Stage 02: Combined Workgroup Report

At what stage is this document in the process?

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

0498:

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

0502:

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

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

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

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

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

Medium Impact: Transporters, Shippers and Consumers

Contents

About this document:

This combined report will be presented to the Panel on 21 May 2015.

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

Any questions?

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1 Summary

Are these Self-Governance Modifications?

The Modification Panel determined that these are not self-governance modifications because they are likely to have an impact on Shippers, Transporters or consumers of gas conveyed through pipes.

Why Change?

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

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

Solution

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

0498 - This modification, in accordance with UNC TPD I 2.2.3(a), proposes an amendment to a Network Entry Provision within the existing NEA in respect of BP Teesside System Entry Point. This amendment would increase the CO_2 limit of gas delivered from the BP Teesside System Entry Point into the National Transmission System to 4.0 mol% from the current limit of 2.9 mol%.

0502 - This modification, in accordance with UNC TPD I 2.2.3(a), proposes an amendment to a Network Entry Provision within the existing NEA in respect of the px Teesside System Entry Point. This amendment would increase the CO_2 limit of gas delivered from the px Teesside System Entry Point into the NTS to 4.0 mol% from the current limit of 2.9 mol%.

Relevant Objectives

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

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

Implementation costs

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

Implementation

The Workgroup has not proposed a timescale for implementation of these modifications, but would suggest that they are implemented simultaneously at the earliest practical opportunity.

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

This does not affect the Nexus delivery.

2 Why Change?

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

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

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

Similar arguments for change have been put forward under Modification 0502.

0502 - The px Delivery Facility receives the same commingled gas from the CATS pipeline as the BP CATS Facility, and therefore any changes to the commingled gas composition that may affect BP's processing ability, would have the same impact upon the px Delivery Facility. If Modification 0498 is approved and the specification in the pipeline changes as predicted by BP, then without this equivalent Modification 0502 to change the carbon dioxide limit at the px Teesside System Entry Point to align with BP, there is a risk that deliveries from the px Teesside System Entry Point will be curtailed when the CATS pipeline specification reaches the current CO_2 limit, resulting in the interruption of gas flows into the NTS.

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

3 Solution

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

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

Modification 0498

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

Modification 0502

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

User Pays
Classification of these modifications as User Pays, or not, and the justification for such classification.
No User Pays service would be created or amended by implementation of either of these modifications and they are not, therefore, classified as User Pays Modifications.
Identification of Users of the service, the proposed split of the recovery between Gas Transporters and Users for User Pays costs and the justification for such view.
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

4 Relevant Objectives

Impact of the modifications on the **Relevant Objectives:**	
Relevant Objective	Identified impact
a) Efficient and economic operation of the pipe-line system.	**0498** and **0502**: Impacted
b) Coordinated, efficient and economic operation of (i) the combined pipe-line system, and/ or (ii) the pipe-line system of one or more other relevant gas transporters.	**0498** and **0502**: Impacted
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.	**0498** and **0502**: Impacted
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.	**0498** and **0502**: Impacted
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

Impact on Relevant Objectives (whole section to be considered and confirmed)

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

A more efficient and economic operation of the pipeline system can be expected, thanks to an increased utilisation of the existing infrastructure capacity and extending the useful life of existing NTS assets compared to potential curtailment of feasible supplies entering at Teeside.

b) Coordinated, efficient operation of the offshore and onshore systems

This positive impact applies to the combined pipe-line system upstream and downstream. In addition, allowing a wider range of gas into the network would likely reduce the instances of interruption in production flows, due to seasonal maintenance programmes which affect the overall blending of gas entering the NTS at Teesside. This is supported by the fact that National Grid NTS' analysis in respect of the NTS has not identified any material impacts that would cause additional costs or reduced operational efficiency.

d) Competition between relevant shippers

Competition between Shippers should be improved through maximization of available 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 the NBP as a liquid hub.

e) Incentives to provide gas for domestic customers in line with supply security standard.

An additional competitive supply source of locally produced gas will make it easier for suppliers to meet current supply security standards with a higher level of certainty.

Initial Representations

Initial representations were received from SSE, GrowHow and Tata Steel and are published alongside this report and views from Scotia Gas Networks were included in the minutes of 3rd July 2014 workgroup meeting (available here).

Issues raised in these Representations include:

- Our CO_2 emissions increase as the additional CO_2 is emitted from our process in addition to the CO_2 we are generating ourselves (this would presumably take the form of an increased emissions factor on the metered incoming gas), leading to higher costs under EU ETS.
- There would be additional load on our CO_2 removal systems, which are already highly loaded at maximum production rates – so this could become a limit on production rate.
- Calorific value is reduced, so our volume of gas consumed needs to increase, this will increase pressure drop in the distribution pipework (both NG system and customers own distribution system).
- The CO_2 acts a diluent, so where we are trying to achieve high temperatures (e.g. in reformer furnaces) we have more mass to heat, which consumes more energy (minor effect).
- If the added CO_2 displaces a 'high' hydrocarbon the effect on these will be different to the displacement of a 'low' hydrocarbon. A quick calc suggests that the move from 2.9% to 4%, with a reduction in CH4, will reduce the CV by about 1% and the Wobbe by 2%.
- Gas turbine combustion dynamics, emissions and operability are impacted by the total level of inerts (principally Carbon Dioxide (CO_2) and Nitrogen) contained in the gas. Certain gas turbine Original Equipment Manufacturers (OEMs) stipulate a maximum level of 4% inerts in their fuel gas specifications, operation outside this specification could invalidate the unit's warranty or service agreement. As a result this will prevent operation of the asset and result in lost revenue and less competition in the market for supplying electricity. Where new build is being considered, an increase in CO_2 to 4 % could restrict the selection of which future gas turbine manufacturer could be used, suppressing market competition.
- Increasing the level of inerts creates the potential for a greater range of gas composition and specification. Varying gas specification within this wider range will lead to a requirement for unpredictable gas turbine re-tuning in order to maintain combustion stability and dynamics within the OEM's specification to avoid warranty and Environment Agency breaches. Currently, re-tuning of gas turbine combustion systems takes around 4 hours, is costly as it requires the services of specialist OEM combustion engineers to retune the combustion system and prevents flexible, load following operation during that period. This lack of flexibility will not only impact on being able to support intermittent generation and security of supply but lead to loss of revenue, the magnitude of which will be dependant upon when the gas composition changes. In addition changes in Gas Quality could result in gas turbine start up and transfer issues. This represents a real risk to the reliability of future operations especially for stations operating in a cyclic mode with implications for providing support for intermittent generation and hence electricity system security.

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

The Workgroup considered these issues as part of their overall assessment and views are discussed further in the sections below.

WORKGROUP ASSESSMENT (to be confirmed)

In addition to the normal Workgroup assessment, these modifications have been preceded by discussion between National Grid NTS and the terminal operators, aimed at assessing the operational feasibility of such change.

Assessment of Risks

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

a) Safety
b) Operations
c) Contractual obligations and cross border flows
***d)* Potential for impacts on parties downstream of the NTS**

a) Safety – There is no prescribed regulatory limit for CO_2 in GB, and parts of the NTS (e.g. two of the St Fergus subterminals) have had 4 mol% legacy contractual CO_2 limits for many years with no known evidence of additional corrosion (as expected from the "dry gas" NTS system). CO_2 levels in the NTS in Scotland are typically higher than in southern parts of the network e.g. September 2013 to August 2014 – average from St Fergus ASEP of 2.0% CO_2, compared to average 1.1% CO_2 in Norfolk.

DRa to provide evidence of flows at [St. Fergus] to demonstrate (or not) that the NTS has experienced gas at 4mol% CO2

b) Operations – This is similar to safety in terms of engineering operation. 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 NTS. Impact on CO_2 emissions from NTS' gas fired compressors is likely to be small and not material in the context of all the other variables that affect this.

c) Contractual obligations and cross border flows – There are currently no regulatory CO_2 limits at cross border points. Whilst the workgroup did discuss EU initiatives on gas quality harmonisation it also recognised that there are no gas quality limits (including CO_2) in the EU legislative development process[1].

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

d) Impacts for parties downstream of the NTS – Prior to these modification proposals being published National Grid NTS wrote out inviting comments from potentially impacted parties. National Grid NTS received 9 responses provided on a private basis and all[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. These maps are shown in Appendix 1.

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.

Include details/diagrams for flow patterns for Teesside into the NTS

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

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

Further Background to the Change (new this version)

BP & TGPP consider that the current specification for CO_2 at the Teesside entry points is incompatible with the composition of some natural gas from potential upstream developments. BP have observed the current CO_2 limit is already causing interruption to existing production on certain days. At least one future development in the Central North Sea area defined by the CATS catchment area would benefit from an increase in the NTS entry specification at Teesside from 2.8 mol% to 4.0 mol%. Studies are currently underway to determine the optimal development plan for the Jackdaw development. The Jackdaw discovery was made in 2005 and is one of a number of significant gas discoveries in the area. Operated by BG plc, the discovery is located in the ultra-High Pressure High Temperature (uHPHT) province of the Central North Sea. Given the uHPHT nature of the reservoir development costs are high (estimated to be in the region of £3bn). Timing of first gas for the development is expected to be in the late teens or early 2020s.
The significant size of the find will help underpin UK energy supply over twenty years but the high cost associated with uHPHT developments makes the developing this and other discoveries challenging. It is essential that the initial capital cost is kept as low as possible. The requirement to remove CO_2 from the Jackdaw gas would add significantly to the development cost.

