removal	Scenario 1 – Non removal Scenario 2 – Reduction to 2.9 mol% 365 days/yr Scenario 3 – Reduction to 2.9 mol% 30 days/yr
Gas production profiles	Offshore - representative production from field operator Onshore – representative flows during summer maintenance days
Amine unit costs	Estimates from BP for fully installed systems
Amine unit efficiency	97%
Temperature required for stored amine when not in use	20^{o}C (manufacturer data)
Heating requirement for stored amine	3.7MW
Electricity, HC emissions	No account is taken of increased emissions from the electrical power required to operate CO_2 removal equipment or from emissions from burning hydrocarbons emitted during CO_2 removal
ETS Carbon Valuation	DECC Updated Energy & Emissions Projections - September 2014, 'Carbon Prices - Industry and Services' upto 2035 (2036+ Traded price equals non-traded price)
Carbon Valuation with Carbon Price Support	DECC Updated Energy & Emissions Projections - September 2014, 'Carbon Prices - Electricity Supply Sector' up to 2035 (2036+ inflated at 6% per year)
Carbon Valuation 'Non Traded'	DECC Appraisal Guide 2014, Table 1-20: supporting the toolkit and guidance - Central Prices
Total UK Forecast CO_2 Emissions	DECC Updated Energy & Emissions Projections - September 2014, Annex B Carbon Dioxide Emissions by Source
Emissions cost by User Group	Gas Usage split by gas demand Users (ETS, Carbon Support, non-ETS) – National Grid, Future-Energy-Scenarios pg.168
Net Present Value Discount Factor	All costs have been discounted using a 10% discount factor back to a start date of 1/1/15
Tax Assumptions	All capex, opex and emissions values are on a pre-tax basis

Analysis

The detailed analysis is shown in the accompanying tables and spreadsheet. The summary of the output of the analysis is shown in the following table:

Assessment of CO_2 Impact from Teesside Gas (2021-2032)	Scenario 1 NTS Delivery at 4 mol % CO_2	Scenario 2 Offshore CO_2 Reduction	Scenario 3 Onshore CO_2 Reduction
CO_2 Removed by Amine unit (4 mol% to 2.9 mol%) (te)	0	462,881	38,045
CO_2 in fuel gas consumed by Amine unit (te)	0	213,510	87,497
CO_2 above 2.9 mol% emitted by consumers (te)	38,045	0	0
Total additional CO_2 emissions (te)	**38,045**	**676,391**	**125,542**

Cost Assessment of CO_2 from Teesside Gas (2021-2032) (£ NVP10 1/1/15, Pre-tax basis)	Scenario 1 NTS Delivery at 4 mol % CO_2	Scenario 2 Offshore CO_2 Reduction	Scenario 3 Onshore CO_2 Reduction
CO_2 Total ETS Traded Cost	£23,416	£1,601,154	£299,936
CO_2 Total Traded Cost with Carbon Price Support	£158,001		
Total CO_2 Cost (Traded & Price Support)	**£181,417**	**£1,601,154**	**£299,936**
CO_2 Total Non-Traded Cost (£/yr) (non-ETS consumption)	£478,416	£0	£0
Total Estimated Emissions Cost	**£659,832**	**£1,601,154**	**£299,936**
Estimated Fully Installed Cost of Amine Unit		£106,685,573	£121,644,132
Estimated Abatement Cost for additional CO_2 prior to NTS entry		**£108,286,727**	**£121,944,068**
Cost per tonne (Emissions Cost/Total Additional Emssions)*	**£17**	**£160**	**£971**

* Includes capital costs for amine units

Conclusions ~~[to be reviewed by DO]~~

1. Over the life of the model (~~2019~~2021-~~2030~~2032), the least impact on overall CO_2 emissions from bringing gas with up to 4 mol% CO_2 content into the CATS system is for such gas to be allowed to flow into the NTS.

2. Significantly more CO_2 is emitted by removing CO_2 from the gas. This is due to the fact that CO_2 removal using amine requires process heat. The highest level of emissions is attributed to reduction of CO_2 offshore (676 kte) as a result of operation of an amine unit on the total field gas export stream each day of operation. Onshore reduction of CO_2 has lower CO_2 emissions (125 kte) as the unit would only be used on days when CO_2 levels are expected to be elevated. However this is still significantly higher than an NTS delivery scenario as, when not in use, amine is required to be stored at 20^{o}C to maintain its operational effectiveness and this requires further process heat and as noted in the assumptions there concerns by the vendor of the amine unit over the impact of thermal cycling on operational reliability of the amine unit.

3. It is usual for amine units to remain operational on small volumes of gas to ensure temperature stability to ensure reliability of unit. This would increase operational emissions from those noted in the model.

4. When considering the cost of emissions to ETS participants over the modelled period, transport of 4 mol% CO_2 gas onto the NTS remains the lowest cost option (£~~24K~~ 181k) while reduction of CO_2 content offshore is the highest cost option £1.~~69M~~ 60m due the continuous operation and the impact of the operational emissions. Removal of CO_2 onshore is less costly at £~~304K~~ 300k due to the reduced operation of the amine unit but is still more costly than 4 mol% gas entering the NTS on those occasions when such gas is not blended with other CATS gas.

5. If the cost of non-traded emissions is included (using the split of NTS gas usage calculated by DECC between consumers paying ETS charges, those paying emissions at the Carbon Price Support rate and those for which emissions are non-traded (largely domestic)) then the cost to consumers of the NTS gas from accepting gas with higher CO_2 content increases to £~~745K~~660k.

6. However, it can be argued that the calculated emissions cost for delivery of high CO_2 gas onto the NTS (Scenario 1) are at the high end of a range as the current mechanism for calculating emissions at ETS registered installations is made either using an average CO_2 assessment for a UK region or an installation specific CO_2 content, both of which are estimated using annual averages. Given that any gas with elevated CO_2 content entering the NTS from Teesside is likely to be blended with other NTS gas, the impact may be considered to have a limited geographical area therefore such gas will only have a limited impact on total overall emissions as the regional average assumptions for CO_2 content will remain unaffected.

7. If the provision of CO_2 removal equipment either offshore is considered to "abate" the additional CO_2 entering the NTS then the total cost of providing that "abatement " needs to be considered.

8. While the capex figures used here are high level estimates and would be refined with further design work it is estimated that the fully installed cost of an amine unit on an offshore platform would be in the region of £~~180M~~ 180m and the cost of an onshore unit would be of the order of £~~200M~~ 200m (Discounted at NPV10, these values equate to £~~129M~~ 107m and £122m~~47M~~ respectively).

9. Including the cost of the amine units brings the total NPV10 of mitigating the increased CO_2 – which may be in only excess of the current 2.9 mol% for 30 days per year and most likely less – to between £~~130m~~ 108m and £~~147m~~122m. In the worst case this is ~~over 200~~about 180 times more costly than the £~~745K~~ 660k estimated emissions cost if the CO_2 were to be delivered onto the NTS.

10. In tonnage terms, the cost of the additional CO_2 to a consumer of gas sourced from the NTS (both ETS payers and non-traded users of gas) is c. £~~20~~17/te, but the cost to mitigate the additional CO_2 either onshore or offshore could be over £~~1,000~~971/te due to the additional CO_2 created during the operation of the amine units to remove the additional CO_2.

