Price Control for Northern Ireland's Gas Distribution Networks GD17

Final Determination

15 September 2016



About the Utility Regulator

The Utility Regulator is the independent non-ministerial government department responsible for regulating Northern Ireland's electricity, gas, water and sewerage industries, to promote the short and long-term interests of consumers.

We are not a policy-making department of government, but we make sure that the energy and water utility industries in Northern Ireland are regulated and developed within ministerial policy as set out in our statutory duties.

We are governed by a Board of Directors and are accountable to the Northern Ireland Assembly through financial and annual reporting obligations.

We are based at Queens House in the centre of Belfast. The Chief Executive leads a management team of directors representing each of the key functional areas in the organisation: Corporate Affairs; Electricity; Gas; Retail and Social; and Water. The staff team includes economists, engineers, accountants, utility specialists, legal advisors and administration professionals.

Our Mission	Value and sustainability in energy and water.
Our Vision	We will make a difference for consumers by listening, innovating and leading.

Our Values

Be a best practice regulator: transparent, consistent, proportional, accountable, and targeted.

Be a united team.

Be collaborative and co-operative.

Be professional.

Listen and explain.

Make a difference.

Act with integrity.

Abstract

We are publishing the final determination for GD17, the price control for the gas distribution companies Phoenix Natural Gas Ltd (PNGL), firmus energy (FE) and SGN Natural Gas Limited (SGN) for the years from 2017 and onwards. The final determination sets out a package of measures to continue the efficient growth of the gas industry in NI through building more pipelines and increased connections.

The price control sets out the amount the gas distribution companies will have to run their businesses and invest in the gas network. The key decisions for the companies are on operating and capital expenditure allowances, targets for new gas pipelines and connections and the rate of return.

Audience

Industry, consumers & statutory bodies.

Consumer Impact

The determination results in a reduction in current distribution charges (before inflation) for all customers.

For FE domestic customers the reduction equates to around £16 per annum in overall bills against current tariffs.

For PNGL domestic customers the reduction is around £1 per annum against current tariffs.

For SGN customers the determination is the first to set distribution charges and results in domestic bills around £33 per annum less than the SGN submission.

For industrial and commercial customers the reductions will be much greater given their higher consumption levels.

Distribution charges make up around 40% of the total domestic customer bill.

Our final determination provides for investment of £226m, sets targets for an additional c89k customers to connect to gas and allows 1,377km of additional gas pipelines to be built. This will ensure a further c134k more customers will have gas outside their property which means by 2022 60% of NI properties will have access to the benefits of natural gas.

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ACRONYMS AND GLOSSARY

ACRT	Annual/Cost Reporting Template
AGSNI	SSE Airtricity Gas Supply Northern Ireland
AIP	Applicant Information Pack for Gas to the West Licence award competition
BPT	Business Plan Template
BSI	British Standards Institution
Capex	Capital expenditure
CAPM	Capital Asset Pricing Model. A model that describes the relationship between risk and expected return.
CBA	Cost Benefit Analysis
cc	Carbon copy
CC	Competition Commission
CCNI	Consumer Council for Northern Ireland
CEAP	Consumer Engagement Advisory Panel
CEOG	Consumer Engagement Oversight Group
CEWG	Consumer Engagement Working Group
ceteris paribus	Other factors remaining constant
CM/SAT	Customer Measures / Customer Satisfaction working Group
CMA	Competition and Markets Authority. The Competition and Markets Authority (CMA) is a non-ministerial government department in the United Kingdom, responsible for strengthening business competition and preventing and reducing anti-competitive activities. The CMA began operating fully on 1 April 2014, when it assumed many of the functions of the previously existing Competition Commission and Office of Fair Trading, which were abolished.

CNG	Compressed Natural Gas
Competition Commission	The statutory body that deals with rejections of price controls and makes a new determination and decision after listening to the evidence from all related parties. From 1 April 2014, this organisation has changed its name to the Competition and Market Authority (CMA).
DAV	Depreciated Asset Value
DD	Draft determination
DECC	Department for Energy and Climate Change
DETI	Department for Enterprise, Trade and Investment
DfI	Department for Infrastructure
DNO	Distribution Network Operator
Domestic Premises	Premises where the supply of gas is taken wholly or mainly for domestic purposes
Domestic New Build	Domestic Premises which have never previously been owned or occupied by any person (that is they are, or are to be, newly built premises) and in respect of which the connection to the Network shall be made prior to the premises first being occupied, but excluding any such premises which fall within the definition of NIHE.
DPA	Data Protection Act 1998
DRD	Department for Regional Development
DRS	Discretionary Reward Scheme
e.g.	For example
etc.	Et cetera (and so forth)
European Gas Directive	Directive 2009/73/EC of the European Parliament of 13 July 2009 concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC
FAQ	Frequently asked questions
FCO	First Call Operative

FD	Final Determination
FE	firmus energy (Distribution) Ltd
FMA study	A study by Fingleton McAdam (FMA) to determine the technical and economic feasibility of extending the natural gas network in Northern Ireland.
FOCD	First Operational Commencement Date
FOIA	Freedom of Information Act 2000
G2W	Gas to the West. This is the name of the project aiming to extend the Natural Gas Network, to other areas of the province, namely Dungannon, Cookstown, Magherafelt, Enniskillen, Omagh and Strabane
GB	Great Britain
GD14	This is the name given to the price control for PNGL and FE. It covers the period 2014 – 2016 (calendar years).
GD17	This is the name given to the next price control for the NI GDNs. It is proposed to cover the period 2017 – 2022 (calendar years).
GD23	This is the name given to the next price control for the NI GDNs. It is proposed to cover the period for the calendar years 2023 and beyond.
GDN	Gas distribution network operator – FE, PNGL and SGN
GDPCR1	GB Gas Distribution Price Control for the years 2008-013
GNI	Gas Networks Ireland
I&C	Industrial and commercial
i.e.	that is
IGT	Independent Gas Transporter
IT	Information Technology
INEA	Innovation & Networks Executive Agency
Manufacturing NI	Manufacturing Northern Ireland
MEAV	Modern Equivalent Asset Valuation
MEUC	Major Energy Users' Council
NEA	National Energy Action Northern Ireland

NI	Northern Ireland
NIE	Northern Ireland Electricity
NIED	Northern Ireland European Development
NIEH	Northern Ireland Energy Holdings
NIEN	Northern Ireland Electricity Networks
NIHE	Domestic Premises which are (or will be when built) owned by: (a) the Northern Ireland Housing Executive; or (b) a housing association in Northern Ireland.
NINGA	NI Natural Gas Association
NISEP	Northern Ireland Sustainable Energy Programme
Ofgem	Office of Gas and Electricity Markets. Regulates the electricity and gas markets in Great Britain.
Ofwat	The economic regulator of the water sector in England and Wales.
OLEV	Office for Low Emission Vehicles
OO (Owner Occupied)	Domestic Premises which do not fall into the definition of: • Domestic New Build; or • NIHE.
Opex	Operating expenditure
p.	page
PAS55	The British Standards Institution's (BSI) "Publicly Available Specification" for the optimised management of physical assets
PC13	PC13 is the second price control for NI Water, which runs from 1 April 2013 until 31 March 2015
PC15	PC15 is the third price control for NI Water, which runs from 1 April 2015 until 31 March 2021
Pi model	Model used for the calculation of conveyance charges for the GDNs.
PIMR	Perceptive Insight Market Research
PMICR	Post-Maintenance Interest Coverage Ratio

PNGL	Phoenix Natural Gas Limited
PNGL12	This is the name given to the price control for PNGL, covering calendar years 2012 and 2013.
PRE	Public Reported Escapes
Profile adjustment	Mechanism embedded in the conveyance licences for NI GDNs which levelises tariffs and profile costs over the period up to the forecasting horizon
PRS	Pressure Reduction Station. A pressure reduction equipment having an inlet pressure greater than 7 barg.
RAB	Regulatory Asset Base
Re	Regarding
REMM	Retail Energy Market Monitoring
RIGS	Regulatory Instructions and Guidance
RIIO	Revenue = Incentives + Innovation + Outputs Price control framework used by Ofgem
RIIO-ED1	This is the first electricity distribution price control by Ofgem under the new RIIO (Revenue = Incentives + Innovation + Outputs) model. The price control is set for an eight-year period from 1 April 2015 to 31 March 2023.
RIIO-GD1	This is the first gas distribution price control by Ofgem under the new RIIO (Revenue = Incentives + Innovation + Outputs) model. The price control is set for an eight-year period from 1 April 2013 to 31 March 2021.
RIIO-GD2	This is the second gas distribution price control by Ofgem under the new RIIO (Revenue = Incentives + Innovation + Outputs) model. The price control is set to take effect on 1 April 2021.
RP5	This is the name given to the price control for NIE, covering the period from 1 April 2012 to 30 September 2017.
RPI	Retail Price Index
SGN	SGN Natural Gas Limited
Shrinkage	Difference between the amount of gas that was recorded to have entered the distribution system and to have exited it.

	Includes: • gas loss through theft; • gas loss through leaks/emergencies; • own use.
SOC Code	Standard Occupational Classification Code
SoLR	Supplier of Last Resort
SONI	System Operator for Northern Ireland and the Transmission System Operator for Northern Ireland
TEN-T	Trans-European Transport Network
TMA	Traffic Management Act. The objective of the TMA is to tackle congestion and disruption on the road network. The TMA places a duty on local traffic authorities to ensure the expeditious movement of traffic on their road network and those networks of surrounding authorities. This has yet to come into force in Northern Ireland, at time of writing.
Totex	Total expenditure, i.e. the sum of capex and opex.
TRV	Total Regulatory Value: the Depreciated Asset Value plus any incentive adjustments including the profile adjustment.
TSO	Transmission System Operator
UKRN	United Kingdom Regulators Network
UKRPA	United Kingdom Revenue Protection Association

1 Executive Summary

Introduction

1.1 This document represents the final determination for the GD17 price control process.

1.2 GD17 is the name given to the price control for the six-year-period from 1 January 2017 onwards for the three gas distribution network operators (GDNs) in Northern Ireland (NI):

- Phoenix Natural Gas Ltd (PNGL)
- firmus energy (FE)
- SGN Natural Gas Limited (SGN)[1]

1.3 The purpose of the price control is to put in place a package of measures to challenge the GDNs to develop the industry over the next six years in line with our statutory duties. The aim of this price control is to deliver a gas industry with more connections and more mains network to extend the benefits of gas to more customers. The package encourages the industry to innovate to achieve more connections and to continue to find efficiencies to ensure the GDNs are comparable to the most efficient operators in the UK.

1.4 A fundamental part of the price control is determining how much the licence holders can charge for the transportation of gas through their networks. The price control sets out the amounts the GDNs have to run their businesses and invest in the gas network. Key decisions for the companies are on operating and capital expenditure allowances, targets for new gas mains and connections, rate of return and volume forecasts.

1.5 Our consultation on the draft determination[2] closed on 31 May 2016. We received eleven responses to the consultation.

1.6 The most important points made in each of the responses, and our response in turn to these, are provided in Annex 13 of this document.

1.7 In formulating our final decisions we have fully and carefully considered each of the responses as well as any new information submitted to us. We have assessed the responses in the light of our statutory duties. As a result, we have adjusted a number of allowances as discussed in the body of this document.

1.8 This document is accompanied by a consultation which includes the licence modifications[3] required to implement the final determination.

1.9 Figures are presented in December 2014 prices.

[1] As detailed in Chapter 3, the first price control for SGN begins on 1 January 2018. Hence, the SGN price control period is for five years only.
[2] http://www.uregni.gov.uk/uploads/publications/2016-03-16_GD17_Draft_Determination_-_Final.pdf
[3] http://www.uregni.gov.uk/publications/2016-09-15_gd17_lic_mod_consultation_-_final

Our Statutory Duties and Regulatory Principles

1.10 Our principal objective in carrying out our gas functions is to promote the development and maintenance of an efficient, economic and co-ordinated gas industry in Northern Ireland, and to do so consistently with our fulfilment of the objectives set out in the European Gas Directive, and by having regard to a number of matters, as set out more fully in the Energy (Northern Ireland) Order 2003.

1.11 Gas Distribution Networks are natural monopolies; it does not make economic sense for a number of businesses to build, maintain and operate gas distribution networks in the same geographic area. A price control is a method to ensure that providers of monopoly services act in the consumer interest.

1.12 In summary, taken in the round, we interpret our duties, in the context of carrying out price controls, as a broad mandate to:

- secure the most cost efficient outcome for the protection of consumers and the promotion of the gas industry in Northern Ireland;
- ensure the gas distribution network operators can continue to finance the activities which are the subject of obligations placed on them; and
- have due regard to all relevant factors.

1.13 It is our aim to do this by:

- providing a strong foundation for the continued and long-term growth of gas distribution networks and delivering service improvements to consumers;
- challenging the GDNs to improve their efficiency and performance at an achievable and sustainable rate;
- promoting long term planning by the licensees and securing the continuity of necessary and efficient investment; and
- ensuring that revenues and prices are set at the minimum levels that are consistent with efficient operation.

1.14 The price controls for each of the companies considered in this final determination are complex, and comprise many different elements. In this context, we interpret our obligation to further our principal objective and fulfil our duties as being a requirement to do so taking all of the elements of each price control together, and viewing the overall price control in the round. Certain aspects of each company's price control may be weighted so that they make particular contributions to the fulfilment of certain aspects of our objective and duties, but no part of the control should be considered in isolation. We aim to ensure that the balance which we are required to strike, having regard to all of the different elements of our objective and duties, is struck in setting each price control as a totality.

Approach

1.15 Following engagement with the GDNs and other key stakeholders during the first quarter of 2015 and after due consideration of the responses received, we published, on 17 April 2015, an update on our overall approach for the GD17 price control. This was followed on 14 May 2015 by the publication of the final GD17 business plan data templates with associated RIGs (regulatory instructions and guidance). The business plans were submitted by the GDNs within the requested timelines. After due consideration the draft determination[4] was published on 16 March 2016.

1.16 We determine price controls for the companies by reviewing their submissions and assessing an efficient level of operating, financing and capital costs to run their businesses and to continue to promote the development of gas within NI.

1.17 For SGN these costs have already largely been identified through its application in the Gas to the West (G2W) licence competition in 2014 and thus, this is a key factor in our consideration. For FE and PNGL a more standard assessment has been applied.

1.18 To assess operating expenditure (opex), we have undertaken a detailed bottom up assessment of the larger cost items taking into account the most recent actual level of expenditure and any changes as a result of changes in outputs. We reflect increases in revenue from latest actual figures where strong justification has been presented. We have worked with our consultants Rune Associates on the maintenance and emergency aspect of opex and applied modelling results in arriving at our figures.

1.19 We have also carried out top down benchmarking with GB GDNs. We have proposed figures based on our bottom up assessment but we intend that our benchmark modelling will be a key part of monitoring local GDNs' respective efficiency performances within our Annual/Cost Reporting publications.

1.20 We have undertaken a detailed assessment of capital expenditure (capex) proposals in conjunction with our engineering consultants, Rune Associates. This has included a review of existing market rates and benchmarking to identify an efficient level of expenditure. We have used a basket of works approach in line with GD14 and other regulators to produce a consistent set of rates into GD17. Our proposed infill mains projects are based on an economic assessment similar to GD14.

1.21 In order to set allowed revenues, we also have to determine an estimate of volumes and we have done this by starting with the current volumes and adjusting this for expected additional connections and specific changes in large customers. For SGN we have relied on the profile of connections set out in the G2W licence competition and applied this to the recent customer data used in designing the network.

1.22 Once we decided upon the level of capex and opex we applied frontier shift across the GD17 period. Our frontier shift assessment is the same for each GDN regardless of relative proportion of labour and materials etc, so that we assess frontier shift on what is the appropriate Real Price Effect (RPE), relative to RPI, for an efficient company using a weighted average of RPEs. We then include our assessment of what a company would improve with regards productivity. The exception to this is SGN opex where we concluded that its G2W licence application figures incorporated an RPE and efficiency element.

1.23 GD17 requires the setting of a weighted average cost of capital (WACC) for PNGL and FE for the first time. We have applied the Capital Asset Price Model (CAPM) and taken into account latest regulatory precedents in arriving at our proposal. As a member of the UK Regulatory Network (UKRN) we have worked with other UK regulators to have our proposals peer reviewed and this has fed into our considerations in arriving at the final determination.

[4] Utility Regulatory: Price Control for Northern Ireland's Gas Distribution Networks GD17, Draft Determination, 16 March 2016.

1.24 We have also undertaken modelling of FE's and PNGL's financeability and considered their ability to raise any debt or equity, as appropriate, to finance their businesses. This analysis considered some of the key financial indicators used by credit rating agencies.

1.25 Determination of opex, capex, volumes, WACC, allowed returns and the TRV enables us to set tariffs. Tariffs are set on a "levelised" basis, that is, given the cost projections until the end of the forecast horizon, the tariffs are set equal in each year of the licence.

1.26 There is a difference between the GDNs. For PNGL and FE we set allowed *revenue* each year. For SGN we set allowed *tariffs* in each year. The capping of tariffs rather than revenue is more appropriate for a company in the early stage of its development as it provides strong incentives to increase volumes and to develop the gas industry.

1.27 As set out in our Approach decision we continue to regard the main aim of GD17 as the growth of the industry and we have focused our outputs in this area. We have included two incentive mechanisms to appropriately encourage the GDNs to continue the growth of an economic gas industry. The two mechanisms are:

- A connections incentive which rewards the GDNs for connecting owner-occupied (OO)[5] domestic customers. In GD14 we had considered that there would be a large reduction in the incentive but we decided on a more gradual reduction in the incentive up to 2022. Furthermore we have increased the incentives since the draft determination to reflect the challenge of the GDNs entering significant new areas;
- A properties passed incentive, which incentivises the GDNs to lay infill mains to pass more properties that do not currently have access to natural gas.

Summary of Key Changes from the Draft Determination

1.28 For ease of reading, at the beginning of each section we have highlighted the main changes that we have made since the draft determination.

1.29 Since the draft determination and after considering the responses to our consultation, further discussions, analysis and evidence provided, we have made the following changes.

1.30 Overall capex allowances increase for FE by c.14% and PNGL by c.2% and decreased by c.2% for SGN.

1.31 We have increased capex unit rates in some areas for FE and SGN, particularly on services.

1.32 We have increased the amount of infill mains allowed for FE by 52km and PNGL by 12km. We have reduced the SGN infill mains by 97km which reflects the reductions in its updated development plan.

1.33 We have decreased target domestic owner occupier connections for SGN by c.1k and PNGL by c.4k with FE remaining unchanged

1.34 We have increased total opex allowances for FE by c.14%, PNGL by c.5% and SGN by c.8%.

[5] Note that owner-occupied domestic premises are those domestic premises that do not fall into the definition of domestic new build or NIHE. In particular, OO domestic premises as defined here can also be private rented.

1.35 We have included an additional connections incentive allowance linked to new areas which amounts to £2.3m for FE, £1.1m for PNGL and £2.2m for SGN. We have also changed the cap/collar regime for all GDNs.

1.36 We have reduced our frontier shift so the net cumulative effect is 4.4% for opex and 4.2% for capex.

1.37 The rate of return has been changed slightly to a pre-tax figure of 4.32% for FE, 4.26% for PNGL and a vanilla rate of 5.3% for SGN.

1.38 We have reduced the estimated volume figures for SGN to 119m therms in GD17 and have applied reductions to volume assumptions beyond 2022 for all GDNs.

1.39 We have introduced a glide path reduction to the rate applied to FE under recoveries.

1.40 There has been no significant change to the opening GD17 TRV assessment with FE at £144.6m, PNGL at £595.6m. The SGN OAV is assessed at £3.76m.

FE

1.41 A summary of the overall final determination for FE is presented in Table 1

Opex (£m, in Dec 2014 prices)	2017	2018	2019	2020	2021	2022	Total
FE Submission (pre efficiencies)	7.2	7.5	7.6	8.0	8.5	9.1	**47.9**
GD17 Final Determination (post efficiencies)	6.4	6.3	6.5	6.7	7.0	7.2	**40.1**

Capex (£m, in Dec 2014 prices)	2017	2018	2019	2020	2021	2022	Total
FE Submission (pre efficiencies)	14.8	14.1	14.2	14.7	15.1	16.2	**89.3**
GD17 Final Determination (post efficiencies)	17.1	14.3	14.5	14.8	15.1	15.4	**91.2**

Revenues (£m, in Dec 2014 prices)	2017	2018	2019	2020	2021	2022	Total
FE Submission	18.9	19.6	20.5	21.4	22.4	23.5	**126.4**
GD17 Final Determination	17.9	17.9	18.8	19.7	20.7	21.7	**116.8**

Properties Passed (p.a.)	2017	2018	2019	2020	2021	2022	Total
FE Submission	12,293	11,917	12,445	11,373	11,682	12,487	**72,197**
GD17 Final Determination	12,166	11,871	12,328	11,214	11,565	12,473	**71,617**

Connections (p.a.)	2017	2018	2019	2020	2021	2022	Total
FE Submission - Total	4,216	4,287	4,372	4,503	4,850	4,996	27,224
- Owner Occupied	2,466	2,537	2,622	2,753	3,100	3,246	**16,724**
- New Build	800	800	800	800	800	800	**4,800**
- NIHE	800	800	800	800	800	800	**4,800**
- Small and Medium I&C	147	147	147	147	147	147	**882**
- Large and Contract I&C	3	3	3	3	3	3	**18**
GD17 Final Determination	4,350	4,700	5,050	5,350	5,650	5,850	30,950
- Owner Occupied	2,600	2,950	3,300	3,600	3,900	4,100	**20,450**
- New Build	800	800	800	800	800	800	**4,800**
- NIHE	800	800	800	800	800	800	**4,800**
- Small and Medium I&C	147	147	147	147	147	147	**882**
- Large and Contract I&C	3	3	3	3	3	3	**18**

Table 1: FE Final Determination Allowances

1.42 For capex, the final determination allows capital investment of £91.2m following the application of the frontier shift compared with the FE submission of £89.3m. The increase in the allowance includes an increased owner occupier connection target and the addition of a new crossing of the River Foyle to secure supplies in Derry/Londonderry. This has been off-set by reduced unit rates in some areas when we roll forward the basket of works rates into GD17 and some areas where we have not allowed certain work items e.g. meter replacement.

1.43 We have updated our assessment for infill mains taking account of detailed information on development of the gas network and gas consumption provided by FE. Our final determination includes 713km of new mains (including new build areas) which is a significant increase on GD14 levels and facilitates 72k more customers having access to gas outside their property.

1.44 For opex we have proposed £40.1m over GD17 after application of the frontier shift compared to FE's proposal of £47.9m.

1.45 We have carefully considered the responses regarding the connections incentive. All parties recognise that a significant element of the connections incentive was put in place to increase awareness of gas as a fuel of choice in NI. To a significant extent this has been achieved which was reflected in our proposal to glide path from the current level of £573 per applicable connection in 2016 down to £420 in 2022. However many of the responses highlighted the challenging conditions facing the GDNs and the need to ensure OO connections continued to receive a strong focus from the GDNs. In consideration of the particular challenge that GDNs face in new areas where there is a need to establish gas as the fuel of choice, we have introduced a new areas incentive for GD17. This has increased the incentive for FE resulting in a range from £700 in 2017 to £570 in 2022.

1.46 For the target number of connections we have taken into account our significant infill mains allowance which will make gas available to more customers. We therefore propose to set a target for FE to connect c.20k OO customers for the GD17 period. For the purpose of calculating the connections incentive we propose to retain the non-additionality rate at 25% for FE to reflect the fact that it still has a significant percentage of customers unconnected.

1.47 For other opex, we have largely applied the latest actual costs with increases in some areas where they have been justified and evidenced from historical trends. Since the draft determination we have provided an additional £2.8m with noticeable increases in insurance and system control.

1.48 For both capex and opex we have assumed productivity growth of 1% per annum as well as applying real price effects to determine our frontier shift.

1.49 Our WACC analysis has resulted in a real cost of debt for FE of 2.45% and a pre tax cost of equity of 6.6%. We have taken a somewhat cautious approach in setting the cost of equity slightly higher than recent UK regulatory decisions e.g. Ofgem's RIIO ED1. We have largely retained our cost of debt figures from the draft determination. Overall we have determined a pre-tax WACC of 4.32%. Given the level of uncertainty for FE in raising so much debt in GD17 we propose to introduce a debt mechanism to adjust the cost of debt to reflect FE's cost for raising new debt. The mechanism will include a pain gain adjustment so that FE only takes 20% of the pain/gain if the adjusted cost of debt is over/under our final determination allowance.

1.50 We have undertaken modelling of FE's financeability, considering the key financial indicators. This analysis indicates that, based on our assumptions in deriving the WACC and the options open to an efficient company, FE ought to be able to finance its activities through a mix of equity and debt finance.

1.51 As part of its submission FE proposed to change its licence to move the Forecast Horizon from 2035 to 2045. The Forecast Horizon has the effect of smoothing out tariffs over time and the FE proposal would essentially transfer costs from customers in the period before 2035 to customers in the period after 2035. For the final determination we have applied a model using 2045 for the Forecast Horizon.

1.52 We considered the treatment of FE under recoveries in GD14 and the draft determination and now propose to reduce the rate of return that applies from 2017. We have introduced a glide path to allow a gradual alignment of FE with other GDN licences.

1.53 We set out in GD14 that we would review the role of the Profile Adjustment and consider the potential of removing it at some point. This would have the benefit of moving into line with a more standard regulatory model but would result in a significant increase in short term tariffs. We will continue to consider this issue in future but have determined not to make changes in GD17.

1.54 We have reduced volumes for FE to reflect its updated forecasts for GD17. We have also reduced volume forecasts in the period beyond 2023 to mitigate risks associated with potential long term uncertainty in the gas industry.

1.55 This determination produces a drop in domestic distribution tariffs of 4% compared to the FE submission. In comparison with current distribution tariffs the determination produces a reduction of 8%. This would result in domestic customers in the FE area paying around £16 less per annum than currently.

1.56 For I&C customers the difference would obviously be much larger with the larger customers potentially saving tens of thousands of pounds per annum.

1.57 However we would caution that the figures above do not factor in the impact of how FE chooses to charge its under recovery amount and so the impact on customers actual bills may be different.

PNGL

1.58 A summary of the overall final determination for PNGL is presented in Table 2

Opex (£m, in Dec 2014 prices)	2017	2018	2019	2020	2021	2022	Total
PNGL Submission (incl. East Down) -Pre Efficiency	17.0	17.4	17.6	17.9	18.3	18.6	**106.9**
GD17 Final Determination - Post Efficiency	14.7	14.4	14.3	14.3	14.2	14.3	**86.2**

Capex - Post Efficiencies (£m, in Dec 2014 prices)	2017	2018	2019	2020	2021	2022	Total
PNGL Submission (incl. East Down) -Pre Efficiency (Pre PDP Adj)	16.1	17.5	20.8	20.8	18.4	19.2	**112.8**
GD17 Final Determination - Post Efficiency (Pre PDP Adj)	11.6	13.2	16.5	18.2	16.8	16.2	**92.6**

Revenues (£m, in Dec 2014 prices)	2017	2018	2019	2020	2021	2022	Total
PNGL Submission (incl. East Down) -Pre Efficiency	55.7	57.2	58.7	60.2	61.7	63.2	**356.8**
GD17 Final Determination - Post Efficiency (Pre PDP Adj)	51.9	53.3	54.7	56.2	57.7	59.1	**332.9**

Properties Passed (p.a.)	2017	2018	2019	2020	2021	2022	Total
PNGL Submission Rev (incl. East Down)	5,078	6,125	9,589	9,481	9,132	6,758	**46,162**
GD17 Final Determination	3,073	4,020	7,484	7,376	7,027	5,553	**34,532**

Connections (p.a.)	2017	2018	2019	2020	2021	2022	Total
PNGL Submission Rev (incl. East Down)	8,191	8,281	8,707	8,984	9,168	9,306	**52,636**
- Owner Occupied	4,047	4,083	4,197	4,343	4,447	4,533	**25,650**
- New Build	2,821	2,846	3,086	3,112	3,112	3,112	**18,089**
- NIHE	1,006	1,022	1,046	1,095	1,137	1,166	**6,472**
- Small and Medium I&C	312	326	373	430	468	491	**2,400**
- Large and Contract I&C	4	4	4	4	4	4	**25**
GD17 Final Determination	8,343	8,299	8,310	8,340	8,321	8,273	**49,886**
- Owner Occupied	5,000	4,900	4,800	4,700	4,600	4,500	**28,500**
- New Build	2,021	2,046	2,086	2,112	2,112	2,112	**12,489**
- NIHE	1,006	1,022	1,046	1,095	1,137	1,166	**6,472**
- Small and Medium I&C	312	326	373	430	468	492	**2,401**
- Large and Contract I&C	4	4	4	4	4	4	**24**

Table 2: PNGL Final Determination Allowances

1.59 For capex, the final determination allows capital investment of £92.6m following the application of the frontier shift compared with the PNGL submission of £112.8m. Our final determination includes infill mains and connections for the East Down extension as well as the existing PNGL area.

1.60 We have reviewed PNGL's proposals for developing its infill mains in its existing area and carried out an economic assessment. Our conclusion is that much of the proposed infill projects do not pass an economic test and thus we have only allowed those related to new build extensions. This largely reflects the fact that much of the PNGL area is now serviced with gas with only more outlying, and less economic areas left. Our final determination includes the infill mains in the East Down extension area which PNGL plans to carry out in GD17. Our final determination is to allow 372km of mains (including new build areas) for GD17 and facilitates 29k more customer having access to gas outside their property.

1.61 Our decision not to include some of the infill mains proposed by PNGL and a lower forecast of new build connections contribute to the reduction in capital investment as well as a reduction in unit rates in some areas when we roll forward the basket of works rates into GD17.

1.62 For opex we have proposed £86.2m over GD17 after application of the frontier shift compared to PNGL's proposal of £106.9m.

1.63 We have carefully considered the responses regarding the connections incentive. All parties recognise that a significant element of the connections incentive was put in place to increase awareness of gas as a fuel of choice in NI. To a significant extent this has been achieved which was reflected in our proposal to glide path from the current level of £573 per applicable connection in 2016 down to £420 in 2022. However many of the responses highlighted the challenging conditions facing the GDNs and the need to ensure OO connections continued to receive a strong focus from the GDNs. In consideration of the particular challenge that GDNs face in new areas where there is a need to establish gas as the fuel of choice, we have introduced a new areas incentive for GD17. This has increased the incentive for PNGL resulting in a range from £610 in 2017 to £480 in 2022.

1.64 For the target number of connections we have taken into account PNGL arguments that its current level of connections is not sustainable and further considered the impact that the limited increase in infill mains will have on potential connections. We therefore propose to set a target for PNGL to connect c.28k OO customers for the duration of the price control. We propose to set a non-additionality rate at 33% for PNGL. This is an increase from GD14 and reflects our view that the overall incentive should reduce as the level of gas awareness in an area increases.

1.65 We have largely applied the latest actual figures for opex costs with increases in some areas where they have been justified and evidenced from historical trends. Since the draft determination we have provided an additional £3m with noticeable increases in maintenance and customer management costs.

1.66 For both capex and opex we have assumed productivity growth of 1% per annum as well as applying real price effects to determine our frontier shift.

1.67 Our WACC analysis has resulted in a real cost of debt for PNGL of 2.36% and a pre tax cost of equity of 6.6%. We have taken a somewhat cautious approach in setting the cost of equity slightly higher than recent UK regulatory decisions e.g. Ofgem's RIIO ED1. We have not made any adjustment to reflect the very high PNGL TRV:totex ratio. We have largely retained our cost of debt figures from the draft determination. Overall we have determined a pre-tax WACC of 4.26%. Given the level of uncertainty for PNGL in raising so much debt in GD17 we propose to introduce a debt mechanism to adjust the cost of debt to reflect PNGL's cost for raising new debt. The mechanism will include a pain gain adjustment so that PNGL only takes 20% of the pain/gain if the adjusted cost of debt is over/under our final determination allowance.

1.68 We have undertaken modelling of PNGL's financeability, considering the key financial indicators. This analysis indicates that, based on our assumptions in deriving the WACC and the options open to an efficient company, PNGL ought to be able to finance its activities through a mix of equity and debt finance.

1.69 We set out in GD14 that we would review the role of the Profile Adjustment and consider the potential of removing it at some point. This would have the benefit of moving into line with a more standard regulatory model but would result in a significant increase in short term tariffs. We will continue to consider this issue in future but have determined not to make changes in GD17.

1.70 We have reduced volume forecasts in the period beyond 2023 to mitigate risks associated with potential long term uncertainty in the gas industry.

1.71 This determination produces a drop in domestic distribution tariffs of 6% compared to the PNGL submission. In comparison with current distribution tariffs the determination produces a reduction of 1%. This would result in domestic customers in the PNGL area paying around £1 less per annum than currently.

1.72 For I&C customers the difference would obviously be much larger with the larger customers potentially saving thousands of pounds per annum.

SGN

1.73 A summary of the overall final determination for SGN is presented in Table 3

Opex (£m, in Dec 2014 prices)	2017	2018	2019	2020	2021	2022	Total
SGN Submission (Rev)		2.6	2.8	2.3	2.5	2.8	**13.0**
GD17 Final Determination		0.8	2.2	2.0	1.7	2.0	**8.7**

Capex - Post Efficiencies (£m, in Dec 2014 prices)	2017	2018	2019	2020	2021	2022	Total
SGN Submission (Rev)		12.0	10.8	7.3	7.5	7.7	**45.4**
GD17 Final Determination		4.5	12.6	9.6	7.5	7.9	**42.1**

Revenues (£m, in Dec 2014 prices)	2017	2018	2019	2020	2021	2022	Total
SGN Submission (Rev)		2.5	3.4	4.0	4.3	4.6	**18.8**
GD17 Final Determination		0.8	3.2	4.5	5.2	5.6	**19.3**

Volumes (therms m)	2017	2018	2019	2020	2021	2022	Total
SGN Submission (Rev)		17,688	21,893	24,653	25,417	26,258	**115,908**
GD17 Final Determination		5,055	21,811	28,333	31,391	32,804	**119,394**

Properties Passed (p.a.)	2017	2018	2019	2020	2021	2022	Total
SGN Submission (Rev)	4,054	4,586	4,887	4,886	4,875	4,876	**28,163**
GD17 Final Determination	1,044	2,480	6,367	6,802	4,964	4,847	**26,505**

Connections (p.a.)	2017	2018	2019	2020	2021	2022	Total
SGN Submission (Rev)	0	531	875	1,172	1,484	1,647	**5,709**
- Owner Occupied		398	633	869	1,105	1,219	**4,224**
- New Build		0	37	59	81	95	**273**
- NIHE		99	158	217	276	305	**1,056**
- Small and Medium I&C		12	14	18	22	27	**93**
- Large and Contract I&C		22	32	9	0	1	**64**
GD17 Final Determination	401	211	2,957	1,772	1,562	1,789	**8,692**
- Owner Occupied	186	140	1,174	951	634	904	**3,989**
- New Build	0	0	282	264	313	294	**1,154**
- NIHE	156	39	945	266	266	242	**1,914**
- Small and Medium I&C	56	27	532	272	349	349	**1,585**
- Large and Contract I&C	2	5	24	19	0	0	**50**

Table 3: SGN Final Determination Allowances

1.74 For capex, the final determination allows capital investment of £42.1m following the application of the frontier shift compared with the SGN submission of £45.4m. These figures relate to the price control period which begins at the 1 January 2018. A further £2.69m prior to this date is included in the opening asset value. The reduction incorporates a significantly reduced unit rate for mains based on the outturn of our benchmarking results. We did not regard proposals to move away from local benchmark rates as justified.

1.75 Based on the updated information SGN has provided, we have determined to allow 292km of mains for GD17 and facilitate 27k customers having access to gas outside their property. While the company's revised plans for GD17 anticipate a lower rate of infill than its original Business Plan submission, we have maintained the connection targets based on the licence application process and increased the number of I&C connections from the draft determination. Our final determination also includes a ring fenced allowance for the possible implementation of the Traffic Management Act which was not included in the company's submission.

1.76 For opex we have proposed £8.7m over GD17 compared to SGN's proposal of £13m.

1.77 The intention of the G2W licence competition was to apply competitive pressure to costs and to produce an outcome that could be used in the initial price controls. The SGN GD17 submission proposed significant changes from the figures in its licence application. We have carefully considered the arguments presented by SGN both before and after our draft determination. However we have not been convinced that they justify making such significant changes from the licence application figures. However we have decided to make some smaller changes to increase opex to reflect increasing customer numbers which we view as being within the flexibility set out in the G2W licence competition.

1.78 We have carefully considered the responses regarding the connections incentive. All parties recognise that a significant element of the connections incentive was put in place to increase awareness of gas as a fuel of choice in NI. To a significant extent this has been achieved which was reflected in our proposal to glide path from the current level of £573 per applicable connection in 2016 down to £420 in 2022. However many of the responses highlighted the challenging conditions facing the GDNs and the need to ensure OO connections continued to receive a strong focus from the GDNs. In consideration of the particular challenge that GDNs face in new areas where there is a need to establish gas as the fuel of choice, we have introduced a new areas incentive for GD17. This has increased the incentive for SGN resulting in a range from £1110 in 2017 to £1010 in 2022.

1.79 We propose not to apply any non-additionality to SGN, which reflects the arguments SGN has made about the circumstances it faces including the fact that gas is new to the area.

1.80 For the target number of connections we have based the profile of connections on those set out at the time of the licence application. This produces a target for SGN to connect c.4k owner occupier customers over the duration of GD17.

1.81 Our final determination sets total volumes over GD17 at 119m therms. As above with connections we have based our volume assumptions on the profile set out in the G2W licence competition. We have also applied the figures used by SGN in its latest network design work as a basis for understanding the available properties in the area. We have reduced volume forecasts in the period beyond 2023 to mitigate risks associated with potential long term uncertainty in the gas industry.

1.82 For capex we have assumed productivity growth of 1% per annum as well as applying real price effects to determine our frontier shift. No frontier shift has been applied to opex as our view is it will have been factored in to the licence application figures.

1.83 We have set SGN WACC at 5.3% which is based on the licence application figure on a vanilla basis.

1.84 The modelling we have applied in the final determination produces a significant drop in domestic distribution tariffs of 22% compared to the SGN submission.

Impact on Consumer Bills

1.85 The table below sets out a summary of the impact on customers. The percentage columns look at the impact of our determination on the distribution tariff compared to the GDNs submission and compared to the current tariff. The SGN distribution tariff is being set for the first time and therefore no current tariff for comparison purposes is available. The final cash column looks at the impact on total customer bills of our determination compared to the GDNs submission.

	GD17 FD P1 tariff	GD17 distribution tariff v submission	GD17 v GD14 distribution tariff	Customer Saving per annum (v submission)
FE (Av. £2014)	43.35	-4%	-8%	£6.47
PNGL (Sep £2014)	39.51	-6%	-1%	£10.39
SGN (Av. £2014)	28.83	-22%	N/A	£33.20

Table 4: Impact on Domestic Customer Bills

Next Steps

1.86 This final determination is published alongside an accompanying licence modification consultation. This consultation closes on 14 October. We will consider any responses and plan to publish a decision on the licence modification at the start of November. The final determination figures would then become effective on 1 January 2017.

1.87 We intend to closely monitor the costs and performance of the GDNs over the GD17 period and will work with the GDNs to continue to evolve and improve our cost reporting templates. We intend to publish an annual report setting out the progress of the GDNs against GD17 targets.

1.88 Our new partnership model for continuous consumer engagement across all GDNs during GD17 will include moves to make collaborative research a reality, with specific reference towards the development of new customer service metrics and satisfaction surveys during GD17, similar to new customer services measures and metrics being developed in the water sector locally. In so doing our long term aim is to facilitate greater comparability across all of our energy and water companies so that consumers can expect a similarly excellent level of customer experience across local utility providers.

2 Introduction

Summary of Key Changes from Draft Determination to Final Determination

2.1 This document sets out our final decisions for GD17, taken after due consideration of the responses received to our draft determination [6]. For ease of reading, at the beginning of each section we have highlighted the main changes that we have made since the draft determination[6].

2.2 With respect to this chapter 2 Introduction, key changes from the draft determination include in particular:

- Provision of information on the consultation responses received and our consideration of same; and
- Updates to the section on Structure of this Document to reflect that this documents now relates to decisions rather than proposals and to enhance clarity through inclusion of listings of consultation responses and supplementary documents.

Purpose of this Document

2.3 This document represents the final determination for the GD17 price control process.

2.4 GD17 is the name given to the price control for the six-year-period from 1 January 2017 onwards for the three gas distribution network operators (GDNs) in Northern Ireland (NI):

- Phoenix Natural Gas Ltd (PNGL)
- firmus energy (FE)
- SGN Natural Gas Limited (SGN)

2.5 The price control sets out the amount the GDNs have to run their business and invest in the gas network. Key decisions for the companies are on operating and capital expenditure allowances, targets for new gas pipelines and connections, rate of return and forecast volumes.

2.6 This final determination details the decisions of the Authority (the Utility Regulator (UR), us), with respect to the GD17 price control period, on price control allowances, incentive mechanisms and outputs. It also considers the expected impact of these decisions on consumers, in particular the expected impact on distribution charges and consumer bills.

2.7 We note that the decisions detailed in this final have been taken after due consideration of the responses received as part of the consultation on the GD17 draft determination and as part of the ongoing engagement with key stakeholders in the preparation of this document.

[6] Utility Regulatory: Price Control for Northern Ireland's Gas Distribution Networks GD17, Draft Determination, 16 March 2016.

Our Statutory Duties and Regulatory Principles

2.8 Our principal objective in carrying out our gas functions is to promote the development and maintenance of an efficient, economic and co-ordinated gas industry in Northern Ireland, and to do so consistently with our fulfilment of the objectives set out in the European Gas Directive[7], and by having regard to a number of matters, as set out more fully in the Energy (Northern Ireland) Order 2003.

2.9 Gas Distribution Networks are natural monopolies; it does not make economic sense for a number of businesses to build, maintain and operate gas distribution networks in the same geographic area.

2.10 Where a monopoly exists, consumers are not able to change their network operator in order to receive better prices or service levels. In the absence of such competitive pressures, natural monopolies may act against consumer interests by:

- becoming or remaining inefficient, passing higher costs on to consumers than would otherwise be necessary; and/or
- delivering poor levels of service rather than seeking innovative or challenging ways to improve performance while reducing costs.

2.11 By subjecting monopoly service providers to external benchmarking and challenge, independent economic regulation helps ensure that they continue to act in the consumer interest.

2.12 Economic regulators also impose budgetary constraints on the regulated company or companies (while at the same time making sure that they are adequately financed). These constraints are based on direct challenge of the company’s proposals, supported by external benchmarking of cost and service to establish the company’s relative efficiency and performance.

2.13 As FE, PNGL and SGN, in their respective geographical areas, are the only monopoly gas distribution service providers, a regulatory framework has been put in place to protect the consumers who use their services. In our role as economic regulator, we take action if we consider that either of the companies performs less well or operates less efficiently than its peers, and we set targets for improvement.

2.14 An important part of this regulatory framework are price controls. A price control is a method of setting the total allowed revenues a GDN is allowed to earn (revenue cap form of price control), or maximum tariffs a GDN is allowed to charge (price cap from of price control), during a given period (the price control period).

2.15 As part of a price control, we establish a clearly defined set of outputs that the GDNs must deliver. We also put in place cost and performance reporting systems that allow monitoring of actual versus determined target outputs. When selecting these outputs we aim to strike a balance between outputs that are clearly defined while allowing the GDNs the flexibility they need to deliver them in the most effective way.

2.16 In addition to the pre-defined outputs, there are other outcomes a price control will have. These will include for example (but are not necessarily limited to) the impact of the price control on distribution costs and consumer tariffs, on the environment and greenhouse gas emissions and on customer service as well as the opportunity for an increasing

[7] Directive 2009/73/EC of the European Parliament and the Council of 13 July concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC.

number of consumers to enjoy the benefits of being connected to the natural gas network.

2.17 In summary, taken in the round, we interpret our duties, in the context of carrying out price controls, as a broad mandate to:

- secure the most cost efficient outcome for the protection of consumers and the promotion of the gas industry in Northern Ireland;
- ensure the gas distribution network operators can continue to finance the activities which are the subject of obligations placed on them; and
- have due regard to all relevant factors.

2.18 It is our aim to do this by:

- providing a strong foundation for the continued and long-term growth of gas distribution networks, delivering service improvements to consumers;
- challenging the GDNs to improve their efficiency and performance at an achievable and sustainable rate;
- promoting long term planning by the licensees and securing the continuity of necessary and efficient investment; and
- ensuring that revenues and prices are set at the minimum levels that are consistent with the efficient operation.

2.19 The price controls for each of the companies considered in this final determination are complex, and comprise many different elements. In this context, we interpret our obligation to further our principal objective and fulfil our duties as being a requirement to do so taking all of the elements of each price control together, and viewing the overall price control in the round. Certain aspects of each company's price control may be weighted so that they make particular contributions to the fulfilment of certain aspects of our objective and duties, but no part of the control should be considered in isolation. We aim to ensure that the balance which we are required to strike, having regard to all of the different elements of our objective and duties, is struck in setting each price control as a totality.

2.20 The price control process starts with a consultation and decision on the approach that will be applied with respect to this price control. The approach document may e.g. include details on the overall context of the price control, on how key areas will be addressed, on the expected impact of the price control as well as on the overall timetable.

2.21 This is followed by the business plans (including actual data for previous years), as submitted by license holders, setting out their proposals for costs going forward. The information submitted is scrutinised by us. In doing so, we seek to ensure that gas distribution licence holders deliver best value for money for all consumers.

2.22 Our approach is based on best practice regulation of natural monopolies. Our task essentially consists in creating a framework within which, in return for providing monopoly services to an acceptable quality, the company receives a reasonable assurance of a revenue stream in future years that will cover its costs and ensure fairness for the consumer.