The CATS and TGPP Network Entry Agreements (NEAs) already have Reasonable Endeavours rights for short-term breaches of CO_2 up to a maximum of 4.0 mol% while other UK terminals currently have a 4.0 mol% NTS entry specification. Increasing the current CO_2 specification at the Teesside entry points to 4 mol% would result in more efficient utilization of existing infrastructure capacity, extend the useful life of existing assets and contribute significantly to maximisation of economic recovery of oil and gas from the UK continental shelf (MERUK).

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

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

An assessment of the impact of CO2 content on Calorific Value, Wobbe Index, Soot Index and Incomplete Combustion Factor has been carried out by BP. The assessment is based on daily average flows between 1st January 2013 and 7th July 2014 and correlates CO_2 content of the NTS delivery gas to the parameter noted above. The findings were presented by BP at the work group meeting on 07 August 2014 (available here). The analysis shows that gas delivered into the NTS from the Teesside entry points will remain well within current NTS specification limits for GCV, Wobbe, ICF and SI even at the max requested CO_2 spec limit of 4.0 mol%. Detailed analysis can be found in Appendix 2.

Forecast Levels of CO_2 in gas at Teesside

The average CO_2 content of gas entering the NTS at the px Teesside entry point over the last two years has been 2.18 mol%. Currently, there are occasional days when CO_2 content exceeds the current specification limit and post 2019, there is the potential for development of at least one new field in the CATS catchment containing elevated levels of CO_2 in the produced gas. Analysis by BP and TGPP of forecast future gas production from offshore fields has shown that for the majority of time, the CO_2 content of gas entering the NTS at the Teesside entry points is likely to be similar to historic norms and well below the current 2.9 mol% specification limit. This is achieved through the blending of gas with high CO_2 content with gas low in CO_2 from other fields feeding into the CATS pipeline and being exported in the pipeline as commingled flow. Issues may arise however, when fields are shutdown during summer maintenance periods or during unplanned production upsets at offshore fields when flows of gas in the CATS pipeline are reduced and there is insufficient gas low in CO_2 to blend the high CO_2 gas into spec.
Up to 2018 CO_2 levels could exceed 2.9 mol% for short periods (c.2-3 days) during summer maintenance periods. As a result, the overall annual average impact is forecast to be 0.03 mol%.

From 2019 onwards, CO_2 levels in CATS/TGPP export gas during the summer months are likely to range between 2.66 mol% and 3.6 mol% (max 4.0 mol%) with CO_2 levels in non-summer months ranging between 2.66 mol% and 3.0 mol% (max 3.57 mol%). It is important to stress that elevated CO_2 levels are not anticipated to be norm and CO_2 levels in excess of 2.9 mol% are only expected to occur for short durations.

Positive and negative effects

Local or wider areas

Wider impacts upstream/downstream

Costs

Also consider the impact on flame stability (JCh?)

Consequential impact on consumer plant to be provided via Energy UK and GSOG

The impact on consumers (warranty, operational and emissions related)

Immediate and future? If change is made / not made…..

Positive and negative?

ETS impacts

Safety related

Shipper identified…commercial and contractual issues – to be considered by shipper participants

Transporter identified …

Consumer identified…..Energy UK

Storage identified…..GSOG

CCGTs can only tolerate limited changes in gas composition (referenced as WI and or Heating Value), dependent on the OEM (Original Equipment Manufacturer) 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 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 sensitivity of CCGTs to gas quality is more fully described in the document shared with the workgroup on: 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.

A number of examples have been provided of times when plant has tripped. The workgroup will investigate the cause of the trips which is suspected to be a change in gas quality.

The proposed increase in CO2 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 CO2 through EU ETS liabilities.[3]

Options for addressing elevated levels of CO^2 in gas at Teesside (new this version)

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 CO2 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).

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

As noted above, flowing gas in excess of the current spec 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 at the terminals

There are a number of technologies available for removal of CO_2 from natural gas. The most suitable technology for a particular application depends on factors such as removal duty, inlet/outlet CO_2 concentrations, contaminants, operating conditions, volumetric flow, downstream processing requirements and relative capital / operating costs.

Based upon likely CO_2 & H_2S partial pressures in the raw gas at the terminal and the required NTS entry specification, most suitable technology to achieve a reduction in CO_2 from 4 mol% to 2.9 mol% for gas delivered to the TGPP entry point is a Formulated Amine Process.

The Formulated Amine Process consists of an absorber column and regeneration unit. Amine solution flows against 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. Apart from capital cost, 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. Electrical power is required to drive pumps and control systems.

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

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

In order to ensure that discoveries such as Jackdaw can be economically developed, it is essential that capital costs are minimised. The fully installed cost of an offshore amine unit is likely to be in the order of £180M which would be borne by the field owners.

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 2.8 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 (c 65 bar) exit points of the terminals as the pipeline and terminal entry points operate at high pressure (c. 105 bar). The cost of installation of an amine unit at a Teesside processing facility is c. £200M. The additional cost over an offshore unit is due to the requirement to process larger volumes of gas from the commingled pipeline stream.

At present the NTS entry points at Teesside are separate (px Teesside and CATS) and governed by separate Network Entry Agreements. Contractually the flow of gas from both the Px Teesside and CATS entry points are required to remain within the NTS entry specifications defined in the NEAs. Currently therefore, two amine units would be required to ensure that contractual obligations are maintained and the cost of provision of these units would be borne by the offshore producers requiring use of the service. However, it will be difficult to force an upstream user processing gas in either TGPP or the CATS plant to pay for CO_2 removal facilities in the other plant where the producer is not processing gas and no contractual relationship exists.

A more efficient approach would be the installation of single amine unit at one plant with costs and blending rights agreed between TGPP, CATS and the upstream parties and the appropriate NTS entry specifications agreed between TGPP, CATS and NGG. At present however, with separate NEAs both flows are required to be on specification to the NTS.

It is anticipated that the amine unit (or units) would be only operated during those periods when the CO_2 content of the gas exported from the terminals exceeded 2.9 mol%. This allows process emissions resulting from operation of the unit(s) to be reduced. However, these cannot be reduced to zero as there is a requirement to maintain the amine tank at about 20^{o}C when the fluid is not in use, which BP/TGPP estimate requires about 3.6MW of process heat.

Environmental impacts

Advantages to which party(ies)

Disadvantages to which party(ies)

Schematic (Appendix?) and explanation of what/how (TGPP/BP)

Tabulation of Advantages/Disadvantages for CO_2 options (new this version)

CO_2 Option	Cost (£MM)	Advantages	Disadvantages
Option 1 Flow gas at 4 Mol% CO_2 into NTS	No equipment cost	• Low cost • 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	• Some high CO_2 content gas enters NTS on occasional days • Slightly elevated emissions charges for consumers
Option 2 CO_2 Removal Offshore at source		• Removes to CO_2 from specific high CO_2 gas • Allows CATS pipeline gas to remain within current specification • CO_2 content of NTS gas remains within current specification	• Additional cost to specific project • Additional CO_2 emissions from the use of process heat in addition to that removed from the gas • Increased emissions charges • Additional cost may make specific project sub-economic at assumed commodity prices • Specific project delayed or not developed • Ultimate recovery of oil and gas from UKCS is impacted
Option 3 CO_2 Removal Onshore at terminal(s)		• High CO_2 content gas can be blended with low CO_2 content gas in the CATS pipeline • Most of year CO_2 content of NTS gas remains within current specification without specific action • CO_2 removal equipment provides backstop if CO_2 current CO_2 specification is exceeded	• Operational pressure of CATS pipeline requires CO_2 removal equipment to be installed after gas is processed, prior to gas entering NTS • Significant cost for provision of CO_2 removal equipment - Current NEA structure and separation of Teesside entry points may require 2 amine units (for CATS & TGPP) • Equipment only operational for short duration • Significant additional CO_2 released through process heat when operational and requirement to ensure amine maintained at $20^{o}C$ when not in use • Significantly increased emissions charges • Additional cost may make specific project sub-economic at assumed commodity prices • Specific project delayed or not developed • Ultimate recovery of oil and gas from UKCS is impacted

Carbon Cost Assessment (new this version)

The detailed carbon cost assessment and assumptions is included in Appendix 3. 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 assessment has been made for the period 2019 to 2030, 2019 being the earliest a field such as Jackdaw might be anticipated to start. For scenarios 2 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 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, this period has been assumed to be 30 days per year and the CO_2 content has been assumed to be a maximum of 4.0 mol% for this period. In reality BP/TGPP would expect this to be a worst case scenario with fewer days per year and with days when the CO_2 content is significantly less than the maximum assumed 4.0 mol%.