CATS CO2 Impact Assessment (Amine Unit Capex Excluded)

	Total CO2 (Te)	NPV10	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total	Annual Average
Reference Data																				
Number of Days Terminals anticipate CO2 in excess of 2.9 Mol %							30	30	30	30	30	30	30	30	30	30	30	30		
Forecast CO2 content when in excess of 2.9 Mol%							4.0%	4.0%	4.0%	4.0%	4.0%	3.8%	3.6%	3.4%	3.4%	3.2%	3.2%	3.2%		
CO2 Emissions from warm Amine when unit not in use (Kg/hr)							718.51	718.51	718.51	718.51	718.51	718.51	718.51	718.51	718.51	718.51	718.51	718.51		
Carbon Valuation 'Traded' (£/te C02)							5	5	6	6	6	6	6	7	7	7	7	8		
Carbon Valuation 'Traded' with Carbon Price Support (£/te C02)							22	27	33	39	44	50	56	60	65	69	74	78		
Carbon Valuation 'Non Traded' (£/te C02)							66	67	68	69	70	71	72	73	74	75	77	78		
Gas Price (p/th)							58.00	60.29	62.57	64.86	67.15	69.44	71.73	72.54	73.35	74.10	75.11	76.37		**72**
Total UK Forecast C02 Emissions (MtC02)							370	349	339	329	324	317	306	300	296	292	296	293	6,609	**300**
Scenario 1 - NTS Delivery at 4mol%																				
Additional C02 emissions from 4mol% to 2.9mol% (te/C02)	38,045						2,675	4,547	4,637	4,637	4,637	4,043	3,121	2,586	2,200	1,873	1,635	1,457	**38,045**	**3,170**
Cost of 'Traded' emissions (£)		**£24,728**	-	-	-	-	3,586	6,324	6,687	6,936	7,194	6,505	5,209	4,477	3,949	3,487	3,158	2,918	**60,431**	**5,036**
Cost of 'Traded' emissions with Carbon Price Support (£)		**£161,371**	-	-	-	-	13,843	29,750	36,672	43,011	49,349	48,553	41,748	37,362	34,132	31,062	28,868	27,279	**421,628**	**35,136**
Total Cost of Traded & Traded with Price Support emissions (£)		**£186,099**	-	-	-	-	**17,429**	**36,073**	**43,360**	**49,947**	**56,543**	**55,058**	**46,957**	**41,838**	**38,081**	**34,549**	**32,026**	**30,196**	**482,059**	**40,172**
Cost of 'Non Traded' emissions (£)		**£559,424**	-	-	-	-	88,273	152,339	157,646	159,964	162,283	143,510	112,348	94,389	81,383	70,220	62,941	56,804	**1,342,099**	**111,842**
Total Cost of emissions (£)		**£745,523**	-	-	-	-	**105,702**	**188,412**	**201,006**	**209,911**	**218,826**	**198,568**	**159,305**	**136,227**	**119,464**	**104,769**	**94,966**	**87,001**	1,824,158	**152,013**
Scenario 2 - Offshore removal																				
Field Forecast Flow (mscfd)							153	259	264	264	264	229	178	147	125	106	93	82		
Field Forecast Flow (mscf/year)							55,725	94,695	96,455	96,455	96,455	83,511	65,000	53,505	45,586	38,871	33,824	30,053	**790,135**	**65,845**
C02 emissions from amine process to 2.9mol% content (te)	462,881						32,545	55,327	56,413	56,413	56,413	49,184	37,969	31,463	26,761	22,783	19,890	17,721	**462,881**	**38,573**
Additional C02 emissions from Amine unit fuel gas (te)	213,510						15,012	25,520	26,021	26,021	26,021	22,687	17,514	14,513	12,344	10,509	9,175	8,174	**213,510**	**17,792**
Total C02 emissions from Offshore removal (te)	676,391						47,557	80,847	82,434	82,434	82,434	71,871	55,483	45,976	39,105	33,291	29,065	25,895	**676,391**	**56,366**
Total cost of emissions (£)		**£1,690,905**	-	-	-	-	**245,238**	**432,408**	**457,285**	**474,288**	**491,923**	**444,838**	**356,177**	**306,115**	**270,049**	**238,451**	**215,920**	**199,524**	**4,132,216**	**344,351**
Scenario 3 - Onshore removal																				
Terminals Forecast Flow When Exceeding 2.9 mol% (mscfd)							153	259	264	264	264	229	178	147	125	106	93	82		
C02 emissions from amine process (4 mol% to 2.9mol% content (te)	38,045						2,675	4,547	4,637	4,637	4,637	4,043	3,121	2,586	2,200	1,873	1,635	1,457	**38,045**	**3,170**
Additional C02 emissions from Amine unit fuel gas (te)	17,549						1,234	2,098	2,139	2,139	2,139	1,865	1,439	1,193	1,015	864	754	672	**17,549**	**1,462**
Additional CO2 emissions from Amine when not in use (te)	69,948						5,829	5,829	5,829	5,829	5,829	5,829	5,829	5,829	5,829	5,829	5,829	5,829	**69,948**	**5,829**
Total C02 emissions from Onshore removal (te)	125,542						9,738	12,474	12,604	12,604	12,604	11,736	10,389	9,608	9,043	8,565	8,218	7,957	**125,542**	**10,462**
Total cost of emissions (£)		**£304,418**	-	-	-	-	**50,215**	**66,717**	**69,920**	**72,520**	**75,217**	**72,640**	**66,694**	**63,971**	**62,450**	**61,349**	**61,050**	**61,312**	**784,055**	**65,338**

CATS CO2 Impact Assessment (Amine Unit Capex Excluded)