2.23 We are a non-ministerial government department, accountable to the NI Assembly.

Market Overview

2.24 Northern Ireland currently has three gas distribution networks.

- FE own and operate the distribution network in the area normally called the ten towns. The ten towns licenced area covers a greater geographical area including Ahoghill, Antrim, Armagh, Ballyclare, Ballymena, Ballymoney, Banbridge, Bessbrook, Broughshane, Bushmills, Coleraine, Craigavon, Cullybackey, Derry~Londonderry, Laurelvale, Limavady, Lurgan, Maghaberry, Magheralin, Moira, Newry, Portadown, Portstewart, Tandragee, Warrenpoint. A map of the ten towns licenced area is shown in Appendix 1: Map of FE Licensed Area.
- PNGL own and operate the distribution network in the Greater Belfast and Larne areas. Furthermore, they have been granted, on 10 December 2015, an extension of their licensed area to bring gas to 13 towns in the East Down area. A map outlining the PNGL distribution licence area is shown in Appendix 2: Map of the PNGL Licensed Area.
- SGN are in the process of building the distribution network in the area typically referred to as Gas to the West area. It covers Dungannon including Coalisland; Cookstown including Magherafelt; Enniskillen including Derrylin; Omagh and Strabane. Appendix 3: Map of SGN Towns to Connect provides an indication of the proposed network design at time of writing.

2.25 PNGL were awarded their conveyance licence in September 1996. They had 191,782 customers connected within the Greater Belfast and Larne licensed area at the end of 2015.

2.26 FE were awarded their conveyance licence in March 2005 and had 27,910 customers connected within the ten towns licensed area at the end of 2015.

2.27 SGN were awarded their conveyance licence in February 2015 and are currently in the design and development phase of the network, with the first customers scheduled to be connected to gas from late 2016 in the Strabane area and in other areas from late 2017, even though the majority of connections will be made from late 2018 onwards.

Price Control Context

GD14 Review

2.28 On 20 December 2013, we published the final determination for the GD14 price control period.[8] This is the price control for FE and PNGL covering the period from 1 January 2014 to 31 December 2016.

2.29 GD14 was conducted under constrained timescales in so far as the directly preceding PNGL price control, PNGL12, had been referred to the Competition Commission which only reached its decision on 28 November 2012[9].

[8] Utility Regulator: GD14 Price Control for Northern Ireland’s Gas Distribution Networks 2014-2016, Final Determination, 20 December 2013.

2.30 The GD14 price control process was the first time that price controls for FE and PNGL were aligned, i.e. they were conducted in parallel and for the same price control periods. As part of GD14, we have attempted to ensure as much consistency between FE and PNGL as appropriate and beneficial, while recognising that there were differences in the operational and business environment of the two companies, and therefore their regulation.

2.31 Despite these differences, the alignment of the price controls for FE and PNGL has offered us the opportunity to adopt, where reasonable and appropriate, a coordinated and consistent approach to gas distribution across NI. This allowed us to apply benchmarking techniques and to provide downward pressure on costs and the continued pursuit of efficiencies and service enhancements. Such "comparative regulation" is widely used, to a beneficial effect, in the rest of the UK.

2.32 As a regulator we constantly strive to re-evaluate our processes and thinking to ensure that we deliver price controls in a focused and timely manner. Therefore, we conducted a GD14 price control process review as part of which a number of lessons learnt were identified as follows:

- Set out an approach document, which has been consulted on well in advance of the GD17 business plan submission;
- Set out a clear timetable for GD17 with key deliverables and sufficient time to allow proper consideration of all comments;
- Build on cost reporting/RIGs (Regulatory Instructions and Guidance) to monitor actual outputs of current performance and establish a recognised and consistent format;
- Set out a template based on cost reporting/ RIGs for population that will be used for the GD17 business plan submissions;
- Stronger and earlier engagement with external stakeholders, including increased focus on consumer interests and priorities; with clear levels of engagement for all stakeholders, from the submission of the business plans to issuing of the final determination.

GD17 Outlook

2.33 For GD17, we have taken on board the lessons learnt as a result of the GD14 price control process. This included in particular the following:

- Publication of a discussion document on our overall approach for the GD17 price control period on 19 December 2014[10], well in advance of the planned business plan submission timeline on 30 June 2015, followed on 17 April 2015 by an update on our overall approach[11]

[9] For further details see Competition Commission: A reference under Article 15 of the Gas (Northern Ireland) Order 1996, Phoenix Natural Gas Limited price determination, Presented to the Northern Ireland Utility Regulator 28 November 2012.
[10] Utility Regulator: Price Control for Northern Ireland's Gas Distribution Networks GD17, Discussion Document on Our Overall Approach, 19 December 2014.
[11] Utility Regulator: Price Control for Northern Ireland's Gas Distribution Networks GD17, Update on Our Overall Approach, 17 April 2015.

- Inclusion of a clear timetable of GD17 with key deliverables and milestones in both the discussion document on our overall approach for the GD17 price control published on 19 December 2014 as well as the update on our overall approach published on 17 April 2015, complemented by a more detailed timetable issued to the GDNs on 8 June 2015
- Development of a template for Annual/Cost Reporting with associated regulatory instructions and guidance, based on the Ofgem reporting requirements, with NI-specific amendments, as appropriate, which was applied for the NI GDNs for the first time for the Annual/Cost Reporting with respect to the 2013 reporting year
- Development of a standardised GD17 business plan data template with associated regulatory instructions and guidance, based on the NI Annual/Cost Reporting template, consulted on together with our discussion document on our overall approach for the GD17 price control period on 19 December 201410 and published in its final version on 14 May 2015[12]
- Increased engagement with external stakeholders, including increased focus on consumer interests and priorities, both:
    - through the Utility Regulator itself in the form of workshops and information sessions with interested parties and through inclusion of key milestones for stakeholder engagement in the GD17 timetable; as well as
    - through us requesting the GDNs to provide as part of their business plan submissions a public facing business plan[13] as well as details on any customer satisfaction surveys and other stakeholder engagement undertaken[14]

2.34 We consider that these measures have helped to conduct the GD17 price control process on a more consistent and improved information basis compared to GD14.

2.35 We are aware that a number of challenges still remain which impact on the robustness and comparability of GDN data and need to be considered as part of the price control process. These challenges include in particular, but are not limited to, the following:

- Different stages of network development in the licensed areas of the three NI GDNs with the PNGL licence granted in 1996, the FE licence granted in 2005 and the SGN licence granted in 2015
- Limited availability of historic data in standardised reporting format, with common Annual/Cost Reporting template for NI GDNs only introduced from the 2013 reporting year onwards and SGN only beginning to set-up their network in 2015
- Significant network development activities entailing associated risks planned by all three NI GDNs during the GD17 price control period with the FE infill programme[15],

[12] Utility Regulator: Price Control for Northern Ireland's Gas Distribution Networks GD17, Regulatory Instructions and Guidance for Business Plan Submission, 14 May 2015 and Utility Regulator: GD17 Business Plan Data Template.
[13] A public facing business plan is a document which explains, in a way that can be understood by consumers, the impact and cost of a proposed business plan.
[14] See Utility Regulator: Price Control for Northern Ireland's Gas Distribution Networks GD17, Update on Our Overall Approach, 17 April 2015, paragraph 4.10.
[15] For further details see section 4 Price Control Submissions, GD17 Outlook, FE.

the PNGL network extension to East Down[16] and SGN building the Gas to the West network[17]

2.36 In addition it is important to note differences in regulatory treatment of the three NI GDNs, with key aspects including the following:

- Duration of GD17 price control period: GD17 price control to take effect on 1 January 2017 for FE and PNGL and 1 January 2018 for SGN[18], with end date of 31 December 2022 for all three NI GDNs
- Form of price control[19]: Revenue cap for PNGL, price cap for SGN and switch from price cap to revenue cap for FE[20]
- Forecasting horizon: PNGL set to end in 2046, change for FE with new end date in 2045[21], and SGN set to end in 2057

Structure of this Document

2.37 This document is structured in a number of chapters as follows, each addressing different aspects of the price control:

- Chapter 1 Executive Summary provides an overview over the key findings and key decisions of this price control process
- Chapter 2 Introduction provides an overview over the purpose of this GD17 final determination, our statutory duties and regulatory principles, the NI gas distribution market as well as the overall context of this price control
- Chapter 3 Approach provides an overview over the price control process and key aspects of same
- Chapter 4 Price Control Submissions provides an overview over the FE and PNGL GD14 performance to date as well as over the strategic context and key focus areas as proposed by each GDN with respect to the GD17 price control period
- Chapter 5 Volumes and Connections comments on volume and connection details for the three NI GDNs
- Chapter 6 Opex details the operating expenditure (opex) allowances requested by each NI GDN, our assessment of same as well as our determined allowances for the GD17 price control period
- Chapter 7 Capex details the capital expenditure (capex) allowances requested by each NI GDN, our assessment of same as well as our determined allowances for the GD17 price control period

[16] For further details see section 4 Price Control Submissions, GD17 Outlook, PNGL.
[17] For further details see section 4 Price Control Submissions, GD17 Outlook, SGN.
[18] For further details see section 3 Approach, Duration – UR Decisions.
[19] For further details on the different forms of price control see section 3 Approach, Form of Price Control – UR below.
[20] For further details see Utility Regulator: firmus energy (Distribution) Limited Licence, Outcome of Consultation paper on moving to revenue cap regime, 16 September 2015.
[21] For further details see section 11 Outputs, Outcomes and Allowances, FE – UR Decisions, Forecasting Horizon.

- Chapter 8 Innovation details our view with respect to funding of innovation initiatives both in general as well as with respect to specific innovations proposed by the GDNs
- Chapter 9 Uncertainty Mechanism details our review of the uncertainty mechanism with respect to the GD14 price control period as well as our decisions with respect to the GD17 uncertainty mechanism
- Chapter 10 Financial Aspects discusses different aspects relating to the finance implications of the price control, including rate of return, depreciation, tax, profile adjustments and financeability
- Chapter 11 Outputs, Outcomes and Allowances summarises key aspects of the price control determination such as designated parameters and determination values[126]
- Chapter 12 Licence Implications provides an overview over the legal and regulatory framework relating to this GD17 price control process as well as over the licence modification proposals[22]
- Chapter 13 Next Steps and Further Issues provides an overview over the next steps and summarises consequential changes as well as further issues we intend to address pursuant to the price control determination

2.38 These chapters are complemented by a range of appendices contained in section Appendices of this document as well as by a set of annexes. See section Annexes, Consultation Responses and Supplementary Documents, Annexes for an overview over these annexes.

2.39 This document is furthermore complemented by the consultation responses we received to our GD17 draft determination and which, unless designated specifically by the respondent as being confidential, are referenced in section Annexes, Consultation Responses and Supplementary Documents, Consultation Responses as well as in our GD17 draft determination consultation report published as Annex 13 to this GD17 final determination.

2.40 The GD17 draft determination consultation report details the key issues raised in the consultation responses as well as our views on these. In addition, we have, where appropriate, addressed specific technical issues in detail directly in this GD17 final determination document and/or in the relevant technical annexes to same.

2.41 Section Annexes, Consultation Responses and Supplementary Documents, Supplementary Documents provides an overview over further key documents which are not listed in the Annexes and Consultation Responses sections, but which form part of the context of this GD17 final determination. These include in particular consultation and decision papers on related policy decisions, as well as the consultation on the licence modifications required pursuant to this GD17 final determination and other regulatory decisions.

[22] We note that our licence modification proposals relating to this GD17 final determination are discussed in further detail and consulted on in a separate licence consultation document published alongside this GD17 final determination: Utility Regulator: Licence Modifications Pursuant to the GD17 Final Determination and other Regulatory Decisions, Consultation Paper, 15 September 2016. This document is referenced in section Annexes, Consultation Responses and Supplementary Documents, Supplementary Documents.

2.42 Where relevant and appropriate, the chapters of this GD17 final determination document are structured in a consistent way as follows.

- Summary of Key Changes from Draft Determination to Final Determination
- Detailed Approach – UR Decisions
- FE – UR Decisions
- PNG – UR Decisions
- SGN – UR Decisions

2.43 The summary section on key changes from draft determination to final determination provides, as the name suggests, an overview over the key changes we have made to our draft determination proposals in arriving at our final determination. We note that the intention of this section is not to provide a complete list of all changes compared to the GD17 draft determination, but to increase readability of this final determination document and help the reader identify quickly aspects that may be of particular importance.

2.44 The detailed approach section details, as the name suggests, the approach we used in arriving at our price control decisions for that area. This may include background information, considerations and proceedings applicable to some or all of the GDNs.

2.45 The GDN-specific sections detail the implications arising for each GDN from applying our detailed approach. This may include details on values, parameters, targets and/or outputs. Where relevant, these sections also clarify if certain aspects of our detailed approach are not applicable for a specific GDN, e.g. due to differences in the regulatory treatment of the GDNs[23] as well as, where appropriate, the relevant alternative approach for such cases.

2.46 We consider that this structure helps increase the readability of this final determination document through reducing duplication and enabling each GDN to quickly identify the sections of the document relevant to them.

[23] For an overview over key differences with respect to the regulatory treatment of the three NI GDNs see paragraph 2.35.

3 Approach

Summary of Key Changes from Draft Determination to Final Determination

3.1 We have updated this chapter following on from the GD17 draft determination, following due consideration of the responses received to same 6. Key changes made in this context include:

- Update of the section Price Control Process, Timelines and Stages with respect to key milestones between the GD17 draft and final determinations
- Update of the section Duration – UR Decisions with respect to related draft consultation feedback and our views on same
- Update of the section Form of Price Control – UR Decisions with respect to the progressing of the licence modifications required to implement the change for FE from a price cap to a revenue cap form of control

Price Control Process

Timelines and Stages

3.2 The key milestones of this GD17 price control process are summarised in:

- Table 5 for milestones leading up to the publication of this GD17 final determination; and
- Table 207 for the remaining milestones to be met after publication of this GD17 final determination.

Key Milestones of GD17	
Key Points	**Date**
Circulation of GD17 approach to key stakeholders, along with 1st draft of business plan submission template (spreadsheet)	19 December 2014
Meetings with GDNs and other key stakeholders, including key stakeholder workshop	January 2015
Response deadline for comments on discussion paper on overall GD17 approach	10 February 2015
GDN workshop on GD17 efficiencies	25 February 2015
Consumer engagement workshop with GDNs, CCNI and DETI	20 March 2015
Business plan submission template workshop with GDNs	30 March 2015
Publication of final approach document	17 April 2015
Publication of the business plan submission template (spreadsheet) and related regulatory instructions and guidance	14 May 2015
Submission by the GDNs of Phase 1 of the business plans	30 June 2015
Submission by the GDNs of Phase 2 of the business plans	30 September 2015

Key Milestones of GD17	
Key Points	**Date**
Business plan presentations by GDNs	October 2015
Publication by GDNs of the public facing business plan	31 October 2015
Meetings with credit rating agencies	9 December 2015
Ongoing engagement with GDNs through bilateral meetings and information requests	October 2015-February 2016
Bi-lateral meetings with key stakeholders including DETI, CCNI, MEUC and Manufacturing NI	February 2016-March 2016
Publication of GD17 draft determination	16 March 2016
Ongoing engagement with GDNs through bi-lateral meetings and information requests	April 2016-May 2016
Engagement with Credit Rating Agencies	April 2016
Stakeholder workshop on GD17 draft determination	10 May 2016
Bi-lateral meetings with key stakeholders including CCNI, DRD, DETI and user representative groups	May 2016
Closure of draft price control consultation	31 May 2016
Ongoing engagement with GDNs through bi-lateral meetings and information requests	June 2016-September 2016
Publication of final determination of GD17 and consultation on related licence modifications	15 September 2016

Table 5: Price Control Process Key Milestones up to Publication of GD17 Final Determination

3.3 On 19 December 2014, we published a discussion document on our overall approach for the GD17 price Control10, alongside with a draft template for the proposed GD17 business plan templates[24]. The discussion document set out for discussion our initial views on the high level approach in relation to the GD17 price control process. The draft business plan templates provided a first insight into the type, amount and structure of data we proposed to capture from the GDNs as input into the price control process.

3.4 We received six responses[25] to the discussion document on overall approach from the following organisations:

- PNGL
- FE
- SGN
- Major Energy Users' Council (MEUC)
- Manufacturing Northern Ireland (Manufacturing NI)
- Consumer Council for Northern Ireland (CCNI)

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[24] Utility Regulator: GD17 Business Plan Template, Draft, 19 December 2014.
[25] For further details see http://www.uregni.gov.uk/publications/gd_17_responses.

3.5 Following engagement with the GDNs and other key stakeholders during the first quarter of 2015 and after due consideration of the responses received, we published, on 17 April 2015, an update on our overall approach for the GD17 price control11, including a revised timeline. In particular (and in contrast to the initial timeline contained in the discussion document, which had stipulated a business plan submission timeline by 30 June 2015), this revised timeline allowed for a submission of the business plans by the GDNs in two stages. An initial set of documents was to be provided by 30 June 2015, with the remainder including the main business plans and completed business plan data templates to follow by 30 September 2015, three months later than initially envisaged. This change provided the GDNs with additional time to prepare their business plan submissions and ensure their consistency with the regulatory accounts and Annual/Cost Reporting for the 2014 reporting year. However, as the dates for subsequent stages of the price control process remained unchanged, it also meant a reduction of the time available for analysis and preparation of the GD17 draft determination document.

3.6 On 14 May 2015, we published the final GD17 business plan data templates with associated RIGs (regulatory instructions and guidance).12 We recognise that this was later than initially envisaged in our discussion document on overall approach. We note, however, that the GDNs had early sight of our reporting requirements from the draft business plan templates published on 19 December 2014 and our intermittent related engagement with them, and that, as outlined in paragraph 3.5, they were furthermore granted an extension of the submission deadline which more than compensated for the delay.

3.7 The GD17 business plans were submitted by the GDNs within the timelines agreed. Furthermore, all three GDNs published a public facing executive summary of their business plan submission on their website by 31 October 2015, as requested.[26]

3.8 The GD17 business plan submission was followed by a phase of analysis and an exchange of information requests and responses between ourselves and the GDNs to clarify any issues and queries arising.

3.9 In addition, and in preparation of the publication of the GD17 draft determination, we engaged with the GDNs through a series of bilateral meetings. As part of these meetings, we provided the GDNs with provisional views and insights into our proposals for the GD17 draft determination, and offered an opportunity to discuss these.

3.10 In addition to the engagement with the GDNs, we also engaged with other key stakeholders, including representatives from CCNI, DETI (Department for Enterprise, Trade and Investment), Manufacturing NI, MEUC as well as with credit rating agencies.

3.11 We considered the feedback received from the ongoing engagement with the GDNs and other key stakeholders in the GD17 draft determination, which was published on 16 March 20166.

3.12 We noted in the GD17 draft determination our intention to request the GDNs, by 31 March 2016, to submit their updated business plan templates with 2015 actuals by 30 June 2016. We indicated that we intended to use this data to account, in our final determination, for 2015 actuals rather than estimates. However, in our subsequent

[26] For further details see:

- Firmus energy: GD17 Business Plan October 2015.
- Phoenix Natural Gas: GD17 Business Plan.
- SGN: Gas to the West, Business Plan for developing the Low Pressure (LP) gas network to the end of December 2022.

engagement with the GDNs, it became clear that not all of the GDNs were able to provide this information within these timelines. We therefore decided not to insist on the submission of the updated business plan templates with 2015 actuals. Instead, we agreed with the GDNs to use more aggregate, high-level 2015 actuals as assurance that there were no significant overall deviation between the 2015 estimates contained in the business plan submissions and the 2015 actuals.

3.13 In line with normal Annual/Cost Reporting timelines, detailed information on 2015 actuals would normally only become available on 30 September 2016[27], i.e. after the planned publication deadline for the GD17 final determination. We note that, seeing the workload associated with the ongoing GD17 price control for both GDNs and ourselves, we will not ask the GDNs to provide the completed Annual/Cost Reporting templates for the 2015 reporting year by 30 September 2016.

3.14 We note, however, that, for consistency of reporting and comparability over time, we will request the GDNs to provide data, as part of the Annual/Cost Reporting update in 2017, for two reporting years (2015 and 2016).

3.15 The publication of the GD17 draft determination was followed by a phase of stakeholder engagement to help stakeholders understand the key issues in relation to the GD17 draft determination and answer any queries they might have. This involved a public stakeholder workshop on 10 May 2016, bi-lateral stakeholder meetings with key stakeholders such as the GDNs, CCNI, DRD, DETI, user representative groups and credit rating agencies as well as a post draft determination query process between the GDNs and ourselves to clarify any issues and queries arising from the GD17 draft determination.

3.16 The consultation on the GD17 draft determination closed on 31 May 2016, and we received 11 responses in return, which we subsequently analysed and considered as part of the preparation of this GD17 final determination document.

3.17 The following months were characterised by a further period of engagement with the GDNs, including bi-lateral meetings and a consultation response query process.

3.18 We note that, other than indicated in the Next Steps section of our GD17 draft determination, we decided not to hold a stakeholder workshop in August 2016 as, with key price control decisions still being finalised, any information we could have provided at that stage would have been fairly limited. We considered that instead, it would be more beneficial to provide updates to key stakeholders such as e.g. the GDNs, the CCNI, the department and the credit rating agencies around the time of publication of our GD17 final determination, and have included a related milestone in Table 207: GD17 Next Steps.

3.19 We note that this GD17 final determination is accompanied by a consultation on related licence modifications, with the consultation period scheduled to end on 14 October 2016.

3.20 Following due consideration of the responses received to this consultation on licence modifications, we expect to publish our related decision on 1 November 2016. This will

[27] This is based on the current Annual/Cost Reporting cycle whereby Annual/Cost Reporting Templates with the associated Regulatory Instructions and Guidance are provided to the GDNs by start of July for completion by end of September. We note that, as indicated in paragraph 13.12, we consider bringing forward the timelines for Annual/Cost Reporting to align with those defined in the GDNs' licences for the submission of financial statements and auditor's reports. In practice, this would mean that Annual/Cost Reporting for a reporting year would need to be submitted by 30 June of the following year, rather than, as has been current practice to date, by 30 September.

allow for the effective date of the licence modifications to be at least 56 days after the publication of the licence modification decision, in line with the requirements of Article 14(10) of the Gas (Northern Ireland) Order 1996[28]. This period provides an opportunity for the licence holder which is subject to the price control, any other licence holder materially affected by the decision, a qualifying body or association representing one of those licence holders, and/or the Consumer Council for Northern Ireland to appeal the decision on the proposed licence modifications to the CMA (Competition and Markets Authority).

3.21 The GD17 price control will take effect on 1 January 2017 for FE and PNGL (i.e. directly after the end of the GD14 price control period on 31 December 2016) and on 1 January 2018 for SGN.[29]

3.22 In line with good regulatory practice, we plan to conduct a lessons learnt process to take place in the second quarter of 2017, after the GD17 price control process has been completed. As part of this lessons learnt process we intend to capture feedback from the GDNs, key stakeholders as well as internally from our colleagues on key aspects of the price control process. We wish to use this information to implement improvements to the way in which we conduct price controls and apply them to future price control processes, where reasonable and possible.

Price Control Principles

3.23 In addressing the key areas of this price control, we are mindful of the need to keep the regulatory burden to a minimum while addressing the information asymmetry that exists between us and the companies.

3.24 Therefore, as detailed in our update on our overall approach to the GD17 price control[11], we adopt and apply a number of principles during the price control process to ensure our approach is proportionate. These principles are:

- GDN's business plan templates as published on the 14 May 2015, along with the accompanying instructions and guidance, are populated and submitted by the GDN's to ensure a consistent and correct format is used at all times.
- Any atypical costs and special factors are identified separately in GDN submissions.
- Areas of high expenditure receive substantially more scrutiny and analysis than low value items, as do new additional opex and capex, where we shall expect to have presented the net impacts from such increases and any decrements.
- Benchmarking is used where possible and a triangulated approach adopted to ensure that allowances are efficient and that efficiency targets are reasonable but challenging. Regional differences and relativities are incorporated into our analyses across both opex and capex efficiency targets, including regional wages and regional price adjustment as appropriate.
- Where possible, any allowances set shall be closely aligned to clearly defined outputs and relevant drivers.
- Costs related to external factors which may or may not happen and about which there are no obvious firm estimates form part of the so called "uncertainty mechanism" which is described in more detail in chapter 9 Uncertainty Mechanism.

[28] http://www.legislation.gov.uk/nisi/1996/275/contents.
[29] For further details on the reasons for the different start dates, see paragraph 3.47.

- If insufficient information is available to make an informed determination, either on grounds of whether the costs will or won't materialise or in absence of any firm estimate if they do materialise, some areas may be subject to re-openers.
- The price control is based on a standard RPI-X framework, which incentivises the GDNs to control their costs through the setting of efficiency targets and subsequent adjustments of opex and capex at subsequent price controls.
- Allowances are not given for costs that the GDNs can recover through other channels, such as (but not necessarily limited to) third parties causing damages to the network.
- Allowances are not given for profit margins for any related parties performing services for the GDNs, where relevant.

3.25 We adopt a light touch approach if:

- there is evidence to show that the company is comparatively efficient;
- past costs are a strong indicator of future costs;
- there is insufficient data to support a more robust approach.

3.26 We adopt a more detailed approach if:

- the company is comparatively inefficient;
- past costs are a weak indicator of future costs;
- data is available for econometrics, serviceability measures, outputs and so on.

3.27 We expect GDNs to provide the data necessary to support a robust assessment of expenditure and outputs. Where it is necessary to adopt a light touch approach because there is insufficient data, we adopt an approach to funding which is prudent but conservative until the company can develop a robust approach based on sound data.

3.28 We also consider as part of our price control, where relevant and appropriate, best practice relating to other price controls and findings from our project to make network price controls more consistent, by adopting cross-utility approaches, principles and standards of regulation.

3.29 We will continue to ensure that the information we require from the GDNs is proportionate but sufficient to:

- allow the GDNs to communicate their business plans to us in a clear and effective manner; and
- ensure that we can submit the plans to effective and focused scrutiny.

3.30 We note that we:

- reserve the right to appoint, where appropriate, an examiner to examine the recording of relevant information by the GDNs;
- reserve the right to request, where appropriate, an audit of specified information relating to the GD17 price control, including specification of the terms on which an auditor is to be appointed by the GDNs for that purpose and of the nature of the audit to be carried out by that person.

Consumer and Stakeholder Engagement

3.31 We shall continue to build on the strong focus on customer service already built up by the GDNs and have considered Draft Determination consultation responses as we progress the GD17 development objective for improved customer services across the GD17 period.

3.32 Firmus recognises the opportunity for further alignment of consumer research between GDNs to improve customer service standards and welcomes the GD17 customer service development objective (including new customer service metrics, satisfaction surveys and enhanced GDN partnership working).

3.33 Firmus also recognised the opportunity to learn from local water / electricity sectors but recommended a balance of focus on existing and new consumers (not already connected to the network).

3.34 PNGL notes how consumer engagement is one of a number of issues to be considered during the GD17 period and suggests a reconvening of a previous Gas Distribution Forum to agree a timetable which is transparent and workable. We note PNGL's suggested way forward and would re-iterate the GD17 developmental objective for consumer service builds on our experience when progressing a similar objective with NI Water over the last couple of years during the PC15 period. The Draft Determination timetable was based on what we considered to be realistic and workable timescales, including the necessary milestones, to bring in new customer service metrics and satisfaction surveys across GD17.

3.35 We note that for the GDNs and given our accepted aspiration to develop (i) greater partnership working (ii) common branding and (iii) a shared research programme we may need to revisit our timetable in the light of resources and priorities.

3.36 CCNI welcomes the inclusion of the developmental objective for delivery of new customer service metrics and satisfaction surveys during GD17, noting excellence in customer service can only be achieved through shared learning and transparency. CCNI notes similar measures and metrics are being developed in the water sector locally and that in so doing for the GDNs UR opens up the possibility for greater comparability across all energy and water companies. Finally, CCNI welcomes the possibility that with improved performance monitoring UR allows consideration of incentivised mechanisms in future price controls.

3.37 We remain of the belief that the work undertaken during consultation over our Approach to GD17 provides a solid foundation to developing GDNs' ongoing consumer engagement, not least because all participants were agreeable towards the partnership models already successfully used in our local water and electricity sectors and price controls. Furthermore, we recognise FE's and PNGL's recognition of the need to work together with other GDNs in collaborative research going forward during the GD17 period. SGN's approach, starting largely from scratch, prompts an immediate requirement to avoid any "re-invention of the wheel" and as such it is our belief SGN has potentially the most to benefit from our GD17 development objective to deliver greater partnership in consumer research and stakeholder engagement.

3.38 Agreeing the timetable for GD17 new customer service outputs will of itself form a developmental objective for the first 6 months of the GD17 period. We shall work to develop this through a partnership working group approach (GDNs, the CCNI, DfE and the UR) subject to an agreed Consumer Engagement Working Group - Terms of Reference.

General Stakeholder Engagement

3.39 During the GD17 price control process, we engaged with key stakeholders to ensure they fully understood the key components of the price control, allowing us to take full account of stakeholders' views in making a final determination and secure a successful outcome of GD17.

3.40 As shown in Table 5: Price Control Process Key Milestones up to Publication of GD17 Final Determination, we held workshops, meetings and various information sessions to interested parties at key stages of the price control process, to more fully engage on the issues that have been raised during the process.

3.41 We also met with credit ratings agencies and took note of their expectations regarding the GD17 price control.

Duration – UR Decisions

3.42 The optimum duration of a price control is a matter of judgement. It needs to balance a number of factors:

- The advantage of giving planning security to the GDNs and of providing them with the flexibility to plan their business and to deliver these plans within the framework and constraints set by each price control
- The need to account for changes in external environment and external drivers which inform the overall level of charging that is possible and which become less predictable as the planning horizon lengthens

3.43 Whilst GD14 was for a period of three years, we indicated in our final determination for that price control our intention for GD17 to be for a longer period such as five years.[30] In our discussion document on the overall approach for the GD17 price control we proposed to also consider, as an alternative, a duration for GD17 of six years.[31]

3.44 The six-year-duration was supported fully by all the GDNs. In their responses to the discussion document on overall approach, they stated that this would strike a reasonable balance between providing a predictable framework for planning and investments and addressing the uncertainties that necessarily become bigger as the planning horizon expands.

3.45 We therefore indicated in our update on overall approach for the GD17 price control[32] our decision to adopt a duration of six years for the GD17 price control period and drafted our GD17 draft determination accordingly.

3.46 We note that in their response to the GD17 draft determination, SGN indicated that, whilst in its response to the overall approach document it has been supportive of a

[30] See Utility Regulator: GD14 Price Control for Northern Ireland's Gas Distribution Networks for 2014-2016, Final Determination, 20 December 2013, paragraph 3.19.
[31] See Utility Regulator: Price Control for Northern Ireland's Gas Distribution Networks GD17, Discussion Document on Our Overall Approach, 19 December 2014, paragraphs 3.15-3.16.
[32] See Utility Regulator: Price Control for Northern Ireland's Gas Distribution Networks GD17, Update on Our Overall Approach, 17 April 2015, paragraph 2.6.

duration of the price control until the end of 2022, SGN would support some sort of mid price control review, given the gaps in allowances evident in the GD17 draft determination. We note the comments made by SGN. However, we are of the view that the price control packages for the GDNs presented in the GD17 final determination are well-rounded, and reflective of the uncertainties and business needs the GDNs are likely to face during the price control period. We therefore consider that a mid-period review would not be proportionate and is not required. We note furthermore the arrangements for special reviews contained in Condition 4.7: Special Reviews of the SGN conveyance licence and that the G2W application pack did not propose a mid-year review.

3.47 SGN also noted that paragraph 3.51 of the GD17 draft determination outlines the fact that SGN will have gas available in its towns from Q4 2017, but that in reality, the current uncertainty surrounding the HP/IP build at present could significantly affect these timescales. SGN asked that this is given consideration when the Utility Regulator sets price control allowances, to allow SGN Natural Gas to recover the agreed rate of return for the full 5 year duration it bid on. The question of gas not being available in many towns in 2017 has been given consideration and we have made changes to SGN volumes accordingly. We will still commence the price control for SGN from 2018, which will allow the 5 years rate of return duration.

3.48 This means the GD17 price control period will run from 1 January 2017 until 31 December 2022 for FE and PNGL and thus follow-on directly after the end of the GD14 price control period. For SGN, the GD17 price control period will run from 1 January 2018 until 31 December 2022.

3.49 Any relevant capital and operational expenditure that was reasonably incurred as well as any revenues received prior to the 1 January 2018 will be considered as part of the opening TRV for SGN.[33]

3.50 The next price control after GD17 will be GD23 which is expected to come into effect on 1 January 2023. It is expected that this will be after the determination for RIIO-GD2 which is due to come into effect on the 1 April 2021, so that any RIIO-GD2 innovations and benchmarking can be considered before and as part of GD23.

3.51 We note that in their consultation response to the GD17 draft determination, SGN suggested the introduction of a mid price period review for the GD17 price control. It is our view that such a review is not required as we consider that the price control packages for the GDNs presented in this GD17 final determination are well-rounded, and reflective of the uncertainties and business needs the GDNs are likely to face during the price control period. We note furthermore the arrangements for special reviews contained in Condition 4.7: Special Reviews of the SGN conveyance licence.

Form of Price Control – UR Decisions

3.52 Different forms of price controls apply in the NI gas distribution market:

- In a revenue cap form of price control, we determine the total allowed revenues. The GDN must set the tariffs to avoid revenue over-recovery.
- In a price cap form of price control, we determine the maximum amount of tariffs based on determined volumes.

[33] For further details see Condition 4.4.5 of the SGN conveyance licence.

3.53 Price cap form of price controls provide an incentive to outperform on volumes as the revenue derived from outperformance can be retained. They are hence suitable in particular for GDNs in their initial years, when there needs to be a strong focus on growing the business and associated volumes. However, as the business grows and matures, it may be more appropriate to switch to a revenue cap form of price control as new volumes become less important and external factors, such as temperatures, can have a bigger impact on overall volumes.

3.54 When PNGL commenced operations, they had an annual price cap in place. As the network matured, the strong volume incentive was no longer needed. Consequently, a decision was taken as part of the PNGL price control review for the years 2007-2011 to change the form of price control from a price cap form of control to a revenue cap one.

3.55 Similarly, when FE commenced operations they had an annual price cap in place. This form of control continued to apply throughout the GD14 price control period. However, we indicated in the GD14 final determination[34] our intention to consult on whether to change this to a revenue cap as part of GD17.

3.56 In our update on overall approach for the GD17 price control period we indicated once more that we believed it was appropriate to change FE from a price cap to revenue cap and would commence a consultation process to make this change.[35] We reiterated our minded to position to change the form of price control for FE from a price cap to a revenue cap in the regulatory instructions and guidance for GD17 business plan submission and indicated that this had been reflected in the assumptions contained in the business plan data template.[36] We thus asked FE to submit their GD17 business plan in line with the requirements of a revenue cap form of price control.

3.57 On 18 June 2015, we published a consultation on changing the price control format for FE.[37] In this paper we consulted on our proposal to change the form of price control for FE from a price cap form of control to a revenue cap one from the start of the GD17 price control period onwards.

3.58 On 16 September 2015, we published, following due consideration of the responses received to that consultation, the outcome to change the form of price control for FE from a price cap form of control to a revenue cap.[38] We indicated that this would be the basis on which we progress GD17. We also indicated our intention to use the PNGL licence as a starting point for drafting the licence changes required pursuant to this decision and to consult on these licence changes in September 2016 as part of the GD17 final determination. In line with this statement, and following due consideration of related responses received to the GD17 draft determination[39], we have included related licence

[34] For further details see Utility Regulator: GD14 Price Control for Northern Ireland's Gas Distribution Networks for 2014-2016, Final Determination, paragraph 16.17.
[35] See Utility Regulator: Price Control for Northern Ireland's Gas Distribution Networks GD17, Update on Our Overall Approach, 17 April 2015, paragraph 3.146.
[36] See Utility Regulator, Price Control for Northern Ireland's Gas Distribution Networks, GD17, Regulatory Instructions and Guidance for Business Plan Submission, 14 May 2015, paragraph 3.6
[37] Utility Regulator: Consultation on modifications to the Price Control conditions of the Firmus energy (Distribution) Limited Licence, 18 June 2015.
[38] Utility Regulator: Firmus energy (Distribution) Limited Licence, Outcome of Consultation paper on moving to revenue cap regime, 16 September 2016.
[39] See Utility Regulator: Price Control for Northern Ireland's Gas Distribution Networks, GD17, Final Determination – Annex 13, Draft Determination Consultation Report, 15 September 2016, section on CCNI Response. This document is referenced in section Annexes, Consultation Responses and Supplementary Documents, Annexes.Supplementary Documents

modification proposals in our consultation on licence modifications pursuant to the GD17 final determination and other regulatory decisions[40], which is published alongside this final determination.

3.59 In preparation of this licence modification consultation paper, we have shared initial drafting of our licence modifications proposals relating to the change from price cap to revenue cap with FE. As part of this engagement, as well as in their response to the GD17 draft determination, FE raised some concerns on the proposed licence modifications to facilitate the change from a price cap to a revenue cap. These concerns relate in particular to the treatment of under-recoveries under a revenue cap form of control and are addressed in more detail in our GD17 draft determination consultation report as well as in section 11 Outputs, Outcomes and Allowances, FE – UR Decisions, Under-Recoveries.

3.60 In line with its licence, SGN is currently subject to a price cap form of price control. Seeing that the business still is in the start-up phase, we consider this to be appropriate and will make no changes to these arrangements for the GD17 price control period.

[40] This document is referenced in section Annexes, Consultation Responses and Supplementary Documents, Supplementary Documents.

4 Price Control Submissions

Summary of Key Changes from Draft Determination to Final Determination

4.1 We have updated this chapter following on from the GD17 draft determination, following due consideration of the responses received to same 6. Key changes made in this context include the update of section GD17 Outlook, PNGL with respect to consultation on East Down matters and ongoing consultation on licence modification proposals relating to East Down.

GD14 Review

Overview

4.2 In GD14 we defined key outputs (e.g. allowances, customer numbers).

4.3 Based on these outputs, we set detailed opex and capex allowances before real price effects and efficiencies, broken down into different cost elements.

4.4 We indicated that the allowances would be updated for actual outputs under the uncertainty mechanism. We then applied real price effects and efficiencies to the allowances on an aggregate level to controllable pre-efficiency opex and capex allowances.

4.5 We have now reviewed adjustments under the uncertainty mechanisms and assessed their impact, after application of real price effects and efficiencies.

4.6 Based on the results we can conduct a first review of GD14 performance, for 2014. We recognise the figures are only for one year actual and so provide limited information.

4.7 We will now consider both FE and PNGL results. The details are contained within Section 9 of the Uncertainty Mechanism.

FE

Cost Items and Outputs	Unit	GD14 FD Updated 2014	Actual 2014
Capex	£m	7.6	11.2
Opex	£m	5.7	6.1
Connections	Nos	4,152	4,019

Table 6: GD14 Review – FE

4.8 FE has overspent on Capex which exceeds the regulatory allowances set. This was due to the phasing of the build on the network development.

4.9 Opex has been overspent as a result in the change of the ownership of the business and a spike in marketing and development costs.

4.10 Since the draft determination FE has provided a high level view of the opex costs for 2015. This shows that opex (excluding connections incentive) was £5.4m which was

£0.4m more than the GD14 allowance for that year. The main areas of overspend were in relation to Office and IT costs as well as fees and consulting costs.

PNGL

Cost Items and Outputs	Unit	GD14 FD Updated 2014	Actual 2014
Capex	£m	12.8	12.9
Opex	£m	14.8	14.6
Connections	Nos	10,178	10,627

Table 7: GD14 Review – PNGL

4.11 PNGL has kept to its regulatory allowances and exceeded on outputs, which is updated as per the Uncertainty mechanism, outlined in Section 9.

4.12 Since the draft determination PNGL has provided a high level view of the opex costs for 2015. This is broadly in line with the GD14 allowances.

GD17 Outlook

Overview

4.13 When assessing the GD17 business plans submitted by the GDNs and the appropriateness of the assumptions made and allowances requested, it is important to do this with consideration of the stage of network development at which each GDN is and of the strategic background against which the GDNs are operating.

4.14 This section therefore summarises the key focus areas as proposed by each GDN for GD17.

4.15 We note that this section does not cover our views with respect to the submissions. This detailed analysis and assessment forms part of the subsequent chapters of this GD17 final determination document.

FE

4.16 FE have to date invested over £110 million in developing their network. It comprises over 1,000 km of pipeline and covers an area of 230 square kilometres. FE currently serve over 25,000 customers and transport around 55 million therms of natural gas per year.[41]

4.17 In developing their network, FE have initially prioritised connecting large Industrial and Commercial (I&C) customers as these large volumes are required to make the network economically viable. Further priorities have then been Northern Ireland Housing Executive housing estates and new build housing. With most of the large load in the FE licensed area connected at this stage, FE propose to now focus on further network roll-out to owner-occupier residential customers.[42]

4.18 FE propose to meet their targets through a comprehensive infill programme, including a combination of both:

[41] See firmus energy: GD17 Business Plan, October 2015, p. 8.
[42] See firmus energy: GD17 Business Plan, October 2015, p.12.

- increasing connections off the network infrastructure already built; and
- further roll-out of their network infrastructure.[42]

4.19 To support their plans for network roll-out, FE have developed a detailed construction programme for the GD17 price control period as well as a high-level programme for the post-GD17 period. It includes details of projected new connections and network extension across the licensed area as well as associated costs and investment requirements.[43]

4.20 FE has built its infill programme on the assumption that government programmes and regulatory mechanisms such as the connections incentive will continue to be available to help them drive connections. [44]

4.21 With its infill programme, FE plans to achieve the following during the GD17 price control period:[45]

- Lay a further 718km of gas mains
- Increase the number of properties with access to natural gas from 90,000 to ca. 161,000
- Increase the number of cumulative connections from 32,000 to nearly 60,000
- Increase volumes by about 18% by the end of the GD17 price control period

4.22 Furthermore, FE aims to achieve a penetration rate for their total licensed area of 65% (expressed as connections as a proportion of total properties passed by the network) by the end of 2045.[46]

4.23 FE consider that through implementing this infill programme, they can reduce volume dependency on a small number of large I&C customers, and thus reduce the risks of significant increase in network costs for other users caused by large businesses closing.

PNGL

4.24 By the end of 2015, PNGL had over 191,000 customers connected to the network and passed over 313,000 premises with a network extending to over 3,300 kilometres of pipeline. The total amount of gas offtaken from the system by suppliers was c.140m therms.

4.25 Over the years, PNGL developed its natural gas network in the Greater Belfast and Larne area extensively to both homes and businesses. Thus, by the end of 2014, approximately 59% of the properties passed by the PNGL network were connected.[47]

4.26 For the GD17 price control period, PNGL propose to connect c.50,000 properties, including c.24,000 owner occupied ones.[48]

4.27 These figures are based on the expectation that "*UR maintains its current position whereby [PNGL] are granted an allowance for the cost of providing a complete service connection and provision of a meter installation during GD17*."[49]

[43] See firmus energy: GD17 Business Plan, October 2015, p.30.
[44] See firmus energy: GD17 Business Plan, October 2015, p.11.
[45] See firmus energy: GD17 Business Plan, October 2015, pages 9, 10 and 29.
[46] See firmus energy: GD17 Business Plan, October 2015, p.32.
[47] PNGL: GD17 Business Plan, p. 3.
[48] PNGL: GD17 Business Plan, p. 7.

4.28 We note that the GD17 business plan presented by PNGL and the figures detailed in paragraph 4.26 do not account for the extension of the PNGL licensed area to East Down. The reason for this is that the decision to grant this extension was made on 10 December 2015[50], i.e. after the timeline for the submission of the GD17 business plan on 30 September 2015.

4.29 The proposed figures for properties passed and connections in East Down are shown in Table 8.

	2017	2018	2019	2020	2021	2022
Properties Passed (cumulative)	1,718	3,737	9,221	14,597	19,624	23,178
Connections (cumulative)	86	262	664	1,343	2,206	3,206
Volumes (therms)	44,557	138,856	363,547	746,656	1,235,495	1,800,329

Table 8: East Down – Properties Passed, Connections and Volumes as Proposed by PNGL

4.30 The need to consider the implications of an extension of the PNGL licensed area to East Down was addressed in both our related consultation and the subsequent decision paper. More specifically, we stated in our consultation paper that, should the extension of the PNGL licensed area be granted, PNGL needed to deliver against its proposal to develop the natural gas network into this area. We noted in particular that we proposed to consider this as part of the GD17 price control and that we were of the view that it might be appropriate to formally set out a development plan, referenced in the PNGL licence conditions. We also indicated these aspects would be subject to a separate consultation. [51] We followed-on on these comments in our decision paper, stating in paragraph 3.5: "*The Utility Regulator agrees with this principle. It intends to progress further work in relation to East Down through the GD17 price control. This will include incentives for connections and cost allowances. As noted in our consultation it will also include consideration of an appropriate development plan to ensure there are obligations to develop the East Down area. This GD17 process will involve further separate consultation and engagement with stakeholders*."[50]

4.31 As part of the ongoing engagement with PNGL in preparation of both the GD17 draft and final determinations we asked the company to provide us with updates on the expected impact of the East Down project on GD17. We have included East Down figures within our analysis for both the GD17 draft and final determinations as we view East Down as being a fundamental part of the PNGL licence area. We indicated in the GD17 draft determination that we considered the draft determination to be a consultation on these matters and our decisions in this determination incorporate the East Down extension.

4.32 In addition, following-on from the indicative East Down development plan provided in Appendix 4 of the GD17 draft determination, and from our stated intention to embed such a development plan into the PNGL licence[52,] we have included related licence

[49] PNGL: GD17 Business Plan, p. 8.
[50] Utility Regulator: Decision Paper on the Extension to the Conveyance Licence Area and Modification of the Conveyance Licence of Phoenix Natural Gas Limited – East Down, 10 December 2015.
[51] Utility Regulator: Notice to Extend the Conveyance Licence Area and Modification of the Conveyance Licence of Phoenix Natural Gas Limited – East Down, 16 October 2016, paragraph 2.7.
[52] For further details see: Utility Regulatory: Price Control for Northern Ireland's Gas Distribution Networks GD17, Draft Determination, 16 March 2016, paragraphs 12.136 and12.137.

modification proposals in our consultation on licence modifications pursuant to the GD17 final determination and other regulatory decisions[40], which is published alongside this final determination.

