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NGGT'S CONSTRAINT COST MANAGEMENT INCENTIVE AND NETWORK CAPABILITY: A REVIEW OF OFGEM'S PROPOSALS FOR RIIO-T2

A REPORT FOR NATIONAL GRID GAS TRANSMISSION (NGGT)

PUBLIC VERSION

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1. Introduction

1.1 Ofgem has recently published its Draft Determinations (the "Consultation") relating to the price control review process for gas transmission in Great Britain ("GB") using the RIIO framework (Revenues = Incentives + Innovation + Outputs).[1] The result of the consultation process will be a RIIO-T2 settlement for gas transmission that will last from 2021 to 2026. With the RIIO-T2 price controls, Ofgem plans to ensure that "*energy consumers across GB get better value, better quality of service and environmentally sustainable outcomes from their networks*".[2]

1.2 National Grid Gas Transmission ("NGGT"), as the gas transmission system operator across GB, is supporting Ofgem on planning for ways to facilitate a better functioning market and reduce greenhouse gas emissions whilst lowering consumer bills. As part of this, well-designed incentives play a fundamental role in the RIIO framework by more strongly aligning the overall costs and risks faced by the network company with those faced by consumers.

1.3 NGGT owns and operates the National Transmission System ("NTS"). The NTS is the high-pressure pipeline network across GB which transports gas from entry points, where it is injected onto the network, to exit points, where it is taken off the network. The gas transported is used either for direct consumption in the case of a small number of very large gas users or for onward transportation via local distribution networks to consumers.

1.4 On occasion, the intended flows of gas across the network cannot be accommodated by the NTS due to a 'bottleneck' at a particular location. In these cases, congestion occurs in part of the network that could potentially prevent users of the network from injecting and receiving gas where and when it is required. NGGT has various tools and options to resolve congestion, each with different cost implications for the industry and ultimately consumers. To encourage NGGT to resolve this congestion efficiently, Ofgem developed the Constraint Cost Management ("CCM") incentive scheme (or "CCM incentive") as part of the RIIO-T1 price control.

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1 The current price control, known as RIIO-T1 specifically for gas transmission, is due to end on 31 March 2021. This will be replaced by the new RIIO-T2 price control.

2 Ofgem (2020), RIIO-2 Draft Determinations – NGGT Annex, page 1.

1.5 For the RIIO-T2 price control, NGGT submitted its Business Plan in December 2019. NGGT developed its Business Plan based on its expectations of market and operational conditions over the price control period (including, for example, the Future Energy Scenarios ("FES"), an increased reliance on Liquefied Natural Gas ("LNG"), greater market volatility, an ageing asset base and more network interventions).

1.6 NGGT's Business Plan included its proposals for the CCM incentive, as follows:[3,4]

- to retain a variant of the RIIO-T1 CCM incentive with an average annual cost target of £22.1m in 2018/19 prices (£29m target in 2018/19 for RIIO-T1);
- a symmetric cap and collar range of +/- £20m per year (£26m cap and £79m collar in 2018/19 for RIIO-T1);
- a sharing factor of 44.36% (same as RIIO-T1);
- a re-opener if the cap is hit two years in a row or if the collar is hit in any given year (no re-opener in RIIO-T1); and
- removal of revenues where NGGT scales back interruptible and/or off-peak capacity.

1.7 In July 2020, Ofgem issued the Consultation with its own RIIO-T2 proposals for the CCM incentive. In contrast to NGGT's proposals, these included:[5]

- a cost target of £0.2m per year;
- a symmetric cap and collar range of +/-£3.2m per year;
- a sharing factor of 20%;
- removal of entry overruns (a revenue component of the scheme); and
- removal of revenues where NGGT scales back interruptible and/or off-peak capacity.

3 NGGT (2019), NGGT Business plan Submission – Annex A3.03: Output Delivery Incentives, pages 5, 19, 42 and 46.

4 FTI was previously commissioned by NGGT to provide a high-level assessment of the consumer value generated by the CCM Scheme during RIIO-T1. The report from this work was shared with Ofgem as part of NGGT's December 2019 Business Plan submission.

5 Ofgem (2020), RIIO-2 Draft Determinations – National Grid Gas Transmission Annex, page 25.

1.8 Ofgem's proposals have been informed by two reports from the consulting firm AFRY, published as Technical Annexes to the Consultation, which were commissioned by Ofgem.[6,7]

Purpose of this report

1.9 FTI Consulting LLP ("FTI Consulting", "FTI" or "us") has been commissioned by NGGT to independently review Ofgem's proposals for the CCM incentive scheme and comment on:

- the role of the CCM incentive in the context of RIIO-T2 and the potential consequences of Ofgem's proposals;
- the outlook for constraint cost management during the RIIO-T2 period, given GB gas market dynamics and other factors; and
- AFRY's critique of NGGT's input assumptions for the CCM incentive scheme, including those relating to network capability which informs the CCM cost target.

1.10 This report presents our findings and conclusions.

Restrictions

1.11 This report has been prepared by FTI for NGGT under the terms of National Grid's/NGGT's engagement letter with FTI, dated 6 August 2020.

1.12 This report has been prepared solely for the benefit of National Grid in connection with the purpose described above and no other party is entitled to rely on it for any purpose whatsoever. We have agreed with National Grid that this report may be made public as part of NGGT's response to Ofgem's Consultation.

1.13 FTI Consulting accepts no liability or duty of care to any person other than National Grid for the content of the report and disclaims all responsibility for the consequences of any person other than National Grid acting or refraining to act in reliance on the report or for any decisions made or not made which are based upon the report.

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6 These are: AFRY (2020), Audit of Network Capability Assessment; and AFRY (2020), NGGT's CCM Incentive Scheme.

7 Any references specific to the non-public versions of these reports have been redacted in this report.

1.14 Nothing in this report constitutes investment, legal, accounting or tax advice, or a representation that any investment or strategy is suitable or appropriate to the recipient's individual circumstances, or otherwise constitutes a personal recommendation.

1.15 Other than for the purposes described above, this report is not to be referred to or quoted, in whole or in part, in any registration statement, prospectus, public filing, loan agreement, or other agreement or any other document, or used in any legal, arbitral or regulatory proceedings without the prior written approval of FTI.

Limitations

1.16 The report contains information obtained or derived from a variety of sources, including NGGT. FTI does not accept any responsibility for verifying or establishing the reliability of those sources or verifying the information so provided.

1.17 No representation or warranty of any kind (whether express or implied) is given by FTI to any person as to the accuracy or completeness of the report.

1.18 The report is based on information available to FTI at the time of writing of the report and does not take into account any new information which becomes known to us after the date of the report. We accept no responsibility for updating the report or informing any recipient of the report of any such new information.

Structure of this report

1.19 This report has four further sections:

- Section 2 provides an Executive Summary of our findings and conclusions.
- Section 3 discusses the channels through which a robust CCM incentive scheme can create consumer value and explains how Ofgem's proposals may put the effectiveness of these channels at risk.
- Section 4 sets out the importance of adopting a forward-looking view for incentive schemes and the key factors that create a risk of higher and more uncertain constraint costs over the RIIO-T2 period.
- Section 5 comments on AFRY's critique (contained across AFRY's two reports cited above) of NGGT's constraint cost forecasts and network capability assessment.

2. Executive Summary

2.1 In network regulation, incentive schemes are tools used by regulators to create additional consumer value, aligning the overall costs and risks faced by the network company more closely with those faced by consumers.

2.2 This can be achieved by designing incentive schemes in a way that correlates a potential financial reward or penalty for the network companies with consumer outcomes. The financial reward is typically linked to the network company outperforming an *ex ante* target, and vice versa for a penalty. Put another way, the network company retains some of the gains or losses from the outperformance or underperformance against the *ex ante* target.

2.3 While network companies are typically obligated via their network licence conditions to act in an 'economic' and 'efficient' manner, in practice this is recognised as difficult to monitor. This is because of the inherent information asymmetries between regulators that assess performance and the regulated network company. Incentive schemes help to overcome this information asymmetry, as information is 'revealed' to the regulator over the long run.

2.4 In circumstances where a network company has historically outperformed a target, and where the *ex ante* setting of the target is complex, it is understandable that a regulator may wish to take a conservative approach. One reason for this is the risk of setting a wrong *ex ante* target which could lead to windfall gains (or losses) for either network companies or consumers. Another reason is that, while consumers share in the gains from the network company's performance, the financial rewards that accrue to the network company are more visible and tangible than the gains that accrue to consumers via the operation of the incentive. An implication of this is that significantly dampening an incentive provides a visible direct benefit to consumers (in terms of lower returns to the network company arising from outperformance), but any losses to consumers (in terms of foregone efficiency gains) are less visible and difficult to quantify.

2.5 These effects are applicable to the CCM incentive, which was developed by Ofgem for RIIO-T1 to *"minimise the cost of constraints in the NTS against a target, as well as to encourage the release of additional capacity"*.[8]

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8 Ofgem (2020), RIIO-2 Draft Determinations - NGGT Annex, page 24.

2.6 NGGT's performance on the CCM incentive over the RIIO-T1 period suggests that the scheme has strongly aligned NGGT's costs and risks with those of consumers, with the costs of constraint management, captured within the incentive scheme, kept low. Specifically, constraint management costs captured within the incentive scheme have been £0.2m per year on average for RIIO-T1 (to 2018/19).[9] This has enabled NGGT to outperform the *ex ante* target set for RIIO-T1.

2.7 For the RIIO-T2 price control, Ofgem has proposed to significantly reduce the materiality of the incentive scheme, with no prospect of a re-opener. This proposal was informed by two reports from AFRY, which conclude that the assumptions underlying NGGT's proposed *ex ante* cost target for the CCM incentive scheme for RIIO-T2 are not robust. A key driver of this conclusion is AFRY's criticism of NGGT's network capability analyses. AFRY also comments on the unit cost assumptions used by NGGT in its constraint cost forecasts.

