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# Proposed disposal of part of NTS for Carbon Capture and Storage

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**Target audience:** NGG, gas shippers, producers, storage operators, interconnectors, GDNs, other stakeholders and other interested parties

**Overview:**

National Grid Gas has approached Ofgem with an outline proposal for the disposal and possible alternative use of some of its National Transmission System assets for Carbon Capture and Storage (CCS) in Scotland. The proposals may have merit because they would help to tackle climate change by allowing faster testing of the feasibility of CCS as a means of abating carbon, and they could benefit customers by finding an alternative (or more valuable) use for network assets leading to lower transportation bills. There may also be downsides if they lead to bottlenecks on the gas network in the event of new supplies, or if the transfer of the assets does not allow others to use the capacity to transport carbon dioxide on reasonable terms. The Authority has a role in granting consent for this and other significant disposals of NTS assets. This initial consultation paper highlights the key issues, regulatory concerns and benefits associated with this proposal. It also invites comments and views on the proposal to inform the decision on whether to grant consent. This is an early consultation on these proposals. We envisage further consultations will be required should the proposal be taken further.

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## Context

The Department of Energy and Climate Change (DECC) is holding a competition to demonstrate commercial scale Carbon Capture and Storage (CCS) in the UK. This competition is driven in part by a realisation that coal will provide a significant proportion of electricity supply both in the UK and worldwide. The use of coal to generate electricity gives rise to the emission of significant quantities of carbon dioxide ($CO_2$). CCS is seen as a technology that will potentially allow the use of coal without compromising the Government's $CO_2$ targets.

Following completion of the competition, a contract will be awarded to the project which best demonstrates integrated capture, transportation and long term geological storage of carbon using post combustion capture from a coal fired power station. The project must be of a commercial scale – using a power station with at least a 300MW electrical output - and must be located in the UK mainland and extended economic zone (an offshore territorial boundary that extends to 200 nautical miles in some places).

National Grid's[1] potential involvement in the competition is through offering onshore transportation services to one of the parties primarily responsible for the $CO_2$ transportation and storage element of one of the bids. National Grid has identified the opportunity to participate in the competition by using some of the current National Transmission System (NTS) assets to transport $CO_2$ to permanent storage. National Grid has approached Ofgem with an outline proposal for the disposal and possible alternative use of several NTS pipelines for this purpose in Scotland.

National Grid's proposal requires Ofgem's consent to go ahead. If consent for the disposal is granted then it is proposed that the assets cease to be used for natural gas transportation in 2013 and instead be used to transport $CO_2$.

We anticipate that there would be several stages to our consultation on this proposed disposal. This initial consultation document outlines the proposals for the disposal of NTS assets and seeks views from interested parties.

[1] National Grid Gas (NGG) is the owner and operator of the NTS and references in this document to NGG are concerned with the NTS transportation business. References to National Grid refer to the company overall. In this context the CCS opportunity is being pursued by National Grid.

## Associated Documents

- Competition for a Carbon Dioxide Capture and Storage Demonstration Project: PROJECT INFORMATION MEMORANDUM, November 2007 (BERR)
- Towards Carbon Capture and Storage: A Consultation Document, June 2008 (BERR)
- Energy Act 2008 (HM Government)
- Climate Change Act 2008 (HM Government)
- Additional material can be found via the government website below: http://interactive.berr.gov.uk/lowcarbon/the-low-carbon-transformation/

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## Summary

The Department of Energy and Climate Change (DECC) is holding a competition to demonstrate commercial scale Carbon Capture and Storage (CCS) in the UK. This competition is driven in part by a realisation that coal will provide a significant proportion of electricity supply both in the UK and worldwide. The use of coal to generate electricity gives rise to the emission of significant quantities of carbon dioxide ($CO_2$). CCS is seen as a technology that will potentially allow the use of coal without compromising the Government's $CO_2$ targets.

National Grid's potential involvement in $CO_2$ transportation is through offering onshore transportation services to one of the parties primarily responsible for transporting and storing $CO_2$ in the context of the DECC competition. National Grid has identified a possible opportunity to participate in the competition by using some of the current National Transmission System (NTS) assets to provide onshore transportation of $CO_2$ from coal fired power stations to permanent storage. National Grid has approached Ofgem with an outline proposal for the disposal and possible alternative use of several NTS pipelines for this purpose, in Scotland.

We see CCS as an important technology and are keen to ensure that the regulatory regime does not act in a way that unduly hinders its development. The proposals may have merit because they would help to tackle climate change by allowing faster testing of the feasibility of CCS as a means of abating carbon, and they could benefit customers by finding an alternative (or more valuable) use for network assets leading to lower transportation bills. However, there may also be downsides if they lead to bottlenecks on the network if new gas supplies come in, or if the transfer of the assets does not allow others to use the capacity to transport $CO_2$ on reasonable terms. National Grid's request poses a number of issues which we have set out in this consultation document and on which we invite views.

The Energy Act 2008 changed the hierarchy of duties so that it is now explicit that our duty is to present and future customers, and that the requirement that the Authority carries out its functions in the manner which it considers is best calculated to contribute to the achievement of sustainable development is of equal importance to the need to secure that, so far as it is economical to meet them, all reasonable demands in Great Britain for gas conveyed through pipes are met; the need to secure that all reasonable demands for electricity are met; the need to secure that licence holders are able to finance the activities which are the subject of obligations on them; and the interests of individuals who are disabled or chronically sick, of pensionable age, with low incomes, or residing in rural areas. In principle, this proposal is one that needs to be considered in the light of our amended duties.

National Grid Gas's (NGG) proposal requires Ofgem's consent to go ahead. If consent for the disposal is granted then it is proposed that the assets cease to be used to transport natural gas and instead be used to transport $CO_2$. The assets in questions are currently used to provide network capacity at the St. Fergus entry point. NGG is not proposing to change its existing network capacity obligations to shippers following asset disposal. As a consequence revenues from the sale of NTS network

capacity will be unaffected by this proposal. Furthermore in order to keep current capacity obligations unchanged, National Grid has outlined proposals for a potential new compressor or for a mechanism which would allow a shared risk/reward approach.

Agreeing a valuation for the assets and the treatment of any revenues arising from such a disposal are major issues. In the event that consent for disposal were to be granted it has been identified that in addition to a straightforward asset disposal/sale which would attract a lump sum payment based on the valuation alternatives, there is also an opportunity for network users to participate actively in the CCS opportunity through a risk and reward sharing mechanism.

We believe that a starting point for valuing the assets is to consider the extent to which NGG and shareholders have already been remunerated for the assets. Where assets are fully depreciated it may be considered that the shareholders have already been fully reimbursed for their investment and, as such, any benefits which are derived from ownership of the assets should fall to consumers.

However we also recognise that such an approach leaves no incentive for a network operator to find another use for assets it no longer needs. In order to provide sufficient information to assess the proposal for disposal of the pipeline assets, alternative methods of asset valuation have been explored. The consultation also sets out other considerations including the legal framework surrounding disposals, the criteria against which Ofgem must assess any decision, the capability of the network in the St. Fergus area and the impact on the NTS, and security of supply considerations.

In considering the proposal, an assessment of the capability of the network under various forecast flow scenarios was undertaken. National Grid's forecast is that future supplies at St. Fergus will be below the current level which National Grid has an obligation to accommodate, even if new supplies appear. In order to look at the potential risk that network capability could be exceeded, other factors were considered which could increase the likelihood of higher flows being seen, exceeding capability and therefore incurring cost. This has resulted in a range of potential risk/reward sharing options being explored and these are presented here. We invite comments on the appropriateness of the methods of valuation and the risk/reward sharing options. We invite views on two key questions:

(1) do respondents think this proposal is a good idea in principle ; and

(2) if they do, how do we make sure we set up the arrangements for disposal so that customers get a fair share of the benefits.

This is the first stage of the consultation on the proposals for potential disposal of NTS assets. We would expect to publish a further consultation document and potentially an impact assessment, which take account of respondent's views and we seek views from all interested parties in relation to any of the issues set out in this document.

# 1. Background

This chapter outlines the climate change challenge and the contribution to global warming of greenhouse gases such as carbon dioxide, which is emitted when fuel is burned to generate electricity. It explains the potential for Carbon Capture and Storage technology to reduce emissions from fossil fuel burning power stations and industrial sites by significant amounts, and describes the Government's competition which aims to demonstrate commercial scale carbon capture and storage in the UK.

## Climate Change

**Action by governments**

1.1. The European Union (EU) considers that increases in global temperature rises due to $CO_2$ emissions need to be limited to two degrees Celsius to avoid dangerous climate change. It is believed that this can be achieved by cutting emissions. In 2008 the UK passed the Climate Change Act to tackle the dangers of climate change.

1.2. In 1997, the Kyoto Protocol was agreed, which was the first international treaty to set legally binding emissions cuts for industrialised nations. It was signed by 178 countries and came into force in 2005. The government is working towards fulfilling its commitments under the Kyoto Protocol. By 2010, the UK's net greenhouse gas emissions should be around 23 per cent below 1990 levels.

1.3. Fossil fuels are, and will continue to be for the foreseeable future, a vital part of the UK's electricity generation mix, essential for providing secure and reliable electricity supplies. But with around a third of UK $CO_2$ emissions resulting from electricity generation, it is important to encourage a shift to low-carbon technologies if the UK is to continue to use fossil fuels for power generation and meet its long term goal of reducing $CO_2$ emissions by at least 60% by 2050 compared to 1990 levels.

## Carbon Capture and Storage

1.4. Carbon capture and storage (CCS) is the removal, capture and storage of carbon dioxide from fossil fuels either before they are burnt (pre-combustion CCS) or after they are burnt (post-combustion CCS). Captured $CO_2$ must then be contained in some kind of long-term storage such as depleted oil and gas fields. The other element that is required under CCS is a means of transporting the $CO_2$ between the capture plant and the storage location. The government has made clear that at present only storage offshore is being envisaged.

1.5. The offshore location of storage sites poses a range of potential transportation issues. It is expected that the gas would be transported by pipeline over land while, offshore, transportation by either a pipeline or a ship may be possible. The relevant regulatory and safety regimes have yet to be finalised.

1.6. The Government believes that CCS is a particularly important way of reducing emissions given that a significant percentage of the increase in world energy demand is expected to be met by fossil fuels. Coal will continue to play a prominent role in electricity generation because of its abundance and the fact that coal-fired generation can easily respond to fluctuations in energy demand. The Government argues that the ability of CCS to reduce emissions could help to meet the UK's growing energy needs and maintain the security of the UK's energy supply by making coal a viable option for reducing dependence on gas imports.

1.7. CCS has the potential to reduce emissions from fossil fuel burning power stations by significant amounts. In addition to being included in new power stations, it is hoped that, if successful, CCS could be retrofitted to existing plants. All of the different components of CCS technology have been demonstrated in isolation from each other. The Government is now seeking to demonstrate the full chain of CCS technology working on a commercial scale.

## DECC Competition for CCS demonstration project

### Overview

1.8. DECC is holding a competition to demonstrate CCS in the UK. The contract will be awarded to the project which best demonstrates integrated carbon capture, transportation and long term geological storage using post combustion capture from a coal fired power station. The project must be commercial scale – that is using a power station with at least a 300MW electrical output - and located in the UK mainland and extended economic zone (an offshore territorial boundary that extends to 200 nautical miles in some places).

1.9. The Government intends only to contribute towards the additional costs incurred by the project developer in demonstrating capture, transportation and storage technology.

### Technical issues to be addressed

1.10. There are four broad technical aspects of competing projects that DECC will score when analysing bids. First, power generation must be provided by a coal fired station (although co-firing of biomass may be permissible). Second, the method of $CO_2$ capture must be suitable for use in pulverised coal-fired plants (these account for the majority of coal plants globally) and must remove condensed water before transmission to the storage site. Capture technology must also be suitable for retrofitting and capable of capturing around 90% of $CO_2$ output. Third, transportation of $CO_2$ can be by existing or new pipelines, or another approved means (e.g. ship). Pipeline transportation must be compliant with Health and Safety regulations, and

Pipeline Safety Act regulations – DECC also insists that analysis be undertaken to ensure pipeline integrity for at least 15 years. Finally, the storage system must be offshore (e.g. depleted oil and gas field or saline aquifer). A comprehensive monitoring programme for the site must be agreed with the regulatory authority responsible for $CO_2$ transportation and storage.

**Regulatory issues**

1.11. DECC anticipates a number of regulatory issues will need to be addressed at all stages of the project. These may fall within existing regulatory frameworks (UK and EU) or require introduction of new procedures and multilateral agreements.

1.12. Planning permission and environmental consents will need to be gained for the construction of onshore elements of the CCS plant. Environmental consents for water abstraction, wastewater, airborne pollution, and solid wastes amongst others will need to be gained.

