

National Grid Gas Transmission

Our Performance for 2016/17

30 September 2017

nationalgrid



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I. Executive Summary

1. The report describes our financial and operational performance against the stakeholder outputs we have committed to deliver.
2. We are proud to report that we have delivered strong output performance and have notably improved customer satisfaction within this period. This year we have effectively facilitated the varying and changing needs of our customers, in particular the material increase in gas supplies at our St Fergus terminal. These higher flows and other significant changes including an increase in power station demand, more flexible power station demand and flexible medium range storage requirements, have resulted in compressor running hours doubling compared to the previous year which has created a significant challenge in terms of system availability and reliability. In addition higher day-on-day variations in demand have resulted in further operational challenges. This comes at a time where we are requiring more outages to facilitate increasing replacement of ageing plant.
3. A further requirement is to decarbonise the energy system by 2050 in the most affordable and least disruptive way. In 2016/17 we have continued to engage with our customers and stakeholders on this topic and they have told us that gas has an integral role to play in delivering the most cost-effective decarbonised future across power, heat, transport and industry. To ensure reliable, affordable gas supplies for our current and future consumers we continue to invest in our network and where it is in consumers interests, for example in the health of our network, exceed allowances. Over the RIIO-T1 period we plan to invest circa £2bn of Capex across our overall business.
4. We are continually seeking ways of delivering this work at lowest overall cost for consumers and developing innovative solutions is vital in achieving this. In 2016/17 we undertook 43 Network Innovation Allowance (NIA) projects, which were aligned to our innovation strategy. A particular success this year has been the 'Artificial Intelligence for Pipeline Coating Inspection' project which uses the latest machine learning technology to develop algorithms to recognise different categories of corrosion found on our network pipeline. This will improve the quality and consistency of asset condition assessment data enabling improved asset maintenance choices and investment decision making. We also published our mid-term innovation value report¹, which highlights output from ten key innovation case studies which have been embedded into business as usual activities. The ten case studies have realised significant value (£6.9m) with a cost – benefit ratio of 4:1 and have highlighted opportunities for future benefits.

Output Delivery

¹ The Innovation value mid-term report can be found at: <http://www2.nationalgrid.com/UK/Our-company/Innovation/Gas-Transmission-Innovation/Innovation-Value-Mid-Term-Report/>

5. We have continued to deliver strong performance for our customers against our five output categories, with performance broadly consistent to 2015/16. Table 1 on page 11 summarises our performance against each individual output and provides a comparison with our 2015/16 performance.
6. We have delivered strong **safety** performance with no injuries to the public and zero Gas Transmission employee lost time injuries in 2016/17. We also remain on track to meet the Department for Business, Energy and Industrial Strategy (BEIS) requirements for introducing enhanced physical security at our key sites.
7. In 2016/17 we have continued to provide high levels of **reliability and availability** for our customers. A key measure of this is the constraint management incentive scheme; this year we have needed to be more active, with constraint management actions taken within day and entering into forward contracts. This has enabled us to facilitate the system usage our customers require, whilst minimising costs to consumers. Our customers have also benefitted through a 40% reduction in our Operating Margin (OM) costs from £21.6m in 2015/16 to £12.9m in 2016/17.
8. In line with what we reported last year, in 2016/17 we have increased the delivery of our asset health with a 35% increase in spend, this has led to a reduction in the number of Replacement Priority 1 (RP1) assets reported through the current Network Output Measures (NOM) regime thus improving the health of the network for the benefit of today's and future consumers. We continue to trade risk across NOMs categories and forecast meeting our overall NOMs target in aggregate for the eight year RIIO-T1 period. The increase in spend has been enabled by the surveying and planning work undertaken in the initial years of RIIO-T1 and the establishment of asset health campaigns to drive an increase in the volume and efficiency of work delivery.
9. In 2016/17 we also secured planning permission from the Secretary of State for our River Humber Gas Pipeline Replacement Project which will replace a 3km underwater section of the Feeder 9 pipeline with a tunnelled solution. This pipeline section is one of the most critical on the National Transmission System (NTS) and removing the risk associated with both subsea erosion and third party interference is essential in continuing to provide a reliable and secure service to our customers. We have begun enabling works on site and tunnelling activities will begin in 2017/18.
10. This year's changing supply patterns have had the most significant impact on our **environmental** outputs. Moving greater volumes of gas from our St Fergus terminal, in Scotland, to demand centres in the South has required more gas compression which has resulted in increased fuel usage and emissions. This has negatively impacted our Green House Gas (GHG) emissions incentive. However, the investments we have made in low emission technology have reduced the relative environmental impact they are having on local communities with our emission of oxides of nitrogen (NOx) increasing by less than 10% for a doubling of compressor running hours. We are also on track to deliver further emission

reduction investments at Peterborough, Huntingdon and Aylesbury compressor stations.

11. We have delivered a marked increase in performance in **customer satisfaction** with our satisfaction survey score increasing by 0.48 since last year to 8.03. This demonstrates our continued efforts to put customers at the heart of everything we do. Our customers scored us particularly highly in Gas Diversions, Gas Customer Liaison, the Operational Forum and Gas Network Control Centre (GNCC) areas which all achieved scores above 8.5. We continue to strive for greater customer satisfaction and in 2016/17 have initiated our customer transformation programme. As part of this the UK Executive team has agreed to meet one of our customer's Senior Leaders every month to elicit feedback on the issues most affecting their businesses.
12. In terms of **customer connections**, we have met all requirements associated with connection and capacity requests submitted by our customers. In addition we are undertaking a self-lay trial with one customer and are progressing well with our Network Innovation Competition (NIC) funded Customer Low Cost Connections (CLoCC) project, which aims to reduce the time and cost to connect. These developments will increase the choice and quality of the service we provide to our customers and help reduce barriers for future opportunities such as low carbon gas connections and Compressed Natural Gas (CNG) vehicles to drive an improvement in air quality. Our customers are recognising the way in which we have improved our engagement with them on connections and as a result our customer satisfaction score has increased to 8.1 out of 10 in this area.

Financial Performance

13. Our updated Totex forecast for the eight years is £3,276m compared to an adjusted allowance of £3,073m. We are investing above allowances to provide the reliability and service that our customers require.
14. In total we are forecasting to overspend our eight year allowances by £227m, which represents a change of £279m compared to the previous year. The main reasons for this change are Ofgem's Mid Period Review decision to remove the allowance (£207m) associated with the Avonmouth output² and an increase in our forecast operating expenditure (Opex). The removal of the Avonmouth allowance is neutral at the specific project level. The main areas of increase for the eight year Opex forecast relate to Planned Inspections and Maintenance, Closely Associated Indirect costs within the Transmission Owner (TO) and Business Support costs. The higher Opex cost is mainly driven by investment in improving our asset management capabilities and supporting the efficient development and delivery of the increasing asset health works to deliver a healthy network that will keep overall costs to consumers low into the future.

² The Avonmouth output was associated with the building of new pipelines to replace the capability provided by the Avonmouth LNG storage facility, which has now closed.

15. There have been no other material movements in our performance, although upward cost drivers exist on our asset health spend and Non Operational Capex as we continue to develop our asset health strategy and system capabilities. In terms of our financial forecasts we are predicting to re-phase spend on emission reduction projects to support efficient deliverability, with more moving into RIIO-T2, otherwise the forecasts are broadly unchanged compared to the previous year.
16. Considering our eight year performance at a category level, in most areas performance is relatively neutral with cost increases on some activities being counteracted by efficiencies and innovation in others. For example we have incurred additional costs on compressor replacement projects from the previous price control but this has been offset by the development of an innovative catalyst solution at Aylesbury compressor station.
17. Aside from Opex the two greatest areas of difference between our allowances and costs both relate to asset management. They are asset health work (Non Load Related Capex) and the associated asset management systems (Non Operational Capex). Our understanding of our assets in terms of condition and criticality continues to improve and, in order to provide the system reliability and availability our customers expect, we are anticipating investing above our allowances. Without these investments, the risk of system constraints and potential customer disruptions will grow. We committed at the start of the RIIO-T1 period to at least maintain the level of network risk and, we are on course to deliver this with our current plans.

Consumer Bill Benefit

18. In 2016/17 approximately £16.29 of an average domestic consumer bill of £604 related to the services we provide. This equates to 2.7% of a typical gas bill. Our current estimate is that the Gas Transmission element of an average domestic consumer bill will fall by 7% (£1.14) by the end of the RIIO-T1 period.

Looking Ahead

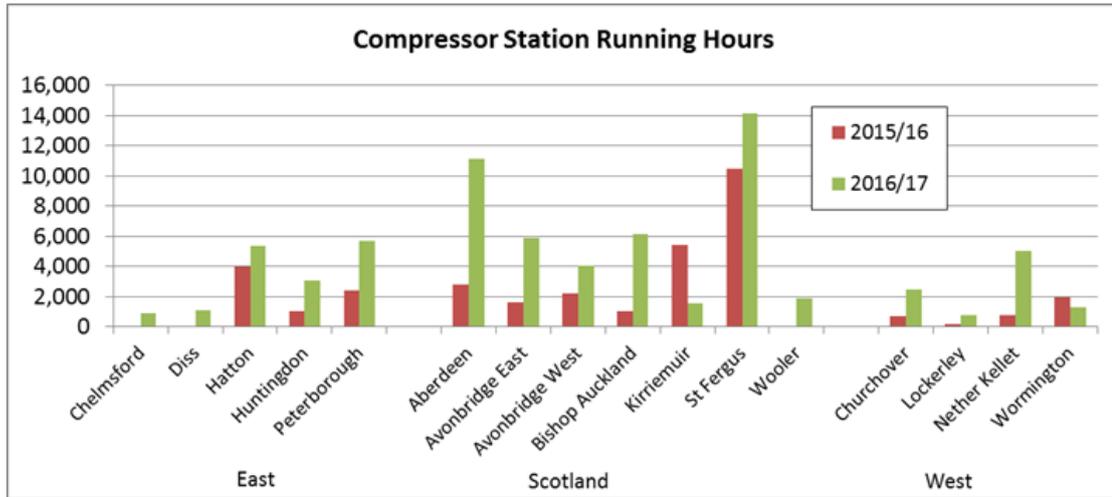
19. In 2017/18 we plan to further increase our Capex spend, with a ramp up in asset health works, the construction of the Feeder 9 tunnel and the compressor emission reduction work at Peterborough and Huntingdon. Our focus will be on delivering these investments safely and efficiently.
20. To ensure the increase in asset health investment is as efficient as possible we are developing new systems to enable us to further refine our investment decision making (e.g. new NOM's methodology). We are also undertaking a data gathering exercise to ensure the data that underpins these systems is sufficiently robust and complete. These actions mean that we will enhance our capability to identify and demonstrate that the work we are doing is the work which delivers the greatest consumer benefit.

21. We are also adopting new approaches to work delivery, most notably our campaign approach. The campaign approach groups together asset replacements that require specific network outage and delivery capabilities across particular geographies. We then develop and contract the schemes as a package to drive efficiency work delivery of a larger volume of work.
22. To further demonstrate the benefits of our asset health investments, we will continue the development of our NOMs methodology. We have already submitted a new monetised risk version of the methodology to Ofgem for comment and are engaging in cross sector workshops to improve consistency and conclude the detail of the RIIO-T1 close out process.
23. In May 2018 we intend to make five regulatory submissions to Ofgem to change our allowed funding through the reopener Uncertainty Mechanism (UM). The submissions will cover the Industrial Emission Directive (IED), One-off Asset Health Shock (Feeder 9), Enhanced Physical Security, Enhanced Security (operational) and Quarry and Loss. These submissions will have a material impact on allowances and we will proactively engage with relevant stakeholders to ensure our plans reflect their needs.
24. Although RIIO-T2 is still four years away, the activities to put in place the next price control will begin in earnest this coming year. Ofgem will initiate this process through the publication of an open letter in July 2017. Throughout RIIO-T1 we have continued to engage with stakeholders on a variety of topics, including reopener submissions, Future Energy Scenarios (FES), UK and European regime developments and more recently the Future of Gas (FoG). Our customers and stakeholders have told us through the FoG project that gas has an integral role to play in providing a secure energy supply, at best value for consumers, as part of a low carbon future across power, heat, transport and industry.
25. In 2017/18 we will be further engaging with industry, policy makers and consumer groups to progress our understanding of the future of gas and what different futures mean for the Gas Transmission network. This work will help to underpin our next price control submission to ensure that the most efficient and sustainable solutions are selected for our customers.
26. We trust you find this 2016/17 Performance Pack informative and we would welcome any feedback on how we can improve our reporting.

II. Operational Context

27. To appreciate our performance in 2016/17 it is first necessary to understand the operational challenges the business has faced during this financial year. As the sole owner and operator of the Gas Transmission network in Great Britain, National Grid manages the day-to-day operation of the NTS including residual balancing of the network, maintaining system pressures and ensuring gas quality. During 2016/17 we have effectively facilitated the varying and changing needs of our customers which impacted our performance under certain incentives and led to significant operational challenges.
28. In 2016/17 the most significant challenge we faced was the change in supply pattern from 2015/16. St Fergus entry flows increased by 33% from 23.2 billion cubic metres (bcm) to 30.7 bcm, with maximum daily flow increasing from 81 million cubic metres (mcm) to 112 mcm. This change was most noticeable in the summer months where, on several days, over 50% of the total supply was entering the NTS through St Fergus.
29. Bacton entry flows increased from 13.7 bcm to 16.6 bcm with the majority of that increase attributable to Interconnector UK (IUK). The IUK daily entry flows were highly variable and the maximum daily entry flow at Bacton increased from 69 mcm in 2015/16 to 110 mcm in 2016/17. Overall 78% of total supplies entered the NTS through just three entry points – St Fergus, Bacton and Easington.
30. This change in supply pattern in 2016/17 resulted in a less balanced overall network and the need to operate increased compression to move gas away from entry points with higher flows, but also towards parts of the network seeing reduced entry flows (e.g. Milford Haven).
31. This resulted in overall compressor running hours doubling from 35,930 to 72,242 hours. Running hours at some specific sites increased even more significantly, e.g. Aberdeen, as can be seen in Figure 1 below. This has increased compressor fuel usage and the quantity of gas vented which has had a negative impact on our GHG incentive.

Figure 1: Key compressor stations on the NTS where running hours have seen significant changes



32. This increased use of compression has put a significant strain on the ageing compressor fleet. Overall compressor availability dropped below our internal target of 90% to 84%, presenting a challenge to system operation. At times the preferred compressors were unavailable, requiring use of alternative operating strategies.
33. With higher system flows and lower asset availability, system capability was tested, and on three days we were required to take entry capacity constraint management actions (for more details, see Chapter V - Constraint Management Incentive Scheme).
34. These system challenges coupled with our maintenance activities, normally scheduled during the summer months to minimise disruption, had the potential to cause disruption to our customers. However to reduce the risk of curtailing entry flows and protect firm entry capacity rights, some maintenance outages were cancelled or moved at short notice. This change in system usage presents a challenge going forward in obtaining access to the assets to carry out repairs and maintenance and in the efficiency of delivering the works.
35. As well as the issues experienced with changing supply patterns, the Rough gas storage facility experienced a number of technical problems, which resulted in all injections stopping from late June 2016 and the facility entered the winter with low stock levels. There were also various outages during winter 2016/17 that restricted withdrawal capacity. This changed the behaviour of the market and meant that at Medium-Range Storage (MRS) sites, we saw shippers cycling more between injection and withdrawal than in recent years, increasing storage injection by 23% from 2015/16.
36. Due to environmental legislation and economics, gas fired power stations are now running ahead of coal. This resulted in NTS connected power generation demand increasing by 37% in 2016/17, with a historic record daily demand of 94 mcm. This also means that gas power stations are increasingly having to flex to balance the changes in electricity demand and renewable generation. For example between 26 and 27 February 2017, wind's share of total electricity generation dropped from 22% to 8% whilst gas increased from 28% to 46%. This

demonstrates how rapidly the operational environment is changing and represents a significant challenge in our ability to respond in a similar time frame in terms of planning and executing physical changes to the network.

37. This changing operational environment has resulted in flexible supply facilities (e.g. storage sites and interconnectors) responding rapidly to market opportunities and requiring more agility and versatility from the NTS. For example, in 2016/17 the number of day-on-day changes over 30 mcm in MRS storage flows increased from 14 to 39 and the number of day-on-day changes over 15 mcm in IUK flows increased from 8 to 17.
38. The challenge for National Grid lies in achieving this level of agility with assets designed for steady state operation, which require longer time periods for any system reconfiguration and compression changes to take effect. Facilitating the varying and changing needs of our customers has required us to develop different system configurations and to plan the network to accommodate a wider dynamic range of supply and demand patterns. Whilst in 2016/17 we have met our contractual obligations, some gas customers have felt the effects of these configurations in increased variability of within-day pressures, especially at the extremities of the network.

III. Outputs

39. Under the RIIO-T1 framework, National Grid's performance as owner and operator of the gas NTS is assessed against five key outputs:
- Safety
 - Reliability and Availability
 - Environment
 - Customer Satisfaction
 - Customer Connections
40. These outputs focus on delivery of outcomes that our customers and stakeholders have told us they value most. There are also a series of more specific outputs that sit within each of these five key output areas. These are detailed within Table 1 and have been used in our assessment of our 2016/17 performance.
41. As previously described, 2016/17 has been a challenging year operationally due to the changing network requirements of our customers. We have continued to implement a number of strategies and applied these through a range of initiatives to deliver our outputs as efficiently as possible and to provide the greatest benefit to customers. Our 2016/17 performance against these key outputs is outlined further in the Output sections below.
42. Please note that all previous year figures are in 2015/16 price base unless otherwise stated.

Table 1: Outputs Performance Table³

Safety				
	Our output	2016/17 Target	2015/16 Performance⁴	2016/17 Performance
1	Comply with Health and Safety Executive (HSE) legislation	100%	Complied	Complied
2	Meet requirements for enhanced physical site security	Meet BEIS requirement by 2021	On track	On track
Reliability and availability				
	Our Output	2016/17 Target	2015/16 Performance	2016/17 Performance
3	Maintain our security of supply obligations in Scotland (Network Flexibility)	Ensure compliance with 1 in 20 obligations by 2020	Strategy in place to ensure compliance	Strategy in place to ensure compliance
5	Meet our targets for investing in our assets to maintain their health (NOMs targets)	Deliver network replacement outputs in accordance with the licence	In aggregate, on track to deliver 8 year target	In aggregate, on track to deliver 8 year target
6	Replace Feeder 9 (pipeline that runs across the Humber Estuary)	Achieve planning consent ahead of reopener submission	On Target – Awaiting planning consent approval (August 2016)	On Target – Planning approved and enabling works commenced
7	Deliver benchmark performance for maintenance outage days	11 days (Remote Valve Operations)	2 maintenance days called	1 maintenance day called
8	Minimise National Grid driven changes to maintenance planning	16.82 days	No changes	No changes
9	Meet constraint management target	£26.99m allowable costs for entry/exit capacity	£0m cost	£0.58m cost
10	Meet target for Transmission Support Services and for Constrained Liquefied Natural Gas & Long Run contracting	£8.9m allowable cost	£0m cost	£0m cost

³ Following the Mid Period Review decision, the Avonmouth output has been removed

⁴ The 2015/16 numbers have been taken from 'Our Performance' publication from September 2016 - <http://www.talkingnetworkstx.com/General-Performance.aspx>

11	Deliver existing capacity obligations in accordance with UNC, Licence and Gas Act	All UNC, Licence and Gas Act capacity obligations to be met in full	System issues impacted a minority of auctions. All changes corrected	System issues, including planned outages, impacted a minority of auctions
12	Deliver accurate 13:00 day ahead demand forecasting	9.39 mcm average forecast error	7.75 mcm average	8.53 mcm average
13	Deliver accurate demand forecasting at the two to five days ahead stage	13.7 mcm average forecast error	12.09 mcm average	12.39 mcm average
14	Meet target for residual balancing linepack performance measure	<2.80 mcm average daily change	1.62 mcm average daily change	1.74 mcm average daily change
15	Meet target for residual balancing price performance measure	Average daily difference between max and min price paid, to be within 1.5% of System Average Price (SAP)	Difference 0.64% of SAP	Difference 0.95% of SAP
16	Procure Operating Margins (OM) in an economic and efficient manner	Incur OM costs efficiently and publish report on the steps taken to promote competition	OM strategy aligned to target, report published to time	Report published to time. £8.7m decrease in costs in 2016/17
Environment outputs				
	Our output	2016/17 Target	2015/16 Performance	2016/17 Performance
17	Develop an integrated and cost-effective plan to ensure the remainder of our compressor units are compliant with the Integrated Pollutions Prevention and Control (IPPC) and Industrial Emissions Directive (IED) legislation	Delivery date 2018	Plan submitted in May 2015	On target for re-submission in May 2018
18	Undertake works at Peterborough and Huntingdon Compressor Stations as part of the IPPC legislation	Delivery date 2020	On track to deliver one new unit at each site as part of IPPC 3	On track to deliver one new unit at each site as part of IPPC 3
19	Undertake works at Aylesbury Compressor Station to ensure compliance with IED	Delivery date 2020	On track to deliver installation of catalytic converter	On track to deliver Installation of catalytic converter
20	Report on our business carbon footprint	Publish in annual report	Published in our annual report	Published in our annual report
21	Meet greenhouse gas emissions targets	<2,897 tonnes for 2016/17	2,882 tonnes	3,590 tonnes

22	Meet our targets for the amount and the cost of the gas we use to run the network	<4,790 GWh (Gigawatt hours) gas equivalent usage target ⁵ <£76.1m cost target	4,592 GWh £73.2m	4,746 GWh £70.5m
Customer Satisfaction outputs				
	Our output	2016/17 Target	2015/16 Performance	2016/17 Performance
23	Undertake annual satisfaction survey with our customers and stakeholders.	Customer 6.9/10 Stakeholder 5/10	7.6 for customer 8.0 for stakeholder	8.0 for customer 8.0 for stakeholder
24	Submit annual stakeholder engagement report	Cap of 9 and collar of 4	Achieved a score of 6.15	Achieved a score of 6.5
Customer Connections outputs				
	Our output	2016/17 Target	2015/16 Performance	2016/17 Performance
25	Achieve our obligated times for delivering extra capacity on the system	Target of 24 months from the point of formal commitment	Compliant - No incremental capacity due for delivery this year	Compliant - No incremental capacity due for delivery this year
26	Meet timescales for connection applications as specified in UNC Modification 373 and comply with reasonable requests for a customer connection to the National Transmission System	2 business days for application acknowledgment 5 business days to confirm competent connection application 2 months for initial connection offer 9 months for full connection offer 3 months for a Feasibility Study Report	Timescales met	Timescales met

Key

Red – Missed an annual output and forecast to miss the remainder of our eight year output commitment

Amber – Missed annual output but on target to progress towards the remainder of our eight year output/successful achievement of annual output and risk of failure of the remainder of our eight year output

Green – Successful achievement of an annual output and on target to meet the remainder of progress towards our eight-year output commitment

⁵ In accordance with the NTS Shrinkage Incentive Ex Ante Baseline Value Statement usage target and actuals are quoted in GWh gas equivalent, using a factor of three to convert from electricity to gas equivalent.

IV. Outputs – Safety

43. The safety of our workforce, the public and our assets, remains a top priority at National Grid. We aim to deliver world class safety performance which is crucial to our customers, the communities we serve and to the reputation of our business. Specific outputs under this theme relate to compliance with safety legislation and meeting the requirements for enhanced physical site security. In 2016/17 we were compliant with our safety related outputs. There was one serious process safety event that occurred in 2016/17 which has been fully investigated in line with HSE legislation, with measures put in place to minimise the likelihood of further issues. We are also on track to meet BEIS's requirements for enhanced physical site security.

Gas Transmission Safety Performance

44. Within the Gas Transmission business, there were no public injuries and zero employee lost time injuries in 2016/17, but there were three lost time injuries associated with contractors. In two of the incidents, the contractors were struck by objects not directly related to their work – a finger trapped in a door blown shut by the wind and a branch striking a contractor in the eye. In the third incident, the contractor injured his shoulder whilst moving an air compressor. The combined employee and contractor lost time IFR was 0.13. Combined employee and contractor Total Recordable Injury Frequency Rate (TRIFR) closed on 0.25, based on six injuries.
45. There was one serious process safety event during 2016/17 which involved the release of gas from a NTS Above Ground Installation (AGI). The event occurred in October 2016, where there was a significant release through the stem seal of a valve on the Kings Lynn compressor tee site. The occurrence was reported to the HSE under RIDDOR. This event has been fully investigated using root cause analysis techniques and corrective actions are being completed according to plan to minimise the likelihood of future occurrences. The event supports the focus we are giving to the health of our assets with further detail on asset health strategy and delivery provided in Section XI.
46. Throughout 2016/17 we have implemented a number of initiatives to promote and encourage safety and wellbeing at National Grid. These include:
- Safety Management System - there has been a review and update of the UK and Gas Transmission Safety Management System to align them to externally recognised standards, such as British Standard Occupational Health & Safety Assessment Series 18001 (BS OHSAS 18001), and provide a clearer framework for managing occupational health and safety, process safety and wellbeing
 - Driving - a company-wide safe driving programme has furthered the development of our strategies to address the risks associated with driving. As part of this programme, we are establishing appropriate technology options,

such as those providing feedback on driver behaviours, and have implemented a ban on mobile phone use whilst driving, including 'hands-free'

- Health and Wellbeing - mental and physical health has continued to be a focus and has included launching new resources to assist leaders, line managers and supervisors to better support employees with mental wellbeing. We are also running a programme using wearable technology, which provides biometric information allowing people to understand the benefits of change, and encouraging more daily physical activity

47. Innovation continues to play an important part in our activities to minimise third party interference on our assets. Following initial reviews investigating farm equipment loadings, subsequent activities have explored techniques to provide effective pipeline depth of cover measurements and undertaken the development of pipeline impact protection slabs. The impact protection slabs, shown in Figure 2, are used as additional pipeline protection from mechanical plant and equipment damage. The slabs utilise the high strength and lightness properties of polyethylene, replacing the conventional reinforced concrete solution. Polyethylene slabs offer savings in both terms of capital and installation costs, and most importantly they provide a highly visible warning of the pipeline location to machine operators if disturbed.

More information about our innovation projects in this area can be found on our innovation web page:

<http://www2.nationalgrid.com/uk/our-company/innovation/>

Figure 2: The installation of the new polyethylene pipe protection slabs



Enhanced Physical Site Security

48. In May 2015 as part of the reopener, we put forward our plans to comply with the BEIS requirements for enhanced physical site security. Details of progress against our reopener can be found within Section XI. In summary, we remain on track to meet BEIS's requirements.

V. Outputs – Reliability and Availability

49. The reliability and availability of our transmission network and the service it provides is vital to our customers. In 2016/17 we continued to provide high levels of reliability and availability for our customers to input and offtake gas from our system. The section below details how we have performed against our Reliability and Availability outputs outlined in Table 1. In summary, all of our outputs in this area have been met, or are on target to be met within the remainder of the RIIO-T1 period. The only area where an issue has been experienced is with regard to 'capacity obligations' (output 11 in Table 1). This is discussed further in the 'Constraint Management Incentive Scheme' section below. Reliability and Availability outputs not discussed in the below section, are covered in Section X and XI.

Network Output Measures (NOMs)

50. The reliability and availability of the NTS to our customers depends predominantly on the health of our assets, both today and into the future. NOMs are currently being used as a proxy for network risk to measure the risk across the RIIO-T1 period. In our 2015/16 submission we reported that the actual network condition was at a lower level (i.e. more observed condition issues) than the modelled view within our current NOMs methodology. This is still the case and it is therefore important to note that our investment plans are not based on the modelled view but targeted to address actual network condition/issues and minimise disruption to customers.
51. During 2016/17 we have further increased the volume of asset health improvement work delivered. Comparing the end of 2016/17 with the end of 2015/16, the additional work has resulted in reduced volumes of modelled RP1 assets across the NTS.
52. We are still forecasting to meet the NOMs targets outlined in our Licence by the end of the RIIO-T1 period. We further discuss network risk and NOMs in Section XI.

Maintenance Days Used Incentive Scheme

53. The Maintenance Days Used incentive is designed to reduce the impact we have on our customers when we undertake our routine maintenance activities. For 2016/17 the incentive only included maintenance days for Routine Valve Operations (RVO); the In Line Inspections (ILIs) element of the scheme ceased in 2015/16.
54. We have sought to align all of our routine valve maintenance work with customer outages where possible, and only three Maintenance Days for RVOs were requested ahead of the summer maintenance period (April to October). However this was reduced down to one after realigning the work with customers. This compares with two Maintenance Days in 2015/16.

55. We have continued to build upon the improvements made in previous years to help us to improve the service we provide to customers.