A summary of the overall CO_2 impact assessment is provided in the table below:

Assessment of CO_2 Impact from Teesside Gas (2019-2030)	Scenario 1 NTS Delivery at 4 mol % CO2	Scenario 2 Offshore CO2 Reduction	Scenario 3 Onshore CO2 Reduction
CO_2 Removed by Amine unit (4 mol% to 2.9 mol%) (te)	0	476,875	66,243
CO_2 in fuel gas consumed by Amine unit (te)	0	219,920	172,046
CO_2 above 2.9 mol% emitted by consumers (te)	64,256	0	0
Total additional CO_2 emissions (te)	**64,256**	**696,795**	**238,289**

The removal of CO_2 offshore results in the greatest level of CO_2 emissions (697 Kte) as there is a requirement to treat the entire gas stream being exported the production platform. Removing CO_2 above the current 2.9 mol% limit at the terminals results in lower CO_2 emissions (238 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 is only required for short periods. At 66 Kte, removal of CO_2 from gas at the onshore terminal/terminals is comparable to but slightly higher than the CO_2 that would be emitted by consumers if such gas were delivered onto the NTS (64 Kte) (the difference being due to the slight inefficiency of the amine system). While an amine unit at the terminal/terminals would remain non-operational for much of the year, there is a requirement to maintain the amine tank at about 20^{o}C when the fluid is not in use. As a result, during the period of assessment, there is over 2.5 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. When this significant volume of CO_2 is considered, the overall level of CO_2 emissions remain significantly higher (238 Kte in total) than allowing the gas to pass onto the NTS.

In terms of cost of abatement of the CO_2 generated above the current 2.9 mol% limit. These costs on an NPV10 basis are summarised in the table below:

Cost Assessment of CO_2 from Teesside Gas (2019-2030) (£ NVP10 1/1/15)	Scenario 1 NTS Delivery at 4 mol % CO2	Scenario 2 Offshore CO2 Reduction	Scenario 3 Onshore CO2 Reduction
CO_2 Total ETS Traded Cost	£42,232	£1,741,921	£578,525
CO_2 Total Traded Cost with Carbon Price Support	£269,723		
Total CO2 Cost (Traded & Price Support)	**£311,954**	**£1,741,921**	**£578,525**
CO_2 Total Non-Traded Cost (£/yr) (non-ETS consumption)	£959,753	£0	£0
Total Estimated Emissions Cost	**£1,271,707**	**£1,741,921**	**£578,525**
Estimated Fully Installed Cost of Amine Unit		£147,189,400	£129,089,543
Estimated Abatement Cost for additional CO2 prior to NTS entry		**£148,931,320**	**£129,668,068**
Cost per tonne	**£20**	**£214**	**£544**

In terms of ETS traded costs where CO_2 emissions costs are measured against market prices, the highest cost option (NPV10 £1.7M) would be removal of CO_2 offshore as this option results in the largest volume of CO_2 emitted. The cost of removal of CO_2 onshore at the terminals is also significant (NPV10 £578K) due to the substantial amount of CO_2 emitted through process heat. 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 £312k this is the lowest cost option given the forecasted small number of days per year when such gas was being produced at the terminals.

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 mol% CO_2 gas increases significantly to c. £1.27M. However, it is felt that if the non-traded cost of CO_2 is taken into consideration then the capital cost of installing CO_2 mitigation should also 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 £130M and the cost of an onshore unit would be of the order of £147M (both discounted to 1/1/15 at 10%).

Including the cost of the amine units brings the total NPV of mitigating the increased CO_2 – which may be in only excess of the current 2.9 mol% for 30 days per year and most likely less – to between £131M and £148M. This is over 100 times more costly than the £1.27M estimate if the CO_2 were delivered onto the NTS. In tonnage terms, the cost to an NTS gas consumer is c. £20/te but costs could be up to £500/te to mitigate the CO_2 prior to gas entering the NTS.

Future outlook for similar gas sources in terms of setting precedents, and the context and value/cost for the UK

Predictions of composition of future gas supplies? Short term and long term views? Forward planning?

Risk of setting precedent

Impacts ? Costs? Immediate and future?

Value to UK economy

Non-discrimination

Policy explanation of Carbon reduction vs sustainable UKCS

TGPP/BP to consider and compile this section

Conclusions

(under narrow remit of UNC) ?

Next Steps

(for wider industry) ?

5 Implementation

The Workgroup has not proposed a timescale for implementation of these modifications, but would suggest that they are implemented [simultaneously] at the earliest practical opportunity.

6 Impacts

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

No other industry change is impacted.

7 Legal Text

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

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

No issues were raised by the Workgroup regarding either content.

Suggested Text - Modification 0498

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

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

[…]

(k) Carbon Dioxide *Not More than ~~2.9%~~ 4.0 mol%*

Suggested Text - Modification 0502

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

2.3 (k) Carbon Dioxide not more than ~~2.9~~ 4.0 mol%

8 Recommendation

The Workgroup invites the Panel to:

- AGREE that these modifications should be submitted for consultation.

[?? Any additional questions for UNC Modification Panel consideration / potential inclusion in the consultation focus ???]

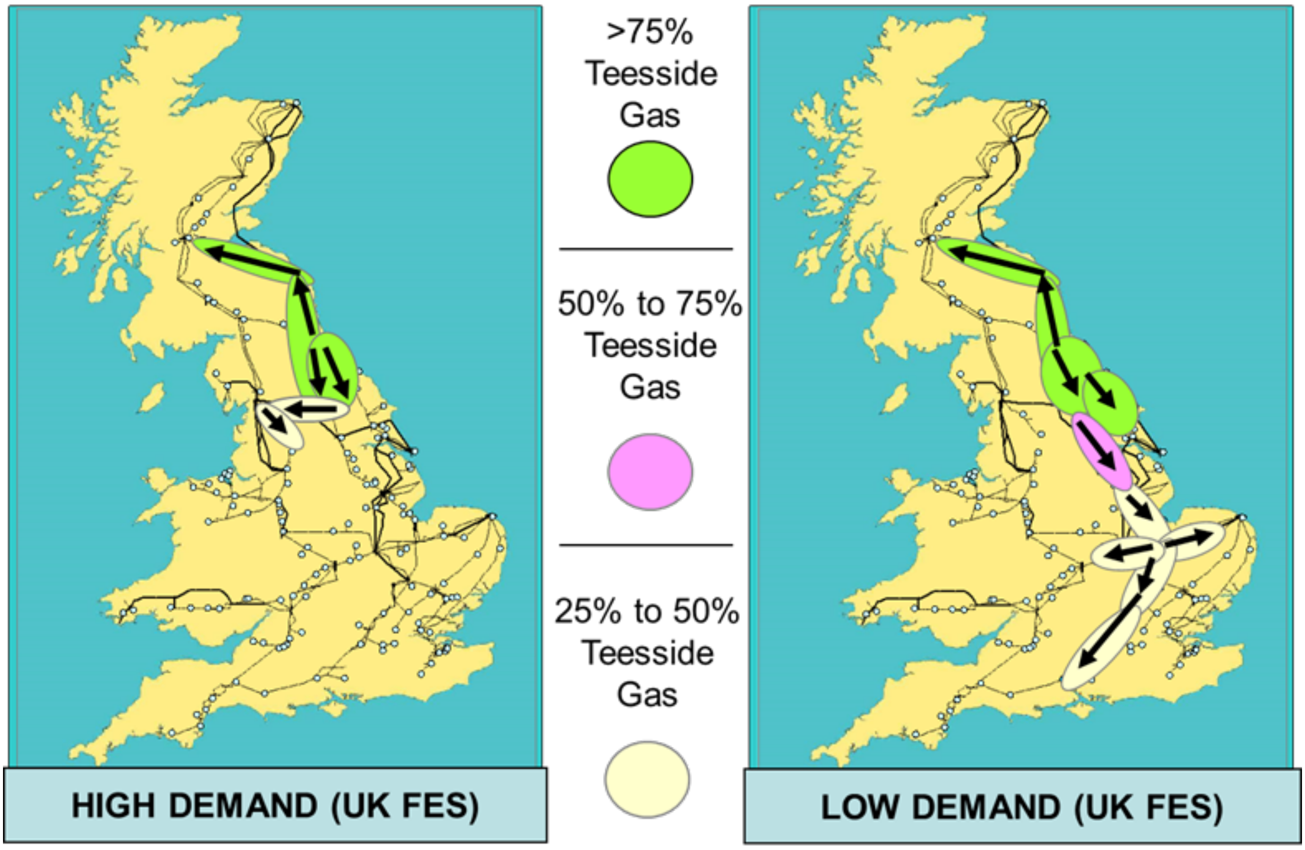
9 Appendices

1 **Teeside Flow Maps**

2 **Detailed analysis of the impact of increasing CO^2 on Gas Quality at Teesside**

3 **CO^2 Impact Assessment**

Appendix 1 - Teeside Flow Maps



Appendix 2 – Detailed analysis of the impact of increasing CO^2 on Gas Quality at Teesside (new this version)

Yet to be completed.

Appendix 3 - CO^2 Impact Assessment (new this version)

Summary

A carbon cost assessment has been calculated for the proposal. The least impact on CO_2 emissions from bringing gas with up to 4.0 mol% CO_2 content into the CATS system is for such gas to be allowed to flow into the NTS. Significantly more CO_2 is emitted by removing CO_2 from the gas due to the need for process heat to remove CO_2. The cost of installing amine unit either at specific fields offshore or at the onshore terminals is considerable. Current estimates for the fully installed cost of an offshore amine unit is of the order of £200M (undiscounted). When this is taken into account, the mitigation cost increases significantly when compared to the costs to NTS gas consumers (including non ETS participants). On a tonnage basis the cost to an NTS gas consumer (both ETS and Non-ETS participants) is c. £20/te but could the cost to mitigate the higher levels if CO_2 prior to gas entering the NTS could be up to £500/te.

