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Decision

RIIO-T1 reopener: One-off Asset Health Costs (Feeder 9)

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Overview

The RIIO-T1 price control includes two reopener windows for companies or Ofgem to propose adjustments to expenditure allowances for certain cost categories that were deemed to be too uncertain to provide ex ante allowances at the time of our Final Proposals.

In May 2018, we received an application from National Grid Gas Transmission (NGGT) for additional allowances under the "One-off Asset Health Costs" category to cover the costs of building a tunnelled replacement of the Feeder 9 pipeline under the River Humber. On 8th August 2018 we published our initial views for consultation with stakeholders. This document sets out our decision on NGGT's application.

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Executive summary

This document sets out our decision on National Grid Gas Transmission's (NGGT's) application for an allowance of £139.9m[1] to fund the replacement of a section of the Feeder 9 pipeline with a new pipeline that would be placed in a new tunnel under the Humber estuary. This application was made under a price control reopener mechanism that allows companies to seek funding for certain categories of costs that were uncertain at the start of the current price control.

Following our assessment of NGGT's application and responses to our consultation, we have decided to accept the need for replacement. We have also decided to increase NGGT's baseline allowance by £111.3m, which is our view of the efficient cost of replacement.

Background

Feeder 9 is a high-pressure gas transmission pipeline built in 1984 and operated by NGGT. It carries gas from the Easington Terminal on the east coast of England towards the South West. The Easington Terminal is the main importation point for Norwegian gas, and provides approximately 20% of the UK's gas supply.

The Feeder 9 pipeline crosses the Humber estuary near the port of Hull through a trench dug into the river bed. Surveys carried out by NGGT in 2009 showed that river bed erosion had exposed sections of the pipeline, leaving it vulnerable to damage. NGGT carried out risk mitigation works on these exposed sections in 2010 by placing concrete frond mattresses and gravel bags on top and on either side of the pipeline. NGGT considers that the risk mitigation works are only likely to last for 5 – 10 years. NGGT believes that a more efficient long-term solution is to build a replacement pipeline through a new tunnel to be built under the river Humber. NGGT has estimated that the replacement would cost £139.9m, and this forms the basis for NGGT's application.

NGGT's application set out its case for the project, which argued that replacing the pipeline now offers the best value for consumers as the cost of replacement is lower than the potential harm to consumers from the loss of Feeder 9. NGGT had identified a number of adverse consequences to consumers from the potential loss of Feeder 9, and had submitted a cost benefit analysis (CBA) to support its position.

Our initial views

We carried out a detailed assessment of NGGT's case for replacement, including its CBA. NGGT's analysis relied on a number of assumptions, including probabilities of different risks to the pipeline materialising, and the possible consequences if that risk were to materialise. While we had broadly accepted NGGT's assumptions about the consequences, we had a number of concerns with the probabilities attached to the different risks to the pipeline. We believed that NGGT's assumptions had substantially overstated the risks to the pipeline. We carried out our own CBA using more reasonable assumptions about risk probabilities, which suggested that immediate replacement of the pipeline is not justified. We therefore set out our initial view that NGGT had not made the case for replacing Feeder 9 now, and that unless new information came to light during the consultation, we would reject NGGT's request for funding.

[1] Unless otherwise stated, all costs and allowances in this document are expressed in constant (i.e. 2009/10) prices.

In reaching our initial view, we had sought advice from the Health and Safety Executive (HSE) and independent technical consultants. Our analysis, and the advice we received from the HSE and technical consultants was published with our consultation document.

Additional information received and consultation responses

Shortly before we published our consultation, we received additional new information from NGGT on the operational impact of the loss of Feeder 9. This information was provided too late for us to take account of when reaching our initial view – however, we said that we would consider this information before making our final decision. NGGT submitted further information on this and other issues as part of its formal consultation response.

The new information provided by NGGT on operational impacts represents a significant shift from its original submission. NGGT identified several new impacts that it had not considered in its original CBA (mainly the impact on electricity prices and impact on gas-fired electricity generators), and made large upward revisions to its assumptions about other impacts (i.e. impact on gas prices and entry capacity constraint costs). NGGT also provided further information about non-quantifiable impacts, such as reduced resilience of the network to further outages, increased costs to consumers through higher perceived risks to security of supply and reduced diversity of gas supplies.

We also received several responses from stakeholders who were concerned about the possible impact of the loss of Feeder 9 on security of gas supplies and gas prices.

Our final decision

We have reviewed the additional information provided by NGGT, and we have decided to accept the changes proposed by NGGT. While it is difficult to estimate with precision the impacts of the loss of Feeder 9, we are satisfied that NGGT’s revised assumptions better capture the potential consequences than its original submission. We updated our CBA model accordingly, and our revised CBA results suggest that the quantitative case for replacement is now finely balanced. However, when the additional qualitative (non-quantifiable) impacts are taken into account, we think the balance is tipped in favour of replacement. We have therefore decided to accept NGGT’s case for replacing the relevant section of Feeder 9 pipeline.

As part of our initial assessment of NGGT’s application, we had carried out an assessment of the efficient costs of replacing the Feeder 9 pipeline. We set out our initial view that the efficient cost of replacement is £104.6m, rather than the £139.9m requested by NGGT. Our initial view was that NGGT’s proposed costs for project management activities and its provision for contingencies/risks were excessive.

In its consultation response, NGGT disagreed with our assessment and provided further information to justify its estimates for project management costs and risk provisions. We have reviewed NGGT’s response and additional information, and have decided to accept, in part, NGGT’s arguments for an increase to our view of efficient costs. We have decided that the efficient cost of the project is £111.3m.

We have therefore decided to increase NGGT’s baseline allowances for the RIIO-T1 period by £111.3m. Any changes to NGGT’s revenues (and consumer bills) will be implemented from 1 April 2019.

1. Introduction

Context

1.1. RIIO-T1 and GD1 were the first price controls to reflect the new RIIO (Revenue = Incentives + Innovation + Outputs) model. The RIIO-T1 price control sets the outputs that the electricity and gas transmission network companies need to deliver for consumers and the associated revenues they are allowed to collect for the eight-year period from 1 April 2013 until 31 March 2021.

1.2. For cost categories where there was significant uncertainty about expenditure requirements at the time of setting allowances, the price controls include a "reopener" mechanism. This mechanism allows network companies to propose adjustments to baseline expenditure allowances for these cost categories when there is more certainty. The reopener mechanism has two windows during which adjustments to allowances maybe proposed – one in May 2015 and the other in May 2018.

1.3. The cost categories subject to the RIIO-T1 reopener for gas transmission are:

- Enhanced Physical Site Security Costs;
- Industrial Emissions Costs;
- Pipeline Diversion Costs;
- Quarry and Loss Development Claim Costs;
- One-off Asset Health Costs; and
- Network Flexibility Costs.

1.4. The reopener process fits into priorities 3 and 4 of the 2018-2019 Ofgem Corporate Strategy.

1.5. We received a number of submissions from network operators under the various cost categories. NGGT submitted five reopener applications

1.6. We consulted on our initial views of the submissions received during the May 2018 window on 8th August. We are required to make a determination by 30 September 2018 on any application received through the reopener mechanism.

1.7. This document sets out our decision on National Grid Gas Transmission (NGGT's) reopener application under the "One-off Asset Health Costs" category.

Background to the reopener

1.8. During the May 2015 reopener window, we received an application from NGGT for additional allowances of £139.9m[2] to fund the costs of building a tunnelled replacement to a section of the Feeder 9 gas transmission pipeline. This application was made under the "One-off Asset Health Costs" category.

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[2] All costs in this document are in 2009/10 prices, unless otherwise stated.

1.9. The Feeder 9 pipeline is a high-pressure gas transmission pipeline owned and operated by NGGT. The pipeline runs from the Easington Terminal on the East coast of England, towards Hatton Compressor Station in Lincolnshire and onwards to the South West.

1.10. Feeder 9 crosses the Humber estuary near the port of Hull through a shallow trench on the river bed. The underwater section of the pipeline is approximately three kilometres long, of which approximately one kilometre is under a busy shipping channel.

1.11. Underwater surveys conducted by NGGT in 2009 showed that river bed erosion in the vicinity of Feeder 9 had led to sections of the Feeder 9 pipeline being exposed, leaving it susceptible to the risk of damage from "freespanning"[3] and third party interference (e.g. anchor drop/drag or shipwreck). In 2010, NGGT carried out remediation works on the underwater section of the pipeline by installing approximately 760m of concrete frond mattresses and 300 tonnes of gravel bags on top and alongside Feeder 9. A further round of remediation work was undertaken in 2013 on a small section of the pipeline (50m).

1.12. NGGT has said that the remediation is temporary and only likely to last for 5 – 10 years. NGGT believes that a more efficient long-term solution is to build a replacement pipeline through a tunnel under the River Humber.

1.13. In its Business Plan submission for the RIIO-T1 price control period, NGGT requested between £100m and £150m to fund the cost of constructing a replacement pipeline in a new tunnel to be dug under the river.

1.14. We did not provide the requested funding for the project. However, in our Final Proposals, we did provide upfront funding of £6.6m to cover the costs of *"preliminary engineering and licensing activities".* [4] We also included a reopener mechanism, through which NGGT could apply for the appropriate funding once it had secured planning permission.

1.15. Since our RIIO-T1 Final Proposals decision in December 2012, NGGT undertook preliminary engineering and licensing work to progress its preferred option of building a tunnelled replacement for Feeder 9. In May 2015, it applied to the Secretary of State for a development consent order (DCO) for the tunnelled replacement, which was granted in August 2016.

1.16. NGGT made its final investment decision for the tunnel project in April 2016, and awarded the necessary main works contract in May 2016. Work on the tunnelled solution commenced in June 2016 (design works) and enabling works commenced in September 2016. NGGT informed Ofgem of the DCO approval in August 2016 and that it commenced tunnelling in May 2018. NGGT expects to commission the new pipeline by June 2020 with all work associated with the pipeline to be completed by September 2021.