1.13. The construction of pipelines will be subject to existing regimes for onshore and offshore infrastructure, the Pipelines Act 1962 and Petroleum Act 1998 respectively. DECC acknowledges there is little precedent for large scale transportation of $CO_2$ under subcritical and supercritical conditions and expect the need for the Health and Safety Executive (HSE) to agree a suitable framework. DECC is in discussion with HSE about exact requirements.

1.14. Injection and storage of the $CO_2$ offshore is governed by an international treaty known as OSPAR[2]. This was amended in 2007 to allow for $CO_2$ storage but requires ratification by seven contracting parties including the UK. The UK is pressing for ratification although this may not be finalised until 2010. Until it is ratified, it will be possible to use purpose built structures or pipelines for injecting $CO_2$ into underground storage sites but it will not be permissible to use existing offshore energy infrastructure to store $CO_2$ under the sea bed except for enhanced oil recovery (EOR). As a form of EOR, $CO_2$ is already being pumped into near-depleted oilfields in the USA and elsewhere to extend their lives. In Norway, Statoil has been re-injecting $CO_2$ co-produced with natural gas into a deep aquifer overlying its offshore Sleipner field, solely for storage.

1.15. The Energy Bill contains dual provisions to enable licences to be issued for regulating underground offshore $CO_2$ storage. The provisions will vest rights to store $CO_2$ offshore. These rights will be administered through the Crown Estate as leases. Additionally permits will be granted by an appropriate regulatory authority.

1.16. The provisions do not contain a detailed regulatory framework; instead it is intended that a framework will be implemented on a case-by-case basis by the

[2] OSPAR is the mechanism by which fifteen Governments of the western coasts and catchments of Europe, together with the European Community, cooperate to protect the marine environment of the North-East Atlantic.

appropriate regulatory authority taking individual site circumstances into account. It is imagined such a licence will include obligations to protect the marine environment, not to interfere with other users of the sea, to pay an annual licence fee, and to state what the operating conditions are for $CO_2$ injection, purity and storage.

**Timetable**

1.17. The following timetable will be undertaken to select a winning bid[3]:

- Pre qualification stage. This closed on 31st March 2008 and interested parties were asked to supply information proving their technical and economic capabilities and understanding.
- First negotiation stage – April to August 2008. This stage took place with the successful bidders from pre-qualification, who were BP Alternative Energy International Limited, EON UK Plc, Peel Power Limited and Scottish Power Generation Limited. This stage will focus on development of technical solutions and address major commercial and contractual issues. These include design issues, review of $CO_2$ storage proposal and additional infrastructure. Once complete, bidders are required to submit an online summary to DECC.
- Second negotiation stage – November 2008 to January 2009. This stage will further develop proposals and DECC's requirements to be set out in the invitation to submit final bids. At the end of this stage bidders are expected to submit fully priced proposals on agreed commercial terms. Topics to be discussed include taxation, financial support model, state aid and regulation issues.
- Final tender stage – March 2009 to September 2009. After consideration of the second stage negotiation submissions, DECC will issue an invitation to submit final bids. These will contain all elements necessary for development of a successful project and be fully costed. Following any further clarifications these final bids will be evaluated with a view to appointing a preferred bidder. DECC will finalise a contract with this preferred bidder.

[3] This is the formal timetable as published by DECC and has not been amended. However we believe that at this moment the project is still at the first negotiation stage.

# 2. Proposal to dispose of assets for $CO_2$ transportation

This chapter describes NGG's proposal to dispose of NTS assets and re-use them for onshore $CO_2$ transportation services, in support of one of the bids in the government's CCS competition. This is to be achieved by the re-use of existing gas feeders which are near to or at the end of their regulatory economic life.

It includes a description of the opportunity to develop CCS and the safeguards that are being considered by National Grid in order to preserve the integrity of the NTS and maintain network capacity obligations at current levels.

**Question 1:** Do you think this proposal is a good idea in principle?

**Question 2:** In the event that a feeder section is removed, existing compressors may be required to work harder to transport the same volumes of gas through fewer pipes. It is proposed to capture these additional compressor fuel costs and to introduce a capped volume for these additional fuel costs, based on pre-disposal levels, over which the new $CO_2$ transportation business would bear the costs and make payment to NGG. What is your view of this proposed treatment of these additional compressor fuel costs?

## Description of NGG's proposal

### Introduction

2.1. National Grid's potential involvement in $CO_2$ transportation is through offering onshore transportation services to one of the bids in the Government's CCS competition. National Grid has identified a possible opportunity to use some current NTS assets, in conjunction with some additional new assets, for providing the onshore transportation of $CO_2$.

2.2. The proposal involves the re-use of existing gas feeders which are near to or at the end of their regulatory economic life. It is viewed that the re-use of existing infrastructure will facilitate a quicker, lower cost and less risky initial deployment of CCS in the UK, which should ultimately benefit the UK economy as a whole through an efficient technical solution to the practical problems posed by CCS. In addition, NGG believes this proposal offers an opportunity for gas consumers to extract some residual value from pipelines which are otherwise expected to be relatively under-utilised in the medium term.

2.3. NGG is not proposing to change existing baselines (which define NGG's obligation to provide capacity at different points on the system) following a disposal, so NGG's existing obligations and auction revenues are unaffected.

In order to keep baselines unchanged, NGG has outlined proposals either: (a) (a) for commissioning a potential new compressor, or (b) establishing a commercial framework that would share the buy-back risk and project rewards with shippers.

2.4. The paragraphs below set out a description of NGG's project and its implications for the NTS, as well as the safeguards NGG is proposing for the gas network, shippers and consumers, should consent be granted to remove these assets from natural gas transport duty.

**Consent for disposal**

2.5. If the bid in which National Grid is involved is successful, NGG will need to seek the formal consent of the Authority to dispose of part of the NTS, so that it may be re-used to transport $CO_2$. This is pursuant to Standard Special Condition A27 (Disposal of Assets) of NGG's gas transporter licence in respect of the NTS.

## Details of the proposal

**Physical Asset Disposal**

2.6. One option being evaluated is to capture $CO_2$ at a Scottish power station and to transport it either onshore (by pipe to St Fergus for onward pipeline transportation) or offshore (by ship) for sequestration in a North Sea field for storage. If the bid partner favours a shipping option to transport the $CO_2$ it would be unlikely to pursue any further involvement for NGG in this project.

2.7. In order to facilitate the option of transporting the $CO_2$ onshore, National Grid has been requested to provide access to onshore pipeline capacity. NGG is considering offering the use of various sections of a feeder pipe from its St.Fergus terminal to the Scottish central belt in order to meet this request. This pipeline option could enable most, if not all, of Scotland's economically recoverable $CO_2$ to be transported into storage, if the project is successful and developed further in the future.

2.8. The assets in question will be nearly fully depreciated for the purposes of their regulatory asset value by the time it is proposed that they will be decommissioned from natural gas use.

2.9. The NGG proposal for the disposal of certain pipeline assets for re-use in $CO_2$ transportation is conditional upon a successful outcome in the DECC demonstration competition, although there may be other opportunities for the development of a Scottish CCS supply chain. To allow sufficient time for the required decommissioning and technical modifications needed for the conversion of the existing assets from natural gas to $CO_2$ transportation, NGG envisages that the relevant sections of the NTS would need to be removed from natural gas service in Q2 2013.

2.10. If National Grid's involvement in a CCS project progresses, NGG will be required to seek the consent of the Authority to dispose of sections of feeder pipelines from the NTS. The general locations of the feeders involved are shown in Figure 1. The pipeline sections are all 36" in diameter and equate to a total pipeline length of nearly 300 km.

2.11. If the Authority consents to the disposal, NGG currently plan to dispose of these assets to a new wholly-owned National Grid company, which will operate them for the purposes of transporting $CO_2$. It is the intention that all maintenance and operation of these assets, once disposed of by NGG, would be fully funded and managed by the National Grid subsidiary and not by NGG.

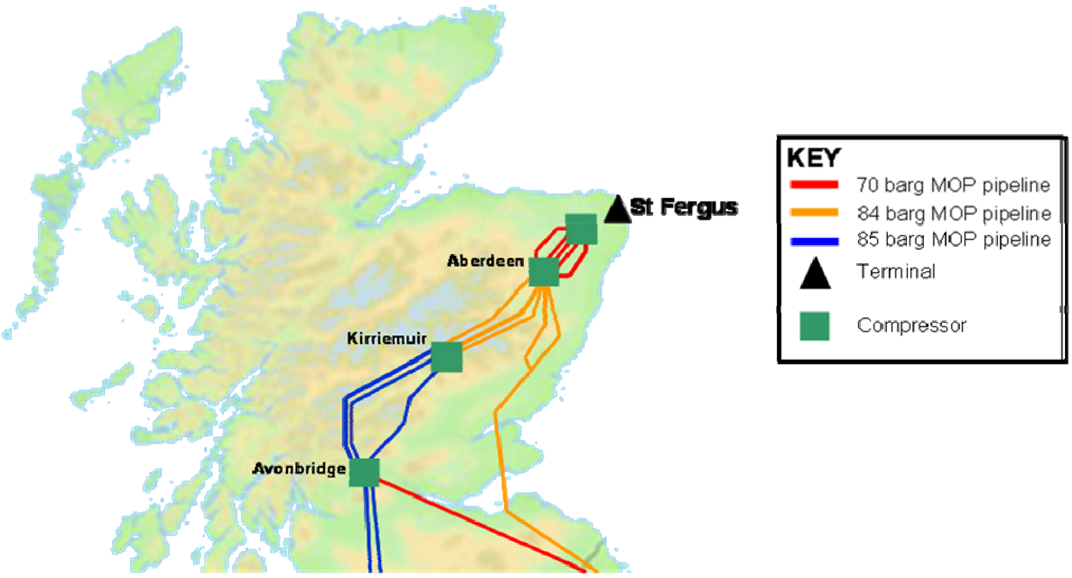


**Figure 1: NTS Pipeline feeders**

2.12. Summary details of the pipeline sections under consideration for conversion to $CO_2$ transportation are shown below:

| Scottish Feeder | Diameter | Approximate length | Pipeline maximum operating pressure |
|---|---|---|---|
| St. Fergus - Avonbridge | 900mm (36") | ~ 300 km | 70 – 85 barg |

**Compressor Fuel**

2.13. There may be an increase in the volume of compressor fuel needed to maintain natural gas system capability if the Authority consents to the disposal of the assets. Under the existing arrangements the costs of this fuel would be recovered through System Operator (SO) commodity charges and are subject to the shrinkage incentive scheme[4]. In order that gas shippers, consumers and NGG are not subjected to higher costs resulting from this disposal, National Grid proposes that the new National Grid subsidiary should pay NGG for any additional volumes of compressor fuel used by NGG in relation to the relevant compressor stations over and above the pre-disposal level. There would also be a need to reflect this in the SO incentives to ensure that the costs are not passed through to shippers.

2.14. NGG's initial analysis suggests that this increase in compressor fuel could generate additional costs in the region of £5m per annum. In order to protect consumers from these higher costs, a mechanism through which this could be managed is being explored. Compressor fuel costs are linked to volume throughput. Current thinking is to introduce a capped volume for these additional fuel costs, based on pre-disposal levels, over which the new National Grid subsidiary would bear the costs and make payment to NGG on an annual basis. However it needs to be recognised that such changes would not be required until 2013, whereas the current SO incentives will be in place until 2012 and will be reviewed as part of the next price control review. We invite views on the appropriateness of such treatment of additional fuel costs.

[4] Under the gas SO incentive scheme NGG is incentivised on a number of cost areas. Shrinkage refers to gas (and electricity) that is either used to operate NTS compressors for system operation purposes or gas that is otherwise unbillable or unaccounted for by the measurement and allocation processes. Shrinkage gas needs to be bought by the SO in its capacity as Shrinkage Provider under the UNC.

# 3. Regulatory issues

This chapter describes the main issues that need to be addressed in assessing whether consent should be granted for the disposal of the assets identified by NGG and sets out the considerations which we will take into account in reaching a decision. It presents detail on the issues and the measures which may be considered to address these. This includes an exploration of the estimated impact in relation to potential buyback exposure.

**Question 1:** Do you agree with our view of the regulatory issues of the proposed asset disposal?

**Question 2:** Do you agree with the projected forecast flows at St. Fergus?

**Question 3:** Are there other flow forecasts or scenarios which should be taken into account?

**Question 4:** What is your view of the indicated capability at St. Fergus with the feeder removed, with and without additional compression?

**Question 5:** What is your view of the projected buyback costs which have been identified?

**Question 6:** Are there any other issues that you believe are relevant?

**Question 7:** What is your view of the proposed disposal of these assets?

## Key Issues

3.1. The planned disposal of part of the NTS to facilitate the transportation of $CO_2$ gives rise to a number of issues which will need to be addressed. These issues include the legal framework surrounding disposals, the considerations that Ofgem will need to have in mind in reaching a decision, the impact on the capability of the network in the St. Fergus area and the NTS more widely, security of supply considerations, the approach to agreeing a valuation for the assets, the treatment of any revenues arising from such a disposal, and the appropriateness of potential consumer involvement in the new business. Each of these issues is discussed below.