SGN

4.33 The context of the GD17 price control for SGN needs to consider the SGN business plan submission in tandem with the application process for the G2W licence.

4.34 On 6 February 2014, we published the G2W Applicant Information Pack (AIP).[53] In addition to details on the licence application process itself, this document also contained clarifications on links between the information revealed as part of the application process and subsequent price control processes. This was to incentivise applicants to submit realistic bids.

4.35 With respect to opex allowances we stated: "*we believe that a direct link between the cost information revealed in the application and the allowances provided in subsequent price controls will act as a powerful incentive to ensure that applicants reveal realistic cost information and that some link should be maintained beyond the first price control period. In particular we would not be minded to accept requests for increased allowances as a consequence of changes in the structure of costs or changes in the allocation of costs from parent or holding companies. However, we will consider requests for different allowances where these are the result of unforeseen significant changes in the market since the application was submitted.*"[54] We also clarified that, "*[as] set out [...] under capex, a number of items are adjusted under an 'uncertainty mechanism' and we intend this to be applied to the new licence*".[55]

4.36 There was further guidance specifically in relation to incentivising IC customers where Paragraph 4.36 of the AIP stated "[*no] incentive payments for non-owner occupier connections have been included in the workbook. However if an applicant believe that in order for them to meet the target for industrial and commercial connections they will require funding for financial incentives they have an opportunity to include such costs in the Operating Expenditure worksheet. They should also explain in their operational business plan how such payments would facilitate connections by non-owner occupier supply points. Only if the successful applicant has included such incentives in their application will these be funded by price control allowances*".

4.37 The Applicant Information Pack also clarified that we intended to use the pattern of volumes and connections derived from the FMA study[56] to set the first and future price controls. However, we also clarified that, should significant changes in expected supply points/consumption patterns arise between the licence application process and the

[53] Utility Regulator: Gas Network Extensions in Northern Ireland, Gas to the West: Applicant Information Pack, 6 February 2014.
[54] Utility Regulator: Gas Network Extensions in Northern Ireland, Gas to the West: Applicant Information Pack, 6 February 2014, paragraph 3.44.
[55] Utility Regulator: Gas Network Extensions in Northern Ireland, Gas to the West: Applicant Information Pack, 6 February 2014, paragraph 3.47.
[56] A study by Fingleton McAdam (FMA) to determine the technical and economic feasibility of extending the natural gas network in Northern Ireland which was used by DETI in its assessment of G2W and the basis for the figures used in the Application Workbook.

setting of the first price control, we would consider if these needed to be reflected in the development plan and price control values.[57]

4.38 In August 2014, the Preferred Applicants chosen were NIEH for the HP pipeline and SGN for the LP pipeline.

4.39 Thus in advance of GD17, it was clear that we intended to put significant weight on the figures used in the G2W licence competition. It was also clearly identified that adjustments would be considered to reflect changes to assumptions on customer numbers and volumes. However, otherwise there was a high bar to making changes from the AIP and this was particularly true for the first price control.

4.40 It is important to recognise that the award of the licence to SGN came after a competitive process. The AIP and indeed the Gas the West final determination were clear in setting out that the allowances in the first price control would be based on the preferred applicant's application.

4.41 There would be considerable risk to the integrity of G2W competitive process were we to facilitate such large changes from the licence application figures.

4.42 We consider that this is a very important principle we need to be mindful to guard against the G2W application process (or future ones) being undermined. This could give rise to applicants bidding low and arguing for increases in the subsequent price control.

4.43 In its GD17 submission, SGN proposed significant changes to opex figures compared to those it submitted in their G2W application. We have examined these carefully in chapters 5 and 6 against the criteria we set out in designing the G2W licence application competition.

[57] See Utility Regulator: Gas Network Extensions in Northern Ireland, Gas to the West: Applicant Information Pack, 6 February 2014, paragraph 3.63 and 3.64.

5 Volumes and Connections

Summary of Key Changes from Draft Determination to Final Determination

5.1 FE connection numbers remain unchanged. FE volumes numbers have been adjusted to reflect updated estimates provided by the company.

5.2 Since the draft determination, PNGLs connections numbers have been updated to reflect the inclusion of East Down and the volumes have changed accordingly.

5.3 At the draft determination stage SGN were developing the detailed design of its network and following publication of the DD further information was provided. We have taken account of the revised information and responses to the DD and as a result SGN volumes have changed in all categories.

5.4 We have made adjustments to all GDNs volume figures in the period beyond 2022 to reflect long term uncertainty over such forecasts.

Detailed Approach – UR Decisions

5.5 The level of scrutiny in this area is based on the type of price control that is in effect.

5.6 PNGL are subject to a revenue cap, reflective of its network age and it being in a more mature state.

5.7 On 16 September 2015, we published, our position[20] to change the form of price control for FE from a price cap form of control to a revenue cap one. Therefore this is the first price control for FE that is on a revenue cap basis.

5.8 The SGN network is still at the very early stages of its development, with no customers planned until the end of 2016. In order to drive the successful development of the network it is key that significant volumes are connected at the earliest stages. We believe that a strong incentive is required to ensure volumes are prioritised in the first price control period. We therefore believe that a price cap is appropriate and will review its suitability at the time of the next price control, namely GD23.

FE – UR Decisions

Connection Assumptions

5.9 Our determination allows for 30,954 connections during the GD17 period.

5.10 Detailed information on OO connections can be found in Chapter 6.

5.11 The connection targets in respect of new build, NIHE and I&C were accepted as submitted.

5.12 Our determined connection targets are set out in Table 9 below.

Connections (per annum)	2017	2018	2019	2020	2021	2022	Total
Domestic – OO	2,600	2,950	3,300	3,600	3,900	4,100	20,450
Domestic – NB	800	800	800	800	800	800	4,800
Domestic – NIHE	800	800	800	800	800	800	4,800
Domestic – I&C	150	154	150	150	150	150	904
Total	**4,350**	**4,704**	**5,050**	**5,350**	**5,650**	**5,850**	**30,954**

Table 9: Determined Connections for FE

Determination of Volumes

5.13 The volumes targets for FE have been updated based on new information provided by the company.

5.14 Table 10 shows FE final determined volumes.

Volumes (Therms)	2017 '000	2018 '000	2019 '000	2020 '000	2021 '000	2022 '000	Total '000
Domestic	11,228	12,780	14,462	16,267	18,185	20,197	93,120
Small & Medium	14,716	15,224	15,720	16,206	16,681	17,145	95,691
Contract	36,036	32,440	32,440	32,440	32,440	32,440	198,236
Total	**61,980**	**60,443**	**62,623**	**64,913**	**67,306**	**69,782**	**387,047**

Table 10 FE Determination of Volumes

PNGL – UR Decisions

Connection Assumptions

5.15 Our determination allows for 49,898 connections during the GD17 period.

5.16 Detailed information on OO connections can be found in Chapter 6.

5.17 PNGL has estimated new development rates of 3000 properties per annum. This is higher than levels of development in the period 2011 to 2014. The company has suggested that the market is expected to pick up as it recovers from a period of depressed activity. We have considered the average rates of medium term household growth by NISRA. This suggests household growth rates of 0.5% per annum which equates to 1600 properties per annum. For the final determination, we have included just over 2000 new build properties per annum.

5.18 Our determined connection targets are set out in Table 11 below

Connections (per annum)	2017	2018	2019	2020	2021	2022	Total
Domestic – OO	5,000	4,900	4,800	4,700	4,600	4,500	28,500
Domestic – NB	2,021	2,046	2,086	2,112	2,112	2,112	12,489
Domestic – NIEH	1,023	1,104	1,046	1,112	1,156	1,152	6,593
I&C	364	360	377	420	381	414	2,316
Total	**8,408**	**8,410**	**8,309**	**8,344**	**8,249**	**8,178**	**49,898**

Table 11: Determined Connections for PNGL

Determination of Volumes

5.19 Table 12 below shows PNGL determined volumes based on forecasts provided by the company updated for adjusted domestic targets.

Volumes (Therms)	2017 '000	2018 '000	2019 '000	2020 '000	2021 '000	2022 '000	Total '000
Domestic	78,885	82,121	85,375	88,665	91,966	95,217	522,229
Tariff	51,229	51,608	52,010	52,439	52,887	53,346	313,518
Contract	18,768	18,768	18,768	18,768	18,768	18,768	292,067
Total	**148,881**	**152,496**	**156,153**	**159,871**	**163,620**	**167,331**	**1,082,409**

Table 12 PNGL Determination of Volumes

SGN – UR Decisions

Assessment of SGN Volumes for GD17

Overview

5.20 SGN volumes are important in setting determined allowances and SGN is incentivised to outperform on volumes.

5.21 We stated in our GD17 approach document that we will use the profiles included in the Application Information Pack (AIP) [53] as a starting point for setting SGN volumes.

5.22 In relation to volumes of gas and connections, we stated that we would use a bottom up approach similar to that of GD14, where we:

- review the targeted number of connections by customer category and associated average burn volume assumptions (for domestic and tariff customer categories) and monthly volume usages (for contract customer categories);
- review the assumptions around customer additions and losses by month over the period of GD17 in relation to all customer categories (with contract being on an individual named customer basis);
- benchmark against actual output data from previous years, where applicable.

5.23 We set out in our AIP[53], paragraph 3.63, that the first and future price controls would base connections on the pattern set out in the Capital Expenditure worksheet of the associated low pressure workbook. This is still the case. The AIP figures were themselves based on a report done by Fingleton McAdam (FMA) on behalf of DETI.

5.24 However, we also stated in the AIP paragraph 3.64 that "*if there are significant changes in expected supply points/consumption patterns between the licence application process and the setting of the first price control we will consider if these need to be reflected in the development plan and price control values.*"

5.25 What this means is that we anticipated that the overall number of properties and potential connections in the SGN area was likely to change and this would be reflected in the price controls. However we were not proposing to change from the AIP the percentage of properties in the area we would expect SGN to connect or the speed/profile at which they should be connected.

5.26 Thus, to provide a simple example, consider that the AIP had assumed 10,000 properties in the area and that SGN would connect 80% (8,000) after 40 years at a rate of 2% (200) every year. If updated analysis showed that there were now 20,000 properties we would expect in the price control SGN to connect 80% (16,000) over 40 years at a rate of 2% (400) per annum.

5.27 The SGN price control starts in 2018. However connections will start before then with Strabane due to connect in 2016. The connections and volumes figures in 2016 and 2017 are included within the determination. These are used to derive the pre price control revenue (using SGN 2016 and 2017 conveyance tariffs) of £550k which forms part of the 2018 OAV (see Chapter 9). We have included 2016 and 2017 connections and volumes for completeness.

5.28 We detail our views on each of the customer categories below.

Domestic

5.29 SGN has presented a number of figures (a) in its GD17 business plan, (b) in its 2014 network design, (c) in its revised design analysis, April 2016 and (d) its GD17 Volumes update paper, June 2016.

5.30 One key point in the updated information from SGN is the target date for the roll out of most towns is 2018 with Strabane connecting in 2016. We have accepted this profile and reflected in our decisions in all categories.

5.31 In our draft determination, we used existing houses in the network design of 41,365 and a further 15,809 new builds giving a total number of domestic households over the lifetime of the project of 57,174. We also assumed that within the existing houses of 41,365 there are 5,312, NIEH households (taken from the AIP profile).

5.32 In SGNs revised network design, April 2016, SGN states that 12,647 is its view of the new build properties over the 40 year period. It also states that the number of existing houses in the area is 37,000 properties. We have revised our draft figures downwards to reflect the revised figures. We have assumed, as with the DD, that within the existing houses of 37,000 there are 5,312 NIEH households (taken from the AIP profile).

5.33 SGN used an 85% penetration rate in their November 2014 design review. We stated in our DD that we would consider our 70% penetration rate further and may consider using a penetration rate of 85%. We have determined that a 70% penetration rate for existing households which is based on the AIP profile is appropriate to set the SGN volumes.

5.34 We have included a penetration rate of 100% for NIHE properties based on the AIP profile.

5.35 SGN assumed a penetration rate of 90% on new builds in the network design. We have also included 90% within our determination as not all will be suitable for connection. Table 13 below shows the penetration rate and the number of households included in DD versus the FD.

	Penetration rate	DD	FD
Existing Owner Occupied Households	70% by year 30	36,053	31,688
Existing Housing Executive Households	100% by year 20	5,312	5,312
Total Existing Households		**41,365**	**37,000**
New Households	90%	15,809	12,647
Total Households		**57,174**	**49,647**

Table 13 SGN Household Numbers and Penetration Rates

Assumptions regarding start dates:

5.36 Existing OO, NIHE and new build (excluding Strabane) is profiled as per the AIP with a start date of January 2019 and assuming half year burn for new connections.

5.37 Strabane Existing OO, NIHE and new build is profiled as per the AIP with a start date of January 2017 and assuming half year burn for new connections.

5.38 Table 14 shows SGN cumulative domestic connection numbers based on the above assumptions.

SGN connection numbers (Cumulative)	Penetration rate	2017	2018	2019	2020	2021	2022
Existing Owner Occupied Households	70%	186	326	1,501	2,451	3,085	3,989
Existing Housing Executive Households	100%	156	195	1,141	1,406	1,672	1,914
Total Existing Households		**342**	**521**	**2,642**	**3,857**	**4,757**	**5,903**
New Households	90%	**-**	**-**	**282**	**546**	**860**	**1,154**
Total Households		**342**	**521**	**2,924**	**4,403**	**5,617**	**7,057**

Table 14: SGN Connection Numbers

5.39 Figure 1 below shows SGN cumulative domestic connection numbers based on the above assumptions.

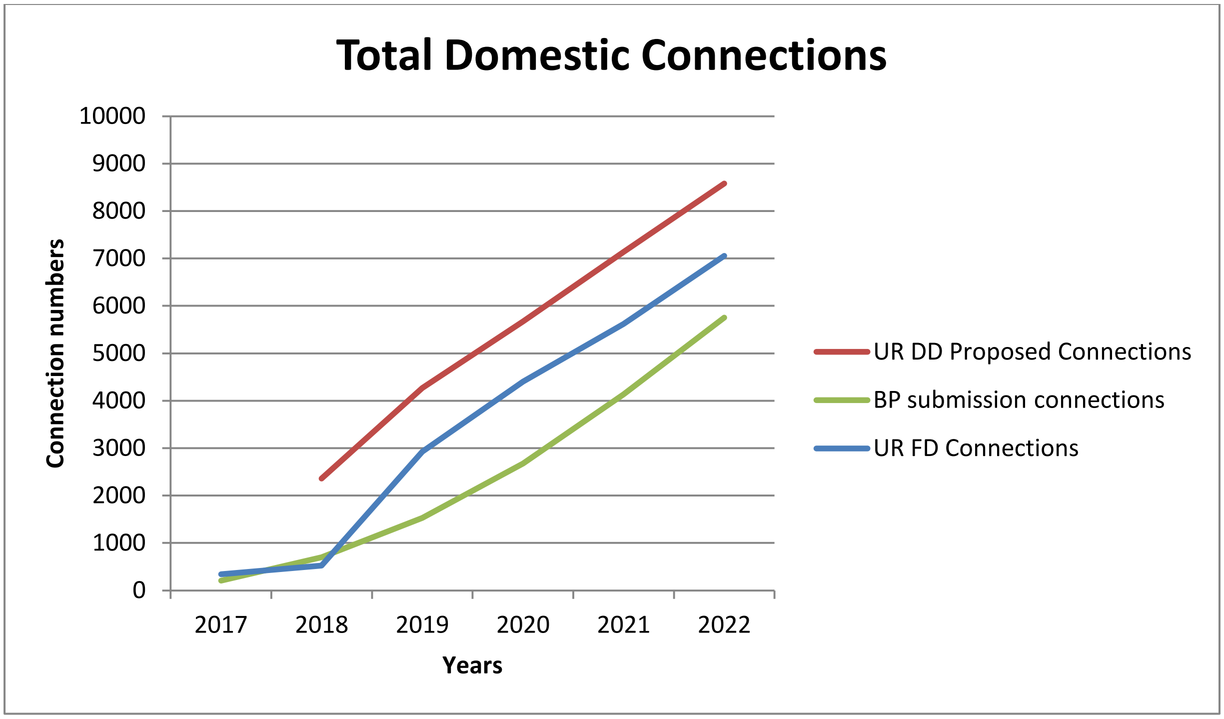

Figure 1: SGN Total Domestic Connections

5.40 We have assumed 380 therms as the average customer burn for SGN. This is slightly lower than the 394 submitted as part of the business plan. However the 380 is in line with our experience with other GDN's and has been used with all GDN's in setting connection incentives.

5.41 Table 15 below shows SGN volumes based on the above assumptions.

Volumes (Therms)	2017	2018 '000	2019 '000	2020 '000	2021 '000	2022 '000	Total (2018-2022)
Existing	35	97	347	751	1,052	1,344	**3,591**
NIHE	30	67	254	484	585	681	**2,072**
New Build	0	0	54	157	267	383	**860**
Total	**65**	**164**	**655**	**1,392**	**1,904**	**2,408**	**6,522**

Table 15: SGN Volumes for Domestic Customers Based on Average Burn Assumptions

Small and Medium I&C

5.42 At the DD stage SGN was still developing the detailed design of the network and further information was expected. Due to the lack of detailed information at the time, we included in the DD the SGN business plan volumes total of 1.9m therms by year 40.

5.43 The revised design analysis was available in April 2016. This analysis provides a properties passed figure of 4,664 for small and medium properties for the 40 year period.

SGN have assumed that 25% of these properties are medium properties and 75% are small properties.

5.44 The assumed start date for small and medium properties is January 2019 with the exception of Strabane which has a start date of January 2017.

5.45 Using the AIP profile with properties coming on half yearly the below table shows the connections numbers based on these assumptions.

5.46 Table 16 below shows the small and medium cumulative connections over the GD17 period.

Connection (cumulative)	2017	2018	2019	2020	2021	2022
Small	44	62	481	665	927	1,189
Medium	12	21	134	222	309	396
Total	56	83	615	887	1,236	1,585

Table 16: SGN Connections for Small and Medium I&C Customers

5.47 We have assumed 1,431 therms as the average customer burn for SGN small customers and 6,140 therms as the average customer burn for SGN mediums. This is the number SGN submitted in their business plan and is broadly in line with other GDNs. We have therefore accepted SGNs average customer burns for small and medium.

5.48 Table 17 below shows SGN volumes based on the above assumptions.

Volumes (Therms)	2017 '000	2018 '000	2019 '000	2020 '000	2021 '000	2022 '000	Total (2018-2022)
Small	31	76	389	820	1,139	1,514	**3,937**
Medium	37	101	476	1,093	1,630	2,164	**5,465**
Small and Medium	68	177	864	1,913	2,769	3,678	**9,470**

Table 17: SGN Volumes for Small and Medium Customers Based on Average Burn Assumptions

Large I&C

5.49 The SGN business plan template does not separate large customers from contract customers. We have however received updated information in June that differentiates between large customers (between 25,000 therms and 75,000 therms) and contract customers (greater than 75,000 therms). There are 33 large customers included in the updated volumes June information. We have applied the AIP profile of year 1 (2018) 0%; year 2 (2019) 40%; year 3 (2020) 80% with customers coming on half yearly.

5.50 We have assumed one large customer with first burn in July 2017 and the same customer in 2018.

5.51 Table 18 below shows the cumulative connections over the GD17 period.

Connections (cumulative)	2017	2018	2019	2020	2021	2022
Large	1	1	13	26	26	26

Table 18: SGN Connections for Large I&C Customers

5.52 We consider that the total annual burn per annum is 1,575,000 therms for large I&C. We have taken the Strabane customer out separately and then taken an average burn of the remaining 32 customers. The average burn (excluding Strabane customers) is 48,047 therms.

5.53 Table 19 below shows the assumed volumes over the GD17 period.

Volumes (Therms)	2017 '000	2018 '000	2019 '000	2020 '000	2021 '000	2022 '000	Total (2018-2022)
Large	19	38	326	926	1,239	1,239	**3,766**

Table 19: SGN Volumes for Large I&C Customers

Contract I&C

5.54 SGN provided updated information in June regarding the customers with a burn greater than 75,000 therms. There are currently 25 customers with a total annual burn per annum of 25,547,600. As with large customers, we have taken the Strabane customers out separately and we have used SGNs estimate of full annual consumption for both of these customers. We have taken an average burn for most of the remaining customers apart from outliers.

5.55 The AIP profile for contract customers is year 1 (2018) 25%; year 2 (2019) 75%; year 3 (2020) 100%. We have included in the final determination this AIP profile based on the average volume figures above with customers coming on half yearly apart from 2018 when we assume customers coming on in mid Q4.

5.56 There is one large customer in Strabane due to start first burn November 2016 and an additional customer to start in October 2017.

5.57 Table 20 below shows the cumulative connections over the GD17 period.

Connections (cumulative)	2016	2017	2018	2019	2020	2021	2022
Contract (plus super contract)	1	2	7	19	25	25	25

Table 20: SGN connections for Contract I&C Customers

5.58 Table 21 below shoes the volumes over the GD17 period.

Volumes (Therms)	2016 '000	2017 '000	2018 '000	2019 '000	2020 '000	2021 '000	2022 '000	Total (2018-2022)
Contract	433	2,623	4,676	19,967	24,101	25,479	25,479	99,702

Table 21: SGN Volumes for Contract I&C Customers

Final Determination of Volumes

5.59 Table 22 summarises the analysis above and sets out the total determination volumes for SGN, by category and by year.

Volumes (Therms)	2018 '000	2019 '000	2020 '000	2021 '000	2022 '000	Total 2018-2022
Existing Owner Occupied Households	97	347	751	1,052	1,344	3,591
Existing Housing Executive Households	67	254	484	585	681	2,071
New Households	-	54	157	267	383	861
Total households	**164**	**655**	**1,392**	**1,904**	**2,408**	**6,523**
Small I/C	76	389	820	1,139	1,514	3,937
Medium I/C	101	476	1,093	1,630	2,164	5,465
Large I/C	38	326	926	1,239	1,239	3,767
Contract I/C	4,676	19,967	24,101	25,479	25,479	99,702
Total I/C loads	**4,891**	**21,157**	**26,940**	**29,487**	**30,396**	**112,871**
Total Cumulative Number of Customers Connected	**5,055**	**21,811**	**28,333**	**31,391**	**32,804**	**119,394**

Table 22: SGN Volumes summary

5.60 Figure 2 below presents the difference in the volumes from the draft determination to the final determination.

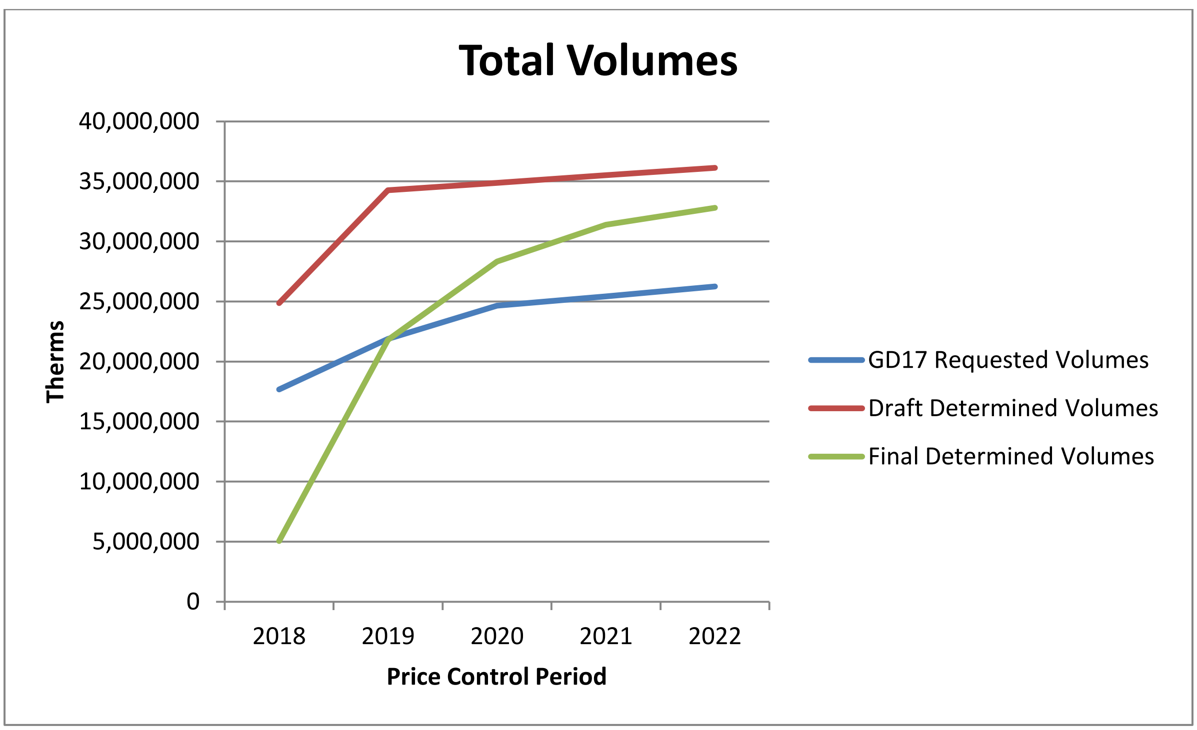

Figure 2: SGN Total Volumes

Volumes for period post 2022

5.61 We have made adjustments to all GDNs volume figures in the period beyond 2022 to reflect long term uncertainty over such forecasts. As noted in the draft determination, it is more appropriate to consider future volume assumptions than to adjust deprecation profiles. Therefore, we have applied reductions to longer term volume assumptions. For FE the reduction starts in 2023 and ramps up to 20% by 2045. For PNGL the reduction starts in 2023 and ramps up to 20% by 2046. For SGN the reduction ramps up to 30% by 2057. This is discussed further in the depreciation section of Chapter 10.

6 Opex

Summary of Key Changes from Draft Determination to Final Determination

FE

6.1 We have provided for an additional 'new areas' allowance. The additional allowance will be recovered through the connections incentive mechanism and equates to an additional £150 per connection.

6.2 A price base error was identified in FE's 2014 cost reporting submission and we corrected this for the final determination which provided for a marginal increase in FE allowances.

6.3 For Asset Management we have provided for a small increase to account for professional and legal fees that FE will incur in the GD17 period.

6.4 For Emergency costs we have adjusted model assumptions to ensure that the profile of total call numbers for FE is more reflective of historic and projected trends. We have also revised projected connection numbers to align with those used elsewhere in the final determination and have adjusted some fixed costs. This has increased the number of calls predicted using the model outputs and the company's allowances.

6.5 We have allowed increased manpower of 1.8 FTEs to reflect customer switching requirements.

6.6 For Maintenance and metering, we refreshed our benchmarked costs to reflect a detailed reconciliation of cost information to Tables 3.8 and 3.10 of the company's business plan submission and an adjustment to the determination of costs for PNGL, resulting in an increase in the allowance.

6.7 For Audit, Finance and Regulation and Insurance we have allowed increases after reviewing additional information and actual historic costs.

6.8 There are no material changes for Operations Management, PRE Repairs, Other Direct Activities, IT & Telecoms, CEO & Group Management, and Licence Fees

6.9 For network rates we have updated the calculation to use the determined revenues from this price control, rather than the revenues submitted by FE. We have also determined that network rates should not be a pass-through item for FE. This is consistent with the approach we have adopted for PNGL.

6.10 We have included a ring fenced amount for Supplier of Last Resort (SOLR).

PNGL

6.11 For connections we have lowered the connection target from the draft determination figure of 32,400 to 28,500 over the GD17 period, to better reflect the projected longer term connection rate.

6.12 We have provided for an additional 'new areas' allowance. The additional allowance will be recovered through the connections incentive mechanism and equates to an additional £60 per connection.

6.13 We have allowed increased overall manpower by 1 FTE to reflect growth requirements.

6.14 For Maintenance and Metering we have added in costs of PNGL staff, transport and plant omitted from the draft determination, resulting in an increase in the allowance.

6.15 There are no changes for Asset Management, Emergency Call Centre, Emergencies, PRE Repairs, IT & Telecoms, HR & Non - Ops Training, Audit, Finance and Regulation, Insurance, Procurement, CEO & Group Management, Stores and Logistics and Licence Fees.

6.16 For network rates we have updated the calculation to use the determined revenues from this price control, rather than the revenues submitted by PNGL.

6.17 Subsequent to the draft determination, PNGL informed us that it had incorrectly used an 85% allocation to owner occupied activities in its GD17 BPT submission. As advised by PNGL during the consultation process, we have reallocated New Build Sales exclusively to non-owner occupied activities, to accurately reflect activities undertaken.

6.18 We have included a ring fenced amount for Supplier of Last Resort (SOLR).

SGN

6.19 For SGN we have lowered the connection target from the draft determination figure of 5,015 Owner Occupied (based on the FMA study) to 3,803 over the GD17 period, to better reflect more up to date information provided by SGN which is based on GIS data.

6.20 We have provided for an additional 'new areas' allowance. The additional allowance will be recovered through the connections incentive mechanism and equates to an additional £560 per connection.

6.21 We have updated the opex allowance in the period before the price control starts to cover the operational costs of Strabane. We have allowed £556k for these costs which will be added to the Opening Asset Value (OAV).

6.22 As identified in the draft determination we have concluded that the SGN submission had input an additional year of opex which is not relevant to the GD17 price control period. This has been removed from the final determination.

6.23 We have increased Manpower (Operations Management), Emergency Call Centre, Emergencies, PRE Repairs and Maintenance allowances by 15% to take account of the overall forecast increase in connections. All other costs remained unchanged from the draft determination and therefore from the Applicant Information Pack (AIP).

6.24 We have included a ring fenced amount for Supplier of Last Resort (SOLR).

Detailed Approach – UR Decisions

Overview

6.25 This is the first price control for the GDNs where we have undertaken top-down opex benchmarking, in addition to our normal bottom-up approach. We have also undertaken some simple opex unit cost comparisons between the NI GDNs and the GB GDNs.

6.26 In our top-down econometric analysis we estimate forecasted opex using two of our preferred models, thus establishing a range of likely efficiency results rather than relying upon one modelling point estimate.

6.27 We have decided to apply the results of our bottom-up opex assessment in the final determination and this chapter is largely focused on the bottom up analysis. However, the top-down econometric and unit cost results have informed the final determination and have provided a useful 'sense-check' of the bottom-up results.

Top-Down Assessment

6.28 For GD17 the Utility Regulator has undertaken benchmarking on Northern Ireland GDNs' operating expenditure (opex), involving a variety of benchmarking techniques typically adopted by economic regulators. These techniques involved Pooled Ordinary Least Squares (POLS) regression analysis as well as the more advanced estimation methods of Random Effects (RE) modelling and Stochastic Frontier Analysis (SFA). The Utility Regulator has also undertaken some unit cost comparisons.

6.29 The Utility Regulator was initially advised in the development of its benchmarking models by Cambridge Economic Policy Associates (CEPA). The Utility Regulator and CEPA met the NI Gas Distribution Network companies (GDNs) on 25 February 2015 to discuss the likely way forward for opex benchmarking in GD17 and beyond.

6.30 Deloitte LLP, utilising expert modelling advice from Dr Melvyn Weeks[58] assisted the Utility Regulator in refining the models for GD17. The analysis from Deloitte LLP can be found at Annex 4: Deloitte LLP - GD17 Efficiency Advice – Relative Efficiency of Northern Ireland's Gas Distribution Networks (published in March 2016).

6.31 In parallel, we have also been receiving expert advice on advanced econometric modelling techniques by Dr Alan Fernihough of Queen's University Belfast, for both the draft and final determination stages of GD17.

6.32 In our draft determination publication Annex 5: Indicative Findings from Top-Down Benchmarking, the Utility Regulator detailed the various data adjustments which were made to ensure a like-for-like comparison. We also showed our interpretation of the results of the econometric analysis and how each company business plan compared to predicted opex from the various models.

6.33 GDNs were invited to consider the modelling approach and model specifications and submit any relevant special factor and atypical adjustment claims within their response to the draft determination. These responses were considered by the Utility Regulator in order to further refine and improve the analysis undertaken at final determination.

6.34 We undertake a number of data exclusions and adjustments to our benchmarking to ensure as like-for-like a comparison between NI and GB GDNs. We undertake a regional wage adjustment to ensure that companies are not unfairly advantaged by being situated in a low cost region for labour or disadvantaged by being situated in a high costs region. At final determination we assess that NI GDNs face labour costs around 10% below UK levels. As we assume that labour makes up 52% of opex, this analysis gives a regional wage adjustment of -5.2% for the NI GDNs for the 2017 to 2022 years.

6.35 As was the case at draft determination, we utilise two preferred models (Model 3 and Model 5)[59] out of eleven assessed model specifications. Model 3 uses a Composite Scale Variable (CSV) of customer numbers (50% weighting), gas volumes (25%) and network length (25%) along with a time trend variable. Model 5 uses the same CSV, but

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[58] Dr Melvyn Weeks is a Senior Lecturer in the Faculty of Economics at the University of Cambridge. He has provided advice to Ofgem for the RIIO-GD1, RIIO-T1, and RIIO-ED1 price reviews.

[59] We regress using GB-only data. As we use pool the data (Pooled OLS), this increases the sample size to 56 observations (7 years of data x 8 GDNs = 56).

also includes an iron mains variable which consists of the proportion of a GDN's network length comprising of iron.

6.36 We believe that the iron mains variable successfully acts as a proxy for network quality. For direct costs (especially repairs, maintenance and emergencies), Northern Ireland GDNs would be expected to experience lower workload levels due to the fact that no iron mains are currently used in the province for gas distribution. Northern Ireland has a relatively new and modern gas network, consisting primarily of polyethylene (PE) pipe, whereas around 27% of the current GB network is iron, which is susceptible to corrosion and subsequent leaks.

6.37 Given some uncertainty therefore about which models are most applicable for assessing the NI GDNs' cost performance, for the final determination the Utility Regulator has decided to assess GD17 opex costs using both Model 3 and Model 5, which provide the Utility Regulator with an efficiency range. The results should be interpreted in this context.

6.38 The Utility Regulator considers Model 3 as being a very conservative approach given that it does not take into account the reduced workload levels in Northern Ireland associated with its more modern network. We regard the above efficiency estimates from Model 3 as being underestimates of what could be achieved by the companies.

6.39 We recognise there are some advantages and disadvantages to both models. For example, while Model 3 may suffer from omitted variable bias by not taking into account network age, the iron mains variable in Model 5 is not conclusive in terms of coefficient significance. Model 5 results are plausible however, given that it can be reasonably assumed that having a substantial proportion of iron mains in a network will lead to higher costs within a number of opex categories. Additional data in the remaining years of Ofgem's RIIO-GD1 may ensure that Model 5 estimates with a greater degree of certainty in future modelling exercises.

6.40 For our final determination we estimate the scope of efficiency catch-up for the NI GDNs historically (namely 2014 year), and the likely scope of opex efficiency for each company's business plan for the six-year GD17 period.

6.41 In terms of catch-up efficiency, our results show that PNGL's catch-up efficiency estimates (relative to the third most efficient GDN) [60] range from 5.2% (Model 3) to 21.6% (Model 5). For FE, the results show catch-up efficiency estimates (relative to the third most efficient GDN) for 2014 range from 10.8% (Model 3) and 26.6% (Model 5).

[60] Which we regard as equivalent to upper quartile efficiency levels

GDN	Model	Specification	2014
PNGL	3	CSV + time_trend	5.2%
	5	CSV + iron_pct	21.6%
FE	3	CSV + time_trend	10.8%
	5	CSV + iron_pct	26.6%

Table 23: Catch-up efficiency estimates (2014 year) at final determination

6.42 In addition to examining historic opex performance we have used model results to forecast efficient opex levels for PNGL and FE up to 2022.

6.43 As was the case in our draft determination, within our forecasts we have held the time-trend variable constant at 2015, for years 2017 to 2022. This ensures that we do not 'double count' a continuation of a time-trend effect, which may include a continuing productivity assumption in these future years. Continuing productivity is taken into account separately within our frontier shift analysis (detailed within Annex 6 of the final determination).

6.44 According to the results, we consider PNGL's forecast costs within their business plan as being less efficient than their current levels, with levels of opex higher than those estimated by the two models. As shown in the table below, our results indicate that there is scope to reduce PNGL's business plan opex costs by up to 24.4% to reach what has been assessed as efficient operational costs.

GDN	Model	Specification	GD17 (2017 – 2022)
PNGL	3	CSV + time_trend	9.4%
	5	CSV + iron_pct	24.4%
FE	3	CSV + time_trend	10.2%
	5	CSV + iron_pct	25.3%

Table 24: Estimated Scope of Business Plan Reduction at Final Determination

6.45 We have used the model results to forecast efficient opex levels for FE up to 2022. According to the results, we consider that FE's forecast costs within their business plan are slightly less efficient than their 2014 levels during the earlier years of GD17, but relative performance does improve somewhat by 2022. As shown in the table above, our results indicate that there is scope to reduce FE's business plan opex costs by up to 25.3%, to reach what has been assessed as efficient operational costs.

6.46 As FE is a clear outlier in terms of scale compared to PNGL and the GB GDNs, the top-down benchmarking results for FE at GD17 final determination should be used for indicative purposes only.

6.47 As a result of changes to our methodology following consultation responses, our findings for both models identify slightly lower efficiency opportunities than estimated at the draft determination stage. Notwithstanding this, we consider that it is likely that opportunities for opex efficiency in PNGL and FE's business plan forecasts lie within an approximate 10% to 25% range. This is a slightly lower and narrower scope for efficiencies than the 12% to 30% range estimated at draft determination.

6.48 Given that Model 3 is a very conservative approach, we consider that the likely scope for efficiency reductions would be closer to the results for Model 5, than Model 3 i.e. towards to upper end of the range. The results from Model 5 correspond well with the findings of the bottom-up approach.

6.49 We have forecast each GDN's annual opex using the resulting coefficients of both models. This is illustrated in the chart below. It should be noted that both the historic and the estimated opex costs illustrated in the graph correspond to our definition of modelled costs (i.e. they exclude metering, network rates, advertising & marketing etc). This means for this GD17 top-down analysis we effectively apply our scope for reductions to the same categories of costs which were included and assessed in the models (but with the regional wage adjustment reversed).[61]

6.50 The graph also shows how our econometric estimates compare to the GD17 allowances, which were based on our bottom-up approach. To ensure the figures are as comparable as possible, we only show the GD17 allowance total which corresponds to our definition of opex modelled costs (i.e. excludes metering, network rates, advertising & marketing etc). Opex figures for 2015 and 2016 are estimates taken from company business plans. These will be revised once RIGs data from PNGL and FE is received.

6.51 The graph below shows that the GD17 opex bottom-up allowances for FE are largely in line with actuals for the 2014 year for cost categories included within modelled opex. The GD17 opex bottom-up allowances for PNGL are somewhat below 2014 actuals – however, this is largely due to PNGL's relatively high business support costs and allocating staff associated with the connection incentive into its cost base.

[61] It is arguably more common for a regulator to apply efficiency results to a wider spectrum of company costs than the categories used for modelling.

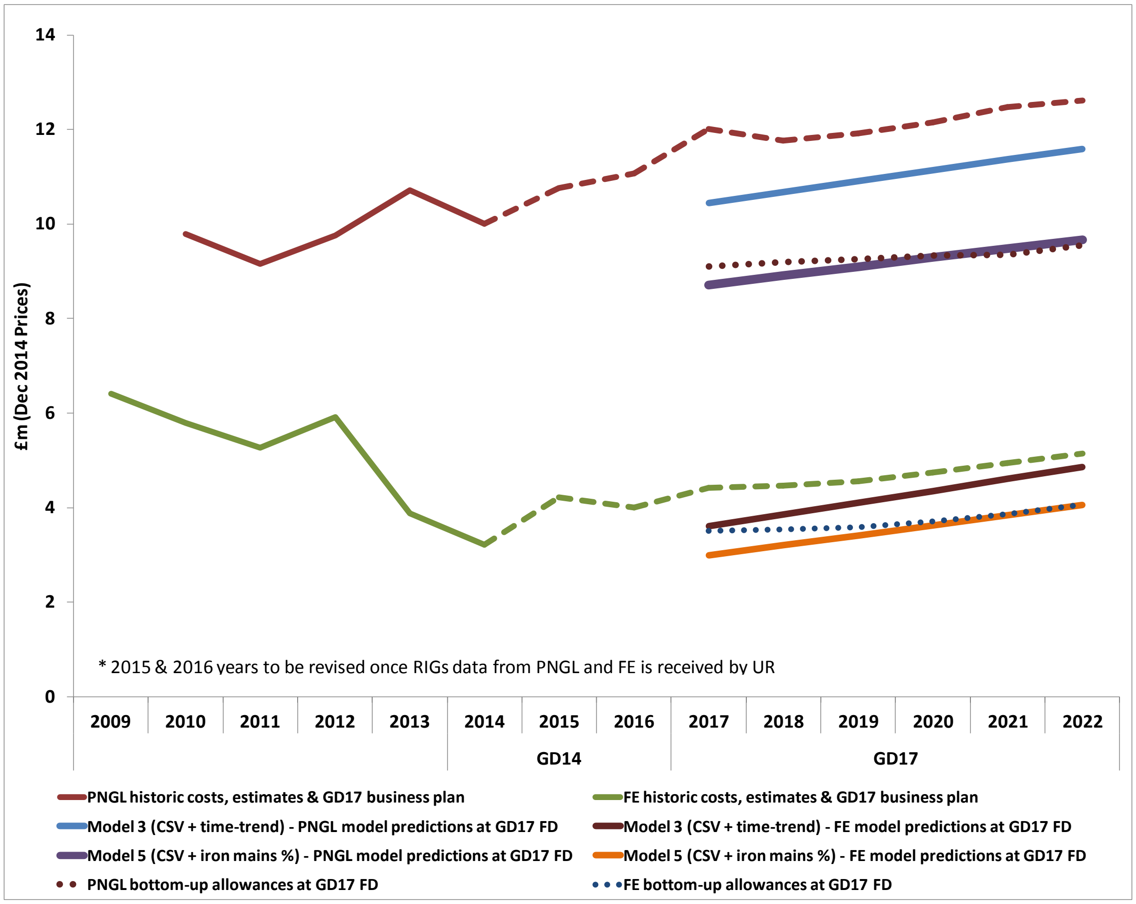

Figure 3: Range of Forecasted Modelled Opex (£m) at Final Determination [62]

6.52 More detailed results and further explanation of the methodology can be found within the GD17 final determination's Annex 5: Top-Down Benchmarking.

6.53 We intend to further develop our benchmarking models, both econometric models and unit cost analyses. These will be used to monitor each company's relative performance within an annual Cost & Performance Report (CPR) covering the outturn performance of the GDNs in Northern Ireland during the GD17 period and beyond. This report will be similar to the Utility Regulator's annual CPR for Northern Ireland Water,[63] as well as Ofgem's RIIO-GD1 Annual Reports which cover the performance of the eight GDNs in Great Britain.[64]

6.54 Through the annual CPR we hope to replicate the success in assessing NI Water's operational efficiency gap, to the assessment of the NI GDNs. This monitoring and reporting will help improve the cost performance and service delivered to gas consumers in Northern Ireland.

[62] Modelled opex excludes metering, network rates, advertising & market development etc.
[63] http://www.uregni.gov.uk/publications/ni_water_2013-2015_cost_and_performance_report
[64] https://www.ofgem.gov.uk/publications-and-updates/riio-gd1-annual-report-2014-15

Bottom-up Assessment

Overview

6.55 In Chapter 3 Approach, we have highlighted the general approach that is to be taken for GD17.

6.56 GD14 set opex allowances in a certain format. As part of GD14, we indicated that we would adopt the Annual/Cost Reporting Template (ACRT), as used by OFGEM. This meant we had to reallocate some cost items used under the previous cost allocation categories to capture PNGL's costs in the cost categories used within the ACRT and in the GD17 Business Plan Template (BPT). This was to commence the process of enabling benchmarking against GB GDNs where appropriate.

6.57 Some judgements were necessary in this transition from moving to the cost lines granted in GD14 FD to the ones used in ACRT, which we worked on with the GDNs. The BPT is based largely on the ACRT and enables us to have a consistent basis of how all GDN's submitted their business plans.

6.58 Annex 9 deals with how costs of previous years have been remapped, to have comparable baseline costs. We have shared this in advance with the GDN's and received no comments that it was incorrect.

6.59 SGN, which is in the start up phase of a developing network, has the additional key factor of the Gas to the West (G2W) licence competition that resulted in the award of its licence. Its costs are largely based on this process.

6.60 To enable us to set efficient allowances for future years, we consider the results of past performance from the GDN's, in terms of submissions in previous price controls and the Annual/Cost Reporting Template (ACRT). The basis of this information enables us to consider efficiency, both from suitable comparisons with other GDNs and in terms of the changes the GDN's propose to make to their future costs.

6.61 We review below the bottom up analysis and methodology used to derive the allowances.

Emergency Costs

<u>Overview</u>

6.62 Emergency costs cover the activities associated with the receipt and resolution of emergency calls.

6.63 Prior to 2013, both PNGL & FE reported costs and forecasts for emergencies in terms of the account headings used within their businesses

6.64 Since 2013 both companies have been asked to report in a common format to help introduce consistency in comparative assessment and to provide an element of comparability to GB networks.

6.65 Information is now reported under the following defined headings:

- *Emergency call centre costs*: covering the handling and dispatch of emergency calls by the emergency call centre. This incorporates calls classified as enquiries by the call centre and those deemed to require further investigation.

- *Emergency first response costs*: covering the initial investigation of an emergency job following dispatch by the emergency call centre or the company's own customer contact centre.
- *Repair activities*: covering mains and service repair jobs raised following the initial first response investigation. This includes repairs as a consequence of third party damage where the majority of costs are subsequently recovered.

6.66 The emergency allowances for each company have been assessed under these headings. A summary of the outcome of the individual GDN assessments is provided in the GDN-specific sections in this Chapter.