Introduction

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

Three scenarios are therefore considered:

- Scenario 1 – Non-removal of CO_2;
- Scenario 2 – Reduction of CO_2 content to 2.9 mol% Offshore, and;
- Scenario 3 – Reduction of CO_2 content to 2.9 mol% Onshore.

The assessment has been made for the period 2019 to 2030, 2019 being the earliest date that fields with elevated CO_2 content might be expected to come on stream. Where gas with an elevated CO_2 content flows into the CATS pipeline (Scenarios 1 and 3) this gas will be commingled with other gas with lower CO_2 content. As a result, it is expected that for the majority of time the CO_2 content of gas entering the Teesside NTS entry points is likely to be below the current limit. Increases above the current limit are most likely to be during summer maintenance campaigns or for short periods of unplanned outages when field outages means that gas flows at Teesside will be lower than normal and low CO_2 content gas for blending gas may be restricted. For the purposes of the CO_2 impact assessment, this period has been assumed to be 30 days per year and the CO_2 content has been assumed to be a maximum of 4.0 mol% for this period. In reality BP/TGPP would expect this to be a worst case scenario.

Assumptions

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

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

Analysis

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

Assessment of CO_2 Impact from Teesside Gas (2019-2030)	Scenario 1 NTS Delivery at 4 mol % CO2	Scenario 2 Offshore CO2 Reduction	Scenario 3 Onshore CO2 Reduction
CO_2 Removed by Amine unit (4 mol% to 2.9 mol%) (te)	0	476,875	66,243
CO_2 in fuel gas consumed by Amine unit (te)	0	219,920	172,046
CO_2 above 2.9 mol% emitted by consumers (te)	64,256	0	0
Total additional CO_2 emissions (te)	**64,256**	**696,795**	**238,289**

Cost Assessment of CO_2 from Teesside Gas (2019-2030) (£ NVP10 1/1/15)	Scenario 1 NTS Delivery at 4 mol % CO2	Scenario 2 Offshore CO2 Removal	Scenario 3 Onshore CO2 Removal
CO_2 Total ETS Traded Cost	£42,232	£1,741,921	£578,525
CO_2 Total Traded Cost with Carbon Price Support	£269,723		
Total CO2 Cost (Traded & Price Support)	**£311,954**	**£1,741,921**	**£578,525**
CO_2 Total Non-Traded Cost (£/yr) (non-ETS consumption)	£959,753	£0	£0
Total Estimated Emissions Cost	**£1,271,707**	**£1,741,921**	**£578,525**
Estimated Fully Installed Cost of Amine Unit		£147,189,400	£129,089,543
Estimated Abatement Cost for additional CO2 prior to NTS entry		**£148,931,320**	**£129,668,068**
Cost per tonne	**£20**	**£214**	**£544**

Conclusions

- The least impact on CO_2 emissions from bringing gas with up to 4.0 mol% CO_2 content into the CATS system is for such gas to be allowed to flow into the NTS.
- Significantly more CO_2 is emitted by removing CO_2 from the gas. This is due to the fact that CO_2 removal using amine requires process heat. The highest level of emissions is attributed to reduction of CO_2 offshore as a result of operation of an amine unit on the total field gas export stream each day of operation. Onshore reduction of CO_2 has lower CO_2 emissions as the unit would only be used on days when CO_2 levels are expected to be elevated. However this is still significantly higher than an NTS delivery scenario as, when not in use, amine is required to be stored at 20°C to maintain its operational effectiveness and this requires further process heat.
- When considering cost of emissions from ETS participants, the impact of CO_2 removal is carried through with transport of 4.0 mol% CO_2 gas onto the NTS being the lowest cost option and reduction of CO_2 content offshore being the highest cost option
- If the cost of non-traded emissions is included then the cost to consumers of NTS gas from accepting gas with higher CO_2 content increases. However, if non-traded emissions are considered, BP/TGPP believe that the total cost of mitigating the CO_2 content of gas entering the NTS from Teesside should be taken into account.
- The cost of installing amine unit either at specific fields offshore or at the onshore terminals is considerable. Current estimates for the fully installed cost of an offshore amine unit is of the order of £200M (undiscounted). When this is taken into account, the mitigation cost increases significantly when compared to costs to NTS gas consumers. On a tonnage basis the cost to an NTS gas consumer is c. £20/te but could cost up to £500/te to mitigate the CO_2 prior to gas entering the NTS.

CATS CO2 Impact Assessment (Amine Unit Capex Excluded)

	Total CO2 (Te)	NPV10	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total	Annual Average
Reference Data																				
Number of Days Terminals anticipate CO2 in excess of 2.9 Mol %							30	30	30	30	30	30	30	30	30	30	30	30		
Forecast CO2 content when in excess of 2.9 Mol%							4.0%	4.0%	4.0%	4.0%	4.0%	3.8%	3.6%	3.4%	3.4%	3.2%	3.2%	3.2%		
CO2 Emissions from warm Amine when unit not in use (Kg/hr)							718.51	718.51	718.51	718.51	718.51	718.51	718.51	718.51	718.51	718.51	718.51	718.51		
Carbon Valuation 'Traded' (£/te C02)							5	5	6	6	6	6	6	7	7	7	7	8		
Carbon Valuation 'Traded' with Carbon Price Support (£/te C02)							22	27	33	39	44	50	56	60	65	69	74	78		
Carbon Valuation 'Non Traded' (£/te C02)							66	67	68	69	70	71	72	73	74	75	77	78		
Gas Price (p/th)							58.00	60.29	62.57	64.86	67.15	69.44	71.73	72.54	73.35	74.10	75.11	76.37		**72**
Total UK Forecast C02 Emissions (MtC02)							370	349	339	329	324	317	306	300	296	292	296	293	6,609	**300**
Scenario 1 - NTS Delivery at 4mol%																				
Additional C02 emissions from 4mol% to 2.9mol% (te/C02)	64,256						6,802	7,563	7,563	7,563	7,563	6,338	5,113	3,879	3,879	2,664	2,664	2,664	**64,256**	**5,355**
Cost of 'Traded' emissions (£)		**£42,232**	-	-	-	-	9,120	10,517	10,908	11,313	11,734	10,199	8,535	6,716	6,965	4,962	5,146	5,337	**101,451**	**8,454**
Cost of 'Traded' emissions with Carbon Price Support (£)		**£269,723**	-	-	-	-	35,203	49,476	59,814	70,153	80,492	76,123	68,405	56,046	60,198	44,195	47,046	49,897	**697,049**	**58,087**
Total Cost of Traded & Traded with Price Support emissions (£)		**£311,954**	-	-	-	-	**44,323**	**59,992**	**70,722**	**81,466**	**92,226**	**86,322**	**76,940**	**62,762**	**67,163**	**49,156**	**52,192**	**55,235**	**798,500**	**66,542**
Cost of 'Non Traded' emissions (£)		**£959,753**	-	-	-	-	224,482	253,349	257,130	260,911	264,693	225,001	184,084	141,593	143,532	99,909	102,573	103,905	**2,261,163**	**188,430**
Total Cost of emissions (£)		**£1,271,707**	-	-	-	-	**268,806**	**313,341**	**327,852**	**342,378**	**356,919**	**311,323**	**261,024**	**204,354**	**210,695**	**149,065**	**154,765**	**159,140**	**3,059,663**	**254,972**
Scenario 2 - Offshore removal																				
Field Forecast Flow (mscfd)							153	259	264	264	264	229	178	147	125	106	93	82		
Field Forecast Flow (mscf/year)							55,725	94,695	96,455	96,455	96,455	83,511	65,000	53,505	45,586	38,871	33,824	30,053	**790,135**	**65,845**
C02 emissions from amine process to 2.9mol% content (te)	476,875						33,530	57,001	58,119	58,119	58,119	50,668	39,119	32,413	27,569	23,471	20,491	18,255	**476,875**	**39,740**
Additional C02 emissions from Amine unit fuel gas (te)	219,920						15,463	26,287	26,803	26,803	26,803	23,367	18,040	14,948	12,714	10,824	9,450	8,419	**219,920**	**18,327**
Total C02 emissions from Offshore removal (te)	696,795						48,993	83,289	84,922	84,922	84,922	74,034	57,159	47,360	40,283	34,295	29,940	26,674	**696,795**	**58,066**
Total cost of emissions (£)		**£1,741,921**	-	-	-	-	**252,645**	**445,466**	**471,089**	**488,605**	**506,772**	**458,228**	**366,934**	**315,335**	**278,189**	**245,643**	**222,424**	**205,527**	**4,256,856**	**354,738**
Scenario 3 - Onshore removal																				
Terminals Forecast Flow When Exceeding 2.9 mol% (mscfd)							360	400	400	400	400	400	400	400	400	400	400	400	**4,760**	**397**
C02 emissions from amine process (4 mol% to 2.9mol% content (te)	66,243						7,013	7,797	7,797	7,797	7,797	6,534	5,272	3,999	3,999	2,747	2,747	2,747	**66,243**	**5,520**
Additional C02 emissions from Amine unit fuel gas (te)	32,304						3,207	3,565	3,565	3,565	3,565	3,145	2,678	2,152	2,152	1,570	1,570	1,570	**32,304**	**2,692**
Additional CO2 emissions from Amine when not in use (te)	139,741						11,645	11,645	11,645	11,645	11,645	11,645	11,645	11,645	11,645	11,645	11,645	11,645	**139,741**	**11,645**
Total C02 emissions from Onshore removal (te)	238,289						21,865	23,007	23,007	23,007	23,007	21,324	19,595	17,797	17,797	15,961	15,961	15,961	**238,289**	**19,857**
Total cost of emissions (£)		**£578,525**	-	-	-	-	**112,751**	**123,051**	**127,626**	**132,372**	**137,294**	**131,984**	**125,790**	**118,493**	**122,899**	**114,324**	**118,575**	**122,984**	**1,488,144**	**124,012**