### Legal framework

3.2. Standard Special Condition A27 (Disposal of Assets) in NGG's Gas Transporter Licence requires NGG to give the Authority prior written notice of its intention to dispose of or relinquish operational control over any transportation asset. The licensee requires the consent of the Authority to any such disposal. In addition, if the transportation asset comprises a significant part of the gas conveyance system in Great Britain, then NGG also needs to notify the Secretary of State and seek their consent to the disposal.

3.3. The last time the forerunner to Standard Special Condition A27 was deployed was in 2003/04 in relation to the sale by Transco of half its distribution assets. This triggered the notification requirements to the Secretary of State. The Authority consented to the disposal of half of the gas distribution network, but imposed a number of conditions on the approval. We believe that a similar notification is required on this occasion, although it is recognised that the proposed disposal of assets by NGG is directly linked to the outcome of the Government's CCS demonstration competition. We believe that if consent were to be given for disposal, it would need to be associated with a number of conditions.

**Considerations for Ofgem in reaching a decision**

3.4. The Authority's powers and duties are largely provided for in statute and are summarised in Appendix 2 of this document. Duties and functions relating to gas are set out in the Gas Act and those relating to electricity are set out in the Electricity Act. The Authority must when carrying out those functions have regard to:

- The need to secure that, so far as it is economical to meet them, all reasonable demands in Great Britain for gas conveyed through pipes are met;
- The need to secure that all reasonable demands for electricity are met;
- The need to secure that licence holders are able to finance the activities which are the subject of obligations on them;
- The need to contribute to the achievement of sustainable development; and
- The interests of individuals who are disabled or chronically sick, of pensionable age, with low incomes, or residing in rural areas.

3.5. The Energy Act 2008 changed the hierarchy of duties contained in the Acts so that the requirement that the Authority carries out its functions in the manner which it considers is best calculated to contribute to the achievement of sustainable development is of equal importance.

3.6. The Authority’s principal objective when carrying out certain of its functions under the Gas Act and the Electricity Act is to protect the interests of existing and future consumers, wherever appropriate by promoting effective competition between persons engaged in, or in commercial activities connected with, the shipping, transportation or supply of gas conveyed through pipes, and the generation, transmission, distribution or supply of electricity or the provision or use of electricity interconnectors.

3.7. The Energy Act 2008 also makes clear in the text of the Authority's principal objective that it should act in the interests of both existing and future consumers. Whilst the Authority was already required to take into account future consumers, increasing the profile of this requirement was intended as a signal about the significance that should be placed on the interests of future consumers.

3.8. Ofgem's environmental and social duties also require us to take account of guidance[5] to the Gas and Electricity Markets Authority from the Secretary of State in this regard. Section 4AB of the Gas Act and section 3B of the Electricity Act 1989 (inserted by sections 10 and 14 of the Utilities Act 2000) provide that the Secretary of State shall give the Authority guidance as to the contribution which they consider the Authority should make towards the attainment of the government's social and environmental policies.

3.9. The Authority is required to have regard to the guidance when discharging its statutory functions to which its principal objective and general duties apply. The Government therefore expects the Authority to take account of this guidance in its corporate planning process. In this way, the Authority can make a contribution, appropriate to its functions, principal objective and duties, towards the wider social and environmental objectives of the government, without compromising the principle of arm's length regulation.

3.10. The Government has set out four goals for energy policy. It considers that these four policy objectives are in the broad interests of current and future consumers. These goals are:

- To put ourselves on a path to cut the UK's $C0_2$ emissions – the main contributor to global warming – by some 60% by about 2050, with real progress by 2020;
- To maintain the reliability of energy supplies;
- To promote competitive markets in the UK and beyond, helping to raise the rate of sustainable economic growth and to improve our productivity; and
- To ensure that every home is adequately and affordably heated.

3.11. The Government expects the Authority, consistent with its statutory duties, to seek to facilitate the achievement of the social and environmental objectives, targets and aims. The government is committed to achieving its target that greenhouse gas emissions are reduced by 12.5% below 1990 levels by 2008-2010 and a national goal that carbon dioxide emissions are reduced by 20% below 1990 levels by 2010.

[5] Ofgem's Environmental and Social Duties - published on Ofgem's website: www.ofgem.gov.uk

It also wants to put the UK on a path to cut carbon dioxide emissions by some 60% by about 2050, with real progress by 2020.

3.12. The Government considers that, in the longer term, carbon trading should be the central plank of our future emissions reduction policies to achieve our carbon targets. Bearing this in mind, the Government expects the Authority to consider how it can help achieve the carbon dioxide emissions target whilst continuing to protect the interests of consumers. The Government expects the Authority to help secure these targets and aims to ensure that, within their area of influence, barriers inhibiting progress are wherever possible removed.

**Future network requirements**

3.13. In considering NGG's proposal, one of the main concerns is to assess the capability of the network between St. Fergus and Avonbridge under various forecast flow scenarios, and to look at what the impact might be if sections of the feeders between these two points were removed. NGG's 2008 Ten Year Statement indicates a forecast decline in peak day values between the current winter (2008/09) and 2017/18. Although the overall trend is downward over this period, between 2011/12 and 2013/2014 there is a temporary increase in peak day values. Throughout the period, however, maximum forecast flows remain below the baseline[6], currently 1671 GWh/d (154 mcm/d), throughout this period. These trends are shown below.

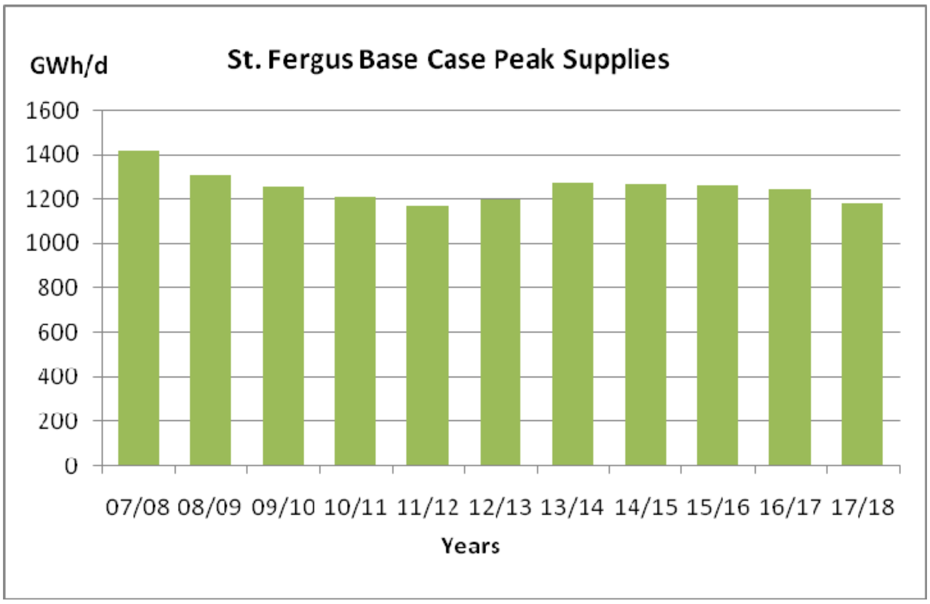


**Figure 2**: **St. Fergus Base Case Peak Supplies**
(Source: data from Table A2.3A in NGG's 2008 Ten Year Statement)

[6] Entry capacity baselines define the reference levels of capacity that the transmission licensee is to release. Baselines also determine the levels above (or below) which incremental capacity is defined.

3.14. In order to assess how projected flows at St Fergus could be accommodated if NGG dispose of part of the assets in this location, we asked NGG to undertake further analysis. This analysis is summarised below.

**NGG view of St. Fergus capability**

3.15. We asked NGG to carry out analysis and provide data about the current capability of the feeders transporting gas south from St. Fergus and to compare this with the situation that would prevail following any asset disposal. In particular, we asked NGG to consider: the current capability and the capability with the pipeline feeder assets removed; the comparison between this capability and forecast flows at St. Fergus; and the comparison with historic flows at St. Fergus. NGG used the following assumptions in its analysis.

- NGG's 2008 Ten Year Statement[7] (TYS) Base Case forecast used, applied to 2012 network infrastructure;
- Removal of a feeder section between Avonbridge and St.Fergus;
- Flows via Teesside and Barrow flows were assumed to be 25mcm/d; and
- As there are no planned changes to NTS infrastructure between 2012 and 2014, NGG assumed the 2012 level of infrastructure.

*St. Fergus capability with current infrastructure and with the feeder removed*

3.16. A demand level of 310mcm was chosen as this is the approximate level at which NGG starts to see flows in excess of 100mcm at St Fergus. A 400 mcm/d demand level is representative of a reasonably high demand day, whereas the 590 mcm/d demand level corresponds to a 1 in 20 peak day demand level (2007 TYS).

3.17. The results of the analysis are shown in Table 1 below:

| | St Fergus Capability | |
|---|---|---|
| | **With current infrastructure** | **With feeder removed** |
| 310mcm demand day | 154mcm/d (stop at baseline) | 132mcm/d |
| 400mcm demand day | 154mcm/d (stop at baseline) | 132mcm/d |
| 590mcm demand day | 154mcm/d (stop at baseline) | 138mcm/d |

**Table 1: St. Fergus capability**

[7] NGG's Ten Year Statement is published in line with Special Condition C2 of its Gas Transporters' Licence and the Uniform Network Code. Special Condition C2 requires that the Ten Year Statement, published annually, shall provide a ten-year forecast of transportation system usage and likely system developments that can be used by companies, who are contemplating connecting to NGG's system or entering into transport arrangements, to identify and evaluate opportunities. In its document NGG has developed a single "Base Case" forecast, which is intended as a starting point for scenario development and analysis.

3.18. The results show little or no variation between the 310 mcm/d and 400 mcm/d demand levels whilst as expected, capability increases when demand levels are high, for example at 590 mcm/d as in the 1 in 20 demand case. This is because the increased demand makes it easier to move more gas south from St. Fergus.

3.19. The results indicate a capability of around 132mcm/d which is equivalent to 1467 GWh/d, using a CV[8] of 40MJ/$m^3$.

*St. Fergus capability with the feeder removed, additional scenarios*

3.20. NGG analysed further scenarios to test the sensitivity of the assumptions and demand levels shown above. For this analysis the following additional assumptions were used:

- In scenarios 1 and 2 Teesside and Barrow flows were flexed to highlight the fact that higher capability at St Fergus is not constraining either terminal;
- Scenario 3 shows historic flows that actually occurred on 30th January 2006 and supports the choice of flow levels used in the analysis for Teesside and Barrow as realistic; and
- Scenarios 4 and 5 were developed to indicate the effect of higher flows at both Teesside and Barrow at the 400mcm/d demand level.

3.21. The results show that capability at St. Fergus remains fairly consistent across the different scenarios; because of the geography the flows are less influenced by actual flows at other terminals. This also indicates that there is no significant variation in capability around average winter demand levels, with little variation even if higher flows are seen at Teesside and Barrow. NGG has calculated that average winter demand (based on the last three years) is 359mcm/d.

3.22. At varying demand levels NGG's analysis gave the following results, which are shown in Table 2 below:

| Scenario | Demand | St Fergus | Teesside | Barrow |
|---|---|---|---|---|
| 1 | 310 | 131.0 | 15.3 | 6.5 |
| 2 | 310 | 133.0 | 25.0 | 25.0 |
| 3 | 395 | 131.0 | 26.0 | 24.2 |
| 4 | 400 | 132.6 | 16.7 | 10.8 |
| 5 | 400 | 130.0 | 25.0 | 25.0 |

*All figures mcm*

[8] Calorific value (CV) is a measure of heating power and is dependent upon the composition of the gas. Gas passing through the NTS has a CV between 37.5 MJ/m3 to 43.0 MJ/m3. An average value of 40 MJ/m3 is used with a conversion factor of 10.833 to convert volumes of gas transported, measured in mcm/d to energy transported, measured in GWh/d.

*St. Fergus capability with the feeder removed, but with added compression*

3.23. The analysis was repeated to analyse the capability with the feeder removed, but with additional compression installed. The assumptions used were:

- New compressor installed
- Teesside and Barrow flows varied to provide different scenarios to illustrate the effect on capability

3.24. The capability results are shown in Table 3:

| *all in mcm* | St Fergus | Teesside | Barrow |
|---|---|---|---|
| 590mcm (1 in 20) demand day | 149 | 44 | 28.6 |
| 400mcm demand day | 147 | 26.7 | 25.8 |

**Table 3: St. Fergus capability with feeder removed and added compression**

**Ofgem initial view**

3.25. We invite comments on the data and analysis carried out by NGG and in particular would like to get views as to whether these figures represent a reasonable approximation of the forecast capability if the proposed feeder sections were removed. We believe that it is reasonable to use the demand levels indicated for the analysis, because they are based on actual historic demand levels which have been experienced. We note that under various scenarios and even with varying demand levels (between 310 - 400 mcm/d) the capability remains at around 130-133 mcm/d. This is some 21-24 mcm/d below the current baseline. Without any compression, this indicates an overall loss in capability of nearly 15%, in comparison to the current level with all feeders available.

