Joint Office of Gas Transporters

UNC Workgroup Report

At what stage is this document in the process?

01 Modification

02 Workgroup Report

03 Draft Modification Report

04 Final Modification Report

UNC 0607S:

Amendment to Gas Quality NTS Entry Specification at the St Fergus NSMP System Entry Point

Purpose of Modification:

This enabling modification will facilitate a change to the current contractual Carbon Dioxide limit at the St Fergus NSMP System Entry Point, through modification of a Network Entry Provision contained within the Network Entry Agreement (NEA) between National Grid Gas plc and North Sea Midstream Partners Limited (NSMP) in respect of the St Fergus NSMP Sub Terminal.

The Workgroup recommends that this modification should: *(delete as appropriate)*

- be subject to self-governance procedures
- be [further] assessed by a Workgroup
- proceed to Consultation

The Panel will consider this Workgroup Report on [15 June 2017]. The Panel will consider the recommendations and determine the appropriate next steps.

High Impact: None

Medium Impact: None

Low Impact: Transporters, Shippers and Consumers

Contents

Timetable

Modification timetable:	
Initial consideration by Workgroup	05 January 2017
Amended Modification considered by Workgroup	dd month year
Workgroup Report presented to Panel	15 June 2017
Draft Modification Report issued for consultation	15 June 2017
Consultation Close-out for representations	dd month year
Final Modification Report available for Panel	dd month year
Modification Panel decision	dd month year

Any questions?

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1 Summary

What

This is an enabling modification that seeks to facilitate an increase in the carbon dioxide limit with the Network Entry Agreement (NEA) at the North Sea Midstream Partners (NSMP) sub-terminal at St. Fergus between National Grid Gas plc and NSMP Ltd. It is proposed to increase the limit from 4mol% to 5.5mol%.

Why

The Rhum gas field can be up to 6.5mol% CO_2, the effects of which are mitigated via blending with low CO_2 gas from Norway to St Fergus via the Vesterled Pipeline. This is not sustainable due to the prohibitive cost of procuring this service from Norwegian shippers, potentially leading to the early cessation of production from Rhum and Bruce fields.

The alternative processing and treatment solutions to remove the excess carbon dioxide have been considered upstream of the NTS (both offshore and onshore at the NSMP sub-terminal), however these would require significant investment and time to implement. Rhum would become cash negative and cease production before any project became operational.

How

In accordance with the UNC Transportation Principal Document Section I 2.2.3 (a), the Proposer is seeking to amend the NEA described above via this enabling modification. On satisfactory completion of the UNC process the parties to the NEA will be able to seek Authority consent to amend the agreement.

2 Governance

Justification for Self-Governance

Self-Governance is proposed because the higher CO_2 gas is unlikely to have a material effect on the following self-governance criteria:

- *(aa)*existing or future gas consumers as the dilution from low CO_2 (<2mol%) gas from the SEGAL sub-terminal and SAGE sub-terminal (<4mo%) and low CO_2 gas from Norway via Vesterled means that the gas export into the NTS will remain below 4mol% under most operating scenarios; and
- *(bb) competition in the shipping, transportation or supply of gas conveyed through pipes or any commercial activities connected with the shipping, transportation or supply of gas conveyed through pipes.* By ensuring continued supplies of UK gas into the system security of supply will be enhanced, competition will be maintained and flow of gas into the NTS will be enhanced; and
- *(cc) the operation of one or more pipe-line system* as continued flow of Bruce and Rhum gas (up to 5% of UK domestic gas supply) will maintain flow rates in the NTS and extend system life ensuring security of supply and the opportunity to develop additional flows into the system in the future; and
- *(dd) matters relating to sustainable development, safety or security of supply, or the management of market or network emergencies.* The modification will enhance security of supply by ensuring that fields do not prematurely cease production and more indigenous gas will flow into the market giving greater coverage for market or network emergencies.

The preliminary views indicate there will be no impact on existing or future gas consumers as the dilution from low CO_2 from the SEGAL and SAGE sub-terminals and low CO_2 gas from Norway via Vesterled means that the gas export into the NTS will remain below 4mol% under most operating scenarios. Indeed, security of supply will be enhanced and recovery of oil and gas from the UKCS will be maximised. The Panel's engagement is sought to assess the impact of the requested change, in order to confirm that a higher CO_2 limit at St Fergus NSMP sub-terminal would be beneficial for the GB gas market.

Requested Next Steps

This modification should: *(delete as appropriate)*

- be subject to self-governance
- be assessed by a Workgroup
- proceed to Consultation

Rationale for requested next steps inserted here

3 Why Change?

With the increasing maturity of UKCS as a gas production area, all producers are being asked by the OGA to focus on maximising economic recovery (MER) from existing fields.

The current CO_2 limit at the St Fergus NSMP sub-terminal is 4.0mol%. The commingled stream that arrives at the terminal via the FUKA pipeline system is derived from a number of Northern North Sea and West of Shetland fields including the BP operated Rhum field. The CO_2 content of the Rhum gas is between 6.2% - 6.5mol% and the Rhum field currently relies on blending with other fields in order to meet Gas Entry Conditions. As this gas is blended with other Shippers' gas within the FUKA pipeline (including the low CO_2 gas from the Laggan/Tormore fields) by the time it enters the NTS the CO_2 content is below 4.0mol%.