Maintenance Day Changes Incentive Scheme

56. The aim of the Maintenance Days Changes incentive is to reduce the impact our maintenance activities have on customers should we make changes to our planned maintenance after 1 April for the forthcoming summer maintenance period. The incentive scope does not include changes which were initiated by customers, only those initiated by National Grid.
57. The Maintenance Days Changes incentive includes any maintenance days called; it is not limited to RVOs. In total there were 232 days of planned maintenance in 2016/17 compared to 55 days in 2015/16. This large increase, driven in part by the initiation of our asset health campaigns, led to a benchmark for changes of 16.82 days in 2016/17, which is 7.25% of all Maintenance Days and Advice Notice Days⁶ called. This compares to a benchmark of 3.99 days in 2015/16.
58. In 2016/17, there were no changes initiated by National Grid during the maintenance period. This is the same level of performance as 2015/16. The incentive was more challenging this year because we received and responded to 26 days of customer change requests during the summer maintenance period, compared to nine in 2015/16, demonstrating our commitment to be flexible to customers' requirements.
59. This performance was primarily delivered by several improvements that we made in 2016/17 including significantly improving our planning processes and telephoning customers eight weeks prior to the planned maintenance affecting them, allowing us to capture any changes to customer outages earlier.
60. Our annual maintenance programme review for 2016/17 can be found on our website at:

<http://www2.nationalgrid.com/uk/industry-information/gas-transmission-system-operations/maintenance/>

Constraint Management Incentive Scheme

61. The Constraint Management incentive is designed to incentivise National Grid to maximise available capacity on the network and minimise constraint management costs through the efficient and economic operation of the NTS. We therefore release as much capacity as possible and develop effective constraint management strategies. This benefits our customers as the costs of commercial constraint management actions to the industry are kept to a minimum whilst

⁶ Where a single maintenance activity affects multiple NTS Exit Points on a day, this is construed as a single day for the purposes of the Maintenance Incentives.

access to the NTS is maximised. An effective Constraint Management strategy should also lead to stronger incentive performance, delivering value to the industry and to the end consumer. National Grid overall 2016/17 constraint management incentive scheme performance was £13.3m. The saving made against the incentive target is shared with consumers.

62. In 2016/17 (pre-sharing factor) revenue from Entry Capacity products, including Entry Capacity Overruns, increased to £3.0m from £1.5m in 2015/16. This is primarily driven by increased market demand for short term capacity at the Bacton UKCS Aggregated System Entry Point (ASEP). Revenue from Exit Capacity products increased to £0.55m in 2016/17 from £0.47m in 2015/16. We continually seek to actively manage constraint risk and in 2016/17 we put in place a contract to mitigate a foreseen risk.

63. In 2016/17 we took a number of Entry Capacity constraint management actions. These are detailed below:

- On 5 September 2016 the Projected Closing Linepack (PCLP) was at its lowest level since October 2012 with PCLP 47 mcm/d light. We took national balancing actions early in the day and the market responded with storage injection reducing, and subsequently switching to withdrawal, and an increase in LNG supplies at Milford Haven. Whilst this meant the system balance recovered, it consequently resulted in a capacity constraint at Milford Haven with key compressor stations (Churchover and Wormington) on planned outages.
- We mobilised our field force to bring the compressor stations back from outage early and scaled back interruptible entry capacity at Milford Haven. We then requested locational bids from the market. Two bids were submitted for a total of 9.5 GWh/d at a large power station in the area, the bids were accepted and no further actions were required. This particular day is described in more detail in Section XVII – Operational Review.
- On 4 November 2016 we observed a significant change in supply patterns, with total flow at Bacton doubling in two days and the majority of supply coming through three entry points (Bacton, Easington and St Fergus). With rising pressures around Bacton, we scaled back interruptible entry capacity and restricted the quantity of unsold daily firm capacity made available to the market at the Bacton entry points. As a result, flows and pressures reduced, and we were able to later restore the previously scaled back interruptible capacity rights.
- On 18 November 2016 Aberdeen compressor tripped at a time when St Fergus flows were high. As a result pressures increased and a Terminal Flow Advice⁷ (TFA) notice was issued at St Fergus to restrict flow. To protect

⁷ A Terminal Flow Advice is an instruction to turn down or cease entering or exiting gas at a given entry or exit point.

customers' existing firm rights (which were below the restricted flow level) we scaled back interruptible entry capacity and restricted the further release of unsold daily firm capacity until later in the gas day when the pressure concerns had eased. A similar issue occurred on 2 January 2017.

- A specific challenge this year has been managing demand for short term entry capacity at Bacton UKCS, particularly for the months January – March 2017 where all obligated firm capacity had sold out in the long term capacity auctions. This meant there was an increase in demand for non-obligated entry capacity and we had customer feedback questioning the consistency of short term non-obligated release. In response to this feedback, we presented our rationale for release of non-obligated capacity to the Operational Forum and, provided further guidance to our Gas National Control Centre (GNCC) to help respond to customer queries more effectively.

64. We have carried out a number of customer education activities on Constraint Management and the Capacity Regime. These activities received positive feedback from our customers and included:

- A presentation and practical game at our operational forum to aid understanding of Constraint Management and a high level overview of the commercial and physical tools available to us.
- A Constraint Management webinar to the industry.

65. During 2016/17 we experienced system issues that impacted our ability to run daily capacity auctions. These issues are largely attributed to planned and unplanned outages of Gemini and PRISMA⁸. With unplanned outages we invoked UNC contingency arrangements and fixed data issues.

Transportation Support Services Incentive Scheme

66. The Transportation Support Services (TSS) scheme incentivises National Grid to minimise the cost of procuring specific tools to support gas demand in the South West as an alternative to network investment. In 2016/17 we spent £0m against a target of £8.9m, the benefit of which is shared with consumers.

67. Based upon our assessment of the supply and demand forecasts we determined that it was not economic or efficient to procure any TSS services in 2016/17. This meant an increase in the risk of network constraints to be managed through the Constraint Management incentive scheme.

Demand Forecasting Incentive Schemes

68. We publish national demand forecasts for day ahead (D-1) and two to five days ahead (D-2 to D-5). These forecasts assist the industry in making efficient

⁸ PRISMA is a European system for booking and trading gas capacities

physical and commercial decisions in order to balance supply to, and demand from, the NTS. We strive to continuously improve the accuracy of these forecasts in order to ensure our customers can effectively and safely manage these elements on a day-to-day basis.

69. In 2016/17 the average error on the D-1 incentive was 8.53 mcm against a target of 9.39 mcm (Fixed target of 8.5 mcm + storage adjuster of 0.89 mcm). The average error has increased this year from 7.75 mcm in 2015/16.
70. The D-2 to D-5 incentive average error was 12.39 mcm in 2016/17 against a target of 13.70 mcm. The average error has slightly increased from 12.09 mcm in 2015/16.
71. This year, demand forecasting has been more challenging due to an increase in the day-on-day change in demand, which averaged 11.50 mcm in 2016/17, compared with 10.87 mcm in 2015/16.
72. There was also an increase in the number of instances of large changes in day-on-day demand, for example, in 2016/17 there were nine instances of a day-on-day change greater than 40 mcm, compared with five in 2015/16. The main reason for this was that injections into MRS facilities across the winter period were higher and more variable than in previous years, in total the injection/withdrawal volume increased by 34% compared to 2015/16. The MRS behaviour was influenced by:
- Variable demand - Winter 2016/17 was relatively mild with it being classed as '1 in 6 warm', however a number of cold snaps were experienced causing large swings in Local Distribution Zone (LDZ) demand.
 - Reduced long range storage capacity - the Rough storage facility entered the winter with lower stocks than in previous years due to a full injection outage from late June 2016, and throughout the winter there were various maintenance events which reduced withdrawal capability.
73. Throughout 2016/17 we have embarked on a number of activities to drive improvements in the accuracy of our demand forecasts, including:
- Forecasting efficiency - implementing a new forecasting solution as part of the new Gas Control Suite (GCS), which reduces the time it takes to run the models and allows us to spend more time gathering and reviewing commercial intelligence.
 - Analytics improvements - as part of the GCS implementation we have also developed a number of visual analytics dashboards to better track trends in our forecasts and recent supply/demand patterns.
 - Process improvements – in 2016/17 we have tested and refined a number of measures that we initiated in 2015/16 to improve our internal processes for forecasting various elements of total demand (e.g. LDZ, Power Station).

Residual Balancing Incentive Scheme

74. The aim of the Residual Balancing incentive scheme is to incentivise National Grid's residual balancing activities in two ways:
- The Linepack Performance Measure (LPM) incentivises National Grid to minimise differences in linepack volumes between the start and end of each gas day. This is to ensure that any system imbalances within day are resolved, and that any associated costs are levied across those system users responsible for that day's imbalance.
 - The Price Performance Measure (PPM) evaluates the impact National Grid has on the market in its residual balancing role by measuring the price range of its trading actions compared to the System Average Price (SAP). This incentivises the System Operator to minimise the impact it has on market prices.
75. The LPM element for 2016/17 achieved a daily average linepack performance of 1.74 mcm over the year, compared to the 2.8 mcm incentive target. This was slightly worse than the level for 2015/16 (which was 1.62 mcm). LPM was better than target on 306 days during the year, comparable to the 307 days in 2015/16.
76. The PPM element achieved an average price spread of 0.95% of SAP, compared to the 1.5% incentive target. This represented a decrease in performance on the 2015/16 value of 0.64% of SAP. We continued to assess the need for residual balancing actions against our operational decision criteria developed in 2015/16. This helped us maintain a year-on-year reduction in the number of days when residual balancing actions were taken (90 days, compared with 115 days in 2015/16). We will continue to monitor and optimise our balancing strategy to the prevailing conditions.
77. Following the implementation of Operational Balancing Accounts (OBAs) in October 2015, we have continued to work with adjacent Transportation System Operators to manage and refine the OBA processes.

Operating Margins (OM)

78. We are required to procure OM services to maintain pressure in the NTS in the intermediate period following operational stresses and during the run-down of the system in the event of a Network Gas Supply Emergency.
79. All costs incurred by National Grid for the procurement and utilisation of OM are a pass through element within the Licence. Under the RIIO-T1 regime, National Grid has a reputational incentive to promote competition in the procurement of OM services for customers. We aim to meet the OM requirement in the most economic and efficient manner.

80. OM costs have materially decreased from £21.6m for 2015/16 to £12.9m for the 2016/17 incentive year.
81. The lower cost base for customers reflect the combined impacts of (i) a lower OM volume requirement (~1.2 Terawatt hours to ~0.7 Terawatt hours); (ii) stimulating a more competitive market response, through industry engagement to bring in new service providers. We received tenders for capacity for the 2016/17 OM year (in comparison to 2015/16) from four new storage sites, four new power stations and one new service provider at an Liquefied Natural Gas (LNG) site.
82. We undertook an extensive review of OM contract templates including an industry consultation which has resulted in improved contracts and better alignment across the contracts for the different provider types. These have been well received by service providers.
83. The financial year 2016/17 has involved managing the OM position against a backdrop of uncertainty of availability at the Rough gas storage facility. This resulted in us taking the unusual step of carrying out a second OM tender later in the year.

VI. Outputs - Environment

84. As one of our key outputs under RIIO-T1, minimising the impact our business has on the environment is important both to us, and to our customers.
85. In 2016/17 we have made good progress against some of our environmental outputs outlined in Table 1. We have reported appropriately on our Business Carbon Footprint and we are on track to meet our IED legislative obligations with delivery of works at Peterborough, Huntington and Aylesbury compressor stations. Further information about IED and works at our compressor stations can be found in Section XI - Emissions.
86. Our outputs relating to environmental incentives continue to set challenging targets. In 2016/17, we had challenges around our GHG incentive performance. The unusually high flows experienced at St Fergus in 2016/17 resulted in a less balanced overall network which required increased operation of compressor stations and resulted in increased venting of GHG. We have implemented a number of initiatives aimed at driving performance and will continue to progress these throughout 2017/18.

Emissions

87. IED has been in force since early 2013. As part of our RIIO-T1 submission and the May 2015 reopener we set out our plan to comply with this legislation. In summary, work at Peterborough, Huntingdon and Aylesbury is progressing and we will submit a revised integrated plan in the May 2018 reopener. We are therefore on track to meet our outputs in this area. Further details on our progress are reported within Section XI - Emissions.
88. In addition to IED, the Medium Combustion Plant Directive (MCP) will be transposed into UK legislation by 19 December 2017. The MCP Directive applies to the smaller gas compressors and will affect a further 26 of the NTS compressor units.
89. The MCP Directive features deadlines for the phase-out of the most polluting plants (2025 for plants above 5MW). Crucially, National Grid secured a longer derogation for gas compressors that are required to ensure the safety and security of the NTS, which now have been given a further five years (2030) to comply with the requirements.
90. Other combustion plants, such as our pre-heating systems, are also captured as part of IED. During 2016/17 we have undertaken an audit of this plant type and an impact assessment will be available to the business to develop mitigation plans.

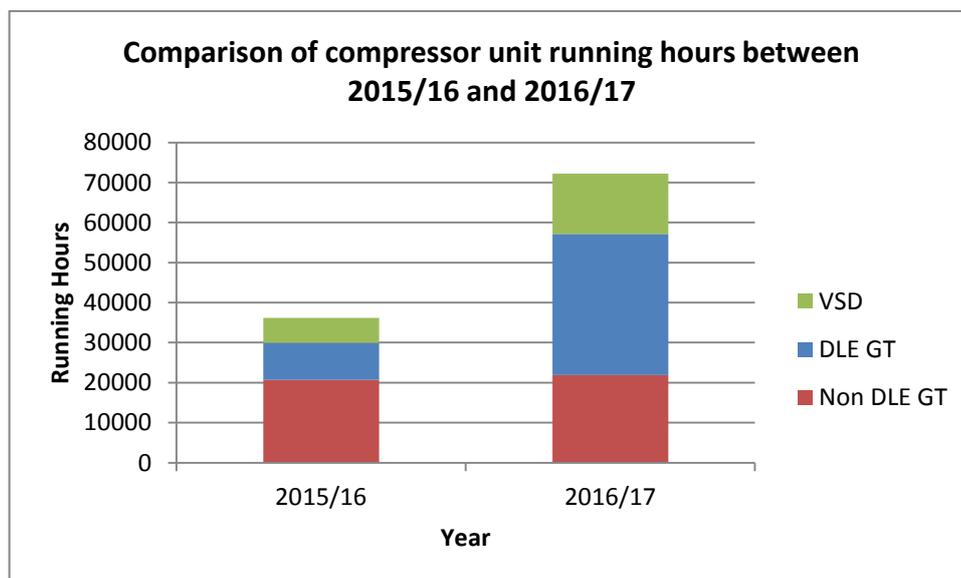
Business Carbon Footprint

91. National Grid plc has set a voluntary target to reduce our Scope 1 and 2 GHG emissions across our UK and US businesses by 45% by 2020 based on 1990

levels. Our National Grid plc baseline emissions level was set at 19.6m tonnes of carbon dioxide equivalent (CO₂e). Our current forecast is that we will better this 2020 target.

92. Scope 1 and 2 emissions in Gas Transmission can be broken down into sources including compression, venting, leakage, buildings and transport.
93. The majority of the emissions in Gas Transmission are from fuel use in gas and electric driven compressors. Emissions from compressor stations are largely dependent on the locational balance between supply and demand conditions, driven by market forces.
94. Our Scope 1 emissions increased from 356 kTCO₂e in 2015/16 to 557 kTCO₂e in 2016/17 due to a significant increase in running hours of our gas-fired compressor units. This increase is due to a combination of gas burnt for compressor operation (resulting in CO₂ emissions) and methane venting. Our Scope 2 emissions also increased – from 61 kTCO₂e in 2015/16 to 119 kTCO₂e in 2016/17 – driven by increased running of electric drive compressors. Average daily gas flows at St Fergus in the north of the network were approximately 30% higher in 2016/17 than 2015/16, resulting in much greater utilisation of compressors in Scotland.
95. Although the CO₂ emissions have significantly increased this has not resulted in comparable increases in NO_x emissions which have only increased by 8.7% due to the increased utilisation of Dry Low Emissions (DLE) gas turbine and electric drive compressors. The figure below shows the increase in utilisation including the type of unit used, it can be seen that there was a slight increase in the number of running hours of non DLE units, and significant increases in running hours of the DLE and Variable Speed Drive (VSD) low emission units.

Figure 3: Compressor running hours broken down by unit type for financial years 2015/16 and 2016/17



96. We provide our annual emissions performance as part of our Carbon Disclosure Project (CDP) submission. This enables us to benchmark our performance against other organisations. In our latest report we achieved an 'A' rating for our CDP submission, putting us in the top 9% of global companies recognised for our actions to reduce emissions and mitigate climate change.
97. Our GHG inventory, measurement, data collection, aggregation and reporting processes are verified by an independent third party, providing assurance of relevance, accuracy, consistency, transparency and completeness.

Shrinkage Incentive Scheme

98. The aim of the Shrinkage incentive scheme is to minimise the costs National Grid incurs in its role as NTS Shrinkage Provider. These costs are recharged back to users as part of NTS commodity charges.
99. The overall volume of shrinkage gas and electricity procured for the combined elements of Shrinkage (Compressor Fuel Usage (CFU), Unaccounted for Gas (UAG) and calorific value (CV) shrinkage) was 4,746 GWh gas equivalent in 2016/17. This represents an increase in overall volume of 154 GWh gas equivalent from 2015/16. This is due to an increase of 1,685 GWh gas equivalent in the volume of CFU outweighing a decrease of 1,510 GWh in the volume of UAG (Please refer to the UAG Incentive section below for further detail).
100. The volume of CFU was nearly double that in 2015/16, driven by the approx. 30% higher supplies at the St Fergus terminal (at a level not seen since 2008/09 and unprecedented in summer over recent years). The electricity usage component of CFU was nearly three times higher than in 2015/16, due to the overall increased use of electric units within our compressor fleet. We continued to manage their operation over periods of peak electricity demand to reduce Transmission Network Use of System charges (often referred to as triad charges).
101. Market conditions meant forward trading for 2016/17 was challenging due to reduced liquidity of quarterly products. We continued to develop our trading strategy to deliver improved price risk management and increased our access to market, by starting to trade National Balancing Point (NBP) futures on the ICE exchange mid-way through the year.
102. In managing the NTS Shrinkage incentive scheme we incurred costs of £70.5m, including £49.2m for gas trades and £15.3 m for electricity trades. This is similar to costs for 2015/16 (£73.2m). Against the total incentive target of £76.1m, this represents a £5.6m reduction in costs that are shared with customers.

Unaccounted for Gas (UAG)

103. UAG is a reputational incentive with a requirement on National Grid to undertake projects and initiatives to investigate the causes and reduce sources of UAG.

104. UAG has continued the trend of year-on-year reduction experienced since 2009/10 (with the exception of 2015/16). The annual UAG volume for 2016/17 was 1,272⁹ GWh, which has decreased by 1,510 GWh compared to the 2015/16 volume.
105. We review and investigate UAG values on a daily basis paying particular attention to any days that exceed +/-20 GWh. During 2016/17 there were 40 days that exceeded the 20 GWh tolerance, which is 12 days less than 2015/16.
106. There were a large number of data errors in July and August 2016 associated with the implementation of GCS. We have now reconciled the identified data errors caused by the implementation. All reconciliations over the past year (102 in total) have equated to a net value of -186 GWh resulting in a reduced net UAG figure of 1,086 GWh for 2016/17.
107. In 2016/17 we have continued to look for ways to improve our UAG performance. The following remain key focus areas for UAG management:
- Improving data handling between sites and billing systems to improve the D+5 close out data quality and reducing billing uncertainty;
 - Reducing meter errors, and the efficient handling of reconciliations; and
 - Maintaining a close relationship with all meter asset owners and validation agencies, providing a consistent and effective platform to receive metering system validations and to solve measurement issues.
108. We have historically received a relatively modest sample of meter validation reports. Over the past six months we have introduced a new process where validation reports have been requested from all facilities and have been actively chased if not received. This has led to us receiving responses from 98% of sites. All of these validation reports have been reviewed and, where necessary, queries have been raised with the asset owners.
109. To further enhance UAG management and reduce the associated costs to our customers, we have been progressing the NGage 'free to use' meter validation assessment tool which was funded through the Network Innovation Allowance (NIA). We have completed further development and extensive user testing of version 2.0 and we are planning to release the new version to meter asset owners in the coming months. This will not only provide unequivocal evidence of meter management performance but will also provide indicators of potential areas for future investment.
110. An independent assessment of a dynamic baseline UAG, which could be expected allowing for normal measurement uncertainties, is currently being undertaken by Manchester University's mathematics department. It is also

⁹ Note these numbers are pre-reconciliation

expected to provide a range of improved analytical methods for identifying potential causes of UAG. This three year study will be completed in 2019.

Greenhouse Gas Emissions Incentive

111. The aim of the GHG incentive scheme is to incentivise National Grid to reduce the amount of natural gas vented from our compressors which is primarily methane, to reduce our effect on the environment.
112. The total amount of natural gas vented from compressors in 2016/17 was 3,590 tonnes. This was 25% or 708 tonnes higher than in 2015/16, and 693 tonnes higher than the target set for 2016/17.
113. This large increase has been primarily caused by 30% higher supplies at the St Fergus terminal, which have driven a doubling in compressor running hours compared to last year. The greater use of compressors has led to higher venting for example through unavoidable seal leakage when running.
114. Also, the unreliability of some compressors has led to more venting when units were shut down and replacements started up. Sometimes multiple contingency units are required to replace the primary compressor.
115. We have developed a more detailed log for compressor operations staff to record the reasons for venting, to support focus on performance improvements and in 2017/18 we are going to complete a review comparing reportable and incentivised emissions. We have also agreed new regulatory reporting for 2017/18 which includes a further breakdown into vent types.
116. An external audit for 2016/17 has been carried out (as required annually by the Licence) to ensure vented volumes are calculated according to the agreed methodology.
117. Further to the above incentive and to fulfil the Licence direction Special Condition 8J of National Grid's Transportation Licence we have been working on a prototype design to monitor the emissions from above ground installations, the project is called GHG Investigative Mechanism (GHGIM).
118. The aim of GHGIM is to design and develop a cost effective methodology to enable National Grid to monitor and control fugitive emissions from AGI's on the NTS and to understand both planned and unplanned venting events. The project will involve trialling a proposed method over a one year period to assess the practicality, performance and cost effectiveness of the approach. In addition there will be a validation of the "portability" of the equipment to expand the application beyond AGIs.
119. In 2016/17 we signed contracts with a third party to design the bespoke equipment needed for the field validation and installation. Monitoring commenced in March 2017.

120. Improved understanding and quantification of emissions will enable better cost benefit analysis for future investment planning. Aligning any rectification works with planned maintenance should present a least-cost route to emission reductions.

VII. Outputs – Customer Satisfaction

121. The RIIO-T1 price control recognised the need to encourage network companies to respond to the changing requirements of an evolving customer base and develop strategies to drive improvements in customer and stakeholder satisfaction.
122. Our customer satisfaction output is supported by two separate financial incentives:
- customer and stakeholder satisfaction survey; and
 - stakeholder engagement incentive scheme
123. In 2016/17, we achieved a customer satisfaction score of 8.03 against a baseline of 6.90. The stakeholder satisfaction score was 7.98 against a baseline of 7.40.
124. Throughout 2016/17, we have improved the way we survey our customers and stakeholders by introducing triggers shortly after we have interacted with them to ensure we get timely and relevant feedback. This has resulted in an improved response rate for both the customer and stakeholder satisfaction surveys increasing from 116 in 2015/16 to 128 in 2016/17. As well as making changes to when we survey our customers, we have also focused on making the additional questions we ask them specific to the interactions we are having with them to ensure the feedback we receive is as relevant and as useful as possible.
125. The customer satisfaction score has increased by 0.48 since last year's score of 7.55, which demonstrates our continued efforts to put customers at the heart of everything we do. Our customers scored us highly in the Gas Diversions, Gas Customer Liaison and Operational Forum and GNCC areas which all achieved scores above 8.5. Throughout the following year we will continue to make improvements to the services we provide to improve overall customer satisfaction.
126. The stakeholder satisfaction score has decreased slightly by 0.04 from the 2015/16 score of 8.02, this is in part due to receiving a score of 7.19 from the Future Energy Scenarios survey. This team is taking the feedback received and are making changes to the ways they engage with their stakeholders over the following year and as a result, we anticipate that this score will increase.
127. Throughout 2016/17, we have started to close the feedback loop with our customers. This has involved our employees calling or meeting with customers that respond to the satisfaction surveys to discuss their feedback. The purpose of these interactions is to ensure that our customers know that we are listening to, and acting upon, their feedback. It also gives them an opportunity to discuss and resolve any specific issues directly with the people within our business that they work with on a regular basis. We have received very positive feedback in response to these calls. This year, we contacted around 40% of customers and

stakeholders and we will aim to contact 100% of customers and stakeholders after receiving their survey responses next year.

128. In 2016/17, we scored 6.50 out of 10 for the Stakeholder Engagement Incentive Scheme. This represents an increase of 0.35 from our 2015/16 score of 6.15 and demonstrates the improvements we have made to the way we engage with our stakeholders. The assessment panel was impressed with how stakeholder engagement has led to changes to our business plans.
129. Our commitment to improving customer and stakeholder service throughout our business has been endorsed at Board level through their commitment to a customer transformation programme of work which will enable us to achieve our vision of *“Exceeding the expectations of our customers, shareholders and communities today and making possible the energy systems of tomorrow”*. This focus on customer is vital to us making a step change in our core business performance. In January 2017 the design and key elements of this programme were agreed by the UK Executive team and the remainder of the programme is now being developed. One of the main vehicles of change is the Net Promoter System (NPS) Programme. Under the Relationship Top-Down approach to NPS, the UK Executive team have agreed to meet one of our customer’s Senior Leaders each month to elicit feedback and dialogue on the issues most affecting their businesses.
130. Another change piece we are introducing is the Customer Journey programme, through which we will establish a governance structure to more carefully manage our customers’ experience in key areas. As part of the Customer Journey programme, the UK Executive have agreed to prioritise the gas connection to disconnection lifecycle.
131. We’ve also introduced a tool called customer immersion, with several sessions being facilitated throughout 2016/17. Customer immersion provides our customers and stakeholders an opportunity to give honest feedback, along with the emotion attached to it, and gives our employees first-hand experience of how our actions impact on our customers.
132. As well as introducing new ways of gathering feedback, taking action and improving our service, throughout 2016/17 we paid particular focus to two key areas:
- **AA1000 Stakeholder Engagement Standard (SES)** – we instructed AccountAbility to carry out a full independent health-check of our stakeholder engagement strategy, processes, practices and our engagement in practice. The assessment found that we demonstrate a high performance across the various elements of AA1000SES. With a total score of 69%, this places us within the advanced stage of their Stakeholder Engagement maturity ladder, presenting an 8% increase since the 2016 Health-check. This score is in the top 15% of all companies reviewed by AccountAbility worldwide since 2012. In addition we are the second highest scorer of the eight Energy and Utilities sector companies reviewed.

- **Engaging with a broad and inclusive range of stakeholders in different ways** – we are engaging with a variety of stakeholders throughout our major projects including local authorities, schools, regulators and government to understand how we can better work together towards an end result which exceeds all our stakeholders' requirements. After receiving excellent stakeholder feedback from our Peterborough and Huntingdon compressor upgrade projects the learning has been included in future engagement events

133. Whilst we have made strong progress this year, we recognise that there is plenty of room for improvement as we strive to continually develop the services we provide to our customers and stakeholders. With the continued roll out of the customer transformation programme planned for 2017/18, we are further enhancing the tools and techniques available to the business to better enable our employees to effectively manage their customer relationships and in turn ensure this remains a priority for our UK business.

VIII. Outputs – Customer Connections

135. Delivering timely capacity and connections to our customers is a licence obligation and key output under RIIO-T1. In 2016/17 we met our output commitments, progressing all NTS connection applications received and issuing three full connection offers within the appropriate timescales.
136. Under this output our performance can be split into two main areas:
- the Connection Application to Offer (A2O) process;
 - the Planning and Advanced Reservation of Capacity Agreement (PARCA) process and the delivery of incremental capacity

The NTS Connection Application to Offer (A2O) Process

137. In total there were eight live NTS connection applications during 2016/17. We received seven customer applications for an NTS connection via the Application to Offer (A2O) process in 2016/17¹⁰, all of which were medium complexity. There was an additional medium complexity customer application received in 2015/2016 for which an offer was due to be made in 2016/17.
138. In 2016/17 we issued three full connection offers within the timescales set out in the UNC, one application was withdrawn by the customer before an offer was made, and four connection applications are still being processed with offers due in 2017/18. Of the three offers made, one application is progressing to detailed design and construction, one is being taken forward by the customer on a self-lay basis, and one is with the customer awaiting a decision to proceed. The application that was withdrawn was due to the customer not being awarded an electricity capacity market contract.
139. Table 2: Summary of the NTS connection applications and offers

Connection Applications		Offers made in 2016/17	
Received in 2015/16 and carried over to 2016/17	1	Offer made - Awaiting Response	1
Received in 2016/17	7	Offer made – customer progressing with self-lay	1

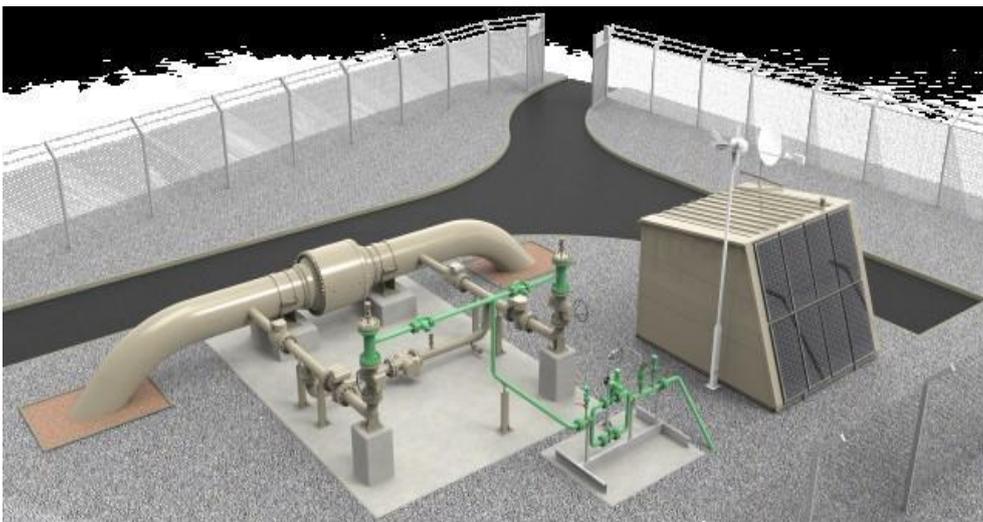
¹⁰ Details of the NTS Connection Application to Offer (A2O) process can be found at the following [link](#).