2.8 Below, we explain that:

- **A robust CCM incentive scheme has enabled NGGT to deliver consumer value, which could be reduced if the scheme is weakened.** The reduction of constraint costs is the most direct benefit to consumers, but there are significant wider benefits at stake given the impact that NGGT commercial actions taken to resolve congestion can have on the wider GB gas market over time.
- **The rapidly changing landscape of the GB gas market means that a CCM incentive target should place weight on a forward-looking assessment of constraint risk and costs.** It is important that Ofgem does not give undue weight to historical actual constraint costs in the context of a dynamic environment (particularly as gas demand is expected to be lower moving forward).
- **Ofgem's dismissal of NGGT's forecast constraint risk and costs is based on a flawed critique.** Ofgem's proposals have been informed by two reports from the consulting firm, AFRY.[10] AFRY suggests that certain extreme assumptions understate network capability, and therefore overstate the likelihood and magnitude of constraints. Broadly, AFRY's critique does not reflect the important distinction in NGGT's modelling between 'entry' and 'exit' capability assessments (with the former rather than the latter relevant for the vast majority of forecast constraint costs).

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9 Ofgem (2020), RIIO-2 Draft Determinations - NGGT Annex, page 27.

10 These are: AFRY (2020), Audit of Network Capability Assessment, and AFRY (2020), NGGT's CCM Incentive Scheme.

A robust CCM incentive scheme has enabled NGGT to deliver consumer value, which could be reduced if the scheme is weakened

2.9 Well-designed incentives play a fundamental role in the RIIO framework by more strongly aligning the overall costs and risks faced by the network company with those faced by consumers.

2.10 In context of the CCM incentive scheme, this happens in two main ways:

- First, it incentivises NGGT to **manage the risk of constraints in a cost-effective manner**; and
- Second, it encourages NGGT to **release additional capacity**.

2.11 However, Ofgem's proposals could put the effectiveness of these channels at risk and, as a result, consumers could lose out. We discuss each of these below.

Managing the risk of constraints in a cost-effective manner

2.12 NGGT's constraint risk management reflects trade-offs between different approaches, which include asset optimisation and commercial actions.[11] To reduce expenditure on commercial actions, NGGT might choose to incur additional cost in the operation of the existing transmission asset base (e.g. rescheduling of compressor outages). In turn, this can reduce the overall costs (to NGGT) of mitigating and managing constraints.

2.13 The CCM incentive scheme generates value for consumers by creating a **direct financial trade-off** for NGGT when choosing between different constraint management approaches. It links the costs and risks borne by NGGT more closely to the costs and risks which are ultimately borne by consumers, encouraging NGGT to undertake the most cost-effective action to avoid or mitigate constraints.[12] A robust CCM incentive scheme encourages NGGT to balance the trade-offs between different approaches effectively, to reduce the risk and cost of constraints to consumers.

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[11] NGGT could also deploy non-market interventions, where it directly intervenes in the market, instructing operators to reduce the amount of gas taken off or injected (e.g. via terminal flow agreements for injections). These interventions are typically used as a last resort physical protection mechanism as they could lead to interruptions to gas customers.

[12] Subject to sharing factors, consumers are ultimately exposed to the costs NGGT incurs in both Totex and constraint management actions.

2.14 Relative to a cost-pass through approach, a robust CCM incentive scheme has two main benefits:

- First, **it encourages NGGT to be less risk averse**. In the absence of a CCM incentive scheme, NGGT may more often choose to take the least risky option to resolve a constraint (i.e. commercial actions). More frequent interventions using commercial actions could have a larger and longer term market impact, potentially leading to higher costs to consumers.
- Secondly, it **prevents a misalignment of regulatory incentives**. The combination of both the CCM incentive scheme and a Totex incentive scheme on NGGT's asset base creates a trade-off for NGGT between commercial tools to resolve a constraint, and asset optimisation actions to alleviate or mitigate the risk of constraints. It encourages NGGT, where appropriate, to favour the use of asset optimisation actions over commercial tools.

2.15 NGGT's actions in respect of mitigating constraints on the NTS can be considered as the forward-looking management of a 'portfolio' of spend, with the aim of reducing the risk and/or cost of constraints. With a robust CCM incentive, NGGT is rewarded when it balances the trade-off between proactive and reactive approaches effectively, leading to lower costs for consumers.

2.16 As noted above, NGGT's performance on the CCM incentive over the RIIO-T1 period suggests that the scheme has strongly aligned NGGT's costs and risks with those of consumers, with constraint management costs kept low. Ofgem's proposals in its Consultation risk shifting NGGT's response away from proactive measures, and towards more risk averse options to manage constraints. These tend to be more reactive responses, which could lead to higher costs for consumers and wider market impacts over time.

2.17 In particular, Ofgem's proposals could lead to increases in overall costs for consumers in the following ways:

- **Increased indirect costs of commercial actions.** Commercial actions that NGGT undertakes to resolve constraints can have a significant impact on the GB wholesale gas market. The impacts are necessarily difficult to estimate, as they are sensitive to the exact nature of the constraint, the commercial action taken, the dynamics of the market on the day of the constraint and the behaviour of the gas market participants. However, for illustration, the last capacity buyback (which occurred in 2006 at St Fergus) corresponded to a National Balancing Point ("NBP") price increase of around 50% over the day's prevailing price before the buyback occurred. The increase in the NBP price caused by a capacity buyback action on-the-day will affect those in the forward market who are short on the day and need to buy gas at a higher price. To the extent that the frequency of buybacks is anticipated by the market, it is likely to be priced in to forward contracts and therefore spread across all gas procured through forward contracts. Given this, the indirect consumer cost of an increase in NBP price of this magnitude could be **considerably higher** than the 'direct' consumer cost (i.e., of the commercial action itself).[13]
- **Increased direct cost of commercial actions.** Beyond the collar of the scheme (which is significantly smaller under Ofgem's recent proposals), NGGT will no longer have as strong an incentive to pursue the least costly action to relieve constraints, which means the balance of trade-offs will tilt in favour of commercial actions, such as locational trades, that are more costly to consumers relative to asset optimisation approaches (which are riskier for NGGT). Furthermore, costs to consumers could be higher if NGGT favours capacity buybacks, which are more costly than locational trades but are more likely to successfully alter gas flows.[14]

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13 It is also possible that in certain circumstances there could be follow-on impacts on electricity prices (as, in the GB market, there are some days where the electricity price is very closely linked to the gas price).

14 This is because capacity buybacks represent a direct restriction of flows at a specific entry or exit point. By contrast, when NGGT undertakes a locational trade, shippers could potentially continue to trade additional gas (if they have sufficient supply), thereby continuing to flow gas through the network.

Releasing additional capacity

2.18 The CCM incentive scheme encourages NGGT to release additional capacity to the GB gas market. This is done primarily through the commercial release of non-obligated capacity,[15] which is firm capacity demanded by the market over and above that which NGGT is obligated under its licence conditions to provide.

2.19 Like other forms of capacity, non-obligated capacity has locational benefits and is highly valued at certain entry and exit points. This is indicative of the significant value of additional firm capacity to shippers at these locations at certain times. Additionally, capacity can also bring benefits to consumers, through system-wide benefits such as:

- **Wholesale gas price moderation:** Releasing non-obligated entry capacity can facilitate better competition amongst GB wholesale gas market participants. This allows more shippers to supply gas into the network and the energy market, which can contribute to lower NBP prices and increased security of supply, which is particularly beneficial during periods of higher demand.
- **Security of supply in electricity markets:** The gas transmission network can also support security of supply in electricity markets by providing additional flexibility through additional exit capacity for Combined Cycle Gas Turbines ("CCGTs"). This is increasingly beneficial for energy systems on the path to decarbonisation, where CCGT usage becomes more variable due to the greater penetration of non-dispatchable renewable generation such as wind.

2.20 When additional capacity is released, this can lead to firm capacity being released that exceeds the physical capability of the network. As a result, this increases the risk of constraints. The benefits to consumers of additional capacity must be balanced against the risk of additional constraints, and a robust CCM incentive helps to drive efficient decision making to best balance these two factors.

2.21 At points beyond the cap of the CCM incentive scheme, NGGT would have less of an incentive to release additional non-obligated capacity. This is because there would be no incremental reward to NGGT from doing so, but there would still be the potential for incremental costs at the margin (as releasing non-obligated capacity would still increase the risk of incurring constraint management costs).

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15 Revenues from the release of non-obligated capacity sales are included as a revenue component of the CCM incentive scheme.

The rapidly changing landscape of the GB gas market means that a CCM incentive target should place weight on a forward-looking assessment of constraint risk and costs

2.22 It can be challenging to set an appropriate *ex ante* cost target (and associated scheme parameters) for schemes like the CCM incentive, where:

- there are no or limited comparators (e.g. other network companies to benchmark against); and
- the *ex ante* cost target is set with a complex process.

2.23 For some kinds of cost targets (e.g., some types of opex), and in a relatively static environment, the exercise is somewhat less challenging, in part because it may be appropriate to place weight on historical outturn costs. For example, items like operating staff costs are likely to be relatively stable between price controls, and therefore historic costs are likely to be more reflective of future costs (subject to appropriate adjustments for inflation, cost drivers, etc.)

2.24 However, where the environment in which an incentive will operate in the future may be significantly different to the past, or is highly uncertain, the level of historic performance may be less relevant and more weight may need to be placed on forward-looking expectations. These forward-looking expectations should reflect the known information about the underlying costs, risks and benefits faced by consumers in the future to determine an efficient level of spend by the regulated company.

2.25 Therefore, although challenging, for the CCM incentive scheme it is particularly important for the incentive design to place weight on a forward-looking assessment of constraint costs. This is because the expected changes in the GB gas market and the NTS are likely to have significant implications for constraint cost management. The three main drivers of this are summarised below.

- First, the **lower demand of gas forecast for GB**. Managing the NTS can prove particularly challenging during periods of low demand, and more so when demand falls even lower than expected. This is evidenced by NGGT’s experience during this year’s COVID lockdown. Indeed, the number of constraint management actions taken during the first half of 2020 is already higher than any previous whole year in the RIIO-T1 period.

- Second, the **increasingly dynamic nature of GB gas markets**, and therefore gas flows in the NTS. The supply and demand dynamics for gas are evolving, driven by falling UK Continental Shelf ("UKCS") gas production (leading to a greater reliance on imported gas at different entry points), continued growth in 'fast-cycle' gas storage, and increased supply of gas from unconventional sources, such as biogas. This in turn is likely to increase the variability of flows on the NTS, leading to a greater risk of constraints. This is likely to be exacerbated by GB's reliance on LNG and imported gas more widely. LNG (and other imports) flows are difficult to forecast, as they are not solely driven by the GB domestic demand or price for gas (which has been the traditional determinant for gas flows onto the network), but are instead also sensitive to global market conditions. This means a greater likelihood of periods of high GB supply becoming less coincident with periods of high GB domestic demand.
- Finally, the **ageing asset base of the NTS**. An ageing asset base implies that the frequency of unforeseen issues such as outages is likely to increase during RIIO-T2. Furthermore, the interventions and planned outages required for maintaining assets will also increase in volume during RIIO-T2. Both of these factors could make the management of constraints more complex and costly.