3.26. If additional compression is installed the deficit is reduced, but capability is not restored to the original level of 154 mcm/d. NGG's analysis indicates that at peak demand under 1 in 20 conditions the capability would only increase to 149mcm/d. This is a net shortfall of 5 mcm/d (just over 3%) compared to the current baseline.

*St. Fergus historic flows*

3.27. Historic flows at St. Fergus, both average and peak, have shown a steady decline since 2004/05. Actual flows are shown in Table 4 and Figure 3.

| Gas Year | Peak | Average |
|---|---|---|
| 2003/04 | 139.4 | 108.7 |
| 2004/05 | 145.2 | 118.3 |
| 2005/06 | 131.1 | 109.3 |
| 2006/07 | 125.3 | 96.5 |
| 2007/08 | 124.7 | 90.4 |

**Table 4: Historic flows at St. Fergus**

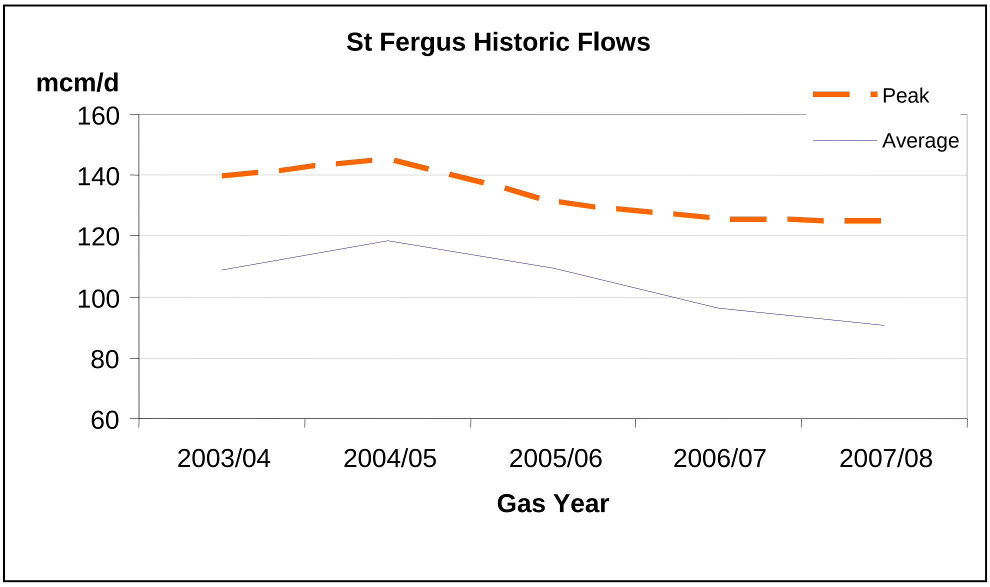


**Figure 3: Historic flows at St. Fergus**

3.28. The trend in historic flows indicates the decline in UKCS gas coming in to St. Fergus, and the underlying trend is believed to continue unless new supply sources connect to this entry point.

*St. Fergus, Teesside and Barrow flows 2008/09 winter to date (January 2009)*

3.29. This winter (October 2008 – March 2009) has been the coldest since 1993, and whilst factors other than just prevailing temperature may determine future flows and the potential risk/exposure at St. Fergus, it does provide some recent data to feed into the analysis. In particular it provides useful information about the interaction between terminals under such conditions, as shown in Figure 4.

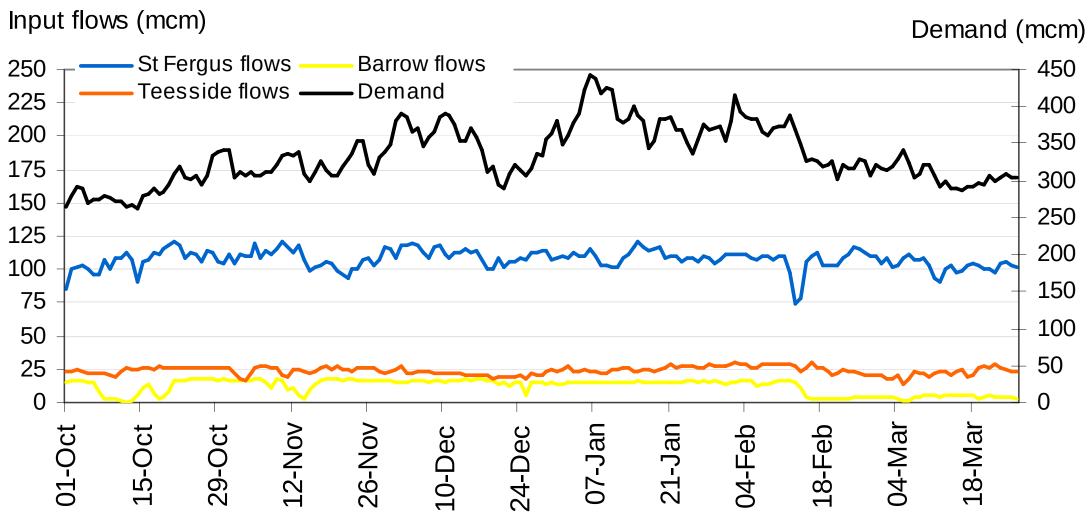


**Figure 4: Actual flows in 2008/09**

*St. Fergus forecast flows 2013 - 2018*

3.30. NGG's Transporting Britain's Energy (TBE) consultation identified two potential new supply sources which could come to St. Fergus. These are the West of Shetland project and potential new imports from Norway. NGG has produced flow forecasts for supplies coming in to St. Fergus through to 2018 and these are shown in Table 5 and Figure 5. Their forecasts use the following assumptions:

- High range as per 2008 Ten Year Statement, and
- All forecasts include provision for West of Shetland and Norwegian imports to St. Fergus

| Forecast basis | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 |
|---|---|---|---|---|---|
| High Range | 134.8 | 135.3 | 136.1 | 134.1 | 128.3 |
| Base Case Peak | 114.7 | 114.1 | 113.8 | 111.4 | 106.1 |
| Base Case Annual | 85.0 | 85.3 | 85.2 | 82.9 | 76.3 |

**Table 5: Forecast flows at St. Fergus**

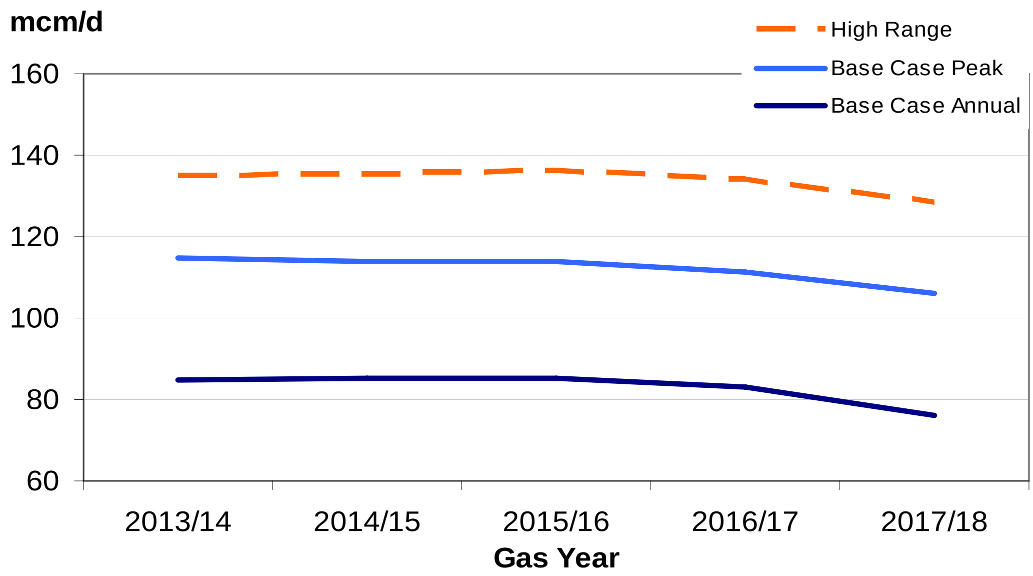


**Figure 5: Forecast flows at St. Fergus**

3.31. Using the latest forecast figures from its 2008 Ten Year Statement base case, NGG's analysis indicates that system capability will be able to meet requirements, although it may come close to the revised capability with the feeder removed. NGG sought advice from Wood Mackenzie to validate its figures given the difficulty in forecasting supply patterns against global influences and commercial drivers. Figure 6 shows the NGG and Wood Mackenzie (WM) views of future supplies against a capability level rounded to 130mcm/d.

3.32. The availability of assets for carbon dioxide transportation is only possible in light of the forecast change in supply patterns over the coming decade. NGG's Ten Year Statement base case forecast for the years 2013/14 - 2017/18 shows that flows are highly unlikely to reach 130mcm/d, with less than 10% probability of flows higher than 113mcm/d between these years.

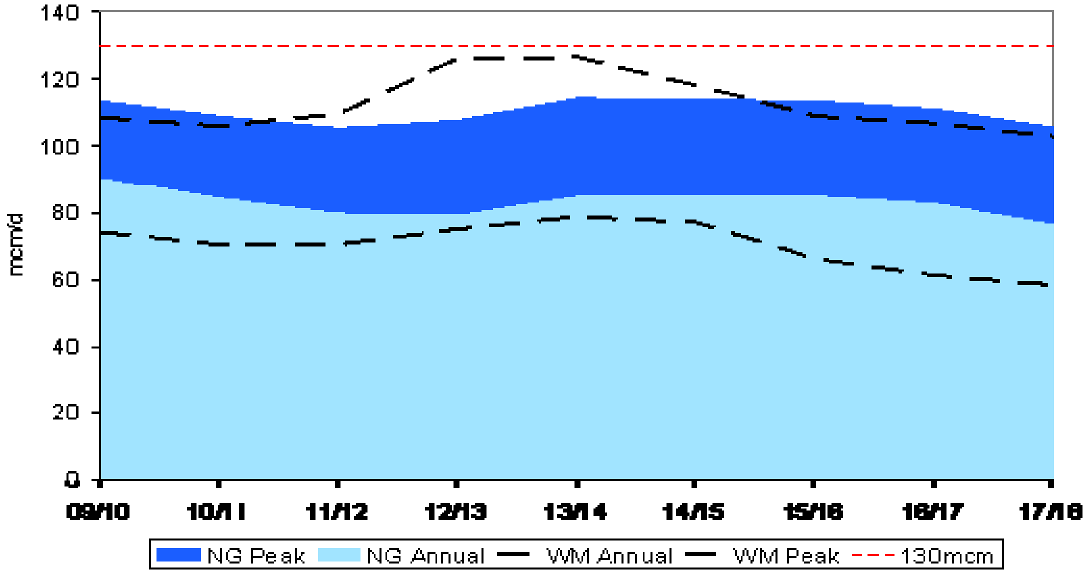


**Figure 6: Capability and forecast flows**[9]

**Ofgem initial view**

3.33. A common feature of all the NGG forecasts is that future supplies at St. Fergus will be below the current baseline level, even if new supplies appear. The highest peak day level is for the year 2015/16 when flows of around 136mcm/d could be expected under the high range scenario. However NGG's 2008 Ten Year Statement base case forecast does not predict peak flows above 115mcm/d over the same period. This compares with a predicted capability of 130-133 mcm/d if one of the existing feeders were to be removed.

3.34. We welcome views on the flow forecasts set out above and invite comments about the robustness and accuracy of the figures presented. In particular we would be interested to hear if there are any other flow forecasts or scenarios which should be taken into account.

3.35. We note that NGG believes that beyond 2018, the continuing decline in existing UKCS production is such that it will not result in forecast flows reaching a level which could not be accommodated within the capability of the network with the feeder sections removed. The main area of uncertainty is about whether potential new supplies will connect to St. Fergus and if they do, whether the expected flows will be in the high range of those which are forecast. We would be particularly interested to hear from project developers and shippers in this regard.

[9] The data used here was taken from a report commissioned by NG and produced by Wood Mackenzie, entitled “UK Natural Gas Supply/Demand Outlook”)

**Baselines and Buy-back**

3.36. NGG's analysis has focussed on the gas years 2013/14 - 2017/18 and they note that there are inherent difficulties with forecasting this far out. Beyond this point there is little perceived risk of capability constraining supplies, based on current forecasts. In order to provide an assessment of the risks of capability constraining supplies, we asked NGG to undertake analysis on the buyback[10] exposure (constraint volumes and values, as well as probabilities) that could occur in the event that flows exceeded capability, with one feeder removed.