		Application withdrawn by customer – no offer made	1
		Offer accepted	1
		Carried over to 2017/18	4
Total	8	Total	8

140. We have worked with our customers and stakeholders to understand their future connection requirements. This led to our successful NIC submission and the launch in February 2016 of project CLoCC – Customer Low Cost Connections. This three year project is aiming to reduce the timeline and cost for simple to medium NTS connections. The project focusses on unconventional gas connections, with every aspect of the connection process being challenged in order to reduce the cost of a connection to less than £2m and the timeframe to less than 12 months.

141. During 2016/17 the project team have been progressing through Stage 2 “Conceptual Design and Change Plan” which saw the successful development of a prototype version of the new online connections platform. A suite of conceptual designs were also created and are to be further developed into detailed designs prior to approval and appraisal during our final project stage, Stage 3, which commenced on 1 May 2017.

Figure 4: Image of a typical block valve site proving the feasibility of a CLoCC physical solution. Potential CLoCC solution additional pipework is shown in green



142. We are also running a trial self-lay connection with a customer based upon the customer request. Through this trial we are developing the processes where the

customer completes the detailed design and construction activities and we only have auditing and asset acceptance roles. Should this trial be successful, we will look to offer self-lay as a standard option for all NTS connection customers.

143. In 2016/17 we undertook a review to identify improvements in how we charge for connections that would benefit our customers. As a result we have introduced two new connection categories as well as categories covering disconnection, preservation and decommissioning of NTS offtakes. The two new connection categories cover minor modifications and re-applications.

Minor Modifications

144. Some of our customers have applied for flow increases at existing offtakes that have required minimal work such as re-ranging of meters, changes to gas regulator settings, and telemetry changes. For these sites the application fee would otherwise be medium (modification to an existing site) but the introduction of a minor modifications category and lower fee is more cost reflective and represents better value for our customers.

Re-applications

145. Some of our customers have applied for NTS connections and their offers have then lapsed due to their projects not progressing; in many cases due to not being successful in being awarded an Electricity Market Capacity Contract. Some of these customers have gone on to re-apply for a NTS connection at a later date; however, the application fee has not been reflective of the work required to review the work done under a previous application and make an updated connection offer. For these reasons, we have introduced a re-application category where a discount to the standard application fee of up to 75% will be made to reflect the work required. Again, the lower fee is more cost reflective and thus fairer to customers.

Incremental Capacity and PARCAs

146. During the year we received a number of enquiries from customers regarding additional NTS Entry or Exit Capacity in excess of the baseline/obligated capacity levels available. While none of these enquiries has led to incremental capacity being released this year, these have led to PARCAs being initiated and could potentially lead to signals being generated in the future.
147. At the start of 2016/17, three PARCA applications (one for Entry Capacity and two for Exit Capacity) were in progress having been deemed competent during 2015/16. The required outputs for these applications were completed successfully within the timescales set out in the UNC. Two of the applicants chose not to proceed to the point of reserving capacity due to financial issues. One applicant progressed to reserving capacity under a PARCA but later terminated the agreement.

148. In total there were four new competent PARCA applications received during 2016/17, all for NTS Exit Capacity. The required outputs and offers to reserve capacity were made for two of these applications in 2016/17 in line with UNC; the remaining two applications have been carried over to 2017/18.

Table 3: Summary of the PARCA applications and offers

PARCA Applications		Offers made in 2016/17	
Received in 2015/16 and carried over to 2016/17	3	Offer made – not accepted	2
		Offer accepted – capacity reserved – PARCA terminated	1
Received in 2016/17 – offers made 2016/17	2	Offer made – awaiting customer decision	1
		Offer made – not accepted	1
Received in 2016/17 – carried over to 2017/18	2	Carried over to 2017/18 - Offer made 2017/18	1
		Carried over to 2017/18	1
Total	7	Total	7

149. As a consequence of no PARCAs progressing to allocation, there have been no funded incremental entry or exit capacity releases during 2016/17.

IX. Totex

150. In 2016/17 our Totex spend was £367m this compares with £323m in prior year (in 2016/17 price base). The year-on-year change is predominantly associated with the TO where:
- Baseline Capex has increased by £15m, largely as a result of increased spend on asset health;
 - Controllable Opex has increased by £11m, with higher costs in Closely Associated Indirect costs, Business Support and Planned Inspections and Maintenance categories; and
 - Uncertainty Capex has increased by £17m, predominantly due to the Feeder 9 works moving into the main construction phase
151. Our updated forecast for the eight years is £3,276m compared to an adjusted allowance of £3,073m. We have restated RRP Table 2.4 to include Xoserve Opex spend (from 2013/14 to 2015/16) not captured by the template and realign allowance categorisation to be consistent with the treatment of spend. Our restated table (summarised in Table 5) shows that forecast costs are £3,300m compared to adjusted allowances with an unchanged total of £3,073m.
152. With reference to the restated table compared to last year, our forecast spend has increased by £48m on a constant 2016/17 price basis and the adjusted allowance has decreased by £231m. The reasons for these changes are due to a number of positive and negative movements that are explained further below.

Transmission Owner (TO)

153. Our updated forecast for the eight years is £2,552m compared to an adjusted allowance of £2,256m.
154. With reference to the restated table compared to last year, our forecast spend has increased by £72m and the adjusted allowance has decreased by £234m. The reasons for these changes are:
- The allowance of £207m in 2016/17 prices, associated with the Avonmouth output has been removed following Ofgem's Mid Period Review decision;
 - Controllable Opex is up by £118m, due to additional Closely Associated Indirect costs, Planned Inspections and Maintenance and Business Support costs; and
 - A reduction in baseline Capex of £79m, predominantly due to a reduction in planned emissions investment in RIIO-T1. This reduction is partly offset by increases in asset health and Non Operational Capex costs

- Uncertainty Capex is up by £33m, due to updated forecasts for Feeder 9 and enhanced physical site security. The uncertainty mechanism allowances have reduced by £27m

System Operator (SO)

155. Our updated forecast for the eight years is £748m compared to an adjusted allowance of £816m.
156. With reference to the restated 2.4 table compared to last year, our forecast spend has decreased by £24m on a constant 2016/17 price base whilst there has been no significant net change to the forecast allowance. The reasons for these changes are due to a number of positive and negative movements, the most notable of which are:
- SO Capex spend forecast has reduced by £25m, with the largest driver being a move towards a refresh rather than replacement strategy for the Gemini system;
 - A decrease in Xoserve forecast allowances following Ofgem's decision on the review of agency costs issued in September 2016 (£14m); and
 - An increase in forecast allowances for enhanced security of £17m driven by latest cost forecasts in relation to our data centre and cyber security projects.
157. These are covered in more detail within the relevant sections.

Summary of Spend and Allowances

158. The table below shows forecast spend and allowances against the six main activity areas (as per RRP Table 2.4).

Table 4: Forecast Spend and Allowances (2016/17 price base)

Activity	Spend (8 Year forecast)	Allowance (inc. uncertainty mechanism) 8 year forecast	Cost vs Allowance
TO Load Related Capex	36.6	42.7	6.1
TO Non Load related Capex	1,525.7	1,359.3	-166.4
TO Non Operational Capex	137.1	67.2	-69.9
TO Opex	852.2	786.9	-65.3
SO Capex	280.2	323.1	42.9
SO Opex	443.8	493.3	49.5
Total	3,275.6	3,072.5¹²	-203.1

159. In order to better understand the underlying position of spend versus allowances, the table below summarises our restated table 2.4. Adjustments to the baseline position in Table 4 above are detailed below:
160. IED allowances of £89m are currently included within baseline Opex in table 2.4. All IED spend is captured within the Non Load Related Capex category. Therefore the IED allowances within Opex are reallocated to Non Load Related Capex consistent with treatment of spend.
161. Enhanced physical site security allowances of £30m are currently included within the Other Capex baseline in Table 2.4 which were categorised as Opex in the May 2015 reopener submission. These allowances are re-categorised to Opex UM allowances consistent with both the treatment of spend and the May 2015 reopener submission.
162. Currently the template does not categorise Xoserve Opex spend with Totex from 2013/14 to 2015/16. Xoserve UM Opex spend of £24m has therefore been included across the first three years of the RIIO-T1 period.

Table 5: Restated table 2.4 (2016/17 price base)

Activity	Spend (8 Year forecast)	Allowance (inc. uncertainty mechanism) 8 year forecast	Cost vs Allowance
TO Load Related Capex	36.6	42.7	6.1
TO Non Load related Capex	1,525.7	1,419.0	-106.7
TO Non Operational Capex	137.1	67.2	-69.9
TO Opex	852.2	727.3	-124.9
SO Capex	280.2	323.1	42.9
SO Opex	468.0	493.3	25.3
Total	3,299.8¹¹	3,072.6¹²	-227.2

163. Based on the table above the main areas of difference between cost and allowances, relate to:
- TO Non-Load Related Capex, where we are forecasting spending above allowances in terms of asset health;

¹¹ Note that the change in spend and therefore the cost vs allowance position is due to inclusion of the Xoserve opex spend from 2013/14 to 2015/16 which is omitted from SO Totex spend in the original template.

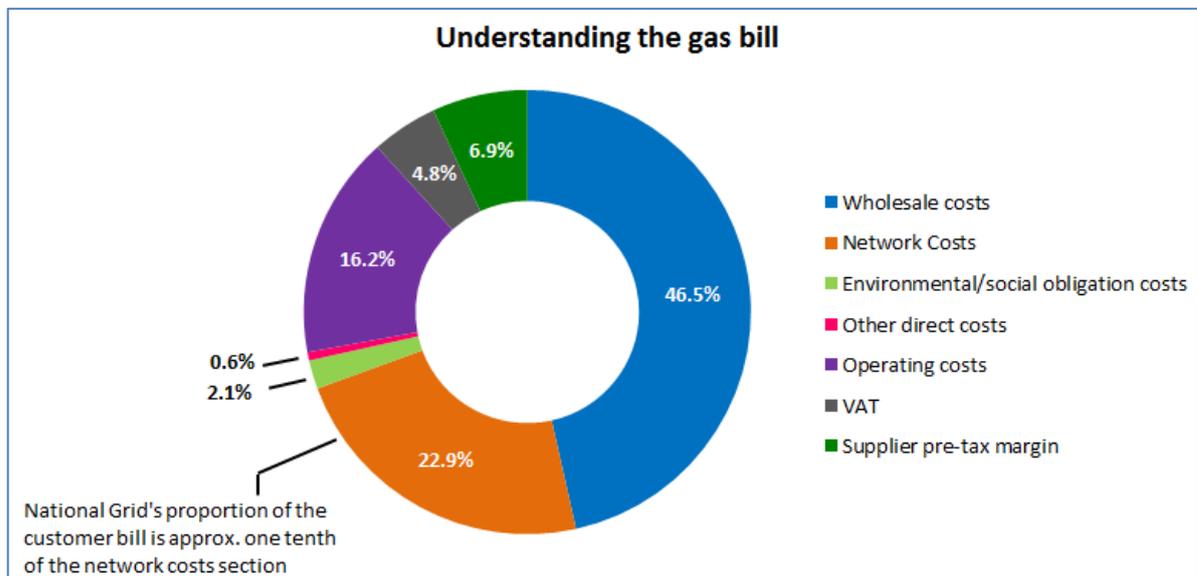
¹² Note that the restated is slightly different from the Allowance stated in RRP table 2.4 due to roundings

- TO Non Operational Capex where we need to invest in data and systems to improve the management of the asset health of our network and;
- TO Opex where we are spending above allowances on Closely Associated Indirect costs and Business Support costs;
- SO Capex where we are forecasting to spend less on Xoserve Capex and telemetry separation; and
- SO Opex where a higher proportion of Xoserve allowances following the outcome of the review of agency costs has been allocated to direct Opex

Customer Bill Impact

164. In 2016/17 approximately £16.29 of an average domestic consumer bill of £604 related to the services we provide; this equates to 2.7% of a typical gas bill. This has reduced compared to 2015/16 where the National Grid element of the consumer bill was £19.60 and the average bill cost was £706. The reduction in the average bill cost is largely driven by a reduction in average consumption by consumers. In 2015/16 average consumption was 14,500 kWh compared to 12,500 kWh in 2016/17.
165. Our current estimate is that the Gas Transmission element of an average domestic consumer bill will fall by £1.14 by the end of the RIIO-T1 period.

Figure 5: Breakdown of the consumer gas bill¹³



¹³ Gas bill breakdown available from Ofgem: <https://www.ofgem.gov.uk/publications-and-updates/infographic-bills-prices-and-profits>

X. Load Related Capital Expenditure (TO)

Introduction

166. This section covers our load related capital expenditure. In 2016/17 our expenditure was £1.7m and our updated forecast for the eight years is £36.6m¹⁴ compared to an allowance of £42.7m. Our forecast spend remains largely unchanged in aggregate although there are some minor movements within categories. The allowance has reduced by £207m (in 2016/17 prices) following Ofgem's Mid Period Review decision on the Avonmouth output.

System Flexibility

167. In 2016/17 we continued with our system flexibility project which was initiated to re-assess the needs case utilising the 'seedcorn' funding received under RIIO-T1. However, although the baseline allowances for this activity are included within Load Related Capital Expenditure, the spend incurred during 2016/17 falls within SO Opex, further detail can be found in Section XIV – Operating Costs.

Scotland 1 in 20

168. Under our 1 in 20 demand obligation we have continued to assess the need case for the Scotland 1 in 20 suite of projects.
169. During 2016 there has been a step change in the summer flows through the St Fergus terminal with supplies peaking at 112 mcm/d; a level not seen since 2009. The Total sub terminal was acquired by North Sea Midstream Partners in 2016 who have a different business model to the previous owners which has in part resulted in these higher flow levels.
170. The average flow through St Fergus for the previous five winters had been 63 mcm/d whereas in 2016/17 winter this increased to 93 mcm/d.
171. There is a high level of uncertainty around how long the increased flows will remain however they are expected to endure based on the recent acquisition of the sub terminal. In the long term it is still expected that they will decline to the point that it would not be possible to maintain the current Assured Operating Pressures¹⁵(AOPs) in Scotland.
172. It had been previously identified that with an agreement with Scotia Gas Networks (SGN) to reduce some of the higher AOPs in Scotland, it would be possible to deal with the minimum forecast St Fergus flow levels into early RIIO-T2.

¹⁴ The £1.7m expenditure and £36.6m forecast exclude Offtakes

¹⁵ A minimum pressure at an offtake from the NTS to a DN that is required to support the downstream network. AOPs are agreed and revised through the annual Offtake Capacity Statement process.

173. A number of discussions were held with SGN in 2015/16 and from November 2016 to March 2017 a trial was completed with SGN operating at lower AOP's. The trial was completed but was not able to prove capability because:
- it was a mild winter meaning that demand at SGN offtakes didn't reach peak levels;
 - the flow increase at St Fergus resulted in high pressures at all SGN offtakes
174. The capability of the offtakes and downstream networks has not been tested to their limits. As a result it was not possible to agree to the reductions and formalise these ahead of winter 2017. We will continue discussions with SGN and look at the benefits of running another trial during the 2017/18 winter period.
175. Analysis to assess the capability level against the updated 2016 FES is on-going. The delivery of an asset solution has an indicative lead time of four years. If the analysis shows the capability can no longer be met by the winter of 2021 the project will be triggered next year.

Avonmouth

176. On the 24 February 2017, Ofgem published its overall decision on the Mid Period Review. Part of this was to remove National Grid's Avonmouth pipelines output and £168.8 million (09/10 prices) in funding. In accordance with our Planning Code we will continue to monitor the demand situation in the South West, however at this time there is not an investment requirement.

Environmental Aftercare

177. The planning consent conditions for two pipeline projects completed during the Transmission Price Control Review 4 (TPCR4) (Wormington to Sapperton and Milford Haven to Tirley) included undertaking monitoring and aftercare regimes for a period of 10 years after project completion. This was to ensure that there were no enduring negative environmental impacts from the pipeline projects. The environmental aftercare category also included funding to complete the Tirley pressure reduction station and associated works (which included activity at Felindre compressor station) delayed into RIIO-T1 due to difficulties obtaining planning consent at Tirley.

Milford Haven to Tirley

178. The Milford Haven to Tirley pipeline project consisted of circa 320km of 48" pipeline routed from Milford Haven, South West Wales to Tirley, Gloucestershire. National Grid began the aftercare works in 2009 with an anticipated closure of the scheme following sign-off by two key stakeholders; Brecon Beacons National Park Authority and Natural Resources Wales in 2019.
179. Within last year's RRP submission, National Grid reported that although several of the aftercare sites had not reached 'full restoration' we anticipated that

stakeholders would support closure of the consent conditions. Both Brecon Beacons National Park Authority and Natural Resources Wales have written to BEIS confirming their support for National Grid discharging its consent conditions. National Grid received a letter from BEIS on 4 May 2017 confirming that the consent conditions had been discharged.

180. The final outturn cost of the scheme is forecast at £14.6m, which is substantially below the anticipated cost of £22.2m. The cost reduction is the result of the quality of the original construction work, combined with working closely with the stakeholders to agree when a location had achieved the required standard sooner than was originally forecast. National Grid will progress internal closure of the scheme in 2017/18.

Wormington to Sapperton

181. The Wormington to Sapperton pipeline project consisted of a 44km, 36" pipeline routed through the Cotswolds Area of Outstanding Natural Beauty (AONB). National Grid began the aftercare works in 2011 with an anticipated closure of the scheme following sign-off by the key stakeholder the Cotswolds Conservation Board (CCB) in 2020.
182. Within last year's RRP submission, National Grid anticipated the CCB would support closure of the consent conditions. CCB wrote to BEIS confirming its support for National Grid discharging its consent conditions. National Grid received a letter from BEIS on 4 May 2017 confirming that the consent conditions had been discharged.
183. The final outturn cost of the scheme is forecast at £0.5m, which is substantially below the anticipated cost of £3.4m. Similar to the Milford haven to Tirley scheme, the reduction is the result of the quality of the original construction work, combined with working closely with CCB to agree when a location had achieved the required standard sooner than was originally forecast. National Grid will progress internal closure of the scheme in 2017/18.

Felindre

184. Felindre Compressor Station was built as part of the South Wales Expansion Project (SWEPE), triggered by the requirement to connect the Milford Haven LNG terminal to the NTS.
185. The compressor station was designed as one VSD with two gas turbine units (GTs) as back-up. Construction of the compressor station was completed in 2010 but final commissioning could not commence until completion of the Tirley pressure reduction installation, which had been delayed by planning issues. Tirley was completed and commissioned in September 2012, however the expected volumes of gas at Milford Haven did not materialise and flows were not high enough to commission the VSD compressor although progress was made in commissioning the smaller GT units.

186. Commissioning runs of the GTs were completed in 2015/16 and the GTs were made available for operation under local work procedures, both on-site and in the GNCC. During 2016/17 work was completed to resolve remaining issues with valves and control systems. Full Operational Acceptance will be sought in Q2 2017/18.
187. In January 2014, due to the continuing low flows through Milford Haven, the VSD unit was put into preservation to avoid degradation of the equipment. The preservation expired in January 2016 and the decision was made to progress with commissioning the VSD due to higher flow forecasts at Milford Haven. The decision was also made at this time to proceed with creating a recycle loop within the network. The loop will reduce dependence on the unpredictable Milford Haven flows for commissioning the VSD and enable operational and environmental testing of any of the Felindre units.
188. Preparatory work to install the cross connection that will create the loop is progressing. To allow sufficient time for the site selection process, stakeholder engagement and lead time for materials, construction has been scheduled for 2018. Site selection has been completed and materials have been ordered. Stakeholder engagement is underway and conceptual design has commenced. The revised indicative cost of the recycle loop is £3.8m, within the previously estimated £3m to £5m.
189. Work is also underway to bring the VSD out of preservation and to prove systems in preparation for commissioning. Initial runs are expected during 2017. Final commissioning is expected in 2019, following completion of the loop. The commissioning cost of the VSD is still anticipated to be up to £7m. This includes a project contingency to resolve commissioning issues (such as those caused by interactions of the VSD with the local electricity network), based on our recent experiences of commissioning similar machines.

XI. Non Load Related Capital Expenditure

Introduction

190. This section covers our Non Load Related Capex. In 2016/17 our expenditure was £146.2m¹⁶ and our updated forecast for the eight year RIIO-T1 period is £1,526m¹⁷ compared to an allowance of £1,419m¹⁸. Compared to last year our forecast spend has decreased by circa £61m on a constant 2016/17 price base. The key variances are due to:

- A forecast increase in Asset Health costs of £35m (£19m baseline and £16m Uncertainty Mechanism)
- A reduction of £107m (includes £15m IED Decommissioning) in planned emissions investment in RIIO-T1, due to some spend re-profiled to RIIO-T2 and proposed changes in the number of units to be replaced at Huntingdon and St Fergus
- A forecast increase in enhanced physical site security costs of £23m, due to inclusion of shared sites and site extensions which has been partly offset by a reduction in forecast delivery costs
- A reduction in decommissioning by £8m predominantly due to the removal of Feeder 1. We are continuing to monitor the pipeline, noting the environmental designation and the Habitats Directive, we are mindful not to undertake further projects in parallel to Feeder 9 and Paul Rationalisation.

Asset Health

191. In 2016/17 we have increased the delivery of our asset health works in order to manage network risk. This increased delivery has been enabled by the surveying and planning work undertaken in the initial years of RIIO-T1 and the establishment of asset health campaigns to drive an increase in efficient project delivery and workload.

192. As we reported in our 2015/16 RRP submission, we continue to observe that the actual network condition is at a lower level (i.e. more observed condition issues) than the modelled view within our current NOMs methodology. As a result we continue to forecast a higher overall workload and therefore cost for asset health baseline investments of £660m over the RIIO-T1 period which is circa £105m over allowances and an increase in forecast of £20m against the 2015/16 RRP submission.

¹⁶ Excluding customer contributions

¹⁷ Excluding customer contributions

¹⁸ As per restated table 2.4

193. We continually review our asset health investment plans and will look to adjust our plans as we gain further understanding of the health of our assets and associated network risk to ensure that we deliver the network required by our customers. During 2016/17 we have identified additional work at our Bacton and St Fergus terminal sites. These Upper Tier Control of Major Accident Hazard (COMAH) sites are key strategic sites on the NTS and require significant asset investment to ensure continued safe and reliable operation. The increased investment at Bacton and St Fergus will be offset by deferral of lower priority asset health work into RIIO-T2.
194. In 2016/17 we have seen a growing number of asset failures affecting customers and therefore believe it is in consumer's interest to invest above our allowances. An incident on the NTS at King's Lynn in October 2016 provides an example of this. Gas leaking from a valve stem would normally be isolated relatively quickly by closing adjacent valves on the network to undertake a repair and restore the network to full resilience. However, on this occasion we experienced a number of further failures in attempting to isolate the faulty valve which led to us having to isolate a larger portion of the network and increased the risk of disruption for our customers.
195. As we have previously indicated, our investment plans are not based on the current NOMs methodology modelled view of network risk but programmed to address actual network condition/risk and minimise disruption to customers. We continue to deliver the work required on our assets irrespective of whether this delivers a NOM output (reduction in RP1 assets) or not. Our efficient and targeted asset health interventions often don't allow us to claim the removal of an RP1 asset where we refurbish or replace only part of a large asset system. During 2016/17 we have made substantial investment in the replacement of assets that do not contribute to the Network Replacement Measure. Nonetheless, this investment has benefitted customers through a reduction in real network risk.
196. There are a number of often complex reasons why asset health investment does not meet the criteria for delivering an output. Typically this is due to the simplified asset modelling within the existing NOMs regime and the targeted interventions that we undertake to ensure that we are spending our allowances as efficiently as possible.
197. We continue to look for opportunities to rationalise and decommission equipment where it is no longer operationally required, in order to reduce ongoing costs. All asset health investment undergoes a needs case assessment so that we can be confident that we are investing in the assets that our customers need. During 2016/17 we took the opportunity to rationalise assets at Paull Offtake and to isolate compressor units at Carnforth and Kirriemuir. This holistic approach to asset management leads to projects being funded from a mix of asset health and asset decommissioning which when combined, delivers our risk reduction requirements.

Campaign Approach

198. In previous RRP submissions we have reported on the establishment of asset health campaigns to drive an increase in efficient project delivery. This started in 2015/16 with asset health campaigns delivering work at both St Fergus and Bacton entry points. During 2016/17 we have further developed our campaign approach and our campaigns now represent the majority of our future spend.
199. Through our campaign approach we have been able to accelerate the volume of work that we are able to deliver and we are forecasting in 2017/18 to achieve higher levels of asset health investment on the NTS. Our campaign approach has been successful because we have been able to provide simpler scopes of work for our delivery units, utilise standard designs, streamline project documentation and make better use of available system outages. Without this approach, our work delivery would be constrained by our ability to take outages on the network.
200. Asset health campaigns also provide an “agile” approach to asset health investment. Campaign Decision Panels (CDPs) are used to review the results of surveys and agree the interventions that will be undertaken during the delivery phase, including rescheduling the work if the risk is deemed acceptable.

Key Project Delivery for 2016/17

201. This section of the narrative details key project deliveries in 2016/17. It should be noted that although the projects may largely have completed within the reporting year, the actual NOM count may be reported in next year’s RRP submission.

Pipeline Work

202. In total 671km of pipeline was in-line inspected in 2016 and 47 significant pipeline excavations and repairs were completed from previous inspections in 2015. The selection of the pipelines requiring inspection is driven by a condition and risk based approach, considering pipeline condition, criticality and performance of corrosion prevention.
203. The volume of excavation works to further examine and address defects identified through our 2016 ILI programme has been broadly similar to the 2015 volumes.
204. In 2015, preparatory work was completed on a number of nitrogen sleeves which provide additional protection for our pipelines as they cross under roads, railways and rivers. Using the methodology developed by United Kingdom Onshore Operators Association (UKOPA), we identified the most critical sleeves for intervention. In 2016/17, the project undertook work on 42 of the priority nitrogen sleeves, installing new fill hoses and above ground cabinets on 38 of the sleeves. The remaining four nitrogen sleeves require significant excavation in difficult locations and alternative approaches are being considered.
205. We continue to drive efficiencies within pipeline work, for example through the use of XYZ mapping, a service provided by ILI vendors. It uses a series of reference beacons placed on the ground above the pipeline from which the ILI

vehicle can determine its true geospatial position as it passes beneath them. Combined with the data captured on pipeline condition, this complementary information provides a greater level of accuracy of pipeline and defect location, reducing the time and costs for excavation and remedial work.

Valves and Civils Campaign

206. During 2015 we investigated the best way to accelerate asset health works on the network. Our identified approach is to batch work into asset classes for survey and delivery by contractors with the requisite skill sets. One of these work batches is the Valves & Civils Campaign, which covers a number of NOMs categories. The approach involves undertaking a review of all sites with valve and civil issues on our Plant Status tool. This tool captures issues on assets that require investment to bring back into good condition and allows us to assess issues across our assets and prioritise investment to manage risk on the network.
207. Following a site survey, works proposals are made to a CDP. This panel consists of a number of Subject Matter Experts and representatives from both Delivery Teams and the Investment Sponsor. The CDP allows timely decisions on scope to be agreed and accelerated into detailed design and delivery phases.
208. The campaign set out with the intention of accelerating and resolving 319 Plant Status Issues across 70 sites. The site surveys have highlighted more issues than originally anticipated – these have generally been approved at CDP such that the work can be bundled for efficient delivery whilst onsite, thus minimising mobilisation/demobilisation, design and procurement costs.
209. Surveys and design options were completed over the winter of 2016/17 with physical work planned to commence in summer 2017.
210. During the design options phase, good use has been made of 3D images to quickly explain variations in options at the CDP. This has further accelerated decision processes.
211. We have also been looking at novel approaches to valve actuation that may mitigate the need for manual gearboxes. In 2016 we concluded an innovation project that looked at the possibility of removing or replacing actuators on non-critical valves with more cost effective manual solutions. The project demonstrated that it would be possible to implement a strategy to replace existing actuators on non-critical valves with high efficiency gearboxes. This would provide a cost effective solution particularly with regard to larger diameter valves. We will be looking to trial this strategy as part of our asset health works in the Valves and Civils Campaign in 2017/18.

Figure 6: Shows design option for a replacement Block Valve site with proposed safe site layout during construction



Civil Assets – Pipe Supports

212. Pipe supports carry the weight of the pipeline, valves, etc. and typically comprise a concrete base slab with either a concrete plinth and steel support above or adjustable steel support direct from the base slab. In all cases the support makes contact with the pipeline but needs to allow for potential movement e.g. due to expansion/contraction of the pipeline. This interaction provides the potential for corrosion or damage to pipeline coatings and ultimately the pipeline. The supporting structure also degrades with time; steel supports corrode and the concrete plinths and bases deteriorate. The works on these assets therefore typically involves inspection and repair or replacement of the concrete and steelwork as required. To check for corrosion of the pipeline and to confirm flexibility in the supports, the works include removal of the support around the pipeline, often requiring complete removal and replacement of the concrete plinth.
213. Two pipe support projects reached completion in 2016/17 at ICI Billingham and Enron. Works in this area are now being progressed through the Valves and Civils Campaign.
214. National Grid is progressing an innovation project that looks at potential alternative solutions to existing pipe support materials and design. The first phase of works reviewed existing pipe supports and developed a prototype based on this initial research. This prototype is lighter, stronger and less costly than existing steel supports and therefore makes provision for safer manual handling and reduced corrosion issues. The second phase of works commenced in 2016/17 and will progress the initial prototype through a programme of testing.