Ofgem's dismissal of NGGT's forecast constraint risk and costs is based on a flawed critique

2.26 Ofgem's conclusions rely on reports from the consulting firm AFRY.[16] AFRY has cited specific assumptions made by NGGT in its network capability assessments that it considers to be *"perhaps extreme"*, and not reflective of the typical operation of the NTS. AFRY suggests that these *"extreme"* assumptions understate network capability, and therefore overstate the likelihood and magnitude of constraints. [17] A key driver of AFRY's conclusions relating to NGGT's proposed CCM incentive is this critique of NGGT's input assumptions.[18]

16 Ofgem (2020), RIIO-2 Draft Determinations – NGGT Annex, page 25.

17 AFRY (2020), Audit of Network Capability Assessment, page 3.

18 AFRY (2020), NGGT's CCM Incentive Scheme, page 41.

2.27 However, **AFRY's comments on NGGT's network capability input assumptions do not sufficiently distinguish between entry and exit capability**. This approach is not correct, since NGGT assesses the capability of the NTS (and subsequently forecasts constraint costs) separately for entry and exit points, in the following way:

- The assumptions applied for the purposes of **exit capability modelling** reflect the need for NGGT to meet its 1-in-20 obligation. This enables NGGT to plan its asset base and network operations in a way that can meet a 1-in-20 level of peak demand, as required by its license.[19]
- By contrast, the assumptions applied for the purposes of **entry capability modelling** are scaled for different levels of demand, and more closely reflect the **typical operation of the network**.

2.28 In fact, the assumptions AFRY cites (and considers *"extreme"*) predominantly take those values in the context of assessing exit capability, and are therefore are mostly relevant to exit constraint cost estimates. .

2.29 Therefore, AFRY's key criticisms of NGGT's constraint cost modelling are **either incorrect or relatively minor in impact** since exit constraints represent a minority (9%) of total constraint costs.[20]

2.30 Based on this, it seems to us that AFRY is incorrect in considering NGGT's proposed CCM incentive to be wholly unjustified, given that the key network capability modelling deficiencies identified by AFRY relate to parameters associated with exit capacity, which forms a small proportion of NGGT's proposed CCM target.

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19 National Grid's Gas Transporter Licence in respect of the NTS requires that the pipeline system must, taking into account operational measures, meet the 1-in-20 peak aggregate daily demand including within day gas flow variations. The 1 in 20 peak day demand is the level of daily demand that, in a long series of winters, with connected load held at the levels appropriate to the winter in question, would only be exceeded in one out of 20 winters, with each winter counted only once. See: National Grid (2019), Transmission Planning Code, page 4 (Standard Special Condition A9: Pipe-Line System Security Standards).

20 At NGGT's forecast level of constraint costs, only 9% of total constraint costs correspond to constraints at exit points.

2.31 AFRY has also commented on the unit cost assumptions used by NGGT in its constraint cost forecasts. As noted above, the unit cost of commercial actions that could be undertaken to resolve constraints are necessarily difficult to estimate and inherently uncertain, given how sensitive they are to market dynamics and the exact nature of the constraint. In light of this, it seems to us a reasonable approach to make some simplified unit cost assumptions over a significant time horizon (such as the 5 year future time period of RIIO-T2), if it also assumed there are mechanisms within the CCM incentive (such as re-openers) to account for the collective impact of parameters which are inherently uncertain (as discussed in Section 4).

Conclusions

2.32 Well-designed incentive schemes play a strong role driving efficient network company performance and delivering consumer value. When a company performs well against an incentive target, as appears to have been the case with the CCM incentive scheme for RIIO-T1, it can be indicative that the incentive scheme has been successful in more strongly aligning the costs and risks faced by the network company with those of consumers. However, it can also raise concerns that the *ex ante* target (e.g., of the actual efficient cost that the network company should incur over the price control period) was set inappropriately.

2.33 These concerns are understandable, especially where it is intrinsically challenging to set an appropriate *ex ante* target (and associated scheme parameters), as is the case for the CCM incentive.

2.34 However, we do not consider that AFRY's critique provides sufficient grounds for dismissing NGGT's constraint cost modelling (and, in turn, the *ex ante* cost target proposed by NGGT).

2.35 Given this, and in light of the substantial potential benefits of a robust CCM incentive, it seems to us that it would not be in the best interests of consumers to dismiss NGGT's (forward-looking) constraint risk and cost modelling forecasts and instead apply a significantly smaller target and CCM incentive regime.

2.36 Instead, where there are concerns that arise from the intrinsically challenging exercise of setting an *ex ante* target in this case, there would be value to Ofgem using the regulatory tools it has at its disposal (including re-openers or interim reviews) to manage uncertainty over the future level of constraint risks and costs. This ensures not only that NGGT has incentives aligned with those of consumers, but also that consumers are protected from material windfall losses arising from having set the scheme parameters incorrectly.

3. The role of a robust CCM incentive in driving consumer value

3.1 The CCM incentive was developed by Ofgem for RIIO-T1 to *"minimise the cost of constraints in the NTS against a target, as well as to encourage the release of additional capacity"*.[21]

3.2 A robust CCM incentive scheme has the following impacts:

- First, **it encourages NGGT to be less risk averse**. In the absence of a CCM incentive scheme, NGGT may more often choose to take the least risky option to resolve a constraint (i.e. commercial actions). More frequent interventions using commercial actions could have a larger market impact, potentially leading to higher costs to consumers.
- Secondly, it **prevents a misalignment of regulatory incentives**. The combination of both the CCM incentive scheme and a Totex incentive scheme on NGGT's asset base creates a trade-off for NGGT between commercial tools to resolve a constraint, and asset optimisation actions to alleviate or mitigate the risk of constraints. It encourages NGGT, where appropriate, to favour the use of asset optimisation actions over commercial tools.

3.3 A robust CCM incentive scheme should therefore reduce the overall costs of commercial actions by incentivising NGGT to efficiently avoid commercial actions. In turn, this avoids potentially distortive effects on wholesale market prices that can arise with some commercial actions. A robust CCM incentive scheme should also effectively encourage the release of additional capacity above NGGT's baseline obligation.

3.4 Ofgem has proposed a much narrower incentive scheme, with a significantly reduced cost target, smaller cap and collar range, and a lower sharing factor.[22] This risks the following:

- distortions of wholesale prices through constraint management may be more likely, imposing cost on consumers;

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21 Ofgem (2020), RIIO-2 Draft Determinations - NGGT Annex, page 24.

22 Ofgem (2020), RIIO-2 Draft Determinations – NGGT Annex, page 25.

- NGGT's incentives to manage the risk of constraints in a cost-effective manner will be affected; and
- NGGT may be less incentivised to release additional capacity in certain circumstances, which reduces the extent to which consumers benefit from this additional capacity.

The CCM incentive encourages NGGT to avoid commercial actions which have impacts on the wholesale market

3.5 Commercial actions could have wider effects on consumers beyond their direct cost to NGGT and consumers, as described later in this section.

3.6 Relative to locational trades, capacity buybacks are more likely to successfully alter gas flows as they represent a direct restriction of flows at a specific entry or exit point. By contrast, when NGGT undertakes a locational trade, shippers may continue to trade additional gas (if they have sufficient supply), thereby continuing to flow gas through the network.

3.7 By way of example, suppose an entry constraint is expected at Entry Point A, which has a capability of 50mcm, for which flows of 53mcm are predicted. Suppose shippers have firm capacity rights of 70mcm on this particular day.

- To manage this constraint, NGGT could undertake a capacity buyback, which would require it to buy back 20mcm of capacity from shippers.[23] This would restrict flows to 50mcm and fully mitigate the constraint.
- Alternatively, NGGT could undertake a locational trade, for example by buying 3mcm of gas from Shipper Y.
- However, with the locational trade, it is not certain that the constraint will be fully mitigated, since in theory Shipper Y could continue to sell additional gas, thereby continuing to flow gas through the constrained entry point.
- By contrast, the capacity buyback can provide certainty that the constraint will be managed.

[23] It is common for firm capacity to be sold in excess of capability, and indeed the level of capacity NGGT is obligated to make available is often greater, by design, than the capability of the network.

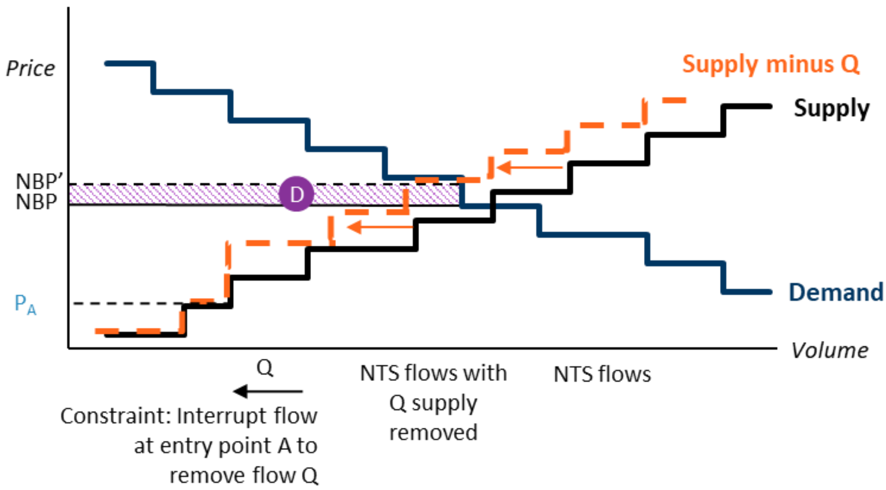
3.8 NGGT is typically disincentivised from undertaking a capacity buyback as it is likely to be more costly to NGGT than locational trades.[24] However, beyond the collar of the scheme, NGGT may be more likely to favour the relative certainty of a capacity buyback in resolving a constraint, over a locational trade. Therefore, all else equal, this could increase costs for consumers.