3.37. Long term capacity bookings (as at January 2009) are indicated in Figure 7. Aggregate AMSEC[11] and QSEC[12] bookings are shown for all formula years.

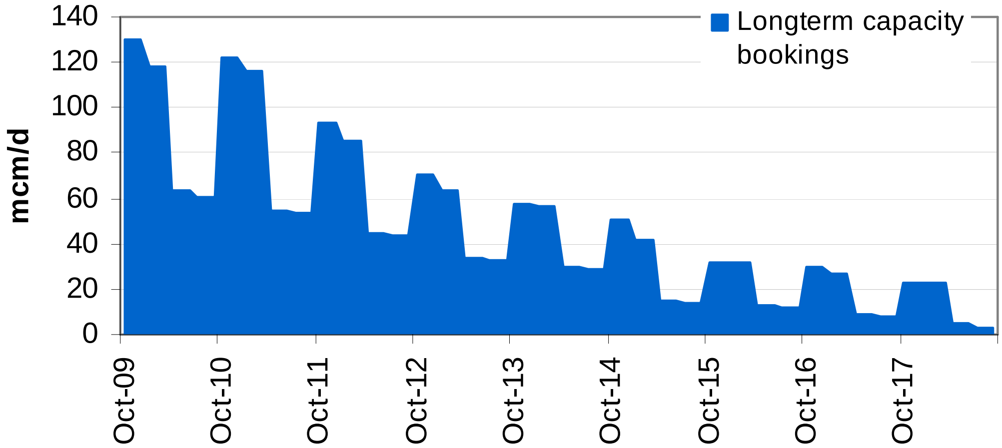


**Figure 7: Capacity bookings**

3.38. Analysis has shown that, because of its position on the NTS, St. Fergus capability is determined by local compression and pipelines, with less dependency on flows from other terminals. In order to look at the potential buyback exposure, NGG has considered other factors which could increase the risk of flows exceeding capability and therefore incurring buyback. The factors they have considered are:

- Failure of a northern compressor and consequent reduction in capability through remaining pipelines with a feeder removed;
- Higher West of Shetland flows; increasing to above the 20mcm/d levels used in the Ten Year Statement high case forecast; and

[10] Buyback is the process of compensating users if NGG is unable to deliver entry capacity, which is sold on a financially firm basis, and users wish to flow gas against the capacity holding.
[11] Annual Monthly System Entry Capacity
[12] Quarterly System Entry Capacity

- Higher imports from Norway; increasing above the 62mcm/d level used in the Ten Year Statement high case forecast

*Failure of a northern compressor*

3.39. NGG undertook analysis of the likelihood of St. Fergus flows exceeding the reduced capability that would be left if either Kirriemuir or Aberdeen compressors were unavailable, having removed a feeder.

3.40. For the buyback analysis NGG has assumed that the northern compression fleet would be working harder than currently and at times of higher flows may be subject to greater stress. NGG has considered compressor reliability statistics and for the purposes of this analysis, assessed the probability of a compressor failure at Kirriemuir or Aberdeen. The analysis was based on the gas network infrastructure that would be in place in 2012, with the feeder section between St. Fergus and Avonbridge removed. The analysis assumes complete unavailability of the Kirriemuir or Aberdeen compressors, or unavailability such that the terminal was unable to recover its end-of-day requirement by overflowing.

3.41. Both Kirriemuir and Aberdeen are generally considered to be reliable compressor stations. Whilst historic data is based on historical performance information, there is no evidence to suggest that compressor reliability should reduce with a reduced number of feeders. All units would still be operating within specified parameters.

3.42. Existing gas compressor data was used in the analysis. However, by 2012 NGG expects to have installed an electric drive at Kirriemuir. The change to an electric drive is not expected to have an adverse effect on reliability, however. NGG intends that the original gas compressor units will remain in place for a time following the changeover to electric drive thereby increasing resilience beyond current levels at Kirriemuir. This increased resilience has been assumed in the analysis.

3.43. The capability at St. Fergus is dependent upon a reliable northern compression fleet. The impact of key compressor stations failing on flow capability was assessed through network simulations. St. Fergus compressors failing were not simulated, as realistically this would mean a reduction in terminal capability regardless of the infrastructure available to move gas away.

3.44. A demand level of 359mcm/d was used, as representative of an average winter demand (based on three years historic data) and represents a more conservative approach than using peak day demand, whereby demand would assist in moving gas south. The buyback price was assumed to be 1p/kWh. The potential buyback costs[13] are shown below:

| | **Total buyback cost for 2013/14 – 2017/18, £m** | |
|---|---|---|
| | **Base case** | **High case** |
| P10 | 0.0 | 0.0 |
| P50 | 21.7 | 27.3 |
| P90 | 60.1 | 77.2 |

**Table 6: Cumulative buyback costs for 2013/14 to 2017/18**

3.45. A year-on-year breakdown of the estimated buyback costs for both "base case" and "high case" flows (as shown in Table 5) is shown in Figure 8 and Figure 9.

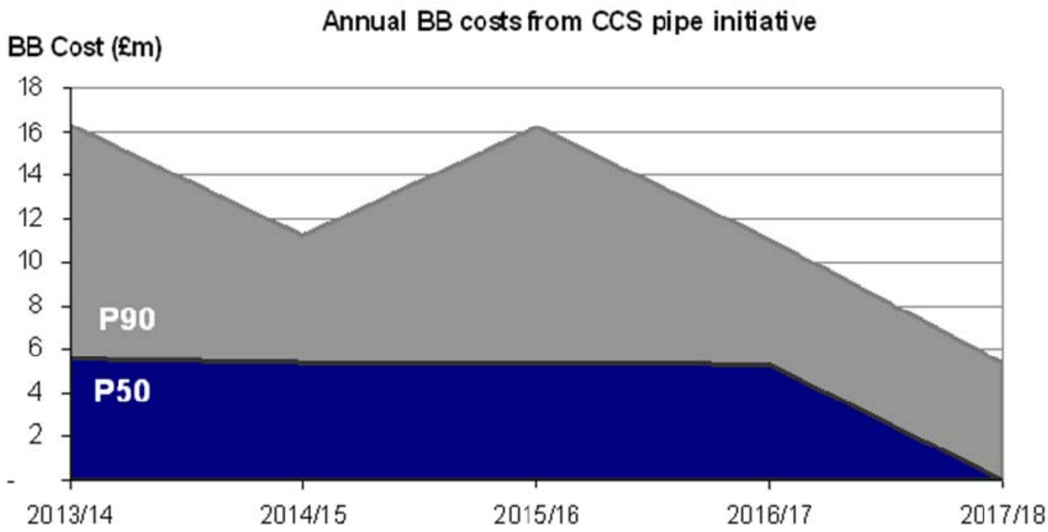


**Figure 8: Base Case buyback estimate**

[13] The values P10, P50, and P90 are percentiles; P90 for example represents the value at the 90th percentile, i.e. the value for which there is a 90% probability that the final value will be lower and a 10% probability that the final value will be higher.

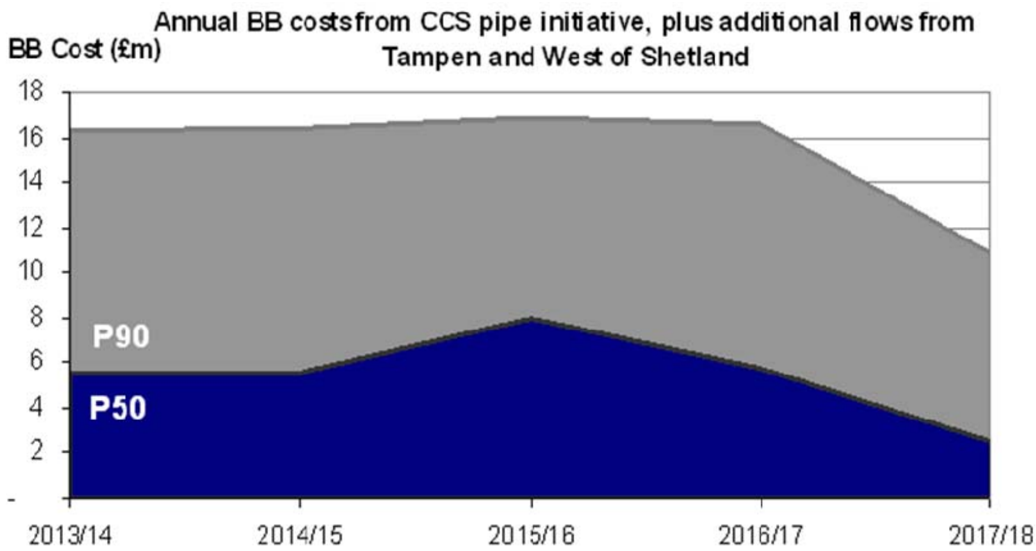


**Figure 9: High Case buyback estimate**

**Ofgem initial view**

3.46. We note that the analysis indicates that there could be a residual buyback risk beyond 2017/18 in both cases. This is particularly so in the event that high case flows occur. We believe that whilst considerable uncertainty remains about future supplies arriving at St. Fergus, it needs to be borne in mind that the removal of a feeder will create additional risk because of the increased reliance on compression to move gas away from the terminal. Based on past data, NGG has chosen a buyback price at the top end of the range, 1 p/kWh/d. Although this is plausible it could be argued that it will over-state the potential exposure to buyback costs.

3.47. Under the current regime, any unsold baseline capacity can be moved to other entry points where it might be valued more using the capacity trade and transfer mechanism. Also, in future we expect a capacity substitution methodology to be developed which would enable the permanent move of baseline capacity from one entry point to another entry point. Such a permanent reduction in baseline at St. Fergus would reduce the obligation with respect to capacity release for NGG and would reduce the buyback exposure as a result. In such circumstances any additional capacity would need to be triggered via an incremental signal allowing NGG to decide whether to invest to meet the new higher obligation.

**NGG Estimated Impact Value (EIV)**

3.48. The potential buyback described earlier may be mitigated by the construction of an additional compressor, the cost of which needs to be balanced against the likelihood of buyback occurring. The greatest part of the EIV relates to the additional capacity buyback costs to which NGG and consumers might be exposed as a result of the overall reduction in the capacity of the NTS south of St. Fergus if the feeders in question were to be removed. While, on its present analysis, NGG considers that the risk of any buyback costs arising is small, NGG recognises that the impact of these costs could be significant. However, NGG considers that an appropriate ceiling can be placed on these costs by considering the costs of the alternative assets that could be installed on the NTS to provide substantially the same capability as if the existing assets had not been removed.

3.49. NGG considers that this can be achieved by assessing the costs of a new compressor which could be installed to give the pipeline system the same (or very similar) operational capability as it would have were the feeders to remain part of the NTS. The installation of additional compression equipment would mitigate buyback risk by preventing constraints from arising and retain the flexibility of the NTS to accommodate higher than forecast levels of new supplies (such as from Norway or West of Shetland).

3.50. Should further investment be required to accommodate new gas flows, beyond that which could be provided by the current infrastructure, investment could be triggered and funded according to the existing market signals and lead-times. The current estimated cost of a compressor (with associated civil works and control equipment) which would achieve the necessary capability increase at St Fergus is in the region of £80m.

3.51. NGG believes that given the current view of natural gas supplies, it could be considered inefficient to invest in a compressor in an area of the network, the use of which is expected to decline significantly long-term. Indeed, the perceived risk of flows at St Fergus in excess of 130mcm/day is such that it may be considered more appropriate to manage any temporary period of constraints through capacity buybacks, should such constraints materialise. This may be appropriate given that the general longer-term decline of UKCS and Norwegian gas supplies means that constraints are less likely to arise in the longer run.

3.52. NGG estimates that these feeder sections would otherwise be decommissioned around 2020 given their expected life, forecast decline in UKCS, and the ultimate decline in Norwegian supplies. The costs associated with decommissioning would normally be borne by NGG and thus gas shippers and consumers, however if sold for re-use, decommissioning costs would be borne by the CCS project. Gas consumers will benefit directly from the removal of the need to continue supporting maintenance of the depreciated assets, as well as by avoiding these decommissioning costs.

**Delivery lead times for an additional compressor**

3.53. NGG believes that the cost of additional compression appears unwarranted when considered against the limited risk over an interim period. However it remains NGG's preferred risk mitigation option if baselines are to be preserved at their current values and a risk/reward approach is not favoured. In the event of higher than forecast flows materialising at St. Fergus additional compression could be added to the remaining feeders to increase capability by around 20mcm/d.

3.54. If such a solution was favoured then NGG could undertake several actions in order to minimise the construction lead time for a new compressor on the NTS. This includes site selection studies to determine potential and preferred locations, conceptual design of the compressor and associated pipework, and the initiation of environmental studies.

3.55. It would not be usual for NGG to undertake such work until an appropriate user commitment signal has been received. However NGG believes that in the event that consent is granted and a feeder is removed, the trigger for the above would be a NGG decision. Depending upon the terms agreed for the disposal of the pipe NGG could undertake such works irrespective of market factors. Doing all of the above could potentially reduce the investment lead time by a year or so. Any costs incurred by this would be paid for by the National Grid subsidiary set up to develop the CCS opportunity.