CATS CO2 Full Cycle Cost/Benefit Analysis

	Total CO2 (Te)	NPV10	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total	Annual Average
Reference Data																				
Field Forecast export Flow (th/year)							1,329,422,233	1,476,241,519	1,476,241,519	1,476,241,519	1,476,241,519	1,476,241,519	1,476,241,519	1,476,241,519	1,476,241,519	1,476,241,519	1,476,241,519	1,476,241,519	**17,568,078,938**	**1,464,006,578**
Number of Days Terminals anticipate CO2 in excess of 2.9 Mol %							30	30	30	30	30	30	30	30	30	30	30	30		
Forecast CO2 content when in excess of 2.9 Mol%							4.0%	4.0%	4.0%	4.0%	4.0%	3.8%	3.6%	3.4%	3.4%	3.2%	3.2%	3.2%		
Carbon Valuation 'Traded' (£/te C02)							5	5	6	6	6	6	6	7	7	7	7	8		
Carbon Valuation 'Traded' with Carbon Price Support (£/te C02)							22	27	33	39	44	50	56	60	65	69	74	78		
Carbon Valuation 'Non Traded' (£/te C02)							66	67	68	69	70	71	72	73	74	75	77	78		
Gas Price (p/th)							58.00	60.29	62.57	64.86	67.15	69.44	71.73	72.54	73.35	74.10	75.11	76.37		**72**
Total UK Forecast C02 Emissions (MtC02)							370	349	339	329	324	317	306	300	296	292	296	293	6,609	**300**
Scenario 1 - NTS Delivery at 4mol%																				
Additional C02 emissions from 4mol% to 2.9mol% (te/C02)	64,256						6,802	7,563	7,563	7,563	7,563	6,338	5,113	3,879	3,879	2,664	2,664	2,664	**64,256**	**5,355**
Cost of 'Traded' emissions (£)		**£42,232**	-	-	-	-	9,120	10,517	10,908	11,313	11,734	10,199	8,535	6,716	6,965	4,962	5,146	5,337	**101,451**	**6,341**
Cost of 'Traded' emissions with Carbon Price Support (£)		**£269,723**	-	-	-	-	35,203	49,476	59,814	70,153	80,492	76,123	68,405	56,046	60,198	44,195	47,046	49,897	**697,049**	**43,566**
Total Cost of Traded & Traded with Price Support (£)		**£311,954**	-	-	-	-	**44,323**	**59,992**	**70,722**	**81,466**	**92,226**	**86,322**	**76,940**	**62,762**	**67,163**	**49,156**	**52,192**	**55,235**	**798,500**	**49,906**
Cost of 'Non Traded' emissions (£)		**£959,753**	-	-	-	-	224,482	253,349	257,130	260,911	264,693	225,001	184,084	141,593	143,532	99,909	102,573	103,905	**2,261,163**	**141,323**
Total Cost of emissions (£)		**£1,271,707**	-	-	-	-	**268,806**	**313,341**	**327,852**	**342,378**	**356,919**	**311,323**	**261,024**	**204,354**	**210,695**	**149,065**	**154,765**	**159,140**	**3,059,663**	**191,229**
Scenario 2 - Offshore removal																				
Field Forecast Flow (mscfd)							153	259	264	264	264	229	178	147	125	106	93	82		
Field Forecast Flow (mscf/year)							55,725	94,695	96,455	96,455	96,455	83,511	65,000	53,505	45,586	38,871	33,824	30,053	**790,135**	**65,845**
C02 emissions from amine process to 2.9mol% content (te)	476,875						33,530	57,001	58,119	58,119	58,119	50,668	39,119	32,413	27,569	23,471	20,491	18,255	**476,875**	**39,740**
Additional C02 emissions from Amine unit fuel gas (te)	219,920						15,463	26,287	26,803	26,803	26,803	23,367	18,040	14,948	12,714	10,824	9,450	8,419	**219,920**	**18,327**
Total C02 emissions from Offshore removal (te)	696,795						48,993	83,289	84,922	84,922	84,922	74,034	57,159	47,360	40,283	34,295	29,940	26,674	**696,795**	**58,066**
Capex of Amine unit (£)		£129,089,543	-	-	90,000,000	90,000,000	-	-	-	-	-	-	-	-	-	-	-	-	**180,000,000**	**11,250,000**
Total Cost of Emissions		£1,741,921	-	-	-	-	252,645	445,466	471,089	488,605	506,772	458,228	366,934	315,335	278,189	245,643	222,424	205,527	**4,256,856**	**266,054**
Total cost of emissions (£)		**£130,831,464**	**-**	**-**	**90,000,000**	**90,000,000**	**252,645**	**445,466**	**471,089**	**488,605**	**506,772**	**458,228**	**366,934**	**315,335**	**278,189**	**245,643**	**222,424**	**205,527**	**184,256,856**	**11,516,054**
Scenario 3 - Onshore removal																				
Terminals Forecast Flow When Exceeding 2.9 mol% (mscfd)							360	400	400	400	400	400	400	400	400	400	400	400	**4,760**	**397**
C02 emissions from amine process (4 mol% to 2.9mol% content (te)	66,243						7,013	7,797	7,797	7,797	7,797	6,534	5,272	3,999	3,999	2,747	2,747	2,747	**66,243**	**5,520**
Additional C02 emissions from Amine unit fuel gas (te)	32,304						3,207	3,565	3,565	3,565	3,565	3,145	2,678	2,152	2,152	1,570	1,570	1,570	**32,304**	**2,692**
Additional CO2 emissions from Amine when not in use (te)	139,741						11,645	11,645	11,645	11,645	11,645	11,645	11,645	11,645	11,645	11,645	11,645	11,645	**139,741**	**11,645**
Total CO2 emissions from Onshore removal (te)	238,289						21,865	23,007	23,007	23,007	23,007	21,324	19,595	17,797	17,797	15,961	15,961	15,961	**238,289**	**19,857**
Capex of Amine unit (£)		£147,189,400	-	50,000,000	50,000,000	100,000,000	-	-	-	-	-	-	-	-	-	-	-	-	**200,000,000**	**12,500,000**
Total Cost of Emissions		£578,525	-	-	-	-	112,751	123,051	127,626	132,372	137,294	131,984	125,790	118,493	122,899	114,324	118,575	122,984	**1,488,144**	**93,009**
Total cost of emissions (£)		**£147,767,925**	**-**	**50,000,000**	**50,000,000**	**100,000,000**	**112,751**	**123,051**	**127,626**	**132,372**	**137,294**	**131,984**	**125,790**	**118,493**	**122,899**	**114,324**	**118,575**	**122,984**	**201,488,144**	**12,593,009**