1.17. During the May 2018 reopener window, we received a request from NGGT for funding of £139.9m to cover the cost of the project.

[3] A freespan on a pipeline is where the seabed sediments have been eroded, or scoured away, and the pipeline is no longer supported on the sea or river bed.
[4] para 7.109, [RIIO-T1: Final Proposals for National Grid Electricity Transmission and National Grid Gas (Cost assessment and uncertainty Supporting Document)]

1.18. The background to Feeder 9 can be found in our consultation document and NGGT's original submission (links below).

Related publications

1.19. The following documents provide additional context around this decision document and the re-opener process.

RIIO-T1 reopener application (Asset Health): River Humber Gas Pipeline Replacement Project (Feeder 9)

RIIO-T1 reopener consultation: One-off Asset Health Costs (Feeder 9)

The Gas Transporter Licence, Special Conditions, for National Grid Gas PLC (NTS)

Informal consultation on RIIO-1 price control reopeners (May 2018)

RIIO-T1: Final Proposals for National Grid Electricity Transmission and National Grid Gas

RIIO-T1: Final Proposals for National Grid Electricity Transmission and National Grid Gas: Cost assessment and uncertainty Supporting Document

RIIO-T1: Initial Proposals for National Grid Electricity Transmission and National Grid Gas

The RIIO-GT1 Price Control Financial Model

GT1 Price Control Financial Handbook – Version 2.0

Impact Assessment

1.20. We consider our decision on NGGT's application for funding for the Feeder 9 project is important within the meaning of section 5A of the Utilities Act 2000 and as such necessitates an Impact Assessment (IA). In our consultation document, we said that our consultation document and cost benefit analysis (CBA) contain a thorough analysis of the issues, including the environmental impacts, therefore we did not consider it necessary to publish a formal section 5A IA as it would be duplicative of the information contained in these documents.

1.21. One stakeholder (Energy UK) commented that it was concerned that "*these consultations serve as a proxy for a full impact assessment and in neither case has the market risk been assessed in the event that security of supply or network flexibility and resilience is reduced"*. In our view, we had considered the risks to the gas market based on the information provided by NGGT on a qualitative and quantitative basis. We were provided with additional information shortly before we published our consultation document. We have considered the additional information alongside the consultation responses before forming our final view.

1.22. We remain of the view that our consultation document, CBA, decision document and revised CBA contain a thorough analysis of the issues, including the environmental impacts, therefore we do not consider it necessary to publish a formal section 5A IA as it would be duplicative of the information contained in these documents.

2. The case for replacing Feeder 9

This section sets out the results of our assessment of the case for replacing Feeder 9.

Background

2.1. As part of our initial assessment of NGGT's reopener application, we considered whether NGGT's application has demonstrated that there is a clear need to replace the relevant section of the pipeline with a tunnelled replacement. We drew on evidence put forward by NGGT in its formal submission, as well as information provided by NGGT during bilateral engagement in the weeks leading up to its formal submission.

2.2. Our initial assessment of the need for replacement was structured as follows:

- We considered whether the Feeder 9 pipeline is needed at all. As part of this, we looked at the information provided by NGGT on the impact of the loss of Feeder 9 on the gas transmission network, the gas market and on consumers.

- We considered whether NGGT had made the case for replacing the relevant section of Feeder 9 with a new pipeline through a tunnel. As part of this, we looked at the evidence submitted by NGGT on the risks to the current pipeline, the effectiveness of mitigation measures already undertaken, the consequences of pipeline failure and the cost of various replacement options. We considered the qualitative arguments for replacement and carried out quantitative analysis of the costs of replacement *vs* the benefits of replacement.

- Noting that NGGT had already commenced tunnelling and had committed approximately £93m of expenditure on the project by the time of its reopener submission, we considered whether NGGT's decision-making process was robust and whether it had acted in the interests of consumers when making its final investment decision in April 2016.

2.3. A few days before we published our consultation, we received substantial additional information from NGGT on the operational impact of the loss of Feeder 9 on the gas transmission network and on the gas market. This included new information as well as corrections and revisions to information previously provided as part of the formal submission. We said in our consultation document that the information was received too late to take into account in reaching our initial views. We said that we would consider the additional information and any other feedback received as part of formal consultation responses in making our final decision.

2.4. The rest of this chapter sets out our initial views on the need for replacement as set out in our consultation, a summary of the information received from NGGT and other stakeholders as part of their consultation responses, and our final assessment of the need for replacement and the reasons for that view.

Our initial views

Needs case for Feeder 9 pipeline

2.5. NGGT's case for the ongoing need for the Feeder 9 pipeline was based on its assessment of the likely consequences of the loss of Feeder 9, either through failure or through pre-emptive isolation of the pipeline by NGGT. These consequences are broadly categorised as follows:

- Reduced capability: Network and entry capability. NGGT said that without Feeder 9, it would not be able to meet its entry capacity obligations in the Easington area as it would lack the ability to transport the required volumes of gas.

- Reduced resilience. NGGT said that the loss of Feeder 9 would mean increased reliance on network assets on the west coast of the UK, leaving the network vulnerable in the event of further outages. It would also lead to an increase in the usage of compressor units along the west coast route, making it difficult for NGGT to comply with emissions control legislation.

- Wholesale gas price and consumer impact. NGGT said that the loss of Feeder 9 could result in a supply shock leading to an increase in the wholesale price of gas in the UK, which, in turn, could lead to an increase in the price paid by end gas consumers.

- Impact on the UK/Norway relationship. NGGT said that the loss of Feeder 9 could damage the collaborative working relationship between the UK and Norway because there would be a reduction in the volume of Norwegian gas brought into the Easington area.

- Operational impact on the GB gas market. Shortly before we published our consultation document, NGGT provided new information on the operational impact of the loss of Feeder 9. We said that we would take this information into account when making our final decision.

2.6. Taking account of the information provided by NGGT in its submission, we set out our initial view that there is a clear need for the Feeder 9 pipeline in the short term, i.e. up to 2024/25. However, we said that there is some uncertainty about the longer-term need for Feeder 9 beyond that date.

2.7. Given our initial view that the Feeder 9 pipeline is likely to be needed, at least in the short term, we then turned to the question of whether the risks to the current pipeline were high enough to justify its immediate replacement.

Risks to the current Feeder 9 pipeline

2.8. NGGT's submission had identified a number of risks with the continued operation of the pipeline. These included:

- The risk of further river bed erosion around the current pipeline, leading to an increased risk of pipeline damage through freespanning and third party interference (TPI).

- The risk to human safety through gas explosions caused by anchor strikes or vessel grounding.

- The risk that the lease to operate the current Feeder 9 pipeline is lost due to a breach of lease conditions.

- The risk that the current method of mitigation (i.e. concrete frond mattressing) is only a temporary solution.

- Environmental considerations that may affect the ability of NGGT to carry out further mitigation works, if required.

2.9. In our consultation document, we acknowledged that the current Feeder 9 pipeline is exposed to some risk of damage from TPI. In relation to freespanning, our initial view was that NGGT's approach to managing the integrity of the pipeline, i.e. frequent inspections and mitigation where needed, means that it is extremely unlikely that the pipeline would suffer damage from freespanning.

2.10. NGGT's submission drew parallels between Feeder 9 and the Feeder 1 pipeline (located in the vicinity of Feeder 9), which was isolated in July 2009 after significant freespanning was discovered. In July 2010, the Feeder 1 pipeline was found to have failed and the unsupported section collapsed and came to rest on the river bed. We said that there are important differences between the circumstances of the two pipelines, which mean that the two are not comparable.

2.11. NGGT's submission highlighted the risk to human safety arising out of possible TPI damage. We consulted the HSE and requested a review of the safety aspects of NGGT's case. The HSE reviewed NGGT's reopener submission and concluded that:

- NGGT's arrangements for managing the risk of freespanning are adequate and meet the requirements to maintain the integrity of the current Feeder 9 pipeline. However, these arrangements should be kept under review and appropriate action taken based on pipeline inspections.

- There is a credible threat of damage to the current Feeder 9 pipeline from TPI, particularly anchor strikes. The HSE noted that concrete mattresses are not designed as an impact protection measure, and do not provide adequate protection from anchor strikes. The HSE reviewed the analysis provided to us by NGGT and concluded that the risk to human life from TPI is within the "tolerable if as low as reasonably practicable (ALARP)" range. This means that the HSE would not normally insist that NGGT reduces this risk further if the risk is ALARP, which it would be if the net cost of building the tunnelled replacement exceeds £5.11m (in 2009/10 prices, taking account of other costs and benefits to NGGT and consumers from building the tunnel).

2.12. In light of the HSE's conclusions, our initial view was that the safety case for replacing the current Feeder 9 with a new tunnelled pipeline is only valid if the additional net cost incurred, taking account of all other reasonable costs and benefits to consumers and NGGT, is below £5.11m (in 2009/10 prices).

2.13. NGGT's submission stated that there is a risk that the lease to operate the pipeline may be lost. NGGT is unlikely to be able to operate the current pipeline if it lost the rights granted under that lease and was unable to secure equivalent rights through other means. Our initial view was that, based on the information provided to us, we did not see reasonable grounds to assume that the lease would be lost, or that pre-emptive action to replace the pipeline is warranted for this reason.

2.14. NGGT has said that mattressing is only a temporary solution that is effective for 5-10 years, and that a long-term solution, in the form of a replacement pipeline, is needed to address the risks to the current Feeder 9. In our consultation document, we noted that concrete frond mattresses have been used on subsea pipelines for many years, and the materials used have a long-term life expectancy. Moreover, NGGT's own river bed survey reports indicated that there are no areas around Feeder 9 that required immediate attention. As such, we did not believe that NGGT had substantiated its view that mattressing is only a temporary solution.

2.15. NGGT's submission said that a release of gas due to pipeline damage and any subsequent repair works could cause disruption to the ecosystem in the Humber estuary. However, we noted that NGGT's own environmental assessment said that mitigation activities would not have a significant impact on the environment.

2.16. In conclusion, our initial view was that while we accepted that there are a number of risks from operating the current pipeline, we did not think the qualitative evidence provided by NGGT pointed towards the need to replace the pipeline now.