3.56. NGG's current view is that investing in a new 40 year compressor asset at an approximate cost of £80m, does not appear to compare favourably with the low probability of a perceived constraint risk of around £30m over a four year period.

**TPCR4 treatment of St. Fergus related capex**

3.57. In December 2006, our TPCR Final Proposals[14] for NGG excluded £19 million of some £75 million expenditure relating to the delivery of baseline capacity at St Fergus. This was because we considered that NGG had not provided adequate justification for this investment in the light of indications of demand for capacity arising from the long term entry auctions.

3.58. We believed that NGG did not review its initial investment decision in light of important new information on the location of large new sources of gas supply. Our view was that NGG ignored key information at the time and made questionable decisions in the context of the entry capacity regime which had recently been introduced. In our TPCR Updated Proposals document[15], we considered whether this investment should be excluded from the Regulatory Asset Value (RAV) in its entirety or should be included at a discounted value.

3.59. We concluded that, since this project was initiated in the early days of the new entry regime when the treatment of such expenditure may not have been fully clear, it would have been inappropriate to exclude it from the RAV altogether. Instead, we treated this expenditure as if it represented expenditure in excess of allowance

[14] TPCR 2007-2012 Final Proposals, December 2006 (Ref No. 206/06)
[15] TPCR 2007-2012 Updated Proposals, September 2006 (Ref No. 170/06)

within the price control period. The effect of this was to allow £56 million to enter the RAV at the time at which the expenditure was incurred.

3.60. A key consideration for us in forming a view on the efficiency of load related capital expenditure (capex) is the extent to which the investment decisions are based on strong evidence of long term demand for capacity from network users (backed by financial commitment). The absence of such user commitment evidence at St Fergus was the main factor in our decision only to include part of the investment undertaken by NGG in the RAV.

3.61. Investment based on strong evidence of long term user commitment has a clear, unambiguous case for inclusion in the RAV subject only to a test that the cost of the required volume of investment is reasonable. We believe that similar arguments should apply to consideration of proposed disposal of assets, as in this instance. In this regard the evidence of strong user commitment would be a factor in any decision made about consent for disposal of assets and the potential investment in a new compressor by NGG to maintain capability and preserve the current St. Fergus baseline.

3.62. Our assessment of the treatment of capex related to St. Fergus under TPCR4 was based on the information available to NGG at the time it made its investment decision. We do not believe that the current proposal for the potential disposal of assets constitutes a reason for us to re-examine this decision and re-open the price control.

## Security of Supply Considerations

3.63. NGG's proposal has been structured in such a way, with the option of constructing additional compressors, as to try and preserve current natural gas capability as far as possible. By retaining current baseline levels at St. Fergus, NGG believes there is no reduction in the flexibility offered to potential new supplies such as those that may materialise from West of Shetland or Norway. Both National Grid and Wood Mackenzie forecasts show future expected flows from West of Shetland and Norway, including growth, and both anticipate actual flows will be well short of the existing baseline at St Fergus.

3.64. Apart from the issues described above in relation to St Fergus capability and the potential to accommodate new supplies, there is a potential wider benefit from the successful demonstration of CCS and NGG's ability to facilitate this.

3.65. From the wider standpoint of the security of UK energy supplies, if the new National Grid subsidiary can provide $CO_2$ transportation services, this should help secure the long-term future of Scottish power generation. In addition, once CCS is proven and developed in both scale and economics, it will allow the UK to use coal reserves at other power stations with minimal carbon emissions and thus provide security of supply whilst facilitating government emissions reductions.

## Other Network Considerations

### Entry capacity substitution

3.66. NGG has a licence obligation to implement entry capacity substitution. Entry capacity substitution is the process by which unsold non-incremental obligated baseline entry capacity is moved from one or more NTS entry points to meet the demand for incremental obligated entry capacity at another NTS entry point. St. Fergus is a potential donor entry point for substitution, because of the level of unsold baseline capacity and declining UKCS production.

3.67. Whereas new supply sources may connect to St. Fergus, NGG's forecast flow data suggests that even if high range estimates for these new supplies are adopted, the current baseline would still be above the maximum forecast flow level. Whilst the methodology for implementing capacity substitution is still under development by NGG, the potential for capacity to be substituted away from St. Fergus remains.

3.68. The potential disposal of assets could therefore impact on substitution at St. Fergus. If capacity remains unsold at St. Fergus and can be substituted away to another entry point (in accordance with the methodology being developed) then this may reduce the need for additional compression to be installed in order to restore capability back to current levels. Since substitution is intended to be a permanent reduction of baseline at the donor entry point, capability above the revised (lower) baseline level could only be provided in response to a signal for incremental entry capacity triggered at an auction.  We would welcome industry views on the relationship between NGG’s proposal and the ongoing work to develop a methodology for substitution.

### NTS Linepack

3.69. This proposal, if executed in full, may have a limited effect on NGG’s provision of flow flexibility services and the amount of linepack NGG holds, although NGG does not anticipate that these will have significant cost or operational implications. It should be noted there is a cost benefit resulting from this proposal as the value of the linepack contained with the disposed feeder sections which will be displaced onto the NTS. NGG estimate the value of this at around £2m, which is a one-off benefit to shippers. We welcome views on this.

### Other benefits

3.70. This proposal also has a benefit resulting from the removal of decommissioning costs for the natural gas pipelines which would be borne by gas shippers and consumers, were the assets left in service allowed to depreciate further following the decline of UKCS.

**NGG's Gas Safety Case**

3.71. NGG believes that the removal of specific feeder sections will not cause any failure to comply with, or fully satisfy, its safety case obligations. NGG contends that sufficient linepack contingency will remain available in Scotland such that NGG does not consider this proposal to present any additional or undue risk to the gas network through weakened physical resilience.

# 4. Valuation of assets

In this chapter, alternative methods of valuing the assets are described including a description of the assumptions associated with each. A resulting range of values for the assets has been calculated, indicating the potential transaction values associated with a disposal. This includes options for the potential sharing of risks and rewards in the event that consent were to be granted and the assets earned revenues from $CO_2$ transportation in future.

**Question 1:** Do you agree with the possible ranges of valuations for the assets which have been identified?

**Question 2:** Do you agree with the assumptions which underpin the asset valuations?

**Question 3:** Is there an alternative method of asset valuation which should be considered?

**Question 4:** Do you agree with the assessment of benefits associated with asset disposal and alternative use?

**Question 5:** Are there any other considerations that should be taken into account?

## Introduction

4.1. An important consideration in any asset disposal is the value that should be ascribed to the asset in question. This is an input to the decision on the extent to which customers should benefit from the disposal of the asset.

4.2. Alternative methods of asset valuation have been considered and these are described below. There are many methods which may be used to calculate such a value and several have been considered here. A range of values for the asset has been estimated using several approaches, to provide enough information to allow a full assessment of the proposal.

### Key assumptions

4.3. NGG balance sheet data, where it is used to calculate a value, is based on April 2008 figures; no subsequent new investment which may occur before disposal, is factored in. It is calculated that pipeline assets comprise 83% of the balance sheet value.

4.4. Depreciation is projected to 2013, in line with the DECC competition timeline and expected decommissioning dates. The assumed asset life of pipelines is taken to be 50 years.

4.5. The length of assets proposed to be disposed of is approximately 300 km in total. The assets are associated with Feeders 10, 11 and 12 and the pipelines identified for disposal represent 18% of the total length of the St. Fergus feeders.

4.6. The analysis excludes any costs which may be incurred to modify the assets in order to make them fit for $CO_2$ duty and does not take account of other costs, such as operating costs, or the costs of adding new infrastructure to connect to the emissions source.

## NGG view of possible methods of asset valuation

4.7. NGG has suggested several approaches to valuing the asset. These include :

| | |
|---|---|
| Value at MEA | The modern equivalent asset (MEA) value is what it would cost to replace an old asset with a technically up-to-date new asset with the same service capability. |
| Economic life adjusted | Remaining value if the assets are not taken out of service until they become surplus, assumed to be for 5 years after 2013, in this case. |
| DECC Competition value | A valuation based on the period of the DECC competition. |
| Original design expectation | A valuation based on the difference between the original design life and the date the assets could be taken out of service. |
| Asset register depreciated | A valuation based on asset register values and depreciation. |
| NTS infrastructure value | Valuation based on balance sheet values. |
| Pipeline years adjusted value | A calculation which takes the age of the assets into account as well. |

4.8. This has resulted in asset valuations in the range £0.2m to £182m. These are further explained below.

## MEA - based valuation

4.9. Modern equivalent asset (MEA) values have been calculated using three different sets of criteria and these are summarised in Table 7 below:

| Pipe Section | First use | Fully depreciated | Value at MEA | Asset value per year (50 year asset life) | Economic life adjusted | DECC competition value | Original design expectation |
|---|---|---|---|---|---|---|---|
| | Year | Year | £m | £m | £m | £m | £m |
| a | 1975 | 2025 | 281.40 | 5.63 | 28.14 | 90.05 | 67.54 |
| b | 1976 | 2026 | 153.08 | 3.06 | 15.31 | 48.99 | 39.8 |
| c | 1978 | 2028 | 134.48 | 2.69 | 13.45 | 43.03 | 40.34 |
| **Totals** | | | 568.96 | 11.38 | **56.9** | **182.07** | **147.68** |

**Table 7: MEA values**

4.10. Economic adjusted life has been calculated as the residual value of the assets, calculated as at a future year when the asset may become surplus, because of continuing forecast UKCS decline (assumed to be 2018 in this case). This is based on the asset value per year multiplied by the remaining economic life. This gives a value of £56.9m.

4.11. The DECC competition value is calculated based on the asset value per year multiplied by the period of the DECC competition, which is 16 years. This calculation assumes the same per year value for $CO_2$ transportation, but this is going beyond the period of full depreciation as a natural gas asset. This gives a value of £182.07m.

4.12. The original design expectation (assuming a 50 year design life) is calculated as the difference between the fully depreciated year and the year when the assets are considered for disposal (2013) multiplied by the asset value per year for each of the pipe sections. This gives a value of £147.68m.

4.13. These MEA methodologies generate a range of values from £57m to £182m, but assign the same theoretical value to depreciated pipelines as would apply to a new-build pipe. These valuations also omit the costs of development for CCS: asset refurbishment and connections. It also assumes a new asset would be built to the same size.

## Asset register depreciated value

4.14. The following values are derived by looking at the balance sheet values for the three pipeline sections in aggregate. The value is calculated by taking the percentage of the total length which is identified for disposal and multiplying this by the remaining balance sheet value at 2013.

| | |
|---|---|
| Feeder 10, 11, 12 Balance sheet value[16] | £3,004,319 |
| Depreciation to 2013 | - £1,908,972 |
| Remaining Balance sheet value at 2013 | £1,201,347 |
| | |
| Total length of feeders | 1,605 km |
| Total length for disposal (in aggregate) | ~300 km |
| Disposal as % of whole | 18% |
| | |
| <u>Value of assets for disposal</u> | **£212,939** |

### Proportionate NTS infrastructure value

4.15. This calculation reflects the value of the assets to be disposed of as a proportion of the entire NTS pipeline infrastructure. The respective pipeline lengths are used to give a value on a simple pro rata basis in comparison with the total.

| | |
|---|---|
| Total NTS pipeline length | 7,383 km |
| Total length for disposal (in aggregate) | ~300 km |
| Disposal length as % of whole | 3.9% |
| | |
| Balance sheet value at 2013 | £3,078,882,000 |
| Pipeline value (83% of balance sheet total) | £2,555,472,000 |
| Total length of feeders | 1,605 km |
| <u>Value of assets for disposal</u> | **£98.5m** |

### Pipeline years adjusted value

4.16. This methodology considers pipeline age in addition to pipeline length. The asset life is assumed to be 50 years from date of commissioning to full depreciation.

4.17. Pipeline usage value is calculated as follows:

pipeline usage value = length x (((year of commissioning) +50) - 2013)

For a 35 km pipeline commissioned in 1970 this is calculated as

= 35 x (((1970) + 50) - 2013)
= 35 x (2020 - 2013)
= 35 x 7
= 245

[16] Taken from the asset register value, as contained in NGG's balance sheet

| | |
|---|---|
| Total network remaining pipeline usage value | 97,416 |
| Pipeline usage value of assets for disposal | 3,646 |
| Pipeline usage value of assets for disposal as a % of total | 3.7% |
| Pipeline value (83% of balance sheet total) | £2,555,472,000 |
| Pipeline years adjusted value | **£95.6m** |

**Ofgem initial view**

4.18. We believe that a starting point for valuing the assets is to consider how NGG and shareholders have been remunerated for the assets. Where assets are fully depreciated it may be considered that the shareholders have already been fully remunerated for their investment and, as such, any benefits which are derived from ownership of the assets should fall to consumers.