Indirect consumer costs from capacity buybacks

3.9 Additionally, capacity buybacks also have an indirect cost to consumers, in the form of a distortion of the wholesale gas price. This is necessarily difficult to estimate, [✂].[25]

3.10 However, the effects can be significant (as illustrated in the St Fergus example discussed below). Capacity buybacks restrict the supply curve for gas in the wholesale market, increasing the NBP price for all consumers. This is illustrated in Figure 3-1 below.

Figure 3-1: Impact of capacity buybacks on the NBP



3.11 Figure 3-1 above shows the supply and demand for gas on a given day, and the effects of a capacity buyback to remove flow Q.

24 Since it is common for firm capacity to be sold in excess of capability, a higher volume of capacity needs to be bought back to successfully restrict flows.

25 [✂]

3.12 Buying back entry capacity shifts the supply curve to the left (as indicated by the new orange supply curve), restricting a volume of cheaper gas from flowing in. The market is then incentivised to replace this gas from another source which, by definition, will not be cheaper (as otherwise the cheaper gas would have been procured). This is likely to result in a higher NBP clearing price (shown by NBP'). As a consequence, consumers face a higher cost, represented as Area D.

3.13 On the day of a given capacity buyback, shippers who are short will face the increased NBP price in the form of higher cash-out charges. To the extent that the increased frequency of capacity buybacks is anticipated by the market, the cost of buybacks will also to be priced in to the forward curve. This premium will increase the price faced by all participants in the forward market.

3.14 It is difficult to forecast the upward effect of a capacity buyback on the NBP price. However, the last capacity buyback (which occurred in 2006 at St Fergus) corresponded to a 0.5p/kWh increase in the NBP price that lasted most of the rest of the gas day. This was an increase of around 50% over the day's prevailing price before the buyback occurred.

3.15 The indirect consumer cost of an increase in NBP price of this magnitude is likely to be considerably higher than the 'direct' consumer cost of actions that consumers are exposed to via the CCM incentive sharing factor.

3.16 AFRY has highlighted that this framework does not take into account possible actions NGGT could take to mitigate this distortive effect on wholesale prices. AFRY states that, in theory, NGGT could undertake locational sales to put downward pressure on prices. However, as a *"residual balancer"*, it is not NGGT's role to undertake actions that manipulate or 'correct' wholesale market prices, and it is surprising to us that AFRY suggests this would be an appropriate action for NGGT.

3.17 This distortive effect on the GB wholesale gas market may have long term effects. If NGGT intervenes frequently in the market to resolve constraints, market participants may come to expect this, and may have less confidence that the NTS is being managed robustly. In addition, the expectation of flow restrictions may lead market participants to adjust their pricing behaviour, for example, by pricing in risk premiums.

3.18 It is also possible that, in certain circumstances, there could be follow-on impacts on electricity prices (as, in the GB market, there are some days where the electricity price is very closely linked to the gas price).

The CCM incentive encourages NGGT to manage the risk of constraints in a cost-effective manner

3.19 To manage constraint risk (forecast or otherwise), NGGT has a choice between:

- managing the risk of a constraint through asset optimisation actions; and
- commercial actions, such as scale-backs of non-firm capacity, locational trades, or capacity buybacks.

3.20 Asset optimisation actions refer to the use of NGGT's asset base to mitigate or manage the risk of a constraint. This can include a range of different operational strategies, such as: (i) arranging for or cancelling maintenance of assets on short notice; (ii) running certain assets like compressors outside their normal operation hours; or (iii) building flexible schedules into third party maintenance contracts. Asset optimisation actions are relatively more proactive, and are typically used to mitigate the risk of a constraint occurring in the first place.

3.21 [✂]

3.22 Commercial actions, by contrast, are relatively more reactive in nature. They involve direct intervention in the market, and because of this, represent the less 'risky' option, as they are more likely to have a direct impact on the physical flows on the network. Examples of commercial actions include withdrawing previously sold non-firm capacity from participants, engaging in locational trades, or buying back firm capacity directly. Locational trades and capacity buybacks have the potential to be more costly to consumers, as they are dependent on day to day market conditions and the amounts participants are willing and able to accept in exchange for modifying their behaviour. Additionally, as explained further below, capacity buybacks can distort wholesale market prices.

3.23 NGGT's actions in respect of mitigating constraints on the NTS can be considered as the forward-looking management of a 'portfolio' of spend, with the aim of reducing the occurrence and/or cost of constraints. With a robust CCM incentive, NGGT is rewarded when it balances the trade-off between proactive and reactive approaches effectively, leading to lower costs for consumers.

3.24 This is aligned with the interests of consumers as a whole, as it reduces the costs they ultimately bear, and the risk of potential distortion of market prices. Ofgem's proposals in its Consultation (and in particular, the significantly reduced cap and collar) risk shifting NGGT's response away from proactive measures, and towards more reactive responses to constraint management.

3.25 To illustrate this, we specifically discus the interaction between the Totex Incentive Mechanism ("TIM") and the CCM incentive below.

Interaction between TIM and CCM sharing factor

3.26 The combination of the TIM and the CCM incentive creates a trade-off for NGGT. In principle, where there is a risk of a constraint, NGGT can choose to mitigate this with:

- asset optimisation actions; or
- commercial actions.

3.27 The incremental costs borne by NGGT of both asset optimisation actions and commercial actions are related to the sharing factors of the TIM and the CCM incentive respectively. NGGT is encouraged to pursue the least costly action to mitigate or manage constraints, and make capacity available.

3.28 However, when the collar of the CCM incentive is reached, the terms of this trade-off will change. In these circumstances, NGGT no longer bears any of the costs of further commercial actions, while NGGT does continue to bear some proportion of any further asset optimisation actions (as per the TIM). All else equal, NGGT will then have a lower incentive to pursue an asset optimisation action regardless of whether this is the least costly action to consumers to relieve a constraint.

3.29 By way of example, suppose for a given constraint event NGGT has a choice between:

- an asset optimisation action that costs £30,000 (for example, incurring significant overtime contractor costs to accelerate maintenance of a compressor); and
- a commercial action that costs £50,000 (for example, a locational trade action).

3.30 Suppose further that the asset optimisation action was not funded by some separate incentive scheme (and was instead considered under NGGT's Totex as per the TIM), and the CCM collar had already been reached. Under the TIM sharing factor, NGGT would bear £11,010 in costs (36.7% of £30,000) for the asset optimisation action. Under the CCM incentive scheme, NGGT would bear no costs, as the cost of the locational trade (£50,000) would be fully passed on to consumers.[26]

3.31 In this way, all else held equal, NGGT would face more of an incentive to select the more expensive constraint management action in such circumstances.

3.32 Ofgem has proposed a narrower cap and collar (±£3.2 million) than NGGT. This means that the point beyond which NGGT has a lower incentive to pursue the least costly action to consumers could be reached sooner (compared to under NGGT's proposals).

NGGT will be less incentivised to release additional capacity

3.33 Revenues from the release of additional capacity are included in the CCM incentive scheme and offset the costs of commercial actions to resolve constraints. Under the CCM incentive, allowed revenues in RIIO-T1 included:

- obligated capacity (both entry and exit) sold at the daily level;
- non-obligated capacity (both entry and exit);
- non-firm capacity (both interruptible and off-peak);[27] and
- entry overrun penalties.[28]

3.34 Table 3-1 below presents the revenues of each of the categories above during RIIO-T1.

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26 It is worth noting that even if the CCM collar is not reached, there are still potentially misaligned incentives due to the difference in sharing factors. For example, suppose that both actions had the same cost, and collar had not already been reached. The proposed lower sharing factor (20%) on the CCM incentive would imply lower costs to NGGT for the locational trade, which in turn, implies higher costs for consumers.

27 For RIIO-2, both NGGT and Ofgem agreed that revenues from non-firm capacity that is scaled-back should not be included in allowed revenues under the CCM incentive. We understand the quantum of this is expected to be minimal.

28 For RIIO-2, Ofgem has proposed to exclude entry overrun penalties from allowed revenues.

Table 3-1: Revenue generated under the RIIO-T1 CCM incentive (to end of gas year 18/19)

	Total *£m*	Average *£m per annum*
Daily obligated capacity	1.9	0.3
Non-obligated capacity	8.4	1.2
Non-firm capacity	3.5	0.5
Entry overrun penalties	5.7	0.8
Total	**19.5**	**2.8**
Total excl. entry overrun penalties	**13.8**	**2.0**

Source: NGGT (2019) RIIO-T2 Business Plan – A3.03, page 37.

3.35 Sales of non-obligated capacity represent the largest revenue component under the CCM incentive scheme. Non-obligated capacity is firm capacity, which is guaranteed to customers once it has been sold.[29]

3.36 The sale of non-obligated capacity can lead to firm capacity being released that exceeds the physical capability of the network. As a result, this increases the risk of constraints. The benefits to consumers of additional capacity must be balanced against the risk of additional constraints, and a robust incentive helps to drive efficient decision making to best balance these two factors.

3.37 One aim of the CCM incentive is to encourage NGGT to release additional capacity above its obligated baseline level in a prudent manner, and manage this trade-off effectively.

3.38 In the remainder of this section, we discuss:

- the benefits of non-obligated capacity to consumers; and
- the potential effect of Ofgem's proposals on these benefits.

Non-obligated capacity benefits NGGT's customers and the energy system

3.39 Non-obligated capacity is guaranteed to customers once it has been sold. Customers of non-obligated capacity encompass a broad range of wholesale participants, including shippers, DNOs and power stations. As firm capacity, non-obligated capacity provides an option and/or forward value to customers, as it guarantees capacity is available for use once sold, if they deem it necessary.

29 Circumstances requiring the use of Emergency Procedures are an exception to this.

3.40 In general, the price of capacity sold at the entry and exit points reflects the value placed by customers on capacity at those points. As shown in Figure 3-2 and Figure 3-3 below, the average price paid per GWh/day of non-obligated capacity varies significantly across different locations. This suggests the value of non-obligated capacity to NGGT's customers is largely location dependent. That is to say, customers place significant value on additional units of non-obligated capacity at specific exit or entry points.

Figure 3-2: [✂]

Figure 3-3: [✂]

3.41 Additionally, the ability to procure non-obligated capacity also generates the following system-wide benefits:

- **Wholesale gas price moderation:** Releasing non-obligated entry capacity can facilitate better competition amongst GB wholesale gas market participants. This allows more shippers to supply gas into the network and the energy market, which can contribute to lower NBP prices and increased security of supply, which is particularly beneficial during periods of higher demand.
- **Security of supply in electricity markets:** The gas transmission network can also support security of supply in electricity markets by providing additional flexibility through additional exit capacity for CCGTs. This is increasingly beneficial for energy systems on the path to decarbonisation, where CCGT usage becomes more variable due to the greater penetration of non-dispatchable renewable generation such as wind.