Scenario 1 - NTS Delivery at up to 4 mol% for Train 2

Case	Check		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Full Field [MMSCFD]	450		180	200	200	200	200	200	200	200	200	200	200	200
Full Field [kSm^3/hr]	530.5		212.4	236.0	236.0	236.0	236.0	236.0	236.0	236.0	236.0	236.0	236.0	236.0
Outlet Flow Pre-Treatement [MMSCFD]	429		172	191	191	191	191	191	191	191	191	191	191	191
Outlet Flow Pre-Treatement [kSm^3/hr]	506.5		202.7	225.1	225.1	225.1	225.1	225.1	225.1	225.1	225.1	225.1	225.1	225.1
Oulet Mass Flow Pre-Treatement [kg/hr]	398,369		159,289	176,716	176,716	176,716	176,716	176,716	176,716	176,716	176,716	176,716	176,716	176,716
Outlet Molecular Weight Pre-Treatement [kmol/kg]	18.63		18.62	18.60	18.60	18.60	18.60	18.60	18.60	18.60	18.60	18.60	18.60	18.60
CO2 Content Pre-Treatement [mol%]	44.01		44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01
CO2 Content Pre-Treatement [mol%]	3.40%		3.56%	3.56%	3.56%	3.56%	3.56%	3.56%	3.56%	3.56%	3.56%	3.56%	3.56%	3.56%
Quantities of CO2 Delivered [kg/hr]	31,993		13,400	14,880	14,880	14,884	14,880	14,880	14,880	14,880	14,880	14,880	14,880	14,880
Quantities of CO2 Delivered [te per annum]	280,258		117,384	130,348	130,348	130,384	130,348	130,348	130,348	130,348	130,348	130,348	130,348	130,348
CO2 Removal Unit Flow [MMSCFD]	67		34	37	37	37	37	37	37	37	37	37	37	37
CO2 Removal Unit Flow [kSm^3/hr]	79.6		39.8	44.2	44.2	44.2	44.2	44.2	44.2	44.2	44.2	44.2	44.2	44.2
Quantities of CO2 removed [kg/hr]	4,878		2,551	2,832	2,832	2,836	2,832	2,832	2,832	2,832	2,832	2,832	2,832	2,832
Export Flow Post-Treatement [MMSCFD]	428.1		170.7	189.5	189.5	189.5	189.5	189.5	189.5	189.5	189.5	189.5	189.5	189.5
Export Flow Post-Treatement [kSm^3/hr]	505.1		201.3	223.6	223.6	223.6	223.6	223.6	223.6	223.6	223.6	223.6	223.6	223.6
Export Mass Flow Post-Treatement [kg/hr]	393,491		156,738	173,883	173,883	173,879	173,883	173,883	173,883	173,883	173,883	173,883	173,883	173,883
Export Molecular Weight Post-Treatement [kmol/kg]	18.45		18.44	18.42	18.42	18.42	18.42	18.42	18.42	18.42	18.42	18.42	18.42	18.42
CO2 Molecular Weight Post-Treatement [kmol/kg]	44.01		44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01
CO2 Content Post-Treatement [mol%]	2.88%		2.88%	2.88%	2.88%	2.88%	2.88%	2.88%	2.88%	2.88%	2.88%	2.88%	2.88%	2.88%
Quantities of CO2 Delivered [kg/hr]	27,040		10,778	11,969	11,969	11,969	11,969	11,969	11,969	11,969	11,969	11,969	11,969	11,969
Quantities of CO2 Delivered [te per annum]	236,874		94,418	104,849	104,849	104,847	104,849	104,849	104,849	104,849	104,849	104,849	104,849	104,849
Additional CO2 emissions [kg/hr]	4,953		2,622	2,911	2,911	2,915	2,911	2,911	2,911	2,911	2,911	2,911	2,911	2,911
Additional CO2 emissions Scenario 1 [te per annum]	43,385		1,888	2,096	2,096	2,099	2,096	2,096	2,096	2,096	2,096	2,096	2,096	2,096

Scenario 1 - NTS Delivery at up to 4 mol% for CATS

Case	Check		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Full Field [MMSCFD]	900		180	200	200	200	200	200	200	200	200	200	200	200
Full Field [kSm^3/hr]	1061.9		212.4	236.0	236.0	236.0	236.0	236.0	236.0	236.0	236.0	236.0	236.0	236.0
Outlet Flow Pre-Treatement [MMSCFD]	874		172	191	191	191	191	191	191	191	191	191	191	191
Outlet Flow Pre-Treatement [kSm^3/hr]	1030.8		202.7	225.1	225.1	225.1	225.1	225.1	225.1	225.1	225.1	225.1	225.1	225.1
Oulet Mass Flow Pre-Treatement [kg/hr]	833,193		159,289	176,716	176,716	176,716	176,716	176,716	176,716	176,716	176,716	176,716	176,716	176,716
Outlet Molecular Weight Pre-Treatement [kmol/kg]	19.15		18.62	18.60	18.60	18.60	18.60	18.60	18.60	18.60	18.60	18.60	18.60	18.60
CO2 Content Pre-Treatement [mol%]	44.01		44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01
CO2 Content Pre-Treatement [mol%]	3.51%		3.51%	3.51%	3.51%	3.51%	3.51%	3.51%	3.51%	3.51%	3.51%	3.51%	3.51%	3.51%
Quantities of CO2 Delivered [kg/hr]	67,210		13,225	14,685	14,685	14,685	14,685	14,685	14,685	14,685	14,685	14,685	14,685	14,685
Quantities of CO2 Delivered [te per annum]	588,762		115,849	128,643	128,643	128,643	128,643	128,643	128,643	128,643	128,643	128,643	128,643	128,643
CO2 Removal Unit Flow [MMSCFD]	162		32	35	35	35	35	35	35	35	35	35	35	35
CO2 Removal Unit Flow [kSm^3/hr]	190.6		37.6	41.7	41.7	41.7	41.7	41.7	41.7	41.7	41.7	41.7	41.7	41.7
Quantities of CO2 removed [kg/hr]	12,053		2,379	2,642	2,642	2,642	2,642	2,642	2,642	2,642	2,642	2,642	2,642	2,642
Export Flow Post-Treatement [MMSCFD]	868.1		170.8	189.7	189.7	189.7	189.7	189.7	189.7	189.7	189.7	189.7	189.7	189.7
Export Flow Post-Treatement [kSm^3/hr]	1024.2		201.6	223.8	223.8	223.8	223.8	223.8	223.8	223.8	223.8	223.8	223.8	223.8
Export Mass Flow Post-Treatement [kg/hr]	821,140		156,909	174,074	174,074	174,074	174,074	174,074	174,074	174,074	174,074	174,074	174,074	174,074
Export Molecular Weight Post-Treatement [kmol/kg]	18.99		18.44	18.42	18.42	18.42	18.42	18.42	18.42	18.42	18.42	18.42	18.42	18.42
CO2 Molecular Weight Post-Treatement [kmol/kg]	44.01		44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01
CO2 Content Post-Treatement [mol%]	2.88%		2.88%	2.88%	2.88%	2.88%	2.88%	2.88%	2.88%	2.88%	2.88%	2.88%	2.88%	2.88%
Quantities of CO2 Delivered [kg/hr]	54,806		10,786	11,978	11,978	11,978	11,978	11,978	11,978	11,978	11,978	11,978	11,978	11,978
Quantities of CO2 Delivered [te per annum]	480,101		94,486	104,926	104,926	104,926	104,926	104,926	104,926	104,926	104,926	104,926	104,926	104,926
Additional CO2 emissions [kg/hr]	12,404		2,439	2,707	2,707	2,707	2,707	2,707	2,707	2,707	2,707	2,707	2,707	2,707
Additional CO2 emissions Scenario 1 [te per annum]	108,660		1,756	1,949	1,949	1,949	1,949	1,949	1,949	1,949	1,949	1,949	1,949	1,949