Gas Analysers

215. The Gas Analysers that we deploy across the NTS have one of two purposes: to determine the CV of the gas to allow accurate billing of consumers; or to measure

the quality of the gas entering the system to ensure that it can be safely transported and used by consumers.

- 216. Our program of investment into the replacement or enhancement of our measurement capability has continued throughout 2016/17 with the installation and commissioning of systems at St Fergus Entry Point and Hatton Multi-Junction, along with Teeside Entry Point currently in the design phase for delivery in 2017/18.
- 217. During delivery of the works in 2016/17, the project teams have actively sought opportunities to deliver the works efficiently, with examples of combining works with other work to realise savings.
- 218. The investment has delivered enhanced gas quality monitoring through additional analysers and replacement of end of life components, thus improving gas sampling solutions at CV measurement sites across the network.

Figure 7: Typical Gas Analyser Installation



Gas Generators

- 219. Gas Generators are a fundamental component of the turbo machinery train required to drive our fleet of compressors. National Grid has five differing asset types of Gas Generator making up the national fleet of 65 Gas Generators currently in operation across the NTS; in addition we have a number of spare Gas Turbines to provide resilience to the operational units.
- 220. The Gas Generators (commonly referred to as the prime mover) are a combination of light industrial and aero-derivative turbines and are monitored and maintained routinely through a series of work and management procedures carried out by the National Grid operational field force.

221. Gas Generator 'major maintenance interventions' including overhaul, are typically carried out every 24,000 running hours or on condition. Our approach undertaken throughout 2016 has highlighted the need for a number of major interventions. This was largely attributed to the significant increase in demand placed on the fleet of compressor plant and ancillary equipment in 2016/17. This increased demand during 2016 resulted in double the number of compressor running hours compared with the previous year. This level of demand may remain for the foreseeable future.

Unit Control Systems

222. Microprocessor based control systems are fundamental to the operation of the compression plant at Entry Points and compressor stations. The majority of our control systems are modular and we are able to optimise our investment through replacement of component parts as they reach the end of their operational life. Throughout 2016/17 we have made significant investment in the replacement of unit control system modules with major spend at Wisbech and Kings Lynn compressor stations.

Cathodic Protection

223. Cathodic Protection (CP) is applied to buried steel pipelines to prevent the steel from corroding. It is achieved by applying a direct current to the buried steel from an external anode with the result that the anode corrodes. If the CP system is effective then the pipeline inspection frequency can be lengthened, which results in fewer inspections and therefore cost savings.
224. In 2016/17 we have undertaken Close Interval Potential Surveys (CIPS) on approximately 700km of NTS pipelines. The results of the surveys have been analysed and where appropriate remediation activities have been scoped and scheduled.
225. The AGI CIPS survey programme has also been established. These surveys are essential to prove that sites which are not protected by pipeline CP have adequate protection. Surveys were completed on 96% of qualifying block valves, AGIs and compressor stations, with the remaining 4% scheduled for surveying in 2017/18. In total, 56% of sites were fully CP compliant and initial works are underway on the remaining 44% to remediate the defects identified.
226. These programmes of work have required significant stakeholder engagement, in particular with landowners where our pipelines cross their property. Before we undertake any surveys associated with CP, we send out a letter informing them of the proposed dates of our activities. We then work with landowners to agree a suitable timeslot and to coordinate our activities in a way that causes minimal disruption and optimum efficiency.
227. Throughout 2017/18 we will continue to undertake surveys and progress the remediation works identified.

River Crossings

228. The point at which our pipelines cross rivers is a specific hazard that needs to be managed to prevent damage to the pipeline from the action of the water or material suspended in it. During 2016/17 the crossing of the River Leader in the Scottish borders has required remedial work to ensure the safe conveyance of gas through this region of the NTS. For details of the work being undertaken on Feeder 9 UM, please see Section XI – The River Humber Gas Pipeline Project (Feeder 9).

River Crossings: Leader Water

229. In the 2015/16 RRP we reported on the background and progress of the Leader Water river crossing. It was previously determined that the preferred option selected was to install a cofferdam and then use an open-cut trenching technique in parallel to the existing pipeline. This technique would be fit-for-purpose, with the minimum whole-life cost without compromising safety, security, reliability and impact on the environment.
230. To deliver the diversion project significant consultation had to take place with Scottish Environmental Protection Agency (SEPA), Scottish Borders Council, Scottish Government local energy & consents, Scottish Natural Heritage, River Tweed commissioners and local landowners.
231. The diversion project was successfully carried out during April-September 2016, utilising a pipeline outage during the summer, and stopple operations near the project site and Boon AGI.

Preheaters

232. National Grid uses Network Exit Agreements (NExA) as a formal contract with our customers, for example the power station operators. A key part of the NExA is the identification and agreement of performance parameters one of which is the agreed offtake temperature of the gas supplied to the customer. The temperature is agreed based upon design calculations to determine the optimum temperature for the customer's operating plant, ensuring the correct offtake temperature also provides protection to the customer's plant from the impact and potential damage that could be caused by temperature variations.
233. In order to manage the offtake temperature National Grid's plant typically includes the provision of boilers and heat exchange equipment with all the ancillary controls and monitoring to maintain the agreed offtake temperatures.
234. In 2016/17 we installed a new boiler system at Didcot B Power Station and also began works at Keadby Power Station. With regards to the latter, the boiler package is now constructed and we will look to install in 2017/18. A further example of Preheat work undertaken is provided within the Bacton section below.

235. National Grid has identified a further five sites requiring work. A campaign approach will be applied to these works to drive efficiency.

St Fergus

236. The St Fergus terminal is a key gas entry point into the UK which was built in 1975 and is in a coastal environment which accelerates corrosion degradation. In 2016/17 the St Fergus site had 684 Plant Status issues that were being progressed through our investment process. The initial focus has been on existing asset issues that pose a safety risk on the site whilst in parallel we are examining the options for providing appropriate levels of compression capability whilst meeting our environmental targets.
237. The commissioning of the electric drive compressors in 2016 enabled the isolation of Plant 2. This was the first time a significant part of the terminal had been isolated and this was done to allow work to be conducted in an efficient manner on valve vent & sealant lines, pit wall transitions, area refurbishment and valve actuator refurbishment.
238. Once the isolation had taken place it became apparent that the condition of the plant was considerably worse than expected and the scope was much greater than envisaged. Whilst the work was expected to be completed by September 2016, the amount of work and the emerging issues of significant corrosion resulted in the isolation of the plant extending to December 2016. Examples of the issues encountered on site included corrosion on over 60 weldolets which were previously encapsulated to reduce the possibility of stress induced corrosion fatigue.
239. The vent stacks were included in the original scope for the Plant 2 works and following surveys their condition was found to be significantly worse than envisaged. The main Vent Stacks required substantial remedial work and emerging issues of Ring Type Joint (RTJ) corrosion required considerable sections of the nitrogen snuffing pipework to be replaced.

Figure 8: Complete air vent works after blasting, radiography and painting had been carried out



240. The emerging issues across the terminal with the RTJ corrosion prompted an intrusive inspection of the metering scrubber dump tank flanges. These inspections have identified that there are over 100 flanges that require weld build up or replacement on the dump tanks, the scrubbers and their associated assets. Due to the volume of issues the decision was made to remove the scrubbers and dump tanks and to send them off-site for specialist repair.
241. The scope for the Plant 2 works also included the aftercoolers. The inspection of the aftercoolers revealed significant issues that have prevented their re-commissioning; there are numerous flanges on the gas pipework to be replaced, and multiple issues on the cooling fans and their associated equipment such as concrete plinths and support frame.

Figure 9: Metering scrubber tanks flanges - After Inspection of the flanges, all three of the Plant 2 metering scrubber dump tanks and main vessels were found to have significant amounts of corrosion.



242. As part of the Operational Risk Assessments undertaken in late 2016 a number of issues were found with the actuator main system (over 60 Corrosion Management category four defects on the 4km main). Non Destructive Testing (NDT) was undertaken on the worst areas of corrosion.
243. Whilst the primary focus has been on resolving issues with corrosion affecting exposed steelwork, the work on Plant 2 has also provided the opportunity to further develop innovative techniques such as the 'shallow dig technique'. Following a number of excavations and inspections it was discovered that below ground corrosion was only occurring at the 'wind and water line' where the lines break the surface of the ground. Therefore for future vent and sealant line works, the shallow dig policy will be used to only replace part of the pipework i.e. the corroded sections from the 'wind and water line' upwards. This will result in circa 80% cost savings due to the significant reduction in excavation costs and less pipework requiring replacement. It is also significantly safer than the deep dig approach and enables the other serious corrosion issues found at St Fergus to be progressed more quickly.
244. In parallel with the works ongoing on Plant 2, the design works for the replacement of the terminal's CP system have been challenged. In some instances it may be possible to refurbish rather than replace assets therefore rather than replace the whole system certain parts of it have been confirmed fit for future use and will be retained. This has resulted in an anticipated cost saving of 30% (circa £2m).
245. The asset health work at St Fergus has delivered 53 NOMs during 2016/17.
246. The intrusive investigation of condition at St Fergus provides the first major opportunity to discover the real condition of plant that has been in operation for over four decades. This learning will allow us to update our understanding of degradation and better forecast the condition of other sites on the network.

Bacton

247. The Bacton terminal is a key gas entry point into the UK both currently and into the future. It was built in 1969 in a coastal environment which accelerates degradation. Bacton as a site has 237 current Plant Status issues that are being progressed through our investment process. By examination of the risks and consideration of the needs case work at Bacton, we have identified issues that should be prioritised and are considering options to retain safe operation of the site while we complete the final stages of the need case review. At Bacton there is a strong interaction between asset health and the needs associated with future operating scenarios. The current phase of asset health works, Deemed AH-1A scheme exemplifies this interaction. Only those assets deemed ‘Least Regrets’¹⁹ are currently being replaced.

Works Completed at Bacton in 2016/17

Replacement of three valves on Feeder 2 metering

248. In summer 2016 high priority replacement works of three valves in close proximity to IUK was undertaken. This was a necessary replacement activity with a short time constrained outage window, aligned to the IUK outage programme.

Figure 10: Feeder 2 valve removed from Bacton



249. The use of Building Information Modelling (BIM – 3D modelling) was key in achieving delivery of timescales, providing efficiencies during design review processes and thus minimising likelihood of alterations in the delivery phase. The

¹⁹ The assets that are most likely to be required in any future operating scenario

works were successfully completed within the IUK outage and plant returned to service.

250. The removal of the old valves allowed us the opportunity to assess the remedial sealing methodologies utilised in the valves previously. This has proven useful in considerations for future asset health works associated with valves that have been in operation for nearly 50 years.

Bacton Preheat Phase 2

251. The site Preheat system provides heat to the incoming gas supplies prior to them entering flow control equipment to prevent the formation of liquids in the pipework and ice build-up on the external surfaces. There were significant concerns about the condition of the Preheat systems and the scheme was scoped to fast track delivery of those items considered critical to continued safe operation of the Preheat system.

252. The scope delivered works across the 2015/16 and 2016/17 reporting years. Works completed within the 2016/17 reporting period window include:

- completion of pipe and vessel supports for five heat exchangers; and
- reinsulating all the renewed Preheat systems assets

Design works – AH-1A

253. In 2016/17 extensive conceptual design works have been ongoing for the AH-1A scheme. This scheme is set to replace 27 valves identified as not being fit for purpose. This phase is set to commence physical site works in late summer 2017, utilising supplier and customer outages in order to minimise disruption.

254. In addition to the valve replacements, there are considerable painting works to be completed. These works have been sanctioned in March 2017. We are testing the pipework we have previously removed under the Eni scheme to inform us and the wider industry of the condition of some of the older pipelines in the UK of this type.

Future works at Bacton

255. Asset health Scheme AH-1A will be delivered over a four year period due to the need to keep the site operational throughout the works. Further work is planned on valves and actuators and the specifics of this will be based upon the outcome of the Future Operating Scenarios review currently being conducted. Until this review and the resulting works are completed, Operational Risk Assessments (ORAs) will be conducted to ensure the plant remains safe and effective in its operation.

Paull

256. Paull AGI is a shared offtake site between National Grid and Northern Gas Networks (NGN). The configuration of the site meant that at the point of sale to NGN in 2005 the transfer of assets ('Project Blackwater') was different to that on more common offtakes, resulting in National Grid having ownership for additional assets.
257. The existing assets required significant asset health investment as a result of their age and condition. We reviewed the requirements for the site with NGN and developed an optimum solution to rationalise the site into a standard minimum connection. This approach is planned to result in a transfer of assets to NGN.
258. Communication is continuing with Ofgem, in accordance with the Standard Special Condition A27 (Disposal of relevant assets and restriction on charges over Receivables) of National Grid's gas transporter licence in respect to the transfer of part of the operational assets at Paull AGI to NGN.

The rationalisation of the site:

- improves the reliability of the network and removes the safety risks associated with poor condition assets;
 - enables the proposed new Feeder 9 pipeline to enter Paull AGI in a more cost efficient location achieving an estimated saving of £0.9m on the Feeder 9 project;
 - achieves full telemetry and electrical separation from NGN, in line with our current policy; and
 - is consistent with other National Grid distribution offtakes
259. Whilst the majority of works were completed in 2015/16, we have continued working with NGN and our Main Works Contractor (MWC) to deliver the project to a point ready for commissioning, along with, also developing several legal documents (Offtake Agreement Document, Land Lease and Asset Sale Agreement) in preparation for the transfer of assets to NGN (pending the outcome from Ofgem).
260. Based on Ofgem consent, we are planning to start decommissioning the existing poor condition plant during 2017/18. Whereby, the reporting of NOMs for the work will follow in 2017/18 when works have finished.

The River Humber Gas Pipeline Project (Feeder 9)

261. In 2016/17 we have continued to progress the replacement of the Feeder 9 pipeline where it crosses the Humber estuary. This is driven by our continuing concerns over the integrity of Feeder 9 due to rapid and unpredictable estuary movements that are reducing the depth of cover over the pipeline.
262. As the sole transportation route across the river Humber, Feeder 9 is one of the most critical pipelines on the NTS. It plays a pivotal role in the provision of entry

gas from the Easington area to demand centres in the South and East and to the UK gas market as a whole. Network analysis using FES demonstrates that there is a long term requirement for the Feeder 9 pipeline to perform this function.

263. If Feeder 9 was to become unavailable, UK Security of Supply would be significantly impacted and there could be substantial entry capacity buy back costs. Capacity buy back costs and the increase in wholesale gas prices associated with a long term unplanned supply loss would result in increased costs for the industry and the end consumer.
264. Through our strategic optioneering process and extensive stakeholder engagement including a national Development Consent Order (DCO) planning process, we have determined that a replacement pipeline in a tunnel is the most economic and least environmentally harmful long term solution. We are therefore progressing with a replacement pipeline solution as well as continuing to monitor and, where appropriate, conduct remediation activities on the current pipeline crossing.

Existing Feeder 9

265. In 2016/17 the Feeder 9 quarterly monitoring survey results showed significant sediment movement occurring over the three day survey periods, with a number of locations along the pipeline experiencing increased rates of erosion compared to previous surveys. Based on these results, in January 2017 we made the decision to increase the survey regime to every two months so that we could continue to closely monitor the crossing. Latest survey results show that the frond mattress remediation is working as intended, but that some areas of the mattresses appear to be more exposed than other areas. We will therefore continue to monitor every two months and take further remediation action if required.
266. The lease from the Association of British Ports (ABP) to operate the existing Feeder 9 pipeline in the Humber expired in September 2016. Lease renewal negotiations have commenced and the lease will continue to 'roll over' with its existing terms intact until this process is concluded.
267. We have opened negotiations for a new lease for the tunnelled replacement pipeline. Good progress has been made to date and we estimate that the tunnel lease negotiations will be concluded in 2017.

Feeder 9 Replacement Project

268. The Humber estuary is a highly sensitive environmental site with a number of designations including; RAMSAR site, Special Area of Conservation (SAC) and Special Protection Area (SPA). As such, the design development process and planning phases of the project were heavily influenced by the need to manage the constraints associated with these environmental sensitivities. In particular, the risk of saline intrusion was identified on the south side (Goxhill) of the Humber bank, therefore, groundwater management has been identified as a key risk to

the project which we will aim to mitigate through design and installation of a robust de-watering system that is consulted, reviewed and accepted by the Environment Agency (EA).

Figure 11: Environment Agency visit at Goxhill during the pump tests



269. The potential environmental impact of this project meant that planning permissions had to be obtained through the DCO process. In addition, local planning permissions were sought to allow the site enabling works to commence ahead of the DCO decision, to accelerate and mitigate the programme.
270. Whilst planning permissions were being sought, in 2016 we undertook a number of geophysical and archaeological surveys at the site to further mitigate potential programme delays. A number of archaeological finds were discovered which will be donated to a local museum for exhibition.

Figure 12: Remnant of an Early Medieval period (9th/10th Century) domestic pot found at Goxhill.



271. The local planning permissions were secured in May 2016 and the DCO for a tunnelled replacement Feeder 9 pipeline was approved by the Secretary of State ahead of schedule in August 2016. We are continuing to work closely with both Local Authorities (North Lincolnshire Council and East Riding of Yorkshire Council) to discharge the remaining DCO conditions.

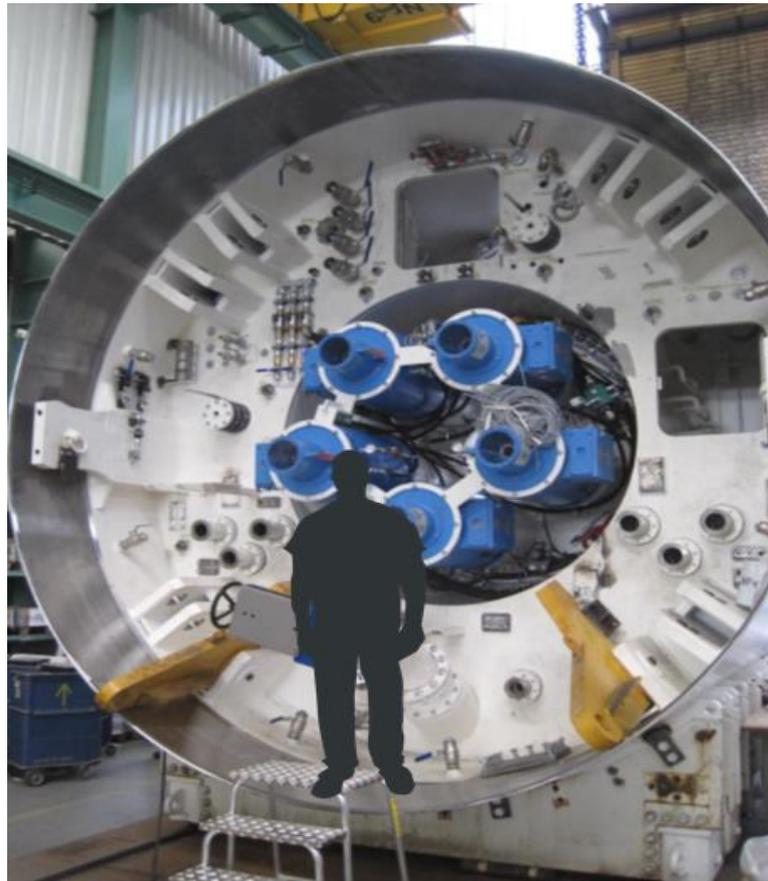
272. In order to establish the site, it was imperative that top soil was stripped ahead of the winter 2016 period to protect the soil structure. The top soil stripping began on the south side of the river (Goxhill) on the 12 September 2016 and was completed by the 7 October 2016 with a total of 38,140 sq.m of top soil stripped.

Figure 13: Stripped top soil at Goxhill to enable site establishment and early works



273. During the development stages of the project, traffic management was consistently raised as a key concern for our stakeholders, including the existing condition of the highway. As part of our DCO submission we developed and agreed a comprehensive traffic management plan that aimed to manage the effects of construction traffic upon the local area. Over the winter 2016 period we focussed on the construction of a series of road passing places in the Goxhill area and the creation of a temporary access road, which will allow better movement of construction vehicles and ease pressure on the existing road infrastructure.
274. The traffic management works have taken longer than originally anticipated, but we have worked closely with our MWC, local authorities and the local community to minimise disruption and address concerns. We have established a dedicated community engagement team, hosted public information drop in events, organised science and engineering workshops with local primary schools and released updated information in regional publications.
275. The passing places in the Goxhill area were completed in March 2017 ahead of the revised schedule and the temporary construction road at South End was completed in May 2017, permitting one way traffic flow.
276. On the north (Paull) side of the river, we negotiated the use of a private farm track to avoid construction traffic through two adjacent villages, at a lower whole life cost than upgrades required to the existing, narrow public highway infrastructure.
277. Due to the challenging ground conditions associated with the river crossing, selecting the appropriate Tunnel Boring Machine (TBM) is vital to the success of the project. Geotechnical data and a robust tendering process were used to assess the potential suppliers for the most efficient TBM. As a result, a 3.65m Slurry Pressure Balanced TBM was selected over an Earth Pressure Balanced TBM. The machine is currently being manufactured in Germany and is expected to be delivered to site for assembly in winter 2017.

Figure 14: Assembly of Main Drive within shield components for the Tunnel Boring Machine



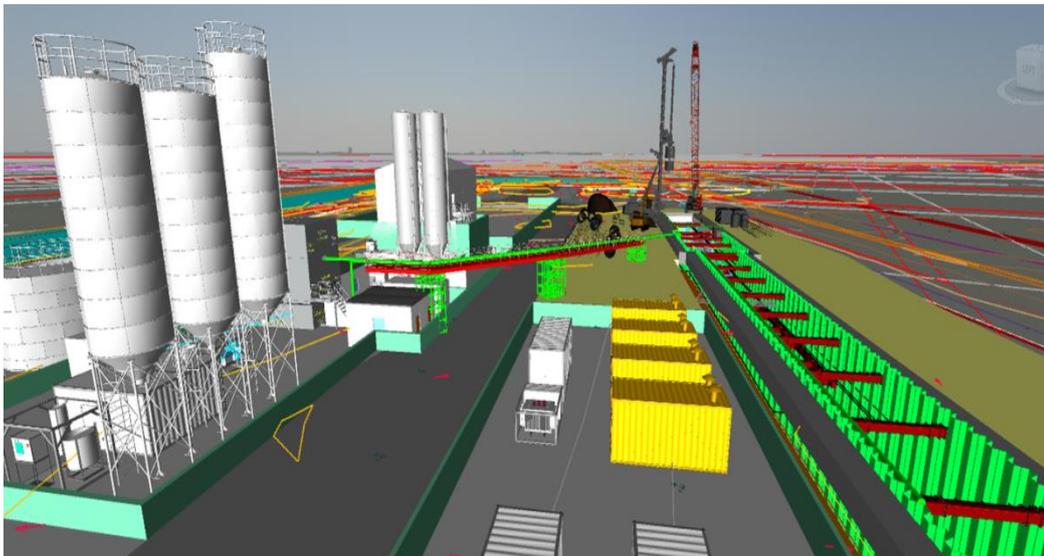
278. Another key activity undertaken in 2016/17 was the development of the CP system and coating of the new pipeline. As the new Feeder 9 pipeline will be sealed in a tunnel, it is important that the CP system chosen is compatible with the pipeline installation, the environment and overall tunnel design. In 2016/17 an optioneering and engineering risk workshop was completed to better inform the design stage. This process was further supported by examination from industry experts. It was concluded that a concrete coated pipeline within an aqueous filled tunnel was the most appropriate solution.
279. Other significant works undertaken in 2016/17 include enabling and site establishment works such as drainage and fencing construction areas; supplementary pump testing to inform the groundwater and de-watering plan; completion of badger and water voles re-settlement and commencement of the piling platform to create the launch pit.
280. In 2016/17 we have made good progress with project delivery but we are behind our original programme schedule. Due to the unique nature and scale of the project we are still in the process of agreeing with our MWC the approach to the CP design which may result in increased project costs. We are working with our MWC to develop a revised programme and to look for opportunities to improve in other areas of the works.

281. Throughout 2017/18 we will continue to prepare the site for tunnel construction activities including full excavation of the launch pit and assembly of the TBM on site in preparation for launch in 2018.

Feeder 9 Innovation

282. The River Humber Gas Pipeline, once constructed will be the longest pipeline in a tunnel in Europe. This unique combination of civil and mechanical construction requires the highest standard of planning. Throughout the project development we continue to look for opportunities to explore innovative ways of working and delivering efficiencies.
283. We have used intelligent 3D modelling developed in the BIM Project (NIA funded) to laser scan, design and assess the existing installations and the traffic management route. The laser scans and 3D models were utilised through design reviews and formal process safety assessments, informing site layouts and performing clash detection in the virtual world prior to construction, reducing project risk. We will continue to use this technology where appropriate to drive efficiencies throughout the duration of the project.

Figure 15: BIM screenshot of tunnel driveshaft and slurry treatment plant at Goxhill



284. Innovation has also been embedded through early engagement with the HSE, EA and lessons learnt from comparable projects. A meeting with the Corrib (Ireland) pipeline team identified the opportunity to build a small above ground section of tunnel, to rehearse utility insertion sequencing as a means of driving efficiency and therefore reducing costs. Through discussions on emergency planning and preparedness with the HSE and Crossrail, there were further benefits identified in the inductions and emergency escape processes.
285. The CP design, installation and operation is another area of innovation. There was previously no CP specification for pipelines in long distance tunnels. Using

NIA funding, a new specification²⁰ was created and has been applied to Feeder 9. The alternative solution considered would have required the entire tunnel annulus to be grouted at an additional cost of £17.5-£25m. The preferred method has been defined as a concrete coated pipe, floated into the tunnel with a water filled annulus and is compliant with the new specification.

Developing our Asset Management Capability

286. We manage our network risk as efficiently as possible, however we recognise that our current approach is more reactive than we would like. Through our ISO55001 accreditation, we are continuously improving our asset management processes to ensure our asset strategies effectively manage risk and deliver value for our customers. A fundamental building block to improving our asset management capability, is our investment in data and technology systems as described in Chapter XII - Non Operational Capex.
287. Improved asset data and technology in conjunction with our new NOMs methodology are key enablers on our journey to asset management excellence. This will enable the planning and targeting of investments, and the reporting of investment outcomes using a monetised risk-based approach.

NOMs Methodology Development

288. During 2016/17 we have developed a new methodology for NOMs and submitted our proposal to Ofgem on the 30 March 2017. This has required a significant input and effort across National Grid, which has been recognised by Ofgem in their initial feedback in May 2017.
289. We still have a number of elements to develop but our initial work has given us confidence that this will be a significant improvement in achieving the methodology objectives (of assessing network risk and prioritising network investment).
290. As part of any development of this kind, our attention now focuses on plans to develop the analytics capability for the methodology so that we can move to a Calibration, Test and Validation (CTV) process to build additional confidence in the outputs. Our aim is to have the analytics capability mobilised for October 2017, with further work being undertaken on CTV during Q3 and Q4.
291. As we have presented to Ofgem over the last year, improvement to the granularity of data and the structure of our data in our core systems is key to ensuring the methodology is fit for purpose to make investment decisions and report our performance. We aim to have the majority of our data collection programme completed in 2017/18 and will be able to base our CTV on the data collected.

²⁰ T/SP/ECP/9 – Specification for design, construction, commissioning and decommissioning of Cathodic Protection systems for carrier pipelines within tunnels

292. We will continue to engage with Ofgem during 2017/18 regarding our methodology development plans and work to ensure the merits and benefits of this approach are understood both internally and shared with our stakeholders during 2018.

Data

293. The improvements to our approach of asset management together with the anticipated demands of the new NOMs methodology require a significant enhancement of our asset data and investment in our asset management technology systems and data analysis capability. To achieve this we are progressing two major improvements:

Asset Data Enhancement

294. This programme will deliver enhanced asset data to support an improved asset management approach and a NOMs methodology based on monetised risk, including:

- ensuring that all of our assets are correctly recorded to an appropriate level of granularity in our core asset management system; and
- ensuring that we have consistent and coherent data in the appropriate structure that allows adherence to our internal data quality standards with the appropriate controls

295. Work is now progressing and to date asset data has been verified at 51 sites following a robust quality assurance process and is being uploaded into the core asset management system.

296. A schedule to verify the data at the remaining 485 sites is in place and we are planning to complete all works by June 2018. Once complete the central asset register held on core systems will have been validated and updated driving greater asset management capability and will support the new NOMs methodology.

Transformation Programme

297. This programme will deliver enhanced asset management, investment management and data analytics capabilities whilst assuring verified data from the asset data enhancement activity is successfully uploaded into core asset management systems. The programme will also review and put in place an enduring data capability to ensure the Gas Transmission asset data is appropriately managed and maintained into the future.

298. These developments are partially system related Non Operational Capex and partially Opex business change activities. The benefits of these projects will be realised in 2018/19 and beyond. These projects will support the development of our NOMs methodology, development of our future business plans and provide insight into the management of network risk at least cost.