Quantitative case for the tunnelled replacement

2.17. We then looked at the quantitative case provided by NGGT for pipeline replacement. The quantitative analysis attempted to compare the cost of replacing the pipeline to quantified estimates of the consequences for consumers of the loss of the current pipeline. NGGT had carried out quantitative analysis that included a CBA that uses a methodology developed for NGGT called "Extreme Value Analysis" (EVA), implemented through a proprietary software package. We had a number of concerns with NGGT's EVA CBA, particularly relating to the lack of transparency around the assumptions and calculations. We said that the EVA methodology as applied to Feeder 9 had a number of weaknesses that compromised its ability to inform major investment decisions.

2.18. In response to a request from Ofgem, NGGT then provided a second CBA model that uses a more traditional approach, implemented in an Excel spreadsheet. We had a number of concerns about the reasonableness of assumptions used in NGGT's model. To address these concerns, we developed our own Excel-based CBA model.

2.19. Our CBA used and built on NGGT's own modelling framework and assumptions, except where we considered there to be good reason to deviate from those assumptions. The main areas where we deviated from NGGT's assumptions are: the probabilities of pipeline exposure, freespanning and loss of lease. We broadly accepted NGGT's analysis of the consequences of the loss of Feeder 9, including in relation to gas price impacts and constraint costs.

2.20. Our CBA modelling showed that continued operation of the Feeder 9 pipeline was cheaper than replacement by between £17m and £54m (under the high risk and low risk scenarios respectively) if we were to compare costs up to 2044 (i.e. to the end of the assumed 60-year life of the current pipeline). If we were to consider a longer time horizon (i.e. to 2072), continued operation was cheaper than replacement by between £8m and £35m (under the high risk and low risk scenarios respectively).

2.21. Our analysis showed that, under a range of assumptions (high and low) and time horizons, the incremental cost of the tunnel option exceeded the ALARP threshold, which was considered by HSE to be £5.11m. Therefore, our initial view was that the safety risk from continued operation of the pipeline was ALARP, and therefore did not need to be reduced further by replacement.

2.22. For these reasons, our initial view was that the evidence provided by NGGT did not support the case for immediate replacement of Feeder 9 with a tunnelled pipeline under the Humber estuary. We said that we would consider the late information provided by NGGT on the operational impact of the loss of Feeder 9 and update our analysis as required before we take a final decision.

2.23. Further details about our analysis and assumptions are set out in our consultation document and accompanying CBA model.

Additional information received and consultation responses

2.24. This section summarises the additional late information received from NGGT on the operational impact of the loss of Feeder 9 and the formal consultation responses received from NGGT and other stakeholders.

Operational impact of the loss of Feeder 9

2.25. Shortly before we published our consultation document, and as part of NGGT's formal consultation response, we received additional information on the impact of the loss of Feeder 9 on the operation of the national transmission system (NTS) and the overall gas market. Some of this information provided further qualitative clarification on impacts that were identified in NGGT's original submission, but there are other areas where NGGT has made significant changes to its previous quantified assumptions – these relate to the impact on gas prices, on electricity prices, on constraint costs and on industrial demand (through the use of value of lost load (VOLL) estimates).

2.26. According to NGGT, the short-term consequences of the loss of Feeder 9 include:

- The volume of gas entering the Easington area would be limited to 75 mcm/day, compared to expected winter peak flows of 125 mcm/day. This implies a reduction in actual entry capacity of around 50 mcm/day.
- NGGT would have to undertake significant demand-side market interventions, which may include the scaling down of large industrial/power generation demand.
- Flows across the network would need to be reconfigured, putting more pressure on the network along the west coast of the UK.
- Wholesale gas prices would increase until there is sufficient market response to make up any shortfall in gas.

- Wholesale electricity prices would increase, particularly if gas-powered generators set prices by being the marginal plant in the electricity system balancing merit order.

- NGGT would need to buy back entry capacity in the Easington area.

- Gas storage reserves in other areas could be accessed, with limited opportunities to re-fill them in the short term.

- In the worst case scenario, a Gas Supply Emergency[5] may be declared by NGGT.

2.27. Over the medium to long term, NGGT said that the loss of Feeder 9 could lead to:

- An increased reliance on imported liquefied natural gas (LNG) and interconnector supplies from continental Europe.

- The rest of the system would be operating at close to full capacity during winter peak conditions, leading to reduced overall resilience of the network to respond to further outages.

- A sustained increase in wholesale gas and electricity prices that would eventually be passed on to consumers.

- The inability to meet the 1:20 requirement in the future without building in sufficient storage and managing LNG stocks.

- Increased utilisation of compressor units along the west coast of the UK that are currently on limited use derogations from compliance with emissions legislation.

2.28. As stated earlier, NGGT made significant revisions to its assumptions relating to gas price impacts, electricity price impacts, entry capacity constraints and VOLL. These changes are summarised in the table below.

Impacts	NGGT's original assumptions (submission)	NGGT's updated assumptions (consultation response)
Gas price impacts	First month (Summer): 0 First month (winter): 25p/th Subsequent months: 2p/th	First month (Summer): 2p/th First month (winter): 25p/th Subsequent months: 7.8p/th

[5] A Gas Supply Emergency in the context of Feeder 9 would mean that there is a critical constraint on the NTS. It may lead to public appeals, greater distribution network utilisation, use of line pack, firm load shedding and potential isolation. Further information is available here.

Electricity price impacts	No impacts modelled	Impact of 2.9 times the gas price impact
Constraint costs	£0.2m per day (Ofgem estimate produced for comparison based on NGGT's assumption of 3-7 days of exposure)	£28m per day (based on an assumed exposure of 10p/kWh)
VOLL for gas	No impacts modelled	£33.5m over a 10-day period

Probability of pipeline failure

2.29. Alongside our consultation document, we published our CBA model, which considered three scenarios (NGGT, high and low). The "NGGT" scenario used probabilities provided by NGGT, whereas the "high" and "low" probabilities reflected our view of those probabilities, taking account of internal and external technical advice that we received. In all cases, NGGT's probabilities were higher than our "high" scenario probabilities.

2.30. As part of its formal consultation response, NGGT provided updated assumptions on the probabilities of different failure modes. NGGT recommended that we use its original probabilities for the "high" scenario, and provided new figures for the "low" scenario. These figures are summarised in the table below.

	Ofgem consultation model assumptions	NGGT's updated assumptions
Probability of exposure (scouring)	Low: 5.80% High: 20.00%	Low*: 42.86% High: 35.00%
Probability of a freespan <20m	Low: 0.58% High: 2.00%	Low: 4.29% High: 12.77%
Probability of a freespan between 20m and 55m	Low: 0.12% High: 0.40%	Low: 0.86% High: 2.46%
Probability of freespan greater than 55m	Low: 0.02% High: 0.08%	Low: 0.17% High: 0.53%

*NGGT's reported probability of exposure in the low scenario is higher than the probability in the high scenario.

Probability of loss of lease

2.31. NGGT said that Ofgem had made errors in how our CBA takes account of the possible scenario where NGGT loses its lease to operate the pipeline, and therefore has to construct a replacement.

- NGGT said that Ofgem had applied discount factors inappropriately in its model, thereby introducing an element of double-discounting. It said that correcting this error would lead to an increase in the net present cost of the mitigation option.
- NGGT said that Ofgem had applied an incorrect formula to calculate the probability that the pipeline remains operational, by assuming that the loss of lease and freespanning of greater than 55m are independent events, when in fact a freespan of greater than 55m could in itself lead to the lease being revoked. It proposed a revised formula to take account of this.

Impact on CBA results

2.32. NGGT submitted a revised CBA model that incorporated its updated assumptions on probabilities and consequences of pipeline failure. The results from NGGT's updated modelling are summarised below.

	Net present costs to 2044		**Net present costs to 2072**	
	High scenario	Low scenario	High scenario	Low scenario
Tunnel option	£384m	£191m	£398m	£211m
Mitigate option	£829m	£305m	£851m	£343m
Option comparison	Tunnel is cheaper by £445m	Tunnel is cheaper by £114m	Tunnel is cheaper by £453m	Tunnel is cheaper by £132m

Responses from other stakeholders

2.33. One respondent (Energy UK) said that it is too simplistic to link the ongoing need for Feeder 9 to entry capacity bookings, as there is a "*tendency for shippers to book capacity on a short-term basis. We consider the FES scenarios to be a better indication of longer term entry requirements*". It goes on to say that while it accepts that there is uncertainty about gas supply sources in the longer term, it expects that a substantial volume of gas from Norwegian sources would continue to flow into Great Britain until at least 2035, if not beyond.

2.34. Energy UK also agreed with NGGT that the loss of Feeder 9 "*could result in a supply shock of a magnitude that has not been seen to date in the UK*", and that the impact on gas prices "*could easily exceed the costs not passed onto customers through not allowing efficient expenditure to be recovered*". It said that entry capacity constraint costs "*could also be dwarfed by the gas price response*".

2.35. Energy UK "*has concerns that system resilience to other supply events and system flexibility to meet offtake nominations could be reduced. There is a concentration of transmission connected gas generation plant in the east of England that could face reduced operating pressures or have within day re-nominations rejected to support electricity balancing mechanism activity, electricity demand profiles or response to falling generation from intermittent sources*".

2.36. The response from the Gas Security Group (GSG) expressed concerns about the potential for disruption to physical supplies and the likely impact on gas prices, which would be disruptive to British businesses. It said that it did not believe that remediation work in the Humber estuary "*is a suitable solution in such a harsh environment and support the proposal for the proposed tunnel solution*".

2.37. The response from the Energy Networks Association (ENA) said that it disagreed with Ofgem's initial view on funding for the Feeder 9 project, because it expected that the failure of the pipeline would have significant consequences. It said that our initial views "*would increase regulatory risks around uncertainty mechanisms for all networks, putting future investment decisions at risk and potentially increasing the cost of finance*".