	Total CO2 (Te)	NPV10	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total	Annual Average
Reference Data																						
Number of Days Terminals anticipate CO2 in excess of 2.9 Mol %									30	30	30	30	30	30	30	30	30	30	30	30		
Forecast CO2 content when in excess of 2.9 Mol%									4.0%	4.0%	4.0%	4.0%	4.0%	3.8%	3.6%	3.4%	3.4%	3.2%	3.2%	3.2%		
CO2 Emissions from warm Amine when unit not in use (Kg/hr)									718.51	718.51	718.51	718.51	718.51	718.51	718.51	718.51	718.51	718.51	718.51	718.51		
Carbon Valuation 'Traded' (£/te C02)			5	5	5	5	5	5	6	6	6	6	6	7	7	7	7	8	13	23		
Carbon Valuation 'Traded' with Carbon Price Support (£/te C02)			20	22	22	22	22	27	33	39	44	50	56	60	65	69	74	78	86	93		
Carbon Valuation 'Non Traded' (£/te C02)			62	63	64	65	66	67	68	69	70	71	72	73	74	75	77	78	85	92		
Gas Price (p/th)									58.00	60.29	62.57	64.86	67.15	69.44	71.73	72.54	73.35	74.10	75.11	76.37		**72**
Total UK Forecast C02 Emissions (MtC02)									370	349	339	329	324	317	306	300	296	292	296	293	6,609	**300**
Scenario 1 - NTS Delivery at 4mol%																						
Additional C02 emissions from 4mol% to 2.9mol% (te/C02)	38,045								2,675	4,547	4,637	4,637	4,637	4,043	3,121	2,586	2,200	1,873	1,635	1,457	**38,045**	**3,170**
Cost of 'Traded' emissions (£)		**£23,416**	-	-	-	-	-	-	3,858	6,803	7,194	7,461	7,739	6,998	5,603	4,816	4,248	3,751	5,737	8,521	**72,731**	**6,061**
Cost of 'Traded' emissions with Carbon Price Support (£)		**£168,042**	-	-	-	-	-	-	21,157	42,183	49,349	55,688	62,027	58,405	48,428	42,897	38,840	35,070	33,639	32,517	**520,201**	**43,350**
Total Cost of Traded & Traded with Price Support emissions (£)		**£191,458**	-	-	-	-	-	-	**25,015**	**48,986**	**56,543**	**63,150**	**69,766**	**65,404**	**54,031**	**47,712**	**43,088**	**38,821**	**39,377**	**41,039**	**592,932**	**49,411**
Cost of 'Non Traded' emissions (£)		**£478,416**	-	-	-	-	-	-	90,518	156,404	162,044	164,617	167,189	148,009	115,992	97,550	84,192	72,714	69,378	67,063	**1,395,668**	**116,306**
Total Cost of emissions (£)		**£669,874**	-	-	-	-	-	-	**115,533**	**205,389**	**218,588**	**227,766**	**236,954**	**213,413**	**170,023**	**145,262**	**127,280**	**111,535**	**108,755**	**108,102**	**1,988,600**	**165,717**
Scenario 2 - Offshore removal																						
Field Forecast Flow (mscfd)									153	259	264	264	264	229	178	147	125	106	93	82		
Field Forecast Flow (mscf/year)									55,725	94,695	96,455	96,455	96,455	83,511	65,000	53,505	45,586	38,871	33,824	30,053	**790,135**	**65,845**
C02 emissions from amine process to 2.9mol% content (te)	462,881								32,545	55,327	56,413	56,413	56,413	49,184	37,969	31,463	26,761	22,783	19,890	17,721	**462,881**	**38,573**
Additional C02 emissions from Amine unit fuel gas (te)	213,510								15,012	25,520	26,021	26,021	26,021	22,687	17,514	14,513	12,344	10,509	9,175	8,174	**213,510**	**17,792**
Total C02 emissions from Offshore removal (te)	676,391								47,557	80,847	82,434	82,434	82,434	71,871	55,483	45,976	39,105	33,291	29,065	25,895	**676,391**	**56,366**
Total cost of emissions (£)		**£1,601,154**	-	-	-	-	-	-	**263,814**	**465,161**	**491,923**	**510,214**	**529,184**	**478,533**	**383,156**	**329,302**	**290,505**	**256,513**	**392,313**	**582,692**	**4,973,309**	**414,442**
Scenario 3 - Onshore removal																						
Terminals Forecast Flow When Exceeding 2.9 mol% (mscfd)									153	259	264	264	264	229	178	147	125	106	93	82		
C02 emissions from amine process (4 mol% to 2.9mol% content (te)	38,045								2,675	4,547	4,637	4,637	4,637	4,043	3,121	2,586	2,200	1,873	1,635	1,457	**38,045**	**3,170**
Additional C02 emissions from Amine unit fuel gas (te)	17,549								1,234	2,098	2,139	2,139	2,139	1,865	1,439	1,193	1,015	864	754	672	**17,549**	**1,462**
Additional CO2 emissions from Amine when not in use (te)	69,948								5,829	5,829	5,829	5,829	5,829	5,829	5,829	5,829	5,829	5,829	5,829	5,829	**69,948**	**5,829**
Total C02 emissions from Onshore removal (te)	125,542								9,738	12,474	12,604	12,604	12,604	11,736	10,389	9,608	9,043	8,565	8,218	7,957	**125,542**	**10,462**
Total cost of emissions (£)		**£299,936**	-	-	-	-	-	-	**54,019**	**71,770**	**75,217**	**78,013**	**80,914**	**78,142**	**71,746**	**68,816**	**67,180**	**65,996**	**110,923**	**179,057**	**1,001,794**	**83,483**

CATS CO2 Full Cycle Cost/Benefit Analysis

	Total CO2 (Te)	NPV10	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total	Annual Average
Reference Data																				
Field Forecast export Flow (th/year)							590,761,403	1,003,907,057	1,022,564,639	1,022,564,639	1,022,564,639	885,340,417	689,091,121	567,229,096	483,272,579	412,084,603	358,584,168	318,603,522	**8,376,567,881**	**698,047,323**
Number of Days Terminals anticipate CO2 in excess of 2.9 Mol %							30	30	30	30	30	30	30	30	30	30	30	30		
Forecast CO2 content when in excess of 2.9 Mol%							4.0%	4.0%	4.0%	4.0%	4.0%	3.8%	3.6%	3.4%	3.4%	3.2%	3.2%	3.2%		
Carbon Valuation 'Traded' (£/te C02)							5	5	6	6	6	6	6	7	7	7	7	8		
Carbon Valuation 'Traded' with Carbon Price Support (£/te C02)							22	27	33	39	44	50	56	60	65	69	74	78		
Carbon Valuation 'Non Traded' (£/te C02)							66	67	68	69	70	71	72	73	74	75	77	78		
Gas Price (p/th)							58.00	60.29	62.57	64.86	67.15	69.44	71.73	72.54	73.35	74.10	75.11	76.37		**72**
Total UK Forecast C02 Emissions (MtC02)							370	349	339	329	324	317	306	300	296	292	296	293	6,609	**300**
Scenario 1 - NTS Delivery at 4mol%																				
Additional C02 emissions from 4mol% to 2.9mol% (te/C02)	38,045						2,675	4,547	4,637	4,637	4,637	4,043	3,121	2,586	2,200	1,873	1,635	1,457	**38,045**	**3,170**
Cost of 'Traded' emissions (£)		**£24,728**	-	-	-	-	3,586	6,324	6,687	6,936	7,194	6,505	5,209	4,477	3,949	3,487	3,158	2,918	**60,431**	**3,777**
Cost of 'Traded' emissions with Carbon Price Support (£)		**£161,371**	-	-	-	-	13,843	29,750	36,672	43,011	49,349	48,553	41,748	37,362	34,132	31,062	28,868	27,279	**421,628**	**26,352**
Total Cost of Traded & Traded with Price Support (£)		**£186,099**	-	-	-	-	**17,429**	**36,073**	**43,360**	**49,947**	**56,543**	**55,058**	**46,957**	**41,838**	**38,081**	**34,549**	**32,026**	**30,196**	**482,059**	**30,129**
Cost of 'Non Traded' emissions (£)		**£559,424**	-	-	-	-	88,273	152,339	157,646	159,964	162,283	143,510	112,348	94,389	81,383	70,220	62,941	56,804	**1,342,099**	**83,881**
Total Cost of emissions (£)		**£745,523**	-	-	-	-	**105,702**	**188,412**	**201,006**	**209,911**	**218,826**	**198,568**	**159,305**	**136,227**	**119,464**	**104,769**	**94,966**	**87,001**	**1,824,158**	**114,010**
Scenario 2 - Offshore removal																				
Field Forecast Flow (mscfd)							153	259	264	264	264	229	178	147	125	106	93	82		
Field Forecast Flow (mscf/year)							55,725	94,695	96,455	96,455	96,455	83,511	65,000	53,505	45,586	38,871	33,824	30,053	**790,135**	**65,845**
C02 emissions from amine process to 2.9mol% content (te)	462,881						32,545	55,327	56,413	56,413	56,413	49,184	37,969	31,463	26,761	22,783	19,890	17,721	**462,881**	**38,573**
Additional C02 emissions from Amine unit fuel gas (te)	213,510						15,012	25,520	26,021	26,021	26,021	22,687	17,514	14,513	12,344	10,509	9,175	8,174	**213,510**	**17,792**
Total C02 emissions from Offshore removal (te)	676,391						47,557	80,847	82,434	82,434	82,434	71,871	55,483	45,976	39,105	33,291	29,065	25,895	**676,391**	**56,366**
Capex of Amine unit (£)		£129,089,543	-	-	90,000,000	90,000,000	-	-	-	-	-	-	-	-	-	-	-	-	**180,000,000**	**11,250,000**
Total Cost of Emissions		£1,690,905	-	-	-	-	245,238	432,408	457,285	474,288	491,923	444,838	356,177	306,115	270,049	238,451	215,920	199,524	**4,132,216**	**258,264**
Total cost of emissions (£)		**£130,780,448**	**-**	**-**	**90,000,000**	**90,000,000**	**245,238**	**432,408**	**457,285**	**474,288**	**491,923**	**444,838**	**356,177**	**306,115**	**270,049**	**238,451**	**215,920**	**199,524**	**184,132,216**	**11,508,264**
Scenario 3 - Onshore removal																				
Terminals Forecast Flow When Exceeding 2.9 mol% (mscfd)							153	259	264	264	264	229	178	147	125	106	93	82	**2,165**	**180**
C02 emissions from amine process (4 mol% to 2.9mol% content (te)	38,045						2,675	4,547	4,637	4,637	4,637	4,043	3,121	2,586	2,200	1,873	1,635	1,457	**38,045**	**3,170**
Additional C02 emissions from Amine unit fuel gas (te)	17,549						1,234	2,098	2,139	2,139	2,139	1,865	1,439	1,193	1,015	864	754	672	**17,549**	**1,462**
Additional CO2 emissions from Amine when not in use (te)	69,948						5,829	5,829	5,829	5,829	5,829	5,829	5,829	5,829	5,829	5,829	5,829	5,829	**69,948**	**5,829**
Total CO2 emissions from Onshore removal (te)	125,542						9,738	12,474	12,604	12,604	12,604	11,736	10,389	9,608	9,043	8,565	8,218	7,957	**125,542**	**10,462**
Capex of Amine unit (£)		£147,189,400	-	50,000,000	50,000,000	100,000,000	-	-	-	-	-	-	-	-	-	-	-	-	**200,000,000**	**12,500,000**
Total Cost of Emissions		£304,418	-	-	-	-	50,215	66,717	69,920	72,520	75,217	72,640	66,694	63,971	62,450	61,349	61,050	61,312	**784,055**	**49,003**
Total cost of emissions (£)		**£147,493,817**	**-**	**50,000,000**	**50,000,000**	**100,000,000**	**50,215**	**66,717**	**69,920**	**72,520**	**75,217**	**72,640**	**66,694**	**63,971**	**62,450**	**61,349**	**61,050**	**61,312**	**200,784,055**	**12,549,003**