6.67 Annex 8 provides further description of this work, the approach applied and the detail behind the individual GDN assessments. It also details our response to the consultation feedback received on the draft determination (as summarised in Annex 13) and any associated adjustments to the GDN allowances.

6.68 All figures quoted in the GDN-specific sections in this Chapter and in Annex 8 are pre efficiency and net of contributions.

Network Maintenance

<u>Overview</u>

6.69 Network maintenance activities are those direct activities necessary to keep the network in safe working order (excluding emergency repairs). They cover a broad range of planned and reactive work and jobs carried out in response to consumer requests. For example, the planned maintenance of pressure regulators, the replacement of batteries on PAYG meters, the replacement of broken street furniture or a change of meter type requested by consumers.

6.70 Some of the work carried out in response to consumer requests is off-set by contributions from consumers. In this section, Business Plan costs and final determination allowances are reported net of contributions.

6.71 We have adopted different approaches for FE and PNGL for the final determination:

- We compared the general level of expenditure proposed by PNGL against our determination for GD14 and the detailed information provided by the company. We concluded that the overall plan submitted by the company (excluding new items) was reasonable and made no adjustment for the final determination. We reviewed the new items of work identified by PNGL for GD17 and made reasoned adjustments to arrive at a final determination allowance.
- FE submitted a plan with a marked escalation in maintenance and metering costs driven by new maintenance activities required on a 10 year cycle which will be carried out for the first time in GD17. The company provided a bottom up estimate of activities and unit costs to support its plan. For the final determination we have benchmarked the cost of network maintenance for FE against the projected costs for PNGL. In doing so, we have taken account of the stage of development of the company by including drivers based on network development 10 years before to estimate current costs.

6.72 Our approach and the outcome of our assessment are described in the company specific sections below.

Real Price Effects, Productivity and Frontier Shift

Overview

6.73 We have assessed particular elements of cost, drawing on our previous experience and current regulatory practice.

6.74 The price of a company's various inputs may differ over time. Price controls have normally been indexed by the Retail Price Index (RPI) to account for broad changes in prices. However, being a measure of general inflation, not all types of cost changes will be reflected in the range of prices used to calculate the RPI. To account for this it is common practice to calculate and make adjustments for the difference, either positive or negative, between particular input price changes for a company or industry and the RPI measure of inflation. This is described as *real price effects* (RPEs).

6.75 The concept of frontier shift is wider than simple productivity assumptions. Within this report, we have adopted the methodology we first introduced at PC13 for NI Water, which aligns closely with the Competition Commission (CC) determination for Northern Ireland Electricity at RP5 and more recent Competition and Markets Authority (CMA) decisions. This process combines nominal input price forecasts with productivity expectations and RPI inflation:

Frontier shift in real terms	=	input price increase	minus
		forecast RPI (measured inflation)	minus
		productivity increase	

6.76 As a result of updates in our data since draft determination, there is a small overall change to the RPEs and frontier shift. This is illustrated in the table below.

Opex	2015	2016	2017	2018	2019	2020	2021	2022
Frontier shift FD	0.0	-0.4	-0.4	-0.8	-0.8	-0.7	-0.7	-0.7
Frontier Shift FD (Cumulative %)	0.0%	0.5%	0.8%	1.6%	2.4%	3.1%	3.7%	4.4%
Frontier shift DD	-0.2	-0.4	-0.7	-0.9	-0.8	-0.6	-0.6	-0.6
Frontier shift DD (Cumulative %)	0.2%	0.5%	1.2%	2.1%	2.8%	3.5%	4.1%	4.7%

Table 25: Opex Frontier Shift

6.77 A further detailed explanation of the precise make up of our overall RPEs and assumed productivity increase is contained in Annex 6 – Real Price Effects and Frontier Shift.

Net Impact

6.78 Once we apply our frontier shift to a pre-efficiency opex we derive our final determination opex profiles, net of frontier shift.

FE – UR Decisions

Overview

6.79 For this final determination, we have decided to apply the results of our bottom-up opex assessment and this section focuses on that analysis.

6.80 In setting allowances for FE and PNGL in general, we have used the most up to date detailed actuals, which is 2014. This sets a sound basis to set up a benchmark were appropriate. In some circumstances there may be good reason for why we have deviated from this approach and a further explanation is given in the relevant area.

Top-Down Assessment

6.81 Our top-down opex benchmarking analysis at final determination utilised two econometric models taken from an examination of a number of competing models, to establish efficient opex levels for FE during the six-year GD17 period.

6.82 We have used the results from the preferred models to forecast efficient opex levels for FE up to 2022. According to the results, we believe that there is scope to reduce FE's business plan opex costs by up to 25.3%, to reach what has been assessed as efficient operational costs.

6.83 More detailed results and further explanation on the methodology used by the Utility Regulator is provided within the GD17 final determination's Annex 5: Top-Down Benchmarking.

Bottom-up Assessment

6.84 We note in the 2014 ACRT, that it was a requirement that all GDNs submitted in a constant price base, which was December 2014 prices. Subsequent to the draft determination we found that that FE had completed its 2014 ACRT in year average 2014 prices, which is in line with its licence. We corrected this for the final determination which provided for a marginal increase in FE allowances.

6.85 The FE business was sold by its previous owner (Gas Networks Ireland (GNI) or formally called Bord Gais) to iCON Infrastructure LLP, in March 2014.

6.86 We note that since the sale of the business, additional costs have been incurred, in respect of Professional, Legal and IT mainly. Our approach is not to make adjustments as a result of change of ownership and no additional allowances will be granted to fund these costs.

6.87 A review of the 2014 performance is contained within Chapter 4, which shows that FE did not keep within the regulatory allowances set in GD14 for 2014. The 2014 figures, taking account of retrospective adjustments, show marked cost spikes in two areas. These largely explain the underperformance in that year. The areas are advertising and marketing and costs associated with the sale of the business. We understand the advertising and marketing costs were one off, although we have not received a full explanation for such a spike. However we do not use actual costs as a basis for setting connection incentive allowances.

6.88 Since the draft determination FE has provided a high level view of the opex costs for 2015. This shows that opex (excluding connections incentive) was £5.4m which was £0.4m more than the GD14 allowance for that year. The main areas of overspend were in relation to Office and IT costs as well as fees and consulting costs.

6.89 We have decided not to use 2015 costs as the basis for GD17 as the data was not available in a timely or detailed manner. We have however used it to verify at a high level, where appropriate, for some of the allowances.

6.90 We have also noted the analysis in Table 23, which suggests that FE 2014 costs are up to 26.6% inefficient. However as discussed above we are not relying on the top down benchmarking in GD17 and so have not applied any catch up efficiency.

6.91 Overall we have decided to use 2014 costs as a basis for setting GD17 opex allowances after adjusting for one off costs of the sale of the business.

6.92 As mentioned at the start of the Bottom up Assessment Overview, GD17 has a different reporting template compared to GD14. However, the fundamentals necessary to run the business are still the same.

6.93 In order to use a bottom up assessment, we considered it important to analyse FE historic costs using the ACRT that we implemented from the 2013 reporting year. For PNGL we were able to analyse historic costs back to 2010 using the ACRT.

6.94 For FE this has not been possible as some of FE former cost reporting lines could not be reconciled fully to the cost categories in the ARCT. As part of the GD17 business plan information requests, we asked FE to provide its historic opex i.e. from 2009 to 2012 using the new ACRT format.

6.95 We found that the historic opex costs provided by FE in the GD17 business plan template were not consistent with previous submissions provided by FE. Therefore, in setting opex allowances for FE in GD17 we have not used FE historic costs as submitted by FE in the GD17 business plan submission.

6.96 Given these issues, where we do use historic trend analysis it is only for 2013 and 2014.

6.97 In GD14 we found that the FE business plan submission contained costs associated with the supply part of the FE business. We have not found this to be the case with the FE GD17 business plan submission.

Cost Items	2014	2015	2017	2018	2019	2020	2021	2022	Average GD17
		Actual	FE GD17 submission						
Opex, £m	6.1	7.0	7.2	7.5	7.6	8.0	8.5	9.1	8.0
OO connections	1580	2085*	2466	2537	2622	2753	3100	3246	2787

* this includes 85 connections made in relation to a network extension in 2015

Table 26: FE 2014 Actuals versus FE GD17 Submission, £m

6.98 In its GD17 Business Plan submission FE requested the following:

- Higher allowances in GD17 to deliver more owner occupied connections than delivered in 2014.
- Significantly higher allowances in GD17 when compared to actual opex in 2014. On average, FE is seeking £1.9 million more allowance per year of GD17 than it spent in 2014, which is a real increase of 31%.
- FE expects to deliver more connections on average in GD17 than it delivered in 2014. This reflects the FE plan for developing its network in the GD17 period. The projected connections are significantly higher than those achieved in 2014 (1580) and significantly more than those which FE expects to connect in 2015 (1980) and 2016 (2000)

6.99 The table below sets out a summary of the overall opex allowances requested by FE in its original submission. More detail of the build-up of some of the individual cost lines was also provided, both in the original FE submission and following our information requests.

Cost item	2017	2018	2019	2020	2021	2022	Total
Asset Management	131.3	131.3	131.3	131.3	131.3	131.3	787.8
Operations Management	379.5	379.5	379.5	379.5	379.5	379.5	2,277.2
Emergency Call Centre	203.7	216.9	230.6	245.1	261.5	278.0	1,436.1
Customer Management	477.6	479.2	456.8	458.4	461.9	465.6	2,799.5
System Control	211.8	211.8	211.8	211.8	211.8	211.8	1,271.3
Emergency	894.7	989.5	1,089.2	1,195.2	1,315.1	1,437.6	6,921.6
Metering	444.2	564.8	535.0	594.7	699.4	907.8	3,746.1
PRE Repairs	53.2	56.1	59.1	62.2	65.7	69.4	365.8
Maintenance	424.7	360.0	363.3	417.9	476.3	533.5	2,575.9
Other Direct Activities	1.3	1.3	1.3	1.3	1.3	1.3	7.7
IT & Telecoms	299.9	299.9	299.9	299.9	299.9	299.9	1,799.6
Property Man	914.4	944.1	979.8	1,017.8	1,058.6	1,102.3	6,017.1
HR & Non-Ops Training	123.0	123.0	123.0	123.0	123.0	123.0	738.5
Audit, Fin and Regulation	603.4	603.4	603.4	603.4	603.4	603.4	3,620.6
Insurance	268.9	268.9	268.9	268.9	268.9	268.9	1,613.5
Procurement	27.9	27.9	27.9	27.9	27.9	27.9	167.9
CEO & Group Management	157.3	157.3	157.3	157.3	157.3	157.3	943.9
Connection Incentive (OO)[65]	1,180.6	1,221.5	1,270.1	1,345.0	1,544.0	1,627.5	8,188.9
AMPR (non-OO)	239.6	239.6	239.6	239.6	239.6	239.6	1,438.2
Trainee's & Apprentices	133.3	133.3	133.3	133.3	133.3	133.3	800.1
Non Controllable Costs	60.0	60.0	60.0	60.0	60.0	60.0	360.0
Total	**7,231.3**	**7,470.2**	**7,621.7**	**7,974.3**	**8,520.5**	**9,059.8**	**47,877.9**

Table 27: FE Operating Expenditure GD17 Submission, £k

Key Cost Lines

Overview

6.100 Table 27 shows the FE GD17 opex submission in the new BPT structure. As in GD14, greater scrutiny has been exercised over those cost categories that represent the greater cost. We have also considered the extent to which some cost items must be separately examined because of the particular way they are treated (e.g. pass-through), or due to other specific circumstances calling for individual treatment, irrespective of their magnitude.

[65] This was previously called AMPR (OO) in the draft determination.

6.101 While the ACRT brought about a change in cost categories, Manpower and Connective Incentive / AMPR (Owner Occupied) still require detailed analysis due to their magnitude and impact on other cost lines and these are discussed below.

6.102 While the Connection Incentive / AMPR (Owner Occupied) has its own cost category, manpower costs are included in such areas as Emergency, Maintenance, Customer Mgt etc, as the areas require a substantial manpower component.

Manpower

6.103 As described above, due to manpower being such an integral part of the price control, we will consider the number of FTEs necessary to run an efficient business.

6.104 In contrast to GD14, for GD17 we have not set an explicit manpower cost allowance, since as stated above manpower costs form part of most of the cost categories within the ACRT, rather than being an individual cost category.

	GD14			GD17					
	2014	2015	2016	2017	2018	2019	2020	2021	2022
FE requested allowances	57.1	59.1	59.1	67.2	67.2	67.2	67.2	67.2	67.2
UR Determination	54.4	55.9	55.5	58.3	58.3	58.3	58.3	58.3	58.3
FE actual	53.7	56.0	60.0*						

*2016 is a forecast

Table 28: FE FTEs Requested, 2014 Actual and GD17 Determination

6.105 Prior to the draft determination FE acknowledged in a query response that its requested GD17 FTE allowance should be reduced by 1.5 FTE to reflect the fact that it had allocated Non Executive Directors (NEDs)'s as salaried staff whereas the costs should have been allocated under professional and legal fees, as per BPT guidance. Consequently, FE actual FTE requested allowance for GD17 is 65.7

6.106 Table 28 sets outs the FE requested allowances for FTEs for both GD14 and GD17. It can be observed that the FE actual number of FTEs for 2014 was below its 2014 requested allowance in GD14 but in line with our GD14 allowance. It can also be observed that its FE actual number of FTEs for 2015 was below its 2015 requested allowances in GD14 but in line with our GD14 FD allowance

6.107 FE has explained that it is projecting increased FTEs mainly as a consequence of its change of ownership and because of the FTEs it considers it requires to facilitate the increase in its network build programme.

6.108 However we do not agree that the level of resources and the need to have FTEs in place from day one is appropriate.

6.109 We have therefore based the levels of FTEs on actual 2014 levels, with a small increase in relation to Operations Management, due to accelerated network development.

6.110 From a Salary perspective, FE stated in its GD17 Business Plan submission that '*Firmus energy has carried out a benchmarking exercise which was reviewed by PwC to confirm that manpower costs are broadly in line with the Northern Ireland market. General indicators suggest, in terms of base pay levels (which excludes variable pay and bonus), firmus energy is in line, apart from specialist Engineering, specialist Sales and qualified Finance staff. These roles are currently approximately 5% behind market rates as a* *result of a shortage of supply for Specialist Finance staff and an increase in competition from new gas network operators for Specialist Engineering staff within the small skill pool in Northern Ireland. Together, these activities make up 30% of the manpower costs included herein, and as a result, the overall salary costs show an increase of 1.5% in real terms (5% x 30%) from current levels*'

6.111 We address all such issues within our Real Price Effects review in Annex 6. This is consistent with the approach we have taken for PNGL.

6.112 In its response to the draft determination FE stated that '*the Utility Regulator's approach fails to take account of the FTE's required to realise firmus energy's challenging network growth plans but also fails to recognise the appropriate salaries required during this period of development. There are three fundamental issues with the Utility Regulator's analysis and use of 2014 actuals i.e. (1) the FTE's assumed by the Utility Regulator is understated by 1.4 FTE's due to the average number of positions open, or furloughs caused by staff turnover, during 2014. This would re-base actual FTE's in 2014 to 5.1 (2) this approach fails to take account of the uplift required to move 2014's actual costs to December 2014 prices, and (3) the analysis does not take account for the additional uplift of 2 FTE's allowed by the Utility Regulator in 2015 for system control as a result of market opening*'.

6.113 We consider that that we have allowed a sufficient increase in FTEs in the final determination for FE in the GD17 period, which recognises the envisaged growth in the FE network. The 2014 FTEs we used for our analysis are not understated since they reflect the FTEs recorded by FE in its 2014 ACRT. We agree that an uplift in 2014 costs is required for the GD17 final determination since FE did not apply the correct RPI figure within its 2014 ACRT submission. The analysis of FTEs undertaken within GD14 did not cover the GD17 period and therefore it should not be assumed that costs allowed in the GD14 automatically transfer into the GD17 period.

6.114 However we recognise that FE requires resources to manage its customer switching operations. To facilitate this we have allowed for an additional 1.35 FTEs within system control and 0.4 FTEs within customer management to asset FE in this area in the GD17 period.

<u>Connection Incentive for GDNs to connect Owner Occupied (OO) Properties</u>

6.115 The connection incentive is a per connection allowance to encourage the connection of domestic owner occupied (OO) properties. This is unique to NI and was created due to initial difficulties in driving gas connections. It is up to the GDN's how they spend the allowance but it tends to cover the sales teams, advertising and marketing, direct customer incentives and associated overheads.

6.116 In arriving at the overall connections package we will look at two key areas. These are a connections incentive for which there is an economic test and an owner occupied connections target. In addition for GD17 we have introduced the concept of a 'new areas' allowance. We will consider each of these in turn.

Economic Test for Connection Incentive

6.117 The basis of this mechanism is a simple economic test, based on the revenues from a connection minus the costs. It adopts the principle that any new connection to the network must be economic and therefore must pay for itself over a reasonable period of time, so that it makes a positive contribution to the network, after making suitable assumptions. We will deal with the assumptions used to create the connective incentive allowance later in this section.

6.118 All parties recognise that a significant element of the connections incentive was put in place to increase awareness of availability of gas in NI. As part of GD14 we indicated that the connections incentive, which was set at £573, would be reduced by 50% in GD17 to reflect the increasing awareness of gas in NI and that this element of the incentive becoming less relevant.

6.119 It should be noted, that the impact of this incentive is wide ranging for the overall business, as it covers a certain percentage of costs to cover all overheads of the organisation.

6.120 Costs for Advertising & Market Development are classified into the following two categories:

- Advertising & market development for domestic owner occupied properties (OO properties); and,
- Advertising & market development (non-OO properties).

6.121 The costs collated under Advertising & Market Development should include costs for:

- Advertising, marketing and PR;
- Incentives (for OO properties only);
- Sales related staff, including relevant director; and
- Shared corporate overheads.[66]

6.122 Before considering what FE has requested, we must first deal with the principles of how the mechanism works in practice.

6.123 We will now in turn deal with the mechanism principles, used to calculate the allowance.

Mechanism Principles

6.124 The main principles used in the development of the mechanism remain largely unchanged from GD14. The key elements are as follows:

- The opex allowance per connection has been calculated using the formula:

Allowance per connection = (Revenue per connection) – (Direct capex cost per connection)

Where:

Revenue per connection = Average consumption X Conveyance tariff, Discounted over the defined Recovery period

AND

Direct capex cost per connection = Determined infill cost per OO connection + Determined meter cost + Determined service cost

[66] This is discussed further in section 6.151

- We have developed a model around the above formulae using estimates, where necessary, for some key assumptions within the formulae.
- The mechanism will apply, as before, only to domestic OO housing. We have therefore separately granted a certain level of fixed allowances for sales-related costs that are NOT associated with OO connections.

Revenue per Connection

6.125 A reminder of the formula:

Revenue per connection = Average consumption X Conveyance tariff, Discounted over the defined Recovery period

Connection Incentive Assumptions - GD17		
Domestic Consumption	tpa	380
Recovery Period	yrs	15
Conveyance Tariff	ppt	40
RoR Post 2016	%	4.0
Dom Service Value	£	889
Dom Meter Value	£	200
Infill Reduction	£	340
Connection Incentive Value	£ / add. conn	420

Table 29: GD17 Connection Incentive Assumptions

6.126 This produces a figure of £420 per connection which is less than the GD14 figure of £573, although significantly higher than our initial thinking to cutting the incentive in half.

6.127 In the DD we proposed to reduce the existing allowance on a glide path, from £550 to £420, over the 6 year duration of GD17, as shown in Table 30.

Connection Incentive Glide Path	2017	2018	2019	2020	2021	2022
Allowance per Connection	550	520	500	470	450	420

Table 30: Connection Incentive Glide Path

Connection Incentive: 'new areas' allowance

6.128 We have carefully considered the responses regarding the connections incentive. All parties recognise that a significant element of the connections incentive was put in place to increase awareness of the availability of gas in NI. To a significant extent this has been achieved which was reflected in our proposal to glide path from the current level of

£573 per applicable connection in 2016 down to £420 in 2022. However many of the responses highlighted the challenging conditions facing the GDNs and the need to ensure new connections continued to receive a strong focus from the GDNs. In consideration of the particular challenge that GDNs face in new areas, where there is a need to establish gas as the fuel of choice, we have introduced a new areas incentive for GD17

6.129 All three GDNs have significant expansions planned in GD17, and this is likely to be the last price control where such expansions are considered. Therefore, there is a case to be made, given our principle objective to grow the gas industry, for an additional allowance to drive awareness of gas, ultimately leading to increased momentum in connection rates. Given the uniqueness of the extent of the extensions in GD17, we would not plan that this allowance would be applied in future price controls.

6.130 We would propose the new areas are defined as a significant new geographic area which has no experience of natural gas. Thus an extension with several new towns would be classified as a new area but an extension to a new estate in a town with gas already would not. The size of the New Area is based on the number of potential properties passed. This is straight forward for PNGL and SGN as it is defined as all potential properties in the East Down and Gas to West areas. The most problematic area is the FE area due to the need to identify separately the new infill areas which has not had gas available previously.

6.131 Following the draft determination we provided a paper to each of the GDNs of how we envisaged the principles of the New Area allowance could be applied. We received responses from each GDN giving their feedback on the principles.

6.132 In respect of the properties FE considered should fall under the new area FE stated '*It is important to note that we consider our full GD17 project plan ie. All 621 areas to be developed with new mains, as "new areas". This is consistent with the properties passed forecast on 1 August 2016, which was calculated using the forecast mains length laid during GD17 as a proportion of total mains laid by firmus energy 2007-2022. That data was in line with the firmus energy GD17 mains laid forecast provided in the GD17 Business Plan submitted on 30th September 2015 and resulted in the following calculation:*

Forecast mains laid length to end of 2016: 1,150km

Forecast mains laid during GD17: 718km

Forecast proportion of connections resultant from GD17 mains laid: 62%'.

6.133 FE further stated that *'Our mains laid forecast submitted to the Utility Regulator on 30 September 2015 included network design plans relating to each of our 621 new development projects, thereby providing a full network development overview for the years 2017-2026. Of those 621 projects, 558 are exclusively driven by an owner occupied properties passed target'*

6.134 We completed our own analysis in this area, in which we used the proportion of properties forecast to be connected in GD17 versus the proportion of properties connected in GD17 which were passed before GD17 we estimated a figure of 44%.

6.135 We recognise that that there is judgement in deciding what is a new area and what is an existing area. FE analysis suggests a figure of 62% whereas our analysis would suggest 44%.

6.136 Based on this analysis we have made the decision that 50% is a reasonable estimate based on the available analysis which results in 45,771 properties in the FE new area.

6.137 We considered what the size of the additional allowance should be in respect of the New Area. We recognise that the question of how much GDNs should spend in marketing the benefits of gas to new areas is one without a perfect answer. We were keen that the size of the allowance should be significant enough to make an impact in the new areas but not too big to begin impacting on tariffs.

6.138 We concluded that a figure of £50 per property passed in the New Area is appropriate. Given that the additional allowance is applied to all properties passed whether in GD17 period or later, this additional allowance can only be applied in the GD17 period and we do not anticipate further new areas allowance in GD23 and beyond.

6.139 To ensure a strong incentive we have decided that the additional new area allowance is included within the overall per connection allowance.

6.140 In practice this means that the following steps are undertaken in order to covert the additional new areas allowance into a per connection allowance.

- **Step 1**: Multiply the properties passed in New Area x £50. For FE this is 45,771 x £50 = £2,288,550;
- **Step 2**: Divide total allowance by total number of additional connections (i.e. excluding non additional @ 25%)[67] in the GD17 period to convert it to a per connection allowance. For FE this is £2,288,550 / 15,338 connections = £149.21, rounded to £150;
- **Step 3**: Add the additional £150 amount to the existing per connection allowance.

6.141 This converts to the following allowances per connection for all OO connections for FE.

	2017	2018	2019	2020	2021	2022
Standard Allowance per Connection	550	520	500	470	450	420
Additional ‘new area’ allowance	150	150	150	150	150	150
Standard Allowance per Connection + New Infill Areas Allowance	700	670	650	620	600	570

Table 31: OO Connection allowance and New Area Allowance

Connection Targets

6.142 FE submitted a Market Development paper together with an owner occupied connections paper as part of its business plan submission for GD17.

[67] This is discussed further in section 6.157

	2012	2013	2014	2015	2016
FE forecast connections	400	400	2000	2000	2000
UR determination	400	400	2000	2000	2000
FE actual connections	1914	1620	1580	2000	2000*

(* 2016 is Best Estimates)

Table 32: FE Actual Connection Numbers versus GD14 UR Determination

6.143 Table 32 shows how FE has performed in terms of actual owner occupied connection numbers versus price control targets.

6.144 In relation to connection numbers in 2014, FE has stated the following in its GD17 business plan. '*The final area of significant cost overspend is for connections related activities. Due to the increased competition in the marketplace resultant from the drop in oil price, firmus energy has had to invest further in advertising and our salesforce in an attempt to meet our owner occupied connection targets. Despite this additional investment we failed to meet our owner occupied connection targets in 2014*'.

6.145 We note that in contrast to FE, PNGL significantly outperformed its connection target for 2014 and that the oil price only dropped below equivalent gas prices in the second half of 2014.

6.146 Also we need to consider what level of properties remain to be connected to the network. Table 33 demonstrates another potential c 40,000 customers with a readily connectable gas supply available. These customers typically connect when their existing heating source comes up for replacement or renovation to the property occurs. As FE has been developing its network for nearly a decade, the level of penetration is still only 20%.

Fe Connection Numbers	2012	2013	2014	2015
Actual Conncetion Numbers	1,678	1,914	1,580	1,980
Cumulative Connections	4,730	6,644	8,224	10,204
OO Propertities Passed	36,513	44,398	48,998	53,998
% Pentration	13%	15%	17%	19%

Table 33: FE Connection Numbers and Properties Passed

6.147 We have considered the FE view on connection numbers for the GD17 period but consider that the target domestic owner occupied connection numbers should be increased. Our target, as shown in Table 34, reflects the FE accelerated capital programme and the rate at which we consider FE should be able to connect based on a review of historic connections by FE. The increasing profile of target connections reflects the growing potential customer base FE will have and contrasts with a reducing target for PNGL, who will have much less new potential customers to target in GD17.

6.148 In its response to the draft determination FE stated *'The Utility Regulator's modelling does not appear to reflect the reduced network growth rate projected beyond the GD17 horizon. No explanation is provided for the very significant increase from the 45% penetration assumption set out in the Utility Regulator's revised GD14 final* *determination modelling. Benchmarking against other utility networks demonstrates that the annual growth rate is likely to be less than 5% (i.e. c.3%) in the post GD17 period when the majority of networks rollout is complete. Modelling by the Utility Regulator on the basis of an arbitrary 85% penetration figure is therefore unsupported, as is its application to backcast connection rates for the GD17 period. This has resulted in a connections target that FE does not believe is achievable, particularly with the proposed funding available.'*

6.149 In our view the increased connection target for GD17 reflects the planned extension of the network. The connection targets are commensurate with the increase in the number of properties passed but not connected. The 5% connection rate (of properties passed and not yet connected) is supported by an analysis of historical connection rates in both the firmus area and PNGL areas and reflects local experience. The 85% figure quoted is an assumption that 15% of owner occupied properties passed will not opt to connect in the long term and is not a penetration rate. This is also the basis of justifying the economic rollout of FE infill discussed in Chapter 7. Based on the planned development of the network in GD17 and the OO connection targets, we estimate an OO penetration rate at the end of GD17 of 24% of properties passed.

	GD17 DD					
FE Connection No's (OO)	2017	2018	2019	2020	2021	2022
FE GD17 Submission	2466	2537	2622	2753	3100	3246
UR determination	2600	2950	3300	3600	3900	4100

Table 34: GD17 Determined OO Connection Numbers

6.150 We had considered in GD14 whether, in the context of a halving of the incentive, it should be more focused on fuel poor customers. However given the proposal to move away from a drastic reduction in the incentive we propose that it should continue to be applied widely and not focused on one group. Furthermore we have taken into account the GDNs points on the difficulties in designing such a system and the role of other schemes such as the Northern Ireland Sustainable Energy Programme (NISEP)[68] and the Affordable Warmth grant scheme[69,] in delivering on social goals.

Costs replaced by the Connection Incentive

6.151 In GD14 we stated that the following opex costs were being replaced by the owner occupied connections incentive:

- Advertising, Marketing and PR;
- Incentives;
- OO sales related staff, including relevant director; and
- Shared corporate overheads.

[68] In line a request from the Minister for Economy, this scheme will operate until 31 March 2018. For further details on the scheme see: Utility Regulator: Framework Document for the Northern Ireland Sustainable Energy Programme 2016-2017, September 2015.
[69] For further details see: http://www.nidirect.gov.uk/index/information-and-services/environment-and-greener-living/energy-wise/energy-saving-grants/affordable-warmth-grant-scheme.htm.

6.152 The corporate overheads (apportioned) cost line in GD14 referred to a share of overheads we considered appropriate to apportion to the Business Development department. These costs included: Human Resources, Insurance (buildings and insurance), IT, office costs, rates (excluding network rates), stationary, telephone and postage, travel and subsistence, corporate support personnel and their apportioned share of the above costs.

6.153 In general, we have adopted a similar approach in GD17 but used different cost categories to reflect the fact that the GD17 business plan template (BPT) and the Annual Cost and Reporting Template now use different cost categories when compared to GD14. The cost categories we have used in GD17 are in the main 'business support' costs, as we consider they most directly relate to the 'indirect' costs referred to above in GD14.

6.154 In contrast to GD14, we have not re-allocated a portion of customer management staff costs for those we consider undertake owner occupied sales activity, as the applicable FTEs in the GD17 business plan submission are in line with the GD14 allowances.

6.155 We have maintained the percentage used for the apportionment of overheads from GD14 for GD17 i.e. 15%, to reflect the number of FTEs we consider FE uses on owner occupied advertising and market development activities. The 15% apportionment is consistent with that used for both PNGL and SGN.

6.156 Our intention is that these costs are to be recovered via the connection incentive mechanism. Therefore we have reduced the fixed allowances for applicable business support cost categories for these costs items by 15%.

Connection Incentive: Non – additional connections

6.157 As in GD14, we have used a concept of non – additionally, as we consider that there will be a certain number of OO connections that would occur anyway without any direct marketing or selling to these customers. We describe these connections as "non-additional". Since FE could in theory avoid any sales-related costs to connect such customers, no allowance will be applicable for these customers.

6.158 One key reason behind the connections incentive was that gas was something of an unknown fuel in NI and that investment was needed in marketing to increase awareness of gas and move it to being the fuel of choice in NI. This has been largely achieved over time and so reduces the need for the connections incentive.

6.159 For GD14 this was set at 25% of all new OO connections. However, having considered the arguments from FE and reflecting on the stage of FE network development and the information on properties passed, we propose that maintaining the 25% "non - additional" represents a reasonable figure which recognises that the FE network is not as developed as that for PNGL.

Application of the Owner Occupied (OO) Connection Incentive

6.160 For the draft determination we noted that the GDNs had raised concerns with the application of the owner occupied incentive mechanism as it applied in GD14. For example, FE made the argument that the connection incentive should be calculated over the entire price control period rather than on an annual basis. In addition, both FE and PNGL made the argument that the connection incentive as applied in GD14 i.e. the cap and collar regime was asymmetrical in that it unduly punished underperformance while not adequately rewarding outperformance.

6.161 We have considered the comments and while we think it is important that there is a strong incentive on the GDNs to prioritise connections, we agree that such incentives could still operate in a slightly different approach.

6.162 We have concluded that the cap should be removed and that a different collar should be implemented such that where a GDN underperforms the annual connection target by more than 50%, a 25% collar (i.e. 25% * 'per connection' allowance) would operate.

6.163 To demonstrate how the new collar will work, consider the following examples:

Exceed target

FE Target Connection for 2017 = 2,600

25% fixed non additionality = 650

Actual Connections = 3,000

Connection Incentive = £700

So 3,000 – 25% fixed non additionality[70] of 650 = 2,350 x £700 = £1,645,000

Underperformance of Target

FE Target Connection for 2017 = 2,600

25% fixed non additionality = 650

Actual Connections = 1,350

Connection Incentive = £700

So 1,350 – 25% fixed non additionality of 650 = 700 x £700 = £490,000

Underperformance of Target where collar applies

FE Target Connection for 2017 = 2,600

25% fixed non additionality = 650

Actual Connections = 500

Connection Incentive = £700

So 500 connections made is less than 50% of target so collar applies:

25% of the Connection Incentive = £175

So 500 - 25% fixed non additionality of 650 = (150) x £175 = (£26,250)

In this situation we would not apply a negative allowance, so it would be zero.

6.164 All connections allowances claimed by GDNs must relate to properties which have a supplier and are burning gas. We expect the GDNs to be able to demonstrate that all connections have a supplier agreement in place and burn a minimum quantity of gas.

[70] For the avoidance of doubt, the non-additional target is fixed at 25% of the annual connections target, irrespective of the actual output connections.

Advertising & Market Development Costs for non Owner Occupied (non-OO) properties.

6.165 The Advertising and Market development (non-OO) cost category covers advertising and market development expenditure in relation to NIHE, New Build and I&C properties.

6.166 FE Advertising and Market development costs are driven by staff costs and market development costs and a small amount for stationary, communications and billing. In the 2014 year FE had advertising and market development (non-OO) costs of £354k. FE had 5.9 FTEs employed within the advertising and market development (non OO) category in 2014 and is proposing to reduce the level of FTEs to 3.4 in GD17.

6.167 We consider that the FE proposed reduction in FTEs for advertising and marketing on non-OO reflects FE focus in the GD17 period on the owner occupied sector. We have based the advertising and market development (non-OO) cost allowance for GD17 on the FE GD17 projected FTEs and using 2014 staff costs.

6.168 For the draft determination we re-allocated some of the costs specifically for Head of Sales under advertising and market development (non-OO) cost category to the owner occupied cost category as we considered that they will spend time on Advertising and Market development for non-owner occupied connections. This was consistent with our approach in GD14 and consequently we have rolled forward the amount we re-allocated in GD14.

6.169 In its response to the draft determination, FE provided further information in relation to how it allocates the costs associated with its Head of Sales and clarified that the costs were allocated in its GD17 business plan in line with the GD14 final determination and we have accepted this for the final determination.

	2017	2018	2019	2020	2021	2022
FE requested allowances	239.7	239.7	239.7	239.7	239.7	239.7
UR Final Determination	228.7	228.7	228.7	228.7	228.7	228.7
Variance	11.0	11.0	11.0	11.0	11.0	11.0

Table 35: Advertising and Marketing (non OO) Costs, Requested and Allowed, £k

Work Management

Overview

6.170 Work Management covers the following cost categories:

- Asset Management;
- Operations Management;
- Customer Management including the Emergency Call Centre; and
- System Control.

Asset Management

6.171 Asset Management covers the activity of managing the network's assets. The costs collated under asset management should be costs incurred in the following areas:

- Network Planning;
- Network Integrity (including gas quality monitoring);
- Network Capacity;
- Network/engineering policy/procedures (covering all policies of the network e.g. records transfer and brought in services & materials).
- Network development/analysis; and
- Management of redundant sites & remediation programmes

6.172 FE asset management costs are in the main driven by its associated manpower costs. In the 2014 year PNGL had Asset Management costs of £139k and had 1.8 FTEs employed within the Asset Management cost category. FE has proposed an additional FTE specifically an additional engineer for Asset Management in the GD17 period.

6.173 In GD14 we stated that '*in our assessment of fe's manpower requirements we have granted 3 additional FTE in each year of the price control'*. This is to take account of the business growth since 2012 and will also allow FE to have sufficient manpower resources to undertake their plans to develop and implement an asset management system for network maintenance in the GD14 period. Consequently, we consider that we have already allowed for an increase in FTEs for asset management in GD14.

6.174 In its response to the draft determination FE stated that 'FE *included professional and legal fees of £12k per annum to cover Asset Management consultancy and legal advice. UR has recognised and appears to allow these costs in UR's detailed calculations. Unfortunately, however, these costs do not appear to flow through to the final total allowed under Asset Management in the draft determination'*.

6.175 We reviewed the FE response and have now included the professional and legal fees in the final determination.

	2017	2018	2019	2020	2021	2022
FE requested allowances	131.3	131.3	131.3	131.3	131.3	131.3
UR Final Determination	92.2	92.2	92.2	92.2	92.2	92.2
Variance	39.1	39.1	39.1	39.1	39.1	39.1

Table 36: Asset Management Costs, Requested and Allowed, £k

Operations Management

6.176 Operations Management covers the cost of the day to day planning and supervision of the operatives and contractors working within the work execution processes. The costs allocated under operations management include for example:

- First line managers (non-field staff);
- Depot Manager etc.;
- Costs of the Safety, Health and Environment section (compliance).
- Operations Support:
- Covering support costs in depots (which include TMA/NRSWA activities);

- Plant protection;
- Digitisation;
- Dispatch;
- Data quality;
- Work scheduling;
- Updating asset records; and
- HSE policy

6.177 FE operations management costs are in the main driven by its associated manpower costs. In the 2014 year FE had Operations Management costs of £186k and had 11.6 FTEs employed within the Operations Management cost category. FE has proposed that there should be 16.6 FTEs for Operations Management in the GD17 period.

6.178 For the draft determination we considered that an increase in FTEs is appropriate for Operations Management in the GD17 period given the extent of FE planned network development. We provided for an increase of 2 FTEs when compared to the 2014 actual FTE, however this is still lower than FE requested FTEs.

6.179 Our allowances for the final determination are unchanged from the draft determination except for adjustment for RPI given that FE submitted its 2014 costs in year average prices rather than Dec 2014 prices.

	2017	2018	2019	2020	2021	2022
FE requested allowances	379.5	379.5	379.5	379.5	379.5	379.5
UR Final Determination	283.5	283.5	283.5	283.5	283.5	283.5
Variance	96	96	96	96	96	96

Table 37: Operations Management Costs, Requested and Allowed, £k

Customer Management

6.180 Customer management is split between two main areas i.e. Emergency Call Centre and Customer Services that cover non-emergency calls and which also handle enquires and complaints. The non-emergency Customer Services also includes costs of commercial/contract department that manages all types of contracts for the whole of the business.

6.181 FE actual 2014 customer management costs were in the main driven by its associated manpower costs. In the 2014 year FE had customer management costs of £254k and had 8.9 FTEs employed within the Customer Management cost category. FE has proposed a marginal increase in FTEs for Customer Management in the GD17 period i.e. from 8.9 FTEs in 2014 to 9.3 FTEs in the GD17 period.

6.182 For the draft determination we did not consider that an increase in FTEs for Customer Management from the 2014 figure was appropriate. However we did not re-allocate any FTEs from Customer Management to the advertising and market development owner occupied cost category as the FE allocation of FTEs between customer management activities and sales related activities appeared consistent with our allowances in GD14.

6.183 In addition, FE has proposed a significant increase in professional and legal costs from circa £13k in 2014 to circa £204k under the Customer Management cost category for expenditure in relation to Land and Property Services mapping, GIS support and maintenance and FAAR and FME software. Initially FE had these costs in its GD17 business plan submission under the 'Emergency Call Centre' cost category but subsequently advised that "*these costs should be allocated under Customer Management (Including Non-Emergency Customer Call Centre) & Network Support (Including System Mapping)*".

6.184 For the draft determination we did not consider that it was appropriate for consumers to fund these professional and legal costs since they appear to be related to the change in ownership of FE. We noted that the other GDN's do not have 'professional and legal' fees costs under the Customer Management cost category.

6.185 In its response to the draft determination FE stated that '*forecasts indicate a doubling of connection numbers across the GD17 period. Based on this connection growth FE believes an uplift of 0.4 FTE's in addition to the 8.9 FTE's already in place is reasonable to provide the additional customer support that will be required*'.

6.186 For the final determination we have allowed the 0.4 increase in FTEs to assist FE in its customer switching operations. However we have not changed our view in respect of professional and legal fees and therefore consistent with the draft determination these costs have not been allowed in the final determination.

	2017	2018	2019	2020	2021	2022
FE requested allowances	477.6	479.2	456.8	458.4	461.9	465.6
UR Final Determination	266.0	266.0	266.0	266.0	266.0	266.0
Variance	211.6	213.2	190.8	192.4	195.9	199.6

Table 38: Customer Management costs, Requested and Allowed, £k

System Control

6.187 System control covers the costs associated with the activity of ensuring the safe flow of gas through the network, ensuring the supply is sufficient to meet the demand of gas on a daily basis. The related costs should represent the cost of running the control room (e.g. staff costs of resource working within the control room).

6.188 The costs allocated under system control should include:

- Salary costs;
- Travel & subsistence;
- Training costs for the delivery of system control migration;
- Any other non-salary costs associated with these resources; and
- Mast Rentals

6.189 FE system control costs are in the main driven by its associated manpower costs. In the 2014 year PNGL had manpower costs of £102k and had 3.1 FTEs employed within the System Control cost category. FE has proposed an additional 1.4 FTE for System Control in the GD17 period.

6.190 For the draft determination we did not consider that an increase in FTEs is necessarily required for System Control is required in the GD17 period and therefore our allowance is based upon 2014 actual FTE numbers. This was consistent with our approach in GD14.

6.191 However for the final determination we recognise that FE requires resources to manage its customer switching operations. We have allowed for an additional 1.35 FTEs within system control and 0.4 FTEs within Customer Management to assist FE in this area in the GD17 period.

6.192 As Table 39 shows our allowances are above those requested by FE. This due to the fact that for this particular cost item, 2014 actual average staff costs on which our GD17 allowances are based are higher than projected GD17 average staff costs.

	2017	2018	2019	2020	2021	2022
FE requested allowances	211.8	211.8	211.8	211.8	211.8	211.8
UR Final Determination	238.3	238.3	238.3	238.3	238.3	238.3
Variance (+)	26.5	26.5	26.5	26.5	26.5	26.5

Table 39: System Control Costs, Requested and Allowed, £k

Emergency Costs

Overview

6.193 FE requested a total allowance of £1.35m in 2017 rising to £1.97m in 2022, to cover the cost of the emergency call centre, emergency first response and repairs. Although we note that this included £2.13m over the period which was incorrectly allocated and has subsequently been removed or reallocated. For comparison, historical actual costs for 2013-2015 averaged around £0.69m.

6.194 Table 40 summarises the emergency costs submitted by FE under each emergency expenditure category.

	2017	2018	2019	2020	2021	2022	GD17 Total
Call centre (£k)	399	414	405	421	441	462	2,543
First response (£k)	895	990	1,089	1,195	1,315	1,438	6,922
Repair activities (£k)	53	56	59	62	66	69	366
Total (£k)	1,347	1,460	1,554	1,679	1,822	1,969	9,830

Table 40 - Emergency costs submitted by FE

6.195 Table 41 summarises the emergency costs submitted by FE under each emergency expenditure category following budget removal due to incorrect allocation.

	2017	2018	2019	2020	2021	2022	GD17 Total
Call centre (£k)	204	217	231	245	262	278	1,436
First response (£k)	767	846	929	1017	1116	1218	5,894
Repair activities (£k)	53	56	59	62	66	69	366
Total (£k)	1,024	1,119	1,219	1,324	1,444	1,566	7,696

Table 41 - Emergency costs submitted by FE net of incorrectly allocated budget

6.196 Table 42 summarises the final determination allowances for FE under each emergency expenditure category.

	2017	2018	2019	2020	2021	2022	GD17 Total
Call centre (£k)	201	210	220	229	239	249	1,347
First response (£k)	695	757	821	887	954	1,020	5,134
Repair activities (£k)	53	56	59	62	66	69	366
Total (£k)	949	1,023	1,100	1,178	1,259	1,338	6,847

Table 42 - Emergency costs allowed in the final determination for FE

6.197 Figure 4 shows FE's GD17 allowances against the submission, historical actuals and the allowances for GD14. The actual outturn cost for 2015 has been added to show that the assessed allowances remain consistent with the company's most recent expenditure.

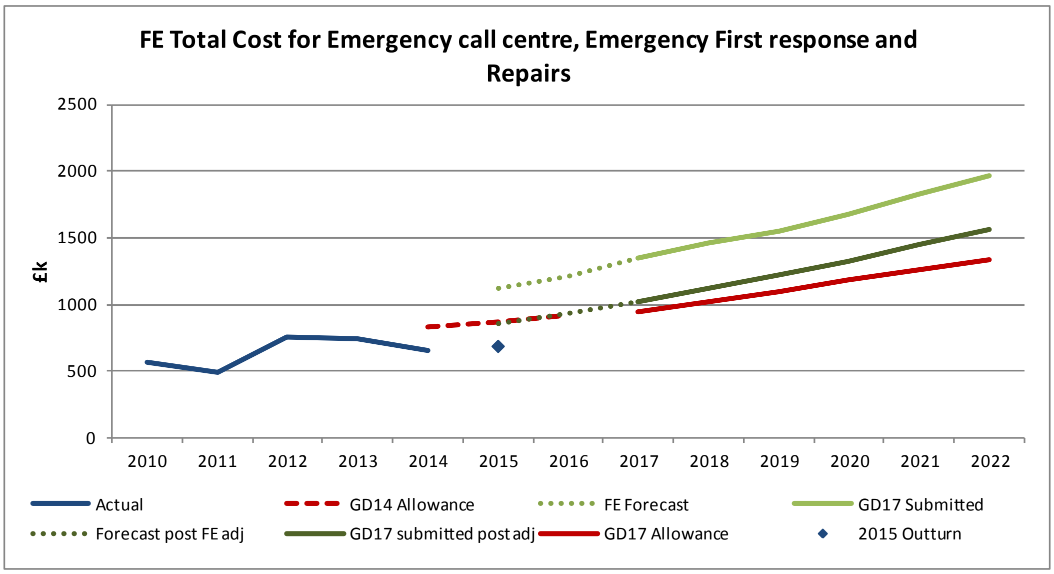

Figure 4 - FE Total cost for emergency activities

6.198 The key changes from the draft determination have been:

- Adjustment of model assumptions for FE to ensure that the profile of total call numbers is more reflective of historic and projected trends.
- Revision of projected connection numbers to align with those used elsewhere in the final determination.
- Inclusion of additional fixed costs for emergency first response services.