Scenario 2 - Onshore CO2 Removal for Train 2

Case	Check		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Full Field [MMSCFD]	450		180	200	200	200	200	200	200	200	200	200	200	200
Full Field [kSm^3/hr]	530.5		212.4	236.0	236.0	236.0	236.0	236.0	236.0	236.0	236.0	236.0	236.0	236.0
Inlet Molecular Weight	20.3		20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3
CO2 Content In [mol%]	4.00%		4.00%	4.00%	4.00%	4.00%	4.00%	3.80%	3.60%	3.40%	3.40%	3.20%	3.20%	3.20%
CO2 Content Out [mol%]	2.88%		2.88%	2.88%	2.88%	2.88%	2.88%	2.88%	2.88%	2.88%	2.88%	2.88%	2.88%	2.88%
Outlet Flow Pre-Treatement [MMSCFD]	429.3		171.8	190.8	190.8	190.8	190.8	190.8	190.8	190.8	190.8	190.8	190.8	190.8
Outlet Flow Pre-Treatement [kSm^3/hr]	506.5		202.7	225.1	225.1	225.1	225.1	225.1	225.1	225.1	225.1	225.1	225.1	225.1
Oulet Mass Flow Pre-Treatement [kg/hr]	398,369		159,289	176,716	176,716	176,716	176,716	176,716	176,716	176,716	176,716	176,716	176,716	176,716
Outlet Molecular Weight Pre-Treatement	18.63		18.62	18.60	18.60	18.60	18.60	18.60	18.60	18.60	18.60	18.60	18.60	18.60
CO2 Content Pre-Treatement [mol%]	4.19%		4.19%	4.19%	4.19%	4.19%	4.19%	3.98%	3.77%	3.56%	3.56%	3.36%	3.36%	3.36%
Shrink Factor	0.9549		0.9543	0.9538	0.9538	0.9538	0.9538	0.9538	0.9538	0.9538	0.9538	0.9538	0.9538	0.9538
CO2 Removal Unit Flow [MMSCFD]	138		55	62	62	62	62	54	47	38	38	28	28	28
CO2 Removal Unit Flow [kSm^3/hr]	163.1		65.3	72.7	72.7	72.7	72.7	64.3	54.9	44.4	44.4	32.8	32.8	32.8
CO2 Content Exit Unit [ppm]	1257		1257	1258	1258	1258	1258	1195	1132	1069	1069	1007	1007	1007
Removal Unit Efficiency [%]	97%		97%	97%	97%	97%	97%	97%	97%	97%	97%	97%	97%	97%
Quantities of CO2 removed [kg/hr]	12,311		4,935	5,491	5,491	5,491	5,491	4,614	3,737	2,854	2,854	1,984	1,984	1,984
Quantities of CO2 removed [te per annum (30 days/yr)]	107,847		3,553	3,953	3,953	3,953	3,953	3,322	2,691	2,055	2,055	1,428	1,428	1,428
CO2 Molecular Weight [kmol/kg]	44.01		44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01
Quantities of Hydrocarbons (assumed 1 mol%) [kg/hr]	44.88		17.99	20.02	20.02	20.02	20.02	16.82	13.62	10.40	10.40	7.23	7.23	7.23
Methane Molecular Weight [kmol/kg]	16.04		16.04	16.04	16.04	16.04	16.04	16.04	16.04	16.04	16.04	16.04	16.04	16.04
Quantities of VOC removed (assumed as 500 ppm) [kg/hr]	10.93		4.38	4.87	4.87	4.87	4.87	4.09	3.32	2.53	2.53	1.76	1.76	1.76
Benzene Molecular Weight [kmol/kg]	78.11		78.11	78.11	78.11	78.11	78.11	78.11	78.11	78.11	78.11	78.11	78.11	78.11
Export Flow Post-Treatement [MMSCFD]	420.0		168.1	186.6	186.6	186.6	186.6	187.6	188.5	189.5	189.5	190.4	190.4	190.4
Export Flow Post-Treatement [kSm^3/hr]	495.6		198.3	220.2	220.2	220.2	220.2	221.3	222.4	223.6	223.6	224.7	224.7	224.7
Export Mass Flow Post-Treatement [kg/hr]	386,058		154,354	171,225	171,225	171,225	171,225	172,102	172,978	173,862	173,862	174,732	174,732	174,732
Export Molecular Weight Post-Treatement	18.45		18.44	18.42	18.42	18.42	18.42	18.42	18.42	18.42	18.42	18.42	18.42	18.42
CO2 Content Post-Treatement [mol%]	2.88%		2.88%	2.88%	2.88%	2.88%	2.88%	2.88%	2.88%	2.88%	2.88%	2.88%	2.88%	2.88%
	MEA		MEA	MEA	MEA	MEA	MEA	MEA	MEA	MEA	MEA	MEA	MEA	MEA
Gas Flowrate [MMSCFD]	138		55	62	62	62	62	54	47	38	38	28	28	28
Sour Gas Processed, Q [MSm^3/day]	3.91		1.57	1.74	1.74	1.74	1.74	1.54	1.32	1.07	1.07	0.79	0.79	0.79
Contactor Pressure, P [kPa abs]	12101.33		12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33
Acid Gas Conc^n, y [mole%]	4.28033		4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033
Amine Concn, x [mass%]	20		20	20	20	20	20	20	20	20	20	20	20	20
mol acid gas pick-up per mol amine	0.33		0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33
Amine Flow, [m^3/hr]	274.78		110.08	122.40	122.40	122.40	122.40	108.27	92.57	74.88	74.88	55.28	55.28	55.28
Amine Flow, [m^3/d]	6594.74		2642.03	2937.72	2937.72	2937.72	2937.72	2598.57	2221.74	1797.08	1797.08	1326.76	1326.76	1326.76
Amine Flow, [GPM]	1209.82		484.69	538.93	538.93	538.93	538.93	476.71	407.58	329.68	329.68	243.40	243.40	243.40
Amine Contactor Diameter, Dc [mm]	2028		1284	1353	1353	1353	1353	1273	1177	1059	1059	910	910	910
Absorbed Reboiler Duty [MW]	25.55		10.24	11.38	11.38	11.38	11.38	10.07	8.61	6.96	6.96	5.14	5.14	5.14
Heater Duty [MW]	28.39		11.38	12.65	12.65	12.65	12.65	11.19	9.57	7.74	7.74	5.71	5.71	5.71
Thermal Efficiency at 90%	90%		90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%
Fuel Gas HHV [MJ/kg]	46.990		47.131	47.080	47.080	47.080	47.080	47.080	47.080	47.080	47.080	47.080	47.080	47.080
Fuel Gas Requirement [kg/hr]	2175		869	967	967	967	967	856	731	592	592	437	437	437
CO2 Emissions Factor [kg CO2 per kg FG]	2.577		2.575	2.573	2.573	2.573	2.573	2.573	2.573	2.573	2.573	2.573	2.573	2.573
CO2 Formed from Operational Amine Unit FG [kg/hr]	5605		2237	2489	2489	2489	2489	2201	1882	1522	1522	1124	1124	1124
CO2 Formed from Operational Amine Unit FG [te per annum (30 days)]	49,101		1,611	1,792	1,792	1,792	1,792	1,585	1,355	1,096	1,096	809	809	809
Heater Duty for amine heating when non-operational [MW]	3.664		3.664	3.664	3.664	3.664	3.664	3.664	3.664	3.664	3.664	3.664	3.664	3.664
FG Requirement for non-operational Amine Unit (kg/hr)	281		280.706	280.706	280.706	280.706	280.706	280.706	280.706	280.706	280.706	280.706	280.706	280.706
CO2 Formed in Standby Mode [kg/hr]	723		723.293	723.293	723.293	723.293	723.293	723.293	723.293	723.293	723.293	723.293	723.293	723.293
CO2 Formed in Standby Mode [te per annum (335 days)]	5,815		5,815	5,815	5,815	5,815	5,815	5,815	5,815	5,815	5,815	5,815	5,815	5,815
Additional CO2 emissions Scenario 2 [te per annum]	156,948		10,979	11,560	11,560	11,560	11,560	10,722	9,861	8,966	8,966	8,053	8,053	8,053

Scenario 2 - Onshore CO2 Removal for CATS

Case	Check		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Full Field [MMSCFD]	500		180	200	200	200	200	200	200	200	200	200	200	200
Full Field [kSm^3/hr]	589.5		212.4	236.0	236.0	236.0	236.0	236.0	236.0	236.0	236.0	236.0	236.0	236.0
Inlet Molecular Weight	20.3		20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3
CO2 Content In [mol%]	3.40%		4.00%	4.00%	4.00%	4.00%	4.00%	3.80%	3.60%	3.40%	3.40%	3.20%	3.20%	3.20%
CO2 Content Out [mol%]	2.88%		2.88%	2.88%	2.88%	2.88%	2.88%	2.88%	2.88%	2.88%	2.88%	2.88%	2.88%	2.88%
Outlet Flow Pre-Treatement [MMSCFD]	483.4		173.8	193.2	193.2	193.2	193.2	193.2	193.2	193.2	193.2	193.2	193.2	193.2
Outlet Flow Pre-Treatement [kSm^3/hr]	570.3		205.1	227.9	227.9	227.9	227.9	227.9	227.9	227.9	227.9	227.9	227.9	227.9
Oulet Mass Flow Pre-Treatement [kg/hr]	460,486		165,388	183,798	183,798	183,798	183,798	183,798	183,798	183,798	183,798	183,798	183,798	183,798
Outlet Molecular Weight Pre-Treatement	19.13		19.10	19.10	19.10	19.10	19.10	19.10	19.10	19.10	19.10	19.10	19.10	19.10
CO2 Content Pre-Treatement [mol%]	3.51%		4.14%	4.14%	4.14%	4.14%	4.14%	3.93%	3.73%	3.52%	3.52%	3.31%	3.31%	3.31%
Shrink Factor	0.9675		0.9658	0.9659	0.9659	0.9659	0.9659	0.9659	0.9659	0.9659	0.9659	0.9659	0.9659	0.9659
CO2 Removal Unit Flow [MMSCFD]	90		55	61	61	61	61	53	45	36	36	26	26	26
CO2 Removal Unit Flow [kSm^3/hr]	105.8		64.4	71.5	71.5	71.5	71.5	62.9	53.4	42.6	42.6	30.7	30.7	30.7
CO2 Content Exit Unit [ppm]	1054		1242	1242	1242	1242	1242	1180	1118	1056	1056	994	994	994
Removal Unit Efficiency [%]	97%		97%	97%	97%	97%	97%	97%	97%	97%	97%	97%	97%	97%
Quantities of CO2 removed [kg/hr]	6,695		4,805	5,338	5,338	5,338	5,338	4,461	3,584	2,701	2,701	1,831	1,831	1,831
Quantities of CO2 removed [te per annum (30 days/yr)]	58,649	720	3,460	3,843	3,843	3,843	3,843	3,212	2,581	1,945	1,945	1,318	1,318	1,318
CO2 Molecular Weight [kmol/kg]	44.01		44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01
Quantities of Hydrocarbons (assumed 1 mol%) [kg/hr]	24.41		17.52	19.46	19.46	19.46	19.46	16.26	13.07	9.85	9.85	6.67	6.67	6.67
Methane Molecular Weight [kmol/kg]	16.04		16.04	16.04	16.04	16.04	16.04	16.04	16.04	16.04	16.04	16.04	16.04	16.04
Quantities of VOC removed (assumed as 500 ppm) [kg/hr]	5.94		4.26	4.74	4.74	4.74	4.74	3.96	3.18	2.40	2.40	1.62	1.62	1.62
Benzene Molecular Weight [kmol/kg]	78.11		78.11	78.11	78.11	78.11	78.11	78.11	78.11	78.11	78.11	78.11	78.11	78.11
Export Flow Post-Treatement [MMSCFD]	480.2		170.1	189.1	189.1	189.1	189.1	190.0	190.9	191.9	191.9	192.8	192.8	192.8
Export Flow Post-Treatement [kSm^3/hr]	566.6		200.8	223.1	223.1	223.1	223.1	224.2	225.3	226.4	226.4	227.5	227.5	227.5
Export Mass Flow Post-Treatement [kg/hr]	453,790		160,583	178,460	178,460	178,460	178,460	179,337	180,214	181,097	181,097	181,967	181,967	181,967
Export Molecular Weight Post-Treatement	18.98		18.95	18.95	18.95	18.95	18.95	18.95	18.95	18.95	18.95	18.95	18.95	18.95
CO2 Content Post-Treatement [mol%]	2.88%		2.88%	2.88%	2.88%	2.88%	2.88%	2.88%	2.88%	2.88%	2.88%	2.88%	2.88%	2.88%
	MEA		MEA	MEA	MEA	MEA	MEA	MEA	MEA	MEA	MEA	MEA	MEA	MEA
Gas Flowrate [MMSCFD]	90		55	61	61	61	61	53	45	36	36	26	26	26
Sour Gas Processed, Q [MSm^3/day]	2.54		1.55	1.72	1.72	1.72	1.72	1.51	1.28	1.02	1.02	0.74	0.74	0.74
Contactor Pressure, P [kPa abs]	12101.33		12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33
Acid Gas Conc^n, y [mole%]	4.28033		4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033
Amine Concn, x [mass%]	20		20	20	20	20	20	20	20	20	20	20	20	20
mol acid gas pick-up per mol amine	0.33		0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33
Amine Flow, [m^3/hr]	178.21		108.47	120.51	120.51	120.51	120.51	106.02	89.92	71.77	71.77	51.67	51.67	51.67
Amine Flow, [m^3/d]	4277.12		2603.38	2892.31	2892.31	2892.31	2892.31	2544.48	2158.01	1722.49	1722.49	1240.14	1240.14	1240.14
Amine Flow, [GPM]	784.65		477.60	530.60	530.60	530.60	530.60	466.79	395.89	316.00	316.00	227.51	227.51	227.51
Amine Contactor Diameter, Dc [mm]	1633		1274	1343	1343	1343	1343	1260	1160	1036	1036	879	879	879
Absorbed Reboiler Duty [MW]	16.57		10.09	11.21	11.21	11.21	11.21	9.86	8.36	6.67	6.67	4.81	4.81	4.81
Heater Duty [MW]	18.42		11.21	12.45	12.45	12.45	12.45	10.96	9.29	7.42	7.42	5.34	5.34	5.34
Thermal Efficiency at 90%	90%		90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%
Fuel Gas HHV [MJ/kg]	47.698		47.727	47.727	47.727	47.727	47.727	47.727	47.727	47.727	47.727	47.727	47.727	47.727
Fuel Gas Requirement [kg/hr]	1390		845	939	939	939	939	826	701	559	559	403	403	403
CO2 Emissions Factor [kg CO2 per kg FG]	2.622		2.622	2.622	2.622	2.622	2.622	2.622	2.622	2.622	2.622	2.622	2.622	2.622
CO2 Formed from Amine Unit FG [kg/hr]	3644		2217	2463	2463	2463	2463	2167	1838	1467	1467	1056	1056	1056
CO2 Formed from Amine Unit FG [te per annum (30 days)]	31,925		1,596	1,773	1,773	1,773	1,773	1,560	1,323	1,056	1,056	760	760	760
Heater Duty for amine heating when non-operational [MW]	3.664		3.664	3.664	3.664	3.664	3.664	3.664	3.664	3.664	3.664	3.664	3.664	3.664
FG Requirement for non-operational Amine Unit (kg/hr)	277		276.539	276.539	276.539	276.539	276.539	276.539	276.539	276.539	276.539	276.539	276.539	276.539
CO2 Formed in Standby Mode [kg/hr]	725		725.104	725.104	725.104	725.104	725.104	725.104	725.104	725.104	725.104	725.104	725.104	725.104
CO2 Formed in Standby Mode [te per annum (335 days)]	5,830		5,830	5,830	5,830	5,830	5,830	5,830	5,830	5,830	5,830	5,830	5,830	5,830
Additional CO2 Emissions for Scenario 2 [te per annum]	90,574		10,886	11,446	11,446	11,446	11,446	10,602	9,734	8,831	8,831	7,908	7,908	7,908