4.19. However we also recognise that such an argument leaves no incentive for a network operator to find another use for assets it no longer needs, as in this instance. Such an approach also ignores the potential 'residual' value of a fully depreciated asset, for which a new use may be found, which may then increase its value for the new duty.

4.20. NGG argues that the higher the asset valuation, the less economically viable it becomes to re-use these assets for $CO_2$ transportation, and the less likelihood of a CCS supply chain wishing to use pipeline transportation in preference to alternatives, such as ship-borne transportation, at the extreme resulting in a "missed opportunity". In this instance there would be no value returned to consumers. We believe that such an argument needs to be balanced against Ofgem's primary duty of protecting consumers and the need to ensure that any valuation represents fair value for consumers and reflects the value of the assets in alternative use.

# 5. Commercial Options

This chapter explores the commercial options for the potential sharing of risks and rewards in the event that consent were to be granted and the assets earned revenues from $CO_2$ transportation in future.

**Question 1:** Do you consider that the opportunity to potentially share in the benefits of CCS using ex NTS assets represents an appropriate balance of risk and reward?

**Question 2:** What is your view of a lump sum payment, in the event that consent is granted for disposal?

**Question 3:** What is your view of a participatory royalty arrangement, in the event that consent is granted for disposal?

**Question 4:** Are there other risks/benefits which should be taken into account?

## Potential Risk/Reward Sharing

5.1. It has been identified that in addition to a straightforward asset disposal/sale which would attract a lump sum payment based on the valuation alternatives described above, there is also an opportunity for network users to participate actively in the CCS opportunity through a risk and reward sharing mechanism.

5.2. We set out the likely impact on the NTS of the proposed asset disposal in chapter 3. From NGG's analysis of capability compared to future forecast flows, there is a clear indication that the probability of flows approaching the current baseline level is low and that the likelihood of the reduced capability being reached or exceeded, is greatest over the period 2014 - 2018. The cost of adding additional compression, which is estimated at approximately £80m, needs to be considered against the limited risk over the interim period. One way to address this uncertainty is to consider the potential risk of buyback over this period and to consider the merits of sharing a proportion of this buyback risk through a risk and reward sharing mechanism.

5.3. If successful in the competition, funding for the project will be provided by DECC. The National Grid subsidiary would wish to offer this bid party a transportation service (comprising capacity and operating costs) which would be designed to recover its costs over the duration and volumes of the DECC competition, together with any additional volume/duration that was negotiable/possible.

5.4. The National Grid subsidiary would pay NGG in one of the following ways:

- a lump sum payment reflecting the value of the physical assets transferred, or

- a royalty payment linked to the tonnage of $CO_2$ transported through the modified assets for the competition.

Both payments would need to offer fair representation of the asset value and EIV, and in the case of the royalty option to reflect the balance of risk borne by each party.

5.5. NGG has explored a number of options which would allow gas shippers and consumers to participate in both the potential risks and rewards of the CCS project. These options have been developed on the basis that baselines will not change as a result of the disposal of the feeders from NGG. The project will only generate net revenues after bearing the costs of acquiring the asset, modifying it for $CO_2$ transportation, and covering resultant and residual gas transmission risks and costs. The structure of pricing options is an attempt to align National Grid and consumers' interests and provide potential benefits and upsides to both.

## National Grid Payment Options

5.6. The aim of these options is to provide a balanced and flexible set of choices for gas Shippers. The options include recognition of the potential buyback risk, balanced by potential of reward from business growth in CCS.

### Option 1: Lump Sum Payment

5.7. Under this option the National Grid subsidiary would pay a lump sum for the value of the asset. Additionally, the National Grid subsidiary would pay NGG in respect of any increased capacity buyback costs resulting from the removal of the sections of the feeder pipes from the NTS, up to the cost of the additional compressor required to restore the capability of the NTS back to the level it would have been at but for the transfer of the feeders.

5.8. There is no exposure to shippers as baselines are preserved and the buyback risk is covered by the National Grid subsidiary. Shipper charges would be reduced as a consequence of the reduced RAV, following the change in use of the asset.

### Option 2: Simple Royalty

5.9. Under this payment option, the National Grid subsidiary would pay NGG a "royalty fee" calculated on the basis of the tonnage of $CO_2$ actually transported. The payment would be set at a level that will remunerate the value of the feeders transferred to it, and pay NGG in respect of any increased capacity buy-back costs resulting from the removal of the feeder pipes from the NTS, up to the cost of the additional compressor required to restore the capability of the NTS back to the level it would have been before the transfer of the feeders.

5.10. This arrangement offers limited share of CCS growth with no exposure to buyback costs. Royalty payments would be enduring beyond competition timescales. There is no share of risk under this structure. NGG has suggested that royalties should be paid on a volume of $CO_2$ capped at 6Mte/yr, as this represents the pipeline capability in terms of $CO_2$ transport without any additional investment. On the basis of a royalty payment of £0.5/tonne, total expected royalty payment between £15m - £35m to 2029 could be expected, depending upon CCS growth. This potential volume growth is shown in Figure 10 below:

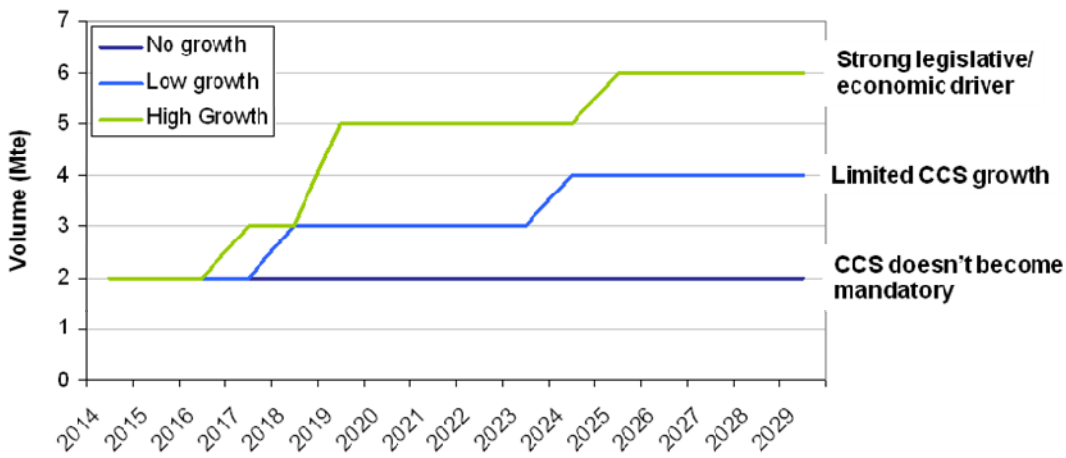


**Figure 10: CCS volume growth examples**

5.11. The notional CCS growth scenarios are based on the following assumptions:

**CCS does not become mandatory (No Growth)** Lack of enforced compliance, and a low carbon price, could result in little or no growth beyond DECC competition volumes. Similarly, economics, technology, regulation and other factors could result in CCS either not being adopted at a larger scale, or only being implemented beyond 2029.

**Limited CCS growth (Low Growth)** This growth profile could reflect (for instance) increased industry commitment to CCS following a successful demonstration, but uncertainty around economic viability. Alternatively, there may be absolute certainty on all aspects of CCS, but a need to adopt a phased approach due to limitations of infrastructure capability. Commodity prices and the cost of money would be just two factors likely to influence the rate of investment and subsequent growth in abated volumes.

**Strong legislative / economic driver (High Growth)** A rise in the carbon price, mandatory legislation, viable economics and appropriate regulation would all support this more aggressive profile. Other factors such as political support and industry collaboration to create more cost-effective CCS clusters could speed up the rate of investment and also reduce the associated risks.

**Further considerations**

5.12. There is some potential upside in a risk reward sharing mechanism between NGG and the new subsidiary. Three scenarios have been considered as a basis for the potential risk/reward valuations. These are linked to the likely growth in CCS volumes in the future, allowing other power stations to be connected to the $CO_2$ transportation system. Higher growth in CCS volume would be achieved by connecting further power stations to the $CO_2$ transportation network and this would require additional investment by National Grid.

5.13. The likelihood of such growth is dependent upon several factors, including the success of the DECC competition, potential changes in legislation and government policy and the desired uptake for CCS overall. The regulatory regime for $CO_2$ transportation is still under development and uncertainty remains about the ability of revenues from higher CCS volumes to flow through to NGG under a risk/reward sharing mechanism.

5.14. Similarly there is a downside risk that constraint volumes could be higher than forecast, which would impact on the net revenues flowing through to NGG under such a mechanism. Similarly the cost of a new compressor could be higher than forecast and if delayed, could also result in higher constraint costs, which we believe that NGG should not be exposed to**.**

**Option 3: Participatory Royalty**

5.15. As for Option 2, the National Grid subsidiary would pay NGG a “royalty fee” calculated on the basis of the tonnage of $CO_2$ actually transported. However, under this option the NG subsidiary would have no further liability to NGG because the risk of the additional buy-back costs faced by NGG as a result of the transfer of the feeders would be factored into the level of the royalty payment. This structure offers limited share of CCS growth with shared exposure to buyback costs. NGG has suggested that royalties should be paid on a volume of $CO_2$ capped at 6Mte/yr, as in Option 2. A royalty payment of between £0.75 - £0.87/tonne would apply depending on the sharing factors for buyback risk. The following sharing factors are suggested:

**Share of risk** Shipper : National Grid subsidiary

| | |
|---|---|
| Option 3A: | 40:60 |
| Option 3B: | 50:50 |
| Option 3C: | 60:40 |

5.16. Total expected royalty payments are £22.5m - £60.9m to 2029 and the total expected buyback risk is £10.9m - £46.3m to 2029. Table 8 summarises the expected royalty payments from 2014 - 2029.

| | Shipper Share of BB Risk | Shipper BB Costs | | Shipper Royalty Rate | Shipper Royalty Income 2014 - 2029 | | |
|---|---|---|---|---|---|---|---|
| | | P50 | P90 | | No growth | Low growth | High growth |
| | % | £m | £m | £/tonne | £m | £m | £m |
| **Option 3A** | 40% | 10.9 | 30.9 | 0.75 | 22.5 | 36.0 | 52.5 |
| **Option 3B** | 50% | 13.7 | 38.6 | 0.80 | 24.0 | 38.7 | 56.0 |
| **Option 3C** | 60% | 16.4 | 46.3 | 0.87 | 26.1 | 41.8 | 60.9 |

**Table 8: Shared risk and royalty income**

5.17. NGG believe that the interests of the National Grid subsidiary and consumers in this option are aligned since the bearing of risk by NGG in return for a higher royalty fee per tonne of $CO_2$ transported can be seen to be more akin to a form of "quasi equity" participation in the $CO_2$ transportation activity of the National Grid subsidiary.

## Summary

5.18. Table 9 summarises the features of each of the payment options. In the table, "Benefit from growth" refers to the scope for customers to gain from increases in the net revenue from $CO_2$ transported (competition volumes) after refurbishment and other costs. "Exposure to downside" refers to the extent to which customers would be required to bear some of the buyback costs.

| | Upfront payment | Benefit from growth | Exposure to downside |
|---|---|---|---|
| **Lump sum payment** | ✓ | ✗ | ✗ |
| **Simple royalty** | ✗ | ✓ | ✗ |
| **Participatory royalty** | ✗ | ✓ | ✓ |

**Table 9: Features of payment options**

## Ofgem's initial view

5.19. We believe that a risk/reward mechanism has merits given the current forecasts, which indicate that there is a low probability of higher flows at St. Fergus, and that it does present an opportunity for consumers to share in the benefits of $CO_2$ transportation in the event that consent is granted for the disposal of assets and that the bid supported by National Grid wins the DECC CCS competition. We therefore invite views on the proposals set out above.

# Appendices

**Index**

# Appendix 1 - Consultation Response and Questions

1.1. Ofgem would like to hear the views of interested parties in relation to any of the issues set out in this document.

1.2. We would especially welcome responses to the specific questions which we have set out at the beginning of each chapter heading and which are replicated below.

1.3. Responses should be received by 22 May 2009 and should be sent to:

Bogdan Kowalewicz
Gas Transmission
Ofgem
9 Millbank
London SW1P 3GE

E-mail responses should be sent to:
gas.transmissionresponse@ofgem.gov.uk

1.4. Unless marked confidential, all responses will be published by placing them in Ofgem's library and on its website www.ofgem.gov.uk. Respondents may request that their response is kept confidential. Ofgem shall respect this request, subject to any obligations to disclose information, for example, under the Freedom of Information Act 2000 or the Environmental Information Regulations 2004.

1.5. Respondents who wish to have their responses remain confidential should clearly mark the document/s to that effect and include the reasons for confidentiality. It would be helpful if responses could be submitted both electronically and in writing. Respondents are asked to put any confidential material in the appendices to their responses.