CATS CO2 Full Cycle Cost/Benefit Analysis

	Total CO2 (Te)	NPV10	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total	Annual Average
Reference Data																						
Field Forecast export Flow (th/year)									590,761,403	1,003,907,057	1,022,564,639	1,022,564,639	1,022,564,639	885,340,417	689,091,121	567,229,096	483,272,579	412,084,603	358,584,168	318,603,522	**8,376,567,881**	**698,047,323**
Number of Days Terminals anticipate CO2 in excess of 2.9 Mol %									30	30	30	30	30	30	30	30	30	30	30	30		
Forecast CO2 content when in excess of 2.9 Mol%									4.0%	4.0%	4.0%	4.0%	4.0%	3.8%	3.6%	3.4%	3.4%	3.2%	3.2%	3.2%		
Carbon Valuation 'Traded' (£/te C02)			5	5	5	5	5	5	6	6	6	6	6	7	7	7	7	8	13	23		
Carbon Valuation 'Traded' with Carbon Price Support (£/te C02)			20	22	22	22	22	27	33	39	44	50	56	60	65	69	74	78	86	93		
Carbon Valuation 'Non Traded' (£/te C02)			62	63	64	65	66	67	68	69	70	71	72	73	74	75	77	78	85	92		
Gas Price (p/th)									58.00	60.29	62.57	64.86	67.15	69.44	71.73	72.54	73.35	74.10	75.11	76.37		**72**
Total UK Forecast C02 Emissions (MtC02)									370	349	339	329	324	317	306	300	296	292	296	293	3,811	**300**
Scenario 1 - NTS Delivery at 4mol%																						
Additional C02 emissions from 4mol% to 2.9mol% (te/C02)	38,045								2,675	4,547	4,637	4,637	4,637	4,043	3,121	2,586	2,200	1,873	1,635	1,457	**38,045**	**3,170**
Cost of 'Traded' emissions (£)		**£23,416**	-	-	-	-	-	-	3,858	6,803	7,194	7,461	7,739	6,998	5,603	4,816	4,248	3,751	5,737	8,521	**72,731**	**4,041**
Cost of 'Traded' emissions with Carbon Price Support (£)		**£158,001**	-	-	-	-	-	-	21,157	42,183	49,349	55,688	62,027	58,405	48,428	42,897	38,840	35,070	5,296	7,866	**467,206**	**25,956**
Total Cost of Traded & Traded with Price Support (£)		**£181,417**	-	-	-	-	-	-	**25,015**	**48,986**	**56,543**	**63,150**	**69,766**	**65,404**	**54,031**	**47,712**	**43,088**	**38,821**	**11,033**	**16,387**	**539,937**	**29,996**
Cost of 'Non Traded' emissions (£)		**£478,416**	-	-	-	-	-	-	90,518	156,404	162,044	164,617	167,189	148,009	115,992	97,550	84,192	72,714	69,378	67,063	**1,395,668**	**77,537**
Total Cost of emissions (£)		**£659,832**	-	-	-	-	-	-	**115,533**	**205,389**	**218,588**	**227,766**	**236,954**	**213,413**	**170,023**	**145,262**	**127,280**	**111,535**	**80,411**	**83,451**	**1,935,605**	**107,534**
Scenario 2 - Offshore removal																						
Field Forecast Flow (mscfd)									153	259	264	264	264	229	178	147	125	106	93	82		
Field Forecast Flow (mscf/year)									55,725	94,695	96,455	96,455	96,455	83,511	65,000	53,505	45,586	38,871	33,824	30,053	**790,135**	**65,845**
C02 emissions from amine process to 2.9mol% content (te)	462,881								32,545	55,327	56,413	56,413	56,413	49,184	37,969	31,463	26,761	22,783	19,890	17,721	**462,881**	**38,573**
Additional C02 emissions from Amine unit fuel gas (te)	213,510								15,012	25,520	26,021	26,021	26,021	22,687	17,514	14,513	12,344	10,509	9,175	8,174	**213,510**	**17,792**
Total C02 emissions from Offshore removal (te)	676,391								47,557	80,847	82,434	82,434	82,434	71,871	55,483	45,976	39,105	33,291	29,065	25,895	**676,391**	**56,366**
Capex of Amine unit (£)		£106,685,573	-	-	-	-	90,000,000	90,000,000	-	-	-	-	-	-	-	-	-	-	-	-	**180,000,000**	**10,000,000**
Total Cost of Emissions		£1,601,154	-	-	-	-	-	-	263,814	465,161	491,923	510,214	529,184	478,533	383,156	329,302	290,505	256,513	392,313	582,692	**4,973,309**	**276,295**
Total cost of emissions (£)		**£108,286,727**	**-**	**-**	**-**	**-**	**90,000,000**	**90,000,000**	**263,814**	**465,161**	**491,923**	**510,214**	**529,184**	**478,533**	**383,156**	**329,302**	**290,505**	**256,513**	**392,313**	**582,692**	**184,973,309**	**10,276,295**
Scenario 3 - Onshore removal																						
Terminals Forecast Flow When Exceeding 2.9 mol% (mscfd)									153	259	264	264	264	229	178	147	125	106	93	82	**2,165**	**180**
C02 emissions from amine process (4 mol% to 2.9mol% content (te)	38,045								2,675	4,547	4,637	4,637	4,637	4,043	3,121	2,586	2,200	1,873	1,635	1,457	**38,045**	**3,170**
Additional C02 emissions from Amine unit fuel gas (te)	17,549								1,234	2,098	2,139	2,139	2,139	1,865	1,439	1,193	1,015	864	754	672	**17,549**	**1,462**
Additional CO2 emissions from Amine when not in use (te)	69,948								5,829	5,829	5,829	5,829	5,829	5,829	5,829	5,829	5,829	5,829	5,829	5,829	**69,948**	**5,829**
Total CO2 emissions from Onshore removal (te)	125,542								9,738	12,474	12,604	12,604	12,604	11,736	10,389	9,608	9,043	8,565	8,218	7,957	**125,542**	**10,462**
Capex of Amine unit (£)		£121,644,132	-	-	-	50,000,000	50,000,000	100,000,000	-	-	-	-	-	-	-	-	-	-	-	-	**200,000,000**	**11,111,111**
Total Cost of Emissions		£299,936	-	-	-	-	-	-	54,019	71,770	75,217	78,013	80,914	78,142	71,746	68,816	67,180	65,996	110,923	179,057	**1,001,794**	**55,655**
Total cost of emissions (£)		**£121,944,068**	**-**	**-**	**-**	**50,000,000**	**50,000,000**	**100,000,000**	**54,019**	**71,770**	**75,217**	**78,013**	**80,914**	**78,142**	**71,746**	**68,816**	**67,180**	**65,996**	**110,923**	**179,057**	**201,001,794**	**11,166,766**