2.38. The response from Citizens Advice said that "*anchoring the funding decision on the planning consent date, without supplying a suitable indication until recently whether the project itself is justified, raises some concerns*". It believes that "*it would have been better to have created a specific process to agree the needs case (rather than relying on the recent reopener), similar to the Strategic Wider Works mechanism*". It is concerned that "*Ofgem's supervision of this project has allowed regulatory uncertainty that could have been avoided*". It goes on to add that "*not providing funding for Feeder 9 may put pressure on GB's security of gas supply*" but that proceeding with the Feeder 9 project "*could weaken incentives for future projects associated with security of energy supply*". It would need "*more detailed evidence from Ofgem, regarding this issue of security of supply risk associated with the Feeder 9 project, than that which is covered in the consultation document*".

2.39. The response from Business Modelling Associates (BMA) (the organisation that developed NGGT's EVA CBA) raised a number of points in response to our criticism of the application of the EVA methodology to the Feeder 9 project. These include:

- In response to Ofgem's concern about the use of proprietary software, it said that the CBA required modelling "*large numbers of uncertain variables and their interdependencies*". It said that this would not be possible in spreadsheet-based software such as Excel. According to BMA, the "*Monte Carlo approach was the critical functionality provided by the proprietary software allowing the CBA to capture tail end risk*". It said that "*the EVA model quantified 1000's of values for each uncertain variable […] rather than the snapshot of only two values achieved in Excel. It also allowed 1000's of combination of variables to be tested rather than the two combinations (scenarios 1 and 2) achieved in Excel. This ability significantly reduced the need to use averages and snapshots that invariably downplay or ignore tail end risk*". It said that the requirement for transparency "*in itself should not be a reason for seeking to simplify and dumb down a model in Excel*".

- BMA challenged our characterisation of our concerns about the errors in the EVA CBA as "*serious*", and said that it was both "*a change in assumption as to how NGGT would respond to a small but growing freespan*" and a "*single minor error regarding the impact of gas ignition*", and also that "*neither had a substantial or fundamental effect on the results*".

- In response to the comments made in the independent review of the EVA model commissioned by Ofgem, BMA said that the "*fundamental premise for the approach taken here was to address the very issue of carrying out a CBA where there are a large number of uncertain and interdependent variables: where a tiny difference in probability may drive significant changes to costs and benefits*".

- In response to our initial view that the EVA methodology and its ability to inform investment decisions is limited by the lack of transparency and extreme sensitivity of results to subjective assumptions, BMA said that the EVA model was intended to contribute to the overall business case through "*better inclusion of tail end risk*".

- In response to our view that the EVA methodology is novel and untested, BMA said that the platform has been used globally since 1984 and by the UK Water industry since 2011. It noted the comment made by Ofgem's academic reviewer that the methodology is based on standard financial economics and is, in general terms, suitable for CBA of investment options involving low probability high impact events.

- Finally it noted that if Ofgem were to prescribe a "*mandatory MS Excel approach, there would be little business improvement and innovation if this were to be the case*".

Our updated view on the case for replacement

2.40. In this section, we set out our updated view on the case for replacing the underwater section of Feeder 9 with a tunnelled pipeline under the Humber estuary. In reaching this view, we have taken account of the additional late information provided by NGGT, as well as views expressed by NGGT and other stakeholders in formal consultation responses.

The need for Feeder 9

2.41. In our consultation document, we set out our initial view that while there is a clear need for the Feeder 9 pipeline in the short term (up to 2025), there is some uncertainty about the longer-term need for the pipeline. It is possible that a like-for-like replacement of the pipeline would not be needed at the end of its current life (i.e. by 2044).

2.42. We note the views expressed by NGGT and stakeholders that entry capacity bookings, on their own, cannot provide reliable evidence of the future need for the pipeline. We agree. Our view of the longer-term need for the pipeline was informed by NGGT's Future Energy Scenarios (FES). While the FES are not forecasts, they provide NGGT's view of gas flows and the need for network assets under credible pathways for the evolution of gas demand and supplies. Several scenarios show a clear need to accommodate large volumes of gas flows from the Easington area – which implies a long-term need for Feeder 9. However, there is at least one scenario in which flows from the North Sea decline to an extent that Feeder 9 is unlikely to be needed. Respondents acknowledged this uncertainty.

2.43. We have seen no reason to revise our initial views regarding the uncertainty surrounding the long-term need for Feeder 9.

The case for replacement

2.44. On the question of whether the Feeder 9 pipeline needs to be replaced now, we set out our initial view that replacement was not in the interests of consumers. This was based on our assessment of the qualitative and quantitative analysis provided by NGGT on the risks to the pipeline and the consequences of failure, supported by our own modelling. We said that we had received late additional information on the operational impacts of the loss of Feeder 9, and that we would take account of this information in reaching our final decision.

2.45. We have now considered the additional information provided by NGGT, and where appropriate, have updated our modelling to reflect this.

2.46. We accept that the loss of Feeder 9 could have consequences for the way in which NGGT manages gas flows and operates the gas transmission network. In its initial submission, NGGT attempted to quantify these impacts in two ways:

- **Gas price impacts**: NGGT said that the loss of Feeder 9 could lead to increased wholesale gas prices. It estimated the size of the potential impact on gas prices and included this in its CBA.

- **Constraint costs**: NGGT said that the loss of Feeder 9 could lead to capacity buy-back actions, leading to constraint costs. It included estimates of these constraint costs in its CBA.

2.47. As part of our initial assessment, we had accepted NGGT's assumptions on gas price impacts and constraint costs – with two relatively minor adjustments. For gas price impacts, we corrected an error in NGGT's calculations which had underestimated the magnitude of these price impacts. For constraint costs, we challenged NGGT's assumption that it may be liable for constraint costs for six months of the year – we considered that a more appropriate assumption would be 78-103 days of the year, which is based on NGGT's own assumptions about the number of days in which forecast demand would exceed the network flow capability (without Feeder 9).

2.48. The new information provided by NGGT made significant changes to these assumptions. As set out in the previous section, NGGT's revised estimates of wholesale gas price impacts and constraint costs were substantially higher than its previous estimates.

2.49. In the case of gas price impacts, NGGT's revised estimates are based on a comparison of typical UK gas prices against spot prices for LNG in the Asian markets. NGGT said that, in the event of the loss of Feeder 9 during winter peak demand conditions, the wholesale price of gas would need to rise to the spot price for LNG in the Asian markets in order to attract sufficient volumes of LNG to be diverted to the UK market. It expects this price increase would be maintained for an extended period (for periods between 3 and 16 months).

2.50. In the case of constraint costs, NGGT revised its view of the value and duration of constraint payments that it may need to make in the event of pipeline failure. In its original submission, NGGT had assumed that its exposure to prompt constraint payments would be limited to between 3-7 days based on its forecast that it would be able to agree an emergency modification to the Uniform Network Code (UNC), which governs the constraint arrangements. NGGT has now said that securing this modification within the relevant timescales of a sudden loss of Feeder 9 would be very difficult. Furthermore, it has updated its view of the likely outcome of the capacity buy-back auction, thereby concluding that its revised view is a more reasonable estimate of constraint costs.

2.51. The additional information provided by NGGT identifies two further market impacts that had not been included in its original submission: electricity price impacts and the cost of demand curtailment.

2.52. NGGT provided estimates of the impact of the loss of Feeder 9 on wholesale electricity prices. NGGT said that the merit order for electricity generation is likely to be such that gas-fired generators (mainly combined cycle gas turbines) are likely to be the marginal plant, and therefore such generators are likely to set the wholesale price of electricity. Any increase in wholesale gas prices could affect the input costs of gas-fired generators, which in turn could lead to higher wholesale electricity prices. NGGT produced estimates of the likely impact of the loss of Feeder 9 on electricity prices by reviewing the historical relationship between wholesale gas and electricity prices.

2.53. The additional information provided by NGGT set out its view that, in the immediate aftermath of the loss of Feeder 9, it would need to undertake demand curtailment action to ensure that pressure is maintained across the network. NGGT provided estimates of the financial impact of this curtailment (as set out in the previous section).

2.54. We have now reviewed this new information provided by NGGT on the additional operational impacts of the loss of Feeder 9. While we are disappointed that NGGT's original submission and CBA failed to properly identify and quantify these impacts, we welcome the updated analysis that NGGT has carried out to produce these estimates. We note that NGGT's estimates of these impacts are subject to much uncertainty, and there is limited precedent to draw on for such events. Given this, we have concerns about the robustness of these estimates and consider they would benefit from further analysis and validation. However, given the limited amount of time available to consider this information, we have decided to accept its revised estimates as provided.

2.55. In our consultation document, we said that while we agreed with NGGT's assumption about the probability of pipeline rupture through TPI, we disagreed with its assumptions about the probabilities associated with pipeline exposure and freespanning. We sought advice from internal and external technical experts on these probabilities and concluded that NGGT's assumptions were too pessimistic, and developed our own estimates drawing on the views of these experts. We set out the rationale for own estimates in our consultation document, and provided a detailed assessment of these probabilities carried out by Ofgem's Chief Engineer.

2.56. NGGT's response disagreed with our estimates of the probabilities of pipeline failure. NGGT said that it did not believe that our assumed "high" and "low" case probabilities are credible. It proposed that we adopt NGGT's original assumptions for the "high" case, and provided updated estimates that it suggested we use for the "low" case.

2.57. Our "low" case assumptions were based on our observation that there had been two pipeline exposures in the 34 years that the Feeder 9 pipeline had been operational – one in 2009 and the other in 2011. This implied a probability of exposure of 5.8% (i.e. 2 in 34 years) NGGT disputed our view that only two exposures had taken place, and argued that there had actually been six pipeline exposures over seven years (2009-2016), of which four could be considered as occurring as part of a single exposure episode – implying that there had been three exposures in total. In NGGT's view, a more reasonable estimate of the probability of exposure would be 43% (i.e. 3 in 7 years). NGGT did not challenge our general approach to estimating the probabilities of freespans of different lengths, but noted that changing the assumed probability of pipeline exposure would have knock-on effects on those probabilities.