Decommissioning (formerly Quasi-Capex)

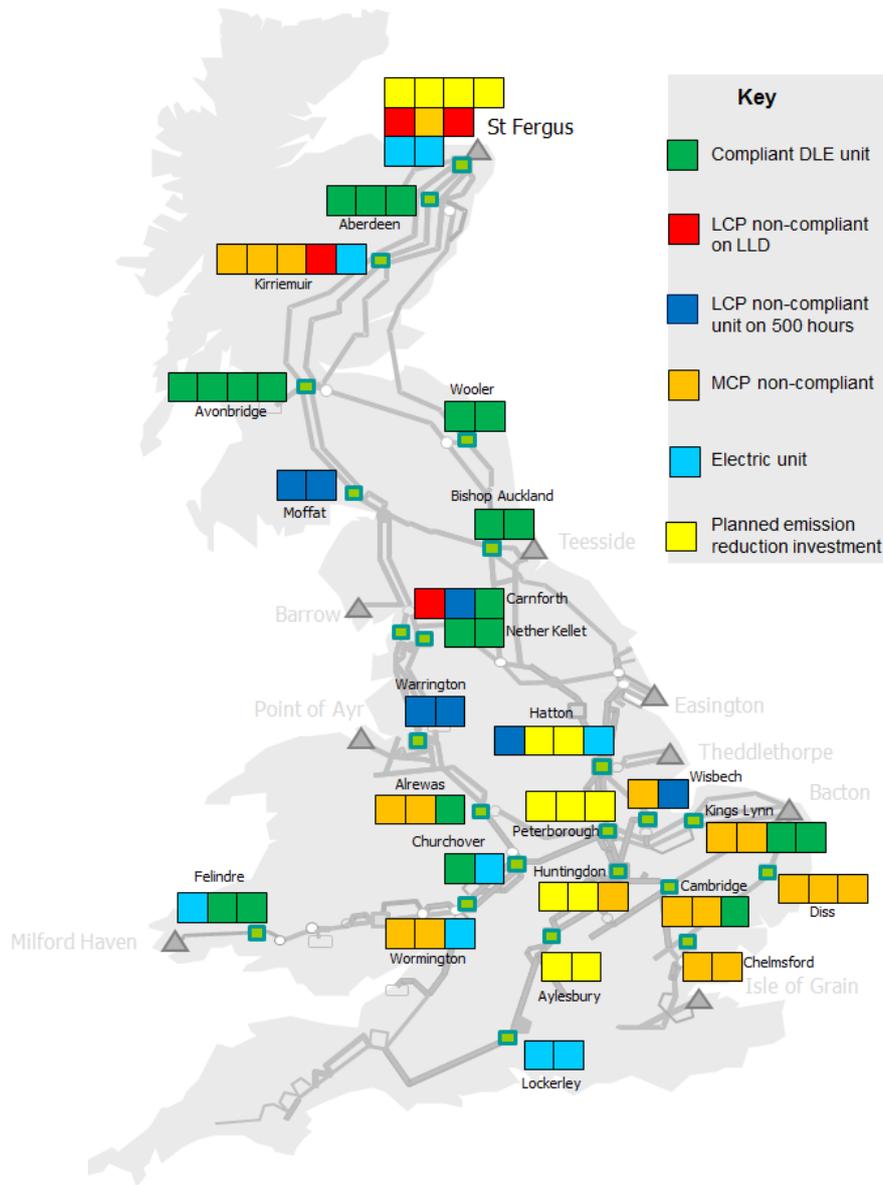
- 299. As our network changes, some assets are no longer required for operation whilst others can be rationalised reducing the asset health investment on these sites.
- 300. Carnforth Unit A and Kirriemuir Unit D have both been isolated from the network due to the condition of the units.
- 301. Plans to disconnect Churchover Compressors units A and B have progressed in 2016/17 and a strategy has been identified to physically isolate the units in accordance with National Grid policies and procedures.
- 302. The majority of spend in this area in 2016/17 has been related to works associated with Paull rationalisation.

Emissions

- 303. This section covers all emissions related work that we have progressed throughout 2016/17. We have arranged the narrative based on project progress and by the applicable legislation. By the end of 2016/17 Operational Acceptance for all IPPC Phase 2 units has been achieved with only minor works on the electric VSD at Kirriemuir outstanding. In 2016/17 we also made good progress on the IPPC Phase 3 and 4 projects at Peterborough and Huntingdon.

304. Figure 16 below shows the current status in terms of compliance with relevant legislation for each of our compressor units.

Figure 16: Map showing compliance status of National Grid’s Compressor Fleet



IED - IPPC Phase 1 St Fergus

305. Phase 1 of our emissions reduction strategy identified St Fergus as a priority site for investment. This led to the initiation of a project to install two compressor trains, each driven by a 24MW electric VSD which were operationally accepted in June 2015 and have been in service for the majority of time since then.

Table 6: St Fergus run hours by unit type for 2016

Driver / Technology Type	Individual Unit Running Hours (calendar year)				
	2012	2013	2014	2015	2016
Avon 1533	6,987	6,902	6,647	5,421	3,535
RB211	4,255	5,893	2,605	2,604	785

Electric VSDs	N/A	N/A	N/A	2,618	8,179
Total Running Hours	11,242	12,795	9,252	10,643	12,499

IED - IPPC Phase 1 Kirriemuir

306. Kirriemuir was also identified as a priority site as part of Phase 1, resulting in a project to install a single 35MW electric VSD compressor train.
307. The recent increase in flows from St Fergus terminal has removed the previously identified need to re-wheel the compressor (in the short term). Asset health works which would have been included within the scope of the re-wheel project will now need to be undertaken as a separate project.
308. During the summer of 2016, operation of unit E was constrained by feeder outages for essential maintenance work south of the compressor. As a result unit E has only been run for two hours of testing during 2016.

Table 7: Kirriemuir run hours by unit type for 2016

Driver / Technology Type	Individual Unit Running Hours (<i>calendar year</i>)				
	2012	2013	2014	2015	2016
Avon 1533	996	456	169	804	2,662
RB211	1,756	157	176	3,962	712
Electric VSD	N/A	N/A	N/A	478	2
Total Running Hours	2,753	614	345	5,244	3,376

IED - IPPC Phase 2 Hatton

309. Phase 2 of our emissions reduction strategy identified Hatton as the next priority site for investment. Investment at Hatton was approved in September 2008 to install a 35MW electric VSD compressor train and bundled works on site.
310. The unit achieved Operational Acceptance on 3 February 2016. Final noise surveys revealed some noise attenuation and vibration issues that required works before full asset acceptance could be achieved. The unit is now providing base load compression at the site following remedial work to resolve pipework noise issues and agreeing with the local planning authorities that the achieved noise levels are acceptable.
311. Asset Acceptance is forecast to be achieved in 2017. We are now progressing financial close out, which will allow the formal project closure paper to be written.
312. Run hours for the electric VSD (unit D) in 2016 were 1,787 hours.

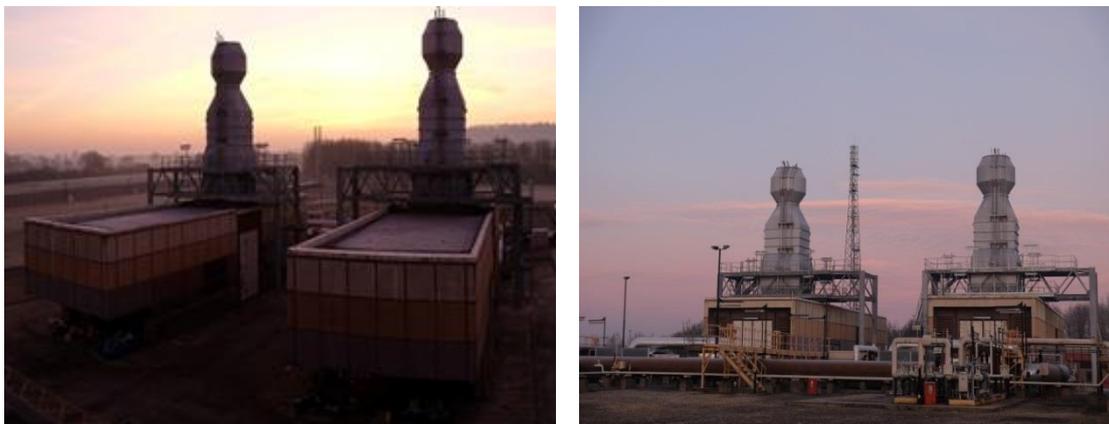
Table 8: Hatton run hours by unit type for 2016

Driver / Technology Type	Individual Unit Running Hours (<i>calendar year</i>)				
	2012	2013	2014	2015	2016
RB211s	1,705	2,936	2,184	3,279	4,068
Electric VSD	N/A	N/A	N/A	N/A	1,787
Total Running Hours	1,705	2,936	2,184	3,279	5,855

IED – LCP²¹ Phase 1 Aylesbury

313. National Grid operates two Rolls-Royce Avon 1535-190G DLE gas turbine driven compressor machinery trains at this site (units A and B). The two units are prototype DLE engine units that were installed in 1999; however, this upgrade path was never commercially adopted and these units remain the only ones of their kind in service. The Avon 1535-190G DLE engines are compliant with the 'existing plant' Emission Limit Values (ELVs) contained in the IED for NO_x but are not compliant with the equivalent levels set for Carbon Monoxide (CO) across the full range from 70% to 100% load (as required by the IED).
314. In the 2015/16 RRP we reported on the progress made to complete the detailed design of the catalyst installation, with construction works underway. The construction phase of the catalyst installation was completed in Q4 2016 as planned. This included the construction works directly associated with the modified exhaust stack and supporting structural work, along with associated site modifications deemed necessary in support of the catalyst solution and our operational requirements for the site.

Figure 17: Exhaust stack and catalyst abatement system at Aylesbury compressor station



²¹ Large Combustion Plant

315. Unit B was successfully commissioned to Operational Acceptance stage in Q1 2017. The catalyst solution has been proven to be operating at circa 98% efficiency level during working conditions.
316. Unit A is expected to move from its commissioning phase to operational acceptance in Q2 2017, following the conclusion of asset health works. Asset acceptance and project closure is expected to conclude by Q1 2018.
317. Aylesbury has now received full permit variation confirmation for the new facility and its operating conditions. We have worked constructively with the Environment Agency to achieve this outcome, including approval of a new Continuous Emissions Monitoring System which formed a key part of the project's delivery requirements.

IED – LCP Phase 2

318. Our plans to achieve compliance with the requirements of the IED-LCP legislation have evolved since the submission of our initial RIIO-T1 business plan. We have been able to make greater use of the derogations within the legislation, allowing us to retain units on the network rather than building replacements.
319. We are investing in asset works on these derogated units in order to ensure their continued safe and efficient operation in line with engineering policy. This work was not included within our RIIO-T1 business plan, however it represents a more economic option than replacement, resulting in reduced costs for consumers.
320. The following sections give a brief overview of the works at each LCP Phase 2 site, building on the proposals from our Integrated Emissions Plan submitted in May 2015.

IED – LCP Phase 2: Wisbech

321. At the start of the RIIO-T1 period Wisbech consisted of two machines, one RB211 and one Maxi Avon, neither of which were compliant with IED-LCP.
322. At Wisbech, we proposed in our Integrated Plan to retain the RB211 unit A on the 500 hour derogation, to exchange the gas generator in unit B from a Maxi Avon to an Avon (by 1 January 2016) and to undertake asset health works on the station. This approach has been followed and the necessary approvals and permit variations have been granted by the Environment Agency.
323. Asset health works associated with retaining the existing units are planned to be undertaken between 2017 and 2019. The continued availability of compression at Wisbech provides network resilience and facilitates outages required to deliver works at Peterborough, Huntingdon and Hatton.

IED – LCP Phase 2 Carnforth

324. Carnforth consists of three units. Unit A and B are both RB211s which are not compliant with IED-LCP emissions limits. Unit C is a compliant DLE machine.

325. Our strategy for Carnforth is to use Unit C to provide the operational capability required, making use of the physically adjacent Nether Kellett site (consisting of two smaller compliant DLE machines) to provide the required backup.
326. Carnforth and Nether Kellett cannot currently be effectively configured so to achieve this strategy requires minor site reconfiguration works to be undertaken. This is a more economic solution than retaining Carnforth units A and B to provide backup.
327. We entered unit B into the 500 hours derogation and unit A into the Limited Life Derogation (LLD). We have since taken the decision to close Unit A, undertaking asset health works on Unit B to ensure continued availability of backup until the site modification works have been completed.
328. Unit A is physically disconnected from the compressor station pipework and is not available for use within the NTS. The unit remains on site and we are reusing parts as spares to lower the cost of maintaining unit B.

IED - IPPC Phases 3 and 4 Peterborough and Huntingdon

329. At the start of the RIIO-T1 period, both Peterborough and Huntingdon consisted of three Avon machines each. We continue to advance the programme of works to deliver new gas turbine compressor units at each site under IPPC Phase 3 and Phase 4, as required to maintain efficient transmission capability across the centre of the network and to meet south west exit capacity obligations.
330. The programme of works was sanctioned internally in Q3 2016, including core and extraordinary work scopes. Extraordinary costs include items such as new station control buildings and new electrical supplies. Extraordinary costs accounted for 22% of sanctioned costs at Peterborough and 19% at Huntingdon respectively.
331. Also to be delivered within this programme is £27m of Asset Health works; this is financially separate from IPPC Phase 3 and Phase 4 core and extraordinary work scopes, but bundling presented a significant opportunity to leverage outage and project management efficiencies.
332. We previously reported successful completion of the Feasibility and Conceptual stages of the Front End Engineering Design (FEED) studies in 2015/16; the output of these FEED studies formed a critical component of the tender package used to appoint a MWC in 2016/17.
333. Also reported previously, planning consent was granted for Huntingdon in Q1 2016 at the first application. Peterborough gained planning consent in Q2 2016 following a second application to include significant enhancements to the visual impact of the compressor trains, in response to external stakeholder feedback on the original (rejected) application.

334. The competitive tender event to select a MWC was launched in Q1 2016 with three Engineering, Procurement and Construction (EPC) contractors shortlisted; during the process one party withdrew due to unforeseen circumstances which left two bidders competing throughout the summer. The procurement event concluded in Q4 2016 with the appointment of Costain Oil & Gas.
335. The MWC's design team mobilised through Q4 2016, with good initial progress made on their detailed design and procurement activities. A number of design opportunities identified by National Grid as part of the procurement event were also investigated by the MWC during this time; these were areas where further efficiencies could potentially be realised through detailed engineering beyond the level to which was achieved during FEED. One example was minimising, as far as practicable, the need for buried concrete pits for header pipework, resulting in both cost and carbon savings.
336. The MWC will mobilise to site at Huntingdon in Q2 2017, and to Peterborough in Q4 2017, to prepare the sites ahead of taking delivery of the compressor machinery train packages from Solar Turbines in Q3 2017 at Huntingdon and in Q3 2018 at Peterborough.
337. Following their appointment in Q4 2014, Solar Turbines undertook their detailed design activities throughout 2015/16 for the gas compressor machinery trains and bespoke low noise enclosures. This process identified an extraordinary cost required to meet strict far field noise limits set out within the respective planning consents. Manufacture of the low noise enclosures for Huntingdon commenced in the UK in 2016/17, with Peterborough to follow in 2017/18. The gas compressor machinery trains will be manufactured and tested in parallel in the USA during 2017/18 prior to shipment and delivery for the above dates.

Figure 18: Aerial photo taken September 2016 mid-way through the Huntingdon Early Works delivery



338. In 2015/16 a separate competitive tender was undertaken to appoint a contractor to deliver the Huntingdon Early Works in 2016/17 in line with the project delivery strategy; this event was delivered in parallel with the MWC procurement event. J Murphy & Sons were appointed in Q1 2016, mobilising to site in Q2 2016 to commence the installation of a new station vent stack and new station valve arrangement, and remove the station after-coolers and existing station vent stack to create space for the new compressor trains.
339. Huntingdon Early Works was successfully delivered; the works were executed safely, with zero injuries and the project consistently averaged positive scores from monthly Safety Leadership visits. The works were delivered below our forecasts and the site was declared operationally available for winter running ahead of the planned return to service date.
340. Activities successfully completed across 2016/17 keep both projects on schedule, with operational acceptance of the new units scheduled for 2020 at Huntingdon and for 2021 at Peterborough.
341. We are currently reviewing the overall compression requirements at both of these sites and at present our investment plan includes in total, three new units at Peterborough and two new units and Huntingdon. Further detail of our updated plans will be provided in the May 2018 reopener.

IED - IPPC Phase 4 and IED – LCP Phase 2 St Fergus

342. St Fergus comprises of three plants; four units at plant 1, three units at plant 2 and two units at plant 3. Plant 1 comprises of:
- four Avon 12.34MW gas generators coupled with GEC EAS1 power turbines (units 1A, 1B, 1C and 1D)
343. Plant 2 comprises of:
- two RB211 21.2MW gas generators coupled with GEC ERB1 power turbine (units 2A and 2D); and
 - one Avon 13.97MW gas generator coupled with GEC EAS1 power turbine (unit 2B)
344. Plant 3 comprises of;
- two 24MW Electric VSD (units 3A and 3B)
345. The gas driven compressors at St Fergus are required both to supplement the operation of electric drives and to provide backup capability. Unlike our other compressor stations, St Fergus' position as an entry point means that it is not possible for other sites in the network to provide backup. If compression is not available on site, gas cannot enter the network from one sub-terminal, and has to be emitted through flares offshore. As a result there is a requirement for more backup capability than at many of our other stations.
346. Our strategy for St Fergus proposes a programme of work, which both addresses the LCP requirement and continues to reduce our fleet emissions in accordance with our IPPC obligations.
347. In terms of LCP, we gained approval from SEPA to enter the RB211 units, 2A and 2D, into the LLD from 1 January 2016.
348. With regard to IPPC, our latest strategic options assessment indicates that four additional new gas turbine compressor units are required. These would reduce emissions (in accordance with IPPC) and supplement and provide backup for the VSDs post 2023 when the two RB211 compressor units (currently operating under the limited life derogation) can no longer be used.
349. A Basis of Design Document (BoDD) with the main pre-feasibility inputs (process duty requirements and preliminary Formal Environmental Assessment studies) is substantially complete. This will inform the Feasibility stage of the Front End Engineering Design (FEED) for the remainder of the year, leading to OEM Conceptual Award currently planned for 2018.

IED – LCP Phase 2 Hatton

350. Hatton is a high utilisation compressor station enabling the efficient movement of gas from the northern and east coast terminals towards demand centres in the south of the network. In addition to the electric VSD, the site consists of three RB211 machines which both supplement the VSD and provide backup capability. The RB211s are IED-LCP non-compliant.
351. The initial option proposed at Hatton was to enter all three existing RB211 units into LLD and then replace them with three smaller units. We revised our plans, entering one of the existing units into the 500 hours derogation and the remaining two units into the LLD commencing 1 January 2016. This decision was based on the positive progress of the electric VSD unit which was operationally accepted in February 2016. Entering one unit into the 500 hours derogation provides us with flexibility in terms of the future solution for the site and extends the potential construction window for any new units.
352. Option development for Hatton is progressing well. A Basis of Design Document (BoDD) with the main pre-feasibility inputs (process duty requirements and preliminary Formal Environmental Assessment studies) is substantially complete. This will inform the Feasibility stage of the Front End Engineering Design (FEED) for the remainder of the year, with OEM Conceptual Award currently planned for 2018. Our current investment plan includes three new units. Further detail will be provided in our May 2018 reopener.
353. Work at Hatton will follow Peterborough and Huntingdon due to outage requirements.

Kirriemuir

354. Kirriemuir consists of five units in total. Units A, B and C are Avon machines (which will not meet the requirements of the MCP Directive), Unit D is an RB211 (non-compliant with IED-LCP) and Unit E, the recently constructed electric VSD. The station provides North-South transmission capability.
355. At Kirriemuir we originally proposed to:
- Enter unit D (RB211) into the LLD, followed by decommissioning once the available hours were exhausted or at the required legislative deadline;
 - De-rate and re-wheel unit E (in response to projected future operating conditions); and
 - Decommission and replace unit C
356. However, this plan was based on the draft MCP Directive requiring all non-compliant units to be addressed by 2025. Subsequently, in part due to our international lobbying, this deadline has moved back to 2030 in the final Directive. In response to this, and as communicated during Ofgem's IED consultation, we have put on hold the decommissioning and replacement of unit C.

357. In March 2016 there was an in-service failure on unit D which would have required significant asset health expenditure to bring the unit back into operation. Given the LLD status of the machine, it was uneconomic to repair therefore the unit was disconnected from the NTS.
358. The recent increase in flows from St Fergus has removed the need for re-wheeling of unit E in the short term. This position will be kept under review. A certain amount of asset health work which was to have been included with the scope of the re-wheel project will now be undertaken as a separate project.

Moffat

359. Moffat consists of two RB211 units (A and B) which are not compliant with IED-LCP. The proposed option was to utilise the 500 hour derogation for both units and undertake necessary asset health works to ensure the condition of the units is appropriate for the required duty and compliant with policy. As per the proposal, the derogations have been obtained from the EA and the asset health works are being planned.
360. The recent increase in flows from St Fergus has led to significantly higher running hours for Scottish compression. Against this background the continued availability of Moffat provides valuable resilience and facilitates network access to maintain other compression sites.

Warrington

361. Warrington consists of two RB211 units (A and B) which are not compliant with IED-LCP. The proposed option was to utilise the 500 hour derogation for both units and undertake necessary asset health works to ensure the condition of the units is appropriate for the required duty and compliant with National Grid Policy. As per the proposal, the derogations have been obtained from the EA and the asset health works are being planned.

Diversions (non-customer funded)

362. National Grid has various agreements for the location of our pipelines (e.g. Deed of Easement or Deed of Grant) so that we can undertake maintenance and gain access to the asset. A number of these easements contain existing liabilities or other obligations to divert pipelines, for example "lift and shift clauses". In some instances we are required to pay the costs associated with the pipeline diversion.

Willington Down Feeder 7 Diversion

363. A historical Deed of Grant agreement exists requiring, at the developer's request, that we fund the protection or diversion of approximately 1.4 km of Feeder 7 pipeline between the Chalgrove and Didcot Power station pipeline. A Conceptual Design Study was completed between October 2014 and March 2015 to outline the various pipeline diversion options. The preferred route was submitted to the HSE for discussion at a meeting in May 2015 with all parties.

The developer agreed with the diversion route and to develop the terms for the easement, and submitted a planning application to the local authority with a view to do the diversion works in 2017.

364. The detailed design was developed throughout 2016, with construction of the pipeline planned for summer 2017, completing in September. We have worked with the developer to identify and deliver efficiencies in construction, e.g. avoiding duplication or additional civil engineering by making the pipeline project's site access the groundwork for the permanent access to the development; and ensure that the diversion route is fit-for-purpose while accommodating the future needs of the developer.

Diversions (customer funded)

365. National Grid has various agreements for the location of its pipelines so that we can undertake maintenance and gain access to the asset. Some of these types of deeds do not have extra liabilities and thus the developer pays for the diversion on a cost pass-through basis. At all times we endeavour to work with developers to ensure costs are kept to a minimum.

Norwich Northern Distributor Road

366. Norfolk County Council (NCC) had been in discussion with us for a number of years exploring its options for a proposed new road scheme. Initial drawings provided by NCC indicated that two NTS pipelines would require diversion to meet the current requirements of IGEM/TD/1²². At an early stage, we offered alternatives for one of the pipelines affected, trying to avoid a costly diversion. This led to a redesign of the road by NCC to comply with TD/1. The cost saving was estimated to be £2m to £3m.

367. Following collaboration meetings with NCC covering design and programme planning, the diversion of the Feeder 3 pipeline commenced in April 2016. A full pipeline outage was utilised, avoiding the need for an expensive stopple operation. The gas was recompressed to the pressurised pipeline, minimising the need to vent the gas to air. After commissioning the new pipeline, the existing pipe section was removed, demobilising from site in September 2016. With close collaboration with NCC, cost savings were achieved by avoiding duplicated effort e.g. excavation works and environmental studies. We received positive feedback from NCC who stated that, "The Service has been excellent, there is nothing I can think of that they could have done any better".

Morley Carr Farm & Tall Trees, Yarm

368. Two housing developers approached us seeking to develop land at Morley Carr Farm and Tall Trees. Separate meetings were undertaken with the developers,

²² This industry standard describes the design considerations for new roads constructed over or near high pressure Gas Transmission pipelines

with their initial site drawings indicating that the Feeder 6 pipeline required diverting through the development with thick-walled pipe, to be compliant with TD/1. Following further meetings with the developers, the final designs were agreed. One design had been developed earlier than the other, but when the National Grid project team saw the benefits of completing the projects at the same time, they accelerated the design process for the second diversion.

369. During the design stage, and with the collaboration of our stakeholders, further financial saving opportunities were possible e.g. bundling works together into the pipeline outage including a pipeline remedial inspection and site maintenance works. Additionally, the original proposal was to complete the individual diversions by utilising a double stopple operation to meet the original customer completion dates, but by analysing opportunities, we managed to plan a pipeline outage period that removed the need for a stopple operation.
370. The construction works took place between April and September 2016. The diversion project delivered savings of circa. £1.4m, providing a credit back to the customers from the original project budget estimate. In addition, the bundled works allowed a saving of approximately 300,000m³ of gas being vented to atmosphere. This was achieved by the use of recompression units.

Figure 19: Diversion Works at Tall Trees and Morley Carr Farm Project



Enhanced Physical Site Security

371. The Physical Security Upgrade Programme (PSUP) is a government mandated initiative to enhance physical site security. All works are closely evaluated by government assigned bodies.

372. BEIS completed a review of National Grid sites in 2014. There were 68 sites requiring PSUP works which were formalised in a letter from BEIS dated 19 May 2015.
373. Phase I sites refer to 41 sites which were identified by BEIS prior to the site review in 2014. A further 27 sites were included by BEIS following completion of the site review which concluded in May 2015; these form the Phase II works.
374. National Grid made a reopener submission to Ofgem under the Gas Transmission Licence, Special Condition 5E in May 2015 to request funding for the PSUP works at the 68 sites identified by BEIS.

Phase I

375. All 41 Phase I sites were completed as of 3 March 2017. Spend on Phase I is broadly in line with the May 2015 reopener submission at £72m.

Phase II

376. 20 of the 27 Phase II sites are currently progressing well and the project services contract has been awarded. Four of the 20 sites are at an advanced stage of detailed design and 16 of the sites are currently progressing through the FEED stage.
377. The latest cost forecasts have reduced from £126m to £102m. These cost reductions are the result of:
- the work being let in two lots which provided a sufficient volume of work and programme visibility to the bidders which drove costs down. The lots were geographical which allowed for efficient resource allocation and a reduction in preliminary site costs;
 - National Grid developing a lean internal and project services management structure which has significantly reduced the overall management overhead for project delivery;
 - each site now having a Site Specific Operational Requirements document developed and surveys completed, this has defined scope requirements and resulted in improved cost forecasts; and
 - a full review of the Technical Standards being undertaken which rationalised multiple specifications into refined "Signature Solutions".
378. Since the site list was finalised in May 2015 National Grid has completed systematic reviews of each site. This review approach ensures that any change in network use is accounted for. As a result seven sites are currently under review and are being discussed with BEIS to confirm if PSUP solutions are required. If BEIS agree that these sites no longer require PSUP solutions then the funding received for these sites will be returned as part of the May 2018 reopener.
379. As part of the systematic site review a number of potential additional sites have been identified. These are currently under review with BEIS. If BEIS believe

PSUP solutions are required then these additional sites may be proposed to be delivered by March 2021 and so could form part of the May 2018 reopener.

Shared Sites

- 380. There are 22 sites owned by a third party which contain National Grid assets that were identified as PSUP sites in 2015. These shared sites were included in the BEIS letter in May 2015.
- 381. The operational and funding arrangements for these shared sites was not finalised prior to the May 2015 reopener so the 22 shared sites were excluded from the submission. The funding arrangements were agreed in November 2015 and will form part of National Grid's May 2018 reopener submission.
- 382. Of the 22 sites, National Grid is responsible for funding and delivering nine of these sites by 31 March 2021. Discussions with the relevant third party owners are underway with initial site assessments due to be completed by December 2017. The current cost estimate for the shared site work is £43.8m.
- 383. At one site funding is being split between National Grid and the site owner, although the site owner will be delivering the works. National Grid's assets have a footprint of 28% on site.
- 384. The remaining 12 shared sites where National Grid assets have a footprint of less than 25% of the site are being funded and delivered by the third party site owners by 31 March 2021.

Site Extensions

- 385. There are two National Grid sites where site extensions are required to accommodate additional assets as part of the IED compressor replacement works. As a result the PSUP solution needs to be extended at both sites.
- 386. These site extension works were not included in the May 2015 reopener as the PSUP solution and costs were not sufficiently developed at the time of the submission. These costs will form part of our May 2018 reopener submission.
- 387. The conceptual FEED design is currently underway for both sites. The detailed designs for both sites are expected to be completed by December 2017. With the site extension works due for completion by December 2019. The current cost estimate for the PSUP extension work is £7.5m.

XII. Non Operational Capex

Introduction

388. This section covers our Non Operational Capex investment. In 2016/17 our expenditure was £22m and our updated forecast for the eight years is £137m compared to an allowance of £67m. Compared to last year our forecast has increased by £16m in real terms, due to the increasing requirements associated with the systems and data needed to support the management of the asset health of our network and the implementation of a new NOMs methodology. This is described in greater detail within Section XI. The two programmes, Transmission Foundation Systems (TFS) and the Transformation Programme, are designed to deliver these requirements in future years and we spent £16m on those programmes during 2016/17. The programmes represent the culmination of a number of programmes referenced in previous years, namely TFO (Transmission Front Office), SAM (Strategic Asset Management), TCR (Technology Change Roadmap) and GAIoS (Gas Asset Information Systems).