6.199 The combined effect of these changes has been to increase FE's allowance by £396k since the draft determination.

6.200 The key factors influencing the final determined emergency and repair allowances are:

- Removal of £1.11m of professional and legal fees from emergency call centre costs.

- Use of call volume modelling to assess the cost for the call centre. The approach carries forward call reduction targets applied in GD14 and results in an additional reduction of £89k in the emergency call centre allowance.
- Reallocation of £1.03m of meter replacement costs included in emergency first response operating expenditure to domestic meter capital expenditure.
- Adjustment of the number of estimated emergency jobs to align with modelled call numbers when assessing emergency first response costs. In addition, a lower unit rate of £5 was applied to jobs closed without a visit. The combined effect results in an additional reduction of £760k in the first response allowance.
- As in GD14, and given that all the GDNs have licence obligations about operating a single emergency number in NI, we are asking that the GDNs work more closely together in procuring an emergency call centre contract to ensure that costs are as low as possible.

6.201 Annex 8 provides further description of the detail behind the assessment and the approach applied. It also details our response to the consultation feedback received on the draft determination (as summarised in Annex 13) and any associated adjustments to allowances.

Network Maintenance

Overview

6.202 In its Business Plan FE identified net costs of network maintenance rising from £0.47m in 2015 to in £1.44m in 2022 (a 209% increase). The expenditure profile proposed by the company is shown in Figure 5.

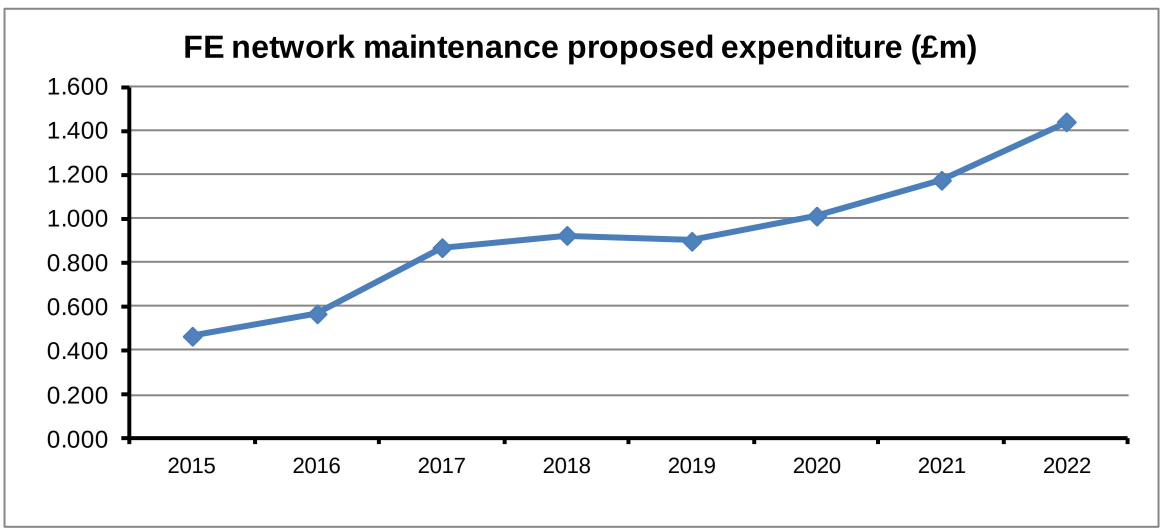

Figure 5: FE Proposed Network Maintenance Expenditure (£m)

6.203 The key driver for the increase in network maintenance over the GD17 period is the introduction of new maintenance activities required on a 10 year cycle which will be carried out for the first time in GD17. For example, the maintenance of pressure regulation equipment and the replacement of batteries on meters.

Assessment of Network Maintenance Expenditure

6.204 FE provided a detailed bottom up estimate of the cost of current and new activities across the GD17 period.

6.205 We asked our consultants to review the bottom up estimate of costs prepared by FE. They concluded that the activities identified were reasonable and that the bottom up estimates of the unit costs was broadly reasonable with some exceptions. However, they highlighted opportunities for synergies and efficiencies which could be achieved between the proposed activities by combining work into single visits or general economies of scale. This reflected similar comments made by FE in its own submission on opportunities to reduce costs through synergies between the activities.

6.206 To address the opportunities for synergies in the FE cost estimates we have developed a benchmarking process which uses the detailed bottom up estimates prepared by FE and the network maintenance costs for PNGL to estimate a reasonable allowance of network maintenance for FE in GD17.

6.207 As an initial high level benchmark we compared the costs of each company against a weighted number of consumers using a weighting of 2.13 for each I&C consumer against 1 domestic consumer. The weighting is based work undertaken to model emergencies and maintenance opex for GD14. This revealed a unit cost for FE of £20 per weighted connection compared to £11.3 for the PNGL Business Plan submission (adjusted for PES profit margin).

6.208 However, a primary driver for the escalation of costs for FE is the first time introduction of 10 year cycle activities during GD17. In the medium term, while the consumer base continues to grow, a simple driver based on the number of current consumers might not adequately reflect the balance of network maintenance activities driven by existing consumers and activities driven by consumers connected 10 years previously.

6.209 For the draft determination, we undertook a benchmark analysis to compare FE’s proposed costs with the determination we made for PNGL in GD17. This considered four major drivers for network maintenance

- Fixed costs related to the management of the business with a weak link to the level of activity. For example GIS and mapping licence costs.
- Annual costs covering activities which must be carried out every year such as the routine maintenance of meters or the response to consumer requested works.
- 10 year cycle costs related to the periodic inspection and maintenance of pressure management equipment and steel riser pipes and the calibration of meters.
- One off costs such as the provision of new telemetry equipment.

6.210 Following the draft determination, we continued to engage with FE to clarify the detail of the activities and costs included in Tables 3.8 and 3.10 of its Business Plan submission. This allowed us to make a number of corrections in our analysis including:

- A clear allocation of costs and activities.
- The allocation of internal labour costs.
- The removal of items covered elsewhere in the submission under legal and professional services including GIS costs, software licences and fees for base maps.
- Removal of one off costs for telemetry allocated to capex and considered in Chapter 7.

- Correction of 10 year cycle activities to take account of repeat maintenance and an assumption that meters and pressure control equipment will be replaced after 20 years.

6.211 Following these adjustments, we have refreshed our benchmarking analysis. To ensure that adequate account was taken of these cost drivers, we allocated the bottom up estimate prepared by FE into 7 cost categories and calculated unit rates for each category based on appropriate cost drivers. The activities, cost drivers used in the analysis and the calculated unit rates for the FE Business Plan costs are shown in Table 43.

Activity	Cost driver	Unit rate (£)
10 year cycle – domestic For example: domestic meter battery replacement and MP regulator maintenance.	Number of domestic connections made 10 years previously plus a repeat maintenance cycle at 30 and 50 years etc., assuming replacement of plant on a 20 year cycle.	149.1
10 year cycle – I&C For example: I&C MP regulator maintenance and meter component replacement.	Number of I&C connections made 10 years previously plus a repeat maintenance cycle at 30 and 50 years etc., assuming replacement of plant on a 20 year cycle.	420.6
Annual For example: annual costs of customer request work, small tools and equipment and telemetry maintenance.	Weighted number of current connections (1 domestic plus 2.13 times I&C).	4.27
Annual – I&C For example: annual costs of I&C meter calibration	Current number of I&C connections.	84.8
Annual - mains The annual cost of maintenance of gas mains valves and ancillaries	Length of mains.	105.6
One-off costs	Not included. Costs of telemetry and replacement of PRS considered as capex.	
Fixed costs GIS costs, software licences and fees for base maps.	Not included in Tables 3.8 and 3.10. The company has identified GIS costs, software licences and fees for base maps separately as legal and professional services.	

Table 43: FE Network Maintenance Benchmarking Cost Drivers

6.212 We applied the unit costs for the variable activity drivers (excluding FE one-off costs and fixed costs) to the same cost drivers for PNGL to calculate an equivalent benchmark cost for PNGL. In doing so, we have adjusted the benchmark estimate for PNGL to account for the higher proportion of LP mains in the PNGL area which will reduce the 10 year cycle costs. Using this methodology, the estimated variable network maintenance costs determined for PNGL in GD17 were 21% lower than the benchmark calculated using unit rates derived from the FE bottom up cost estimate for GD14. For our final determination, we applied a reduction of 15% to the variable costs estimated by FE to reflect this benchmarking exercise.

6.213 In its response to the draft determination, FE disagreed with our use of benchmarking to inform our determination of costs in an area where new activities will materially increase costs asking us to accept its bottom up estimates instead. We have concluded that benchmarking is essential to protect consumers and have continued to apply it in our final determination. FE also asked us to take account of special factors, in particular that a more sparsely populated area (relative to PNGL) will make it more expensive for the company to maintain its network on a per-customer basis (a 'sparsity effect). The company provided an analysis by a consultant which used anonymised operational data to show the impact of sparsity on unit costs including a regression analysis showing that sparsity effects would explain all of the gap identified in our in the benchmark calculation prepared for the draft determination. We reviewed the data provided by the company and concluded that it could supported a range of adjustments from as low as 3% to the 25% proposed by the company, depending on the approach taken to the treatment of outliers. We also noted that Ofgem has considered sparsity in its determination of GDN costs in GB, but concluded that it should only be applied to emergency call out costs to reflect the high proportion of standby cover inherent in this type of work. In view of the precedent, we have not applied a sparsity adjustment to our benchmark costs for FE.

Summary of expenditure for GD17

	2017	2018	2019	2020	2021	2022
FE Business Plan total costs (£k)	869	925	898	1,013	1,176	1,441
Draft determination allowance (£k)	758	805	782	872	1,012	1,242

Table 44: FE GD17 allowance for network maintenance

6.214 The final determination allowance for network maintenance costs in GD17 is £17.3 per weighted connection compared to £10.2 per weighted connection for PNGL.

Expenditure post GD17

6.215 We have included an allowance for network maintenance activities post GD17 based on the benchmarked unit rates identified for GD17. Increasing numbers of connections and an accompanying change in the proportion of works driven by current connections and connections 10 years previously, results in the cost per connection reducing to £13.5 by 2035. This assumes that current maintenance activities continue and allows for a general increase in costs in line with increasing numbers of connections. We have not made any assumptions about new maintenance activities which might be required in the future.

Other Direct Activities

6.216 FE has requested an allowance of circa £1.3k pa in the GD17 period for 'other direct activities' and this was accepted for the draft determination since it is below 2014 actual expenditure. Our allowances for 'other direct activities' for the final determination is unchanged from the draft determination.

	2017	2018	2019	2020	2021	2022
FE requested allowances	1.3	1.3	1.3	1.3	1.3	1.3

UR Final Determination	1.3	1.3	1.3	1.3	1.3	1.3
Variance	0	0	0	0	0	0

Table 45; Other Direct Activities Costs, Requested and Allowed, £k

Business Support Activities

Overview

6.217 Business support opex includes the following activities:

- IT & Telecoms;
- Property Management;
- HR & Non-operational Training;
- Audit, Finance & Regulation;
- Insurance;
- Procurement;
- CEO & Group Management; and
- Stores & Logistics.

IT & Telecoms

6.218 The IT & telecoms cost category covers the provision of IT services for day to day service delivery.

6.219 The costs collated under IT & Telecoms should include:

- The purchase, development, installation and maintenance of non-operational computer and telecommunications systems and applications.
- Provision of IT services for the day to day service delivery and including the cost of Help Desk, data centres, IT application development, maintenance and support; establishing and maintaining information system infrastructure projects (IT network provision, network maintenance, and servers support/services).
- Voice and data telecoms (e.g. WAN, landline rental and call charges, ISDN data and costs/rental of mobiles except where costs are charged directly to user departments).
- Developing new software for non-operational IT, assets including the costs of maintaining an internal software development resource or contracting external software developers. This will include any cost of software licences to use the product where those costs cover more than one year.
- Installing new or upgrading software, other than where it is capitalised. This does not include upgrading of software that is included within the costs of annual maintenance contracts for the software.
- Maintenance and all the operating costs of the IT infrastructure and management, along with application costs. This includes any annual fee for the maintenance of software licences, whether or not they include the right for standard upgrades or ‘patches’ to the software as they become available.

- IT applications maintenance and running costs.
- IT new applications software and upgrade costs.

6.220 FE IT & Telecoms costs are in the main driven by its associated manpower costs and costs for professional and legal fees stationary as well as nominal expenditure on stationary, communications and billing. In the 2014 year FE had IT & Telecoms costs of £608k. FE explained that in 2014 it incurred addition IT transaction costs as a consequence of firmus energy's sale to iCON Infrastructure. For the GD17 period FE has proposed IT & Telecoms expenditure of £300k pa.

6.221 FE had 0.75 FTEs employed within IT & Telecoms cost category in 2014 and has proposed an increase in FTEs of 1.25 FTE in the GD17 period when compared to 2014. Part of this increase is in relation to IT systems development and FE has explained this is a consequence of its change in ownership.

6.222 For the draft determination we based the IT & Telecoms allowance for GD17 on 2014 FTEs but using 2014 staff costs and accepted the proposed professional and legal fees. We did not accept the proposed increase in FTEs as we didn't consider that consumers should fund the consequences of the change in ownership of FE.

6.223 In its response to the draft determination FE stated that '*The growth in all activities of FE has placed significant strain on the IT and Telecoms function. FE's Business Plan forecast the requirement for an extra 1.2 FTE's within this area to support the original FTE count of 0.75 FTE's. FE would contend that headcount of 2 FTEs is not unreasonable for managing, developing and administering the IT and Telecoms function within firmus energy'.*

6.224 This area has been more difficult to access, due to FE change of ownership which has resulted in higher costs in the 2014 base year. We have set the allowance based on business as usual costs (after removing the cost associated with change of ownership). We consider this is appropriate based on size and scale of FE operations. Consequently our allowances for the final determination are unchanged from the draft determination except for adjustment for RPI given that FE submitted its 2014 costs in year average prices rather than Dec 2014 prices

6.225 We have re-allocated some of the costs under IT & Telecoms to be recovered under the owner occupied connections incentive / AMPR (OO), as we consider that some of FE's IT and Telecoms systems will be used for Advertising and Marketing for domestic Owner Occupied connections. This is consistent with our approach in GD14.

	2017	2018	2019	2020	2021	2022
FE requested allowances	299.9	299.9	299.9	299.9	299.9	299.9
UR FD before re-allocation	245.3	245.3	245.3	245.3	245.3	245.3
Re-allocation to AMPR (OO)	44.9	44.9	44.9	44.9	44.9	44.9
UR Final Determination	200.4	200.4	200.4	200.4	200.4	200.4
Variance	99.5	99.5	99.5	99.5	99.5	99.5

Table 46: IT & Telecoms Costs, Requested and Allowed, £k

Property Management

6.226 The Property Management cost category covers the activity of managing, providing and maintaining non-operational premises. This should include costs such as rent, rates (business), utilities costs including electricity, gas and water, maintenance/repair costs of premises and the provision of the facilities/property services such as reception, security, access, catering, mailroom, cleaning and booking conferences. The costs of property surveyors should also be included here.

6.227 The costs collated under Property Management also include:

- Stores, depots, offices (properties with the primary function to accommodate office based staff during their business hours), including training centre buildings & grounds;
- Rent paid on non-operational premises;
- Rates and taxes payable on non-operational premises;
- Utilities including electricity, gas and water (supply and sewerage);
- Inspection and maintenance costs of non-operational premises;
- Facilities management costs including security and reception;
- Training centre buildings & grounds; and
- Control rooms and data centres.

6.228 The most significant cost item under FE property management costs are in relation to network rates. We have in the past set network rates using a formula which links the allowance to FE revenues. FE allowance request was also calculated using the current formula.

6.229 We are comfortable with the approach of using a formula linked to revenue in order to set the network rates allowances for FE. We have used this approach historically in GD14 and we are retaining it for GD17. The network rates allowances have therefore been calculated accordingly. For the final determination we have updated the formula to take account of information on 2016-17 rating valuations.

6.230 For the draft determination we were of the view as per the treatment in GD14, the allowance for rates should be treated as pass-through, subject to FE demonstrating that it has taken appropriate actions to minimise valuations.

6.231 For the final determination we have decided to keep consistency with PNGL in this area and therefore for FE this will no longer be a pass through item. FE has the ability to influence the valuation that it is given and hence the business rates incurred. Also we have followed the decision of the CMA in RP5 on this area.

6.232 FE also has rent and rates costs in relation to its offices and these costs have been accepted for the final determination.

6.233 FE had 1 FTE under the Property Management cost category in 2014 and has not proposed any increase for the GD17 period and consequently we have allowed for 1 FTE in the GD17 period.

6.234 We have re-allocated some of the costs under Office costs to be recovered under the owner occupied connections incentive / AMPR (OO) as we consider that some of FE offices will be used for Advertising and Marketing for domestic Owner Occupied connections. This is consistent with our approach in GD14.

	2017	2018	2019	2020	2021	2022
FE requested allowances	914.4	944.1	979.8	1,017.8	1,058.6	1,102.3
UR FD before re-allocation	878.6	797.2	826	856.5	888.5	921.8
Re-allocation to AMPR (OO)	2.3	2.3	2.3	2.3	2.3	2.3
UR Final Determination	876.3	794.9	823.7	854.2	886.2	919.5
Variance	38.1	149.2	156.1	163.6	167.4	182.8

Table 47: Requested and Determined Property Management Allowances, £k

HR & Non-Operational Training

6.235 HR covers provisions of the HR function i.e. the full range of professional activity for an individual's career path from recruitment to retirement and post retirement where applicable, e.g. management and administration of pension payments and from related professional advice to directly resolving grievances for staff.

6.236 The HR costs collated under HR & non-operational training should include:

- Costs of payroll and pension's management and operation;
- Facilitating staff performance, development and reviews;
- Industrial and employee relations including HR strategy, policies and procedures;
- Monitoring equal employment opportunities; and
- HR advice to management, succession planning and also retentions and rewards

6.237 FE HR and non-operational training costs are in the main driven by staff costs and professional and legal fees.

6.238 In the 2014 year FE had HR & Ops training costs of £66k. FE had 0.6 FTEs employed within HR and Ops training cost category in 2014 and has proposed an increase in FTEs of 0.6 in this area for the GD17 period.

6.239 For the draft determination we based the HR and Ops training allowance for GD17 on the 2014 FTEs and rolled forward 2014 staff costs and 2014 professional and legal fees.

6.240 In its response to the draft determination FE stated '*FE included professional and legal fees of £67k per annum to cover recruitment and HR consultancy and legal advice. Together with a reduction of 0.6 FTEs under this activity, the Draft Determination has proposed reducing the allowance for these professional and legal fees to £28k per annum (a 57% reduction). The fees have been reduced to their 2014 level. HR consultancy and legal advice can fluctuate year and to year, depending on employee relationship issues, and to use a single year does not provide a true representation of average costs. This borne out by the fact that HR professional and legal fees in 2013 were £71k. Upon review of the Utility Regulator's analysis, FE notes that costs have not been provided for all of the determined FTEs (56.5), specifically 0.6 FTEs under HR and Non-Operational*'.

6.241 As we set out in the draft determination we consider that using the 2014 year as a base year for analysing costs is appropriate as we found that it was not possible to use historic opex prior to 2013 as the historic opex costs provided by FE in its GD17 Business Plan template were not consistent with previous submissions provided by FE.

We have for the final determination corrected staff costs for HR and Non-operational training to reflect the determined number of FTEs.

6.242 We have re-allocated some of the costs under HR and Ops training as before under the owner occupied connections incentive / AMPR (OO) as we consider that some of FE HR and Ops training will be used for Advertising and Marketing for domestic Owner Occupied connections. This is consistent with our approach in GD14.

	2017	2018	2019	2020	2021	2022
FE requested allowances	123.1	123.1	123.1	123.1	123.1	123.1
UR FD before re-allocation	98.5	98.5	98.5	98.5	98.5	98.5
Re-allocation to AMPR (OO)	5.0	5.0	5.0	5.0	5.0	5.0
UR Final Determination	93.5	93.5	93.5	93.5	93.5	93.5
Variance	29.6	29.6	29.6	29.6	29.6	29.6

Table 48: HR & Non-Operational Costs, Requested and Allowed, £k

Audit Finance & Regulation

6.243 Audit Finance & Regulation covers performing the statutory, regulatory and internal management cost and (business support activity) performance reporting requirements and customary financial and regulatory compliance activities for the network.

6.244 The costs collated under Audit, Finance & Regulations should include:

- Process of payments and receipts;
- Time sheet evaluation where not part of the payroll process;
- Financial & risk management – e.g. credit & exposure management;
- Financial planning, forecasting & strategy;
- Financial accounting;
- Management accounting;
- Investment accounting;
- Treasury management;
- Transportation income accounting;
- Pricing;
- Statutory & regulatory reporting;
- Tax compliance & management;
- Internal audit & management of the relationship with external audit function;
- External audit fees; and
- Cost of regulatory department.

6.245 FE Audit Finance and Regulation costs are in the main driven by staff costs, professional and legal fees, stationary, communications and billing costs.

6.246 In the 2014 year FE had Audit Finance and Regulation costs of £416k. FE had 7.4 FTEs employed within Audit Finance and Regulation cost category in 2014 and has proposed an increase of circa 1 FTEs in this area for the GD17 period. Part of this proposed increase relates to a 0.5 FTE for a regulatory analyst.

6.247 For the draft determination we based the Audit Finance and Regulation allowance for GD17 on the 2014 FTEs and used 2014 staff costs and 2014 costs for professional and legal fees and accepted FE proposals for stationary, communications and billing costs.

6.248 In its response to the draft determination FE stated '*Firmus energy included professional and legal fees of £85k per annum to cover financial and regulatory consultancy and legal advice, audit and taxation fees and professional subscriptions. Together with a reduction of 1.1FTEs under this activity, the Draft Determination has reduced the allowance for these professional and legal fees to £20k per annum (a 77% reduction) from the figure in 2014. Whilst the professional and legal fees have been produced to their 2014 level, the stationary communications and billing costs of £11k per annum have been accepted as presented (by the Utility Regulator) and not uplifted to the 2014 cost of £27k. The Utility Regulator's approach is therefore inconsistent'.*

6.249 We have accepted FE argument in respect of using 2014 costs for stationary billing communications and this has been reflected in the final determination. We however consider that the FTEs that we allowed for in the draft determination, which is based on 2014 actuals, is appropriate and therefore this is unchanged for the final determination

6.250 We have re-allocated some of the costs under Audit Finance and Regulation to be recovered under the owner occupied connections incentive / AMPR (OO) as we consider that some of FE Audit Finance and Regulation function will be used for Advertising and Marketing for domestic Owner Occupied connections. This is consistent with our approach in GD14.

	2017	2018	2019	2020	2021	2022
FE requested allowances	603.4	603.4	603.4	603.4	603.4	603.4
UR FD before re-allocation	462.5	462.5	462.5	462.5	462.5	462.5
Re-allocation to AMPR (OO)	62.2	62.2	62.2	62.2	62.2	62.2
UR Final Determination	400.3	400.3	400.3	400.3	400.3	400.3
Variance	203.1	203.1	203.1	203.1	203.1	203.1

Table 49: Audit Finance & Regulation Costs, Requested and Allowed, £k

Insurance

6.251 The Insurance cost category covers support and expertise to develop the business risk profile, managing the claims process and provision of information and understanding to the business in relation to insurable and uninsurable risks.

6.252 The costs collated under Insurance should include:

- Insurance premiums;
- Insurance premium tax;
- Insurance contract negotiating and monitoring;
- Insurance claim processing;

- Insurance risk management;
- Payments relating to uninsured claims;
- Costs of in house insurance team; and
- Brokers fees.

6.253 The main element of FE insurance costs is business insurance, which in turn is dominated by business interruption and public liability.

6.254 The total insurance costs requested by FE represent a significant increase on 2014 actuals. The increase between 2014 actuals and the request for 2017 is over 37%. We do not have any evidence to warrant such an increase and believe FE can negotiate lower premiums.

6.255 For the draft determination we were of the view that in the absence of adequate justification warranting the magnitude of the claimed increases in business insurance, we should continue with the approach of granting a business insurance allowance based on the benchmark of 1.04% of turnover. The FE requested costs for car insurance and office insurance which were reasonable and therefore we granted the requested costs.

6.256 In its response to the draft determination FE stated '*The Draft Determination proposes a reduced allowance for these costs by applying the GD14 driver of 1.04% of turnover. Applying this metric leads to a reduction in costs in 2017 of £103k (39%) and £0.5 million over the GD17 period. FE would challenge the Utility Regulator's approach in this regard. A material weakness in application of this calculation is consideration of firmus energy's revenues when accounting for profile adjustment. Failure to account for profile adjustment results in an artificially low calculation of insurance requirements. Further, as revenue is a function of items including Opex, Capex and WACC and the draft determination proposes reductions to each, there is a material impact upon any allowance calculated as a function of revenue'.*

6.257 FE also stated in its response to the GD17 draft determination that '*the UR's approach to setting its insurance allowance is inconsistent with the approach taken to setting PNGL's insurance allowance*'.

6.258 We have taken into consideration a benchmarking report provided by FE in setting insurance allowances for FE in the GD17 final determination. We note that in some areas the report explains that FE has options to lower its insurance premiums and our insurance allowances for FE take into account these comments. We have set the FE GD17 final determination allowances based mainly on the FE 2015 actual insurance. We note that the 2015 FE actual insurance was lower than that forecast in the FE GD17 BP submission and that shown in the insurance benchmarking report provided by FE. We also note that the benchmarking report provided by FE covers the period July 2015 to June 2016.

6.259 The final determination allowances for car and office insurance remain unchanged from the draft determination

6.260 Our determined allowances for 2017-2022 are shown in the table below along with FE requested allowances and the variance between the two.

6.261 We have re-allocated some of the costs under Insurance to be recovered under the owner occupied connections incentive / AMPR (OO) as we consider that some of Insurance will be used for Advertising and Marketing for domestic Owner Occupied connections. This is consistent with our approach in GD14.

	2017	2018	2019	2020	2021	2022
FE requested allowances	268.9	268.9	268.9	268.9	268.9	268.9
UR FD before re-allocation	230.9	230.9	230.9	230.9	230.9	230.9
Re-allocation to AMPR (OO)	0.64	0.64	0.64	0.64	0.64	0.64
UR Final Determination	230.3	230.3	230.3	230.3	230.3	230.3
Variance	38.6	38.6	38.6	38.6	38.6	38.6

Table 50: FE Insurance Costs, Requested and Allowed, £k

Procurement

6.262 This cost category covers the procurement of goods & services in the support of the business operations, through the management of procurement contracts with suppliers.

6.263 The costs collated under Procurement should include:

- The cost of carrying out market analysis;
- Identifying potential suppliers, undertaking background review, negotiating contracts, purchase order fulfilment and monitoring supplier performance;
- Setting up and maintaining vendor accounts within the accounting system, and maintaining e-procurement channels;
- Setting procurement guidelines and monitoring adherence to the guidelines.

6.264 FE procurement costs are driven by staff costs and professional and legal fees. In the 2014 year FE had procurement costs of £18k. FE had 0.25 FTEs employed within the Procurement cost category in 2014 and has marginal increases in FTEs and professional and legal fees.

6.265 In its response to the draft determination FE stated that '*Firmus energy included professional and legal fees of £18k per annum to cover ongoing consultancy and legal advice. As regulated utility, firmus energy is governed by the EU Utilities Directive with regard to how it awards contracts. As such, FE continuously reviews procurement policies and procedures, as well as collating and evaluating tender documents for new and existing contracts. The Draft Determination has reduced the allowance for these professional and legal fees to£11k per annum (a 38% reduction). The fees have been reduced to their 2014 level, thus reducing FE's opportunity to market test cost categories or to drive Opex savings. Upon review of the Utility Regulator's analysis, FE notes that costs have not been provided for all of the determined FTEs (56.5), specifically 0.1 FTEs under Procurement*'.

6.266 For the final determination have corrected the number of FTEs for Procurement to reflect the total number allowed for in the draft determination. However we consider that using 2014 actual costs for professional and legal fees is appropriate as we found that it was not possible to use historic opex prior to 2013 as the historic costs provided by FE in its GD17 Business Plan template were not consistent with previous submissions provided by FE

6.267 For the draft determination we based the Procurement allowance for GD17 on the 2014 FTEs and rolled forward 2014 professional and legal fees.

6.268 We have re-allocated some of the costs under Procurement to be recovered under the owner occupied connections incentive / AMPR (OO) as we consider that some of

PNGL's Procurement function will be used for Advertising and Marketing for domestic Owner Occupied connections. This is consistent with our approach in GD14.

	2017	2018	2019	2020	2021	2022
FE requested allowances	27.9	27.9	27.9	27.9	27.9	27.9
UR FD before re-allocation	21.4	21.4	21.4	21.4	21.4	21.4
Re-allocation to AMPR (OO)	1.6	1.6	1.6	1.6	1.6	1.6
UR Final Determination	19.8	19.8	19.8	19.8	19.8	19.8
Variance	8.1	8.1	8.1	8.1	8.1	8.1

Table 51: FE Procurement Costs, Requested and Allowed, £k

CEO & Group Management

6.269 The costs collated under CEO & Group Management should include:

- Communications – communication within the UK businesses, internal communications, external communications, media relations, issues management, regional communications, community relations, community awareness, branding, events management;
- Group Strategy – function which has the responsibility of evaluating the strategic options of the Group;
- Legal/Risk and Compliance/Company Secretary – legal department, the management corporate governance for all companies to ensure they comply with legislation, regulations and best practice;
- Corporate Responsibility and Investor Relations – corporate responsibility and interaction with institutional equity investors and market analysts, management of rating agencies, advertising, charity and sponsorship arrangements;
- Board Members and Other – staff and other costs of Board members and other corporate costs not fitting into other categories;
- Incremental ring-fence compliance; and
- Credit reference agencies.

6.270 FE CEO & Group Management costs are driven by associated staff costs as well as professional and legal fees together with stationary, communications and billing costs.

6.271 FE acknowledged in response to a query from us that its requested GD17 FTE allowance should be reduced by 1.5 FTE to reflect the fact that it had allocated NED's as salaried staff whereas their costs should be allocated under professional and legal fees. Consequently, the corrected FTEs for GD17 are similar to actual FTEs in 2014.

6.272 Our final determination allowances are unchanged from the draft determination and therefore we have accepted the corrections made by FE in relation to FTEs.

6.273 We have re-allocated some of the costs under CEO & Group Management to be recovered under the owner occupied connections incentive / AMPR (OO) as we consider that some of CEO & Group Management will be used for Advertising and Marketing for domestic owner occupied connections. The amount we have re-allocated is the same as we applied in GD14 and our approach is consistent with GD14.

	2017	2018	2019	2020	2021	2022
FE requested allowances	157.3	157.3	157.3	157.3	157.3	157.3
UR FD before re-allocation	157.3	157.3	157.3	157.3	157.3	157.3
Re-allocation to AMPR (OO)	10.6	10.6	10.6	10.6	10.6	10.6
UR Final Determination	146.7	146.7	146.7	146.7	146.7	146.7
Variance	10.6	10.6	10.6	10.6	10.6	10.6

Table 52: CEO and Group Management Costs, Requested and Allowed, £k

Stores & Logistics

6.274 The Stores and Logistics cost category covers the activity of managing and operating stores.

- The costs collated under Stores & Logistics should include:
- Delivery costs of materials or stock to stores;
- Labour and transport costs for the delivery of materials or stock from a centralised store to a satellite store/final location (and vice versa), taking into account the stock management policies;
- Monitoring stock levels; and
- Quality testing of materials held in stores.

6.275 FE has not requested an opex allowance for stores and logistics and therefore we have not provided for one. FE had opex of £27k for this cost category in 2014.

Trainees & Apprentices

6.276 This cost category covers (i) the costs of any operational training and (ii) the cost of training any employees engaged on approved formal training or apprentice programmes (either operational or non-operational).

6.277 The costs collated under Training & Apprentices should include:

- Cost of staff who organise and provide training, and maintain the individual employee training/apprentice records;
- Cost of running training courses;
- Fees paid to external training providers for provision of training;
- Cost of externally advertising training and apprentice programmes;
- Salary cost of apprentices or trainees whilst engaged on a training or apprentice programme; and
- Cost of ongoing professional development for operational staff.

6.278 FE trainees and apprentices costs are driven mainly by professional and legal fees as well as agency costs. FE has requested trainees and apprentices allowances of £133k in each year of GD17. FE actually spent £66k on trainees and apprentices in 2014. The requested increase in allowances is driven from an increase of FTEs from 1FTE in 2014 to 2 FTEs in GD17 and by a circa 50% increase in professional and legal fees.

6.279 For the draft determination we based our GD17 allowances on the actual number of FTEs in 2014 and rolled this forward the associated costs into GD17. We did not accept the professional and legal fees for the GD17 period as we considered this expenditure was not justified within the FE GD17 business plan.

6.280 In its response to the draft determination FE stated that '*FE had included 2 FTEs (agency staff) for trainees and apprentices to provide engineering assistance, whilst also fulfilling their licence obligations and firmus energy values to promote training and development. The Draft Determination allows for only 1 trainee but FE would welcome the opportunity to train and develop an additional trainee to support the growth of the industry in Northern Ireland*'.

6.281 We consider that 1 FTE is sufficient and is consistent with the actual number of trainee's and apprentices utilised by FE in 2014. We have allowed for the final determination trainings costs in relation to trainee's and apprentices in line with 2014 actual spend, recognising the need for appropriate allowances in this area.

	2017	2018	2019	2020	2021	2022
FE requested allowances	133.4	133.4	133.4	133.4	133.4	133.4
UR Final Determination	66.4	66.4	66.4	66.4	66.4	66.4
Variance	67	67	67	67	67	67

Table 53: Trainee's and Apprentice's Costs, Requested and Allowed, £k

Non-Controllable Opex

6.282 The only costs shown under non-controllable opex are FE licence fees. We have accepted FE forecast costs for licence fees and therefore our final determination allowance is unchanged from the draft determination. Any difference between forecast licence fees and actual licence fees will be taken account of by the uncertainty mechanism in GD23.

Supplier of Last Resort

6.283 With regard the Supplier of Last Resort (SOLR), we believe that there is merit including an allowance to cover any unforeseen costs that may occur, if an event were to happen. This amount is ring fenced and will be removed at the time of the next price control, if an incident fails to materialise. For the GD17 final determination we have allowed £150k for these costs in 2017 only.

	2017	2018	2019	2020	2021	2022
FE requested allowances	60	60	60	60	60	60
UR Final Determination	60	60	60	60	60	60
Variance	0	0	0	0	0	0

Table 54: Non-controllable Opex Costs, Requested and Allowed, £k

Capitalised Opex

6.284 For the GD17 final determination we have accepted FE capitalisation rates.

Summary of Bottom-up Assessment Findings

6.285 Table 55 summaries the GD17 final determination cost allowances for FE. The costs for each category are net of any re-allocation of costs to the advertising and marketing (owner occupied) cost category.

Cost item	2017	2018	2019	2020	2021	2022	Total
Asset Management	92.2	92.2	92.2	92.2	92.2	92.2	553.2
Operations Management	283.5	283.5	283.5	283.5	283.5	283.5	1,700.9
Emergency Call Centre	200.9	210.0	219.5	229.1	239.1	248.6	1,347.3
Customer Management	266.0	266.0	266.0	266.0	266.0	266.0	1,595.8
System Control	238.3	238.3	238.3	238.3	238.3	238.3	1429.7
Emergency	694.9	756.6	821.4	886.9	954.4	1,019.7	5,133.9
Metering	326.7	347.2	337.2	376.0	436.0	535.4	2,358.6
PRE Repairs	53.2	56.1	59.0	62.2	65.7	69.4	365.8
Maintenance	431.3	458.3	445.1	496.3	575.5	706.8	3,113.3
Other Direct Activities	1.3	1.3	1.3	1.3	1.3	1.3	7.7
IT & Telecoms	200.4	200.4	200.4	200.4	200.4	200.4	1,202.1
Property Man	876.3	794.9	823.7	854.2	886.2	919.5	5,154.8
HR & Non-Ops Training	93.5	93.5	93.5	93.5	93.5	93.5	560.8
Audit, Fin and Regulation	400.3	400.3	400.3	400.3	400.3	400.3	2,401.5
Insurance	230.3	230.3	230.3	230.3	230.3	230.3	1,381.6
Procurement	19.8	19.8	19.8	19.8	19.8	19.8	119.1
CEO & Group Management	146.7	146.7	146.7	146.7	146.7	146.7	880.2
AMPR (OO)	1,365.0	1,482.4	1,608.8	1,674.0	1,755.0	1,752.8	9,637.9
AMPR (non-OO)	228.7	228.7	228.7	228.7	228.7	228.7	1,371.9
Trainee's & Apprentices	66.4	66.4	66.4	66.4	66.4	66.4	398.4
Non Controllable Costs	60.0	60.0	60.0	60.0	60.0	60.0	360.0
SOLR	150.0						150.0
Total: Pre Efficiency	**6,425.6**	**6,432.7**	**6,641.8**	**6,906.1**	**7,239,179**	**7,579.5**	**41,224.7**
Frontier Shift[71]	0.992	0.984	0.976	0.969	0.963	0.956	
Total: Post Efficiency	**6,371.5**	**6,329.9**	**6,483.4**	**6,695.1**	**6,969.9**	**7,247.5**	**40,097.3**

Table 55: FE GD17 Opex Final Determination, Pre and Post Efficiency (£k)

Real Price Effects, Productivity and Frontier Shift

Overview

6.286 A detailed explanation of the precise make up of our overall RPEs and assumed productivity increase is contained in Annex 6 – Real Price Effects and Frontier Shift: Final Determination GD17.

[71] As discussed in Table 25

Net Impact

6.287 Once we apply our frontier shift to a pre-efficiency opex we derive our final determination opex profiles, net of frontier shift.

PNGL – UR Decisions

Overview

6.288 For the final determination, we have decided to apply the results of our bottom-up opex assessment and this section focuses on that analysis.

Top-Down Assessment

6.289 Our top-down opex benchmarking analysis at final determination utilised two econometric models taken from an examination of a number of competing models, to establish efficient opex levels for PNGL during the six-year GD17 period.

6.290 We have used the results from the preferred models to forecast efficient opex levels for PNGL up to 2022. According to the results, we believe that there is scope to reduce PNGL's business plan opex costs by up to 24.4%, to reach what has been assessed as efficient operational costs.

6.291 More detailed results and further explanation on the methodology used is provided within the GD17 final determination's Annex 5: Top-Down Benchmarking.

Bottom-up Assessment

Overview PNGL OPEX – Pre Efficiency – September 2014 Prices

6.292 We note in the BPT, that it was a requirement that all GDNs submitted in a constant price base, which was December 2014 prices. PNGL submitted prices in Sept 2014 prices, which is in line with their licence. We note the reasons, but this risks causing unnecessary confusion, when analysis has been undertaken against other GDNs and we wish to make clear that costs referred to are in September 2014 prices. FE and SGN have applied the correct cost base of December 2014.

6.293 A review of the 2014 performance is contained within section 4, which broadly shows that PNGL has kept within the regulatory allowances set in GD14 although we note that we only had actual costs for one year of GD14 for the draft determination. Since the draft determination PNGL have provided us with its total opex costs for 2015. PNGL informed us that its opex spend for 2015 was £14.4m which is c1.5m less than it forecast in its GD17 business plan submission.

6.294 Before we consider each component of the price control in detail, we will review what PNGL has requested at a summary level.

Cost Items	2014	2015	2017	2018	2019	2020	2021	2022	Average GD17 submission
	Actual	Actual	PNGL GD17 submission						
Opex, £m	14.5	14.4	16.9	17.3	17.5	17.7	18.0	18.3	17.6
OO connections	7751	6504	4000	4000	4000	4000	4000	4000	4000

Table 56: PNGL GD17 Submission, £m

6.295 PNGL in its GD17 Business Plan submission has requested the following:

- Higher allowances in GD17 to deliver fewer owner occupied connections than delivered in 2014.
- Significantly higher allowances in GD17 when compared to actual opex expenditure in 2014. On average, PNGL is seeking £3.1 million more allowance per year of GD17 than it spent in 2014, which is a real increase of 21%.
- PNGL expects to deliver significantly less connections on average in GD17 than it delivered in 2014. This reflects PNGL's view that the favourable conditions that they consider existed for making connections in the 2010 – 2014 period won't exist in the GD17 period. Nevertheless, the projected connections are significantly lower than those achieved in 2014 (7751) and in 2015 (6504) and those which PNGL expects to connect in 2016 (5,500)

6.296 In response to the GD17 draft determination PNGL has stated that it now expects 2016 connection numbers to be closer to 4,500.

6.297 The table below sets out a summary of the overall opex allowances requested by PNGL in its original submission. More detail of the build-up of some of the individual cost lines was also provided, both in the original PNGL submission and following our information requests.

Cost item	2017	2018	2019	2020	2021	2022	Total
Asset Management	251.6	255.3	262.7	256.6	257.1	257.7	1,541.2
Operations Management	542.7	550.8	551.1	552.0	552.6	553.2	3,302.7
Emergency Call Centre	444.5	451.0	461.3	471.8	475.2	490.2	2,794.2
Customer Management	830.0	851.9	865.9	869.5	878.2	886.8	5,182.6
System Control	130.4	132.6	133.3	132.6	132.6	132.6	794.2
Emergency	1,404.0	1,432.5	1,481.2	1,521.0	1,534.8	1,598.9	8,972.7
Metering	724.8	1,167.6	1,105.7	997.3	948.2	1,049.0	5,992.7
PRE Repairs	460.4	471.8	485.1	497.6	506.7	521.3	2,943.1
Maintenance	2,043.3	1,724.1	1,770.1	1,948.1	2,081.9	2,058.8	11,626.4
IT & Telecoms	604.3	588.1	591.9	590.9	592.0	618.3	3,585.7
Property Man	2,541.1	2,733.9	2,796.7	2,872.0	2,963.7	3,012.3	16,919.9
HR & Non-Ops Training	240.3	243.1	244.5	244.0	244.4	244.8	1,461.3
Audit, Fin and Regulation	1,185.8	1,159.2	1,170.2	1,127.1	1,225.8	1,230.2	7,098.6
Insurance	910.2	930.2	910.7	970.9	991.3	1,011.6	5,725.2
Procurement	73.5	74.8	75.3	74.8	74.8	74.8	448.2
CEO & Group Management	1,883.6	1,897.6	1897.7	1,897.9	1,898.0	1,898.2	11,379.4
Stores and Logistics	29.8	29.8	29.8	29.8	29.8	29.8	176.7
Connection Incentive (OO)[72]	2,114.3	2,123.7	2,131.8	2,126.5	2,127.9	2,128.8	12,752.5
AMPR (non-OO)	350.6	356.2	360.1	356.5	356.2	356.8	2,136.8
Non Controllable Costs	115.5	115.5	115.5	115.5	115.5	115.5	693,215
Total	**16,881.5**	**17,289.8**	**17,441.3**	**17,653.0**	**17,987.7**	**18,270.4**	**105,524.1**

Table 57: PNGL Operating Expenditure GD17 Submission, £k

Key Cost Lines

Overview

6.298 Table 57 shows the PNGL GD17 opex submission in the new BPT structure. As in GD14, greater scrutiny has been exercised over those cost categories that represent the greater cost. We have also considered the extent to which some cost items must be separately examined because of the particular way they are treated (e.g. pass-through),

[72] Referred to as AMPR (OO) in the draft determination.

or due to other specific circumstances calling for individual treatment, irrespective of their magnitude.

6.299 In its response to the GD17 draft determination PNGL clarified to us that it had incorrectly allocated some staff costs between the AMPR (OO) cost category and the AMPR (non-OO) cost category in its GD17 business plan submission. Table 57 has been updated to reflect the updated allocations. The corrected allocations have no impact on the total opex requested by PNGL

6.300 While the ACRT brought about a change in cost categories, two key cost lines still require detailed analysis due to their magnitude i.e. Manpower and Connection Incentive/ AMPR (Owner Occupied) and these are discussed below. While the Connection Incentive / AMPR (Owner Occupied) has its own cost category, manpower costs form part of the costs for many of the cost categories shown in Table 57.

6.301 In setting the allowances for PNGL in general, we have used the most up to date actuals, which is 2014. This sets a sound basis to set up a benchmark were appropriate. In some circumstance there may be good reason of why we have deviated from this approach and a further explanation is given in the relevant area

Manpower

6.302 In contrast to GD14, for GD17 we have not set an explicit manpower cost allowance, since as stated above manpower costs form part of most of the cost categories within the ACRT, rather than being an individual cost category.

	GD14			GD17					
	2014	2015	2016	2017	2018	2019	2020	2021	2022
PNGL requested allowances	128	130	128.6	127.8	128.2	128.7	129.1	129.6	130
UR Final Determination	124.2	125.7	124.8	121.8	121.8	121.8	121.8	121.8	121.8
PNGL actual	118.8	117.5	127.3*						

*2016 is a forecast

Table 58: PNGL FTEs Requested, 2014 Actual and GD17 Determined

6.303 Table 58 sets outs PNGL's requested allowances for FTEs for both GD14 and GD17. It can be observed that PNGL's actual number of FTEs for 2014 and 2015 were significantly below its 2014 and 2015 requested allowances in GD14 as well as our GD14 FD allowance.

6.304 PNGL has indicated that the gap exists due to the fact that employees have left and that it takes time to recruit similar skilled people. PNGL therefore use agency staff on occasions to fill this gap. We consider that the FTEs necessary to run the business are included in all FTEs, whether agency staff or otherwise, and see no reason why we should not use 2014 as a suitable base figure.

6.305 On observing the future workload for PNGL, we note that customer numbers will continue to increase, as will maintenance and emergency work. Conversely work on infill mains and connections will reduce over time.

6.306 We therefore have based the levels of FTEs on actual 2014 levels, with a small increase in relation to Customer Management and Operations Management, due to continuing cumulative connection numbers.

6.307 From a salary perspective, PNGL has incorporated stepped salary increases for the years 2016 to 2018 in its GD17 submission. It has cited the reason for this as retention of staff. We have dealt with all such cost increases under Real Price Effects in Annex 6.