On occasions when the Laggan/Tormore fields trip and temporarily cease to export low CO_2 gas into the FUKA pipeline high CO_2 content gas from the Rhum field can remain in the pipeline. Restarting gas export from the Laggan/Tormore fields then leads to a short duration increase in the CO_2 content of gas arriving at the St Fergus NSMP sub-terminal above 4.0mol% as the increasing pipeline pressure from the Laggan/Tormore restart pushes the high CO_2 Rhum gas along the pipeline and into the sub-terminal. In order to mitigate this intermittent risk of exceeding the 4.0mol% when Laggan Tormore restarts, a guaranteed daily flow of additional low CO_2 blend gas is procured from Norway to the St Fergus NSMP sub-terminal via a commercial arrangement. This gas is transported daily to the St Fergus NSMP sub-terminal via the Norwegian Vesterled pipeline. The commercial mechanism with the Norwegian shippers is costly and Rhum cannot endure having to continually purchase blend gas to cover the brief periods when additional blending gas may be required. The two other sub-terminals which are adjacent to the NSMP sub-terminal contribute blending gas which reduces the combined CO_2 content of the export gas before the gas reaches consumers.

Rhum has been delivering natural gas into the NTS as part of a commingled stream since 2005. St Fergus NSMP sub-terminal delivery to the NTS has not exceeded 4.0mol%. Rhum production flows of c.4.5 mcmd is, on average, about 15% of the total flow through FUKA and Rhum and Bruce combined account for approximately 5% of the UK National Supply.

Historically Rhum was able to export gas into the FUKA system above 3.8mol% CO_2 without increasing the CO_2 content of sub-terminal NTS delivery gas above 4.0mol% by blending the gas with low CO_2 gas from the Bruce/Keith fields (now almost depleted) and from the Alwyn area field (rates now much lower and not far from 4.0mol% CO_2 content. The suspension of Rhum production in 2010 to comply with EU sanctions against Iran (Rhum is jointly owned by the Iranian Oil Company) has created a disparity in the relative remaining gas volumes and production rates of Rhum gas relative to the Bruce/Keith and Alwyn fields resulting in the requirement for additional firm delivery to the NSMP sub-terminal of low CO_2 volumes of Norwegian blend gas.

The import of firm volumes of low CO_2 Norwegian gas was imported via the Vesterled pipeline (from Heimdal in the Norwegian sector to the NSMP terminal) to offset the decline in blending sources within the FUKA pipeline and ensure the CO_2 content in the export gas from the sub-terminal into the NTS remained below 4.0mol% commenced in 2015.This activity was viewed as a short term measure until the Laggan/Tormore fields and the associated Shetland Gas Plant started up (February 2016). While Laggan/Tormore gas provides low CO_2 gas directly into the FUKA system, modelling of pipeline flow behaviour and the subsequent observation of actual pipeline flows, has led to a requirement for an increase in the volume of firm Norwegian gas which has to be delivered on a daily basis. This is because when there is an unplanned trip/outage of the Laggan/Tormore fields, gas from the Rhum field that is already in the FUKA pipeline causes an increase in the CO_2 content of FUKA pipeline gas. On restart and ramp-up of Laggan/Tormore production the “slug” of high CO_2 content gas already in the FUKA pipeline is accelerated into the St Fergus terminal causing a pulse of higher CO_2 gas which requires the firm delivery of Norwegian gas to blend down to <4.0mol% prior to entry into the NTS.

Once delivered into the FUKA system the Rhum gas delivery rate at the terminal is largely determined by the flow rates into the FUKA system from the Alwyn area (up to 6 mcm/d) and from the Laggan/Tormore fields (currently up to 14 mcm/d) in addition to the Bruce and Rhum flow rates. Hence a slug of up to 10 mcm of Rhum composition gas (between 3.8-6.5mol% CO_2) could in principle arrive at the NSMP sub-terminal at rates of 20 up to mcm/d. As an unplanned outage of the Laggan/Tormore fields cannot be predicted, the St Fergus terminal operator has requested a constant volume of Norwegian gas at sufficient quantity to constantly cover the risk of a Laggan/Tormore restart generating a pulse of higher CO_2 gas causing a breach of the CO_2 specification in the NEA (4 mol%). A constant flow of Norwegian gas is required to guarantee meeting the NEA specification limit of 4.0mol% CO_2 as it would take too long for a reactive increase in Norwegian gas flow to reach the terminal. The cost of continuous provision of this gas at the flow rates required to cover Laggan Tormore field re-starts is prohibitive.

The provision of processing and treatment solutions to remove the excess CO_2 upstream of the NTS (both offshore and onshore at the NSMP sub-terminal) have been considered however, these would require significant investment and substantial time (3+ years) to implement. The Rhum field will become sub-economic and cease production before such a project became operational. While, the planned life of the Rhum field is until at least 2023, longevity is limited by the economic life of the host platform at the Bruce field. There is insufficient production from the Bruce field to cover the operating costs for the Bruce platform which is reliant on a throughput related cost share arrangement with the Rhum field to cover such costs. If Rhum field cannot flow at sufficiently high rates (either due to the cost of providing Norwegian blend gas or due to curtailment to meet current CO_2 specifications) there will be insufficient flow to cover Bruce platform costs and the Bruce, Rhum and Keith fields will cease production.

To assess the feasibility of gas with a higher CO_2 content exiting the NSMP sub-terminal, BP 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 associated with 5.5mol% CO_2 content. In addition, as gas at other St Fergus System Entry Points has a CO_2 content significantly lower than 4.0mol%, modelling demonstrates that gas with higher CO_2 content at the NSMP System Entry Point could be blended with gas from the adjacent sub-terminals 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. Therefore no consumers are impacted.

What the effects are should the change not be made

The significant cost of securing additional firm blend gas from Norway will lead to the early Cessation of Production from the Rhum and associated Bruce and Keith fields. 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, take many years to complete and would make these fields uneconomic.

This modification seeks to establish a change to the existing NEA parameters as 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. Therefore, in light of the preliminary views achieved so far, the Panel's engagement is sought to assess the impact of the requested change, in order to confirm that a higher CO_2 limit at St Fergus NSMP sub-terminal would be beneficial for the GB gas market.

If the change is not made then the resulting impacts will most likely be:

- Early abandonment of Rhum, Bruce and Keith, loss of 600 jobs and U.K. tax revenues.
- Stranded reserves (~50% reserves) that would otherwise be economic to produce.