2.58. We have reviewed NGGT's arguments about the probability of pipeline exposure and accept that our assumed probability of pipeline exposure in the "low" case was potentially too low. We have revised upwards our "low" case assumption from 5.8% to 10%, and maintain our "high" case assumption at 20%. We think our revised figures represent a more reasonable range for these probabilities. We have tested our revised range using a number of different methods of estimating the probability of exposure, for instance, NGGT has identified exposure in four years out of 34 years (implying a probability of 12%), and one exposure event in the seven years since mattressing has been carried out (implying a probability of 14%).

2.59. We note the additional information provided by NGGT in its consultation response on the expected life of concrete frond mattresses. However, we also considered further the extent to which the pipeline is currently protected by those mattresses. On the probabilities of freespanning, our updated review concluded that our original estimates of the probability of failure were potentially too high given the level of protection that NGGT has put in place. However, we do not believe there is sufficient evidence to warrant reducing these probabilities further. As such, we have decided to maintain our initial views of these probabilities.

2.60. NGGT's response raised two concerns about the way in which our CBA model takes account of the impact of the potential loss of lease to operate the pipeline.

- The first concern relates to potential double-discounting. We disagree with NGGT's view, and do not think that our approach leads to double-discounting. We think it is necessary to apply the discount factors twice. The model uses discount factors to estimate the net present cost to consumers of building a tunnelled replacement in year t (by discounting a 45-year stream of allowed revenue), where t is the year in which the lease may be lost. The model then applies a further discount factor to discount from year t to year 1, which is required to allow comparison of all costs on a consistent basis.

- The second concern relates to our assumption that the loss of lease and freespanning were independent events. NGGT argued that these were not necessarily independent, and that freespanning could lead to a loss of lease. We accept NGGT's point and have revised our assumptions and calculations accordingly.

2.61. We have now updated our own CBA model to take account of the new information on the operational impacts of the loss of Feeder 9, the revised range of probabilities for pipeline exposure, and the updated assumption about the loss of lease. We have also updated our view of the efficient costs of the tunnel option in light of information provided by NGGT in its consultation response (see Chapter 3). The updated results are set out below.

	Net present costs to 2044		**Net present costs to 2072**	
	High scenario	Low scenario	High scenario	Low scenario

Tunnel option	£97m	£95m	£113m	£114m
Mitigate option	£109m	£52m	£134m	£87m
Option comparison	Tunnel is cheaper by £13m	Mitigation is cheaper by £42m	Tunnel is cheaper by £21m	Mitigation is cheaper by £26m

2.62. Our updated CBA results now paint a mixed picture. Under the high probabilities (risk) scenario, our CBA now suggests that building a tunnelled replacement is the best option for consumers. However, under the low probabilities (risk) scenario, mitigation continues to be the best option. This is a substantial change compared to the results of the CBA we had carried out to inform our initial views. We note that this change is almost entirely driven by the impact of changes to our assumptions based on the new information on operational impacts provided by NGGT and our updated view of the efficient costs of the tunnel.

2.63. We have no reason to attach particular weights to the high or low scenarios. Given the uncertainty about our assumed probabilities for different failure events and the values of their consequences, we also do not think it would be appropriate to rely on mid-points of these estimates to inform our decision. It is important to note that our results are sensitive to our estimates of the efficient costs of the tunnel option – changes to these costs would have a direct impact on the results and potentially also our conclusions.

2.64. In light of our updated CBA results, we have also considered the various qualitative arguments for replacing the pipeline. In addition to the operational impacts identified by NGGT, we note that a number of stakeholders have responded to our consultation raising concerns about the possible adverse consequences of the loss of Feeder 9.

2.65. We believe that a number of these qualitative concerns are valid, but have not been taken into account in our CBA. In particular, we believe that:

- The loss of Feeder 9 could have adverse implications for the resilience of the network to further outages. We note that, in the absence of Feeder 9, NGGT would have to operate its network in a way that places greater reliance on network assets along the west coast of the UK. This means that those assets become more critical than they currently are, and NGGT's ability to react to further adverse events is restricted. Furthermore, compressor units along the west coast may have to run for longer, putting NGGT's compliance with emissions legislation at risk.

- The loss of Feeder 9 would reduce NGGT's ability to accept imports of gas from Norwegian gas fields. Feeder 9 is the primary route for Norwegian gas imports into Great Britain, and its loss would leave NGGT more reliant on alternative supplies of gas (i.e. LNG and interconnectors) to balance demand under peak demand conditions. While our quantitative analysis does take some account of this (through assumptions about gas price increases), there are additional risks that could arise from having a less diverse gas supply mix, including an increased vulnerability to global LNG price shocks.

- There are likely to be adverse consequences if the loss of Feeder 9 leads to demand-side action by NGGT to manage gas pressures in the event of a sudden outage. These consequences may involve increased risk premia and/or reduced confidence in the reliability of the gas network.

2.66. We were not able to attach financial values to these impacts. However, we think that these impacts are likely to be serious and need to be considered alongside the results of our CBA. When taken together, we think that overall case for replacement is now sufficiently strong to tip the balance in favour of replacement of Feeder 9, particularly if we were to consider the case over a longer time horizon (i.e. up to 2072). A longer-term time horizon reflects our initial view that consumers are likely to get better value from replacement if the pipeline is needed over a longer period.

NGGT's decision-making process

2.67. In our consultation document, we expressed a number of concerns with NGGT's internal governance processes leading up to its decision to commence construction works on the replacement for Feeder 9. We noted that:

- NGGT appears not to have given proper consideration to all available options when making its final decision in April 2016 to construct the tunnel. We said that NGGT had discarded too early the option of continued mitigation and did not take account of available evidence on the performance of previous mattressing rounds before reaching its decision.

- NGGT did not carry out a full and comprehensive CBA of all options including the option of continued mitigation before making its final investment decision in April 2016. The CBA submitted by NGGT as part of its reopener application was carried out after it had made its final decision.

- NGGT did not appear to have engaged with the HSE to determine whether continued mitigation would have been acceptable to the HSE, and therefore failed to properly explore an option that would have been substantially cheaper for consumers.

2.68. In its consultation response, NGGT disagreed with our assessment. It said that "*in reaching our Final Investment Decision in April 2016, all credible ways forward were discussed at length over three senior governance meetings. Part of the discussions included continuing with frond mattresses, but, for the reasons stated in the main body of this response, this was not in consumer interests*". NGGT provided a summary of the internal briefing note that was used to support these discussions. NGGT also referred to a technical report produced in January 2018 that considered the risks to the pipeline from freespanning and the options for mitigation.

2.69. We note that the option of continued mitigation was discussed at internal governance meetings in the period leading up to its final decision in April 2016. However, our central point remains that NGGT does not appear to have carried out a full CBA of the various options before that point. While the risks with continued operation of the pipeline were discussed in qualitative terms at a relatively high level, this does not seem to us to provide a robust basis for investment decisions for high-value projects. We also note that the technical report referred to by NGGT was produced in January 2018, 21 months after the investment decision was taken.

2.70. While we now agree with NGGT that the decision to replace the pipeline is justified, our concerns with the robustness of its decision-making process and internal governance remain. We expect NGGT to take account of our concerns when making future investment decisions, particularly for large projects.

Our concerns about the EVA methodology

2.71. We note the detailed response by BMA to our concerns about the EVA methodology used by NGGT to carry out its CBA.

2.72. BMA said that a key benefit of the EVA approach and the software that it had used to implement the methodology is its ability to apply the Monte Carlo approach to capture uncertainty and "tail end risk", and allowed thousands of values to be modelled for each variable. According to BMA, this "*significantly reduced the need to use averages and snapshots that invariably downplay or ignore tail end risk*".

2.73. We accept that the EVA approach and the software used does provide this functionality. However, in the context of Feeder 9, we do not consider that this functionality was used in a way that provided additional benefits. As set out in NGGT's original submission (which included the BMA report), the model assumed either a uniform probability distribution function or a triangular distribution function (focussed on a simple arithmetic average of the extremes) to generate values for its Monte Carlo simulation. This assumption meant that generating thousands of values in this case provided almost no useful additional information than the approach that we eventually used (in Excel) of modelling the two extreme sets of values. Indeed, the Excel implementation of the EVA model produced central estimates that were almost identical to the ones produced through the complex Monte Carlo simulation approach.

2.74. BMA's response notes that transparency in itself should not be a reason for "*seeking to simplify or dumb down a model in Excel*". While that is true, we think that approaches that reduce transparency or add complexity should be justified by the benefits that those approaches can bring over simpler approaches. In this case, for the reason set out above, we do not think that the EVA approach was applied in a way that provided those benefits.

2.75. BMA noted that its approach had been used globally since 1984, and in the UK water industry since 2011. However, this approach had not been previously used by energy network companies in Great Britain to support funding submissions to Ofgem. Indeed, we note that the EVA CBA report was paid for by NGGT using a funding mechanism specifically intended for developing network innovation (i.e. the Network Innovation Allowance). This mechanism is not intended to fund initiatives that might be considered "business as usual".

2.76. Finally, BMA's response notes that if Ofgem were to prescribe a "*mandatory MS Excel approach, there would be little business improvement and innovation*". We agree. We are not prescribing particular software packages or approaches, and network companies may choose any suitable means to inform its decisions. However, we expect any funding application to Ofgem to be supported by robust analysis that is transparent and is capable of being reviewed and challenged by Ofgem and other stakeholders.

2.77. We plan to have further engagement with NGGT and other network operators on these cost-benefit modelling issues as part of the RIIO-2 process.

Our conclusion on the case for replacement

2.78. Taking account of our updated analysis, which reflects the new information provided by NGGT, and the concerns expressed by NGGT and other stakeholders, we have come to the view that replacing the underwater section of the Feeder 9 pipeline with a tunnelled pipeline is likely to be in the interests of consumers.

3. Assessment of the efficient costs of the tunnelled replacement

This section sets out the results of our assessment of efficient costs for the tunnelled replacement.