6.308 In its response to the draft determination PNGL requested that we consider the impact of the new Apprenticeship Levy as part of the final determination. PNGL explained '*that from 6 April 2017 all employers in the UK with a pay bill in excess of £3m per annum will be required to pay an Apprenticeship Levy to HMRC. The Apprenticeship Levy is set at 0.5% of an employer's gross total employee earnings. Employers paying the Apprenticeship levy will be eligible to an allowance of £15,000 to spend on Apprenticeship training*. *However, there is currently no guarantee PNGL will receive this allowance as the NI Executive is yet to communicate on how it will use the new income from the Apprenticeship Levy'*.

6.309 In its response to the draft determination PNGL also explained that '*The Government's National Living Wage was introduced on 1 April 2016. Employers are required by law to pay applicable employees a minimum of £7.20 per hour worked. NLW is scheduled to increase to £9 per hour by 2020. In order to comply with the NLW PNGL has been required to provide (in 2016), and will continue to be required to provide (during the GD17 period) salary increases to lower paid workers in excess of the level of inflation. PNGL estimates that these salary increases will, in total amount to £25k-£30k per annum.'* PNGL consequently requested that the final determination should include these additional salary costs across GD17*.*

6.310 We consider that we have set sufficient allowances in the final determination that cover staff costs for an efficient GDN. We consider that the there is uncertainty over both the impact of the apprenticeship levy and the living wage but that they are unlikely to be of such an extent that an efficiently run utility cannot manage them within the proposed allowances.

<u>Connective Incentive for GDNs to connect Owner Occupied (OO) Properties</u>

6.311 The connection incentive is a per connection allowance to encourage the connection of domestic owner occupied (OO) properties. This is unique to NI and was created due to initial difficulties in driving gas connections as the public had limited experience of the fuel. It is up to the GDN's how they spend the allowance but it tends to cover the sales teams, advertising and marketing, direct customer incentives and associated overheads.

6.312 In arriving at the overall connections package we will look at two key areas. These are a connections incentive for which there is an economic test and owner occupied connections target. In addition for GD17 we have introduced the concept of a 'new areas' allowance. We will consider each of these in turn.

Economic Test for Connection Incentive

6.313 The basis of this mechanism is a simple economic test, based on the revenues from a connection minus the costs. It adopts the principle that any new connections to the network must be economic and therefore must pay for itself over a reasonable period of time, after making suitable assumptions. We will deal with the assumptions, used to create the connection incentive allowance later in this section.

6.314 All parties recognise that a significant element of the connections incentive was put in place to increase awareness of gas as a fuel of choice in NI. As part of GD14 we indicated that the connections incentive, which was set at £573, would be reduced by

50% in GD17 to reflect the increasing awareness of gas in NI and that this element of the incentive would become less relevant.

6.315 It should be noted, that the impact of this incentive is wide ranging for the overall business, as it covers a certain percentage of costs to all overheads of the organisation.

6.316 Costs for Advertising & Market Development are classified into the following two categories:

- Advertising & market development for domestic owner occupied properties (OO properties);
- Advertising & market development (non-OO properties).

6.317 The costs collated under Advertising & Market Development should include costs for:

- Advertising, marketing and PR;
- Incentives (for OO properties only);
- Sales related staff, including relevant director; and
- Shared corporate overheads.[73]

6.318 Before considering what PNGL has requested, we must first deal with the principles of how the mechanism works in practice.

6.319 We will now in turn deal with the Mechanism principles, used to calculate the allowance.

Mechanism Principles

6.320 The main principles used in the development of the mechanism remain largely unchanged from GD14; the key elements are as follows:

The opex allowance per connection has been calculated using the formula:

Allowance per connection = (Revenue per connection) – (Direct capex cost per connection)

Where:

Revenue per connection = Average consumption X Conveyance tariff, Discounted over the defined Recovery period

AND

Direct capex cost per connection = Determined infill cost per OO connection + Determined meter cost + Determined service cost

6.321 We have developed a model around the above formulae using estimates, where necessary, for some key assumptions within the formulae.

6.322 The mechanism will apply, as before, only to domestic OO housing. We have therefore separately granted a certain level of fixed allowances for sales-related costs that are NOT associated with OO connections.

Revenue per Connection

[73] As discussed in section 6.349

6.323 A reminder of the formula:

Revenue per connection = Average consumption X Conveyance tariff, Discounted over the defined Recovery period

Connection Incentive Assumptions - GD17		
Domestic Consumption	tpa	380
Recovery Period	yrs	15
Conveyance Tariff	ppt	40
RoR Post 2016	%	4.0
Dom Service Value	£	889
Dom Meter Value	£	200
Infill Reduction	£	340
Connection Incentive Value	£ / add. conn	420

Table 59: GD17 Connection Incentive Assumptions

6.324 This produces a figure of £420 per connection which is less than the GD14 figure of £573, although significantly higher than our initial thinking of cutting the incentive in half.

6.325 The GDNs have set out in significant detail, covered in sections below, the issues they are facing with connections and the risks of halving of the connections incentive. We have taken these representations into account and for the draft determination we proposed to reduce the existing allowance on a glide path, from £550 to £420, over the 6 year duration of GD17, as shown in Table 60.

Connection Incentive Glide Path	2017	2018	2019	2020	2021	2022
Allowance per Connection	550	520	500	470	450	420

Table 60: Connection Incentive Glide Path

Connection Allowance: 'new areas' allowance

6.326 We recognise that significant new areas where gas is first made available may require greater incentives in educating customers on the benefits of natural gas. All three GDNs have significant expansions planned in GD17, and this is likely to be the last price control where such expansions are considered. Therefore, there is a case to be made, given our principle objective to grow the gas industry, for an additional allowance to drive awareness of gas, ultimately leading to increased momentum in connection rates. Given the uniqueness of the extent of the extensions in GD17, we would not plan that this allowance would be applied in future price controls.

6.327 PNGL have informed us that an *additional 'new area' allowance 'would be used to facilitate a broad range of activity in order to;*

- *build aspiration for natural gas in small towns who will have limited knowledge of the natural gas message;*

- *encourage early adopter activity;*
- *build the support of the wider supply chain (i.e. installers and natural gas retailers); and*
- *help create an infrastructure in new areas that will support ongoing core marketing activity and connections activity in the future'.*

6.328 In relation to applying the new areas allowance to East Down PNGL informed us that '*Due to the geographic location of the East Down network PNGL's promotional activity in our existing Licensed Area will have had limited impact on householders in East Down. As well as not having local exposure to natural gas and the benefits of natural gas, our experience is that householders will only absorb our communication if it seen as relevant– which will have not generally been the case for homeowners in East Down who did not previously have access to the natural gas network'.*

6.329 PNGL also highlighted that *'It is important that this promotional activity begins at the earliest stage so that the customer base becomes aware of the future availability of natural gas, to build momentum and to enable householders with older central heating boilers to delay plans to replace their existing system until natural gas arrives*'

6.330 We believe that the comments made, are worthy of further consideration and developing this concept of a New Area. We believe for PNGL, this would readily apply to the recent extension granted for East Down. We will now consider how this concept could be formulated further.

6.331 The size of the new area is measured by the number of all property types that can be passed in each new area (not just in GD17) Consequently we consider that an additional allowance is appropriate for all properties passed (except new build) in new areas in the GD17 period (and beyond.)

6.332 In the case of PNGL the new areas allowance would only apply to properties passed in the East Down area given there is no new areas in the existing PNGL network.

6.333 We consider that the additional allowance of £50 per property passed is appropriate and should be recovered through the existing connection incentive mechanism. Given that the additional allowance is applied to all properties passed whether in the GD17 period or later in the incentive mechanism, that this additional allowance can only be applied in the GD17 period.

6.334 For ease of monitoring we will ensure that the additional New Area allowance is captured through the connection incentive mechanism across all targeted connections

6.335 In practice this means that the following steps are undertaken in order to covert the additional per properties passed allowance into a per connection allowance.

- **Step 1**: Multiply the properties passed for 'new areas' x £50. For PNGL this is 22,621 x £50 = £1,131,050 over the GD17 period.
- **Step 2**: Divide total allowance by total number of additional connections (less non additional)[74] in GD17 period to convert in to a per connection allowance i.e. for PNGL this is £1,131,050 / 19,095 connections = £59.23, rounded to £60.
- **Step 3**: Add the additional allowance to the existing connection incentive mechanism and apply to the connection incentive

[74] As discussed in section 6.355

6.336 This in practise converts to the following allowances per connection for all OO connections for PNGL

	2017	2018	2019	2020	2021	2022
Standard Allowance per Connection	550	520	500	470	450	420
Additional 'new area' allowance	60	60	60	60	60	60
Standard Allowance per Connection + New Infill Areas Allowance	610	580	560	530	510	480

Table 61: PNGL OO Connection allowance and New Area Allowance £

Connection Targets

6.337 PNGL submitted a Market Development paper together with an owner occupied connections paper as part of its business plan submission for GD17. PNGL highlighted that the high number of connections seen in the period 2010 - 2014 were in part due to unique market conditions. Figure 6 which has been provided by PNGL gives a summary of PNGL view on factors it considers influenced connections numbers since 2010.

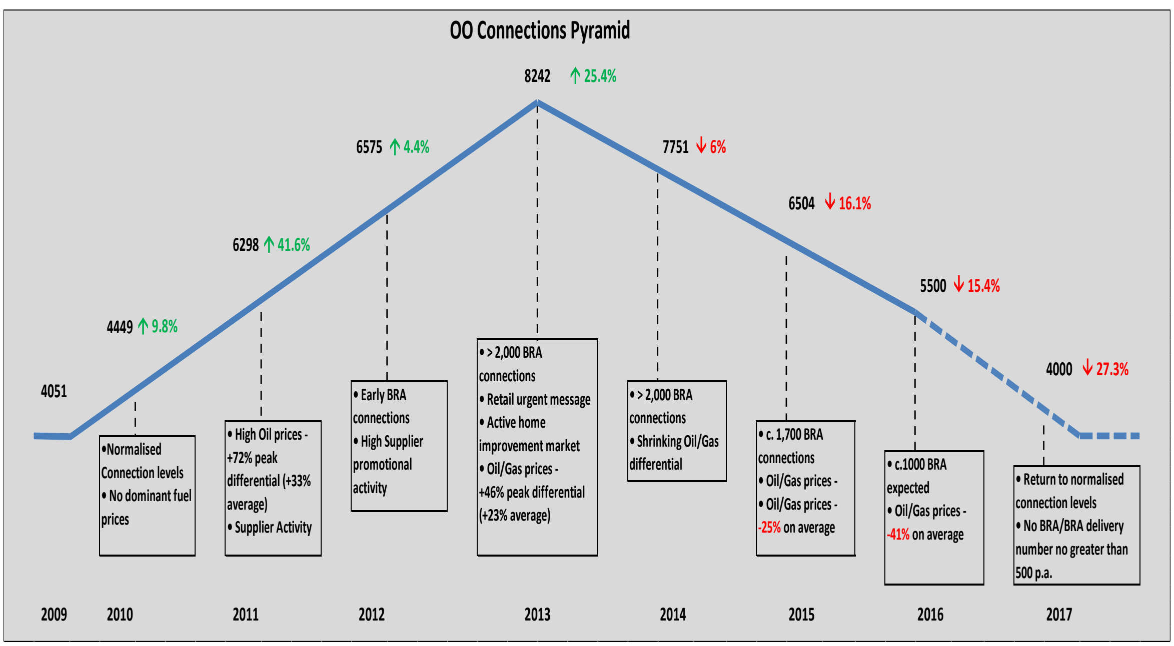

Figure 6: PNGL Graphical Representation of Issues Influencing Connection Numbers

6.338 PNGL stated within its submission that in relation to 2011 and 2012 '*Despite the challenging economic environment during 2011 and 2012, the level of owner occupiers* *expressing an interest and the numbers of owner occupiers connecting to PNGL's network was higher than the anticipated normalised level of c.4,000 connections per year*.

A range of factors contributed to the increase; however we believe (i) the collapse of the housing market; (ii) the decline of the new build market; and (iii) the level of promotional activity and positive publicity following the introduction of domestic supply competition in the natural gas market coupled with the negative publicity surrounding oil, are the main contributing factors', and 'Individually each factor may have only had a small impact; however performance in 2011 and 2012 was the result of an unprecedented culmination of a range of factors which created the conditions for previously 'uncommitted' owner occupiers to have a more specific interest in installing natural gas. We believed that these set of influencing factors were unique and not repeatable and that the levels of interest experienced would drop to the normalised level of c.4,000 connections as these factors were removed'.

6.339 In relation to 2013 and 2014 PNGL stated '*2013 and 2014 produced the highest owner occupied connections levels since the peak in 2003. We believe these performance levels were the result of (i) a continuation of many of the market conditions experienced between 2011 and 2012; (ii) the impact of the introduction of the Northern Ireland Executive Boiler Replacement Allowance in September 2012; and (iii) the rapidly rising cost of home heating oil and the associated publicity. We believe that the removal of these short term market conditions support a return to the consistent level of 4,000 owner occupied connections per year across GD17 as experienced between 2006 and 2010*'.

6.340 Also we note that "*PNGL agrees that the costs of developing the market should decrease as the development moves through the cycle from a fledgling business to maturity, however, neither PNGL nor the Northern Ireland market for natural gas can yet be considered mature. In the meantime an appropriate level of market development expenditure will be required to ensure that PNGL's current business model can be achieved*".

6.341 On this basis PNGL has proposed an annual owner occupied connections target of 4000. We note that some of these arguments were put forward in previous price controls by PNGL and we have set out in Table 62 previous PNGL forecasts of connection levels against outturn.

	2012	2013	2014	2015	2016
PNGL forecast connections	3700	3700	5100	4700	4300
UR determination	4200	4200	6500	6500	6500
PNGL actual connections	6575	8242	7751	6504	5500*

*2016 is an estimate by PNGL provided within its GD17 business plan which PNGL has since updated to around 4,500

Table 62: PNGL Actual OO Connection Numbers v PNGL Requested Targets and UR Determined Targets

6.342 For the draft determination we considered the PNGL arguments but did not believe they justified PNGL's proposal to reduce the connections target to 4000 pa. We considered that using a 15 year average give a useful indicator of what is achievable at the beginning of GD17 as it takes into account favourable and unfavourable factors that can influence the number of connections PNGL can achieve. We disagreed with PNGL that the 15 year average should not take account of the most recent 5 year period. We don't consider that using historic connection data from 16 to 20 years ago to be more relevant than the most recent five years. Consequently we considered using average data from the last 15 years as being relevant for consideration in arriving at a target for connection numbers.

6.343 While there is likely to be some connection between the oil/gas price differential and connections there is no evidence here that the link is the primary driver for growth in the gas industry. We also note that in advertising the benefits of gas PNGL and FE have put significant weight on the lifestyle benefits and not overly focused on price.

6.344 In its response to the draft determination PNGL updated their 2016 forecast OO connection numbers to around 4,500 from the 5,500 contained in its GD17 business plan submission. PNGL argued this reflected actual market conditions.

6.345 We have given consideration to the PNGL arguments and evidence provided by PNGL. In particular we put significant weight on the context of a reduction in the level of new infill mains and the associated opportunity to get new connections from recently passed properties. We have therefore set the connections target in 2017 to 5,000 for the final determination. We have maintained a downwards glidepath on the connections target for the final determination to recognise that over GD17 PNGL ability to maintain the same level of connections is likely to diminish.

6.346 Also we need to consider what level of properties remains to be connected to the network. As Table 63 demonstrates, another 100,000 customers may be connected, with a readily connectable gas supply available. These customers typically connect when their existing heating source comes up for replacement or renovation to the property occurs.

PNGL Connection Numbers	2012	2013	2014	2015
Actual Conncetion Numbers	6,575	8,242	7,751	6,500
Cumulative Connections	73,192	81,434	89,185	95,685
OO Propertities Passed	191,517	194,434	198,051	201,251
% Pentration	38%	42%	45%	48%

Table 63: PNGL Connection Numbers and Properties Passed

6.347 Therefore, for the final determination we have set a figure taking into account both the 15 year average connection rate as well as PNGL revised 2016 forecast connection rates, but have adjusted a glide path downwards, to reflect the more gradual decline in the number of new connections. For avoidance of doubt this proposal includes connection in the East Down area.

	2017	2018	2019	2020	2021	2022
PNGL submission	4,145	4,145	4,238	4,433	4,452	4,428
UR Final Determination	5,000	4,900	4,800	4,700	4,600	4,500

Table 64: OO Connection Numbers and Allowances

6.348 We had considered in GD14 whether, in the context of a halving of the incentive, it should be more focused on fuel poor customers. However given the proposal to move away from a drastic reduction in the incentive we propose that it should continue to be applied widely and not focused on one group. Furthermore we have taken into account the GDNs points on the difficulties in designing such a system and the role of other schemes such as the Northern Ireland Sustainable Energy Programme (NISEP)[75] and the Affordable Warmth grant scheme[76,] in delivering on social goals

Costs replaced by the Connection Incentive

6.349 In GD14 we stated that the following opex costs were being replaced by the owner occupied connections incentive:

- Advertising, Marketing and PR
- Incentives
- OO sales related staff, including relevant director; and
- Shared corporate overheads

6.350 The corporate overheads (apportioned) cost line in GD14 referred to a share of overheads we considered appropriate to apportion to the Business Development department. These costs included: Human Resources, Insurance (buildings and insurance), IT, office costs, rates (excluding network rates), stationary, telephone and postage, travel and subsistence, corporate support personnel and their apportioned share of the above costs.

6.351 In general, we have adopted a similar approach in GD17 but used different cost categories to reflect the fact that the BPT and the ACRT now use different cost categories when compared to GD14. The cost categories we have used in GD17 are in the main 'business support' costs as we consider they most directly relate to the 'indirect' costs referred to above in GD14.

6.352 As in GD14 we also re-allocated a portion of staff costs for those we consider undertake owner occupied sales activity and this includes a portion of customer management staff which we have rolled forward from GD14 FTEs and in addition a portion of the Sales Director and Finance Director costs.

6.353 From the draft determination we reduced the percentage used for the apportionment of overheads from 18.5% in GD14 to 15% in GD17 to reflect the decrease in target number of owner occupied connections for PNGL versus that in GD14. The 15% apportionment is consistent with that used for both FE and SGN. We have maintained this 15% apportionment for the final determination.

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[75] In line a request from the Minister for Economy, this scheme will operate until 31 March 2018. For further details on the scheme see: Utility Regulator: Framework Document for the Northern Ireland Sustainable Energy Programme 2016-2017, September 2015.
[76] For further details see: http://www.nidirect.gov.uk/index/information-and-services/environment-and-greener-living/energy-wise/energy-saving-grants/affordable-warmth-grant-scheme.htm.

6.354 Our intention is that these costs are to be recovered via the connection incentive mechanism. Therefore we have reduced the fixed allowances for applicable business support cost categories for these costs items by 15%. This is shown in each of the tables showing the GD17 final determination allowances for business support cost categories.

Connection Incentive: Non – additional connections

6.355 As in PNGL12 and GD14, we include a concept of non – additionally, as we consider that there will be a certain number of OO connections that would occur anyway without any direct marketing or selling to these customers. We describe these connections as "non-additional". Since PNGL could in theory avoid any sales-related costs to connect such customers, no allowance will be applicable for these customers.

6.356 One key reason behind the connections incentive was that gas was something of an unknown fuel in NI and that investment was needed in marketing to increase awareness of gas and move it to being the fuel of choice in NI. This has been largely achieved over time and so reduces the need for the connections incentive.

6.357 For GD14 (and as for PNGL12) this was set at 25% of all new OO connections. For GD17 we consider that as more customers connect to the existing gas network and the awareness of gas increases, it is appropriate to consider this percentage, which has a direct effect on the allowances given to PNGL.

6.358 In GD14 next steps, we considered that cutting the overall allowance by 50% would be appropriate, which reflects that gas has now moved to being the fuel of choice in Greater Belfast.

6.359 However, having considered the arguments from PNGL on the potential impact of such a change we propose that 33% "non - additional" represents a reasonable figure which recognises that the awareness of gas has increased since 2014 in the existing PNGL area while still facilitating a substantial amount of resources to be available for continuing the growth of the industry.

Application of the Owner Occupied Connection Incentive

6.360 For the draft determination we noted that the GDNs had raised concerns with the application of the owner occupied incentive mechanism as it applied in GD14. For example, FE made the argument that the connection incentive should be calculated over the entire price control period rather than on an annual basis. In addition, both FE and PNGL made the argument that the connection incentive as applied in GD14 i.e. the cap and collar regime was asymmetrical in that it unduly punished underperformance while not adequately rewarding outperformance.

6.361 While we do not consider that there is sufficient merit to move to a situation where the connection incentive is calculated over a Price Control period e.g. because by moving to a connection incentive there is a greater risk that the connection incentive would unduly be based on forecast rather than actual connection numbers, however we do consider there is merit in modifying the cap and collar regime used in GD14.

6.362 We have concluded that the cap should be removed and that a different collar should be implemented such that where a GDN underperforms the annual connection target by more than 50%, that a 25% collar (i.e. 25% * 'per connection' allowance) would operate.

6.363 To demonstrate how the new incentive mechanism might work, consider the following examples:

Exceed target

PNGL Target Connection for 2017 = 5,000

33% fixed non additionality[77] = 1,650

Actual Connections = 6,000

Connection Incentive = £610

So 6,000 – 33% fixed non additionality of 1,650 = 4,350 x £610 = £2,653,500

Underperformance of Target

PNGL Target Connection for 2017 = 5,000

33% fixed non additionality = 1,650

Actual Connections = 3,000

Connection Incentive = £610

So 3,000 – 33% fixed non additionality of 1,650 = 1,350 x £610 = £823,500

Underperformance of Target where collar applies

PNGL Target Connection for 2017 = 5,000

33% fixed non additionality = 1,650

Actual Connections = 1,500

Connection Incentive = £610

So 1,500 connections made is less than 50% of target so collar applies:

25% of the Connection Incentive = £152.5

So 1,500 – 33% fixed non additionality of 1,650 = (150) x £152.5 = (£22,875)

In this situation we would not apply a negative allowance, so it would be zero.

All connections allowances claimed by GDNs must relate to properties which have a supplier and are burning gas. We expect the GDNs to be able to demonstrate that all connections have a supplier agreement in place and burn a minimum quantity of gas.

Advertising & Market Development Costs for non Owner occupied (non OO) properties

6.364 The Advertising and Market Development (non-OO) cost category covers advertising and market development expenditure in relation to NIHE, New Build and I & C properties.

6.365 PNGL Advertising and Market development costs are driven by staff costs and stationary, communications and billing costs and a small amount for entertainment. In the 2014 year PNGL had advertising and market development (non-OO) costs of £359k. PNGL had 6.97 FTEs employed within the advertising and market development (non OO) category in 2014 and proposed 0.5 FTE increase in this area for the GD17 period.

[77] For the avoidance of doubt, the non-additional target is fixed at 33% of the annual connections target, irrespective of the actual output connections.

6.366 We have based the advertising and market development (non-OO) cost allowance for GD17 on the 2014 FTEs and using 2014 staff costs.

6.367 For the draft determination we re-allocated some of the costs under CEO and Group Management to the Advertising and Market development (non-OO) cost category as we considered that PNGL's sales director will spend 50% of their time on Advertising and Market development for non-owner occupied connections. This is consistent with our approach in GD14. We have maintained this for the final determination.

6.368 Subsequent to the draft determination PNGL informed us that it had incorrectly used an 85% allocation to owner occupied activities in its GD17 BPT submission. PNGL advised us that we should therefore reallocate New Build Sales exclusively to non-owner occupied activities, to accurately reflect activities undertaken.

6.369 We have accepted the reallocation as presented by PNGL and taken it into account for the final determination.

	2017	2018	2019	2020	2021	2022
PNGL requested allowances	350.6	356.2	360.1	356.2	356.2	356.8
UR FD before re-allocation	351.4	351.4	351.4	351.4	351.4	351.4
Re-allocation from CEO and Group Management	91.5	91.5	91.5	91.5	91.5	91.5
UR Final Determination	443.6	443.6	443.6	443.6	443.7	443.7
Variance (+)	93	87.4	83.5	87.4	87.5	86.9

Table 65: Advertising and Marketing (non OO) Costs, Requested and Allowed, £k

Work Management

Overview

6.370 Work Management covers the following cost categories

- Asset Management
- Operations Management
- Customer Management including the Emergency Call Centre
- System Control

Asset Management

6.371 Asset Management covers the activity of managing the network's assets. The costs collated under asset management should be costs incurred in the following areas:

- Network Planning;
- Network Integrity (including gas quality monitoring);
- Network Capacity;
- Network/engineering policy/procedures (covering all policies of the network e.g. records transfer and brought in services & materials).
- Network development/analysis; and
- Management of redundant sites & remediation programmes

6.372 PNGL's asset management costs are in the main driven by its associated manpower costs. In the 2014 year PNGL had Asset Management costs of £215k and had 4 FTEs employed within the Asset Management cost category. PNGL has proposed an additional FTE specifically an additional engineer for Asset Management in the GD17 period.

6.373 In GD14 we stated that '*PNGL has provided justification for 1 additional FTE in 2014 and 2015 to facilitate the introduction of the new asset management system. PNGL advises that this FTE will not be needed in 2016*'. Consequently, for the draft determination we did not consider that an additional FTE was required in the GD17 period as this is already included in the PNGL costs base.

6.374 In response to the draft determination PNGL stated that it had 'estimated that 1 additional asset management FTE would be sufficient to develop and introduce an ISO55001 complaint asset management system. However, at the time PNGL did not fully comprehend the significant volume of new activities required in order to ensure ongoing compliance with the standard. The additional FTE now requested by PNGL for the 2017 period reflects the actual resource required to administer and manage an asset management system that remains complaint with ISO55001 each year'

6.375 PNGL also clarified that the additional FTE allowed for in GD14 started in 2015 rather than in 2014.

6.376 We are also of the view that the purpose of the additional FTE was to assist in implementing the Asset Management system. We consider that PNGL should be able to maintain its Asset Management system from existing resources. Consequently, our allowances for Asset Management are unchanged from the draft determination.

	2017	2018	2019	2020	2021	2022
PNGL requested allowances	251.6	255.3	262.7	256.6	257.0	257.7
UR Final Determination	216.7	216.6	216.6	216.6	216.6	216.6
Variance	34.9	38.7	46.1	40.0	40.4	41.1

Table 66: Asset Management Costs, Requested and Allowed, £k

Operations Management

6.377 Operations Management covers the cost of the day to day planning and supervision of the operatives and contractors working within the work execution processes. The costs allocated under operations management include for example:

- First line managers (non-field staff);
- Depot Manager etc.;
- Costs of the Safety, Health and Environment section (compliance).
- Operations Support:
- Covering support costs in depots (which include TMA/NRSWA activities);
- Plant protection;
- Digitisation;
- Dispatch;

- Data quality;
- Work scheduling;
- Updating asset records; and
- HSE policy

6.378 PNGL's operations management costs are in the main driven by its associated manpower costs. In the 2014 year PNGL had Operations Management costs of £415k and had 19.6 FTEs employed within the Operations Management cost category. PNGL have proposed that there should be 22.2 FTEs for Operations Management in the GD17 period.

6.379 For the draft determination we did not consider that an increase in FTEs was necessarily required for Operations Management in the GD17 period and therefore our proposed allowance was based on 2014 actual FTE numbers. This is consistent with our approach in GD14.

6.380 In its response to the draft determination PNGL stated that '*the maintenance activities proposed to be performed by the additional FTE is directly related to the volume of connected properties. The proposed increase in FTEs amounts to only 9% within Operations compared to a forecast increase of c54k connections (or 24%) over the GD17 period*'. PNGL also stated that '*UR's proposal that the end of life replacement for larger industrial and commercial meters is extended beyond the industry standard of 20 years will also impact on the resources required within Operations*'.

6.381 For the final determination we have taken account of the points made by PNGL and provided for an additional FTE in Operations Management.

	2017	2018	2019	2020	2021	2022
PNGL requested allowances	542.7	550.8	551.1	552.0	552.6	553.2
UR Final Determination	509.3	508.9	508.7	508.6	508.5	508.3
Variance	33.4	41.9	43.1	43.4	44.1	44.9

Table 67: Operations Management costs, Requested and Allowed, £k

Customer Management

6.382 Customer management is split between two main areas i.e. Emergency Call Centre and Customer Services that cover non-emergency calls and which also handle enquires and complaints. The non-emergency Customer Services also includes costs of commercial/contract department that manages all types of contracts for the whole of the business.

6.383 PNGL's customer management costs are in the main driven by its associated manpower costs. In the 2014 year PNGL had customer management costs of £737k and had 34.4 FTEs employed within the Customer Management cost category. PNGL has proposed that there should an incremental increase in FTEs for Customer Management in the GD17 period i.e. from 37 FTEs in 2017 to 39.2 FTEs in 2022.

6.384 We consider that an increase in FTEs for Customer Management from the 2014 figure is appropriate given the expected increase in customer connections in GD17. However, we do not consider the scale of increase in FTEs proposed by PNGL is necessary. We have therefore based our allowance on PNGL's projected 2015 figure for FTEs of circa 36 FTEs.

6.385 For the draft determination we re-allocated some of the costs under Customer Management to the Advertising and Marketing (OO) as we consider staff in Customer Management will deal with Advertising and Marketing for domestic Owner Occupied connections. Specifically, we re-allocated 7.66 FTE under the Advertising and Marketing (OO). This was consistent with our approach in GD14.

6.386 For the final determination we have reduced this re-allocation to 6.66 FTE as we recognise that targeted annual number of owner occupied connections is lower in the GD17 period compared to the GD14 period.

6.387 In its response to the draft determination PNGL stated that '*PNGL welcomes UR's small increase in Customer Management FTE's. However, the proposed increase in FTE's for Customer Management is not sufficient as:*

- *PNGL's 2014 average FTE's for Customer Management were understated due to high levels of staff turnover experienced in 2014 and 2015. The actual FTE's currently employed are 37.5 FTE's.*
- *The proposed increase is not sufficient when compared with the increase in connections forecast during the GD17 period'*.

6.388 We consider we allowed a sufficient increase i.e. 1 FTE in the draft determination in recognition of the growth of the PNGL network and retain this in the final determination.

	2017	2018	2019	2020	2021	2022
PNGL requested allowances	830.0	851.9	865.9	869.5	878.2	886.8
UR FD before re-allocation	797.3	797.9	798.6	799.5	800.1	800.7
Re-allocation to AMPR (OO)	161.5	161.5	161.5	161.5	161.5	161.5
UR Final Determination	635.8	636.4	637.1	638.0	638.6	639.2
Variance	194.2	215.5	228.8	231.5	239.6	247.6

Table 68: Customer Management Costs, Requested and Allowed, £k

System Control

6.389 System control covers the costs associated with the activity of ensuring the safe flow of gas through the network, ensuring the supply is sufficient to meet the demand of gas on a daily basis. The related costs should represent the cost of running the control room (e.g. staff costs of resource working within the control room).

6.390 The costs allocated under system control should include:

- Salary costs;
- Travel & subsistence;
- Training costs for the delivery of system control migration;
- Any other non-salary costs associated with these resources; and
- Mast Rentals

6.391 PNGL's system control costs are in the main driven by its associated manpower costs. In the 2014 year PNGL had system control costs of £100k and had 5.3 FTEs employed within the System Control cost category. PNGL has proposed an additional FTE for System Control in the GD17 period.

6.392 Our final determination allowances for System Control are unchanged from the draft determination. We do not consider that an increase in FTEs is necessarily required for System Control in the GD17 period and therefore our allowance is based upon 2014 actual FTE numbers. This is consistent with our approach in GD14.

	2017	2018	2019	2020	2021	2022
PNGL requested allowances	130.4	132.6	133.3	132.6	132.6	132.6
UR Final Determination	110.2	110.2	110.2	110.2	110.2	110.2
Variance	20.2	22.4	23.1	22.4	22.4	22.4

Table 69: System Control Costs, Requested and allowed, £k

Emergency Costs

Overview

6.393 PNGL has requested a total allowance of £2.31m in 2017 rising to £2.62m in 2022, to cover the cost of the emergency call centre, emergency first response and repair activities. For comparison, historical actual costs for 2013-2014 averaged around £2.21m.

6.394 Table 70 summarises the emergency costs submitted by PNGL under each emergency expenditure category.

	2017	2018	2019	2020	2021	2022	GD17 Total
Call centre (£k)	445	451	461	472	475	490	2,795
First response (£k)	1,409	1,437	1,481	1,526	1,540	1,604	8,998
Repair activities (£k)	461	472	485	498	507	522	2,946
Total (£k)	2,314	2,361	2,428	2,496	2,523	2,617	14,739

Table 70 – Emergency costs submitted by PNGL

6.395 Table 71 summarises the final determination allowances for PNGL under each emergency expenditure category.

	2017	2018	2019	2020	2021	2022	GD17 Total
Call centre (£k)	445	451	461	472	475	490	2,795
First response (£k)	1,290	1,316	1,355	1,396	1,409	1,467	8,232
Repair activities (£k)	447	458	470	482	491	505	2,853
Total (£k)	2,181	2,225	2,287	2,350	2,375	2,462	13,880

Table 71 - Emergency costs allowed in the final determination for PNGL

6.396 Figure 7 shows PNGL's GD17 allowances against the submission, historical actuals and the allowances for GD14.

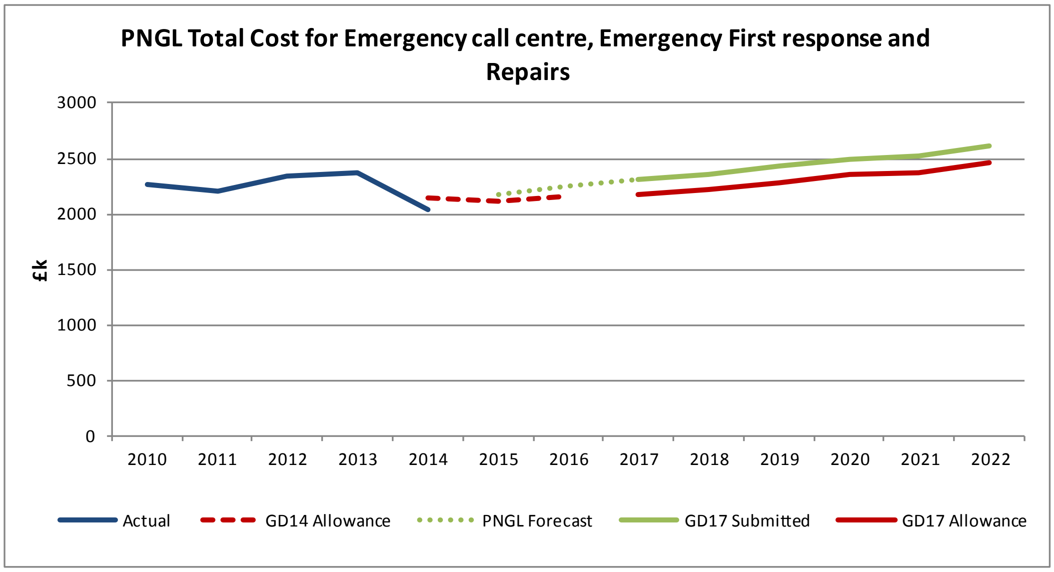

Figure 7 – PNGL Total cost for emergency activities

6.397 The key changes from the draft determination have been:

- Adjustment of model assumptions to ensure that the profile of FE's total call numbers is more reflective of historic and projected trends.
- Revision of projected connection numbers to align with those used elsewhere in the final determination.

6.398 The combined effect of these changes had no material impact on the overall assessment for PNGL and so the final allowances remain the same as in the draft determination.

6.399 The key factors influencing the determined emergency and repair allowances are:

- The profit element has been removed from PNGL Energy Services (PES) related works in line with the approach adopted in GD14. This results in a total reduction of £859k.
- Call volume modelling was used to assess the submitted cost for the call centre. This carried forward the call reduction targets applied in GD14.
- The number of estimated emergency jobs was adjusted to align with modelled call numbers to assess the submitted cost for emergency first response activity.
- The cost reductions delivered in 2014 by PNGL as a result of operational changes in the handling non-emergency meter calls are noted and welcomed.
- As in GD14, and given that all the GDNs have licence obligations about operating a single emergency number in NI, we are asking that the GDNs work more closely together in procuring an emergency call centre contract to ensure that costs are as low as possible.

6.400 Annex 8 provides further description of the detail behind the assessment and the approach applied. It also details our response to the consultation feedback received on the draft determination (as summarised in Annex 13).

Network Maintenance

<u>Overview</u>

6.401 In its Business Plan, PNGL identified net costs of network maintenance over GD17 averaging £2.94m per annum.

6.402 The majority of the expenditure identified by the company continues well established activities required to maintain the assets and the service they deliver. The company also identified three material new maintenance activities for GD17 estimated to add an average of £516k per annum (23%) to the cost of network maintenance:

- A valve accessibility project to free the covers of valve surface boxes and clear debris from the valve boxes.
- The inspection and maintenance of steel riser pipes serving blocks of flats.
- Replacement of pressure reducing station (PRS) covers to secure safe access to PRS chambers.

6.403 In its response to our draft determination PNGL made two key points:

- It noted that we had not taken account of expenditure of c.£230k per annum on internal staff, transport and plant. We have corrected this for the final determination.
- It criticised our decision to include only part of the allowance requested for a valve accessibility project on the basis that the company should consider risk based targeting of this work and that there were opportunities to obtain more efficient rates on planned volumes of work. In the final determination we have maintained the position set out in the draft determination. Further comment is provided in the section beginning at paragraph 6.409 below.

6.404 Significant parts of PNGL's network maintenance work is carried out by a related company, Phoenix Energy Services (PES). In GD17, we have maintained the approach applied in GD14 where we remove the profit element from maintenance and metering works carried out by PES. PNGL identified profit element of PES work as 9.85% of turn over based on 3 years accounts and identified the work in its plan costed on the basis that it would be carried out by PES.

6.405 PNGL proposed expenditure for GD17 is set out in Table 72.

	2017	2018	2019	2020	2021	2022
Maintenance opex (£k) net	1,827	1,504	1,544	1,726	1,859	1,835
Metering opex (£k) net	725	1,168	1,106	997	948	1,049
Staff, trasport and plant costs (£k)	222	225	227	228	229	230
Total (£k)	2,774	2,897	2,876	2,951	3,036	3,114
New items						
Valve accessibility project	375	375	375	375	377	373
Steel riser project	123	123	123	123	123	123
PRS cover maitenance	0	0	0	40	140	90
Total new items (£k)	498	498	498	538	640	586
Total (£k) net excluding new items	2,276	2,399	2,378	2,413	2,396	2,528
PES profit element (£k)	116	153	145	142	145	160
Total (£k) net excluding new items and PES profit	2,160	2,246	2,233	2,271	2,251	2,368
Total (£k) net including new items, excluding PES profit	2,658	2,744	2,730	2,809	2,891	2,954

Table 72: PNGL Network Maintenance Proposals (Adjusted for PES Profit Element)

Assessment of Network Maintenance Expenditure Excluding New Items

6.406 Projected network maintenance expenditure for GD17 proposed by PNGL is shown in Figure 8 where it is compared with historical expenditure and the allowance for GD14 projected into GD17. Both total expenditure and expenditure in GD17 excluding new items are shown. The proposed expenditure has been adjusted and GD14 projections have been adjusted to exclude PES profits.

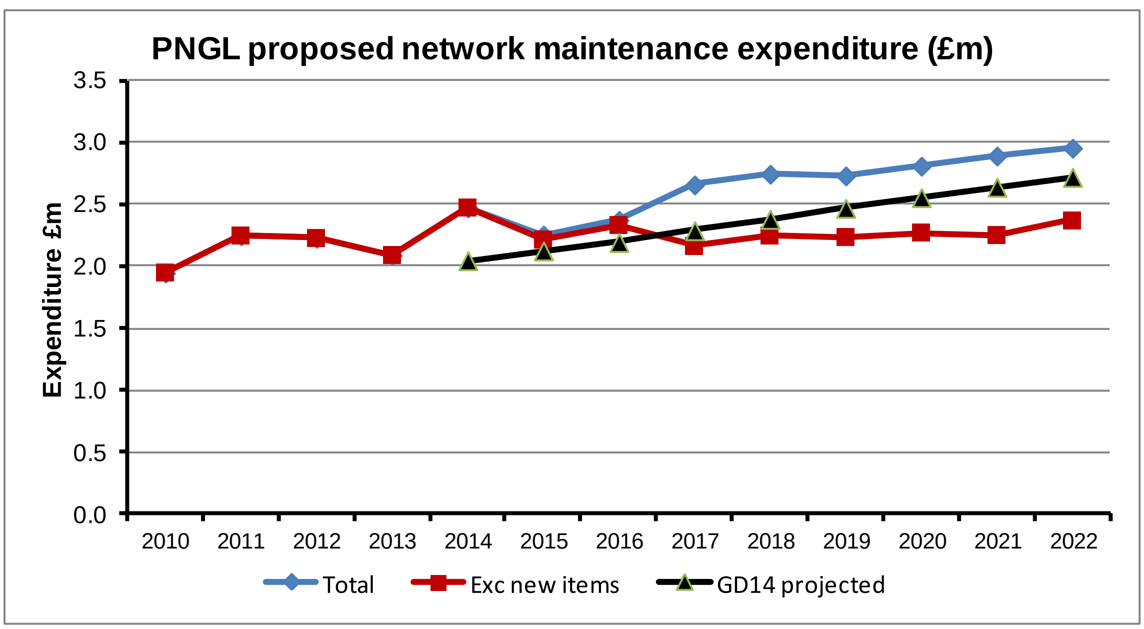

Figure 8: PNGL Proposed Network Maintenance

6.407 Excluding new items and PES profits, the network maintenance expenditure proposed for GD17 by PNGL is consistently less than the projected allowance for GD14. In view of this, and in view of the supporting information provided by PNGL in its Business Plan submission, we have adopted a proportionate approach and accepted the company's proposal for network maintenance excluding new items subject to the deduction of the PES profit element.

Assessment of Network Maintenance Expenditure New Items

6.408 PNGL identified three new items of network maintenance expenditure which are identified in Table 72. In this section we set out our conclusion on these three items.

Valve Accessibility Project

6.409 PNGL proposed to begin the regular inspection of the valve boxes which allow access to valves on the gas network. The company planned to inspect and carry out any remedial works at all valves installed up to 2012 by the end of GD17 and move to a 10 year cycle of valve cover inspection and maintenance thereafter. The company estimated that there are 23,768 valves constructed up to 2012 which would be addressed in this programme. The company highlighted the need for this work as a safety measure to ensure that any valve could be accessed in an emergency.

6.410 To prepare an estimate of the scope and cost of this work, the company carried out a trial in one area, inspecting 1,328 valves (a sample of 5.5%). Three key defects were identified in the trial project:

- Valve boxes which could not be opened and had to be excavated and replaced (26%).
- Valve boxes which could be opened where it was necessary to replace the locking screws (7%).
- Valve boxes where it was necessary to bring in a gulley cleaner to clear debris blocking access to the valve (12%).

6.411 This indicates that 38% of valves cannot currently be accessed to maintain the network without excavating the valve box or bringing in additional equipment to remove debris.

6.412 Based on this survey, the company estimated the costs of inspecting and carrying our remedial works at all valves installed in 2012 or earlier is £2.25m. Twenty five percent of the estimated cost relates to the initial inspection and 73% relates to the excavation and replacement of valves surface boxes.

6.413 At the draft determination we noted that the company's approach was based on the assumption that all valves should be inspected and remedial works carried out at a given frequency (10 years) with a higher rate of activity in GD17 to clear 16 years of valve installation up to 2012. We also note that the unit rate for the key activity (valve box replacement at £265 per unit) is based on a contract rate which appears to be for an ad-hoc activity and that synergies could be achieved on a planned and area based programme of work.

6.414 We asked our consultants to review the company's proposals. They confirmed that valve accessibility is an activity that any prudent GDN would undertake as part of a wider maintenance and inspection strategy and framework. However they would expect that the strategy a GDN adopts would differentiate the valve population and assess maintenance frequencies on the basis of strategic importance and risk. They concluded that, in the absence of a compelling risk based rationale, they did not believe there is a sound economic basis for undertaking the whole cycle of such maintenance activity within a single regulatory period.

6.415 In view of this advice, we have based our draft determination on the following:

- We included an allowance based on half the proposed level of inspection in the GD17 period targeted using a risk assessment to identify strategic valves.
- Synergies can be achieved on the current rate for valve box replacement as part of a planned area based programme of maintenance work. We have allowed a rate of £151 per valve box.

6.416 At the draft determination we suggested that the company:

- Considered developing a clear risk based approach including undertaking further work to better understand when defects occur to inform the development of a planned schedule of inspection and maintenance.
- In view of the fact that, as a defect which affects valve accessibility might occur at any time, a regular cycle of inspection and maintenance cannot eliminate the risk that it will be difficult to access a valve when it is necessary to do so, the company considers how it can access valves if the valve box has seized and ensure that this is taken into account as it develops its plans for routine inspection and maintenance.

6.417 In its response to the draft determination the company contended that its proposed strategy for including the entire underground valve asset within the project is the most prudent and appropriate approach with regards to controlling the risks posed by inaccessibility across the underground valve asset. The company also noted that, as an efficient operator, it will always attempt to negotiate lower unit costs with its contractor by increasing productivity. It considered our proposed rate reduction to be excessive and asked that the final determination includes the allowances requested in the company's Business Plan. The company did not provide any additional information or analysis in response to the issues raised in the draft determination.

6.418 For the final determination, we have maintained the position set out in the draft determination. In the absence of any further information, we have continued with a reduced rate for valve box replacement to reflect the opportunity to achieve synergies from planned programmes of work. We have considered the company's view that it should inspect all valves with a view to undertaking remediation work. We note that the company has been operating its network safely for over 15 years and that the mitigation measures it has taken in the past remain valid for the future. In view of the advice we received for the draft determination, we consider it appropriate for the company to consider a risk based approach to target its work. It is for the company to continue to take such steps as are necessary to operate its network safely.