4 Code Specific Matters

Reference Documents

None.

Knowledge/Skills

No additional skills or knowledge are required to assess this modification.

5 Solution

This modification seeks to amend a Network Entry Provision within the existing St Fergus NSMP System NEA. This amendment would increase the CO_2 upper limit for gas delivered from the St Fergus NSMP Sub terminal System Entry Point into the National Transmission System to 5.5mol% from the current limit of 4.0mol%.

6 Impacts & Other Considerations

All parts of this section must be completed; showing "None" where the Workgroup believes this is so.

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

No impact identified.

Consumer Impacts

No impact/positive impact. Consumers can currently receive gas at 4mol% from both the SAGE and St Fergus NSMP sub-terminals. Occasional increases in CO_2 content of export gas from St Fergus NSMP sub-terminal are currently permitted by NTS as the adjacent terminals provide additional low CO_2 gas which commingles with the NSMP sub-terminal gas, to maintain NTS gas below 4mol%.

For Information; NSMP gas including Rhum is GS(M)R compliant with or without Laggan Tormore flows from the Shetland Gas Plant. Rhum gas on its own is GS(M)R compliant.

If Rhum gas flows at normal export rates and is commingled with all FUKA sources excluding Laggan/Tormore, the composition of the combined export gas is ~4.5mol% CO_2. With Laggan/Tormore fields flowing and Rhum at peak rates, the CO_2 content of the commingled gas in the FUKA pipeline is <2.7mol%.

Implementing the change will remove the significant cost of securing additional firm blend gas from Norway and remove the probability of early Cessation of Production from the Rhum and associated Bruce and Keith fields. This will have a positive impact on the security of supply for the UK as a whole. Recovery of oil and gas from the specific fields will be maintained, while the continued flow of gas into the pipeline systems ensure a more efficient and economic operation of the pipeline system and the increased utilization of the existing infrastructure capacity will extend the useful life of existing assets and enable further new developments to access the pipeline infrastructure in the future.

Consumer Impact Assessment

(Workgroup assessment of proposer initial view or subsequent information)

Criteria	Extent of Impact
Which Consumer groups are affected?	*Please consider each group and delete if not applicable.* • Domestic Consumers • Small non-domestic Consumers • Large non-domestic Consumers • Very Large Consumers
What costs or benefits will pass through to them?	*Please explain what costs will ultimately flow through to each Consumer group. If no costs pass through to Consumers, please explain why. Use the General Market Assumptions approved by Panel to express as 'cost per consumer'.* Insert text here

When will these costs/benefits impact upon consumers?	*Unless this is 'immediately on implementation', please explain any deferred impact.* Insert text here
Are there any other Consumer Impacts?	*Prompts:* *Are there any impacts on switching?* *Is the provision of information affected?* *Are Product Classes affected?* Insert text here
General Market Assumptions as at December 2016 *(to underpin the Costs analysis)*	
Number of Domestic consumers	*21 million*
Number of non-domestic consumers <73,200 kWh/annum	*500,000*
Number of consumers between 73,200 and 732,000 kWh/annum	*250,000*
Number of very large consumers >732,000 kWh/annum	*26,000*

Cross Code Impacts

The Workgroup is to identify and assess any other impacted energy code – a full list is available in the CACoP (Ofgem) - and the extent of those impacts e.g. a similar modification has been raised in another Code.

None identified.

EU Code Impacts

The Workgroup is to identify and assess any other impacted EU energy code

None identified.

Central Systems Impacts

The Workgroup must provide an assessment of the impacts on central systems (inc. Gemini and UK Link) that may be affected; this will be supported by further input from the Central Data Services Provider (Xoserve) later in the process. If 'none', please also explain.

None.

Workgroup Impact Assessment *(Joint Office to complete)*

The Workgroup identified a number of areas requiring closer assessment and collated them into a number of key themes, as follows:

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

Further Background to the Change

Chris Shanley 20/1/2017 13:25
Comment [1]: Data from January 607S WG presentations and minutes, have been used for this initial draft report

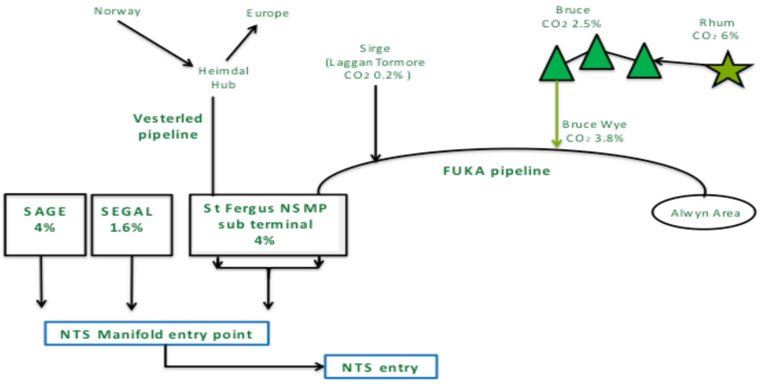
Historic operational procedures & flows at the site

When Rhum had been in operation previously [dates] there had not been any C02 limit issues as it had been able to blend with other offshore fields, which were now out of commission/running low. Previously all the gas that flowed was within the specification but Rhum flow rates are now higher and the capability does not exist in the Bruce field (insufficient gas) to alleviate the problem.

[Insert further explanation and or diagrams of the historic position to help set the proposal in context and provide a better understanding of why some perceived options might not be available]

Current operational procedures & flows at the site

A schematic illustrating the St Fergus sub-terminal entry to the NTS can be found below that shows the configuration of the various connections and how gas flows combine and feed into the NTS entry point.



Problems arise when an unplanned trip occurs at Laggan Tormore and there is insufficient blend gas to manage the requirement to reduce the CO_2 limit to 2.5mol% before reaching the NTS entry point.