Scenario 1 - NTS Delivery at 4 mol%

Case	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Full Field [MMSCFD]	153	259	264	264	264	229	178	147	125	106	93	82
Full Field [kSm^3/hr]	180.1	306.1	311.8	311.8	311.8	270.0	210.1	173.0	147.4	125.6	109.3	97.1
Calculation of CO2 above 2.89 mol% delivered to NTS												
CO2 Content In [mol%]	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
CO2 Content Out [mol%]	2.89%	2.89%	2.89%	2.89%	2.89%	2.88%	2.89%	2.88%	2.88%	2.89%	2.88%	2.88%
CO2 Removal Unit Flow [MMSCFD]	43.7	74.3	75.7	75.7	75.7	66.0	51.0	42.2	35.9	30.6	26.7	23.8
CO2 Removal Unit Flow [kSm^3/hr]	51.5	87.6	89.3	89.3	89.3	77.9	60.1	49.8	42.4	36.1	31.5	28.1
CO2 Content Exit Unit [ppm]	1249	1249	1249	1249	1249	1249	1249	1249	1249	1249	1249	1249
Removal Unit Efficiency [%]	97%	97%	97%	97%	97%	97%	97%	97%	97%	97%	97%	97%
Quantities of CO2 removed [kg/hr]	3,715	6,316	6,440	6,440	6,440	5,615	4,334	3,592	3,055	2,601	2,271	2,023
Quantities of CO2 removed [te 30 days per annum]	2,675	4,547	4,637	4,637	4,637	4,043	3,121	2,586	2,200	1,873	1,635	1,457
CO2 Molecular Weight [kmol/kg]	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01
Additional CO2 for Scenario 1 [te 30 days per annum]	2,675	4,547	4,637	4,637	4,637	4,043	3,121	2,586	2,200	1,873	1,635	1,457

Emission
38,045

Scenario 1 - NTS Delivery at 4 mol%

Case	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Full Field [MMSCFD]	153	259	264	264	264	229	178	147	125	106	93	82
Full Field [kSm^3/hr]	180.1	306.1	311.8	311.8	311.8	270.0	210.1	173.0	147.4	125.6	109.3	97.1
Calculation of CO2 above 2.89 mol% delivered to NTS												
CO2 Content In [mol%]	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
CO2 Content Out [mol%]	2.89%	2.89%	2.89%	2.89%	2.89%	2.88%	2.89%	2.88%	2.88%	2.89%	2.88%	2.88%
CO2 Removal Unit Flow [MMSCFD]	43.7	74.3	75.7	75.7	75.7	66.0	51.0	42.2	35.9	30.6	26.7	23.8
CO2 Removal Unit Flow [kSm^3/hr]	51.5	87.6	89.3	89.3	89.3	77.9	60.1	49.8	42.4	36.1	31.5	28.1
CO2 Content Exit Unit [ppm]	1249	1249	1249	1249	1249	1249	1249	1249	1249	1249	1249	1249
Removal Unit Efficiency [%]	97%	97%	97%	97%	97%	97%	97%	97%	97%	97%	97%	97%
Quantities of CO2 removed [kg/hr]	3,715	6,316	6,440	6,440	6,440	5,615	4,334	3,592	3,055	2,601	2,271	2,023
Quantities of CO2 removed [te 30 days per annum]	2,675	4,547	4,637	4,637	4,637	4,043	3,121	2,586	2,200	1,873	1,635	1,457
CO2 Molecular Weight [kmol/kg]	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01
Additional CO2 for Scenario 1 [te 30 days per annum]	2,675	4,547	4,637	4,637	4,637	4,043	3,121	2,586	2,200	1,873	1,635	1,457