Steel Riser Project

6.419 PNGL has proposed a programme of works for maintenance of steel riser pipes which generally serve flats. The work will be carried out on a 10 year cycle. It will begin in GD14 and the company plans to have completed inspections and remedial works for all properties where steel risers have been installed for 10 years or more by the end of GD17.

6.420 We asked our consultants to review the company's proposals. They confirmed that the work is necessary and concluded that the proposed costs were reasonable. Therefore we have included the costs estimated by the company in the final determination.

PRS Cover Maintenance

6.421 PNGL has proposed a new programme of works to maintain the access covers on major PRS valve chambers. The company has identified the potential need for the major repairs as chamber covers and mechanisms come to the end of their life. The company estimated a number of chamber covers which will require remedial action and costed the works on the full replacement of the existing covers.

6.422 There is a high degree of uncertainty over the extent and timing of this new activity. It is possible that it will overlap with planned PRS replacement. There may be opportunities to carry out part replacement rather than full cover replacement when defects occur. In view of this, we have included an allowance in the draft determination of half the activity requested by the company and assumed that the start of this activity can be delayed by one year.

Summary of Expenditure for GD17

	2017	2018	2019	2020	2021	2022
PNGL proposed maintenance opex excluding new items (£k)	2,276	2,399	2,378	2,413	2,396	2,528
Less PES profit margin (£k)	-116	-153	-145	-142	-145	-160
Nerw items (£k)						
Valve accessibility project	129	129	129	129	129	129
Steel risers	123	123	123	123	123	123
PRS cover maintenance	0	0	0	0	20	70
	2,412	2,498	2,484	2,523	2,523	2,690

Table 73: PNGL GD17 Allowance for Network Maintenance

Expenditure post GD17

6.423 We have included an allowance for network maintenance activities post GD17 based on £10 per weighted connection based on our final determination allowance for 2020 to 2022. This assumes that current maintenance activities continue and allows for a general increase in costs in line with increasing numbers of connections. We have not made any assumptions about new maintenance activities which might be required in the future.

Other Direct Activities

6.424 PNGL has not proposed any costs under this category and this is consistent with PNGL historical information. Therefore the UR does not propose to provide for any costs under this category.

Business Support Activities

Overview

6.425 Business support opex includes the following activities:

- IT & Telecoms;
- Property Management;
- HR & Non-operational Training;
- Audit, Finance & Regulation;
- Insurance;
- Procurement;
- CEO & Group Management; and

- Stores & Logistics.

IT & Telecoms

6.426 The IT & telecoms cost category covers the provision of IT services for the day to day service delivery.

6.427 The costs collated under IT & Telecoms should include:

- The purchase, development, installation and maintenance of non-operational computer and telecommunications systems and applications.
- Provision of IT services for the day to day service delivery and including the cost of Help Desk, data centres, IT application development, maintenance and support; establishing and maintaining information system infrastructure projects (IT network provision, network maintenance, server's support/services).
- Voice and data telecoms (e.g. WAN, landline rental and call charges, ISDN data and costs/rental of mobiles except where costs are charged directly to user departments).
- Developing new software for non-operational IT assets including the costs of maintaining an internal software development resource or contracting external software developers. This will include any cost of software licences to use the product where those costs cover more than one year.
- Installing new or upgrading software, other than where it is capitalised. This does not include upgrading of software that is included within the costs of annual maintenance contracts for the software.
- Maintenance and all the operating costs of the IT infrastructure and management costs and applications cost. This includes any annual fee for the maintenance of software licences, whether or not they include the right for standard upgrades or 'patches' to the software as they become available.
- IT applications maintenance and running costs.
- IT new applications software and upgrade costs.

6.428 PNGL's IT & Telecoms costs are in the main driven by its associated manpower costs along with costs for stationary, communications and billing. In the 2014 year PNGL had IT & Telecoms costs of £485k. PNGL had 4.5 FTEs employed within IT & Telecoms cost category in 2014 and has not proposed any increase in FTEs in this area for the GD17 period.

6.429 Our final determination allowances for IT & Telecoms are unchanged from the draft determination We have based the IT & Telecoms allowance for GD17 on the FTEs as submitted by PNGL but using 2014 staff costs and 2014 costs for stationary, communications and billing.

6.430 In its response to the draft determination PNGL noted the allowances for IT & telecoms in the draft determination but requested additional allowances for the final determination for:

- Maintenance and support costs of IT equipment
- System development support

- Resources to protect its network, internet and mail services
- Upgrade to financial software solutions
- Costs associated with reviewing hosting requirements

6.431 We consider that we allowed sufficient allowances within the draft determination to facilitate PNGL to undertake IT maintenance and updates. The extent of any IT enhancements is a matter for PNGL.

6.432 We have re-allocated some of the costs under IT & Telecoms to be recovered under the Connection Incentive / AMPR (OO) as we consider that some of PNGL's IT and Telecoms systems will be used for Advertising and Marketing for domestic Owner Occupied connections. This is consistent with our approach in GD14.

6.433 Our allowances (before taking into account re-allocation to be recovered under the Connection Incentive / AMPR (OO) for GD17 are similar to the three year average over the 2012 -2014 period at circa £488k

	2017	2018	2019	2020	2021	2022
PNGL requested allowances	604.3	588.1	591.9	590.9	592.0	618.3
UR FD before re-allocation	488.7	487.7	488.0	488.0	487.9	489
Re-allocation to AMPR (OO)	49.8	49.8	49.8	49.8	49.8	49.8
UR Final Determination	438.9	437.9	438.2	438.2	438.1	439.2
Variance	165.4	150.2	153.7	152.7	153.9	179.1

Table 74: IT& Telecoms Costs, Requested and Allowed, £k

Property Management

6.434 The Property Management cost category covers the activity of managing, providing and maintaining non-operational premises. This should include costs such as rent, rates (business), utilities costs including electricity, gas and water, maintenance/repair costs of premises and the provision of the facilities/property services such as reception, security, access, catering, mailroom, cleaning and booking conferences. The costs of property surveyors should also be included here.

6.435 The costs collated under Property Management also include:

- Stores, depots, offices (properties with the primary function to accommodate office based staff during their business hours), including training centre buildings & grounds;
- Rent paid on non-operational premises;
- Rates and taxes payable on non-operational premises;
- Utilities including electricity, gas and water (supply and sewerage);
- Inspection and maintenance costs of non-operational premises;
- Facilities management costs including security and reception;
- Training centre buildings & grounds; and
- Control rooms and data centres

6.436 The most significant cost item under PNGL property management costs are in relation to network rates. We have in the past set network rates using a formula which links the allowance to PNGL revenues. PNGL's allowance request was also calculated using the current formula.

6.437 We are comfortable with the approach of using a formula linked to revenue in order to set the network rates allowances for PNGL. We have used this approach historically in PNGL12 and GD14 and again for the GD17 draft determination. For the final determination we updated the formula to take account of information on 2016-17 rating valuations and our final determination revenue forecast for PNGL.

6.438 The only other modification we have made to the PNGL submission on network rates is to remove any forecast prior year adjustments as over the medium term we would expect any such prior year adjustments to be released as occurred in 2014. This approach is consistent with the approach we adopt for FE.

6.439 PNGL also has rent and rates costs in relation to its offices. We have reviewed these costs and consistent with our approach in GD14 made an adjustment to take account of our view that PNGL has the opportunity to sub-let part of its premises. We have therefore allowed a cost of £420k per annum in relation to rental of premises and this is a reduction of c136k against the PNGL GD17 submission. Our allowance is marginally above the actual 2014 costs rental costs incurred by PNGL for 2014 i.e. c398k.

6.440 As per the treatment in PNGL12 and GD14, the allowance for rates will not be treated as pass-through, but will continue to form part of the Uncertainty Mechanism.

6.441 In response to the draft determination PNGL stated that '*Ofgem's three price control reviews under the RIIO model treat business rates as non-controllable opex and therefore treat network rates as pass-through. The effect of the Competition Commission's decision in relation to PNGL's network rates was essentially to implement a pass-through mechanism for rates since 1996. Furthermore it would be unreasonable for UR to align the price controls of NI's GDNs while treating this uncontrollable cost differently for PNGL and the other NI GDNs*'. *PNGL would therefore expect UR to allow a pass-through of rates in line with the body of relevant precedent'*.

6.442 We have considered how Ofgem has treated business/network rates, which is deemed to be an uncontrollable costs. Although, we have taken this on board, we believe that as the PNGL network is still growing, they have more scope to deal with this cost line in an efficient manner.

6.443 We disagree with PNGL suggestion that the CC indicated that this should be pass through in PNGL12. We have considered the comments made by the CMA on RP5, on this area, which said the following; "*We have not sought to characterize NIE's costs as either 'controllable' or 'uncontrollable' costs. Instead, we recognized that NIE has some ability to influence its rates liability. For the reasons set out above (paragraphs 5.348 to 5.357), we did not consider it appropriate for NIE's rates liability to be passed on to consumers in full or to use the Ofgem approach that NIE referred us to*".

6.444 For the final determination we have concluded it is not appropriate to maintain FE rates as a pass-through and therefore there is now consistency of how we treat network rates for FE and PNGL

6.445 As indicated in the section above, we are following the principle of the CMA on this area and not treating rates as pass through.

6.446 We have re-allocated some of the costs under Office costs to be recovered under the Connection Incentive / AMPR (OO), as we consider that some of PNGL's offices will be used for Advertising and Marketing for domestic Owner Occupied connections. This is consistent with our approach in GD14.

	2017	2018	2019	2020	2021	2022
PNGL requested allowances	2,541.1	2,733.9	2,796.7	2,872.0	2,963.7	3,012.3
UR FD before re-allocation	2,553.5	2,659.0	2,737.8	2,771.6	2,883.9	2,966.1
Re-allocation to AMPR (OO)	32.8	32.8	32.9	32.8	32.9	32.8
UR Final Determination	2,520.7	2,625.2	2,704.9	2,783.8	2,851.0	2,933.3
Variance	20.4	108.7	91.8	88.2	112.7	79

Table 75: Property Management Costs, Requested and Allowed, £k

HR & Non-Operational Training

6.447 HR covers provisions of the HR function i.e. the full range of professional activity for an individual's career path from recruitment to retirement and post retirement where applicable, e.g. management and administration of pension payments and from related professional advice to directly resolving grievances for staff.

6.448 The HR costs collated under HR & non-operational training should include:

- Costs of payroll and pension's management and operation;
- Facilitating staff performance, development and reviews;
- Industrial and employee relations including HR strategy, policies and procedures;
- Monitoring equal employment opportunities; and
- HR advice to management, succession planning and also retentions and rewards

6.449 PNGL HR and non-operational training costs are in the main driven by staff costs and professional and legal fees.

6.450 PNGL In the 2014 year PNGL had HR & Ops training costs of £228k. PNGL had 2.4 FTEs employed within HR and Ops training cost category in 2014 and has not proposed any increase in FTEs in this area for the GD17 period.

6.451 Our final determination allowances for HR & Non-Operational Training are unchanged from the draft determination. We have based the HR and Ops training allowance for GD17 on the FTEs as submitted by PNGL but using 2014 staff costs and 2014 costs for professional and legal fees as well as 2014 materials costs.

6.452 Our allowances (before taking into account re-allocation to Advertising and Marketing (OO) for GD17 are marginally above the three year average over the 2012 - 2014 period at circa £196k.

6.453 We have re-allocated some of the costs be recovered under the Connection Incentive / AMPR (OO), as we consider that some of PNGL's HR and Ops training will be used for Advertising and Marketing for domestic Owner Occupied connections. This is consistent with our approach in GD14.

	2017	2018	2019	2020	2021	2022
PNGL requested allowances	240.3	243.1	244.5	244.0	244.4	244.8
UR FD before re-allocation	226.4	226.4	226.5	226.5	226.6	227.7
Re-allocation to AMPR (OO)	12.2	12.2	12.2	12.2	12.2	12.3
UR Final Determination	214.2	214.2	214.3	214.3	214.4	214.4
Variance	26.1	28.9	30.2	29.7	30	30.4

Table 76: HR & Non-Operational Costs, Requested and Allowed, £k

Audit Finance & Regulation

6.454 Audit Finance & Regulation covers performing the statutory, regulatory and internal management cost and (business support activity) performance reporting requirements and customary financial and regulatory compliance activities for the network.

6.455 The costs collated under Audit, Finance & Regulations should include:

- Process of payments and receipts;
- Time sheet evaluation where not part of the payroll process;
- Financial & risk management – e.g. credit & exposure management;
- Financial planning, forecasting & strategy;
- Financial accounting;
- Management accounting;
- Investment accounting;
- Treasury management;
- Transportation income accounting;
- Pricing;
- Statutory & regulatory reporting;
- Tax compliance & management;
- Internal audit & management of the relationship with external audit function;
- External audit fees; and
- Cost of regulatory department.

6.456 PNGL Audit Finance and Regulation costs are in the main driven by staff costs, professional and legal fees, and stationary, communications and billing costs.

6.457 In the 2014 year PNGL had Audit Finance and Regulation costs of £942k. PNGL had 12.7 FTEs employed within Audit Finance and Regulation cost category in 2014 and has proposed an increase of circa 0.8 FTEs in this area for the GD17 period.

6.458 Our final determination allowances for Audit, Finance and Regulation are unchanged from the draft determination. We have based the Audit Finance and Regulation allowance for GD17 on the 2014 FTEs and using 2014 staff costs and 2014 costs for professional and legal fees as well as 2014 stationary, communications and billing costs.

6.459 In its response to the draft determination PNGL noted that our proposed allowances for Professional and Legal costs are based on actual costs incurred by PNGL during 2014 of £308k. PNGL stated that it disagrees with the use of 2014 as the base year as 2014 does not reflect the underlying average costs PNGL has incurred or will incur during the GD17 period. For example:

- 2014 was the first year of the GD14 price control;
- There were no major changes to PNGL's structure or activities;
- Supply competition has stabilised;
- There were no major Licence modifications.

6.460 PNGL stated that '*the allowances proposed by the UR for the GD17 period are understated by c.£130k per annum. Additional consultancy costs forecast around each price control e.g. in 2015, 2016 and 2017 for the GD17 review; and in 2021, 2022 and 2023 for the GD23 review. Given the scope and duration of this and future price control reviews, PNGL would request UR to reconsider its proposal on this basis*'.

6.461 We consider that 2014 provides the best basis for a typical base year and have not made any large scale adjustments up or down. Therefore we consider that such issues will cancel each other out on average.

6.462 We have re-allocated some of the costs under Audit Finance and Regulation to be recovered under the Connection Incentive / AMPR (OO), as we consider that some of PNGL's Audit Finance and Regulation function will be used for Advertising and Marketing for domestic Owner Occupied connections. This is consistent with our approach in GD14.

	2017	2018	2019	2020	2021	2022
PNGL requested allowances	1,185.8	1,159.2	1,170.2	1,127.1	1,225.8	1,230.2
UR FD before re-allocation	943	942.8	942.8	942.6	943.2	943.2
Re-allocation to AMPR (OO)	79.4	79.4	79.4	79.4	79.4	79.4
UR Final Determination	863.6	863.4	863.4	863.2	863.8	863.8
Variance	322.2	295.8	306.8	263.9	362.0	366.4

Table 77: Audit Finance & Regulation Costs, Requested and Allowed, £k

<u>Insurance</u>

6.463 The Insurance cost category covers support and expertise to develop the business risk profile, managing the claims process and provision of information and understanding to the business in relation to insurable and uninsurable risks.

6.464 The costs collated under Insurance should include:

- Insurance premiums;
- Insurance premium tax;
- Insurance contract negotiating and monitoring;
- Insurance claim processing;

- Insurance risk management;
- Payments relating to uninsured claims;
- Costs of in house insurance team; and
- Brokers fees.

6.465 The main element of PNGL's insurance costs is business insurance, which in turn is dominated by business interruption and public liability, and to a lesser extent employer's liability insurance. PNGL states that these costs are assumed to be driven by changes in company turnover and therefore would need to be calculated on the basis of the final allowable income derived.

6.466 The business insurance costs requested by PNGL represent a significant increase on historical premiums. For example, the increase between 2014 actuals and the request for 2017 is over 30%. PNGL has stated that that there are risks associated with its insurance costs, in particular the premium related to business interruption, which is very specific to the PNGL network.

6.467 It should be noted that in PNGL12, we adopted the approach used by Ofgem to base business insurance costs on 1.04% of turnover. We have decided not to use this approach to set allowances for PNGL in the GD17 period as doing so would result in significantly lower allowances. OFGEM in RIIO GD1, moved away from the link in setting insurance to revenue, indicating that due to its specialist nature, a variety of factors can influence the premium paid.

6.468 In the draft determination we did not view that PNGL's arguments provided sufficient rationale for why premiums are expected to increase over time. We also noted that the historical trend for actual insurance costs has not increased year-on-year, indeed it has reduced since 2012. We therefore continued with the approach of granting a business insurance allowance based on a 3-year average of the actual costs incurred during 2012 – 2014. We believe this approach is more reflective of market conditions of the insurance market, which can vary based on circumstances not directly related to operational performance.

6.469 In its response to the draft determination PNGL stated that '*UR is proposing to grant PNGL a business insurance allowance based on a three-year average of the actual costs incurred during 2012 to 2014. PNGL's GD17 business insurances are driven by inflation, turnover, capex and number of employee's. PNGL's business insurance requirements will therefore flex with the outputs of UR's final determination*. *PNGL has no scope to reduce the car insurance premiums further. The allowances provided by the UR should be sufficient to cover the actual premiums paid by PNGL. PNGL would request UR to reconsider its proposal on this basis*'.

6.470 For the final determination we have maintained our view that the 30% increase between 2014 actuals and the request for 2017 has not been justified We have used an average over 3 years costs, which differs from using the 2014 year, to reflect the variability of the insurance market on premiums. We believe this approach is more reflective of market conditions of the insurance market, which can vary based on circumstances not directly related to operational performance.

6.471 PNGL's requested allowance for car insurance is marginally under £1.5k per annum per car. We consider this to be unreasonably high when compared to the other GDN's requested allowances. The AA's average premium for annual comprehensive car insurance in Northern Ireland for Q4 2015 was around £750. We propose to grant an allowance of £750 per car in the final determination to an assumed fleet of around 65 cars.

6.472 Finally, for building insurance costs, we have granted allowances on the same basis of GD14, which in overall terms, is a relatively small area.

6.473 Our final determined allowances for 2017 - 2022 which are unchanged from the draft determination and are shown in Table 78 below along with PNGL's requested allowances and the variance between the two.

6.474 We have re-allocated some of the costs under Insurance to be recovered under the Connection Incentive / AMPR (OO) as we consider that some of Insurance will be used for Advertising and Marketing for domestic Owner Occupied connections. This is consistent with our approach in GD14.

	2017	2018	2019	2020	2021	2022
PNGL requested allowances	910	930	911	971	991	1012
UR FD before re-allocation	798	798	798	798	798	798
Re-allocation to AMPR (OO)	8.6	8.6	8.6	8.6	8.6	8.6
UR Final Determination	789	789	789	789	789	789
Variance	112	132	113	173	193	214

Table 78: Insurance Costs, Requested and Allowed, £k

Procurement

6.475 This cost category covers the procurement of goods & services in the support of the business operations, through the management of procurement contracts with suppliers.

6.476 The costs collated under Procurement should include:

- The cost of carrying out market analysis;
- Identifying potential suppliers, undertaking background review, negotiating contracts, purchase order fulfilment and monitoring supplier performance;
- Setting up and maintaining vendor accounts within the accounting system, and maintaining e-procurement channels;
- Setting procurement guidelines and monitoring adherence to the guidelines.

6.477 PNGL procurement costs are driven by staff costs. In the 2014 year PNGL had procurement costs of £72k. PNGL had 2.4 FTEs employed within the Procurement cost category in 2014 and has not proposed any increases in this area for the GD17 period.

6.478 Our final determination allowances for Procurement are unchanged from the draft determination. We have based the Procurement cost allowance for GD17 on the 2014 FTEs and using 2014 staff costs.

6.479 We have re-allocated some of the costs under Procurement to be recovered under the Connection Incentive / AMPR (OO), as we consider that some of PNGL's Procurement function will be used for Advertising and Marketing for domestic Owner Occupied connections. This is consistent with our approach in GD14.

	2017	2018	2019	2020	2021	2022
PNGL requested allowances	73.5	74.8	75.3	74.8	74.9	74.9
UR FD before re-allocation	71.1	71.1	71.1	71.1	71.1	71.1
Re-allocation to AMPR (OO)	10.7	10.7	10.7	10.7	10.7	10.7
UR Final Determination	60.4	60.4	60.4	60.4	60.4	60.4
Variance	13.1	14.4	15.4	14.4	14.5	14.5

Table 79: Procurement, Requested and Allowed £k

CEO & Group Management

6.480 The costs collated under CEO & Group Management should include:

- Communications – communication within the UK businesses, internal communications, external communications, media relations, issues management, regional communications, community relations, community awareness, branding, events management;
- Group Strategy – function which has the responsibility of evaluating the strategic options of the Group;
- Legal/Risk and Compliance/Company Secretary – legal department, the management corporate governance for all companies to ensure they comply with legislation, regulations and best practice;
- Corporate Responsibility and Investor Relations – corporate responsibility and interaction with institutional equity investors and market analysts, management of rating agencies, advertising, charity and sponsorship arrangements;
- Board Members and Other – staff and other costs of Board members and other corporate costs not fitting into other categories;
- Incremental ring-fence compliance; and
- Credit reference agencies.

6.481 PNGL CEO & Group Management costs are driven by the senior management team costs as well as professional and legal fees together with stationary, communications and billing costs. The number of FTEs PNGL has allocated for the GD17 period is consistent with that in 2014 at 3.9 FTEs.

6.482 Our final determination allowances for CEO & Group Management are unchanged from the draft determination. We have retained remuneration for the senior management team at the levels determined in GD14 and rolled forward. We have also rolled forward 2014 actual costs for professional and legal fees as well as stationary, communications and billing costs.

6.483 In its response to the draft determination PNGL stated that '*UR's proposed allowance for the PNGL Management Team is based on outdated analysis performed in 2011 and results in allowances c.42% less than PNGL's forecast costs and potentially c.52% less once you take into account the impact of the allocation methodology employed as part of the connection incentive mechanism. PNGL would therefore urge UR to reconsider its current proposal as it is entirely inconsistent with actual costs incurred as dictated by market conditions*'.

6.484 We consider that the Benchmark used for the PNGL Management team is appropriate, based on no significant change in market conditions.

6.485 We have re-allocated some of the costs under CEO & Group Management to be recovered under the Connection Incentive / AMPR (OO), as we consider that some of CEO & Group Management including the Sales Director will be used for Advertising and Marketing for domestic owner occupied connections. This is consistent with our approach in GD14. We have also re-allocated part of the Sales Director costs to the non-OO cost category as we consider that they will spend a portion of their time on this activity

	2017	2018	2019	2020	2021	2022
PNGL requested allowances	1883.6	1897.6	1897.7	1897.9	1898.0	1898.2
UR FD before re-allocation	1228.2	1228.3	1228.3	1228.3	1228.3	1228.3
Re-allocation to AMPR (OO)	159.5	159.5	159.5	159.5	159.5	159.5
Re-allocation to AMPR (non-OO)	91.6	91.6	91.6	91.6	91.6	91.6
UR Final Determination	977.3	977.3	977.3	977.3	977.3	977.3
Variance	906.3	920.3	920.4	902.6	920.7	920.9

Table 80: CEO and Group Management Costs, Requested and Allowed, £k

Stores & Logistics

6.486 The Stores and Logistics cost category covers the activity of managing and operating stores.

- The costs collated under Stores & Logistics should include:
- Delivery costs of materials or stock to stores;
- Labour and transport costs for the delivery of materials or stock from a centralised store to a satellite store/final location (and vice versa), taking into account the stock management policies;
- Monitoring stock levels; and
- Quality testing of materials held in stores.

6.487 We have accepted PNGL requested allowances for stores and logistics for GD17.

	2017	2018	2019	2020	2021	2022
PNGL requested allowances	29.8	29.8	29.8	29.8	29.8	29.8
UR Final Determination	29.8	29.8	29.8	29.8	29.8	29.8
Variance	0	0	0	0	0	0

Table 81: Stores and Logistics Costs, Requested and Allowed, £k

Other Area

Trainees & Apprentices

6.488 This cost category covers (i) the costs of any operational training and (ii) the cost of training any employees engaged on approved formal training or apprentice programmes (either operational or non-operational).

6.489 The costs collated under Training & Apprentices should include:

- Cost of staff who organise and provide training, and maintain the individual employee training/apprentice records;
- Cost of running training courses;
- Fees paid to external training providers for provision of training;
- Cost of externally advertising training and apprentice programmes;
- Salary cost of apprentices or trainees whilst engaged on a training or apprentice programme; and
- Cost of ongoing professional development for operational staff.

6.490 PNGL has not proposed any costs under this category and this is consistent with PNGL historical information. Therefore we have not provided for any costs under this category.

<u>Non-Controllable Opex</u>

6.491 The only costs shown under non-controllable opex are licence fees. We have accepted PNGL forecast costs for licence fees. Any difference between forecast licence fees and actual licence fees will be taken account of by the uncertainty mechanism in GD23.

	2017	2018	2019	2020	2021	2022
PNGL requested allowances	115.5	115.5	115.5	115.5	115.5	115.5
UR Final Determination	115.5	115.5	115.5	115.5	115.5	115.5
Variance	0	0	0	0	0	0

Table 82: PNGL Non-controllable Opex Costs, Requested and Allowed, £k

<u>Supplier of Last Resort</u>

6.492 With regard the Supplier of Last Resort (SOLR) we believe that there is merit including an allowance to cover any unforeseen costs that may occur, if an event were to happen. This amount is ring fenced and will be removed at the time of the next price control, if an incident fails to materialise. For the GD17 final determination we have allowed £300k for these costs in 2017 only.

Capitalised Opex

6.493 For the GD17 final determination we have accepted PNGL capitalisation rates.

East Down

6.494 In relation to East Down we have previously informed PNGL that we did not plan to allow a specific additional opex allowance for 2015 and 2016 other than connections allowances which will be reflected in the GD14 uncertainty mechanism. For GD17 the costs proposed above include East Down. Costs such as manpower which are related to the bulk mains are properly capitalised in such a project and are all included in Chapter 7.

6.495 Further detail is provided on East Down from paragraph 11.114.

Summary of Bottom-up Assessment Findings

6.496 Table 83 summaries the GD17 final determination cost allowances for PNGL. The costs for each category are net of any re-allocation of costs to the advertising and marketing (owner occupied) cost category.

Cost item	2017	2018	2019	2020	2021	2022	Total
Asset Management	216.7	216.6	216.6	216.6	216.6	216.6	1,300.0
Operations Management	509.3	508.9	508.7	508.6	508.5	508.3	3,052.2
Emergency Call Centre	444.6	451.0	461.3	471.9	475.3	490.3	2,794.6
Customer Management	635.8	636.4	637.1	638.0	638.6	639.2	3,825.1
System Control	110.2	110.2	110.2	110.2	110.2	110.2	661.4
Emergency	1,289.7	1,315.8	1,355.4	1,396.0	1,408.5	1,466.6	8,232.2
Metering	1,062.6	1,100.6	1,094.6	1,111.5	1,111.5	1,185.2	6,665.9
PRE Repairs	446.7	457.6	469.8	482.3	491.0	505.0	2,852.7
Maintenance	1,349.2	1,397.4	1,389.7	1,411.3	1,411.3	1,504.8	8,463.6
IT & Telecoms	438,9	437,9	438,2	438,2	438,1	439,2	2,630.8
Property Man	2,520.7	2,625.2	2,704.9	2,783.8	2,851.0	2,933.3	16,419.1
HR & Non-Ops Training	214.2	214.2	214.3	214.3	214.4	214.4	1,286.0
Audit, Fin and Regulation	863.6	863.4	863.4	863.2	863.8	863.8	5,181.5
Insurance	789.2	789.2	789.2	789.2	789.2	789.2	4,735.2
Procurement	60.3	60.4	60.4	60.4	60.4	60.4	362.4
CEO & Group Management	977.2	977.3	977.3	977.3	977.3	977.3	5,863.9
Stores and Logistics	29.8	29.8	29.8	29.8	29.8	29.8	178.8
Connection Incentive (OO)[78]	2,043.5	1,904.1	1,800.9	1,668.9	1,571.8	1,447.2	10,436.6
AMPR (non-OO)	443.6	443.6	443.6	443.6	443.7	443.7	2,661.8
Non Controllable Costs	115.5	115.5	115.5	115.5	115.5	115.5	693.2
SOLR	300.0						300.0
Total: Pre-Efficiency	**14,861.9**	**14,655.5**	**14,681.6**	**14,731.0**	**14,727.0**	**14,940.5**	**88,597.6**
Frontier Shift[79]	0.992	0.984	0.976	0.969	0.963	0.956	
Total: Post Efficiency	**14,736.8**	**14,421.5**	**14,331.3**	**14,280.9**	**14,179.3**	**14,286.4**	**86,236.3**

Table 83: PNGL GD17 Opex Final Determination Pre and Post Efficiency, (£k)

Real Price Effects, Productivity and Frontier Shift

Overview

[78] Referred to as AMPR (OO) in the draft determination.
[79] As discussed in Table 25

6.497 A detailed explanation of the precise make up of our overall RPEs and assumed productivity increase is contained in Annex 6 – Real Price Effects and Frontier Shift: Final Determination GD17.

Net Impact

6.498 Once we apply our frontier shift to a pre-efficiency opex we derive our final determination opex profiles, net of frontier shift, as shown in Table 83.

SGN – UR Decisions

Overview

6.499 For SGN we did not set any efficiencies for opex given our judgement that its licence application figures included efficiency.

Top-Down Assessment

6.500 SGN do not have any years of actual operational data as yet; therefore we have excluded them from our top-down opex benchmarking analysis.

6.501 Further explanation of the methodology used by the Utility Regulator is within the GD17 final determination's Annex 5: Top-Down Benchmarking.

Bottom-up Assessment

Overview

6.502 As previously outlined in Section 4, SGN was awarded a licence for G2W area in February 2015. As a result of this competitive process, the overall opex allowances do not follow the exact same structure as the other GDNs, but are broken down into 3 distinct areas as follows:

6.503 The structure of this section reflects three main periods:

- The Mobilisation Period i.e. the period from licence grant up to First Operational Commencement Date (FOCD). FOCD is programmed to be in 2018 and we have assumed mobilisation costs will run until 1 January 2018;
- The period associated with the early section completion of Strabane until the start of the price control on 1 January 2018. This overlaps with the mobilisation period;
- SGN's GD17 price control period which covers the period 1 January 2018 to 31 December 2022.

6.504 We will now in turn go over each section of the request made and make a consideration of the comments made.

Mobilisation Period

<u>SGN Proposals</u>

6.505 The opex costs to be included within applicants' submissions for G2W included two main elements; mobilisation costs, which related to all opex incurred after the award of the licence until FOCD (First Operational Commencement Date), and opex costs from the FOCD.

6.506 Paragraph 3.20 of the G2W Applicant pack stated "*opex costs will be allowed from the FOCD (First Operational Commencement Date) of the pipeline. All costs in advance of this should be included in the application*", and this was further clarified in Annex 7 'High Pressure Workbook Notes' and Annex 8 'Low Pressure Workbook Notes' of the associated rulebooks. The Annex 8 'Low Pressure Workbook Notes' is relevant to SGN since it covers the low pressure pipeline.

6.507 In our GD17 final approach document we stated "*that the timing of when the SGN price control would come into effect has also been considered. It has been decided that this will come into effect from the 1 January 2018. This is to coincide with the expected operational commencement date of the High Pressure pipeline in Q4 2017 and also ties into the 5 year price control period of the applicant pack*".

6.508 In its response to the draft determination SGN stated the following in relation to mobilisation costs '*SGN Natural Gas would like to reiterate our position concerning the mobilisation dates. As previously discussed in response to supplemental question DD-019 (Post Draft Determination) April 2016, throughout the bid process and the submission, SGN Natural Gas have taken the mobilisation date to end on First Operational Commencement Date (FOCD), as stated in the bid application pack (page 3, Annex 6) and further understood this date to be the date that gas was first available, which is scheduled for Strabane in October 2016. However from the draft determination it is stated that FOCD is currently envisaged to be Q4 2017. SGN Natural Gas is of the opinion that this would be Full Operational Commencement Date and the time between the two dates will in effect be the first year of business as usual'*.

6.509 UR disagrees with this view. The FOCD is defined in the high pressure licence, as is Early Section Completion which was drafted specifically with Strabane in mind and clearly takes place before FOCD. The term 'Full Operational Commencement Date' referred to by SGN was not defined or used in any UR documentation. Furthermore, if mobilisation was to end in 2016 then, by extension the price control should start then and SGN has not made this argument.

6.510 The FOCD for the G2W project is scheduled to be in 2018 when the high pressure pipeline is complete, providing access to all the towns in the SGN licence area. For the purposes of GD17 we assume that mobilisation will end on 1 January 2018 at the start of the price control.

6.511 Annex 8 'Low Pressure Workbook Notes' of the G2W Applicant pack stated that "*mobilisation costs relate to all opex incurred after award of the licence until FOCD (First Operational Commencement Date). These costs include:*

Manpower costs

Office costs

Insurance costs

Professional and Legal Fees

Information Technology (IT)

Miscellaneous Costs;

and that it should be noted that all IT costs will be considered to be opex; there will be no allowance for capex IT".

6.512 In its successful G2W application SGN submitted mobilisation costs of £1.0m. In its GD17 business plan submission it has proposed to increase these to £3.7m.

6.513 Table 84 provides an overview for SGN's rationale contained within its GD17 business plan submission for its proposed increase in mobilisation costs. There are four main areas were SGN are seeking increased allowances within mobilisation costs; IT costs, transition team, delay in the start of GD17 and 'sales and marketing'. For each of these areas we have set out what SGN said in its G2W licence application, what SGN said in its GD17 business plan submission and our position for the GD17 final determination which is unchanged from the draft determination.

	£m	SGN rationale for change
Mobilisation Costs as per bid	1.0	
Additional IT costs	0.6	Originally assumed an industry solution for the Network Code systems, still in discussion with the NI GDN's but this is likely to be difficult in the short term. Have included bespoke G2W solution in the business plan
Transition team	0.6	Additional costs relating to development of a network design and supporting analysis to develop the business plan. Additional regulation and finance support for the GD17 process. This work was not anticipated to be at such an early stage and it was assumed work would be picked up by the business as usual core team.
Revised Mobilisation Opex	2.1	
Delay in the start of GD17 (2017 costs)	0.9	2017 is largely a business as usual year and the bid assumed this, however the price control is now commencing a year later in 2018.
Sales and Marketing (2017 costs)	0.6	Our enhanced sales and marketing activity will commence prior to GD17.
Total & Marketing (2017 costs)	3.7	

Table 84: SGN Rationale for Increased Mobilisation Allowances

IT costs – SGN G2W Application

6.514 Within its G2W application SGN stated the following in relation to IT costs:

"*While we will look to migrate to our existing IT systems in managing Meter Asset management. (MAM) services, supplier interfaces and other aspects of asset management, it is our intention to introduce cost effective systems that are simple and fit for purpose and to transition to core systems over time as the network develops and the number of connections and interactions increase.*

These systems will have the capability to generate relevant management information to support the efficient operation of our network assets in NI. We will also utilise other existing applications to provide performance management information (eg, accident and incident metrics; and effectiveness of occupational and process safety risk control systems (via leading and lagging indicators).

Our existing financial recording and reporting systems support the customisation of reports at the required level of granularity to satisfy the needs of all tiers of management (by activity, location, manager, process etc). We will employ these systems to create a bespoke suite of reports and metrics for dissemination to managers – to allow the ongoing monitoring and assessment of financial performance and operating/cost efficiency.

We do not envisage a requirement for any additional external support services. We will put in place suitable MSAs for those areas where our NI business utilises services from SGN.

We will scale our IT systems to be appropriate for the number of customers being served, with support provided through our existing SGN support structures in order to minimise operational support costs

IT operating costs cover the ongoing support of the depot and core IT systems. A 5% cost for the upgrade of all systems has been factored into year 6 of the IT costs. On-site IT support is also included as this will be part of a bought-in service".

IT Costs – SGN GD17 Business Plan

6.515 Within its GD17 business plan submission SGN rationale for the proposed increase in IT costs is that "*our increased development plan which will facilitate a forecast penetration rate of 20% across the GD17 period will require strong and robust IT systems to deliver the required level of business support to meet customer and Licence demands. By bringing the opportunity to connect to the natural gas network to many more customers our IT requirement must match this increased demand*".

"*The increased forecast in customer numbers under our six year build programme will require increased IT investment especially in the area of systems to support the Network Code and customer switching requirements. IT investment as specified in our business plan is a crucial determinant to successfully deliver the customer numbers and volumes which are the foundation of the economics of the whole project.*

We have analysed our IT requirements, subsequent to the original bid submission, in greater detail and have concluded that significant investment is required in the systems to support asset management activities and systems to support the Network Code obligations".

IT Costs – Utility Regulator Final Determination.

6.516 We have considered the SGN request against the criteria which were set out in the AIP and discussed in Chapter 4. We have not seen any strong reason to conclude that such costs were unforeseen.

6.517 SGN in page 89 of their GD17 business plan submission state that that they "*have analysed their IT system requirements in more detail since the bid and have concluded that more IT investment is required to support asset management activities and to support network code and customer switching requirements*".

6.518 Our view is that it was up to SGN to identity the full costs of any IT systems it deemed necessary for G2W at the time of the licence application. The analysis that SGN has undertaken since being awarded the licence could have been undertaken when SGN formulated its licence application.

6.519 Furthermore we would expect that investments in an IT system would provide robust long term capability for the network and do not accept that increased customers in the development plan would justify any significant changes in IT costs.

Transition team – SGN G2W Application

6.520 Within their licence application SGN stated the following in relation to the transition team.

"*our mobilisation activities relate to all the activities up to the FOCD (First Operational Commencement Date) and this included the following objectives.*

Establish the business

Design of the network

Establish external and governmental relationships

Establish contracts

Establish business partnerships".

Transition team – SGN GD17 Business Plan

6.521 Within its GD17 business plan SGN has stated the following to justify the increase in transition costs "*these are additional costs that relate to activities associated with the development of a network design and supporting analysis required to develop this GD17 business plan. They also include costs associated with the regulatory and finance activities required as part of this price control process*". SGN consider that these costs amount to an increase of £0.6m in comparison to their G2W application.

6.522 SGN within their GD17 business plan submission further stated that "*this work was not anticipated at for this stage in the bid. It was assumed this work would be picked up by the SGN Natural Gas team as business as usual following mobilisation. We had also anticipated the lead time for development of our business plan would be significantly longer, as experienced in GB and by other Northern Ireland by other GDNs. Given shorter lead times we have had to secure additional support from SGN*".

Transition Costs – Utility Regulator Final Determination

6.523 The AIP was clear that mobilisation costs should include all opex up until the FOCD. There was no reason to suggest that SGN would not be involved in a price control or significant design work in the early stages of the project and we see no basis to describe this as unforeseen. We consider that it is matter for SGN to decide what resource they wish to use on issues relating to network design and price control issues and it was up to SGN to provide appropriate opex costs within their G2W Application.

6.524 Consequently we are not providing any additional transition cost allowances for the draft determination.

Delay in the start of GD17 – SGN GD17 Business Plan

6.525 SGN have said the following in their GD17 business plan in relation to the start date of the GD17 period as it pertains to SGN ie 1 January 2018, "*2017 is largely a business as usual year and the bid assumed this, however the price control is now commencing a year later in 2018. SGN are citing increased costs associated with meetings with the UR*" etc. SGN consider that the cost of the delay to the start of GD17 is £0.9m.

Delay in the start of GD17 – Utility Regulator Final Determination

6.526 As set out in paragraph 6.511 above the AIP was clear that all costs before the FOCD should be included within mobilisation costs.

6.527 Therefore all costs up to 2018 are included within the SGN mobilisation licence application figure and all costs from 2018 will be included in GD17 opex.

Sales and Marketing – SGN G2W Licence Application

6.528 SGN in relation to Sale and Marketing stated the following within their G2W Licence Application "*we will have a small internal team focused on marketing and sales, predominantly managing relationships with third parties. The majority of these costs will be absorbed by the owner occupier incentive. These costs have been excluded from the input to the workbook and this has been outlined in the analysis in Annexe B. The remaining costs which form part of the stated marketing allowance relate to the staff required to liaise with larger industrial and commercial customers, NIHE and new housing providers.*

We will engage with local partners from the private, public or third sectors to help us complete appliance installations, shape our marketing incentives and identify areas or communities requiring connections. We will use their skills to provide advice and promote energy efficiency grants, or work with them to build their skills and competencies in gas utilisation such that they can be directed towards appliance installation services, encouraging potential commercial and domestic consumers to switch to gas.

This will be the means by which we will meet (and outperform) the expected pattern of connections and we will develop the necessary strategic alliances or partnership arrangements to enable this.

By drawing on our group strengths we will create a separate unique brand identity for our licenced business in NI. We will engage locally with businesses by hosting events and seminars in each of the towns, designed to inform the business community and encourage connection applications".

Sales and Marketing – SGN GD17 Business Plan

6.529 Within its GD17 business plan submission SGN stated the following to justify its proposed increased 'sales and marketing' costs:

"*we require additional resources of £0.6m in comparison to the bid to advance our sales and marketing plans particularly given the absence of third party funding which we assumed would be available when we submitted the bid*".

6.530 SGN consider that additional resources and therefore increased cost allowances are required both for domestic owner occupied, and other customer groups such as NIHE and Industrial and Commercial properties.

6.531 SGN have also stated that "*increased costs are primarily a result of the significant reduction in oil prices and downturn in economic outlook. Additional advertising and customer support is needed to help customers connect and ensure we deliver penetration rates of 20%. This strategy also supports our accelerated development programme and maximises opportunities for customers to connect sooner and realise the benefit of natural gas*".

6.532 SGN have stated that "*they are concerned the development plan would mean a significant number of customers would be disappointed and not be able to connect for a* *further 5 to 10 years. This is likely to result in some of the significant I&C customers making alternative investment decisions and a significant proportion of domestic customers being lost for a further 15 to 25 years. We believe it would be remiss of us to build on the positive publicity around G2W and maximise opportunities to benefit from a reliable, affordable, low carbon energy source*".

6.533 SGN have also stated that "*for a new start up business a significant amount of expenditure will be required up front e.g. on customer meetings, providing technical support and direct financial support. Support is likely to be required significantly in advance of connection*".

6.534 A key aspect of the SGN rationale for the proposed cost allowances for sales and marketing is that it considers that there has been a significant change in the market in terms of the gas / oil price differential and therefore part of section 2.4.2. of the G2W final determination should apply i.e. "*we will consider requests for different allowances where these are the result of unforeseen significant changes in the market since the application was submitted*".

6.535 In summary we consider that SGN have put forward three main points to argue for increased allowances 'for sales and marketing' in the mobilisation period. SGN have also used these same points to argue for increased 'sales and marketing' allowances in the GD17 period.

6.536 The main three points are:

- A worsening economy since SGN submitted their G2W application; and
- The impact of the worsening economy on third party funding which SGN assumed would be available when they submitted their G2W application.
- The current oil / gas price differential

6.537 Our view of each of these three arguments put forward by SGN is considered below.

Utility Regulator's View on SGN Argument on 'Third Party Funding and Economy'

6.538 We have considered SGN's points on economic conditions and third party funding together since SGN consider the points are related.

6.539 We do not agree with SGN's rationale that the economy in Northern Ireland has materially changed since SGN submitted their G2W licence application and we have seen no strong evidence to justify this statement.

6.540 For example if there had been a material change in the economy this might have been apparent through decreased gas consumption in the existing gas network areas in Northern Ireland and indeed in volumes of water and electricity used in particular by businesses. We have not observed that this is the case.

6.541 In relation to third party funding we consider that it was SGN's choice on what assumptions it made in relation to the extent of any third party support it would receive during the development of the G2W network. The fact the assumptions SGN made in terms of third party funding at the time of its licence application appear not to have materialised is an issue for SGN to resolve.

Utility Regulator's View Oil / Gas Price Differential

6.542 As discussed above the hurdle UR has put in place for moving away from the licence application figures is high. We will consider whether the change in the oil/price differential has resulted in an unforeseen significant change in the gas market.

6.543 In order to assist us we have considered Figure 9 below which sets out the trend in retail oil prices, retail gas prices and domestic owner occupier connection levels in the PNGL area since 2005.

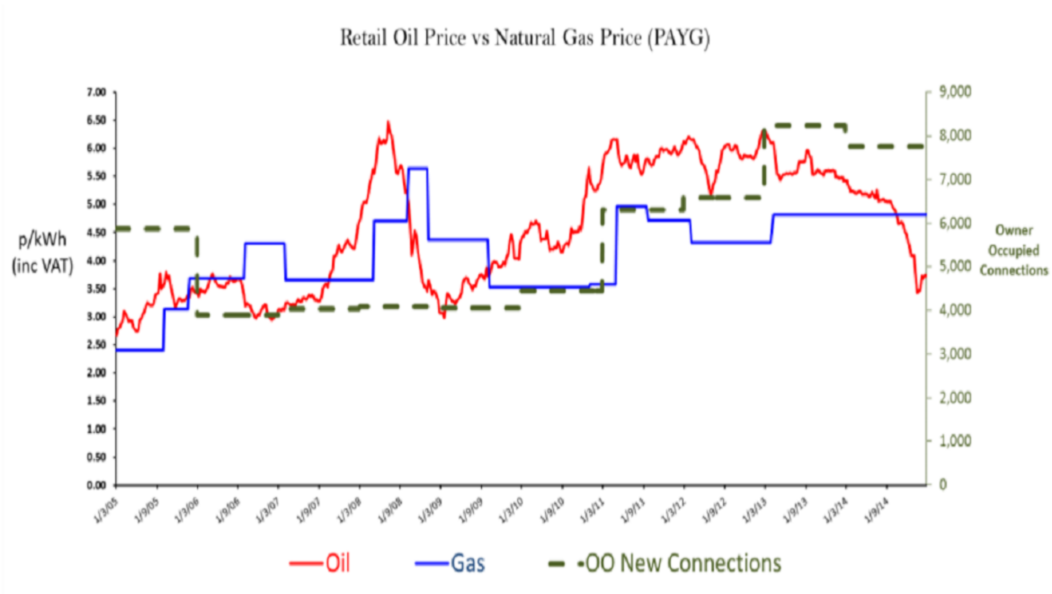

Figure 9: Oil and Gas Price in PNGL Area

6.544 This graph suggests a number of things:

- There have been a number of historic periods where retail oil prices have been cheaper than gas;
- The oil price tends to be more volatile than gas retail price which tends to follow at a lag to the oil price. There is no reason to think that this volatility in the differential over time will not continue in the long run.
- While there is likely to be some connection between the oil/gas price differential and connections there is no evidence here that the link is the primary driver for growth in the gas industry. We also note that in advertising the benefits of gas PNGL and FE have put significant weight on the lifestyle benefits and not overly focused on price.
- The retail price of gas in the SGN area is likely to be somewhat cheaper than in the PNGL area (based on network charges being cheaper) and so the graph above would overstate the issue for SGN. For our final determination the SGN distribution tariff is c11ppt lower than that for PNGL.[80]

6.545 In addition to the number above we note that the OO gas connection numbers in the FE area (not presented in Figure 9) were at a record high in 2015 and a significant number of larger industrial and commercial customers have continued to connect to gas in recent times when oil has been cheaper.