There are no CO_2 removal systems at the terminal so the Rhum owners currently manage the risk by purchasing Vesterled gas on a daily basis to ensure there is a sufficient supply of gas available for blending should Laggan Tormore experience an unplanned trip. If this safeguard were not in place then the whole Frigg system would have to be shut down.

Frequency of occurrence and the penetration into the NTS

Number of occurrences where St Fergus NSMP Terminal CO2 limit could have been over 4mol%

The 5.5% limit would only be needed operationally if an offshore trip at the low CO_2 Laggan Tormore field occurred. When Laggan Tormore restarts after such a trip it pushes a volume of high CO_2 gas from Rhum towards the terminal in a stream of other UKCS gas and thus cause a temporary CO_2 spike, resulting in a shut in of all UKCS gas in the Frigg line and not just the Rhum flows.

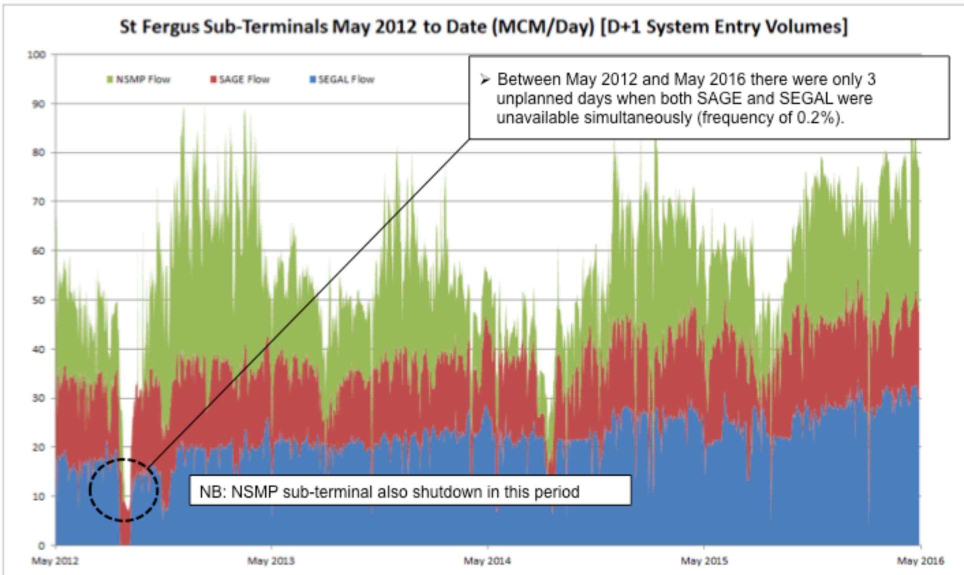
Since the start up of twin compressor operation in May 2016, there had been 8 separate "total" outages of Laggan Tormore (see diagram below).

	Double Compressor Trips at SGP since 2 Compressor Operations (May 16)		
	Date Start	Date End	Total Time (Days)
1	21/05/2016 03:00	21/05/2016 09:00	0.25
2	21/06/2016 20:50	24/06/2016 12:00	2.63
3	26/06/2016 03:00	26/06/2016 10:45	0.32
4	14/07/2016 16:30	15/07/2016 09:00	0.69
5	18/07/2016 18:10	18/07/2016 23:48	0.23
6	07/08/2016 05:32	08/08/2016 22:03	1.69
7	03/10/2016 00:00	04/10/2016 10:30	1.44
8	06/10/2016 13:18	07/10/2016 05:00	0.65
			7.91

Laggan Tormore gas had been unavailable only 4% of the time. The cost of purchasing this contingency blend gas to cover these unplanned outages is prohibitive to Rhum and no longer sustainable. If another contingency mechanism cannot be found then it will lead to the early closure of both the Rhum and the Bruce fields. It was suggested that this point should be noted in the Workgroup's report.

<u>St Fergus Sub Terminal System Entry Volumes (May 2012 to May 2016)</u>

A blend gas graph illustrating St Fergus sub-terminals system entry volumes from May 2012 - May 2016 can be found below.



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It should be noted that there were only 3 unplanned days when both SAGE and SEGAL were unavailable simultaneously (a frequency of 0.2%). In these circumstances SAGE and SEGAL do not mitigate the risk of there being CO2 over 4mol% and the fields would need to be shutdown.

<u>St Fergus C02 Blending Analysis</u>

An example of operational flows at the St Fergus NSMP terminal can be found in [Appendix 2]. SAGE and SEGAL have separate entry points into the NTS and are downstream of the compression station, and the blending happens within the NTS terminal. Frigg gas blends with Vesterled and then further with SAGE and SEGAL before entering the NTS terminal.

Four different scenarios were analysed (see Appendix []?) and all four assume Laggan Tormore trips for over 60 hours on an ordinary summer's day. Actual average flow rates from SAGE and SEGAL are used but NSMP flows are adjusted in each scenario. The scenarios suggest that the gas flowing into the NTS does not go above 4mol% even when Laggan Tormore goes offline unplanned.

[Chart of probabilities required to assist understanding and National Grid NTS' views on the BP/NSMP's analysis would be useful]

Penetration into the NTS

Chris Shanley 20/1/2017 13:37
Comment [2]: Will the following action assist with the understanding of the penetration of increased CO2 levels into the NTS and/or what else do we require? Would a diagram help?

Action 0101: National Grid NTS (PH) to provide historical flow and CO_2 data at each St Fergus sub terminal, in order to provide a view on the BP/NSMP analysis as presented.

CO2 content at Norwegian gas fields

Action 0102: BP (MK) to investigate the CO_2 content of the Norwegian gas at its source(s) and assess the potential effects if a change were to be made to the current CO_2 limits.

Anticipated Impact on Gas Quality

Simplified Technical Explanation of impact of increasing CO_2 on Gas Quality at St Fergus

[?. Insert analysis of consequential impacts of increased C02 on Wobbe and Calorific Value (CV)]

Potential European Standard on Gas Quality

Chris Shanley 20/1/2017 12:38
Comment [3]: From modifications 498/502. Is this relevant/up to date, given recent events?