Background

3.1. Our initial view, as set out in our consultation document, was that NGGT had not demonstrated that replacing the Feeder 9 pipeline now is the best option for consumers. Nevertheless, we carried out an assessment of the efficient costs of both leading options, i.e. continued operation of the existing pipeline through mitigation and replacing the pipeline with a tunnelled alternative. Our consultation document set out our initial views of the efficient costs of both options.

3.2. Shortly before our consultation, NGGT submitted further information on the operational impacts of the loss of Feeder 9, which we have now taken account of. We have now updated our view of the need for replacement, concluding that replacement is likely to be in the best interests of consumers. In light of this, we have focussed our cost assessment on the costs of the replacement option.

3.3. The rest of this section provides an overview of our initial assessment of the efficient costs of replacement, a summary of views expressed by NGGT and other stakeholders, and our final view of the efficient costs of replacement.

Our initial view of efficient costs

3.4. In our consultation document, our initial view of the efficient costs of continued operation of the current Feeder 9 pipeline was £0.803m per year, and £6.424m over the duration of the RIIO-T1 price control period. However, in light of our updated view of the need for replacement, we do not take this option any further.

3.5. Our consultation also set out our initial view of the efficient costs of replacing the Feeder 9 pipeline. Our view was based on cost estimates provided by NGGT as part of its reopener submission, as well as information provided in response to our subsequent queries. As part of our assessment, we sought the views of an external technical consultancy, who provided advice on aspects of NGGT's cost submission. We also took account of cost benchmarks from other large investment projects that we had previously reviewed, as well as information from published external reports.

3.6. NGGT had proposed costs of £139.9m for the replacement option. In reaching our initial view of the efficient costs of this option, we split our assessment into three parts.

- **The "base" cost**, i.e. the cost of the construction works, which are being delivered by a consortium of contractors. We took the view that these costs were likely to be efficient. This element comprised [Redacted] of the total amount requested by NGGT.

- **Project management costs**. These are costs incurred by NGGT and its contractors to carry out the supporting activities that are required to manage and deliver the project. NGGT's submission included [Redacted] of costs that we considered to be project management costs. Our initial view of the efficient project management costs was [Redacted].

- **The risk allowance**. These are additional contingent costs that could materialise in the event that certain unexpected events occur. We consider that it is appropriate in any construction project that a certain allowance is made for such risks. NGGT's submission proposed a risk allowance of [Redacted], which we considered to be excessive. Our initial view was that an allowance of [Redacted] is appropriate.

3.7. NGGT's requested allowances and our initial view of efficient costs are summarised in the table below.

Cost category	NGGT request	Our initial view	Difference
Capital costs	[Redacted]	[Redacted]	[Redacted]
Project management costs	[Redacted]	[Redacted]	[Redacted]
Risk allowance	[Redacted]	[Redacted]	[Redacted]
Total	**£139.89m**	**£104.64**	**£35.24m**

Consultation responses

3.8. While we received several responses to our consultation, only NGGT's response directly addressed our initial view of efficient costs.

3.9. NGGT's response to our consultation was critical of our initial position and concluded that *"[NGGT] do not consider that Ofgem have undertaken an appropriate assessment of the Feeder 9 costs as stipulated within Final Proposals. Without a more rigorous assessment we believe Ofgem have no basis on which to disallow any of NGGT's costs"*.

3.10. NGGT made a number of comments on our assessment of the efficient risk allowance and project management costs. Alongside its submission, NGGT also provided two reports that it had commissioned from external consultancies: one which focussed on the risk allowance and the other on project/programme management costs. These reports were provided in a confidential annex and are not published alongside the decision document.

3.11. We discuss each of these cost categories in turn below.

Risk allowances

3.12. Following the publication of our consultation document, NGGT requested additional information including any supporting reports that substantiate Ofgem's view of the "top down" benchmark that it had applied to estimate efficient costs for risk. We provided a written response on 21 August setting out further details of our risk assessment, including reports from which we had drawn our benchmarks for comparison (see the documents referenced at Appendix 1). We also provided a report from our technical consultants that set out their views of NGGT's risk register and cost estimates.[6]

3.13. In its consultation response, NGGT said that Ofgem's benchmarks are drawn from projects that are not relevant, other than in very general terms, to the Feeder 9 project. NGGT commented that the most relevant report, ACER[7] (2015), which reviews gas transmission projects, presents a single average figure for engineering and project management and provides that *"the indicators and the corresponding values should not be regarded as a substitute for the due diligence in each instance of an existing or planned investment"*.

3.14. One of the reports produced for NGGT after we published our initial views, stated that Feeder 9 *"remains a High Risk project environment …. throughout the project delivery phase, so we consider that project norms and top-down applications of percentages would be too crude a determination of the programme contingency in this case"*.

3.15. NGGT's response said that we had not fully understood NGGT's project risk register and that the report from our consultant was the basis of an initial discussion rather than an indicative figure for costs. NGGT commented that the report is heavily caveated and that the *"numerous basic errors and at times clearly shows that the consultant does not appreciate the scale and complexity of the project".* This response raises two specific comments about our consultant's assessment.

- NGGT challenged our consultant's indicative estimate of [Redacted] for the cost of delays to the project, and said that this was based on an incorrect value of number of staff employed on the project (i.e. in full-time equivalent (FTE) terms). It said that correcting this error would increase the cost of delay estimate to [Redacted].

- NGGT said that our consultant's review of the risk register did not consider two risks.

3.16. One report reviewed NGGT's approach to the identification and management of risk. it concluded that there is *"no reason to consider that the impacts have been overstated; fair rationale for both probabilities and impacts were captured by the programme team where possible. In addition, the probabilities and impacts have appropriately taken account of potential mitigations"*.

3.17. In light of NGGT's response, we asked for further clarity on its criticism of our consultant's approach. Beyond the previously mentioned points, NGGT made the following additional points:

- A misinterpretation of the day rate split as [Redacted] for NGGT and [Redacted] for the main work contractor (MWC), a wrong assumption that

[6] Not published for confidentiality reasons.
[7] ACER (July 2015) Report on unit investment cost indicators and corresponding reference values for electricity and gas infrastructure. The electricity report can be found here; the gas report can be found here.

underpins much of our consultants' analysis. (NGGT had originally submitted the split as [Redacted] for MWC and [Redacted] for NGGT).

- The assumption of 253 working days per year leaves out weekends – the tunnelling, for example, takes place 24/7. Other project activities are also conducted on weekends.

- The assumption that the flat day rate is run across the entirety of the project when in fact different project stages have different day rates.

- Assumption of average salaries of FTE does not seem based on similar projects or any of the Feeder 9 project costs. The average salaries do not appear to consider the wider costs of employment to give an 'all in cost'.

- The day rate of [Redacted] does not take into account any other costs to the project that would be incurred on a daily basis.

3.18. NGGT said that our consultant's review of the risks shows a general lack of understanding of the specific details of the project; e.g. [Redacted]. NGGT considered these to be evidence of our consultant's lack of understanding and knowledge of this project.

3.19. Our consultant's report specifically highlighted five areas where "*more evidence for the existing analysis would be useful in order to guide a discussion with NG*". NGGT noted that Ofgem had not organised an opportunity for its consultants to engage with NGGT.

3.20. NGGT commented that the "*risk/ contingency of* [Redacted] *contained a significant proportion of costs related to scope change, which on other projects, as noted by Ofgem's consultants, are not included within the risk/contingency category. These scope changes have now been progressed with the MWC and have moved* [Redacted] *of risk costs into base."*

3.21. [Redacted].

Project management costs

3.22. On project management costs, NGGT's response said that it disagrees with our "*cost allocation to Project Management and the application of a high level benchmark of 15%"*. NGGT claimed that Ofgem had miscategorised project management costs, including those of NGGT and the MWC.

3.23. NGGT said that Ofgem had categorised costs of [Redacted] "*related to inspection activities*", which should not be considered as project management costs. It said that *"client side inspection teams provide assurance that assets are fit for purpose for the design life of each asset. Their roles are site based during construction activities, ensuring that contractors are complying with relevant standards and specifications."*

3.24. NGGT also claimed that Ofgem had miscategorised "[Redacted] *of costs associated with undertaking physical work".* NGGT said these are *"legitimate costs associated with delivering the project and should not be classified as project management"*. NGGT further stated that Ofgem had included costs relating to *"all aspects of engineering (civil / electrical / mechanical / commissioning), setting out and surveying, general foreman, CAD works, temporary works, project accounting etc."*. NGGT went on to add that *"these costs are* *legitimate costs associated with delivering the project and should not be classified as project management.".*

3.25. NGGT provided Ofgem with a third party report it commissioned to justify its own project management costs (client side management costs) – this is separate from project management costs that might be incurred by its contractors. The report suggests that the client side management cost for the Feeder 9 project would be approximately [Redacted] (nominal prices). The [Redacted] report concludes that its estimated figure represented [Redacted] of aggregate capital expenditure (CAPEX) costs, and provided a "*representative estimate*" and "*compares favourably with equivalent large-scale construction projects in the energy sector*".

Our updated view of efficient costs

3.26. We do not agree with NGGT's comment that Ofgem did not undertake an appropriate assessment of the efficient costs of the Feeder 9 project. We believe our assessment has been appropriate and proportionate. We have reviewed all aspects of NGGT's cost submission, and have procured external specialist advice on aspects of project costs relating to risks and contingencies. We have also reviewed efficient costs of comparable large energy sector projects in arriving at our benchmarks for risk and project management costs.

3.27. We did not challenge NGGT's stated "base costs" as these were the outcome of a competitive procurement process that we had deemed to have been efficiently conducted. Our assessment therefore focused on efficient risk allowances and project management costs. The rest of this section provides our final view on NGGT's proposed costs in these areas.

Risk allowances

3.28. Our view of the efficient risk allowance for the Feeder 9 project was primarily based on a "top down" approach that looked at comparable projects in the energy sector. We recognise that any large construction project could have unexpected costs that may materialise after the project has commenced, and it is therefore prudent to make an allowance for such risks.