3.42 The possibility for realising the consumer benefits arising out of non-obligated capacity are reduced under Ofgem's proposals, as we explain further below.

Ofgem's proposals disincentivises the release of non-obligated capacity

3.43 When non-obligated capacity is offered by NGGT, the reward from the additional revenue earned must balance the physical and commercial risk of constraints on the network.

3.44 NGGT carries out its own analysis of how much capacity is available, the risks associated with releasing incremental capacity and whether there needs to be incremental investments to meet demand. For example:

- When there is a possibility for sustained demand, incremental capacity investment would be more appropriate.

- For discrete bursts of demand, incremental capacity investment would typically not be appropriate. In this case, NGGT may release non-obligated capacity to help the customer meet that need.[30]

3.45 However, NGGT may decide against releasing non-obligated capacity if it anticipates that this will cause constraints on the network. This is because a constraint could lead NGGT to take market-based commercial actions (i.e. locational trades and commercial buybacks), which are costly to NGGT (and ultimately to consumers).

3.46 It appears constraints are relatively more likely to occur when short term non-obligated capacity is sold. From April 2013 to March 2019, on days when non-obligated capacity was sold, the probability of a constraint occurring was 0.9%. Over the same period, on days when non-obligated capacity was not sold, this probability was 0.3%.[31]

3.47 Therefore, the decision on whether or not to release non-obligated capacity is a risk and reward assessment, whereby NGGT balances the additional revenues earned against the likelihood of the additional gas flows causing a constraint.

3.48 At points beyond the cap of the CCM incentive scheme, NGGT would have less of an incentive to release additional non-obligated capacity. This is because there would be no incremental reward to NGGT from doing so, but there would still be the potential for incremental costs at the margin (as releasing non-obligated capacity would still increase the risk of incurring constraint management costs).

3.49 Ofgem has proposed a significantly narrower cap than NGGT, so the point beyond which NGGT loses the incentive to sell additional capacity may be reached sooner.

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30 In the short term, the decision-making process is driven by the control room and relies on NGGT staff judgement.

31 Between 1 April 2013 and 31 March 2019, short-term non-obligated capacity was sold on 1,536 gas days (out of a total of 2,191 gas days). Of those days when short-term non-obligated capacity was sold, NGGT had to take actions to resolve constraints on 16 of them. That is, a constraint occurred on 0.9% of the gas days in which short-term non-obligated capacity was sold. By contrast, of the 655 gas days in which no short-term non-obligated capacity was sold, NGGT had to take actions to resolve constraints on only 2 of them. That is, a constraint occurred on 0.3% of the gas days in which no short-term non-obligated capacity was sold. Source: NGGT data.

4. The risk of higher and more uncertain constraint costs in the T2 period

4.1 Over the last three decades, policy makers across the globe have wrestled with the problem of how to deliver higher quality and lower cost goods and services to consumers in sectors of the economy where historically there has been limited or no competition.

4.2 In those parts of the sector where it has been considered difficult to introduce competition and monopoly provision of a good or service persists, policy makers have developed regulatory regimes with the aim of delivering higher quality goods and services at a lower cost.

4.3 A common approach to regulation in liberalised markets is a 'price control' which restricts the amount of revenue that a monopoly company may recover from customers (or alternatively capping prices). However, the question of what an appropriate level of revenue is (given the asset base, costs and risks of the company) raises an issue of asymmetry of information between the regulated company and the regulator.

4.4 The problem of asymmetric information between the regulated company and the regulator was considered in the 1980s in the UK during the period of privatisation. Stephen Littlechild, at the time a Treasury economist, developed the concept of price or revenue cap regulation which recognised there was asymmetry of information between the regulated company and the regulator, but financially incentivised the regulated company to 'reveal information' to the regulator over the longer run.[32]

4.5 The same principle can apply to *ex ante* incentive regimes for specific areas of performance – put another way, the level of performance achieved by the regulated company can in some circumstances be used to inform the next *ex ante* target.

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[32] It was first applied to British Telecom in 1983 and extended to gas electricity and water sectors over the course of the decade. See *The Regulation of privatized monopolies in the United Kingdom,* M. E. Beesley and S. C. Littlechild, *The RAND Journal of Economics*, Vol. 20, No. 3 (Autumn, 1989), pp. 454-472.

4.6 However, it needs to be recognised that the information revelation properties of incentive regimes typically work best in relatively 'static' environments and for costs that are more stable or mechanically linked to specific drivers (such as some types of opex).

4.7 Where the context in which an incentive will operate in the future may be significantly different to the past, or is highly uncertain, the level of historic performance may be less relevant and more weight may need to be placed on forward-looking expectations. These forward-looking expectations should reflect the **known information about the underlying costs, risks and benefits** faced by consumers in the future.

4.8 As such, an ex ante target should reflect a reasonable expectation of efficient costs. It can be challenging to set an appropriate ex ante cost target (and associated scheme parameters) for schemes like the CCM incentive, where there are no or limited comparators (e.g. other network companies to benchmark against) and the ex ante cost target is set with a complex process.

4.9 Where there are concerns that arise from the intrinsically challenging exercise of setting an *ex ante* target in this case, there would be value to a regulator in using the regulatory tools it has at its disposal (including re-openers or interim reviews) to manage uncertainty over the future level of constraint risks and costs. This ensures not only that regulated company has incentives aligned with those of consumers but also that consumers are protected from material windfall losses arising from having set the scheme parameters incorrectly.

4.10 The underlying costs and risks of constraint management are quantified through NGGT's constraint cost modelling. In Section 5, we explain why we consider that AFRY's criticisms of NGGT's constraint cost modelling (which Ofgem relies on for its proposals) are either incorrect or relatively minor in impact.

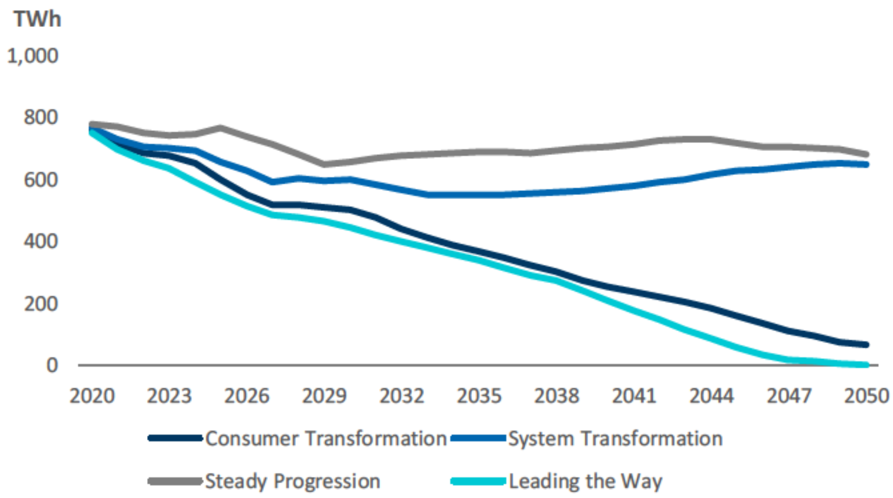
4.11 In the remainder of this section, we summarise three factors which are relevant to how NGGT manages constraint costs over the RIIO-T2 period, and may contribute to higher constraint costs over the period. These factors are:

- the falling demand for gas;
- an increasingly dynamic GB gas market; and
- the interactions with an ageing asset base.

Falling demand for gas

4.12 While there are uncertainties around the future usage patterns of gas (as explained further below), there is consensus that the gas demand is likely to fall. This is illustrated by the fact that across all four of National Grid Electricity System Operator's ("NG ESO's") FES scenarios,[33] there is a fall in gas demand, as illustrated in Figure 4-1 below.

Figure 4-1: Average forecast annual demand for gas



Source: NG ESO (2020), Future Energy Scenarios databook.

4.13 Over the RIIO-T2 price control period, gas demand is forecast to decline cumulatively by c. 17%, based on an unweighted average of all four FES scenarios.

4.14 Falling gas demand in the future presents significant challenges for the NTS. This is because, as gas demand falls, flows into the NTS are likely to become **more concentrated at specific entry points**, increasing the likelihood and magnitude of constraints. This is explained further as follows:

- When gas demand is low, and the NBP price falls, shippers choose to flow gas from only those entry points with lower costs of supply, which remain profitable under the lower NBP price. Shippers will not flow gas in through entry points where the cost of supply is higher than the NBP price.
- This leads to gas supply being concentrated on a selected set of entry points with lower costs of supply.

33 NG ESO (2020), Future Energy Scenarios.

- However, the spread of demand at exit points does not change in the same way that supply does.
- Therefore, the NTS would still need to transport gas concentrated at a selected set of entry points to a wider spread of exit points.

4.15 When this happens, the risk of constraints on the NTS increases. In part, this is because the physical capability of the NTS has historically been based on gas coming in from multiple entry points to meet the national spread of demand, and particularly to accommodate North-to-South flows from gas entering the network in Scotland.

4.16 While the anticipated decline in gas demand will cause challenges, there is also a risk that gas demand declines even faster than anticipated. In this case, the likelihood and severity of constraints would be even higher. Whilst it is difficult to say with certainty what the impact on the NTS would be under significantly lower gas demand, it is informative to examine the recent experience of the NTS in 2020 as a result of the ongoing COVID-19 pandemic.