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

Chris Shanley 20/1/2017 12:43
Comment [4]: Data from modifications 498/502. Is this relevant/up to date?

Gas quality at a particular NTS Exit Point is dependent on:

- the quality of gas at System Entry Points

- which supply sources flow to the exit point on the network, and
- the degree to which different streams of gas co-mingle within the NTS between the relevant System Entry Points and the exit point in question.

Thus typically the gas quality at System Entry Points such as St Fergus would be expected to be an influence on the gas quality at a particular NTS Exit Point, but it would unlikely be the sole influence. Approval of this modification proposal would support a change to the permitted level of Carbon Dioxide entering the NTS at St Fergus but 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

Chris Shanley 20/1/2017 12:43
Comment [5]: From modifications 498/502. Will NTS require an assessment with regards to 0607S?

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), although it is noted that recent flows are well below this level. 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 figures A1.1 to A1.4 in Appendix 1 for more information.

Operations

Risk 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[1]) 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

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

Scenarios) shows that gas from St Fergus 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 St Fergus) for more than a decade. Again St Fergus 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 this modification proposal being published National Grid NTS wrote out inviting comments from potentially impacted parties. National Grid NTS received X responses provided on a private basis and all[2] 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. Please see figure A2.1 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.

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 electricity cashout penalty derives from the portfolio now being short following a trip on its nominated position.
- The penalty regime refers to the electricity 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:

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

Chris Shanley 20/1/2017 12:25
Comment [6]: From modifications 498/502. Have NTS contacted parties with regards to 0607S?

Chris Shanley 20/1/2017 13:26
Comment [7]: From modifications 498/502. What do we expect the impacts to be for 0607S? Do we need to know NTS penetration of increased CO2 first?

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 figure A3.1 in 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.[3] An estimate of this is included in the Carbon Cost Assessment.

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

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

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

Chris Shanley 20/1/2017 13:27
Comment [8]: From modifications 498/502. Are there any storage operator impacts for 0607S?

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

Chris Shanley 20/1/2017 16:08
Comment [9]: David Reilly has offered to give an overview of the Carbon Cost Assessment process. Current guidance can be found via: https://www.ofgem.gov.uk/sites/default/files/docs/2010/07/ghg_guidance_july2010update_final_080710_0.pdf

Info from modifications 498/502. What are the realistic options for 0607S that would need to be considered in the 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 6 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.

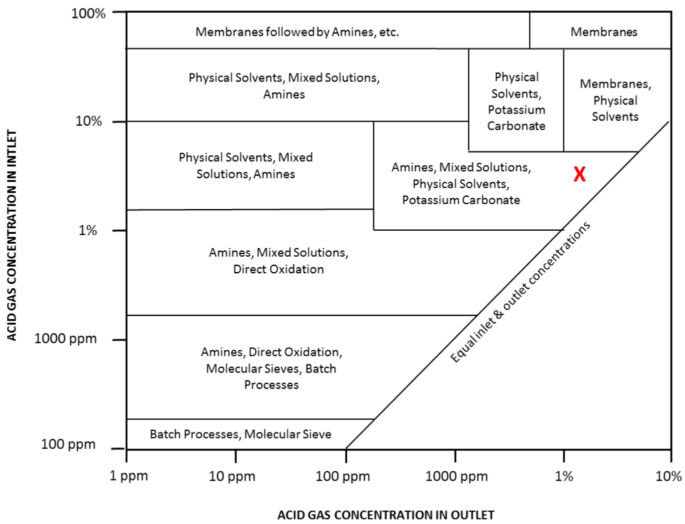
Removal of CO_2 above 2.9 mol% at the upstream platform or onshore at the terminals

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 CO_2 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 CO_2 in the inlet stream against that required in the outlet stream (see figure 3). The red X shows the approximate concentrations of the CATS gas scenario under consideration.

Figure 3: Inlet/outlet relationships: CATS Gas concentration



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 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 (£107m when discounted at a 10% discount rate as per the CO_2 Impact Assessment - see Appendix 6), 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 (£122m when discounted at a 10% discount rate (see above)). 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 $20^{o}C$. This allows process emissions resulting from operation of the unit(s) to be reduced but the requirement to maintain the amine tank at about $20^{o}C$ when the fluid is not in use, which BP and TGPP estimate requires about 3.6MW of process heat.

See figure A5.1 in 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[4] sites while ground source or water sourced heat are unlikely to be able to provide sufficient

[4] Control of Major Accidents and Hazards

power on demand. The options considered and the issues attached to these are summarised in the figure 4.

Figure 4: Alternative options for powering an 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)

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 **Gas Consumers:** • Development of domestic gas sources gives improved security of supply compared to gas imports/LNG	**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 limited 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 (£107M as a discounted Net Present	**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 • Emission levels remain within	**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

	Value at 10%) (NPV10)	current ranges	• Increased emissions charges • Ultimate recovery of oil and gas from UKCS is impacted **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 (£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 • Emission levels remain within current ranges	**Producers/Terminal Operators** • 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°C 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 **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 2021 to 2030, 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 2021-2032

Figure 5 below displays a summary of the total estimated overall CO_2 emitted under the three modelled scenarios during the period 2021-2032:

Figure 5: Assessment of CO_2 emitted (tonnes equivalent) by scenario

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°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 2021 and 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 2021-2032

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 figure 6 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.

Figure 6: Cost assessment of CO_2 emitted by scenario

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) 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 £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 £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 £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 NPV10 of £107m and £122m 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 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 only in excess of the current 2.9 mol% for 30 days per year and most likely less – to between £108m and £122m. In the worst case this is about 180 times more costly than the £660k 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

Chris Shanley 23/1/2017 11:12
Comment [10]: Info from modifications 0498/502. Need to update to reflect security of supply benefits - If another contingency mechanism cannot be found then it will lead to the early closure of both the Rhum and the Bruce fields. [5%] of GB gas supplies?