3.29. Our review of NGGT's risk register and associated provisions resulted in a number of concerns about the assumptions that were used to produce the overall figure. We considered that these suffered from insufficient consideration of mitigation options, high levels of uncertainty and somewhat arbitrary and subjective assumptions. Our consultant agreed with this assessment and separately raised a number of issues with NGGT's risk estimates. We engaged with NGGT extensively during our assessment to seek additional clarity about its assumptions and estimates, but our concerns remained largely unaddressed. In view of these concerns, we took the view that a detailed "bottom up" cost assessment would not be feasible within the timescale of this reopener assessment. We opted for a "top down" benchmark based on assessments carried out in similar construction projects and used these benchmarks to come to a view on the efficient risk provision for Feeder 9.

3.30. The evidence from comparator projects suggested that risk/contingency allowances for similar projects typically range from 5%-15%, with an average of around 10% [see Appendix 1]. We acknowledged that the Feeder 9 project is unique, and that we would be willing to accept a risk allowance at the higher end of this range, i.e. 15% of the total project value.

3.31. We note that while NGGT's response questions whether our benchmark is drawn from projects that are comparable to Feeder 9, it does not dispute our overall benchmark of 15% of total project costs for risks/contingencies. However, it suggests that Ofgem should review the specific costs of the Feeder 9 project before arriving at a final view.

3.32. Separately, NGGT said that "*Ofgem have not compared our actual risks […] on a like for like basis with the high level industry benchmarks. NGGT's risk/contingency of* [Redacted] *contained a significant proportion of costs related to scope change, which on other projects, as noted by Ofgem's consultants, are not included within the risk/contingency category.*" It went to say that "*these scope changes have now been progressed with the MWC and have moved* [Redacted] *of risk costs into base*", and that [Redacted]".

3.33. In response to a specific question from Ofgem on the movement of [Redacted] of costs from the risk/contingency allowance to base costs, NGGT said that "*the change in scope was driven by the design development of the pipeline protection system and its interaction with the tunnel design, which is required to meet our minimum requirements. This scope change was anticipated at the start of the design and build contract, whereby the conceptual design used for tender purposes needed to be developed by the contractor into a detailed design for construction. The contractual terms allows for compensation events (CEs) as part of the process*". It said that the movement to base costs was implemented in June 2018 after 15 months of discussions with the contractor.

3.34. We note that NGGT had previously (August 2017) moved [Redacted] of costs relating to the same risk from the risk register to base costs. This was prior to NGGT's reopener submission, so it had included that amount in its base costs for the submission.

3.35. In our view, the risk allowance benchmark of 15% of total project costs that we had applied is a reasonable provision for unexpected costs on an *ex ante* basis, i.e. before the start of construction works but after there is reasonable certainty about the scope of works. We have no doubt that as the project progresses towards completion, some of those costs for which provisions have been made may materialise, and therefore become part of base costs. In the same way, some risks may not materialise (or materialise to a lesser extent than expected), leading to those risks being retired and removed from the register.

3.36. It would be generally inappropriate to apply *ex ante* risk allowance benchmarks to estimate an appropriate risk allowance mid-way through the project once some risks have materialised. However, we note that we are in the unusual situation of carrying out our assessment based on cost estimates submitted while the project is under construction.

3.37. In this instance, we have decided to apply the risk allowance benchmark to the risk register as submitted to Ofgem as part of the reopener submission, which is soon after the time when NGGT started construction works on the tunnel. We consider that NGGT would have had reasonable certainty about the scope of works by that time. Any remaining uncertainty should be accounted for through an appropriate allowance for risks or scope variations.

3.38. We have therefore accepted the movement of [Redacted] of risk allowances into base costs in August 2017. However, we do not accept the movement of [Redacted], which NGGT moved to base costs in May 2018. We consider that these costs, if they are to materialise, should be funded through the risk allowance. If there was sufficient certainty at the start of construction that these costs would materialise, then these costs should have been included in the base cost at an earlier date, as highlighted by our consultant. Instead, NGGT has included these costs within the scope of defined "compensation events" as part of its contract with its contractors. Taking NGGT's logic to the extreme, it would not be appropriate to apply the 15% benchmark to calculate a risk allowance for the remainder of the project at the end of the project. By then, there would be near-complete certainty about costs, and the residual risk allowance should be close to zero.

3.39. [Redacted].

3.40. For these reasons, we do not accept NGGT's attempt at re-designating large parts of its risk/contingency costs as base costs for the purpose of applying our risk benchmark.

3.41. We now respond to NGGT's comments about our consultant's detailed comments on its risk register. We said in our consultation document that our consultant had carried out a detailed "bottom up" assessment of NGGT's risk register and allowances, and that "*while acknowledging that producing an accurate risk allowance would require significantly more information, our advisers provided an indicative estimate that implied a total risk allowance of* [Redacted] *compared to NGGT's proposed* [Redacted]"[8].

3.42. NGGT's response makes a number of specific points about our consultant's bottom up assessment. While we did not explicitly rely on the bottom up estimate to arrive at our initial view of efficient costs, we address the main points raised in NGGT's response below.

3.43. We accept that our consultant's assessment is heavily caveated and is based on information provided by NGGT in its submission and in response to our questions. NGGT's response states that we had not arranged for NGGT to engage with our consultant to discuss the concerns raised by our consultant. However, we raised a number of queries with NGGT on its risk register that had been passed on to us by our consultant. In our consultant's view, the responses from NGGT did not provide sufficient clarity to allow a firm view to be taken on the appropriateness of NGGT's risk estimates.

3.44. In our consultation, we expressed concerns about NGGT's use of a flat rate of [Redacted] per day to produce estimates of the cost of a delay to the project. In its response, NGGT provided us with a range of different calculations for the cost of delay, ranging from [Redacted] per day to between [Redacted] per day.

3.45. We summarise these different numbers along with the assumptions therefore below.

Cost category	Cost/day (£)	Assumptions
NGGT original	[Redacted]	Based on tunnel and NGGT staff actual costs on 15th May. NGGT claims in line with costs.
NGGT calculation following corrections to our consultant's estimate	[Redacted]	Based on an average of 180 FTEs. Corrected but caveated by NGGT not to include various non-human resource-related costs.

[8] Para 6.15, RIIO-T1 reopener consultation: One-off Asset Health Costs (Feeder 9)

NGGT relevant cost lines average	[Redacted]	Based on tunnel and NGGT staff forecast and actual costs 1st April – 31st May averaged.
NGGT cost of delay when handling pipes (R-07-001)	[Redacted]	No justification given beyond the statement *"depending on the level of damage, the impact has currently assumed at* [Redacted]*".*

3.46. Following a request from us for additional clarity on these estimates, NGGT said that its estimate of between [Redacted] was based on a simple calculation that took the total annual costs of the project and divided it by the number of working days in the project's life. It asserted that its original estimate of [Redacted] per day was based on its assessment of critical path activities on a daily basis throughout the project, but did not provide further justification for this figure.

3.47. We asked NGGT to explain how its estimates of delay costs take account of activities that take place in parallel, and links and dependencies between them. In particular, we asked NGGT to explain its assumption that a delay of one day on one activity would lead to the entire project being delayed by a day. NGGT's response did not address this question to our satisfaction.

3.48. In the absence of a convincing explanation from NGGT to support any of its estimates, we do not accept them as being reasonable. However, we have updated our consultant's bottom up estimate of risk costs using the figure of [Redacted] to test the sensitivity of our results to this assumption.

3.49. We note that NGGT's own consultants ([Redacted]) highlighted that *"some risk events will impact the critical path of the programme (performance of the tunnel boring machine) in series or the impact of the risk will be netting off as one impact of extension of the TBM progress*". This point was also noted by a second consultancy report commissioned by NGGT which stated that "*due to the lack of a fully developed and linked programme schedule, it was not possible to undertake full Quantitative Schedule Risk Analysis, including the associated duration uncertainty to planned activities".*

3.50. This was also a point noted by NGGT's other consultants [Redacted], which stated that "*…due to the lack of a fully developed and linked programme schedule, it was not possible to undertake full Quantitative Schedule Risk Analysis, including the associated duration uncertainty to planned activities".*

3.51. In response to a request from us for NGGT to clarify the dependencies between the different risks, NGGT stated that *"each risk in the project risk register is considered as an independent event"* and the dependencies which may exist with a few risks are negligible.

3.52. However, we note that if one risk was to occur, other time-dependent risks would decrease in probability.

3.53. The [Redacted] report claimed that an "*uncertainty risk analysis has been undertaken to assess the potential impact of key project risks on programme duration and costs*" based on its mandate which included reviewing "*linkages between contractual risk, programme delivery, processes and resources*". The report states that "[Redacted] *validated the probability and likely programme impact in terms of delay arising from each risk*" based on the National Grid provided "*Project Risk Register which identified a number of key risks*".

3.54. However, we note that there are several inconsistencies between the "key risks" identified by [Redacted] and the most risks that "impact the critical path" identified by NGGT and submitted to us in response to a question. We also note inconsistencies in the likelihood of the event occurring (probability) and the likelihood of the impact (most likely delay). In particular, we note:

- [Redacted]
- [Redacted]
- [Redacted]
- [Redacted]

3.55. In comparison, the [Redacted] report reviewed risk and contingency values of [Redacted] in (09/10 prices) and concluded that "*there is no reason to consider that the impacts have been overstated; fair rationale for both probabilities and impacts were captured by the programme team where possible. In addition, the probabilities and impacts have appropriately taken account of potential mitigations*." We note that this figure does not match the risk allowance requested by NGGT in its submission [Redacted].

3.56. In conclusion, we continue to have serious concerns about NGGT's bottom up estimate of the risk allowance based on its risk register. Even if we were to update our consultant's indicative estimate of [Redacted] to take account of the updated calculation provided by NGGT of [Redacted] or use an alternative figure based on NGGT average costs for 18/19 i.e. [Redacted], the risk allowance would be [Redacted] or [Redacted] respectively. These bottom up figures are lower than our initial view, which proposed an allowance of [Redacted] based on a top down benchmark.