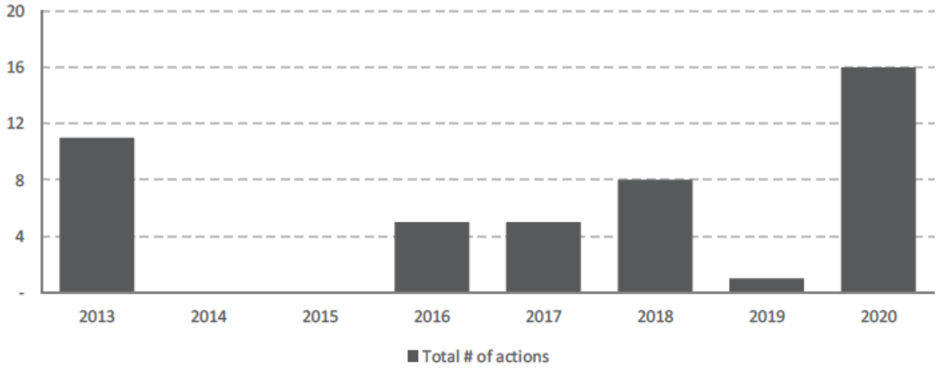
4.17 As the Government introduced lockdown measures during the onset of the COVID-19 crisis in the UK, energy demand fell dramatically. Gas output from the transmission system was 16.74 bcm in the three months to May 2020, which represents a 9.6% decline over the previous year.[34] Furthermore, during the first seven weeks of the UK entering lockdown, actual gas demand from Local Distribution Zones ("LDZs"), industrials and power stations was lower by 9%, 7% and 15% respectively, relative to forecast levels.[35]

4.18 This contributed to an increase in constraint management actions during the same period. Of the 16 constraint management actions taken in H1 2020, 14 were taken in April 2020. Further, as Figure 4-2 below demonstrates, the number of actions the NTS was required to take during H1 2020 is already higher than any previous whole year in the RIIO-T1 price control period.

34 BEIS, UK Government (2020), Energy Trends: UK gas, Natural gas production and supply (ET 4.2 – monthly), tab- "Month (Million m3)".

35 NGGT (2020), Gas Operational Forum Webex, 14 May 2020, Slides 20-22.

Figure 4-2: Number of constraint management actions on the NTS



Source: NGGT.

Note: Constraint management actions in the data presented include scale-backs, locational trades and withholding the release of additional firm capacity.

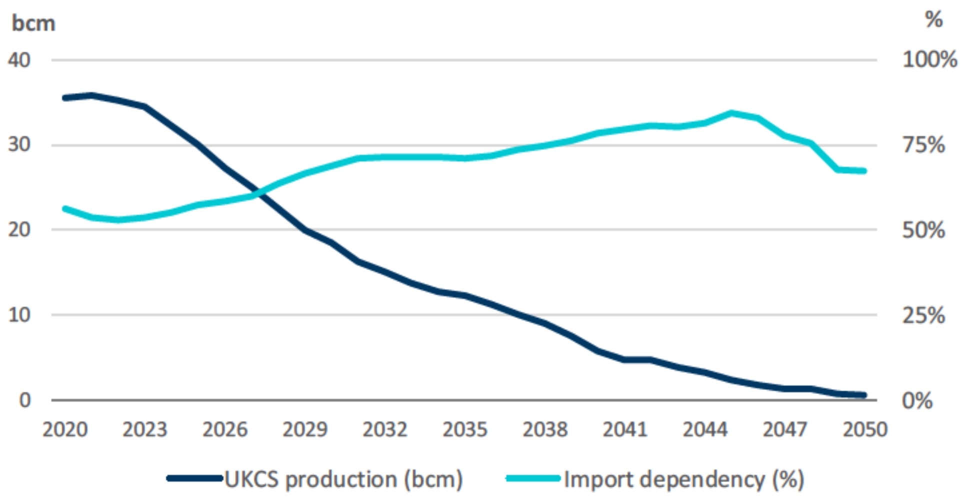
4.19 While the changes to demand during the start of the COVID-19 crisis were unprecedented, the experience is indicative of the CCM risks that NGGT faces in a market where demand is forecast to decline, and indeed could decline faster than expected.

Increasingly dynamic GB gas markets

4.20 While overall gas demand is declining, the GB gas market and the use of the NTS is becoming increasingly dynamic. There is growing variability and uncertainty in the levels of (and locations of) supply and demand for gas, which increases the challenging of managing the NTS and reducing constraint costs.

4.21 One key factor is that gas production from the UKCS is expected to continue to fall (and indeed, the rate of change of this fall is somewhat uncertain), leading to a greater reliance on imported gas. This is illustrated in Figure 4-3 below.

Figure 4-3: UKCS production and import dependency (FES average)



Source: NG ESO (2020), Future Energy Scenarios databook.
Note: The data points in the above curves reflect equally weighted averages across all FES scenarios. The gap between UKCS and imports is expected to be mostly filled by Shale and Green Gas.

4.22 As the dependency on imports rises, the GB network becomes increasingly exposed to movements in the global market, and in turn increasingly affected by factors other than GB domestic demand alone. This could lead to flows becoming more unpredictable.

4.23 As an example of this, LNG shipments are particularly difficult to forecast because they are strongly affected by global market movements and geopolitical factors (i.e., rather than only, or principally, by domestic demand conditions in GB).[36] For example, LNG shipments can be diverted to or away from GB at short notice. This leads to an increasing risk that supply and demand patterns are to some extent dislocated, with consequent stress on the NTS.

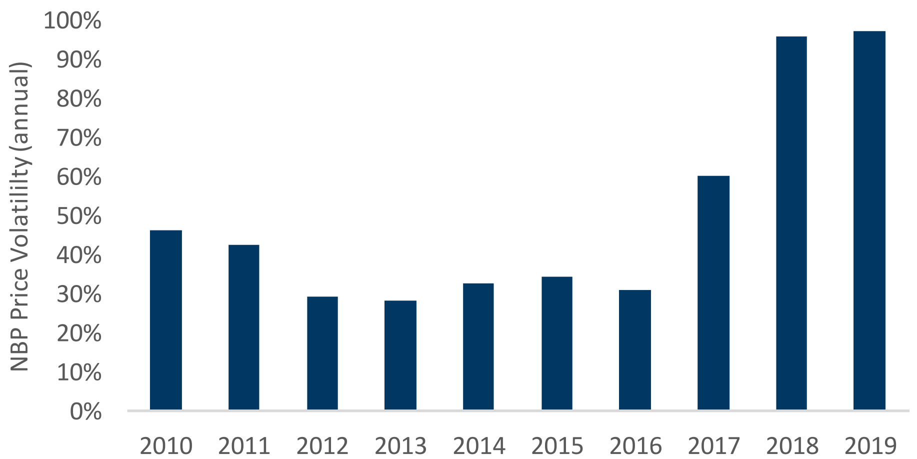
36 For example, the Oxford Institute for Energy Studies highlights that *"the availability of spot market LNG supplies is related to patterns of supply and demand on the global LNG market, and the price spreads between Europe and the Asian market, where the latter has traditionally commanded a price premium and has therefore attracted LNG supplies away from Europe in periods of market tightness."* See: Oxford Institute for Energy Studies (2018), UK Dependence on Imported Hydrocarbons: How Important is Russia?

4.24 Other drivers of volatility and uncertainty in the GB gas market include:

- Increased volatility in the use of CCGTs in different locations to accommodate the rise of intermittent renewable energy, which may lead to significant variability in flows;
- continued growth in 'fast-cycle' storage and the lack of substantial seasonal storage due, in part, to the closure of Rough;[37]
- expected increases in the supply of gas from unconventional sources such as biogas, which are more volatile;
- the increasing reliance of distribution networks on NTS linepack to provide flexibility as assets in LDZs (such as compressors, local storage or pipelines) are decommissioned; and
- significant uncertainties over Brexit, and the potential for significant macroeconomic and trading disruption from 1 January 2021 if the UK exits the transition period without a trade deal.

4.25 Increased volatility in demand and supply conditions is reflected in the volatility of the NBP price. The day-ahead price volatility for the NBP price has increased significantly over the last several years, as demonstrated in Figure 4-4 below.

Figure 4-4: Historic NBP price volatility (using day-ahead prices)



Source: FTI analysis using pricing data from Capital IQ. Note: Volatility is calculated as the annualised standard deviation of daily log returns, as applied to a daily price series.

[37] Which will be complete between 2021 and 2022. Source: Guardian (2017) Closure of UK's largest gas storage site 'could mean volatile prices' (link).

Ageing asset base

4.26 As explained in the earlier sections, GB gas market dynamics and changes to demand can create stresses on the NTS, increasing the risk of constraints in the future. However, a further factor which may impact on the risk of constraints is NGGT's ageing asset base.

4.27 NGGT is reliant on an ageing asset base for physically managing gas flows. An ageing asset base implies that the frequency of unforeseen issues such as outages is likely to increase during RIIO-T2. Furthermore, the interventions and planned outages required for maintaining assets will also increase in volume during RIIO-T2. Both of these factors could make the management of constraints more complex and costly.

4.28 Further, we note that Ofgem is proposing a significantly reduced Totex allowance for NGGT's transmission assets in RIIO-T2, which may impact NGGT's ability to carry out asset optimisation actions to mitigate constraints. For example, Ofgem has proposed to reduce NGGT's allowance for non-load related expenditure to £517.5 million, a 42% reduction from the £898.7 million in NGGT's Business Plan.[38]

4.29 It is not clear to us that Ofgem has fully considered the interaction between its proposals on the CCM cost target and its proposals for significantly reduced Totex allowances. All else equal, it would be expected that reduced expenditure allowances increase the risk of asset failure, which could make it more challenging for NGGT to manage constraints than would otherwise be the case.

[38] Ofgem (2020), RIIO-2 Draft Determinations – NGGT Annex, page 66.

5. AFRY's critique of NGGT's constraint cost forecasts

5.1 As explained in Section 4, a regulatory framework for the CCM incentive should place considerable weight on forward-looking information about the underlying costs and risks that the incentive is trying to address in the interests of consumers.

5.2 NGGT's constraint cost forecasts are forward-looking estimates that follow on from its network capability analyses, that are an integral part of NGGT's management of the NTS.

5.3 NGGT's network capability analyses are complex, assessing the extent to which NGGT's asset base is likely to be able to meet combinations of gas supply and demand at various levels of demand for gas transmission capacity.

5.4 Network capability is:

- assessed separately for entry and exit capability; and
- assessed regionally, and separately for different permutations of flows at entry and exit points.[39]

5.5 Broadly speaking, for given levels of demand for gas transmission, constraints are considered to be more likely at a given entry or exit point if there are many possible supply and demand combinations that breach NGGT's estimated network capability level. These forecast constraint events are then combined with assumptions of the per unit costs of managing constraints which results in NGGT's raw constraint cost risk estimates for either exit or entry points.

5.6 The resultant 'raw' constraint cost risk estimates drive NGGT's view as to the appropriate future cost target(s) for the CCM regime in T2 (after making an adjustment for Business As Usual ("BAU") risk management activity, and associated revenues that fall within the scheme).