Questions from Julie Cox. Have the oil and gas authority been involved as their role is all about maximising recovery – utilisation of infrastructure etc?

Also has any consideration has been given to seeking an amendment to the point of compliance?

Chris Shanley 20/1/2017 13:28
Comment [11]: From modifications 0498/502. TBC

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.

User Pays *(Workgroup assessment of Proposer initial view or subsequent information)*	
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 this modification and it is not, therefore, classified as a User Pays Modification.
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.	None
Proposed charge(s) for application of User Pays charges to Shippers.	None
Proposed charge for inclusion in the Agency Charging Statement (ACS) – to be completed upon receipt of a cost estimate from Xoserve.	None

7 Relevant Objectives

Impact of the modification on the Relevant Objectives:	
Relevant Objective	Identified impact
a) Efficient and economic operation of the pipe-line system.	Positive
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.	Positive
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 binding decisions of the European Commission and/or the Agency for the Co-operation of Energy Regulators.	None

Demonstration of how the Relevant Objectives are furthered inserted here

This modification to change the CO_2 limit at the NSMP Sub Terminal has been preceded by discussion between National Grid NTS and BP, aimed at assessing the feasibility of such change. Some of the following considerations therefore reflect both the results of National Grid NTS analysis and BP's own assessment of changes.

Positive impacts have been identified on the objectives of *a) efficient and economic operation of the pipeline system* and on *d) competition among shippers*.

The combined flows of Bruce and Rhum fields contribute around 5% of UK domestic gas supply into the NTS. These flows help towards a more efficient and economic operation of the pipeline system thanks to an increased utilisation of the existing infrastructure capacity and extending the useful life of existing assets. In addition, extending the production life of the Bruce and Rhum assets allows a wider range of gas into the network and mitigates instances of interruption in production flows, due to seasonal maintenance programs which affect the overall supply of gas to the UK market.

Competition between shippers should be improved through maximization of available production by avoiding early cessation of production, maintaining diversity and reducing reliance on imported gas. In addition, the presence of domestic supplies could contribute to efficient price formation and help sustain NBP as a liquid hub.

8 Implementation

As self-governance procedures are proposed, implementation could be sixteen business days after a Modification Panel decision to implement, subject to no Appeal being raised.

No direct costs have been identified and implementation on the earliest practical opportunity is requested, effective from XXXX . As a backstop, implementation by XXXXXXX is necessary to enable timely final investment decision-making. Implementation within the NEA could be completed immediately following approval, through a bilateral agreement to amend the NEA.

9 Legal Text

Text Commentary

As this is an enabling modification, no UNC legal text is required.

Suggested Text

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

"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 5.5mol%."

The Workgroup has considered the legal text and is satisfied that it meets the intent of the Solution.

10 Recommendations

Workgroup's Recommendation to Panel

The Workgroup asks Panel to agree that:

- This self-governance modification should proceed to consultation.
- This proposal requires further assessment and should be returned to Workgroup.

11 Appendices

Chris Shanley 20/1/2017 13:24
Comment [12]: Place holder for appendices. Some are from modifications 0498/502 – are they required?

1 CO_2 Levels at NTS Entry Points

2 St Fergus Flow Maps

3 CCGT Plant trips

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

5 St Fergus Schematic

6 CO_2 Impact Assessment

ANY OTHER ADDITIONAL INFORMATION????