Transmission Foundation System

389. TFS focussed on the system-health replacement of our core asset management systems, including Ellipse Enterprise Asset Management solution and ESRI Geospatial Information System. The priority of this was to replace our legacy core systems enabling the continuation of our planning and work delivery. These core systems are used by both Electricity and Gas Transmission. TFS is providing the like-for-like replacement of the common elements of the IT infrastructure and was implemented on 30 May 2017.

Transformation Programme

390. The Transformation Programme delivers the National Grid requirements that build on TFS and increases the capability of the asset management systems through modification of data structures and improved system functionality to enable a number of strategic priorities. These include:

- easy access to better data through enhanced structures;
- improved analytical reporting tools to model condition data and degradation trends;
- fast-tracking of asset health outturn planning; and
- improved investment planning and delivery and enhanced compliance

391. We are currently undertaking a detailed design and will commence implementation following approval of the associated business case.

392. The Transformation programme has replaced the GAIInS programme and is focused on delivering a sustainable, efficient approach to asset management across people, process, technology and data. The business case expected in October 2017 will set out the required Non Operational Capex investment for the remainder of RIIO-T1 ensuring any investment is necessary, efficient and drives value for customers and stakeholders.
393. Throughout 2016/17, we successfully implemented a number of mobile solutions that drive greater field connectivity and coverage, a new analytics platform that gives the ability to quickly analyse large data sets and make better informed asset management decisions and the implementation of an Investment Management database.

XIII. Capital Expenditure (SO)

Introduction

394. This section covers our SO Capex investment. In 2016/17 our expenditure was £32.9m and our updated forecast for the eight years is £280m compared to an allowance of £323m. Forecast allowances are £29m lower in real terms compared to last year due to a change to Xoserve Capex allowances following Ofgem's recent review.
395. The SO Capex forecast has reduced by £25m compared to last year on a constant 2016/17 price basis, driven predominantly by a change in our Gemini strategy. This change reflects our commitment to prioritising investments that will deliver value to our customers at the pace they value during a period of increased industry change. Looking forwards, we will continue to review our plans in light of these changes to ensure the overall investment portfolio delivers the optimal balance of customer value and future risk mitigation.
396. Our main areas of spend in 2016/17 have been:

iGMS Evolution Programme (iEP)

397. IEP was a critical multi-year project which replaced our Gas Transmission monitoring and control system and delivered a new suite of reporting and analytics applications. In 2016/17 £10.8m was spent on iEP.
398. The new system, called GCS, was commissioned to plan in September 2016 following a transition from the outgoing iGMS system which has now been decommissioned. GCS comprises a number of new applications which will enable our ability to support future change and growth.
399. GCS is built on a modular architecture which reduces the complexity of future enhancements. This "evergreen" maintenance approach will ensure that both software and infrastructure components are kept in step with the supplier's maintenance releases and patches, reducing the need for large scale upgrade projects. It also supports an agile approach to delivering system enhancements, reducing the time and cost of delivering change. These two features also help to reduce the total cost of ownership of the new solution. Work is ongoing to deliver our first set of enhancements using this approach.
400. The new reporting and analytics capability also allows us to rationalise our data management and reporting, reducing the need for offline tools and the associated potential data inconsistencies.

Telemetry

401. Telemetry systems allow us to monitor and control the flow of gas through the NTS; they consist of telemetry outstations and the communications network

which connects the outstations to GCS. This facilitates safe operations and ensures the quality and quantity of gas meets consumer requirements.

- 402. With total spend of £3.2m, 2016/17 saw the Phase 3 roll out of the telemetry replacement programme as well as procurement of a new solution for future phases to comply with EU regulations.
- 403. Throughout the RII0-T1 period we will be investing in refurbishment and replacement of telemetry outstations in order to manage the risk of asset ageing and obsolescence. We continue to review the drivers for Distribution Network separation at telemetry sites focusing on a risk based approach which will provide efficient investment for customers.

Gas Remote Sites Communication (GRSC)

- 404. The existing Ulysses Telemetry network is reaching the end of its life and is being replaced under the Gas Remote Sites Communication project (GRSC). This project is drawing to a conclusion with the first steps to switching off the old Ulysses Telemetry Network (UTN) starting in June 2017, with a planned completion in September. In 2016/17 we have spent £3.3m on this project.
- 405. The new network provides a communication service between the GCS and our remote telemetered outstations, to monitor and regulate the flow of gas. The programme has delivered benefits including improved reliability, compliance and availability and provides a far more secure cyber solution. It will also serve to reduce the running costs of providing a telemetry service.

Market Facilitation – Xoserve

- 406. In 2016/17 £3.1m was spent on the delivery of system enhancements to support the implementation of new EU codes which ensures we meet our EU legal and regulatory obligations.
- 407. During the year, our EU Phase 3 project was completed which implemented changes required to meet new EU operability codes alongside delivering the necessary system changes to support specific reporting requirements on European Transmission System Operators (ETSO) for Gas. Following that, Phase 4 of the project was kicked off and will be implemented in December 2017. We also delivered system changes to support ETSO reporting requirements (REMIT).

Cyber Security and Data Centres

- 408. Cyber security is viewed as a critical issue by the Government and this is evidenced by the development of the National Cyber Security Centre (NCSC). The threats in the cyber environment are continuing to adapt and change in nature, and the threat level is now significantly higher than forecast at the start of the current price control. The security, resilience and reliability of our key assets is considered to be a critical business issue and is recognised as one of the top

five key risks at National Grid plc Board level. As a result of this we are continuing to invest in this area in order to develop our maturity and resilience to protect energy delivery across the UK.

- 409. To be able to maintain security and resilience in the services we provide, we are forecasting significant investment in this area. Our costs incorporate several elements of work across Data Resilience and Security, Data Centres and Operational activity. We anticipate seeking recovery of the additional investment in the May 2018 reopener, and will look to discuss this with Ofgem in the near future. Our forecast costs are currently an estimate as the investments for the cyber security programme are still being developed in response to the evolving threat.
- 410. During 2016/17 we have spent circa £7m on the implementation of our Data Centre strategy and Cyber security programme.

XIV. Operating Costs (TO and SO)

Introduction

411. This section covers our TO and SO operating costs. The costs and allowances outlined within this section are based on our restated table 2.4, as referenced in Section IX. In 2016/17 our expenditure was £165m and our updated forecast for the eight years is £1,323m compared to an allowance of £1,221m. Compared to last year our forecast spend has increased in real terms by £119m mainly within TO driven by higher Closely Associated Indirect costs of £65m, increased Planned Inspections and Maintenance £32m, and Business Support costs of £28m (TO only).

TO Overview

412. TO Controllable Opex spend in 2016/17 was £96.9m, representing a real terms increase versus prior year of £11.1m, £1.8m being inflation. Our updated forecast for the eight years for TO Opex (including uncertainty mechanism spend) is £852m representing a £118m increase compared to allowances of £727m. The areas of increase both within year and for the eight year forecast are:

- Closely Associated Indirect costs year-on-year have increased by £5.6m in real terms, primarily driven by increased headcount to support the asset health additional workload. These costs are largely within Network Design and Engineering and Engineering Management and Clerical Support. The £65m increase in the eight year forecast in real prices reflects the higher headcount to support improved asset management capabilities and programmes to deliver data and systems enhancements. This work will underpin decision making which is required to support the increase in asset health requirements forecast in RIIO-T1 and into RIIO-T2.
- Planned Inspections and Maintenance have increased year-on-year in real terms by £2.9m driven by increased work to support the asset health agenda. The asset health work has resulted in more onsite assets, such as gas quality equipment, electric drives and telemetry, which require more man hours to maintain and are driving a higher level of call outs. In addition, through our work to ensure that our asset quantities and information about their condition are collected centrally, we have identified areas relating to our electrical and instrumentation assets and cathodic protection systems that will require additional work to maintain compliance and reduce risk. This includes work to comply with Dangerous Substances and Explosive Atmospheres (DSEAR) Regulations and Close Interval Potential Surveys (CIPS) on our CP systems. The eight year forecast of £235m is now broadly in line with allowances of £233m (2016/17 prices), but £32m more in real prices than the previous year for the same reason.
- Business Support costs have increased year-on-year in real terms by £2.1m with the largest increases in the Finance, Audit and Regulation category (the

key change being spend on costs of supporting Sarbanes Oxley Act to maintain compliance); and Property Management (the key change was crystallisation of an onerous lease for the regulated businesses as a shared lease was transferred to National Grid Property Holdings at the time of the Gas Distribution sale). In addition to the specific changes highlighted above the £28m increase in the eight year forecast in real terms is also driven by changes in underlying allocation metrics used to allocate shared costs.

SO Overview

413. In 2016/17, our SO expenditure was £59m this was flat year-on-year with higher Business Support costs being offset by lower direct costs.
414. Direct costs decreased by £1.5m in real terms as a result of lower Xoserve costs. This was primarily due to an adjustment in relation to the true-up of 2015/16 charges which resulted in a credit of £1.2m in 2016/17. Other direct costs were broadly flat year-on-year with lower change programme costs for the SO and lower legal fees in relation to EU code changes being offset by higher cash costs in relation to organisational changes and costs incurred on initial strategy work for Future of Gas and Brexit.
415. Business Support costs were £2.4m higher in real terms than prior year. An additional £1.6m of cost was incurred in transitioning GCS into the live control room environment. This major IT system delivery replaces our critical operational control system (iGMS) and delivers a new suite of applications enhancing our ability to support future change and growth. Other Business Support cost increases resulted from a change in underlying allocation metrics used to allocate shared costs, and the crystallisation of an onerous lease (as for the TO)
416. In 2016/17 we continued with our system flexibility project which was initiated to re-assess the needs case utilising the 'seedcorn' funding received under RIIO-T1. Activities have been split across analyses to understand the system flexibility issue in more detail as well as our external stakeholder engagement.
417. We undertook further analysis of some of the key operability challenges associated with Combined Cycle Gas Turbine (CCGT) operation, and shared the results of this analysis with the industry during July 2016. We considered a number of scenarios which pushed the network to the point of constraint. The broad conclusion of our initial analysis was that we identified relatively few scenarios in which CCGTs alone cause constraints if supplies are delivered to the NTS at a steady rate. However when moderate or high levels of supply profiling are applied, more constraints were identified affecting our ability to deliver our pressure obligations both on Exit and Entry.
418. Our first Gas Future Operability Planning document was published alongside the 2016 Gas Ten Year Statement, to provide a holistic view for stakeholders on how changes in the energy landscape impact future system operability, investment and commercial solutions.

419. In 2016/17 we commenced work on the Gas Planning and Operating Standards (GPOS) and new Cost Benefit Analysis (CBA) projects. The GPOS aims to deliver further clarification around our existing Pipeline Security Standard (which is defined in our Gas Transporters Licence) and to further align our planning and operational approaches to ensure ongoing suitability for network operation. In February 2017 we held discussions with Ofgem outlining the process we are following and our initial proposals. We will also be consulting with the industry on the required changes to our Transmission Planning Code document during 2017/18.
420. The CBA project is looking at how we develop a robust methodology and tools to ensure we continue to make efficient decisions on the NTS. In 2016/17 the new methodology, tools and processes for the CBA have been produced and received internal sign-off for use on investment cases.
421. Our updated forecast for the eight years is £468m compared to allowances of £493m. Our forecast spend for controllable Opex is in line with last year's forecast, although forecast allowances have increased by £31m to include forecast allowances in relation to the physical security uncertainty mechanism and to reflect the Xoserve Opex allowances as per the outcome of the review of agency costs.
422. As in the prior year our direct costs excluding agency costs are expected to exceed allowances mainly due to the cost of supporting our role in Europe which is not fully funded. Agency costs are forecast to be £27m below allowances which, as noted above, is largely due to the reallocation of Xoserve allowances from Non Operational Capex to Controllable Opex.

Econometric Benchmarking - E2Gas

423. On the 2 June 2016, Sumicsid published their Final report on Benchmarking European Gas Transmission Operators. This was a project, termed e2Gas, which was initiated by a group of National Regulatory Authorities (NRAs) in the Council of European Energy Regulators (CEER). Ofgem was a member of this group and had requested our involvement. We actively participated in the study, which included data from 21 other ETSOs. The data requirements and time required to participate and understand the results was significant and from our perspective, although academically interesting, there was very little benefit gained from our participation.

XV. Innovation

424. Innovation is at the heart of the RIIO regulatory framework and we work to find a better way in everything we do. Last year we published our mid-term innovation value report, which highlighted output from ten case studies which have realised significant value for National Grid and consumers.
425. In 2016/17 we spent £3.9m, including £107k of eligible NIC bid preparation costs, of the £5.0m allowable NIA expenditure. Of this spend, £476k (13%) was internal expenditure. Our total NIC expenditure incurred in 2016/17 for Project GRAID (Gas Robotic Agile Inspection Device) and CLoCC totalled £2.5m. Our NIC 2016 submission, Haven Energy Bridge passed the ISP (Initial Screening Process), but was withdrawn before full submission. The bid preparation work highlighted a level of uncertainty and risk that was not compatible with a successful NIC project.
426. We undertook 43 NIA projects, which were aligned to our innovation strategy. The NIA portfolio incorporates projects across all of our key themes; safety, reliability, environment, strategic, system operability and customer and connections. Particular successes this year have been projects such as 'Utilisation of 3D laser scanners for pipeline damage and coating assessments'. The laser scanner offers significant benefits over the traditional manual method for assessing pipeline defects. These benefits include highly accurate and repeatable results regardless of the conditions under which the equipment is used, and the lightweight design that makes it easier for our engineers to transport and use.

Figure 20: Demonstration of the 3D laser scanner



427. Another significant NIA project is Artificial Intelligence for Pipeline Coatings. Using the latest machine learning technology, we are developing algorithms to

recognise the different equipment types and categories of corrosion found on our network pipework. The tool will improve our asset data collection methods and standardise how corrosion condition is categorised.

428. Project GRAID is now over two years into a three and half year programme, and the project team delivered their third and fourth project progress reports to Ofgem in June and December 2016. A change control was presented in September 2016 for a number of modifications: reallocation of funds from one cost category to the other; changing the timing of a Successful Delivery Reward Criteria (SDRC), adding a voluntary contribution from National Grid to the budget and changing some of the locations for the live trials. This was accepted by Ofgem. A key highlight of the year has been the successful development of the UMS (Umbilical Management System) that sends drive commands to the robot and feeds data back to the operator. In addition, the launch and receive vessel is now built and the team have commissioned the bespoke pipe configuration that is now being used for the offline testing. In February 2017 Project GRAID had the opportunity to exhibit at the Annual Pipeline and Pigging Integrity Management Conference.

Figure 21: Offline Test Rig and Launch and Receive Vessel



429. Project CLoCC is now in its second year. Key deliverables included the issue of the first six monthly report and the completion of the Stage 1 Market Assessment, Tech Watch and Feasibility Studies in August 2016. As part of ongoing work in Stage 2, Conceptual Design and Change Plan, the team have successfully delivered the prototype Customer Connections Portal. A key highlight of the year was the CLoCC stakeholder day on the 22nd February 2017. Attended by 24 stakeholders, the attendees were given the opportunity to speak to the team to voice their opinions and give their input to help shape the outcome of the project.
430. National Grid had a very successful showcase at the Low Carbon Networks and Innovation (LCNI) conference held in Manchester in October 2016. We showcased a selection of NIA and NIC projects, including the Composite

Transition Piece, the new design prototype robot from Project GRAID and the customer connections portal from Project CLoCC. The event was also a great opportunity for knowledge sharing with the other network licensees and industry contacts.

Figure 22: National Grid Showcase at the LCNI Conference



431. We have continued to share learning and work collaboratively with other network licensees, including taking the role as chair of the Gas Innovation Governance Group (GIGG) for 2017 and continuing to lead on the production of a quarterly GIGG newsletter. We also participated in a joint presentation at the IGEN Annual Conference.
432. A key deliverable from this year has been the publication of our mid-term report Embedding Innovation Value. The reports reflects on our performance in delivering innovation value to date and highlights output from ten case studies which have been embedded into business as usual activities. The ten case studies have realised significant value (£6.9m) with a cost – benefit ratio of 4:1. In September 2016 we undertook an innovation stakeholder survey, asking over 100 of our internal project leads and external project partners for their views on our innovation performance. Highest scoring was the support provided by our centralised innovation function, and also our openness to new ideas.
433. Our ambition for the fifth year of NIA is to continue to enhance our value tracking activities and ensure that project learning continues to be embedded into business as usual activities. We will continue to grow the portfolio in order to maximise value for our customers over the RIIO-T1 period.

XVI. Market Facilitation

434. National Grid has a number of roles in facilitating the GB and EU gas markets. This section discusses the areas we have focussed on in 2016/17 including the Future of Gas (FoG) project, Brexit and the Gas Transmission Charging Review. Our customers and stakeholders have told us that one of their priorities is that we “facilitate and lead the debate” and this section will highlight examples of how we have engaged them and built systematic processes to continuously gather feedback from and respond to them. We have received positive feedback from our customers and stakeholders over the year and will look to build on this to make improvements in the future.

Background

435. Over the coming years there is set to be significant changes in the UK energy industry and it will be important to ensure the GB gas regime remains flexible and adaptable to this change. Financial year 2016/17 has been a significant year for us as we have worked with our customers and stakeholders to ensure our business strategy fully prepares us for the future. Most notable of these activities include;

- the Future of Gas (FoG) project which sets out our view of the key role Gas Transmission can and will play throughout the 2020s to 2050
- the implications of the Brexit vote through the EU referendum, the impacts on the EU and GB gas regime and preparation for the UK’s exit from the EU
- Gas Transmission Charging Review (GTCR) to deliver improvements to the GB charging regime

436. We continue to play an active role in the GB and EU gas market activities by influencing the development of EU change both in terms of the continued development of EU Network Codes, other Code and legislative developments. Within the GB market we are proactively reviewing our Gemini strategy and Xoserve arrangements as a service provider to ensure that this is fit for purpose and has the ability to manage future industry change.

Future of Gas Project (FoG)

437. The FoG project was launched in November 2016 at our Gas Customer Seminar, where we provided the opportunity for customers and stakeholders to tell us their views on the UK’s gas future. The output of these discussions helped us to identify common topics that customers and stakeholders view as a priority. To enable more focused debate we then used these topics as the basis for a series of workshops during February and March 2017. These were themed around: Gas and Electricity Interaction; Heat; Supply; and Industrial Demand. During the workshops we sought to gain further insights into what our customers and stakeholders believe the future energy landscape could look like, what risks,

challenges and opportunities this creates for GB, for the energy industry. Additionally we wanted to gain further insights into how the gas and other energy markets may need to adapt in the future. This will enable us to consider how the Gas Transmission system may be able to meet future energy needs.

438. The overarching message we heard was that gas had a significant role to play in delivering the most cost-effective decarbonised future across power, heat, transport and industry. There is already an extensive GB gas network and a mature supply chain. Adapting the existing gas infrastructure to facilitate new technology and innovation, as well as opening up the market to greater diversity in sources of gas supply, will help us to meet GB's future energy demands. Optimising use of the existing infrastructure and supply chains will be more affordable than full electrification of heat and transport. Not only does gas play a vital role today in providing secure energy supplies to our homes, businesses and industry, providing the vast majority of our home heating, hot water and cooking needs and much of our electricity; but gas can also continue to play an important role in providing a secure energy supply, at best value for consumers, as part of a long term low carbon future.

439. Some other common themes to come out of the FoG workshops were:

- Lack of certainty around the future, including the timing and direction of national energy policy, is prohibiting much needed investment and innovation in the energy sector
- There are many potential pathways to decarbonisation, including the use of the existing network to transport greener gas. Consequently keeping options open for the role of the gas network in the future, as far as possible, is likely to ensure the best consumer value in the long term. Our network is currently capable of managing low and high gas flows, and this flexibility should be maintained
- The potential benefits of greater future interactions between the gas and electricity markets and networks needs to be better understood. Stakeholders have suggested that it may be appropriate to consider new SO, industry and policy approaches to the gas and electricity systems, which could facilitate greater operational and cost efficiencies to benefit customers and consumers. We are therefore exploring options for increasing interactions between gas and electricity, and the associated benefits for customers and consumers.
- Stakeholders are in agreement that there is no one single solution to the decarbonisation challenge and it is likely that a combination of different solutions will take shape in heat, power and transport. A whole system national policy framework is therefore needed to support development of a range of different technologies and regional approaches that ensure the most optimal national solutions. As we have highlighted previously in FES, it is our view that transport should be decarbonised in advance of heat as the

transition is likely to be easier as people change their vehicles more often than they change their heating systems.

- Engagement with the end-users of gas, both domestic and industrial, in order to ensure their voices are heard in the formation of appropriate decarbonisation solutions, will become increasingly important as things begin to change. The balance of cost and convenience, alongside the variety of current housing stock and property ownership/rental arrangements, should also be considered.
- Affordability remains an important concern, in particular the impact on unit cost of reducing demand for gas, and the potential for network costs to be spread over a smaller group of customers.
- Carbon Capture and Storage is going to be crucial to meeting the 2050 carbon targets at lowest cost – this is supported by FES and a range of academic and industry reports.

440. We will publish a final report in early 2018 that will set out our view of how the future could look; the role that gas (and the Gas Transmission network) can play in heat, transport, power generation, industry and storage; and the various sources of gas supply that might be in place. We will also consider the innovation that already exists and where we can see gaps. We will also make recommendations for the actions that can and need to be taken in each decade by Government, industry and National Grid in order to ensure the right solutions remain or become available at the right times.

441. The outputs from the FoG project, along with the FES, are being used to shape the National Grid business strategy, which will set the direction for the business from today through to 2030. This will include consideration of market changes that may be required to facilitate security of supply; support an attractive and liquid GB gas market; and facilitate access to the market for a variety of sources of gas.

Brexit

442. Following the UK's decision to leave the EU in the referendum held on 23 June 2016 the two year process of leaving the EU was triggered in a letter to the EU Council President on 29 March 2017. Under the terms of Article 50 of the Treaty of Lisbon the UK is scheduled to leave the EU on 29 March 2019 although this may be extended provided all 28 EU member states agree.

443. During 2016/17 we have been working to understand the potential impact of the UK exit from the EU on the GB gas regime. There is significant uncertainty regarding the future arrangements between the UK and EU energy markets and what effect this might have on the GB gas system generally. We have participated in workshops with BEIS and Ofgem and contributed views to UK energy market associations and UK Parliament consultations.

444. We will carry out further work during 2017/18 to assess and prepare for the UK withdrawal from the EU and will engage and work together with customers and stakeholders to listen to and address opportunities and concerns as appropriate. The uncertainties around the UK exit from the EU extend to the expected role for National Grid in the withdrawal preparations with any enhanced role having funding implications.

Gas Transmission Charging Review (GTCR)

445. Throughout 2016/17 National Grid, along with industry and Ofgem has continued to discuss the GTCR that looks to deliver improvements to the GB charging regime and consider the EU Tariffs Code and Ofgem's GTCR policy letter. The scope of the GTCR is to consider changes to the overall GB Gas Transmission charging regime for 2019 and lay the foundation for additional change beyond this.
446. For the 2019 change, NTS Charging Methodology Forums (NTSCMF) have been held every month during 2016/17 and discussed a wide range of topics related to the GTCR and the GB Charging arrangements. In addition to the NTSCMF which is facilitated by the Joint Office of Gas Transporters, from November 2016 National Grid and industry stakeholders also established a GTCR sub group to provide additional input to the NTSCMF. The purpose of the sub group has been to allow more detailed discussion on specific topics and development of analysis to support the NTSCMF and enable industry forums to be as efficient as possible. The sub groups have operated every month from November 2016. Working with the NTSCMF, the sub group has developed a library of discussion topics to help support the charging review, provided analysis to facilitate potential change to the methodology of calculating capacity charges and provided a solid foundation upon which we can raise a UNC Modification in 2017. The UNC modification would be required to progress the GTCR and further discuss and develop options and potential changes with industry and Ofgem.
447. The NTSCMF, and the sub group, will continue to provide a forum for stakeholders to raise and discuss issues and opportunities for developing the GB charging framework under the GTCR. The overall aim of GTCR is to ensure that charging arrangements are fit for purpose both now and in the future. It looks to ensure that customers have a charging regime which fits with how the NTS is used and expected to be used in the future. It also helps with the efficient access to, and use and operation of, the NTS for Network Users.

European Market Activities

EU Capacity Allocation Mechanisms (CAM) Network Code

448. The CAM code standardises EU capacity mechanisms at Interconnection Points. Since its introduction in November 2015, further changes have been developed to:

- include the ability for Network Users to signal incremental capacity to Transmission System Operators (TSOs);
- provide for a standard TSO process for obtaining Network User demand, an assessment phase, design phase and allocation process (Interconnection Point PARCA). Subject to a successful application and allocation a joint build phase would commence;
- in addition changes have been made to amend the annual auction from March to July (from 2018) and the introduction of a new quarterly product from July 2017; and
- UNC Modifications 0597 and 0598 were raised to introduce these changes into UNC and were approved by Ofgem on 6 April 2017

449. We continue to work very closely with our customers and stakeholders in the development of these rules and to ensure that any changes to the CAM Regulation are appropriate for the GB regime. The next phase of this is to develop a Capacity Conversion Service by 1 January 2018 as specified in the amended CAM Regulation. We have been active in the development of the service within ENTSOG and the development work is underway via the UNC modification development process and is expected to conclude in Q3 2017 ready for the 1 January 2018 start date.

EU Tariff (TAR) Network Code

450. The TAR network code aims to harmonise transmission tariff structures for gas. It sets out the EU-wide rules which aim to enable market integration, enhance security of supply and to promote the interconnection between gas networks. It will drive a number of changes to the GB charging regime such as ensuring that the majority of allowed revenue is recovered via capacity tariffs and increased obligations in transparency and consultation. The TAR code came into force on 6 April 2017.

451. We have also been proactive in the development of the TAR code both at a EU and UK level. We have been working closely with BEIS and Ofgem and have been holding regular discussions and providing frequent updates to the industry. Industry discussions on the TAR network code have been incorporated into the GTCR to ensure a holistic approach is taken in the development of a GB charging framework that is both fit for purpose and compliant with the EU tariff code.

452. The implementation solutions are still being developed, but we have successfully influenced the final draft of the code to ensure that many of the changes being considered are largely driven by GB requirements rather than simply EU compliance. We will continue to be active at the European level to facilitate a coherent implementation of the TAR code between Member States and to influence the development of the process to monitor implementation.

EU Gas Quality

453. Following the adoption of the CEN EU²³ gas quality standard, the European Commission (EC) announced its intention to make the standard legally binding via an amendment to EU Network Code on Interoperability and Data Exchange Rules – Regulation No 2015/703. To this end, in December 2015, the EC invited ENTSOG to prepare a detailed analysis on the impacts and issues associated with codifying the standard and submit a proposal to ACER to amend the Network Code by 30 June 2017. National Grid supported ENTSOG in this work which included attending three stakeholder workshops and responding to two consultation processes during 2016. In order to do this we engaged with a range of GB stakeholders to encourage their participation in the ENTSOG process and develop a consistent GB view.
454. ENTSOG consulted on a number of implementation options for the standard ranging from mandatory application across all EU gas networks to voluntary adoption. National Grid's preference was for voluntary adoption for a number of reasons:
- there was no clear problem that mandatory implementation of the standard would solve;
 - rules already exist in the Interoperability Code to manage cross border barriers to gas flow caused by different gas quality specifications locally, which is preferable to a 'one size fits all' standard for the whole of Europe;
 - implementation at IPs only would be unworkable for National Grid given the current gas quality limits and flows on the network; and
 - application of the carbon dioxide and oxygen limits in the standard would be to the detriment of GB security of supply, with approximately 20% of UK supply being locked out
455. The majority of stakeholder responses to the ENTSOG consultations shared National Grid's preference, which in October 2016 led to the EC announcing that it was no longer proposing to pursue making the standard binding at this stage, although it may revisit harmonisation when further CEN work to include Wobbe Index in the standard has been completed.

Gas EU Security of Supply Regulation

456. During 2016/17 we have been engaging with BEIS and Ofgem on the revised Gas EU Security of Supply Regulation as it has been progressing through the EU negotiations. Our involvement in these discussions has been fundamental to ensure that the UK is in the best position to influence within the EU arena. The aim has been to ensure minimal impact on the GB gas regime.

²³ The European Committee for Standardisation

457. It is expected that the revised Regulation will come into force in late summer/early autumn 2017. Prior to that, and post implementation, we will be actively involved with BEIS and Ofgem to achieve the key Regulation milestones to ensure compliance.

GB Market Activities

Gas Demand Side Response (DSR)

458. Gas Demand Side Response (DSR) is when consumers offer to enter an agreement to reduce their gas demand during the build up to a gas emergency, in return for payment. This area of change was identified as part of the Ofgem Significant Code Review (SCR) on security of supply as a potential further development to help end consumers access the market. This resulted in a new Gas Transporter Licence Special Condition 8I.
459. Since the introduction of this licence condition in 2014 we have been working to implement an appropriate solution. Initially we focussed on developing a Gas DSR methodology which was both regulatory compliant and met the expectations of our customers and stakeholders. Once approved we conducted a successful Gas DSR trial in summer 2015, which resulted in Ofgem directing National Grid to implement Gas DSR through subsequent changes to the UNC. We raised UNC modification 0504 in November 2015 and following a number of industry discussions it was subsequently approved by Ofgem in February 2016.
460. In line with the modification, focus this year has been centred on implementing Gas DSR by 1 October 2016. This included updating our internal processes and working with ICE Endex, the On-the-day Commodity Market (OCM) operator to implement the necessary system changes for Gas DSR.
461. During detailed solution design some financial and regulatory barriers were uncovered impacting implementation of some of the “non-core” aspects of the Gas DSR methodology which were not envisaged during development. We launched an industry consultation in May 2016 which concluded that in light of the industry responses received, and the underlying regulatory & financial barriers that subsequent changes to the Gas DSR methodology should be made. Ofgem approved our recommendations in July 2016 and we raised UNC modification 0591S which was approved by industry in August 2016. Gas DSR was successfully implemented on the 1 October 2016.
462. In conjunction with implementation we have also looked to promote greater understanding of the Gas DSR service. This includes the development of a Gas DSR brochure and filmed webinar.