Scenario 3 - Offshore CO2 Removal

Case	Design		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Full Field [MMSCFD]	300		153	259	264	264	264	229	178	147	125	106	93	82
Full Field [kSm^3/hr]	353.7		180.0	305.9	311.5	311.5	311.5	269.7	209.9	172.8	147.2	125.6	109.3	97.1
CO2 Content In [mol%]	4.00%		4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
CO2 Content Out [mol%]	2.74%		2.89%	2.89%	2.89%	2.89%	2.89%	2.88%	2.89%	2.88%	2.88%	2.89%	2.88%	2.88%
CO2 Removal Unit Flow [MMSCFD]	100		45	76.5	78	78	78	68	52.5	43.5	37	31.5	27.5	24.5
CO2 Removal Unit Flow [kSm^3/hr]	117.9		53.1	90.2	92.0	92.0	92.0	80.2	61.9	51.3	43.6	37.1	32.4	28.9
CO2 Content Exit Unit [ppm]	1249		1249	1249	1249	1249	1249	1249	1249	1249	1249	1249	1249	1249
Removal Unit Efficiency [%]	97%		97%	97%	97%	97%	97%	97%	97%	97%	97%	97%	97%	97%
Quantities of CO2 removed [kg/hr]	8,506		3,828	6,507	6,635	6,635	6,635	5,784	4,466	3,700	3,147	2,679	2,339	2,084
Quantities of CO2 removed [te per annum]	74,512		33,530	57,001	58,119	58,119	58,119	50,668	39,119	32,413	27,569	23,471	20,491	18,255
CO2 Molecular Weight [kmol/kg]	44.01		44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01	44.01
Quantities of Hydrocarbons (assumed 1 mol%) [kg/hr]	31.01		13.95	23.72	24.19	24.19	24.19	21.08	16.28	13.49	11.47	9.77	8.53	7.60
Methane Molecular Weight [kmol/kg]	16.04		16.04	16.04	16.04	16.04	16.04	16.04	16.04	16.04	16.04	16.04	16.04	16.04
Quantities of VOC removed (assumed as 500 ppm) [kg/hr]	7.55		3.40	5.77	5.89	5.89	5.89	5.13	3.96	3.28	2.79	2.38	2.08	1.85
Benzene Molecular Weight [kmol/kg]	78.11		78.11	78.11	78.11	78.11	78.11	78.11	78.11	78.11	78.11	78.11	78.11	78.11
	MEA		MEA	MEA	MEA	MEA	MEA	MEA	MEA	MEA	MEA	MEA	MEA	MEA
Gas Flowrate [MMSCFD]	100		45	76.5	78	78	78	68	52.5	43.5	37	31.5	27.5	24.5
Sour Gas Processed, Q [MSm^3/day]	2.83		1.27	2.17	2.21	2.21	2.21	1.93	1.49	1.23	1.05	0.89	0.78	0.69
Contactor Pressure, P [kPa abs]	12101.33		12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33	12101.33
Acid Gas Conc^n, y [mole%]	4.28033		4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033	4.28033
Amine Concn, x [mass%]	20		20	20	20	20	20	20	20	20	20	20	20	20
mol acid gas pick-up per mol amine	0.33		0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33
Amine Flow, [m^3/hr]	198.78		89.45	152.06	155.05	155.05	155.05	135.17	104.36	86.47	73.55	62.61	54.66	48.70
Amine Flow, [m^3/d]	4770.65		2146.79	3649.54	3721.10	3721.10	3721.10	3244.04	2504.59	2075.23	1765.14	1502.75	1311.93	1168.81
Amine Flow, [GPM]	875.19		393.83	669.52	682.65	682.65	682.65	595.13	459.47	380.71	323.82	275.68	240.68	214.42
Amine Contactor Diameter, Dc [mm]	1725		1157	1509	1523	1523	1523	1422	1250	1138	1049	968	904	854
Absorbed Reboiler Duty [MW]	18.49		8.32	14.14	14.42	14.42	14.42	12.57	9.71	8.04	6.84	5.82	5.08	4.53
Heater Duty [MW]	20.54		9.24	15.71	16.02	16.02	16.02	13.97	10.78	8.94	7.60	6.47	5.65	5.03
Thermal Efficiency at 90%	90%		90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%
Fuel Gas HHV [MJ/kg]	49.494		49.494	49.494	49.494	49.494	49.494	49.494	49.494	49.494	49.494	49.494	49.494	49.494
Fuel Gas Requirement [kg/hr]	1494		672	1143	1165	1165	1165	1016	784	650	553	471	411	366
CO2 Emissions Factor [kg CO2 per kg FG]	2.626		2.626	2.626	2.626	2.626	2.626	2.626	2.626	2.626	2.626	2.626	2.626	2.626
CO2 Formed from Amine Unit FG [kg/hr]	3923		1765	3001	3060	3060	3060	2667	2059	1706	1451	1236	1079	961
CO2 Formed from Amine Unit FG [te per annum]	34,363		15,463	26,287	26,803	26,803	26,803	23,367	18,040	14,948	12,714	10,824	9,450	8,419

Additional CO2 Emissions for Scenario 3 [te per annum]	108,874		48,993	83,289	84,922	84,922	84,922	74,034	57,159	47,360	40,283	34,295	29,940	26,674