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

Figure A1.1: CO_2 at St. Fergus

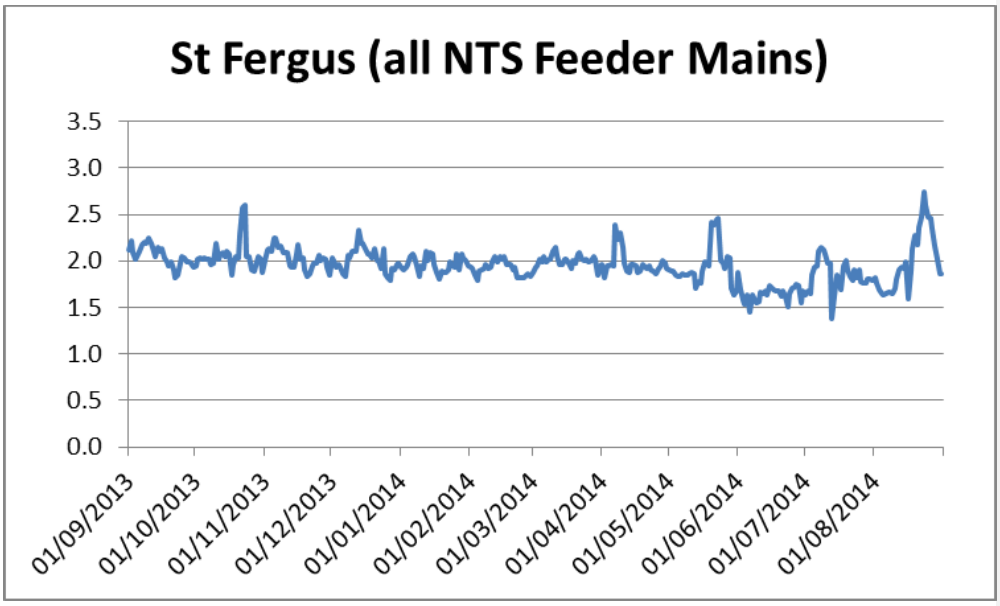


Figure A1.2: CO_2 at Teesside

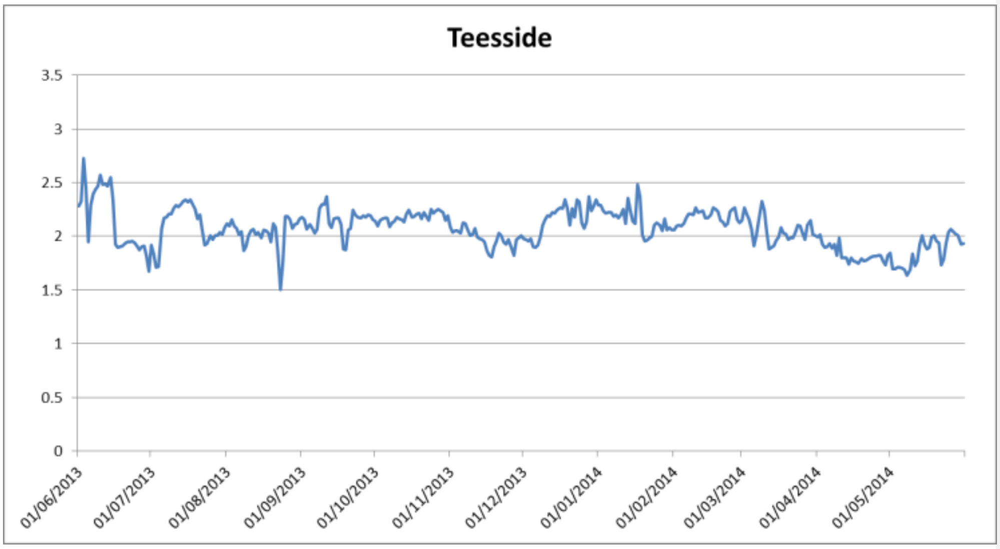

Teesside
3.5
3
2.5
2
1.5
1
0.5
0
01/06/2013
01/07/2013
01/08/2013
01/09/2013
01/10/2013
01/11/2013
01/12/2013
01/01/2014
01/02/2014
01/03/2014
01/04/2014
01/05/2014

Figure A1.3: CO_2 at Easington

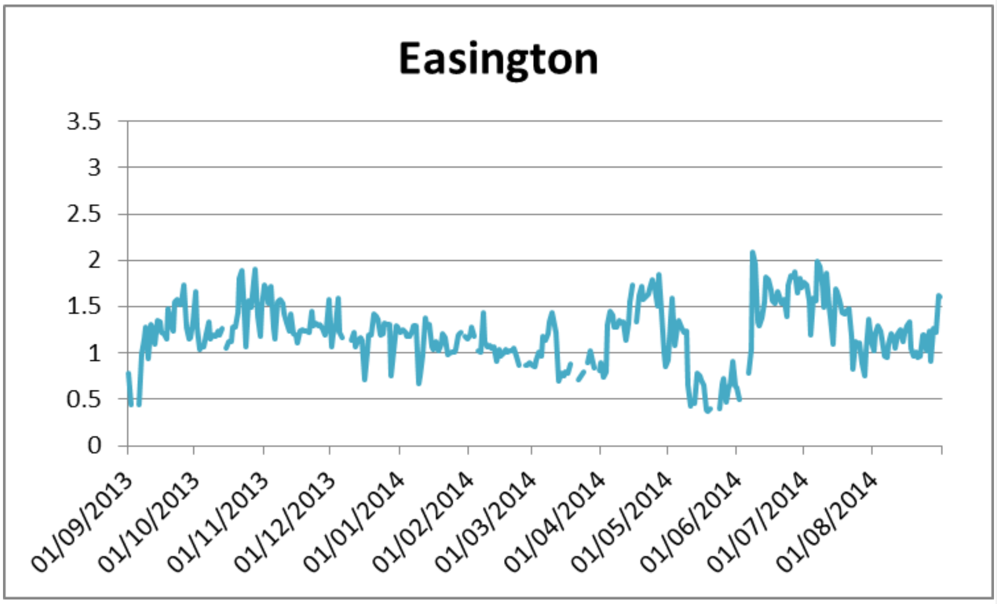
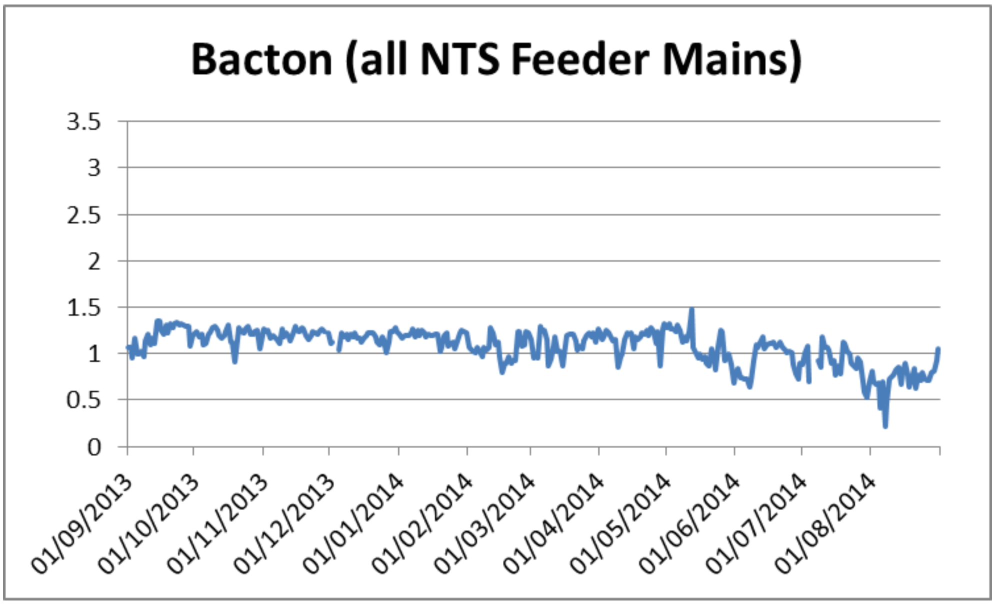
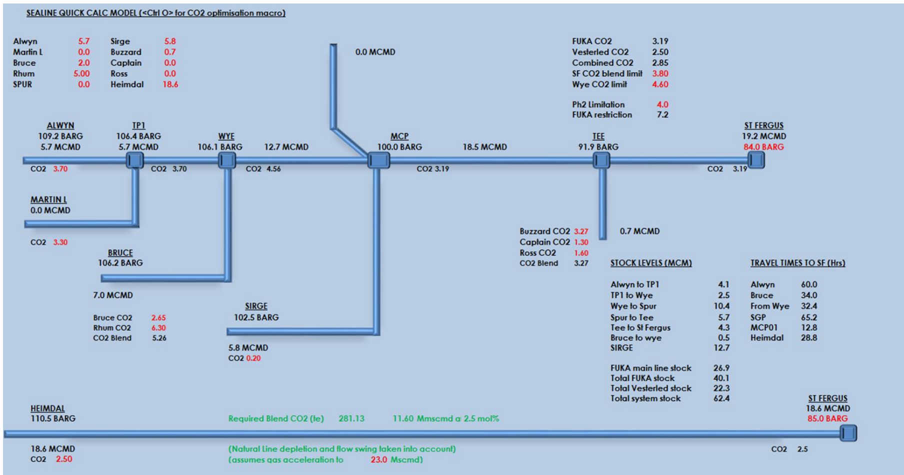