Gemini Strategy

463. The Gemini system is the means by which the NTS capacity and gas nominations and gas energy balancing regimes operate. At present, National Grid owns Gemini and Xoserve manages it.

464. Gemini is now a mature system and Xoserve has identified a number of maintenance requirements to ensure that it continues to perform reliably. Therefore, in 2016, we have engaged Xoserve to investigate options for sustaining Gemini.
465. The various options for the future of Gemini include piecemeal replacement of components that are approaching end-of-life, a re-platform exercise to enable Gemini to run on the latest hardware and software and a complete system replacement. We will need to consider these options in the light of Xoserve's report and a forward view of Xoserve's service provision in the RIIO-T2 period.

Xoserve Services in RIIO-T2

466. Xoserve currently provide a number of services to National Grid which in the main are associated with Gemini operation and change management, shipper invoicing, energy balancing processes and shipper lifecycle activities. Under the current regulatory arrangements, National Grid receives a funding allowance for the provision of these services from Xoserve.
467. In order to inform the National Grid business plan in these areas for RIIO-T2, during 2016/17 we began to review the services we procure from Xoserve and to explore whether reform in this area could deliver more efficient outcomes. This work aims to capture the relevant processes, consider scenarios for how the industry, and Xoserve's role in it, might change in the 2020s and what that might mean for Xoserve's service provision to National Grid, as well as considering alternative options for service provision.

Xoserve Relationship

468. The customer experience when interfacing with our back office systems has been a key area of focus for us this year, which has led us to review and seek improvements in the delivery of data services across a range of operational areas in partnership with Xoserve. The results of this work has led us to:
- work closer and in a more integrated manner with Xoserve in key operational areas where both companies play a role in the customer interface; and
 - implement a more structured contract management approach where Xoserve deliver services more directly on our behalf.
469. In terms of the current interface, we have been in discussions to deliver new and improved KPIs and a contract management balanced scorecard with Xoserve. We have also trialled new more collaborative and agile ways of working during the delivery of EU Phase IV, and will be making this permanent going forward. Alongside this, we have led on delivering a new simpler and more streamlined Xoserve change process and change documentation on behalf of the whole industry.

470. We are reviewing the current Gemini functionality and the delivery of the Gemini Service Desk and plan to make changes in this area in the near future which should greatly improve the customer experience. We have also begun working with Xoserve in order to deliver enhanced competition in the Gemini supply chain in order to drive efficiencies.

The Xoserve Funding, Governance and Ownership (FGO) programme.

471. On 1 April 2017 we implemented the Funding, Governance and Ownership (FGO) programme. This introduces new regulatory and contractual arrangements between National Grid, Xoserve, its customers and stakeholders.
472. The three key elements of the FGO program will deliver immediate improvements to Xoserve's engagement with its stakeholders and customers, making it easier for industry parties to influence the operation and evolution of those services which they procure.

Funding

473. We have revised Xoserve's cost allocation model giving individual organisations direct buy-in to, and visibility of, the cost drivers for their investments with Xoserve. Under the new arrangements, nearly a third of Xoserve's activities will be paid for directly by Gas Shipper companies. Also the costs attributed to gas transporters are more closely aligned to the activities of those businesses (e.g. transmission or distribution). This reduces the likelihood of cross-subsidisation of costs associated with wholesale and retail markets.

Governance

474. Significant changes have also been made at corporate and regulatory levels. Xoserve's Board now includes Directors nominated by Shipper and independent Gas Transporter (iGT) communities, bringing additional skills and greater understanding of customers' needs to the organisation. At the working level, two new Uniform Network Code (UNC) committees have been established to manage operational performance and industry change.

Ownership

475. National Grid and the other large Transporters remain Xoserve's shareholders but some fundamental revisions to the nature of our relationship with Xoserve have been implemented to better fit with the collaborative nature of the new all-industry governance arrangements. These include creating a not-for-profit financial model, ensuring that all efficiencies are reinvested directly into its operational and change delivery functions.

XVII. Operational Review

476. In 2016/17 we have seen a relatively mild winter which is classed as 1 in 6 warm. The highest demand seen this year was 372.2 mcm on the 26 January 2017. This was marginally higher than the highest demand experienced in 2015/16.
477. The System Average Price was 46 pence per therm (p/th) and ranged from 30 p/th to 60 p/th, this was an increase versus the previous year average of 33 p/th ranging from 26 p/th to 41 p/th.
478. The total consumption for the year was 87.4 bcm compared to 83.9 bcm in 2015/16. This increase was largely driven by an increase in demand from NTS connected power generation which went from 15.5 bcm in 2015/16 to 21.3 bcm in 2016/17.
479. The coldest day in 2016/17 was recorded on the 26 January 2017, and was the 15th warmest in the last 57 years. The lowest demand seen was 114.5 mcm on 7 August 2016. This was 27.6 mcm lower than last year's minimum.
480. With these relatively low demand conditions, no Operating Margins gas was utilised and no Gas Deficit Warnings or Margins Notices were issued. However, we experienced a number of operational challenges largely brought about by the changing flow patterns experienced at the St Fergus and Bacton terminals. With regards to St Fergus, supplies increased from 23.2 bcm in 2015/16 to 30.7 bcm in 2016/17. This led to a significant increase in compressor utilisation as larger volumes of gas needed to be moved away from entry points with higher flows towards parts of the network experiencing reduced entry flows. In addition, and contrary to expectation, we received lower volumes of LNG with only 64 cargoes received compared to 91 cargoes in 2016/16.
481. Throughout these periods of operational challenge, National Grid has endeavoured to minimise customer disruption and maintain performance. In 2016/17 99.03% of significant offtake pressure customer obligations were delivered during the year with no material impact reported when they were not. The construction and execution of our operational plans ensured 100% of firm capacity purchased by customers was made available for use and 456 maintenance operations were completed successfully during the year.
482. This section provides an overview of the key operational highlights within 2016/17. For more detailed information please visit our Future of Energy publications page:
483. <http://www2.nationalgrid.com/uk/industry-information/future-of-energy/>

Operational challenges

484. Within day operability has remained an ongoing challenge, caused principally by increased power generation intermittency, fast cycle medium range storage and supply predominantly being delivered through three entry points and in particular

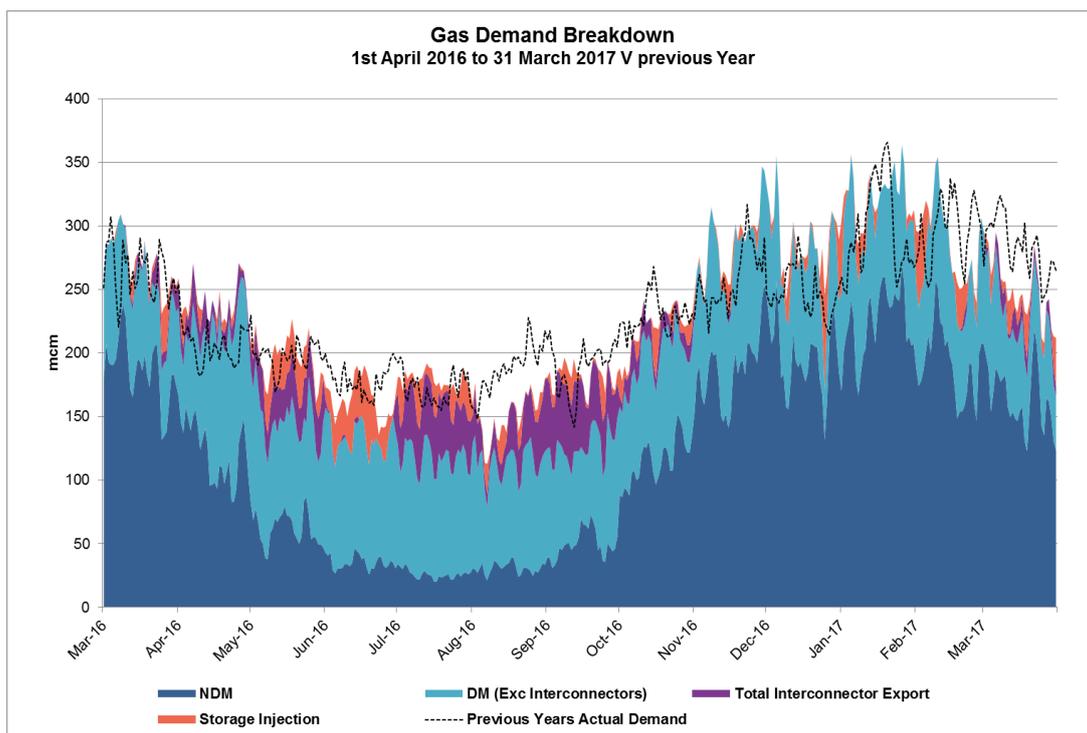
through St Fergus. This has resulted in a less balanced overall network and the need to operate increased compression to move gas away from entry points.

485. During winter there were 132 Gas Safety (Management) Regulations supplier excursions, which were resolved using the relevant processes. Enhanced support was provided to one potentially significant situation to ensure both environmental and customer safety was not compromised.
486. There were unplanned system events at two NTS offtakes for a partial gas day resulting in a loss of flow to the offtake. All efforts were made to return the flow at both sites in a timely manner, whilst ensuring the safe operation of the NTS.

Gas Demand and Supply

487. The chart below displays the gas demands for the past 12 months by the individual demand components.
488. LDZ demand was higher in 2016/17 at 48.5 bcm compared to 46.4 bcm last year; averaging 185 mcm in winter 2016/17 compared to 173 mcm in 2015/16.

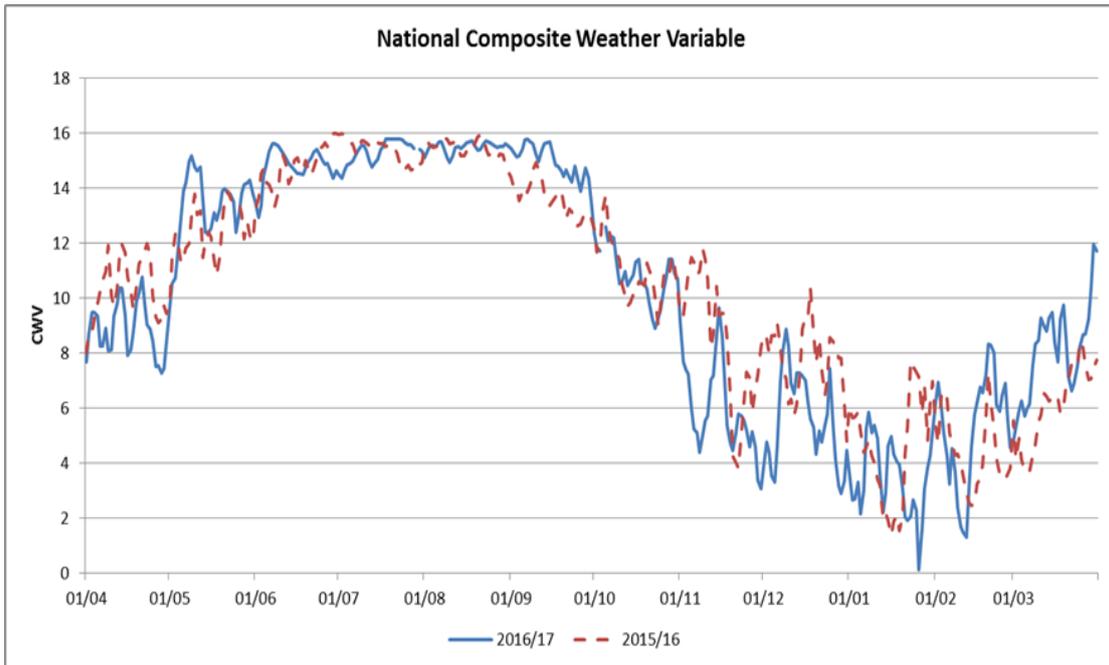
Figure 23: Chart showing gas demand breakdown from the 1 April 2016 to 31 March 2017 vs previous year



Weather

489. The National Composite Weather highlights a colder winter than last year which correlates with LDZ demand levels seen.

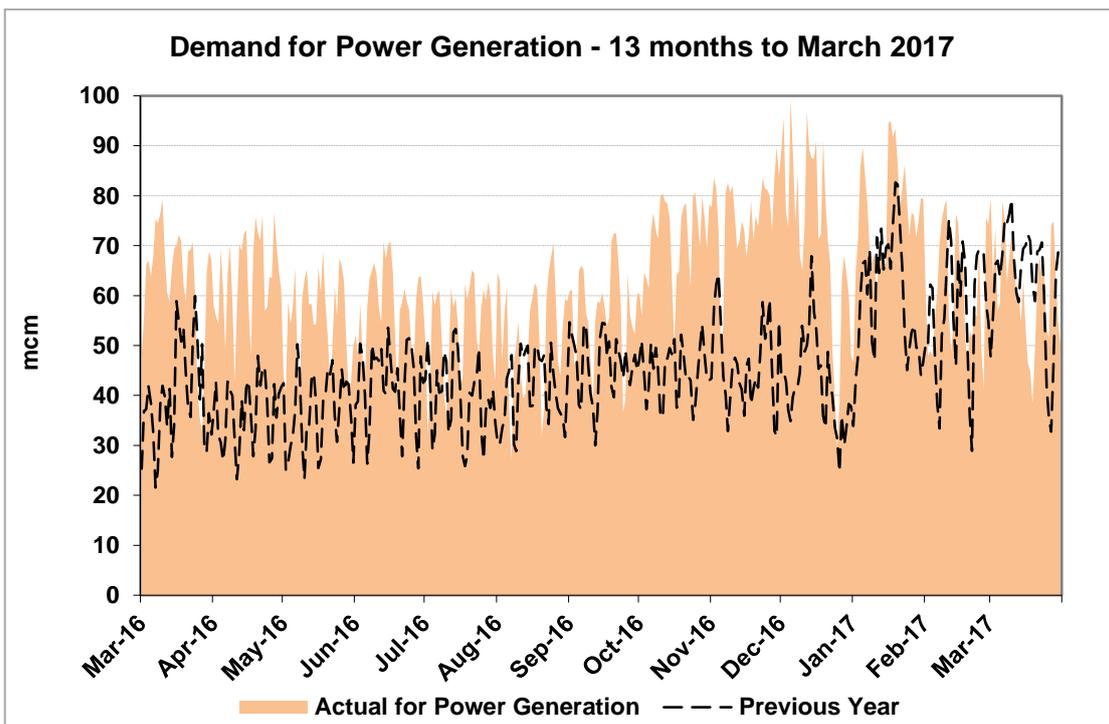
Figure 24: Chart showing National Composite Weather variable data



Demand for Power Generation

490. The chart below shows the gas demand for power generation this year. The overall total demand is significantly higher to last year; with noticeable large increases during the first half of the winter.

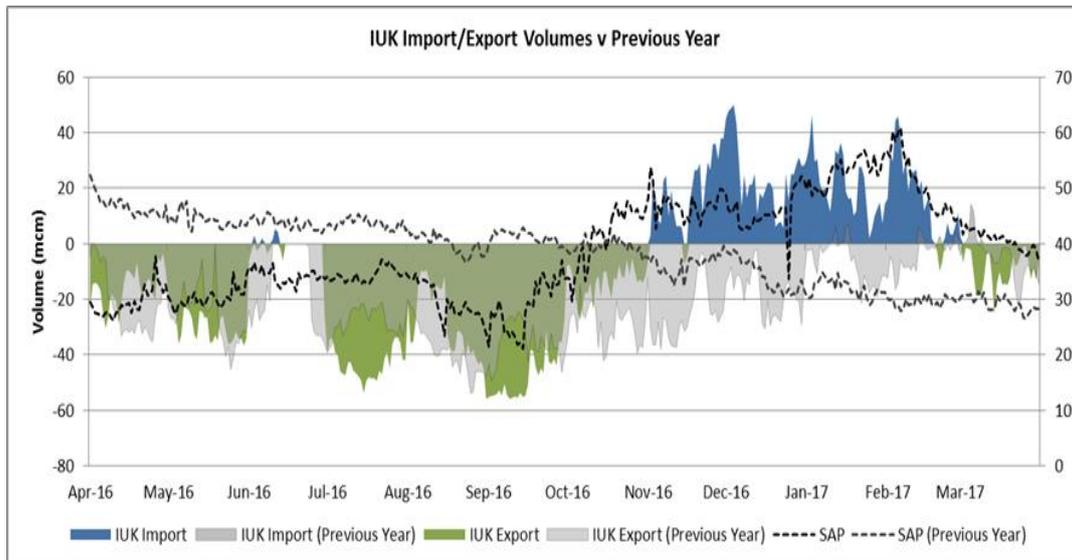
Figure 25: Chart showing demand for power generation on a 13 month basis up to March 2017



Import/Export Flows at IUK

491. The below chart shows the import/export flows at IUK for this year in comparison to last year showing an overall increase in imports from 0.08 bcm to 2.45 bcm due to higher UK prices.

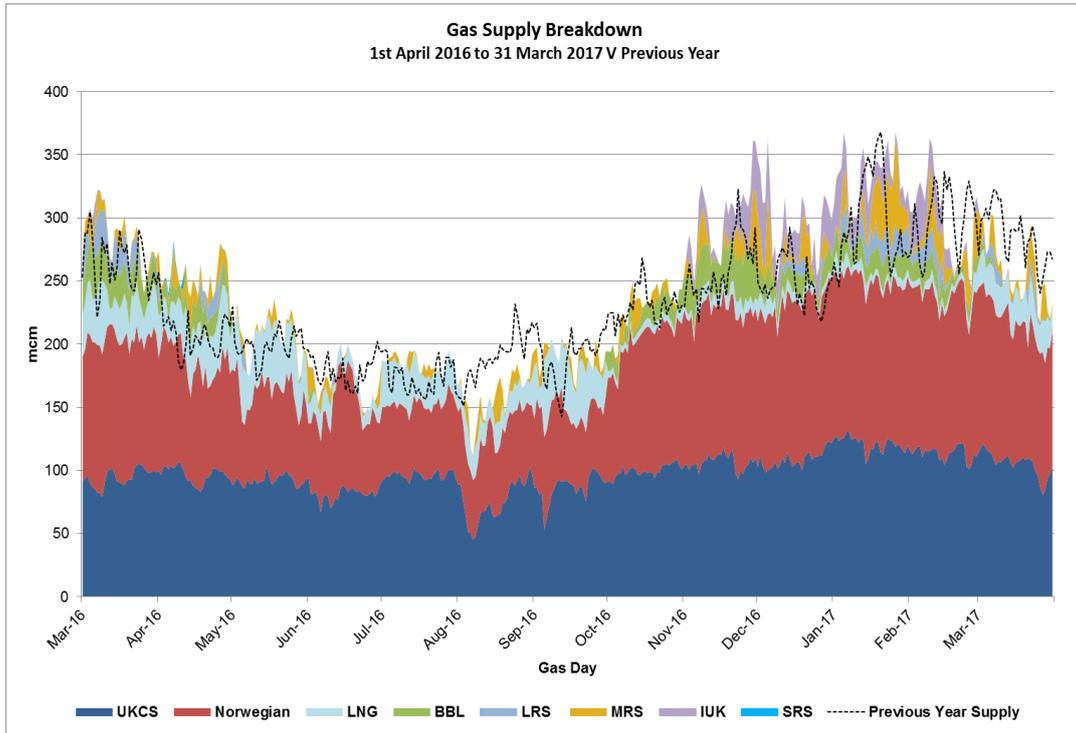
Figure 26: Chart showing IUK import/export volumes for 2016/17 vs the previous financial year



Supply Breakdown

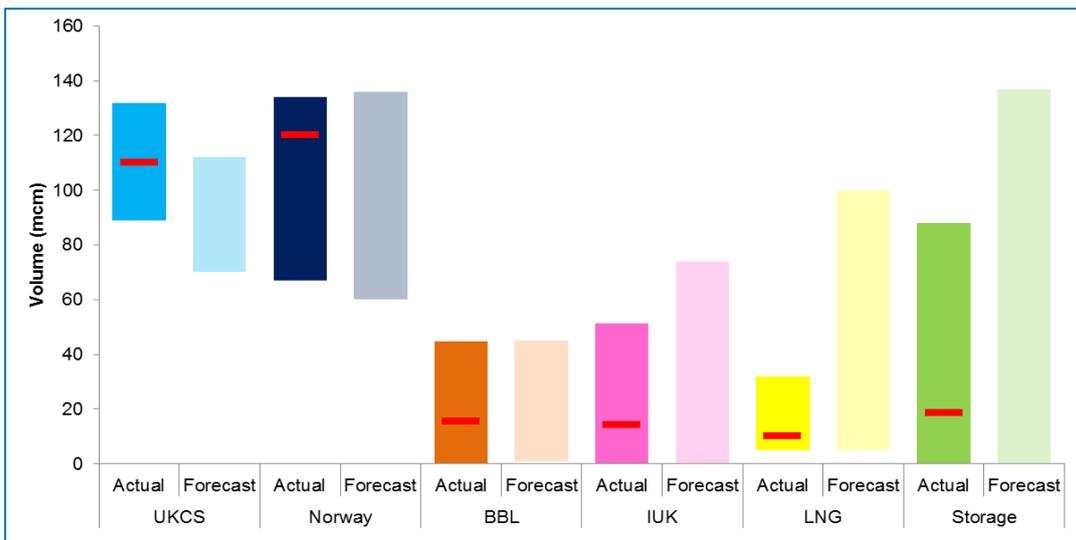
492. The below graph shows a comparison of the daily supplies by supply type compared to last year with the continued reliance on Norwegian supplies being evident; increasing from circa 29 bcm to 34 bcm. Storage withdrawal fell from 4.9 bcm to 4.6 bcm and interconnector imports increased significantly from 3.4 bcm to 5.5 bcm.

Figure 27: Chart showing gas supply breakdown 1 April 2016 to 31 March 2017 vs previous year



493. LNG and Storage delivered below the Winter Outlook²⁴ forecast with additional flows at UKCS and IUK.

Figure 27: Chart showing the forecast and actual volume of gas supplies delivered to the UK



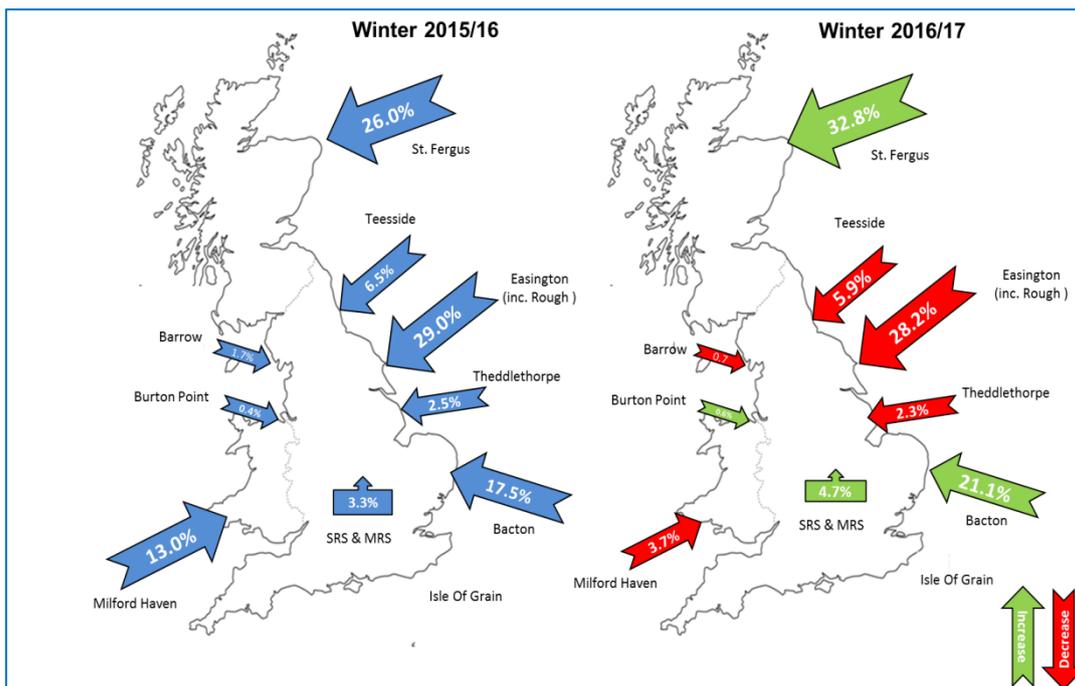
²⁴ The winter outlook can be found at: <http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/FES/Winter-Outlook/>

- Average

Supply Profile by Location – Winter 2015/16 vs Winter 2016/17

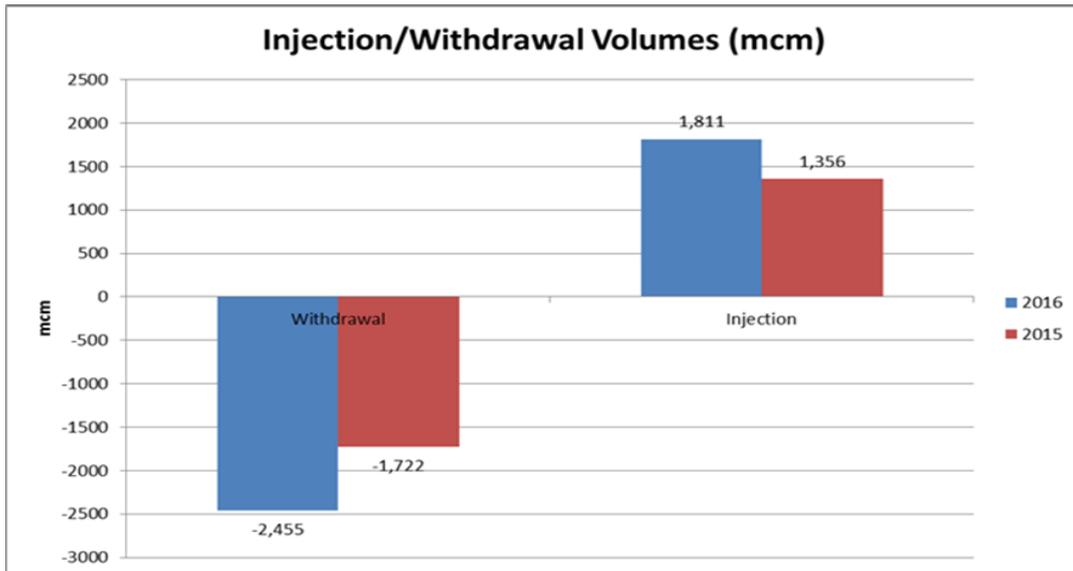
494. The below chart shows the percentage of gas supplied to the GB by geographic location, and shows the majority of the gas continues to be supplied through Easington, St Fergus and Bacton, with over 80% of winter supplies being delivered via these terminals, a 13% increase on the previous year.

Figure 28: Image showing supply profile by location for winter 2015/16 and winter 2016/17

Medium-Range Storage Winter

495. MRS behaviour has seen a 34% increase in the volume injected into store and a 43% increase in the volume withdrawn potentially as result of lower opening stock levels and restrictions at the Rough storage facility.

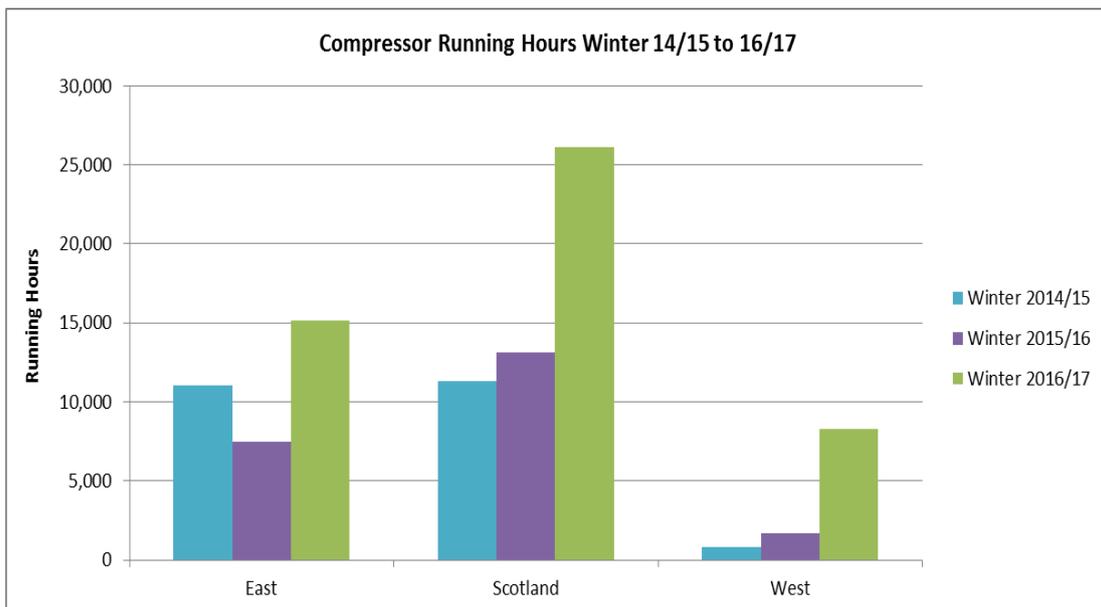
Figure 29: Chart showing injection and withdrawal volumes in 2015 and 2016



Compressor Utilisation

- 496. Overall compressor running hours doubled from 35,930 in 2015/16 to 72,242 hours in 2016/17. Running hours at some specific sites increased even more significantly due to the change in flow pattern.