[39] The relevant regions are: Scotland and the North, the North West, the North East, the East Midlands, the South East, South Wales, and the South West.

5.7 In the Consultation, Ofgem states that it is "*not persuaded by NGGT's arguments regarding the robustness and validity of its forecast constraint costs and its proposed RIIO-GT2 CCM Incentive target*".[40] Ofgem's views are informed by findings from AFRY, which has critiqued NGGT's network capability analysis and constraint cost assumptions across two reports.[41]

5.8 AFRY concludes that the assumptions underlying NGGT's *ex ante* cost target for the CCM incentive scheme for RIIO-T2 are not robust. A key driver of this conclusion is its criticism of NGGT's network capability analyses. AFRY cites specific input assumptions and considers that such assumptions reflect "*extreme"* market conditions, which understate network capability and therefore overstate the likelihood and magnitude of constraint events. AFRY also comments on the unit cost assumptions used by NGGT to calculate the expected total cost of resolving constraints.

5.9 Based on AFRY's views, Ofgem effectively dismisses NGGT's detailed modelling of expected constraint costs and considers the "*best available evidence on future constraint costs*" is actual historical constraint costs and proposes a net constraint cost target of £0.2 million on this basis (along with a smaller sharing factor, a narrower cap and collar, and no prospect of a re-opener).[42,43]

5.10 However, as we explain below:

- AFRY's key criticisms of NGGT's constraint cost modelling are **either incorrect or relatively minor in impact**. This implies that AFRY is incorrect in concluding that NGGT's proposed CCM incentive is unreliable.
- Notwithstanding the above, it seems to us that Ofgem have ignored AFRY's recommendation to work with NGGT to develop a **better joint understanding of NGGT's work in T1** to avoid constraint costs.

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40 Ofgem (2020), RIIO-2 Draft Determinations – NGGT Annex, page 25.

41 These are: AFRY (2020), Audit of Network Capability Assessment, and AFRY (2020), NGGT's CCM Incentive Scheme.

42 Ofgem (2020), RIIO-2 Draft Determinations – NGGT Annex, page 27.

43 Ofgem's proposals also include a smaller sharing factor of 20% and a narrower cap and collar of ±£3.2 million.

AFRY's criticism of NGGT's input assumptions

5.11 In respect of network capability, AFRY states [✂].[44] This is a key driver of AFRY's primary conclusion that NGGT's constraint cost forecasts are unreliable.

5.12 AFRY critiques NGGT's input assumptions for NGGT's network capability assessments collectively for entry and exit. However, NGGT assesses the capability of the NTS (and subsequently forecasts constraint costs) separately for entry and exit points and in turn, the input assumptions are applied separately for entry and exit as well. In general:

- The assumptions applied for the purposes of **exit capability modelling** reflect the need for NGGT to meet its 1-in-20 obligation.[45]
- By contrast, the assumptions applied for the purposes of **entry capability modelling** are scaled for different levels of demand, and more closely reflect the **typical operation of the network**.

5.13 For example, the exit capability assessment assumes that Gas Distribution Networks ("GDNs") receive gas at Assured Offtake Pressures ("AOP") for all levels of gas demand, which corresponds to NGGT's 1-in-20 obligation. However, the entry capability assessment assumes GDNs receive gas at pressure levels that have historically been agreed with the control room at the specific gas demand level being tested.

5.14 AFRY's comments on NGGT's network capability input assumptions do not sufficiently reflect this distinction. In fact, the assumptions AFRY cites (and considers *"extreme"*) predominantly take those values in the context of assessing exit capability, and are therefore are mostly relevant to exit constraint cost estimates.

44 [✂]

45 National Grid is obliged to ensure the gas network is able to transport the gas demand on a 1 in 20 peak winter demand day.

5.15 Key comments from AFRY on input assumptions are highlighted below:

- AFRY states that it *"would expect less extreme assumptions on within-day flow patterns to yield greater levels of network capability"*.[46] In addition, AFRY "*expect relaxed assumptions on pressure to yield greater levels of network capability*".[47]
- AFRY's assessment of these two specific classes of assumptions led it to conclude that "*current assumptions are <u>perhaps extreme</u> and therefore in many circumstances <u>may</u> understate actual network capability*".[48]
- In assessing NGGT's proposed CCM incentive AFRY then states [✂].[49]

5.16 The specific within-day flow and pressure assumptions criticised by AFRY as being *"extreme"* or *"perhaps extreme"* generally only (or principally) apply to exit capability.

5.17 This is relevant because the majority of NGGT's forecast constraint costs relate to entry constraints, as shown below.

5.18 Table 5-1 below illustrates the concentration of forecast constraint costs at entry points compared to exit points. It presents specific points on the distribution of NGGT's raw constraint cost forecasts, and shows, for the full RIIO-T2 period, the proportion of total forecast constraint costs that correspond to exit points.

Table 5-1: Forecast raw constraint costs in RIIO-T2

	Average £m	**P10** £m	**P50** £m	**P90** £m
South West Entry	184	113	166	274
South East Entry	33	-1	6	94
Southern Exit	21	-	3	64
Total constraint costs	**238**	**113**	**175**	**432**
of which correspond to exit points	21	-	3	64
% of constraint costs related to exit points	**9%**	**-**	**2%**	**15%**

Source: NGGT (2019) RIIO-T2 Business Plan – A3.03, page 34.

46 AFRY (2020), Audit of Network Capability Assessment, page 22.

47 AFRY (2020), Audit of Network Capability Assessment, page 23.

48 AFRY (2020), Audit of Network Capability Assessment, page 3. Emphasis added.

49 [✂].

5.19 As shown in Table 5-1 above, for the average of NGGT's forecasts, only **9% of total constraint costs correspond to constraints at exit points**. At the P90 level, this figure is 15%.

5.20 Therefore, even if NGGT's exit capability is understated, only a small proportion of total forecast constraint costs would be overstated. Therefore, AFRY's criticisms do not point to a significant overestimation of total constraint costs.

5.21 In the remainder of this sub-section, we discuss the specific input assumptions criticised by AFRY. These are NGGT's:

- backloaded within-day flow assumptions;
- power sector assumptions;
- pressure cover mitigations; and
- GDN assured pressure assumptions; and
- GDN capacity rights assumptions.

Backloading entry flow assumptions

5.22 AFRY states that NGGT's within-day flow assumptions *"only considers backloading and disregards any coincident frontloading"*. In AFRY's view, this is therefore *"likely to be overstating an average requirement for within-day flow"*.[50] This contributes to AFRY's conclusion that *"less extreme assumptions on within-day flow patterns* [would] *yield greater levels of network capability"*.[51]

5.23 AFRY's views do not reflect how within-day flow profiles are applied by NGGT, and consequently AFRY overstates the impact of this input assumption on NGGT's constraint cost estimates.

5.24 At a national level, NGGT assumes within day flows are backloaded to a greater degree than has been the case historically (i.e., beyond 'normal' behaviour). This may understate exit capability, since it is more difficult for exit points to accommodate flows when there is a high degree of backloading behaviour. In turn, this may overstate exit constraints.

50 AFRY (2020) Audit of Network Capability Assessment, page 22.

51 AFRY (2020) Audit of Network Capability Assessment, page 22.

5.25 However, when assessing individual *entry* points on the network, NGGT's within-day flow assumptions 'flatten' at points closer to the maximum capability of that entry point. This reflects the operational reality of the network; when an entry point approaches capability, flows at the end of the day cannot rise further than the maximum capacity of that entry point, and so flows must rise earlier in the day.

5.26 This 'flattening' assumption continues to apply at times of low gas demand which, as explained in Section 4 above, is associated with an increased risk of entry constraints. Therefore, for any given entry point, constraints are likely to correspond with scenarios where flow assumptions have already been flattened (i.e., they are no longer backloaded beyond 'normal' behaviour).

5.27 Therefore NGGT's within-day flow assumptions do not materially affect the assessed capability of entry points, which account for the vast majority of total estimated constraint costs.

Power sector assumptions

5.28 AFRY has highlighted that NGGT's power sector assumptions do not *"filter out those situations which are otherwise considered as un-forecasted within-day change…which may mean that some historical observations are double-counted".*[52]

5.29 In respect of flows to power stations, it is not clear to us why flows resulting from unforecasted changes would be filtered out, nor is it clear what specific observations may be double counted as a result of this. Nevertheless, power station assumptions would primarily impact exit capability, rather than entry capability. As a result, these assumptions primarily impact exit constraint costs, rather than entry constraint costs which, as already noted, account for the vast majority of NGGT's forecast constraint costs.

Effect of pressure covers on mitigating pressure trips

5.30 AFRY states that *"the element of pressure cover…designed to mitigate the effect of a compressor trip…is disregarded later in the Network Capability process where compressor availability is taken into account"*.[53] AFRY explains that this would have led to an understatement of network capability.

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52 AFRY (2020), Audit of Network Capability Assessment, page 22.

53 AFRY (2020), Audit of Network Capability Assessment, page 23.

5.31 Pressure covers add a level of headroom to overall pressure requirements. This headroom gives the Gas Control Room the necessary time to implement network reconfigurations (for example, bringing an alternative compressor online), or to make use of additional supplies or demand response to ensure the continued operation of the network during stress events, such as compressor trips or supply or demand shocks. AFRY's concern is that, in later assessments of compressor availability, the headroom granted by the application of pressure covers are not taken into account, thus leading to an understatement of network capability.

5.32 AFRY fails to acknowledge that NGGT applies pressure covers to both exit and entry capability assessments. In fact, pressure covers are applied to the assessment of exit capability only, and they are not applied in the assessment of entry capability.

5.33 AFRY's critique therefore does not apply to entry constraints, which account for the vast majority of NGGT's forecast constraint costs.

5.34 In any case, AFRY considers the effect of this assumption to be small. When discussing pressure covers, AFRY explains that *"the number of days of outage in a year due to Minor trips is small…therefore it is expected that the implication would be small."* [54]

GDN assured pressures

5.35 AFRY states that NGGT did not consider that the Uniform Network Code ("UNC") *"requires that GDNs agree to receive gas at lower pressure"* than their Assured Offtake Pressures ("AOP").[55]

5.36 This is not an accurate representation of the manner in which NGGT's assumptions are used. As explained above, NGGT generally assesses network capability separately for entry and exit points. In this case:

- When assessing entry capability, the GDN pressure assumptions used reflect Agreed Offtake Pressures (where these would be expected to be agreed). These are levels that NGGT has historically been able to agree with GDNs, and are typically lower than AOP. These pressures more accurately reflect the operational conditions of the network.
- AOP levels are only solely used when estimating exit capability, consistent with NGGT's obligation to ensure exit capability is able to accommodate a 1-in-20 demand scenario.