Emission
38,045

Scenario 2 - Offshore CO2 Removal

Case	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Emissions
Full Field [MMSCFD]	153	259	264	264	264	229	178	147	125	106	93	82	
Full Field [kSm^3/hr]	180.1	306.1	311.8	311.8	311.8	270.0	210.1	173.0	147.4	125.6	109.3	97.1	
CO2 Content In [mol%]	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	
CO2 Content Out [mol%]	2.89%	2.89%	2.89%	2.89%	2.89%	2.88%	2.89%	2.88%	2.88%	2.89%	2.88%	2.88%	
Calculation of CO2 Removal to meet 2.89 mol% spec													
CO2 Removal Unit Flow [MMSCFD]	43.7	74.3	75.7	75.7	75.7	66.0	51.0	42.2	35.9	30.6	26.7	23.8	
CO2 Removal Unit Flow [kSm^3/hr]	51.5	87.6	89.3	89.3	89.3	77.9	60.1	49.8	42.4	36.1	31.5	28.1	
CO2 Content Exit Unit [ppm]	1249	1249	1249	1249	1249	1249	1249	1249	1249	1249	1249	1249	
Removal Unit Efficiency [%]	97%	97%	97%	97%	97%	97%	97%	97%	97%	97%	97%	97%	
Quantities of CO2 removed [kg/hr]	3,715	6,316	6,440	6,440	6,440	5,615	4,334	3,592	3,055	2,601	2,271	2,023	
Quantities of CO2 removed [te per annum]	32,545	55,327	56,413	56,413	56,413	49,184	37,969	31,463	26,761	22,783	19,890	17,721	
CO2 Molecular Weight [kmol/kg]	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	
Quantities of Hydrocarbons (assumed 1 mol%) [kg/hr]	13.54	23.02	23.48	23.48	23.48	20.47	15.80	13.09	11.14	9.48	8.28	7.37	
Methane Molecular Weight [kmol/kg]	16.04	16.04	16.04	16.04	16.04	16.04	16.04	16.04	16.04	16.04	16.04	16.04	
Quantities of VOC removed (assumed as 500 ppm) [kg/hr]	3.30	5.60	5.71	5.71	5.71	4.98	3.85	3.19	2.71	2.31	2.01	1.80	
Benzene Molecular Weight [kmol/kg]	78.11	78.11	78.11	78.11	78.11	78.11	78.11	78.11	78.11	78.11	78.11	78.11	
Amine Unit Operational Data & Calcs	MEA	MEA	MEA	MEA	MEA	MEA	MEA	MEA	MEA	MEA	MEA	MEA	
Gas Flowrate [MMSCFD]	43.68675	74.26781	75.72496	75.72496	75.72496	66.02211	50.96799	42.23395	35.92241	30.58201	26.69963	23.78772	
Sour Gas Processed, Q [MSm^3/day]	1.24	2.10	2.14	2.14	2.14	1.87	1.44	1.20	1.02	0.87	0.76	0.67	
Contactor Pressure, P [kPa abs]	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	
Acid Gas Conc^n, y [mole%]	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	
Amine Concn, x [mass%]	20	20	20	20	20	20	20	20	20	20	20	20	
mol acid gas pick-up per mol amine	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	
Amine Flow, [m^3/hr]	86.84	147.63	150.52	150.52	150.52	131.24	101.31	83.95	71.41	60.79	53.07	47.28	
Amine Flow, [m^3/d]	2084.14	3543.05	3612.57	3612.57	3612.57	3149.68	2431.50	2014.83	1713.73	1458.96	1273.74	1134.83	
Amine Flow, [GPM]	382.34	649.98	662.74	662.74	662.74	577.82	446.07	369.63	314.39	267.65	233.67	208.19	
Amine Contactor Diameter, Dc [mm]	1140	1486	1501	1501	1501	1401	1231	1121	1034	954	891	841	
Calculation of CO2 Emission from Fuel Gas Usage in Amine Unit													
Absorbed Reboiler Duty [MW]	8.08	13.73	14.00	14.00	14.00	12.21	9.42	7.81	6.64	5.65	4.94	4.40	
Heater Duty [MW]	8.97	15.25	15.55	15.55	15.55	13.56	10.47	8.67	7.38	6.28	5.48	4.89	
Thermal Efficiency at 90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	
Fuel Gas HHV [MJ/kg]	49.494	49.494	49.494	49.494	49.494	49.494	49.494	49.494	49.494	49.494	49.494	49.494	
Fuel Gas Requirement [kg/hr]	653	1110	1131	1131	1131	986	761	631	537	457	399	355	
CO2 Emissions Factor [kg CO2 per kg FG]	2.626	2.626	2.626	2.626	2.626	2.626	2.626	2.626	2.626	2.626	2.626	2.626	
CO2 Formed from Amine Unit FG [kg/hr]	1714	2913	2970	2970	2970	2590	1999	1657	1409	1200	1047	933	
CO2 Formed from Amine Unit FG [te per annum]	15,012	25,520	26,021	26,021	26,021	22,687	17,514	14,513	12,344	10,509	9,175	8,174	
Additional CO2 Emissions for Scenario 2 [te per annum]	47,557	80,847	82,434	82,434	82,434	71,871	55,483	45,976	39,105	33,291	29,065	25,895	**676,391**

Scenario 2 - Offshore CO2 Removal

Case	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Full Field [MMSCFD]	153	259	264	264	264	229	178	147	125	106	93	82
Full Field [kSm^3/hr]	180.1	306.1	311.8	311.8	311.8	270.0	210.1	173.0	147.4	125.6	109.3	97.1
CO2 Content In [mol%]	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
CO2 Content Out [mol%]	2.89%	2.89%	2.89%	2.89%	2.89%	2.88%	2.89%	2.88%	2.88%	2.89%	2.88%	2.88%
Calculation of CO2 Removal to meet 2.89 mol% spec												
CO2 Removal Unit Flow [MMSCFD]	43.7	74.3	75.7	75.7	75.7	66.0	51.0	42.2	35.9	30.6	26.7	23.8
CO2 Removal Unit Flow [kSm^3/hr]	51.5	87.6	89.3	89.3	89.3	77.9	60.1	49.8	42.4	36.1	31.5	28.1
CO2 Content Exit Unit [ppm]	1249	1249	1249	1249	1249	1249	1249	1249	1249	1249	1249	1249
Removal Unit Efficiency [%]	97%	97%	97%	97%	97%	97%	97%	97%	97%	97%	97%	97%
Quantities of CO2 removed [kg/hr]	3,715	6,316	6,440	6,440	6,440	5,615	4,334	3,592	3,055	2,601	2,271	2,023
Quantities of CO2 removed [te per annum]	32,545	55,327	56,413	56,413	56,413	49,184	37,969	31,463	26,761	22,783	19,890	17,721
CO2 Molecular Weight [kmol/kg]	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01
Quantities of Hydrocarbons (assumed 1 mol%) [kg/hr]	13.54	23.02	23.48	23.48	23.48	20.47	15.80	13.09	11.14	9.48	8.28	7.37
Methane Molecular Weight [kmol/kg]	16.04	16.04	16.04	16.04	16.04	16.04	16.04	16.04	16.04	16.04	16.04	16.04
Quantities of VOC removed (assumed as 500 ppm) [kg/hr]	3.30	5.60	5.71	5.71	5.71	4.98	3.85	3.19	2.71	2.31	2.01	1.80
Benzene Molecular Weight [kmol/kg]	78.11	78.11	78.11	78.11	78.11	78.11	78.11	78.11	78.11	78.11	78.11	78.11
Amine Unit Operational Data & Calcs	MEA	MEA	MEA	MEA	MEA	MEA	MEA	MEA	MEA	MEA	MEA	MEA
Gas Flowrate [MMSCFD]	43.68675	74.26781	75.72496	75.72496	75.72496	66.02211	50.96799	42.23395	35.92241	30.58201	26.69963	23.78772
Sour Gas Processed, Q [MSm^3/day]	1.24	2.10	2.14	2.14	2.14	1.87	1.44	1.20	1.02	0.87	0.76	0.67
Contactor Pressure, P [kPa abs]	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33
Acid Gas Conc^n, y [mole%]	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033
Amine Concn, x [mass%]	20	20	20	20	20	20	20	20	20	20	20	20
mol acid gas pick-up per mol amine	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33
Amine Flow, [m^3/hr]	86.84	147.63	150.52	150.52	150.52	131.24	101.31	83.95	71.41	60.79	53.07	47.28
Amine Flow, [m^3/d]	2084.14	3543.05	3612.57	3612.57	3612.57	3149.68	2431.50	2014.83	1713.73	1458.96	1273.74	1134.83
Amine Flow, [GPM]	382.34	649.98	662.74	662.74	662.74	577.82	446.07	369.63	314.39	267.65	233.67	208.19
Amine Contactor Diameter, Dc [mm]	1140	1486	1501	1501	1501	1401	1231	1121	1034	954	891	841
Calculation of CO2 Emission from Fuel Gas Usage in Amine Unit												
Absorbed Reboiler Duty [MW]	8.08	13.73	14.00	14.00	14.00	12.21	9.42	7.81	6.64	5.65	4.94	4.40
Heater Duty [MW]	8.97	15.25	15.55	15.55	15.55	13.56	10.47	8.67	7.38	6.28	5.48	4.89
Thermal Efficiency at 90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%
Fuel Gas HHV [MJ/kg]	49.494	49.494	49.494	49.494	49.494	49.494	49.494	49.494	49.494	49.494	49.494	49.494
Fuel Gas Requirement [kg/hr]	653	1110	1131	1131	1131	986	761	631	537	457	399	355
CO2 Emissions Factor [kg CO2 per kg FG]	2.626	2.626	2.626	2.626	2.626	2.626	2.626	2.626	2.626	2.626	2.626	2.626
CO2 Formed from Amine Unit FG [kg/hr]	1714	2913	2970	2970	2970	2590	1999	1657	1409	1200	1047	933
CO2 Formed from Amine Unit FG [te per annum]	15,012	25,520	26,021	26,021	26,021	22,687	17,514	14,513	12,344	10,509	9,175	8,174