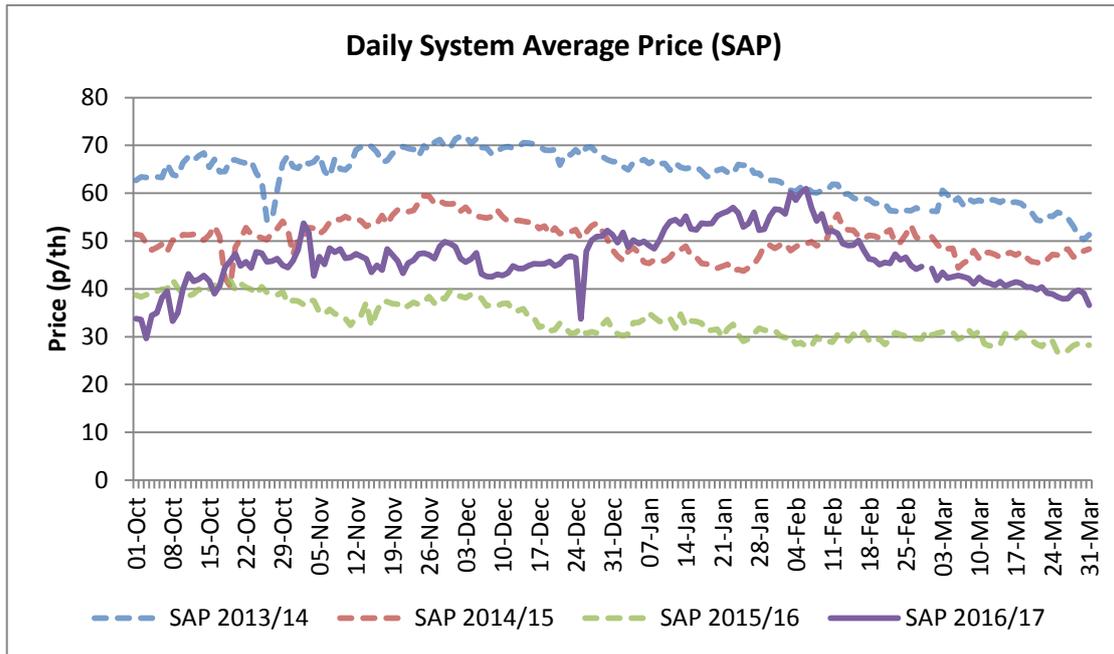
Figure 30: Chart showing compressor running hours from winter 2014/15 to winter 2016/17



Commercial prices

- 497. Commercially, gas prices were higher than last year ranging between 30 p/th and 60 p/th.

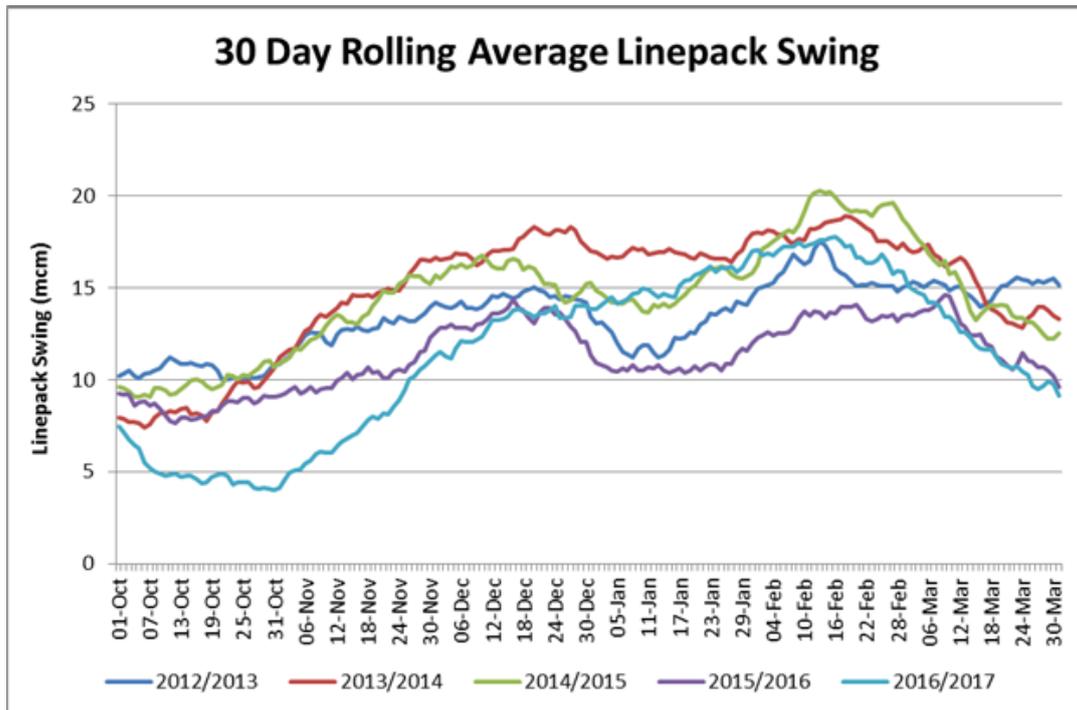
Figure 31: Chart showing daily SAP from 2013/14 to 2016/17



Comparison of NTS linepack swing for a 30 day rolling average

498. Within day profiling remains an ongoing issue for system operability since the NTS, and associated contractual rules, have historically been built to operate based on flat supply and demand profiles. It can therefore be challenging to meet customer requirements, in particular maintaining required pressures on days of significant linepack swing.

Figure 32: Chart showing 30 day rolling average linepack swing from 2012/13 to 2016/17



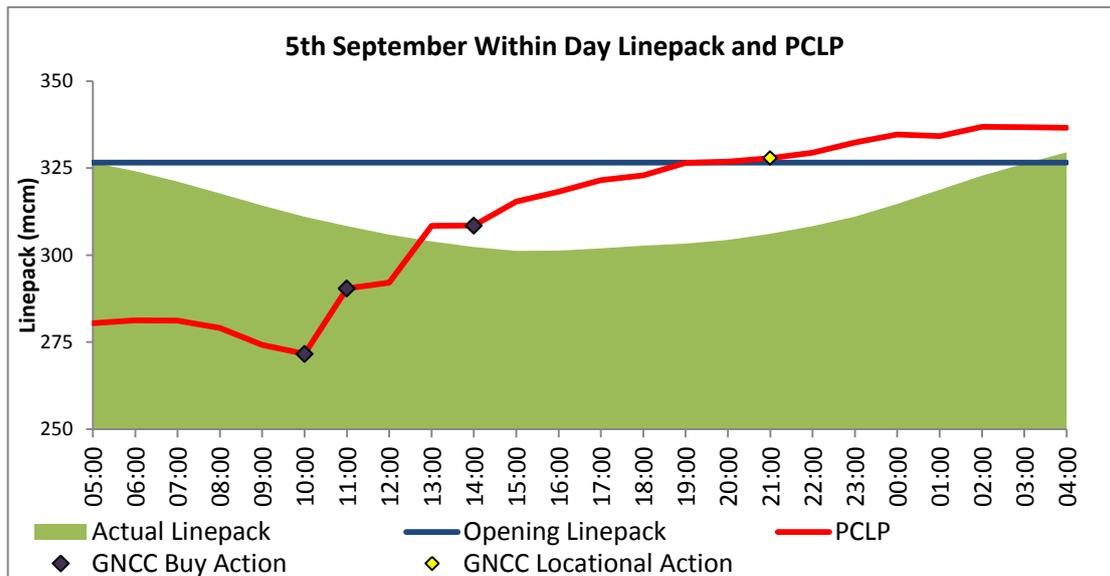
Operational Challenging day example

499. The following describes the events of 5 September 2016. This section is included to provide an example of the events of an operationally challenging day, the actions taken and the impact.

Beginning of gas day

500. Actual physical NTS stock (linepack) opened at 326 mcm which was approximately 5 mcm below the level of linepack we had planned to operate at in order to accommodate the conditions on the day. This was due to supply losses at the St Fergus and Bacton terminal which had occurred on the previous Gas Day.
501. During the early morning, demand exceeded supply and linepack continued to fall. The end of day closing position based on our customers' supply and demand notifications, predicted a loss of 47 mcm of linepack by the end of the gas day. This could potentially result in unusually low pressures on the NTS.

Figure 33: Linepack volumes 4 and 5 September 2016:



Actions taken

502. The above chart shows that early in the day, there was little market response to the decline in linepack and as a result we took commercial energy actions to encourage the market to rebalance. On three occasions during the gas day we made the decision to buy energy. These trades resulted in the following market responses:

- storage sites switched from injection to withdrawal; and
- supplies from Milford Haven increased.

503. These responses were successful in boosting supplies, which in turn increased the physical linepack in the NTS. However, this presented a new network challenge requiring localised actions.

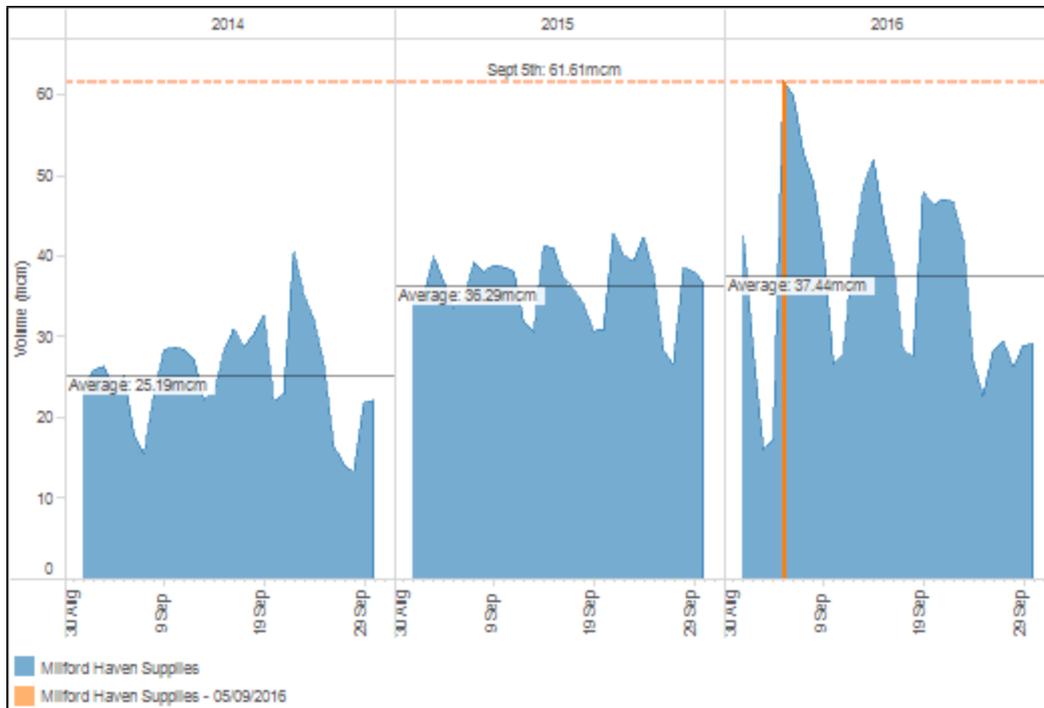
Why were localised commercial actions needed as well?

504. The flows from the Milford Haven entry point increased the pressures in the South Wales area resulting in a pressure constraint. Three actions were taken to manage the situation:

- We requested the return to service of the Churchover and Wormington compressor units from planned maintenance. This helped to reduce pressure in the local area by moving the gas away from South Wales to other demand points across the NTS.
- A commercial action was taken to scale back any off-peak firm capacity to protect our firm capacity holders.

- A request for locational energy bids was issued and a demand increase was accepted. The increase in demand helped to reduce the pressure in South Wales.

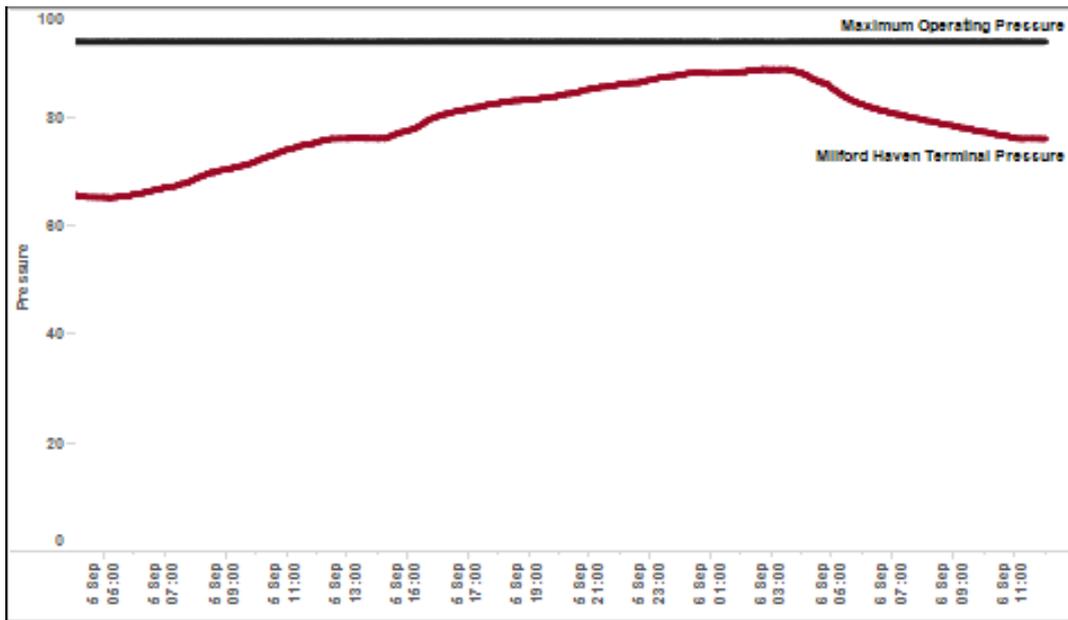
Figure 34: Milford Haven flow profiles



Midnight

505. Supplies at Milford Haven had begun to reduce, so together with the help of the localised actions South Wales pressures began to fall. The chart below illustrates the pressure gradient at Milford Haven on 5 September 2016 with pressures edging close to the Maximum Operating Pressure (MOP) of the pipeline. We see the pressures reduce in the early hours of the morning in response to the localised actions.

Figure 35: Pressure profiles in the Milford Haven area on 5 September 2016



Impact on our customers

506. On the day, power stations, LDZs and IUK all queried the lower than usual pressures they were seeing.
507. We met all our contractual obligations, but the situation did create operational challenges for our customers. The clearest example of this is that IUK, the company that operates the interconnector between UK and Belgium, published a note to the market to say that they could not meet their end of day flows due to low pressure on the NTS.

Summary

508. NTS linepack fell to the lowest level seen in the last five years. An undersupplied system required both physical and commercial actions to manage the situation effectively without compromising safety or contractual obligations.
509. This case study demonstrates the consequences of unplanned supply losses. These require real time management, using the commercial and operational tools available to us. The scenario reinforces the need to continually allow for a dynamic range of supply and demand assumptions in our planning and configuration of the system.

Appendix I – Revenue

Maximum Allowed Revenue - TO

510. The Gas Transmission TO Maximum Allowed Revenue for 2016/17 out-turned at £797.6m.

Licence Term	2015/16 (£m)	2016/17 (£m)	Commentary for year on year variance
Base Revenue (BR)	686.9	719.6	<ul style="list-style-type: none"> • +£40.0m (2015/16 price base) equivalent to +7.3% increase in opening base revenue allowances. • +£0.7m (2015/16 price base) increase in MOD. <p>Detailed MOD commentary included in Final Proposals base revenue against adjusted base revenue section.</p> <ul style="list-style-type: none"> • -£11.5m relating to TRU (2015/16 price base) in 2016/17 as a result of the movement between forecast and actual RPI in 2016/17 compared to the movement in 2015/16. • +£3.5m due to further year's RPI uplift
Pass Through (PT)	12.2	4.7	<ul style="list-style-type: none"> • Business rates, licence fees and policing costs are trued up against the ex-ante allowances with a two year lag. The value from 2015/16 to 2016/17 has increased by £0.3m. • Independent systems costs are trued up within year. The true up value was £12m in 2015/16 and is £4.2m in 2016/17 the reduction is due to the decrease in the Licence and Special Condition 11F.
Incentives (OIP)	1.8	35.7	The 2016/17 incentive includes the Customer and Stakeholder Satisfaction Incentive and Stakeholder Engagement Reward for 2014/15 performance. The incentive revenue has increased from £1.8m in 2015/16 to £3.5m in 2016/17. The year of 2016/17 includes the incentive relating to Permits this is a two year incentive with a value of £32.2m.
Network Innovation Allowance (NIA)	3.1	3.5	NIA costs have increased slightly on a year on year basis.
Network Innovation Competition	5.7	18.0	As per the Ofgem direction, the NICF revenue term has increased from 2015/16 to 2016/17. The £18.0m award in 2016/17 includes one Gas Transmission project, Customer Low Cost

Licence Term	2015/16 (£m)	2016/17 (£m)	Commentary for year on year variance
Funding (NICF)			Connections. There are another three awards which are collected on behalf of other Networks.
PARCA (PTV)	-	-0.0	There is a value for this term in 2016/17 due to a gas connection not proceeding because of a change in customer requirements. Therefore the PARCA related to this connection has been duly terminated.
Correction Term (-K)	37.4	16.1	The correction term in 2016/17 is based on the £15.5m under-collection of revenue in 2014/15 (as reported in the 2014/15 submission) uplifted as per the licence algebra requirements. There has been a reduction in Kt from the £37.4m reported in 2015/16 as the over recovery was lower in 2014/15 compared with that in 2013/14.
Maximum Allowed Revenue	747.1	797.6	

Maximum Allowed Revenue - SO

511. The Gas Transmission SO Maximum Allowed Revenue for 2016/17 out-turned at £282.7m.

Licence Term	2015/16 (£m)	2016/17 (£m)	Commentary for year on year variance
Base Revenue (SOBR)	165.8	160.2	<ul style="list-style-type: none"> • +£4.9m (2015/16 price base) equivalent to 6% increase in opening base revenue allowances. • -£25.3m (2015/16 price base) equivalent to 26% decrease in legacy revenue drivers. • +£18.2m (2015/16 price base) increase in MOD. <p>Detailed MOD commentary included in Final Proposals base revenue against adjusted base revenue section.</p> <ul style="list-style-type: none"> • -£4.1m relating to TRU (2015/16 price base) in 2016/17 as a result of the movement between forecast and actual RPI in 2014/15.

Licence Term	2015/16 (£m)	2016/17 (£m)	Commentary for year on year variance
			• +£0.8m due to further year's RPI uplift.
Constraint Management (CM)	11.9	11.6	<p>The 2016/17 revenue includes the 2016/17 ex-ante allowance of £32.0m plus the cost adjustment of -£34.6m plus incentive revenue of £14.2m for 2014/15 performance. All values are quoted after the WACC and RPIF uplifts have been applied.</p> <p>The cost adjustment and incentive revenues are subject to a two year lag from the year of performance.</p>
Transportation Support Services (TSS)	3.5	3.5	<p>The 2016/17 revenue includes the 2016/17 ex-ante allowance of £8.9m plus the cost adjustment of -£9.7m plus incentive revenue of £4.3m for 2014/15 performance. All values are quoted after the WACC and RPIF uplifts have been applied.</p> <p>The cost adjustment and incentive revenues are subject to a two year lag from the year of performance.</p>
Permits (DELINC)	-	-	This term was applicable to 2013/14 revenues only.
Incentives (SOOIRC)	114.7	103.2	
Correction Term (-SOK)	-10.2	4.2	The correction terms in 2016/17 is based on the £4.0m under-collection of revenue in 2014/15 (as reported in the 2014/15 submission) uplifted as per the licence algebra requirements.
Maximum Allowed Revenue	285.7	282.7	

Appendix II – Totex Tables

Totex National Grid Gas Transmission 2016/17

2.4 Published Totex

Actual/Forecast Expenditure (£m, 2016/17 Prices)

	Actual 2014	Actual 2015	Actual 2016	Actual 2017	RIIO-T1 Forecast				Total
					2018	2019	2020	2021	
TO									
Load Related Capex	3.6	1.5	1.4	1.7	5.0	11.2	9.1	3.2	36.6
Asset Replacement Capex	52.7	58.9	71.8	92.8	100.2	88.6	82.7	69.4	617.0
Other Capex	38.1	34.9	33.7	18.7	64.4	92.9	80.3	138.7	501.8
Non Operational capex	12.9	12.2	13.7	22.1	26.4	30.3	9.8	9.7	137.1
Total Capex	107.3	107.6	120.6	135.2	196.0	223.0	181.9	221.0	1,292.6
Opex									
Faults	9.0	6.3	3.2	4.3	5.0	5.2	4.4	4.1	41.5
Planned Inspections and Maintenance	25.3	27.1	24.4	27.4	35.0	36.4	30.5	28.4	234.5
Other direct costs	1.1	6.6	5.1	5.0	5.3	5.3	5.2	5.2	38.7
Closely Associated Indirect Costs	22.4	19.7	24.3	29.9	36.4	37.9	31.8	29.5	231.9
Business Support	23.6	25.5	28.9	31.0	31.9	32.7	31.5	31.1	236.3
Adjustment for IAS 19 pension accrual	- 0.6	0.2	- 0.2	- 0.7	-	-	-	-	1.4
Total Controllable Opex	80.8	85.4	85.8	96.8	113.6	117.5	103.3	98.2	781.5
UNCERTAIN EXPENDITURE									
Load Related Capex	-	-	-	-	-	-	-	-	-
Asset Replacement Capex	-	2.3	2.5	30.7	58.9	46.1	27.7	6.8	175.0
Other Capex	37.6	24.4	14.9	4.0	22.8	25.2	66.6	36.4	231.8
Total Uncertain Capex	37.6	26.8	17.4	34.7	81.7	71.2	94.2	43.1	406.8
Controllable Opex	6.3	4.5	6.3	7.9	22.3	8.4	8.2	6.9	70.7
TO TOTE	232.0	224.2	230.0	274.7	413.6	420.2	387.6	369.3	2,551.6
SO									
Non Operational capex	21.8	33.5	43.9	32.9	44.4	44.8	33.4	25.5	280.2
Direct costs	21.5	26.2	25.1	33.3	36.4	35.2	33.9	33.3	244.9
Business Support	22.8	23.5	23.9	26.2	26.2	25.8	25.9	25.6	199.9
Adjustment for IAS 19 pension accrual	- 0.4	0.2	- 0.2	- 0.6	-	-	-	-	1.0
Controllable Opex	43.9	49.9	48.9	59.0	62.6	61.0	59.8	58.9	443.8
SO TOTE	65.7	83.3	92.8	91.9	107.0	105.8	93.2	84.4	724.1

Total Allowances (£m, 2016/17 Prices)

	RIIO-T1 Allowances								Total
	2014	2015	2016	2017	2018	2019	2020	2021	
TO									
Load Related Capex	18.6	7.6	1.5	1.3	7.3	6.2	0.3	-	42.7
Asset Replacement Capex	106.6	123.1	132.4	144.7	163.0	139.2	117.3	104.8	1,031.0
Other Capex	33.0	22.3	13.2	15.6	39.3	40.1	25.2	7.9	196.6
Non Operational capex	12.7	11.9	8.1	7.5	6.8	5.1	7.8	7.2	67.2
Total Capex	170.8	164.8	155.3	169.1	216.5	190.7	150.6	119.8	1,337.6
Opex									
Faults	7.9	8.0	8.1	8.1	8.2	8.2	8.3	8.4	65.3
Planned Inspections and Maintenance	27.9	28.1	29.0	28.9	29.3	29.5	30.6	30.1	233.4
Other direct costs	6.4	6.8	11.4	21.9	27.3	27.3	20.9	16.8	138.6
Closely Associated Indirect Costs	18.7	19.5	20.2	20.1	20.3	20.3	20.3	20.6	159.9
Business Support	18.3	17.7	18.2	18.5	18.5	18.7	19.1	19.3	148.3
Adjustment for IAS 19 pension accrual	-	-	-	-	-	-	-	-	-
Total Controllable Opex	79.2	80.1	86.9	97.5	103.6	104.0	99.1	95.2	745.5
UNCERTAIN EXPENDITURE									
Load Related Capex	-	-	-	-	-	-	-	-	-
Asset Replacement Capex	-	2.3	2.5	30.7	58.9	46.1	27.7	6.8	175.0
Other Capex	1.3	4.7	- 19.8	- 62.3	- 51.9	- 29.2	19.3	94.8	- 43.3
Total Uncertain Capex	1.3	7.0	- 17.3	- 31.6	7.1	16.8	46.9	101.5	131.7
Controllable Opex	4.3	2.5	2.6	3.6	18.7	4.4	3.7	1.7	41.4
TO TOTE	255.6	254.4	227.5	238.5	345.7	315.9	300.4	318.3	2,256.2
SO									
Non Operational capex	65.8	41.0	33.8	35.3	45.1	38.8	36.4	26.9	323.1
Direct costs	54.2	57.1	63.0	64.8	59.9	64.2	65.5	64.8	493.3
Business Support	-	-	-	-	-	-	-	-	-
Adjustment for IAS 19 pension accrual	-	-	-	-	-	-	-	-	-
Controllable Opex	54.2	57.1	63.0	64.8	59.9	64.2	65.5	64.8	493.3
SO TOTE	120.0	98.1	96.7	100.0	105.0	102.9	101.9	91.7	816.4

Variance Actual/Forecast v Allowances

	Variance to Allowance								Total
	2014	2015	2016	2017	2018	2019	2020	2021	
TO									
Load Related Capex	14.9	6.1	0.1	- 0.4	2.3	- 4.9	- 8.8	- 3.2	6.1
Asset Replacement Capex	54.0	64.1	60.6	52.0	62.7	50.5	34.6	35.4	414.0
Other Capex	- 5.1	- 12.6	- 20.5	- 3.2	- 25.1	- 52.8	- 55.2	- 130.8	- 305.2
Non Operational capex	- 0.3	- 0.3	- 5.6	- 14.5	- 19.5	- 25.1	- 2.0	- 2.5	- 69.9
Total Capex	63.5	57.2	34.7	33.9	20.4	- 32.4	- 31.3	- 101.1	45.0
Opex									
Faults	- 1.1	1.7	4.9	3.8	3.2	3.0	3.9	4.4	23.8
Planned Inspections and Maintenance	2.6	1.0	4.5	1.6	- 5.6	- 6.9	0.1	1.7	- 1.1
Other direct costs	5.3	0.2	6.3	16.9	22.0	22.0	15.7	11.6	99.9
Closely Associated Indirect Costs	- 3.7	- 0.2	- 4.1	- 9.8	- 16.1	- 17.6	- 11.5	- 9.0	- 71.9
Business Support	- 5.4	- 7.7	- 10.7	- 12.5	- 13.5	- 14.0	- 12.4	- 11.8	- 88.0
Adjustment for IAS 19 pension accrual	0.6	- 0.2	0.2	0.7	-	-	-	-	1.4
Total Controllable Opex	- 1.6	- 5.3	1.2	0.7	- 10.0	- 13.6	- 4.2	- 3.1	36.0
UNCERTAIN EXPENDITURE									
Load Related Capex	-	-	-	-	-	-	-	-	-
Asset Replacement Capex	-	0.0	0.0	-	-	-	-	-	0.0
Other Capex	- 36.3	- 19.8	- 34.6	- 66.3	- 74.7	- 54.4	- 47.3	58.4	- 275.1
Total Uncertain Capex	- 36.3	- 19.8	- 34.6	- 66.3	- 74.7	- 54.4	- 47.3	58.4	- 275.1
Controllable Opex	- 2.0	- 2.0	- 3.7	- 4.3	- 3.6	- 4.0	- 4.5	- 5.2	- 29.4
TO TOTE	23.6	30.2	- 2.5	- 36.1	- 67.9	- 104.3	- 87.3	- 51.0	- 295.4
SO									
Non Operational capex	44.0	7.5	- 10.1	2.3	0.8	- 6.0	3.0	1.4	42.8
Direct costs	32.6	31.0	37.8	31.5	23.5	29.0	31.6	31.4	248.4
Business Support	- 22.8	- 23.5	- 23.9	- 26.2	- 26.2	- 25.8	- 25.9	- 25.6	- 199.9
Adjustment for IAS 19 pension accrual	0.4	- 0.2	0.2	0.6	-	-	-	-	1.0
Controllable Opex	10.3	7.3	14.1	5.8	- 2.7	3.2	5.7	5.9	49.5
SO TOTE	54.3	14.8	4.0	8.1	- 2.0	- 2.8	8.6	7.3	92.3

Totex

National Grid Gas Transmission

2016/17

2.5 Published Outputs

1. Stakeholder Satisfaction

	2014	2015	2016	2017	2018	2019	2020	2021
NGGT Customer survey - baseline	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9
NGGT Customer survey - score	7.2	7.6	7.6	8.0	-	-	-	-
Stakeholder survey - baseline	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4
Stakeholder survey - score	7.8	7.9	8.0	8.0	-	-	-	-

2. Incremental Capacity

	2014	2015	2016	2017	2018	2019	2020	2021
Signals for incremental capacity (GWh/day)								
Entry								
Exit								

3. Gas Constraints

	2017
Constraint management revenues - Entry	3.0
Constraint management revenues - Exit	0.5
Constraint management costs - Entry	0.6
Constraint management costs - Exit	0.0