54 AFRY (2020), Audit of Network Capability Assessment, page 33.

55 AFRY (2020), Audit of Network Capability Assessment, page 23.

5.37 GDN pressures only take values that AFRY considers *"extreme"* when they are applied to exit capability assessments, and thus affect exit constraint estimates only. AFRY's critique therefore does not apply to entry constraints, which account for the vast majority of NGGT's forecast constraint costs.

GDN capacity rights

5.38 AFRY also states that NGGT has assumed *"all GDNs simultaneously demand all of their capacity rights"*.[56]

5.39 This is not an accurate representation of NGGT's assumptions. When assessing entry capability, NGGT has not assumed that GDNs demand the full amount of their capacity rights simultaneously. Instead, NGGT has reflected the capacity rights demanded by GDNs' planning data, capturing daily variations in demand for each year.

5.40 AFRY's critique therefore does not apply to entry constraints, which account for the vast majority of NGGT's forecast constraint costs.

FES scenarios

5.41 AFRY correctly explains that each of the different FES scenarios *"will lead to different utilisation levels of assets"*, and therefore that *"there will be markedly different constraint costs in each scenario"*.[57] AFRY criticises NGGT's approach to using the FES scenarios, for which *"a probability is associated to each, leading to a single set of constraint cost forecasts"*.[58] AFRY then concludes that *"this assumption is likely to overstate requirements in the long-run"*.[59]

5.42 NGGT has applied an equal weighting to all FES scenarios. Indeed, the purpose of the FES scenarios is to cover a credible range of future evolutions of the energy sector until 2050.

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56 AFRY (2020), Audit of Network Capability Assessment, page 22.

57 AFRY (2020), Audit of Network Capability Assessment, page 30.

58 AFRY (2020), Audit of Network Capability Assessment, page 30.

59 AFRY (2020), Audit of Network Capability Assessment, page 30.

5.43 AFRY has not explained why applying an equal weighting to the FES scenarios is likely to overstate constraint costs. The application of an equal weighting to each scenario should mean the resulting distribution of constraint costs is just as likely to understate costs as it is to overstate them.[60] AFRY has not explained what alternative treatment of the FES scenarios would improve accuracy, or how. Nevertheless, we discuss two possible alternative treatments of the FES scenarios below.

- One alternative would be for NGGT to make a judgment on which of the FES scenarios are more likely, and apply a greater weighting on those. However, it is not clear how NGGT would be able to make this judgment, given the uncertainty of the future evolution of the energy sector. Indeed, when publishing the FES scenarios, NG ESO intentionally makes no statement on which of the scenarios it believes is more likely.
- Another alternative would have been for NGGT to estimate a distribution of constraint costs for each of the FES scenarios. The network capability assessment and subsequent forecast of constraint costs already represent a highly complex set of analyses. NGGT has already presented its forecast constraint costs at the minimum, maximum, average, P10, P50 and P90 level. Estimating a distribution of constraint costs for each scenario would increase the number of modelling 'runs' and increase the number of results presented fourfold. This would increase the complexity of the information, and one would still need to take a view on how to utilise the four different sets of results to arrive at a single constraint cost target.

AFRY's comments on NGGT's assumptions regarding the cost of specific actions

5.44 AFRY has also commented on the unit cost assumptions used by NGGT to calculate the expected total cost of resolving constraints. AFRY states that NGGT used a single price assumption that is *"applied regardless of the type of action that would be required (capacity buy-back, locational actions, etc.)"*.[61]

[60] This is the purpose of taking an equally weighted average.

[61] AFRY (2020), Audit of Network Capability Assessment, page 23.

5.45 It is challenging to forecast the costs of managing constraints, for a number of reasons including:

- The costs of locational trades and capacity buybacks are heavily dependent on day to day market conditions and participant behaviour. Individual participants may have varying motivations for accepting locational trades or capacity buybacks. This behaviour is difficult to predict.
- A key purpose of the CCM incentive is to encourage NGGT to reduce its use of constraint management actions, which are costly to NGGT and consumers. As such, there is relatively little historical evidence on the cost of these actions.

5.46 In the remainder of this subsection, we discuss locations trades and then capacity buybacks.

Locational trades

5.47 NGGT's modelling assumptions (for the CCM incentive as well as parts of its Business Plan) reflect a long-range prevailing market price of 60p/therm, based on BEIS' forecasts of future gas prices over the period 2020 to 2035.[62]

5.48 AFRY appears to suggest that NGGT assumes that all locational actions will cost 60p/therm. In fact, NGGT has assumed that locational sells will be made at a discount [✂] to the prevailing market price, while locational buys will be purchased at a premium [✂].

5.49 We consider the use of a discount and a premium to be a reasonable approach. This approach reflects the fact that NGGT will have to offer a significant discount to the market price for parties to be willing to purchase more gas than they otherwise would under normal market conditions. Similarly, a significant premium would be necessary for parties to be willing to sell more gas to NGGT than they otherwise would to the rest of the market.

Capacity buybacks

5.50 The unit cost of a capacity buyback is difficult to anticipate, since:

- the actual cost to NGGT for any given action will ultimately depend on the prevailing gas market supply and demand conditions at the particular location on the specific day of the buyback, as well as the particular behaviour of shippers; and

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[62] BEIS (2019), Fossil fuel price assumptions, page 12. 60p/therm is given by the average price in the Central scenario over 2020 to 2035, rounded to the nearest 10p/therm.

- there is limited recent historical evidence that can be used to provide an empirical basis for a forecast.

5.51 One way of proxying the unit price of a capacity buyback is to assume that a shipper would expect to be compensated, at a minimum, an amount which would make the shipper 'whole'.

5.52 In FTI's September 2019 report to Ofgem, for the purpose of estimating the consumer value from the CCM incentive, we assumed the compensation would be equivalent to the revenue a shipper would have earned from the sale of gas on the spot market, less the marginal cost of production (that is, the cost of extracting gas, most relevant to production from the UKCS). For example, a shipper with entry capacity rights at St Fergus, having agreed to a capacity buyback, would not be able to sell gas on the spot market on that given day, but would no longer incur the cost of extracting the gas from the UKCS. It would therefore expect to be compensated for the difference.

5.53 An alternative estimate of the shipper's foregone net profit might also consider the actions a shipper could take to mitigate this loss, by selling a similar quantity of gas either:

- **on the same day** as the capacity buyback; or
- **on some future day** after the capacity buyback.

5.54 If a shipper is able to sell a similar quantity of gas **on the same day**, the shipper's foregone net profits from agreeing to a capacity buyback would depend on factors such as:

- the foregone cost of extracting gas at the restricted entry point the shipper may no longer be required to incur;
- the additional cost of extracting gas at a different entry point, which is likely to be higher than the gas it would have purchased at the restricted entry point; and
- the additional cost of entry capacity at the alternative location.

5.55 In this case, revenue does not need to be considered, since there is no loss in revenue.

5.56 Alternatively, a shipper may instead foresee an opportunity to sell its gas **on another day**. For example, an LNG shipper might have intended to offload gas from its carriers at Milford Haven. Having agreed to a capacity buyback, it might be able to offload its gas and sell it on the spot market on a future day. In this case, the shipper's foregone net profits would depend on factors such as:

- the difference in spot market prices between the day of the capacity buyback and the alternative day;
- the cost of storing gas already bought so it can be resold at a later date; and
- the cost of purchasing entry capacity elsewhere (for a later date).

5.57 In this example, the cost of procuring gas does not need to be considered, since the same production cost has been incurred irrespective of when the gas is sold.

5.58 It is difficult for NGGT to know with certainty if any given shipper is able to take these loss mitigating actions on the same day, or on some future day, or at all. This is governed by the shipper's contractual upstream arrangements at the specific entry points that face a given constraint, which is information that is not available to NGGT.

5.59 It is also difficult to estimate with certainty the likely magnitude of all of these potential factors, and the competitive dynamics that drive the willingness and ability of shippers to accept capacity buybacks at that point in time.

5.60 Further, to significantly affect flows when resolving a constraint, NGGT may have to first buyback all allocated but unused capacity, before it is able to buy back capacity that would successfully restrict actual intended flows. This increases the quantity of capacity that needs to bought back, and the foregone profits facing these capacity holders may be materially different from those who were intending to make use of their allocated capacity. These capacity holders might expect to be compensated for the option value of their allocated capacity.[63] This further adds to the uncertainty over the expected cost of any given capacity buyback.

5.61 In light of this, it seems to us a reasonable approach to make some simplified unit cost assumptions over a significant time horizon (such as the 5 year future time period of RIIO-T2), if it also assumed there are mechanisms within the CCM incentive (such as re-openers) to account for the collective impact of parameters which are inherently uncertain.

[63] Even if a shipper was not originally intending to use its allocated capacity, by selling it back to NGGT the shipper is no longer able to benefit from the flexibility to make use of that capacity, should market conditions change at the last minute.

Ofgem has ignored AFRY's recommendation of further engagement with NGGT on its network capability assumptions

5.62 In its audit of NGGT's Network Capability analysis, AFRY acknowledges that the *"process put forward by NGGT provides a very useful framework"*. AFRY then suggests that Ofgem and NGGT should work together to investigate *"the sensitivity of network capability to these underlying assumptions"*[64] and *"what a more representative set of assumptions would look like"*.[65]

5.63 Based on the above, the AFRY reports do not appear to suggest there has been sufficient deficiency in NGGT's modelling framework such that it would be proportionate for Ofgem to dismiss it entirely in favour of historical backward-looking data.

5.64 Instead, AFRY's conclusions appear to support further dialogue between Ofgem and NGGT on the specific input assumptions that AFRY considers are inappropriate. AFRY acknowledges that NGGT's methodology is useful, and recommends additional engagement in the form of specific sensitivity analyses, or discussions of alternative input assumptions.

5.65 Given Ofgem's reliance on AFRY's analysis otherwise, it is not clear why Ofgem has ignored AFRY's views in this regard.

[64] AFRY (2020), Audit of Network Capability Assessment, page 26.

[65] AFRY (2020), Audit of Network Capability Assessment, page 26.