1.6. Next steps: Having considered the responses to this consultation, Ofgem intends to issue a further consultation. Any questions on this document should, in the first instance, be directed to:

Bogdan Kowalewicz
Senior Manager, Gas Transmission Policy
9 Millbank
London, SW1P 3GE
Tel: 020 7901 7293
gas.transmissionresponse@ofgem.gov.uk

**CHAPTER 2: Proposal to dispose of assets for $CO_2$ transportation**

**Question 1:** Do you think this proposal is a good idea in principle?

**Question 2:** In the event that a feeder section is removed, existing compressors may be required to work harder to transport the same volumes of gas through fewer pipes. It is proposed to capture these additional compressor fuel costs and to introduce a capped volume for these additional fuel costs, based on pre-disposal levels, over which the new $CO_2$ transportation business would bear the costs and make payment to NGG. What is your view of this proposed treatment of these additional compressor fuel costs?

**CHAPTER 3: Regulatory issues**

**Question 1:** Do you agree with our view of the regulatory issues of the proposed asset disposal?

**Question 2:** Do you agree with the projected forecast flows at St. Fergus?

**Question 3:** Are there other flow forecasts or scenarios which should be taken into account?

**Question 4:** What is your view of the indicated capability at St. Fergus with the feeder removed, with and without additional compression?

**Question 5:** What is your view of the projected buyback costs which have been identified?

**Question 6:** Are there any other issues that you believe are relevant?

**Question 7:** What is your view of the proposed disposal of these assets?

**CHAPTER 4: Valuation of assets**

**Question 1:** Do you agree with the possible ranges of valuations for the assets which have been identified?

**Question 2:** Do you agree with the assumptions which underpin the asset valuations?

**Question 3:** Is there an alternative method of asset valuation which should be considered?

**Question 4:** Do you agree with the assessment of benefits associated with asset disposal and alternative use?

**Question 5:** Are there any other considerations that should be taken into account?

**CHAPTER 5: Commercial options**

**Question 1:** Do you consider that the opportunity to potentially share in the benefits of CCS using ex NTS assets represents an appropriate balance of risk and reward?

**Question 2:** What is your view of a lump sum payment, in the event that consent is granted for disposal?

**Question 3:** What is your view of a participatory royalty arrangement, in the event that consent is granted for disposal?

**Question 4:** Are there other risks / benefits which should be taken into account?

# Appendix 2 – The Authority's Powers and Duties

1.1. Ofgem is the Office of Gas and Electricity Markets which supports the Gas and Electricity Markets Authority ("the Authority"), the regulator of the gas and electricity industries in Great Britain. This Appendix summarises the primary powers and duties of the Authority. It is not comprehensive and is not a substitute to reference to the relevant legal instruments (including, but not limited to, those referred to below).

1.2. The Authority's powers and duties are largely provided for in statute, principally the Gas Act 1986, the Electricity Act 1989, the Utilities Act 2000, the Competition Act 1998, the Enterprise Act 2002 and the Energy Act 2004, as well as arising from directly effective European Community legislation. References to the Gas Act and the Electricity Act in this Appendix are to Part 1 of each of those Acts.[17]

1.3. Duties and functions relating to gas are set out in the Gas Act and those relating to electricity are set out in the Electricity Act. This Appendix must be read accordingly[18].

1.4. The Authority's principal objective when carrying out certain of its functions under each of the Gas Act and the Electricity Act is to protect the interests of consumers, present and future, wherever appropriate by promoting effective competition between persons engaged in, or in commercial activities connected with, the shipping, transportation or supply of gas conveyed through pipes, and the generation, transmission, distribution or supply of electricity or the provision or use of electricity interconnectors.

1.5. The Authority must when carrying out those functions have regard to:

- The need to secure that, so far as it is economical to meet them, all reasonable demands in Great Britain for gas conveyed through pipes are met;
- The need to secure that all reasonable demands for electricity are met;
- The need to secure that licence holders are able to finance the activities which are the subject of obligations on them[19];
- The need to contribute to the achievement of sustainable development; and
- The interests of individuals who are disabled or chronically sick, of pensionable age, with low incomes, or residing in rural areas.[20]

1.6. Subject to the above, the Authority is required to carry out the functions referred to in the manner which it considers is best calculated to:

[17] entitled "Gas Supply" and "Electricity Supply" respectively.
[18] However, in exercising a function under the Electricity Act the Authority may have regard to the interests of consumers in relation to gas conveyed through pipes and vice versa in the case of it exercising a function under the Gas Act.
[19] under the Gas Act and the Utilities Act, in the case of Gas Act functions, or the Electricity Act, the Utilities Act and certain parts of the Energy Act in the case of Electricity Act functions.
[20] The Authority may have regard to other descriptions of consumers.

- Promote efficiency and economy on the part of those licensed[21] under the relevant Act and the efficient use of gas conveyed through pipes and electricity conveyed by distribution systems or transmission systems;
- Protect the public from dangers arising from the conveyance of gas through pipes or the use of gas conveyed through pipes and from the generation, transmission, distribution or supply of electricity; and
- Secure a diverse and viable long-term energy supply.

1.7. In carrying out the functions referred to, the Authority must also have regard, to:

- The effect on the environment of activities connected with the conveyance of gas through pipes or with the generation, transmission, distribution or supply of electricity;
- The principles under which regulatory activities should be transparent, accountable, proportionate, consistent and targeted only at cases in which action is needed and any other principles that appear to it to represent the best regulatory practice; and
- Certain statutory guidance on social and environmental matters issued by the Secretary of State.

1.8. The Authority has powers under the Competition Act to investigate suspected anti-competitive activity and take action for breaches of the prohibitions in the legislation in respect of the gas and electricity sectors in Great Britain and is a designated National Competition Authority under the EC Modernisation Regulation[22] and therefore part of the European Competition Network. The Authority also has concurrent powers with the Office of Fair Trading in respect of market investigation references to the Competition Commission.

[21] or persons authorised by exemptions to carry on any activity.
[22] Council Regulation (EC) 1/2003

# Appendix 3 - Glossary

**A**

### Aggregate System Entry Point (ASEP)

A point where gas can enter the NTS.

### Annual Monthly System Entry Capacity (AMSEC) auction

An auction, held annually, for the sale of monthly rights to enter capacity on to the NTS at the various entry points for up to two years in advance.

### The Authority (Ofgem)

Ofgem is the Office of Gas and Electricity Markets, which supports the Gas and Electricity Markets Authority (GEMA), the body established by Section 1 of the Utilities Act 2000 to regulate the gas and electricity markets in Great Britain.

**B**

### Baseline

Baselines define the levels of capacity that the transmission licensee is obligated to release. Baselines also determine the levels above which incremental capacity is defined.

### Baseline Capital Expenditure

Baseline capital expenditure is the total amount of capex required in association with the baseline. It includes both load related capex and non-load related capex.

### Buy-back

The process of compensating users if NGG is unable to honour entry capacity holdings, which have been sold on a financially firm basis and users wish to flow against them.

**C**

### Capital Expenditure (Capex)

Expenditure on investment in long-lived transmission assets, such as gas pipelines or electricity overhead lines.

CCS

Carbon capture and storage

Calorific Value (CV)

The ratio of energy to volume measured in Megajoules per cubic meter (MJ/m3) which for a gas is measured and expressed under standard conditions of temperature and pressure.

**D**

DECC

Department of Energy and Climate Change. The Department brings together much of the Climate Change Group, previously housed within the Department for Environment, Food and Rural Affairs (Defra), with the Energy Group from the Department for Business, Enterprise and Regulatory Reform (BERR).

**F**

Free increment

The highest amount of additional capacity that can flow into that zone without investment.

**I**

Incremental Entry Capacity

Entry capacity in addition to the baseline which NGG releases for allocation. Obligated Incremental Entry Capacity is capacity which has been signalled to be released as a result of QSEC auction.

**L**

Least helpful Supply Substitution

This is an approach to determine the level of baselines which seeks to identify the maximum capacity that could be released at each entry point at system peak. It can be characterised by increasing the supply at the entry point being investigated whilst reducing supply across other entry points in order to keep the NTS balanced. Supply is reduced at other entry points according to which has least benefit to the NTS in terms of incurring lower network reinforcement costs, with the least helpful reduced first. This is likely to be the entry point which is geographically furthest from the one under investigation.

**N**

### National Grid Gas (NGG)

The licensed gas transporter responsible for the gas transmission system, and four of the regional gas distribution companies.

### National Transmission System (NTS)

The high pressure gas transmission system in Great Britain.

**O**

### One in Twenty Obligation

This is a security standard for the licensee to have a pipeline network which meets peak aggregate daily demand at levels which would be expected to occur in one year in twenty when considering the historical weather data for at least the previous 50 years, and other relevant factors.

### OSPAR

OSPAR is the mechanism by which fifteen Governments of the western coasts and catchments of Europe, together with the European Community, cooperate to protect the marine environment of the North-East Atlantic. It started in 1972 with the Oslo Convention against dumping. It was broadened to cover land-based sources and the offshore industry by the Paris Convention of 1974. These two conventions were unified, up-dated and extended by the 1992 OSPAR Convention. The new annex on biodiversity and ecosystems was adopted in 1998 to cover non-polluting human activities that can adversely affect the sea.

The fifteen Governments are Belgium, Denmark, Finland, France, Germany, Iceland, Ireland, Luxembourg, The Netherlands, Norway, Portugal, Spain, Sweden, Switzerland and United Kingdom. Finland is not on the western coasts of Europe, but some of its rivers flow to the Barents Sea, and historically it was involved in the efforts to control the dumping of hazardous waste in the Atlantic and the North Sea. Luxembourg and Switzerland are Contracting Parties due to their location within the catchments of the River Rhine.

**P**

### Practical Maximum Physical Capacity

An approach to determining the level of baselines which can be characterised by estimating the volume of maximum capacity available at each node on the network, according to a range of plausible flow scenarios whilst taking into account interactions with flows elsewhere on the network.

## Q

### Quarterly System Entry Capacity (QSEC)

Firm NTS Entry Capacity which may be bid for in the Quarterly System Entry Capacity (QSEC) auctions and registered as held by a User for each day in a particular calendar quarter. Entry capacity is sold forward via QSEC Auctions which offer capacity at each aggregate system entry point between two and sixteen years in advance.

## S

### Substitution of Entry Capacity

As part of the TPCR 2007-2012 package, NGG is obliged to facilitate the permanent substitution of baseline capacity from one or more entry points to another entry point to meet the demand for incremental obligated entry capacity.

### System Operator (SO)

The system operator has responsibility to construct, maintain and operate the NTS and associated equipment in an economic, efficient and co-ordinated manner. In its role as SO, NGG NTS is responsible for ensuring the day-to-day operation of the transmission system.

## T

### Ten Year Statement (TYS)

Special Condition C2 (Long Term Development Statement) requires NGG NTS to annually publish a ten-year forecast of NTS usage and likely developments that can be used by companies, who are contemplating connecting to the NTS or entering into transport arrangements, to identify and evaluate opportunities.

### Theoretical Maximum Physical Capacity

An approach to determining the level of baselines which can be characterised as the maximum amount of gas that can be taken through a particular entry or offtake point by reducing supplies at other nodes in order to balance the network but not taking into account interactions with flows elsewhere on the network.

### Transfer and Trade of Entry Capacity

As part of the TPCR 2007-2012 package NGG is obliged to facilitate the temporary transfer of unsold capacity (and trade of previously sold capacity) at an entry point to another entry point on the NTS where there is demand for this capacity.

### Transmission Owners (TO)

Companies which hold transmission owner licences. NGG NTS is the gas TO.

### Transmission Price Control Review (TPCR)

The TPCR established the price controls for the transmission licensees and took effect in April 2007 for a 5-year period. The review applies to the three electricity transmission licensees, NGET, SPTL, SHETL and to the licensed gas transporter responsible for the gas transmission system, NGG NTS

**U**

### Unit Cost Allowance (UCA)

A parameter of the current revenue restriction for NGG. A UCA is set for each entry point, and is intended to reflect the cost of providing additional capacity at that point on the network. The actual additional revenue entitlement for NGG if it releases such additional capacity at a particular entry point is a function of the UCA for that entry point.

### Uniform Network Code (UNC)

As of 1 May 2005, the UNC replaced NGG NTS's network code as the contractual framework for the NTS, GDNs and system users.

# Appendix 4 - Feedback Questionnaire

1.1. Ofgem considers that consultation is at the heart of good policy development. We are keen to consider any comments or complaints about the manner in which this consultation has been conducted. In any case we would be keen to get your answers to the following questions:

1. Do you have any comments about the overall process, which was adopted for this consultation?
2. Do you have any comments about the overall tone and content of the report?
3. Was the report easy to read and understand, could it have been better written?
4. To what extent did the report's conclusions provide a balanced view?
5. To what extent did the report make reasoned recommendations for improvement?
6. Please add any further comments?

1.2. Please send your comments to:

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