													Emissions
Additional CO2 Emissions for Scenario 2 [te per annum]	47,557	80,847	82,434	82,434	82,434	71,871	55,483	45,976	39,105	33,291	29,065	25,895	**676,391**

Scenario 3 - Onshore CO2 Removal

Case	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Full Field [MMSCFD]	153	259	264	264	264	229	178	147	125	106	93	82
Full Field [kSm^3/hr]	180.1	306.1	311.8	311.8	311.8	270.0	210.1	173.0	147.4	125.6	109.3	97.1
CO2 Content In [mol%]	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
CO2 Content Out [mol%]	2.89%	2.89%	2.89%	2.89%	2.89%	2.88%	2.89%	2.88%	2.88%	2.89%	2.88%	2.88%
Calculation of CO2 Removal to meet 2.89 mol% spec												
CO2 Removal Unit Flow [MMSCFD]	43.7	74.3	75.7	75.7	75.7	66.0	51.0	42.2	35.9	30.6	26.7	23.8
CO2 Removal Unit Flow [kSm^3/hr]	51.5	87.6	89.3	89.3	89.3	77.9	60.1	49.8	42.4	36.1	31.5	28.1
CO2 Content Exit Unit [ppm]	1249	1249	1249	1249	1249	1249	1249	1249	1249	1249	1249	1249
Removal Unit Efficiency [%]	97%	97%	97%	97%	97%	97%	97%	97%	97%	97%	97%	97%
Quantities of CO2 removed [kg/hr]	3,715	6,316	6,440	6,440	6,440	5,615	4,334	3,592	3,055	2,601	2,271	2,023
Quantities of CO2 removed [te 30 days per annum]	2,675	4,547	4,637	4,637	4,637	4,043	3,121	2,586	2,200	1,873	1,635	1,457
CO2 Molecular Weight [kmol/kg]	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01
Quantities of Hydrocarbons (assumed 1 mol%) [kg/hr]	13.54	23.02	23.48	23.48	23.48	20.47	15.80	13.09	11.14	9.48	8.28	7.37
Methane Molecular Weight [kmol/kg]	16.04	16.04	16.04	16.04	16.04	16.04	16.04	16.04	16.04	16.04	16.04	16.04
Quantities of VOC removed (assumed as 500 ppm) [kg/hr]	3.30	5.60	5.71	5.71	5.71	4.98	3.85	3.19	2.71	2.31	2.01	1.80
Benzene Molecular Weight [kmol/kg]	78.11	78.11	78.11	78.11	78.11	78.11	78.11	78.11	78.11	78.11	78.11	78.11
Amine Unit Operational Data & Calcs	MEA	MEA	MEA	MEA	MEA	MEA	MEA	MEA	MEA	MEA	MEA	MEA
Gas Flowrate [MMSCFD]	43.6867471	74.26781	75.72496	75.72496	75.72496	66.02211	50.96799	42.23395	35.92241	30.58201	26.69963	23.78772
Sour Gas Processed, Q [MSm^3/day]	1.24	2.10	2.14	2.14	2.14	1.87	1.44	1.20	1.02	0.87	0.76	0.67
Contactor Pressure, P [kPa abs]	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33
Acid Gas Conc^n, y [mole%]	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033
Amine Concn, x [mass%]	20	20	20	20	20	20	20	20	20	20	20	20
mol acid gas pick-up per mol amine	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33
Amine Flow, [m^3/hr]	86.84	147.63	150.52	150.52	150.52	131.24	101.31	83.95	71.41	60.79	53.07	47.28
Amine Flow, [m^3/d]	2084.14	3543.05	3612.57	3612.57	3612.57	3149.68	2431.50	2014.83	1713.73	1458.96	1273.74	1134.83
Amine Flow, [GPM]	382.34	649.98	662.74	662.74	662.74	577.82	446.07	369.63	314.39	267.65	233.67	208.19
Amine Contactor Diameter, Dc [mm]	1140	1486	1501	1501	1501	1401	1231	1121	1034	954	891	841
Calculation of CO2 Emission from Fuel Gas Usage in Amine Unit												
Absorbed Reboiler Duty [MW]	8.08	13.73	14.00	14.00	14.00	12.21	9.42	7.81	6.64	5.65	4.94	4.40
Heater Duty [MW]	8.97	15.25	15.55	15.55	15.55	13.56	10.47	8.67	7.38	6.28	5.48	4.89
Thermal Efficiency at 90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%
Fuel Gas HHV [MJ/kg]	49.494	49.494	49.494	49.494	49.494	49.494	49.494	49.494	49.494	49.494	49.494	49.494
Fuel Gas Requirement [kg/hr]	653	1110	1131	1131	1131	986	761	631	537	457	399	355
CO2 Emissions Factor [kg CO2 per kg FG]	2.626	2.626	2.626	2.626	2.626	2.626	2.626	2.626	2.626	2.626	2.626	2.626
CO2 Formed from Amine Unit Fuel Gas [kg/hr]	1714	2913	2970	2970	2970	2590	1999	1657	1409	1200	1047	933
CO2 Formed from Amine Unit Fuel Gas [te (30 days)]	1,234	2,098	2,139	2,139	2,139	1,865	1,439	1,193	1,015	864	754	672
Calculation of CO2 Emissions from Fuel Gas Usage for Amine Standby												
Heater Duty for amine heating when non-operational [MW]	3.664	3.664	3.664	3.664	3.664	3.664	3.664	3.664	3.664	3.664	3.664	3.664
FG Requirement for non-operational Amine Unit (kg/hr)	276.000	276.000	276.000	276.000	276.000	276.000	276.000	276.000	276.000	276.000	276.000	276.000
CO2 Formed in Standby Mode [kg/hr]	725.000	725.000	725.000	725.000	725.000	725.000	725.000	725.000	725.000	725.000	725.000	725.000
CO2 Formed in Standby Mode [te per annum (335 days)]	5,829	5,829	5,829	5,829	5,829	5,829	5,829	5,829	5,829	5,829	5,829	5,829

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	**Emissions**
Additional CO2 emissions Scenario 3 [te per annum]	**9,738**	**12,474**	**12,604**	**12,604**	**12,604**	**11,736**	**10,389**	**9,608**	**9,043**	**8,565**	**8,218**	**7,957**	**125,542**