3.57. In conclusion, we maintain our initial view as set out in our consultation document that the appropriate risk allowance is 15% of total project costs, which is at the upper end of the range for our comparator projects. When applied to our updated view of base costs (see next section on project management costs for details), our revised view of the appropriate risk allowance is now [Redacted].

Project management costs

3.58. In our consultation document, our initial view was that an appropriate allowance for project management costs would be 15% of total project costs, based on our review of costs for comparable projects in the electricity and gas sectors. The application of this benchmark to Feeder 9 led to our initial view that the allowance for project management costs should be [Redacted]. This covers project management costs incurred NGGT (i.e. client side project management costs) and its main works contractors (MWC project management costs).

3.59. In reaching our initial view of efficient costs, we noted that NGGT had not provided an explicit budget line for project management costs. We therefore made an assessment of the cost items that we would normally consider to be part of project management activities.

3.60. On NGGT's own project management costs, NGGT disagreed with our allocation of its costs to project management. Our allocation resulted in an estimate of [Redacted] for client side project management costs, whereas NGGT said that it should be [Redacted], with the difference of [Redacted] to be considered as part of base costs, which it said related to *"client side inspection teams provide assurance that assets are fit for purpose for the design life of each asset. Their roles are site based during construction activities, ensuring that contractors are complying with relevant standards and specifications."*

3.61. The third party report from [Redacted] that NGGT submitted as part of its consultation response suggests that the client side management cost for the Feeder 9 project would be approximately [Redacted] (nominal prices). The [Redacted] report concludes that this figure provided a *"representative estimate"* and *"compares favourably with equivalent large-scale construction projects in the energy sector"*.

3.62. However, we note that the [Redacted] report, in computing its estimates of client side project managements costs, includes costs associated with the following:

- One lead inspector and three other inspectors (total of approx. 2 FTE) within the tunnelling team.
- One senior pipeline inspector and three welding and coating inspectors (total of approx. 1.8 FTEs) within the pipeline team.

3.63. According to [Redacted], these inspectors are required to review, monitor and audit the contractor's work. Given NGGT's own consultants consider that tunnelling and pipeline inspectors form part of client side project management activities, we are not convinced by NGGT's argument that these costs should be removed from our estimates of NGGT's project management costs.

3.64. Moreover, we note that [Redacted] estimates include a total of [Redacted] (nominal) for costs associated with "*management of the consenting and permitting process to ensure that the employer's permits are obtained prior to dates agreed under the EPC contract*". NGGT has been provided separate funding for permitting activities and preliminary engineering. Therefore, these costs should be removed from [Redacted] estimates of a like-for-like comparison.

3.65. In calculating the contractor's reported project management costs, we included [Redacted] of costs reported against "contractor's project & administration staff" and [Redacted] of costs reported against "principal contractor duties / site supervision".

3.66. In relation to the contractor project management costs, NGGT claimed that Ofgem had miscategorised "[Redacted] *of costs associated with undertaking physical work".* NGGT said these are *"legitimate costs associated with delivering the project and should not be classified as project management"*. NGGT further stated that Ofgem had included costs relating to *"all aspects of engineering (civil / electrical / mechanical / commissioning), setting out and surveying, general foreman, CAD works, temporary works, project accounting etc."*. NGGT went on to add that *"these costs are legitimate costs associated with delivering the project and should not be classified as project management".*

3.67. We asked NGGT for an explanation of why these contractor cost elements should not be considered as project management costs. NGGT responded by providing a more detailed breakdown of its contractor costs, showing those elements of costs that it believed should not be included within the project management function.

3.68. We accept that there may be a variety of views of what constitutes project management costs, and we have not been able to find a generally accepted definition of these costs that allows us to form a definitive view based on the detailed cost allocations provided by NGGT. However, we believe that it is important to use an approach that is consistent with the allocation methods used in the sources for our top down benchmarks.

3.69. Our top down benchmark of 15% for project management costs was drawn from a range of sources. One of these, the report from ACER on cost indicators for gas infrastructure, says that the benchmark includes "engineering and project management" costs. Another external benchmark that we relied on for project management costs comes from a report produced by Atkins for Ofgem to support our cost assessment of the NSL interconnector.[9] This report provided a figure of 5.9% for developer project management costs, which included "cable and installation engineers", "engineering and design assurance", SHEQ (safety, health, environment and quality) engineers, project accountants and finance as part of its project management function, and therefore its benchmark.

3.70. In light of the allocations provided by NGGT and the evidence from comparator benchmarks, we have reviewed our allocation of contractors' activities to the project management function. In addition to the activities that NGGT has categorised as project management, we have included the following additional activities in the project management function:

- Pipeworks – Staff and supervision. This includes the project engineers and surveyors/CAD support.
- Pipeworks – Design support and SHE training.
- Tunnel works – Inspectors, shift engineers, pit boss, electrical and mechanical superintendents, surveyors and tunnel works engineers.
- Main contractor design activity – Designers and subcontractors.
- Main contractor PIT and temporary works – Engineers and supervisors.

3.71. This means that we have re-categorised the remaining contractor activities as base costs, thereby increasing our view of efficient base costs by [Redacted]. We have applied our benchmark of 15% of total project costs to the revised base cost figure, which means that our final view of efficient project management costs is [Redacted].

Our decision on overall efficient costs

3.72. Following our assessment of the additional information provided by NGGT, we have updated our view of the base costs, risk allowance and project management costs as set out above. Our final view of efficient costs for the Feeder 9 project is set out in the table below.

Cost category	NGGT request	Our initial view	Our final view
Capital costs	[Redacted]	[Redacted]	[Redacted]

[9] https://www.ofgem.gov.uk/ofgem-publications/105006

Project management costs	[Redacted]	[Redacted]	[Redacted]
Risk allowance	[Redacted]	[Redacted]	[Redacted]
Total	**£139.89m**	**£104.64**	**£111.30m**

4. Conclusion and next steps

4.1. Following our assessment of NGGT's application for additional allowances under the "One-off Asset Health Costs" category to cover the costs of building a tunnelled replacement of the Feeder 9 pipeline under the River Humber, we have decided to make an adjustment of £111.3m to its allowances as set out in the table below.

[Redacted]

4.2. Our decision will be implemented through the 2018 Annual Iteration Process, which means that the adjustments to NGGT's allowed revenues will take effect from 2019/20.

Appendices

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Appendix 1: External benchmarks for risk allowances and project management costs

To inform our assessment of efficient costs for the Feeder 9 project, we have considered benchmarks from a number of internal and external documents. Some of these are publicly available, and we provide extracts and links to these reports in Table 1 below.

Table 1 External consultancy reports with benchmarks for project management and risk allowances

Document title and reference	Benchmarks for project management and risk
Parsons Brinckerhoff (Jan/April 2012) – Electricity Transmission Costing Study [Weblink]	**Note**: PM + Overheads in this report include Engineering design, procurement, tendering, PM, planning permission, head office overheads. **Project management and risk for typical electricity transmission projects** **AC O/H Line (400kV)** Total build cost: £4.5m - £134.6m PM + overheads: 10-11% of capex (£0.4m - £11.2m) Risk/contingency: 10-11% of capex (£0.4m - £11.2m) **AC U/G cable – direct buried (400kV)** Total build cost: £35.5m - £1,360.4m PM + overheads: 22% of capex (£5.7m - £216.7m) Risk/contingency: 14% of capex (£3.7m - £141.3m) **AC U/G cable – Tunnel (400kV)** Total build cost: £98.6m - £1,932.6m PM + overheads: 18-19% of capex (£14.8m - £302m) Risk/contingency: 1-1.5% of capex (£0.7m - £23.9m) **AC U/G GI cable – direct buried (400kV)** Total build cost: £47.1m - £944.8m PM + overheads: 20% of capex (£7.0m - £140m) Risk/contingency: 15% of capex (£5.2m - £105m) **AC U/G GI cable – Tunnel (400kV)** Total build cost: £109.4m - £1,720m PM + overheads: 17-19% of capex (£15.6m - £265.5m) Risk/contingency: 4-6% of capex (£3.6m - £83.4m) **DC Subsea cable (400kV DC)** Total build cost: £739.1m - £1,743.6m

	PM + overheads: 9-10% of capex (£56.9m - £130.4m) Risk/contingency: 14% of capex (£85.2m - £194.6m) In the context of OHL, the report adds that "PM costs for capital projects within the industry are generally within the 2.5% to 4% band, dependent upon type and scale of project."
ACER (July 2015) Report on unit investment cost indicators and corresponding reference values for electricity and gas infrastructure. [Weblink for electricity] [Weblink for gas]	**Electricity** OHL – 19% of total project cost (project management, consents, studies etc) UG – 12% of total project cost (project management, consents, studies etc) Subsea cables - 10% of total project cost (project management, consents, studies etc) **Gas** Pipelines – 7% for "engineering and project management" Compressors – 10% for "engineering and project management"
Atkins (June 2016) Consultancy support for Ofgem's cost assessment of the proposed NSL interconnector [Weblink]	Developer project management cost of 5.9% (as a proportion of capex) "lie within the expected ranges for a HVDC and subsea cable projects".
Black and Veatch (February 2014) Capital costs for transmission and substations – Updated recommendations for WECC transmission expansion planning (for the Western Electricity Coordination Council, North America) [Weblink]	Recommended value of 10% of capital cost for overhead costs for a range of projects and ownership structures.
British Power International (Nov 2013) Consultancy support for the NEMO interconnector – Cost assessment report [Weblink]	Assessed project management costs to be in the region of EUR 10m out of a total project cost of EUR 631.8m (1.6%) [Developer PM costs only]
Ofgem (April 2018) Offshore Transmission: Cost assessment for the Burbo Bank Extension transmission assets [Weblink]	On project management costs: "[Our consultants - OWC] reviewed the level of project management costs incurred by the Developer in relation to the Project and estimated the standard level of project management

	costs for such a project would range between 7% and 10% of the cost of the entire project." Ofgem proposed to allow project management costs of 10% of asset value. Contingency of £13.3m was included in the Initial Transfer Value (6.1% of transfer value).