Figure A1.4: CO_2 at Bacton



Appendix 2 - St Fergus Flow Maps

Please find below an example of the operational flows at St Fergus NSMP terminal.



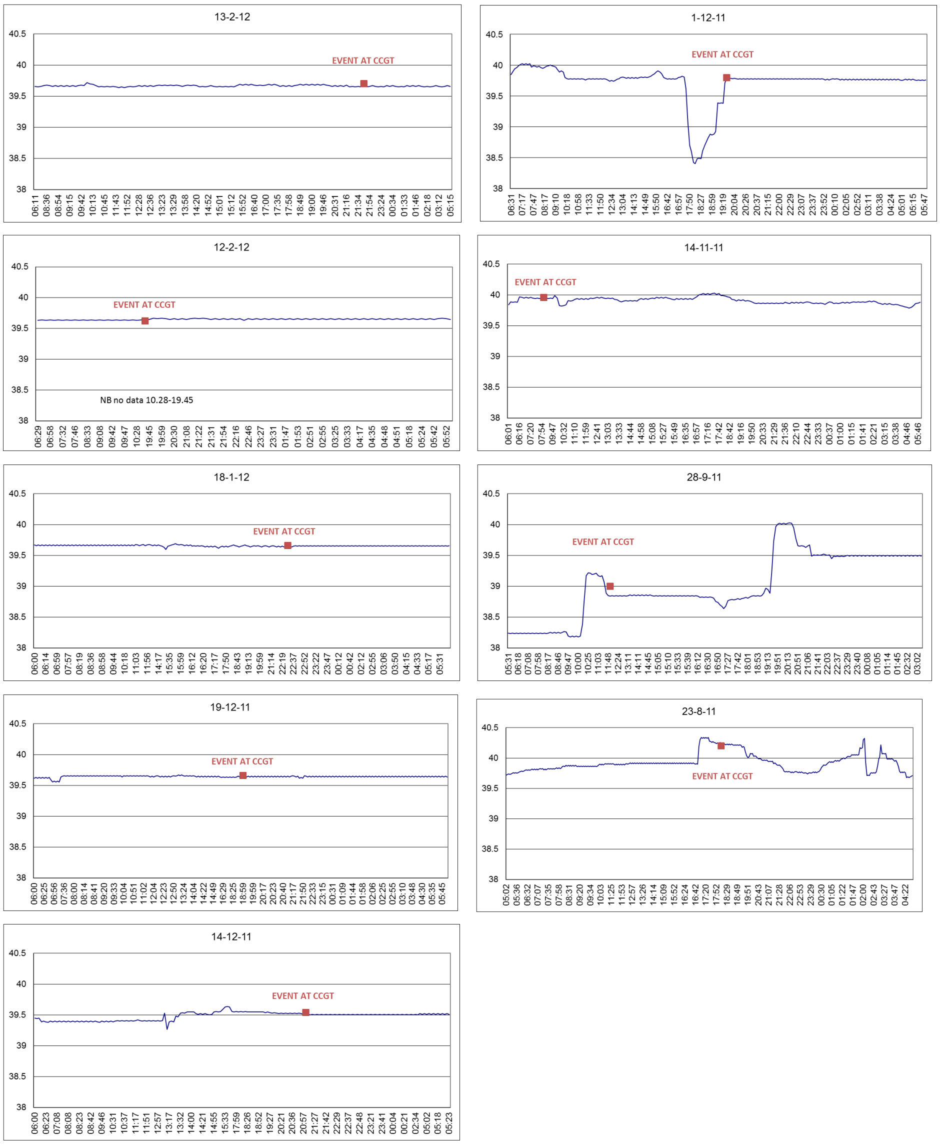
Appendix 3 – CCGT Plant trips

Figure A3.1: Trips at a 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

Figure A3.2: 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 St Fergus

Analysis of the impact of increasing CO_2 on gas quality at St Fergus has been carried out by BP and NSMP……

Appendix 5 - St Fergus Schematic

Figure A5.1: Schematic of St Fergus facilities

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Appendix 6 - CO_2 Impact Assessment

Summary

A carbon cost assessment has been calculated for the proposal.

Introduction

A carbon cost assessment has been calculated for the proposal. The impact assessment ……

CO_2 Impact Assessment - Assumptions

The assumptions for the CO_2 impact assessment are detailed in figure A6.1 below.

Analysis

The summary of the output of the analysis is shown in in figures A6.2 and A6.3 below. ……

Conclusions

Over the life of the model …….

12 Glossary

ADD TABLE HERE (if necessary)