Scenario 3 - Onshore CO2 Removal

Case	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Full Field [MMSCFD]	153	259	264	264	264	229	178	147	125	106	93	82
Full Field [kSm^3/hr]	180.1	306.1	311.8	311.8	311.8	270.0	210.1	173.0	147.4	125.6	109.3	97.1
CO2 Content In [mol%]	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
CO2 Content Out [mol%]	2.89%	2.89%	2.89%	2.89%	2.89%	2.88%	2.89%	2.88%	2.88%	2.89%	2.88%	2.88%
Calculation of CO2 Removal to meet 2.89 mol% spec												
CO2 Removal Unit Flow [MMSCFD]	43.7	74.3	75.7	75.7	75.7	66.0	51.0	42.2	35.9	30.6	26.7	23.8
CO2 Removal Unit Flow [kSm^3/hr]	51.5	87.6	89.3	89.3	89.3	77.9	60.1	49.8	42.4	36.1	31.5	28.1
CO2 Content Exit Unit [ppm]	1249	1249	1249	1249	1249	1249	1249	1249	1249	1249	1249	1249
Removal Unit Efficiency [%]	97%	97%	97%	97%	97%	97%	97%	97%	97%	97%	97%	97%
Quantities of CO2 removed [kg/hr]	3,715	6,316	6,440	6,440	6,440	5,615	4,334	3,592	3,055	2,601	2,271	2,023
Quantities of CO2 removed [te 30 days per annum]	2,675	4,547	4,637	4,637	4,637	4,043	3,121	2,586	2,200	1,873	1,635	1,457
CO2 Molecular Weight [kmol/kg]	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01
Quantities of Hydrocarbons (assumed 1 mol%) [kg/hr]	13.54	23.02	23.48	23.48	23.48	20.47	15.80	13.09	11.14	9.48	8.28	7.37
Methane Molecular Weight [kmol/kg]	16.04	16.04	16.04	16.04	16.04	16.04	16.04	16.04	16.04	16.04	16.04	16.04
Quantities of VOC removed (assumed as 500 ppm) [kg/hr]	3.30	5.60	5.71	5.71	5.71	4.98	3.85	3.19	2.71	2.31	2.01	1.80
Benzene Molecular Weight [kmol/kg]	78.11	78.11	78.11	78.11	78.11	78.11	78.11	78.11	78.11	78.11	78.11	78.11
Amine Unit Operational Data & Calcs	MEA	MEA	MEA	MEA	MEA	MEA	MEA	MEA	MEA	MEA	MEA	MEA
Gas Flowrate [MMSCFD]	43.6867471	74.26781	75.72496	75.72496	75.72496	66.02211	50.96799	42.23395	35.92241	30.58201	26.69963	23.78772
Sour Gas Processed, Q [MSm^3/day]	1.24	2.10	2.14	2.14	2.14	1.87	1.44	1.20	1.02	0.87	0.76	0.67
Contactor Pressure, P [kPa abs]	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33
Acid Gas Conc^n, y [mole%]	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033
Amine Concn, x [mass%]	20	20	20	20	20	20	20	20	20	20	20	20
mol acid gas pick-up per mol amine	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33
Amine Flow, [m^3/hr]	86.84	147.63	150.52	150.52	150.52	131.24	101.31	83.95	71.41	60.79	53.07	47.28
Amine Flow, [m^3/d]	2084.14	3543.05	3612.57	3612.57	3612.57	3149.68	2431.50	2014.83	1713.73	1458.96	1273.74	1134.83
Amine Flow, [GPM]	382.34	649.98	662.74	662.74	662.74	577.82	446.07	369.63	314.39	267.65	233.67	208.19
Amine Contactor Diameter, Dc [mm]	1140	1486	1501	1501	1501	1401	1231	1121	1034	954	891	841
Calculation of CO2 Emission from Fuel Gas Usage in Amine Unit												
Absorbed Reboiler Duty [MW]	8.08	13.73	14.00	14.00	14.00	12.21	9.42	7.81	6.64	5.65	4.94	4.40
Heater Duty [MW]	8.97	15.25	15.55	15.55	15.55	13.56	10.47	8.67	7.38	6.28	5.48	4.89
Thermal Efficiency at 90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%
Fuel Gas HHV [MJ/kg]	49.494	49.494	49.494	49.494	49.494	49.494	49.494	49.494	49.494	49.494	49.494	49.494
Fuel Gas Requirement [kg/hr]	653	1110	1131	1131	1131	986	761	631	537	457	399	355
CO2 Emissions Factor [kg CO2 per kg FG]	2.626	2.626	2.626	2.626	2.626	2.626	2.626	2.626	2.626	2.626	2.626	2.626
CO2 Formed from Amine Unit Fuel Gas [kg/hr]	1714	2913	2970	2970	2970	2590	1999	1657	1409	1200	1047	933
CO2 Formed from Amine Unit Fuel Gas [te (30 days)]	1,234	2,098	2,139	2,139	2,139	1,865	1,439	1,193	1,015	864	754	672
Calculation of CO2 Emissions from Fuel Gas Usage for Amine Standby												
Heater Duty for amine heating when non-operational [MW]	3.664	3.664	3.664	3.664	3.664	3.664	3.664	3.664	3.664	3.664	3.664	3.664
FG Requirement for non-operational Amine Unit (kg/hr)	276.000	276.000	276.000	276.000	276.000	276.000	276.000	276.000	276.000	276.000	276.000	276.000
CO2 Formed in Standby Mode [kg/hr]	725.000	725.000	725.000	725.000	725.000	725.000	725.000	725.000	725.000	725.000	725.000	725.000
CO2 Formed in Standby Mode [te per annum (335 days)]	5,829	5,829	5,829	5,829	5,829	5,829	5,829	5,829	5,829	5,829	5,829	5,829
Additional CO2 emissions Scenario 3 [te per annum]	**9,738**	**12,474**	**12,604**	**12,604**	**12,604**	**11,736**	**10,389**	**9,608**	**9,043**	**8,565**	**8,218**	**7,957**

Emissions
125,542

10 Glossary

ASEP	Aggregated System Entry Point *(where more than one entry point exists)*
BG	BG Group plc
BSi	British Standards Institute
Capex	Capital Expenditure
CATS	Central Area Transmission System *(ie from the UK Continental Shelf)*
CCGT	Combined Cycle Gas Turbine *(a gas-fired electricity generation unit)*
CEN	European Committee for Standardisation
CH_4	Methane
CO_2	Carbon Dioxide
CV	Calorific Value
EU ETS	EU Emissions Trading System *(multi-country, multi-sector greenhouse gas emissions trading system, see* https://www.gov.uk/participating-in-the-eu-ets.*)*
FEED	Front End Engineering Design
FES	Future Energy Supply *(document, available on nationalgrid.com)*
GSMR	Gas Safety (Management) Regulations
GSOG	Gas Storage Operators Group
H_2S	Hydrogen Sulphide
ICF	Incomplete Combustion Factor
kte	Kilo tonnes equivalent *(thousands of tonnes equivalent)*
MERUK	Maximisation of Economic Recovery of oil and gas from the UK continental shelf
mol%	Mole % *(a measure of the constituents in a mixture)*
NEA	Network Entry Agreement
NOX	Generic term for mono-nitrogen oxides (nitric oxide and nitrogen dioxide)
NPV10	Net Present Value discounted at 10%
OEM	Original Equipment Manufacturer
RE	Reasonable Endeavours
SEP	(NTS) System Entry Point
SI	Soot Index
SSO	Storage System Operator
te	Tonnes equivalent
TEG/MEG	Tri- and mono- ethylene glycols *(commonly used in dewatering applications)*
uHPHT	ultra-High Pressure High Temperature
VOC	Volatile Organic Compounds
WI	Wobbe Index *(an indicator of the interchangeability of gas)*