[80] Based on P1 tariff i.e. up to 2500 terms pa.

6.546 In terms of the change in oil/gas price being unforeseen we understand the point that SGN has made in this regard to the extent that it is difficult for any party to foresee how commodity markets will develop. However we do not think the concept of the oil/gas differential moving over time could be describe as unforeseen and this is demonstrated by Figure 9 above.

6.547 Indeed we could apply the same principles to the finance markets where it can be very difficult to foresee changes. This approach could in theory lead us to reviewing the WACC figures proposed by SGN and use latest market figures e.g. risk free rate. We think this example usefully highlights that should the barrier to changing G2W licence application figures be low then these matters would have to be given further consideration. However UR continues to be of the view that the barrier to such changes rightly remains high to protect the integrity of the G2W application process.

6.548 In addition the fact that we have included condition 4.2.8 in the SGN licence, which deals with under recoveries and was specifically put in place to facilitate managing events such as gas been cheaper than oil, emphasises that this type of event was not unforeseen.

6.549 Considering whether this is a significant change in the gas market we would accept that the current oil/price differential is one factor in the growth of the gas industry. However 10,000 customers spent up to £3k in 2015 to move from oil to gas at a time when gas was more expensive. Clearly gas is seen as a superior product to oil and we would not support the view that the oil/price differential is a fundamental driver of growth in the gas industry.

6.550 Therefore for the reasons set out above, while we do not discount that the oil/gas price differential has an impact, we are not convinced that the change in the oil/price differential represents an unforeseen and significant change in the gas market.

6.551 We have considered the arguments and challenges SGN faces in connecting customers further in Advertising & Market Development (OO Properties).

<u>Sales and Marketing – Utility Regulator Final Determination</u>

6.552 Taking into account the criteria set out in the AIP and for the reasons we previously outlined we are not convinced that the arguments set out by SGN amount to a significant unforeseen change to the gas market and justify UR reopening the figure submitted by SGN in its licence application.

6.553 In addition to the considerations set out above we would also note that a significant element of the SGN request to adjust the licence application figures relates to incentivising the industrial and commercial business. As set out in paragraph 4.36 above the AIP was particularly clear on this point stating that "*Only if the successful applicant has included such incentives in their application will these be funded by price control allowances*".

6.554 We don't consider it appropriate to change from a figure provided by SGN for incentives for non-owner occupied customers which was submitted as part of a competitive application. This is particularly true in the circumstances where the other applicants included substantially higher incentive costs than SGN.

6.555 Therefore we have only allowed 'sales and marketing' costs for these groups as submitted in the SGN licence application.

Summary of Utility Regulator's View on SGN's Proposed Increase in Mobilisation Costs

6.556 For the draft determination we set out that we did not accept SGN's rationale for the proposed increase in mobilisation costs of circa £2.7m versus its G2W licence application figures

6.557 In our view the G2W AIP and subsequent final determination was very clear in relation to mobilisation costs (including 'sales and marketing' costs). The AIP made it clear that mobilisation costs covered all costs up to the FOCD (First Operational Commencement Date).

6.558 Overall we are not convinced that there is a compelling argument to justify changing the mobilisation figures from those submitted in the G2W licence application and consequently our final determination allowances are unchanged from the G2W licence application and indeed the draft determination.

The period associated with the early section completion for the High Pressure (HP) mains i.e. Strabane.

6.559 There are costs associated with the early section completion i.e. Strabane, which is scheduled to have its first gas customer by Q4 2016.

6.560 The treatment of these costs will be dealt with under licence condition 4.4.5 (d) (i) of the licence for SGN states "*the following provisions shall apply to the first Periodic Review alone:*

The value of TRVn used for the purposes of the first Periodic Review (the opening asset value) shall be a value approved by the Authority as reflecting the Capital Expenditure and Operating Expenditure indicated in the Application Pack, where relevant, as to be incurred by the Licensee in the period up to 1 January 2018, and which is reasonably incurred by the Licensee during that period".

6.561 We consider that there are four main categories of costs relevant to Strabane in the pre First Operational Commencement Date period:

- <u>Licence fee and rates:</u> we have used the 2018 costs as a proxy for these costs and this gives a figure of £100k;

- <u>OO connection incentive:</u> We have assumed 186 OO connections will be made before 1 Jan 2018. Multiplying this with an allowance of £1110 = £206k. We assume that these connections are made in 2017;

- <u>2017 costs:</u> In the GD17 draft determination we increased the G2W bid opex to reflect a higher number of connections compared to the G2W AIP. Applying a similar principle to 2017 costs would provide for an increase of costs of circa £126k. As an alternative proxy using the forecast change in km provides for a figure of circa 225k. We have therefore determined that a figure of £200k for 2017 is appropriate as we recognise that neither of the two proxies is fully robust but a figure between the two proxies is likely to provide for a rationale estimate of costs.

- <u>2016 costs</u>: We have determined 2016 opex costs for Strabane of £50k which was calculated by taking the estimated 2017 costs and multiplying this by ¼ to reflect the assumption that Strabane will commence on Q4 2016.

6.562 Thus our final determination for these costs to be included in the OAV is £1.56m. See Chapter 9.

6.563 It should be noted that the OAV will be corrected to reflect actual costs as part of the GD23 price control in line with the Uncertainty Mechanism in Chapter 9.

SGN Price Control opex costs (2018 – 2022)

<u>Overview</u>

6.564 The structure of this section differs to the comparable section for FE and PNGL as the format issued to applicants for the G2W application aggregated some of the cost categories found in the GD17 Business Plan Template (BPT). In addition manpower costs within the G2W application where shown as a separate line whereas in the GD17 Business Plan Template they are included within the opex cost categories.

6.565 We asked SGN to provide their G2W application figures in a format consistent with the GD17 Business Plan Template to facilitate comparison with their GD17 Business Plan submission and this is shown in Table 85.

6.566 For the draft determination we were not convinced that the SGN response had correctly identified the appropriate opex figures from the G2W application to facilitate a meaningful comparison to their GD17 BP submission. We considered that this may have arisen, due to the SGN interpretation of the timing of the FOCD and the costs associated with this. We said we would review this further for the GD17 final determination and this is discussed in section 6.509

6.567 We have also considered the responses made by SGN and have made further consideration in the following areas:

- Costs that are related to the Network Design
- Connective Incentive 'New Area' allowance

<u>SGN G2W Application (GD17 Period)</u>

6.568 The mobilisation and pre GD17 costs within the SGN G2W application amounted to £1m. The SGN GD17 costs amounted to £6.1m and therefore the total amount in the SGN G2W application was £7.1m for both mobilisation and GD17 opex costs.

	2018	2019	2020	2021	2022	Total
Senior management	194.295	198.677	199.825	199.148	197.122	**989.068**
Operations	56.414	56.414	56.414	56.414	54.399	**280.054**
Marketing and Admin	53.392	72.532	84.621	93.687	102.754	**406.986**
Emergency Call Centre	0.028	5.066	8.401	10.975	13.519	**37.988**
Emergency	31.020	58.386	78.461	93.885	104.009	**365.759**
PRE Repairs	4.267	6.584	8.118	9.302	10.001	**38.272**
Maintenance	36.301	74.460	65.964	69.085	72.370	**318.181**
IT and Telecoms	19.878	19.878	19.878	19.878	19.878	**99.391**
Property Management	34.251	34.251	34.251	34.251	34.251	**171.256**
Insurance	18.311	18.311	18.311	18.311	18.311	**91.557**
CEO & Group Management	33.294	33.294	33.294	33.294	33.294	**166.471**
Connection Incentive[81] (OO)	211.252	330.222	397.716	398.551	380.074	**1,717.814**
Rates and licence	100.014	269.326	308.745	347.993	387.160	**1,413.237**
Total	**792.718**	**1,322.620**	**1,391.723**	**1,283.584**	**1,344.008**	**6,096.035**

Table 85: SGN Opex Application for GD17 Period for G2W in GD17 Business Plan Template format (Dec 2014 Prices), £k

SGN GD17 Business Plan Submission

6.569 The SGN business plan submission for the GD17 period shows significant cost increases versus the SGN G2W licence application - from £6.1m to £13m. Adding in SGN's increase in mobilisation costs from £1m to £3.7m, the total change in SGN's G2W application to the GD17 business plan submission is from £7.1m to £16.7m (dec 2014 prices).

6.570 In summary SGN has argued that the cost increases are due to the following reasons:

- The impact of the delay to the start of their price control period from 2017 to 2018
- Increased mobilisation costs
- Impact of the oil price / gas price differential on the SGN marketing strategy for customer connections
- Change in economic circumstances
- Change in the extent of third party funding from that assumed by SGN at the time of their G2W application.

6.571 Table 86 below shows the SGN GD17 business plan submission for the GD17 period. The start period of the SGN GD17 price control submission differs from the G2W AIP as

[81] Referred to as AMPR (OO) in the draft determination.

it made no reference for when the first price control would come into effect. In the event it will start in 2018 for SGN and therefore costs are shown from 2018 rather than 2017.

	2018	2019	2020	2021	2022	Total
Asset Management	30.031	57.242	63.520	68.402	73.320	**292.516**
Operations Management	168.477	176.222	176.046	176.662	176.737	**874.143**
Customer Management	18.958	18.958	18.958	18.958	18.958	**94.792**
System Control	53.173	36.494	36.494	36.494	36.494	**199.148**
Emergency	10.932	12.127	13.839	16.036	18.756	**71.690**
Metering	98.392	10.9139	124.553	144.325	168.802	**645.210**
PRE Repairs	4.275	5.198	6.521	8.219	10.320	**34.533**
Maintenance	39.013	73.784	117.990	153.862	187.227	**571.876**
Other Direct Activities	15.750	15.750	15.750	15.750	15.750	**78.750**
IT and Telecoms	97.384	98.570	97.786	97.786	97.786	**489.311**
Property Management	36.340	36.340	36.340	36.340	36.340	**181.700**
HR and Ops training	10.741	11.418	10.876	10.876	10.876	**54,788**
Audit, Fin & Regulation	81.613	82.513	81.833	81.912	81.807	**409.677**
Insurance	23.486	24.798	24.486	24.785	25.104	**122.660**
Procurement	7.379	7.844	7.472	7.472	7.472	**37.639**
CEO & Group Management	109.297	186.027	185.402	185.137	185.088	**850.950**
Connection Incentive (OO)[82]	1,497.373	1,559.513	981.161	1,033.997	1,216.973	**7,155.364**
Rates and licence	267.350	306.480	345.440	384.320	444.250	**1,747.840**
Total	**2,569.965**	**2,818.416**	**2,344.468**	**2,501.332**	**2,812.060**	**13,046 .242**

Table 86: SGN GD17 Business Plan Submission for the GD17 Period, £k

6.572 We have set out in detail in the mobilisation discussion above our views on these arguments and the same points apply to the GD17 opex points made by SGN.

6.573 However in addition to the points addressed above we did make clear in the AIP that *'if there are significant changes in expected supply points / consumption patterns between the licence application process and the setting of the first price control we will consider if these need to be reflected in the development plan and the price control values'*.

6.574 It is clear that there has been a significant change in customer numbers and volumes since the licence application and this warrants an adjustment to the opex that was submitted by SGN in its licence application.

[82] Referred to as AMPR (OO) in the draft determination.

6.575 For the draft determination we proposed to use a proxy of total domestic connections determined by us for the GD17 period versus total domestic connections contained within the G2W application guidelines to change the relevant cost categories shown above. We considered that this was the most appropriate proxy in order to uplift relevant costs.

6.576 For the final determination we have updated the calculation to take account of information on connection numbers for small I & C's as SGN have provided better information on GD17 forecast connections for this customer group. This has increased the applicable allowances by 15% i.e. from 7% to 22%. The calculation is shown in Table 87.

6.577 We then uplifted the following cost categories in comparison to the SGN G2W application by 22%.

- Manpower and MSA/SLA costs under operations management
- Emergency Call Centre
- Emergencies
- PRE repairs
- Maintenance

6.578 We have chosen these cost categories as we consider them to be most impacted by the increased customer numbers. These cost categories are the only ones that we have uplifted from the SGN G2W licence application figures as we consider these cost drivers are most closely related to the change in network design versus that assumed in the AIP.

6.579 We also consider that our approach is reflective of how we have determined similar allowances for FE and PNGL in both GD14 and GD17. For example in GD14, for Network Maintenance and Emergencies we used the driver of the number of customers as a primary driver to roll forward the base expenditure for the forecast years.

	G2W applicant pack	UR GD17 FD	% change
Owner occupied and NIHE	5814	5903	
New build	967	1154	
SME I & C	351	1621	
Total domestic connections	7132	8678	Circa +22%

Table 87: Change in Domestic Connection Numbers (GD17 vs. G2W Assumptions)

6.580 The only other cost category where we have made changes from the SGN G2W application is in relation to owner occupied connections and this is discussed below.

Advertising and Marketing Overview

6.581 In common with the other GDN's our allowance for Advertising and Marketing for domestic owner occupied connections has been set by reference to the connections incentive. Within the SGN GD17 business plan submission SGN incorrectly assigned all costs in relation to advertising and marketing under the domestic owner occupied category. For the GD17 draft determination we split out allowances to be covered under the domestic owner occupied connections and those covered by non owner occupied connections which covers groups such as 'New Build', NIHE and Industrial and Commercial connections. We have maintained this approach for the final determination.

<u>Connections Incentive for GDNs to connect owner occupied (OO) properties</u>

6.582 By way of background Annex 8 of the G2W AIP stated that '*the domestic connections incentive estimate provides for an allowance of £425 per OO (owner occupier) connection, a figure that is subject to change in the future to reflect operational requirements and new arrangements such as an energy efficiency obligation. The aggregate allowance, hardcoded in the Capital Expenditure worksheet in the workbook has been calculated by multiplying this amount with the expected number of OO connections*'.

6.583 The connection incentive allowance of £425 assumed in the AIP was derived from the GD14 connection allowance of £570 but also took account of a 25% non-additional assumption used in GD14.

6.584 For the GD17 draft determination we updated the connection incentive allowance to apply to SGN to reflect the profile of allowances provided to all GDN's for the GD17 period as set out in Table 90.

6.585 SGN has set out its plans to expedite the roll out of its network and increase the number of customers to which gas will be made available. It has argued that it will need additional support to make this approach successful and that it faces significant head winds in delivering its targets. Many of these arguments are discussed in sections above.

6.586 An additional argument it has made is that it is a new distribution company and faces particular challenges. We are of the view that this was well known at the time of the licence application and is not new information. However we do view the AIP as providing clear flexibility in terms of how the connections incentive would be set in GD17 and given our objective to promote the growth of the gas industry we regard it as reasonable for UR to move away from the figures identified in the AIP in this specific circumstance.

Connection Incentive: Non – additional connections

6.587 In recognition of the fact that SGN is at the beginning of its network development and therefore some of its challenges are different to that faced by FE and PNGL in terms of convincing domestic owner occupied customers to connect to the gas network we have not applied any non-additional assumption to the connection incentive.

6.588 Consequently this is a change from the 25% non-additional assumption used in the AIP.

Connection Allowance: 'new areas' allowance

6.589 We recognise that significant new areas where gas is first made available may require greater incentives in educating customers on the benefits of natural gas. All three GDNs have significant expansions planned in GD17, and this is likely to be the last price control where such expansions are considered. Therefore, there is case to be made, given our principle objective to grow the gas industry, for an additional allowance to drive awareness of gas, ultimately leading to increased momentum in connection rates. Given the uniqueness of the extent of the extensions in GD17, we would not plan that this allowance would be applied in future price controls.

6.590 SGN have informed us that '*we would be supportive of any initiative that gives GDN, especially SGN Natural Gas, access to additional funding to support our sales and marketing activities. We do not however believe the proposal will adequately support the sales and marketing required for a new 'greenfield' business, such as ourselves, which is key to the success of our project. Our previous proposals sought to achieve this in a more equitable way'.*

6.591 We believe that the comments made, are worthy of further consideration and developing this concept of a New Area. We consider that the regime outlined below is equitable and gives SGN adequate allowances to support its sales and marketing activities taking into account that SGN is at the beginning of developing its network. We believe for SGN, this would readily apply to its entire network within the Gas to the West project. We will now consider how this concept could be formulated further.

6.592 The size of the new area is measured by the number of all property types that can be passed in each new area (not just in GD17) Consequently we consider that an additional allowance is appropriate for all properties passed (except new build) in new areas in the GD17 period (and beyond.)

6.593 In the case of SGN the New Area allowance would apply to properties passed in the entire SGN area given that the SGN network is at the beginning of its development.

6.594 We consider that the additional allowance of £50 per property passed is appropriate and should be recovered through the existing connection incentive mechanism. Given that the additional allowance is applied to all properties passed whether in GD17 period or later in the incentive mechanism, that this additional allowance can only be applied in the GD17 period.

6.595 For ease of monitoring we will ensure that the additional New Area allowance is captured through the connection incentive mechanism across all targeted connections

6.596 In practice this means that the following steps are undertaken in order to covert the additional per properties passed allowance into a per connection allowance.

- **Step 1**: Multiply the properties passed for 'new areas' x £50. For SGN this is 44,727 x £50 = £2,236,350 over the GD17 period.
- **Step 2**: Divide total allowance by total number of additional connections in GD17 period to convert in to a per connection allowance i.e. for SGN this is £2,236,350 / 3,989 connections = £560.63, rounded to £560.
- **Step 3**: Add the additional allowance to the existing connection incentive mechanism and apply to the connection incentive.

6.597 This in practise converts to the following allowances per connection for all OO connections for SGN.

	2018	2019	2020	2021	2022
Standard Allowance per Connection	550	520	500	470	450
Additional 'new area' allowance	560	560	560	560	560
Standard Allowance per Connection + New Infill Areas Allowance	1110	1080	1060	1030	1010

Table 88: SGN OO Connection allowance and New Area Allowance

Connections targets

6.598 The profile number of target owner occupied connections and associated allowance for SGN is set out in Table 89.

	2018	2019	2020	2021	2022	Total
SGN G2W application	1217	1217	761	761	761	4717
SGN GD17 BP submission	398	633	869	1105	1219	4386
UR final determination	140	1174	951	634	904	3803

Table 89: SGN vs. UR View on GD17 'OO' Connection Numbers

6.599 Our GD17 draft determination OO numbers are set out in the table above. The impact of our proposed connection incentive allowances and together with target owner occupied connection numbers is shown in Table 90.

	2018	2019	2020	2021	2022
UR final determination target	140	1174	951	634	904
Incentive allowance (£)	550	520	500	470	450
GD17 allowance (£k)	77.0	610.48	475.5	297.98	406.8

Table 90: SGN GD17 Owner Occupied Connection Incentive Allowance

6.600 This represents an increase of £0.5m compared to the connections incentive in the AIP.

Costs replaced by the Connection Incentive

6.601 For SGN it has not been necessary for the Utility Regulator to re-allocate costs to the owner occupied connection incentive cost category. This is because this issue was dealt with within the G2W AIP.

6.602 Annex 8 of the G2W AIP stated that '*as with our GD14 Determination, the domestic connections incentive is expected to cover for a sub-set of owner occupied related sales and connection costs, namely*:

- Market Development and Advertising costs related to OO sales and connections.
- Incentive payments to OO consumers.
- Manpower costs for OO-related sales staff (incl. Directors).
- Overhead costs apportioned to OO-related sales and connections should be assumed to be 15%. These overhead costs consist of relevant IT, Office, Insurance, Professional and Legal Fees and Miscellaneous costs'.

6.603 SGN in its G2W 'Low Pressure Operational Business plan' stated that '*we have assumed that all costs associated with the marketing to Owner occupiers including management of the process will be accounted for within the £425 per property incentive as detailed in the guidance; 15% of overheads have also been assigned to this*'.

6.604 Consequently we consider no re-allocation of costs is required to the owner occupied cost category.

Application of the Owner occupied Connection Incentive

6.605 For the draft determination we noted that the GDNs had raised concerns with the application of the owner occupied incentive mechanism as it applied in GD14. For example, FE made the argument that the connection incentive should be calculated over the entire price control period rather than on an annual basis. In addition, both FE and PNGL made the argument that the connection incentive as applied in GD14 i.e. the cap and collar regime was asymmetrical in that it unduly punished underperformance while not adequately rewarding outperformance.

6.606 While we do not consider there it is sufficient merit to move to a situation where the connection incentive is calculated over a Price Control period e.g. because by moving to a connection incentive there is a greater risk that the connection incentive would unduly be based on forecast rather than actual connection numbers, however we do consider there is merit in modifying the cap and collar regime used in GD14.

6.607 We have concluded that for the GD17 final determination that the cap should be removed but that a collar should be implemented such that, where a GDN underperforms the annual connection target by more than 50%, a 25% collar (i.e. 25% * 'per connection' allowance) would operate.

6.608 To demonstrate how the new incentive mechanism might work, consider the following examples:

Exceed target

SGN Target Connection for 2018 = 140

Actual Connections = 200

Connection Incentive = £1,110

So 200 x £1110 = £222,000

Underperformance of Target

SGN Target Connection for 2018 = 140

Actual Connections = 100

Connection Incentive = £1,110

So 100 x £1,110 = £111,000

Underperformance of Target where collar applies

SGN Target Connection for 2018 = 140

Actual Connections = 50

Connection Incentive = £1,110

So 50 connections made is less than 50% of target so collar applies:

25% of the Connection Incentive = £277.50

50 connections x £277.50 = £13,875

6.609 All connections allowances claimed by GDNs must relate to properties which have a supplier and are burning gas. We expect the GDNs to be able to demonstrate that all connections have a supplier agreement in place and burn a minimum quantity of gas.

<u>Advertising & Market Development Costs for non Owner Occupied (Non OO) properties</u>

6.610 As discussed earlier in the advertising and marketing overview SGN within their GD17 business plan submission grouped all advertising and marketing costs for all customer groups incorrectly under the 'Advertising and Marketing' OO category. In response to a query from the Utility Regulator SGN partially clarified the advertising and marketing costs for non-owner occupied groups such as NIHE, New Build and Industrial and Commercial.

6.611 Specifically SGN provided a split for direct support costs between the domestic owner occupied category and the non owner occupied category. However SGN did not provide a split for other costs such as staff costs. Consequently it is not possible to provide a full comparison between the SGN GD17 G2W licence application submission and the GD17 Business Plan submission.

6.612 SGN did however provide a breakdown of their proposed sales and marketing expenditure by activity for the GD17 period and this is shown in Table 91.

Sales and Marketing Activity	Total to end of GD17 (£m)	Activity
Literature	0.02	Newsletters and bulletins
Meetings and Contacts	0.17	Site meetings with customers, seminars
Working with others	0.24	Cross GDN initiatives to improve awareness around natural gas
Staff Costs	0.93	Support from the SGN natural gas team for site meetings with customers, public events, technical analysis etc.
Direct Support (OO)	2.83	Allowances to assist with cost of new boiler / heating system.
Direct Support (non OO) – upfront payment or loan to small I and C customers	0.01	Proposed allowance to cover the cost of conversion via an interest free loan
Direct Support (non OO) – extended supplies	0.64	Support in a number of cases of where a extended supply or outlet pipe may be required
Direct Support (non OO) – project management and technical support	0.26	Additional project management and technical support for medium and large I&C customers and contract customers
Direct Support (non OO) – I and C appliance changeover costs	1.6	Support medium, large and contract I&C customers to change over their existing appliances
Total	6.7	

Table 91: SGN GD17 Proposed Allowances for Sales and Marketing Activities

6.613 In total, SGN have proposed that direct support of around £5.34m is allowed for non-owner occupied customers, in the GD17 period. Its licence application had an equivalent proposal of £0.051m as shown in Table 92.

	2018	2019	2020	2021	2022	Total (£k)
SGN G2W application	8.0	9.0	11.1	12.1	11.1	51.3

Table 92: SGN Advertising and Marketing Costs (G2W Bid) for non OO Customers, £k

6.614 The amounts in the SGN bid for G2W were to cover costs in relation to provision of a 0% finance offer (only available for 2 years) and assumed that 75% of small I & C's would avail of this offer.

6.615 The Utility Regulator considers that Paragraph 4.36 of the G2W AIP of 6 February 2014 was clear in its conclusion on incentives for Industrial and Commercial connections i.e. 'no incentive payments for non-owner occupier connections have been included in the workbook. *However if an applicant believe that in order for them to meet the target for industrial and commercial connections they will require funding for financial incentives they have an opportunity to include such costs in the Operating Expenditure worksheet. They should also explain in their operational business plan how such payments would facilitate connections by non-owner occupier supply points. Only if the successful applicant has included such incentives in their application will these be funded by price control allowances'.*

6.616 Annex 8 of the G2W information pack clarifies that Marketing Advertising & PR for Non-OO Connections comprises costs for the promotion of connections to non-OO customers (e.g. NIHE, Industrial and Commercial (I&C) customers, New Build developers), and covers such costs as

- Market Research;
- Marketing;
- Advertising;
- Public Relations;
- Engagement with Key Stakeholders;
- Any other relevant costs deemed necessary by the applicant.
- Incentives i.e. costs used in assisting non-OO in converting from existing fuel source to natural gas.

6.617 Consequently the Utility Regulator is of the view that it will only allow opex for non-OO connections as set out by SGN in its G2W licence application for the GD17 period.

Non-Controllable Opex

6.618 Section 3.21 of the G2W AIP clarifies '*that Licence fees to the Utility Regulator and Business Rates will be pass through items. We expect the licence holder to demonstrate that there has been adequate challenge on business rate assessments to justify the allowance of full pass through of business rates*'.

6.619 Consequently we have accepted SGN forecast costs for licence fees and business rates as outlined in the G2W application. Any difference between forecast licence fees and business rates and actual licence fees and business rates will be taken account of by the uncertainty mechanism.

Manpower

6.620 We note that SGN within its GD17 business plan submission has increased the number of FTEs they consider that they require when compared to their G2W licence application and this is shown in Table 93.

	2018	2019	2020	2021	2022
SGN G2W application	19	19	19	17	17
SGN GD17 BP submission	13.7	19.8	21	20	20

Table 93: SGN FTEs G2W BP Submission vs. GD17 BP Submission

6.621 While it is a matter for SGN to decide the number and mix of staff it employs our GD17 allowances are based on the FTEs as submitted by SGN in its G2W licence application.

Summary of Bottom-up Assessment Findings

6.622 Table 94 below provides an overview of the cost allowances we are proposing for SGN for the GD17 period. The allowances we have provisionally determined for GD17 are as per the G2W licence application with the exception of cost categories which we consider are most directly related to the changes in customer numbers. In addition we have updated the advertising and marketing owner occupied category to allow a higher overall owner occupied connections incentive for GD17.

6.623 It is important to recognise that the award of the licence to SGN came after a competitive process. The AIP and indeed the G2W final determination were clear in setting out that the allowances in the first Price Control would be heavily weighted towards the figures submitted in the competition.

6.624 There would be considerable risk to the integrity of G2W competitive process were UR to facilitate such large changes form the licence application figures without compelling evidence and our initial view is that there is not adequate justification for such a change.

6.625 This is not something which only concerns us but also the other G2W licence applicants. We note firmus' point in responding to our decision paper on the G2W licence where it stated that it would be *'extremely disappointed if the opex allowed for the preferred applicant in the initial G2W price control period were materially higher than that identified in the submission on which the UR's decision was based'*.

6.626 In many of the areas SGN has requested cost increases, e.g. IT and manpower, it seems clear that SGN should have been fully aware of all issues at the time of its application. In other areas there have been changes e.g. oil/price differential, but we do not view it as justifying the changes proposed by SGN, and for some cost areas e.g. I & C incentives, the AIP stated that all such costs must be included in the application.

6.627 However there are some areas we have proposed that an adjustment is appropriate.

6.628 We have uplifted costs which we consider are related to increased customer numbers from that assumed at the time of the licence application. Our proposed connection incentive for SGN now includes a significant new areas allowance for domestic owner occupied properties and we have applied no non additional assumption in order to take into account the challenges facing SGN.

6.629 For the draft determination we stated that we are not convinced that the SGN had correctly identified the appropriate opex figures from its G2W application to facilitate a meaningful comparison to their GD17 business plan submission. We considered that this may have arisen due to SGN's interpretation of the timing of the FOCD and the costs associated with this. For the final determination we have removed the additional year's opex.

<u>Supplier of Last Resort</u>

6.630 With regard the Supplier of Last Resort (SOLR) we believe that there is merit including an allowance to cover any unforeseen costs that may occur, if an event were to happen. This amount is ring fenced and will be removed at the time of the next price control, if an incident fails to materialise. For the GD17 final determination we have allowed £75k for these costs in 2017 only

	2018	2019	2020	2021	2022	Total
Senior management	194.295	198.677	199.825	199.148	197.122	**989.068**
Operations	68.825	68.825	68.825	68.825	66.367	**341.667**
Marketing and Admin	53.392	72.532	84.621	93.687	102.754	**406.986**
Emergency Call Centre	34.000	6.180	10.249	13.389	16.493	**65.924**
Emergency	37.844	71.230	95.722	114.540	126.890	**590.585**
PRE Repairs	5.205	8.033	9.904	11.349	12.201	**46.692**
Maintenance	44.288	90,841	80,476	84,283	88,292	**388,180**
IT and Telecoms	19.878	19.878	19.878	19.878	19.878	**99,391**
Property Management	34.251	34.251	34.251	34.251	34.251	**171,256**
Insurance	18.311	18.311	18.311	18.311	18.311	**91.557**
CEO & Group Management	33.294	33.294	33.294	33.294	33.294	**166,471**
AMPR (OO)[83]	155.259	1,268.213	1,007.678	652,773	913.056	**2,932.262**
AMPR (non OO)	8.059	9.067	11.081	12.089	11.081	**51.377**
Rates and licence	100.014	269.326	308.745	347.993	387.160	**1,413.237**
SOLR	75.000					**75.000**
Total	**819.783**	**2,124.459**	**1,935.043**	**1,651.085**	**1,971.206**	**8,730.432**

Table 94: SGN Final Determination Opex for the GD17 Period, £k

[83] Referred to as AMPR (OO) in the draft determination.

7 Capex

Capital Investment Summary for the GD17 Final Determination

7.1 Our final determination of capital investment allowances for GD17 is summarised by investment category in Table 95 below.

Investment category	Capital investment allowances for GD17 (£m)			
	FE	PNGL	SGN	Total
7 Bar Mains	0.000	1.126	0.000	1.126
LP, 2Bar or 4Bar Mains	48.598	24.354	24.869	97.821
Pressure Reduction	0.095	0.600	0.626	1.321
Domestic Services	23.815	29.903	5.578	59.296
Domestic Meters	6.789	19.381	1.353	27.523
I&C Services	1.774	3.923	3.884	9.581
I&C Meters	1.403	8.491	3.954	13.849
Other Capex	3.672	1.432	2.371	7.475
TMA	7.419	5.931	3.433	16.782
Totals (Dec 2014 price base)	**93.565**	**95.141**	**46.068**	**234.774**
Frontier shift	-2.389	-2.589	-1.318	-6.296
Totals included in FD	**91.176**	**92.552**	**44.750**	**228.478**

Note: Investment before partial allocation of East Down investment to postalised tariffs. Costs exclude 2016 investment of £0.45m (Foyle crossing), £0.58m (East Down), and £0.03m (Strabane I&C connection) for FE, PNGL and SGN respectively, post frontier shift

Table 95: Capital Investment Included in the GD17 Final Determination

Summary of Key Changes from Draft Determination to Final Determination

7.2 Each of the GDN's provided a response to the capital section of the GD17 draft determination and additional supporting information. We have summarised the issues raised by the companies and our response in Annex 13. In this section of the final determination we summarise the key changes to investment from the draft determination. Further information on these changes is included in the relevant sections of this chapter.

7.3 The impact of these changes on investment relative to the draft determination is summarised by investment category in Table 96.

Investment category	Capital investment allowances for GD17 (£m)			
	FE	PNGL	SGN	Total
7 Bar Mains	0.000	0.000	0.000	0.000
LP, 2Bar or 4Bar Mains	3.677	1.273	-5.105	-0.155
Pressure Reduction	0.000	0.000	0.058	0.058
Domestic Services	3.626	-3.022	-0.159	0.445
Domestic Meters	0.000	-0.806	-0.292	-1.098
I&C Services	0.000	0.122	2.554	2.676
I&C Meters	0.000	3.484	2.088	5.572
Other Capex	2.939	0.000	0.000	2.939
TMA	0.730	-0.163	-0.271	0.297
Totals (Dec 2014 price base)	**10.972**	**0.889**	**-1.129**	**10.732**
Frontier shift	0.401	0.551	0.183	1.135
Totals included in FD	**11.374**	**1.440**	**-0.946**	**11.868**

Table 96: Impact of Changes on Capital Investment from the GD17 DD

7.4 In the final determination we continue to apply capex unit rates which are derived from an analysis of historical expenditure by FE and PNGL over a 4 year period 2011 to 2014, subject to a ‘frontier shift, which takes account of both real price effects and an on-going productivity improvement. We have considered the representations made by the GDNs in respect of these ‘basket of works unit rates’ and made the following changes for the final determination:

- Unit rates for spine and infill mains greater than or equal to 315 mm diameter have been increased for all GDNs to reflect our current view of benchmark rates for large diameter pipes.
- Unit rates for spine and infill mains for SGN have been increased to reflect the higher proportion of work in higher classification roads necessary to develop a network in a new area.
- Unit rates for domestic services have been increased for SGN and FE to reflect differences in length and surface type when compared to PNGL.

7.5 The ring-fenced allowance for TMA costs is estimated at 10% of selected final determination allowances and the change in TMA reflects changes in those allowances.

7.6 Other changes in investment reflect changes in activities, where the GDNs have either provided additional evidence to justify an activity, or have provided evidence to justify an alternative profile for an activity.

7.7 The key changes in investment in GD17 are summarised below.

PNGL (including East Down)

- Investment in East Down has been re-profiled to reflect an updated programme of works from PNGL. As a result, mains investment and investment in connections and meters has reduced.
- Investment in domestic services and meters in the existing PNGL area has reduced by £2.7m reflecting a reduction in connection targets.

- An additional £3.2m has been included to allow PNGL to replace I&C meters at a 20 year life following receipt of information on the cost of meter replacement within existing meter installations and outline costs of a potential testing regime necessary to extend the life of the meters.

FE

- Investment in LP, 2bar and 4bar mains has increased following the assessment of further information provided by FE to support the economic case for further extensions of the gas network. The revised investment allows the company to develop the network in a practical order with some more expensive schemes undertaken in GD17. As a result, the investment assumed for GD23 to complete the extension of the gas network has reduced.
- Investment in domestic services has increased by £3.6 due to an increase in the basket of works unit rate to reflect differences in length and surface type compared to PNGL.
- A ring-fenced amount for a River Foyle crossing to secure supplies on the Cityside of Derry/Londonderry in the long term has been included in 'Other Capex'. Further details are included in Section 7.192.

SGN

- Investment in the distribution network has been reprofiled to take account of the latest construction programme for the high pressure mains which will bring gas to the west, with the exception of Strabane where gas is expected to be available from 2016.
- Distribution network investment has been re-profiled to reflect the current development plans proposed by SGN.
- Investment in I&C connections and meters has increased to reflect revised targets for I&C connections.
- Changes to the basket of works unit rates has had the following impact: increased rates for large diameter mains £0.4m; increased rates for mains to reflect road classification £0.2m; and, increased rate for domestic services £0.8m.

7.8 The revised allowances represent our best estimate of investment in developing the gas network in GD17. The uncertainty mechanisms included in the final determination allow further economic development of the network to be carried out in GD17 as opportunities arise and protect consumers if the rates of development included in the final determination are not delivered.

Detailed Approach – UR Decisions

Overview

7.9 This chapter of the final determination summarises the capital expenditure proposed by the three GDNs in their business plans and sets out our conclusions on reasonable levels of capital expenditure for GD17.

7.10 In initial sections of this chapter we describe the structure of capital expenditure information in the business plan submissions. We have followed this structure in our description of each GDNs submission. We then describe five areas where we have developed common approaches to our assessment of the capital submissions, as follows:

- Assessing economic levels of infill mains.
- Mains laying incentive and uncertainty mechanisms.
- Assessing benchmark rates for capital expenditure using capital expenditure performance in Northern Ireland from 2011 to 2014.
- The potential for the implementation of additional traffic management legislation in the future.
- The application of a frontier shift to reflect movements in capital expenditure input costs relative to RPI and the on-going efficiency gains attributable to productivity improvements.

7.11 We outline our general approach to each investment category and, in subsequent sections for each GDN, we summarise the GDNs' submission, describe our assessment and challenge of the submissions and conclude with the level of capital investment included in the final determination.

7.12 The capital expenditure proposed by the GDNs in their business plans was presented at a common price base of December 2014. Our assessment of the GDNs' submission is presented in the same common price base. The final determination also includes a 'frontier shift' to reflect real price effects and productivity improvements over GD17 from the base year. We have identified the impact of the frontier shift as a final adjustment.

7.13 While our assessment has focused on the GD17 period (2017 to 2022), we have also made an assessment of long term activity and capital investment up to 2045, 2046, and 2057 for FE, PNGL, and SGN respectively, to ensure that the GD17 tariffs reflect a reasonable long term view of the industry. In the sections relating to the individual GDNs, we have provided a brief summary of the assumptions we have made of capital investment post GD17. These assumptions were made for modelling GD17 tariffs and do not reflect a conclusion on any specific issue or commitment to long term investment which will be assessed in a future price control.

7.14 PNGL's business plan submission did not include the development of the East Down area which was the subject of a separate submission and licence revision. Investment in infill mains and connections for this area has been included in the GD17 determination. The overall investment proposed by the GDNs for GD17 and our final determination allowances are presented in the tables below.

Investment category	Capital investment proposed for GD17 (£m)				
	PNGL	PNGL East Down	FE	SGN	Total
7 Bar Mains	1.412		0.000	0.000	1.412
LP, 2Bar or 4Bar Mains	16.260		50.052	37.875	104.187
Pressure Reduction	0.732		0.323	4.905	5.959
Domestic Services	28.673		21.521	5.099	55.294
Domestic Meters	23.230		4.724	1.115	29.069
I&C Services	2.408		2.678	0.986	6.071
I&C Meters	10.685		1.416	1.584	13.686
Other Capex	3.182		1.133	2.826	7.141
TMA	4.875		7.455	0.000	12.331
Totals	**91.457**		**89.302**	**54.391**	**235.150**

Table 97: Capital Investment Proposed by the GDNs for GD17

Investment category	Capital investment allowances for GD17 (£m)			
	FE	PNGL	SGN	Total
7 Bar Mains	0.000	1.126	0.000	1.126
LP, 2Bar or 4Bar Mains	48.598	24.354	24.869	97.821
Pressure Reduction	0.095	0.600	0.626	1.321
Domestic Services	23.815	29.903	5.578	59.296
Domestic Meters	6.789	19.381	1.353	27.523
I&C Services	1.774	3.923	3.884	9.581
I&C Meters	1.403	8.491	3.954	13.849
Other Capex	3.672	1.432	2.371	7.475
TMA	7.419	5.931	3.433	16.782
Totals (Dec 2014 price base)	**93.565**	**95.141**	**46.068**	**234.774**
Frontier shift	-2.389	-2.589	-1.318	-6.296
Totals included in FD	**91.176**	**92.552**	**44.750**	**228.478**

Note *Investment before partial allocation of East Down investment to postalised tariffs. Costs exclude 2016 investment of £0.45m (Foyle crossing), £0.58m (East Down), and £0.03m (Strabane I&C connection) for FE, PNGL and SGN respectively, post frontier shift*

Table 98: Capital Investment Included in the GD17 Final Determination

Overall Structure of Capital Expenditure Submissions and Assessment

7.15 The capital investment submissions for GD17 were structured around the following categories of investment:

Investment category	Description
7 bar mains	Intermediate pressure mains operating up to 7 bar pressure which provide bulk distribution of gas from the high pressure network to the distribution networks which operate at up to 4 bar. In GD17, one project was included by PNGL to reinforce the existing 7 bar intermediate pressure network.
LP, 2Bar or 4Bar Mains	Distribution mains operating at up to 4 bar pressure. Consumers are connected to these distribution mains through service connections and metered supply points which include local pressure regulation. Distribution mains are included in each GDN's price control as: • Infill mains to serve existing developments. • New build mains to serve new developments.
Pressure Reduction	Pressure reducing stations are used to manage pressure between different parts of the network, typically from 7 bar intermediate pressure to 4 bar or 2 bar medium pressure distribution mains and from 4 bar or 2 bar distribution mains to distribution mains operating at low pressure up to 75 mbar.
Domestic Services	Domestic services provide the connection between the distribution mains and the metered supply point of individual domestic consumers. The domestic service includes the connection pipe, new meter box and isolation valve.
Domestic Meters	Domestic meters are provided for measuring and billing gas supplied to domestic consumers. The domestic meter includes the meter, the local pressure regulator and supply valve. Domestic meters are included in each GDN's price control for new connections of domestic properties. Both PNGL and FE proposed beginning 'end-of-life replacement' of existing domestic meters in GD17.
I&C Services	Industrial and commercial services provide the connection between the distribution mains and the metered supply point of individual industrial and commercial consumers. The service includes the connection pipe, new meter box and isolation valve.
I&C Meters	Industrial and commercial meters are provided for measuring and billing gas supplied to industrial and commercial consumers. Each I&C meter installation includes the meter, the local pressure regulator and associated pipework and valves. I&C meters are included in each GDN's price control for new connections of I&C properties. Both PNGL and FE proposed beginning 'end-of-life replacement' of existing I&C meters in GD17.
Other Capex	Other capex covers investment in systems and assets required to manage service delivery including vehicles, buildings and IT equipment and systems.

Investment category	Description
Traffic Management Act (TMA)	The Traffic Management Act, if implemented in full, would require GDNs to make additional payments to Transport NI in respect of streetworks. Allowances of 10% of total mains and services costs have been included in the determination against the future implementation of this legislation. In practice, the GDNs will not receive this funding unless and until the legislation is implemented, at which time the impact on costs will be reassessed.

Table 99: Investment Category Descriptions

7.16 We have used this structure to present both our assessment and challenge to the GDNs' proposals and our conclusions and the allowances included in the final determination. Within each investment category, we have considered reinforcement of the existing system, growth (infill, new build and additional connections) and replacement of existing assets separately where appropriate.

Common Approach to Key Areas

Introduction

7.17 In this section we outline five key areas where we have adopted a common approach to inform our final determination of investment for each GDN as follows:

- Economic levels of infill mains.
- Mains laying incentive and uncertainty mechanisms.
- Benchmark rates for capital expenditure.
- Potential for the implementation of additional traffic management legislation.
- Application of a frontier shift to reflect movements in capital expenditure input costs and on-going productivity improvements.

Common Approach – Economic Level of Infill Mains

7.18 We have continued to apply the approach used in GD14 to determine whether it is economic to further develop the gas network in the PNGL and FE areas.

7.19 The development of the gas network in both the SGN area and the PNGL East Down area were subject to separate DETI economic appraisals and relevant government policy in terms of government subvention and/or the inclusion of some costs in the postalised transmission tariff. We have not subjected the development of the gas network in these areas to a further economic test and the determination allows for the wholesale construction of gas mains within the towns served.

7.20 The main principle we have used when carrying out an economic test is that gas mains should only be laid where there is a reasonable prospect that the initial outlay cost will be paid back in the useful economic period by consumers connecting and burning gas.

7.21 The economic appraisal is based on the following key data and assumptions:

Key parameter	Value	Rationale
Economic life	40 years	The depreciation period for gas mains assumed in our financial models.
Economic discount rate	4.3%	Consistent with the return on capital for GD17.
Domestic properties passed	95% for FE 100% for PNGL	Consistent with the property counts identified by the respective GDNs in their detailed assessments of properties passed.
I&C properties passed	5% for FE 0% for PNGL	As above.
Domestic consumption	Average of 461 therms/a for FE Average of 380 therms/a for PNGL	Based on an analysis of consumption by property type linked to a detailed development plan (see Table 101 below). Consistent with the average therms per property currently reported by the GDN or projected at the end of GD17.
I&C consumption	2000 therms/a	Consistent with our approach at GD14.
Domestic connection rate	Variable	We have assumed that 85% of properties will connect to the network in the long run at a rate of 5% per annum of properties passed but not connected. This is generally in line with the long term connection rate that we have seen to date. It is higher than the connection rate assumed for GD14.
Industrial and commercial connection rate	Variable	Connection rate used in GD14 based on PNGL experience of I&C connections.
Asset replacement	20 years	For meters and associated regulators and ancillaries.
Reinforcement	None	No allowance for additional pressure reducing stations or mains reinforcement. Consistent with the general design approach, historical development of the network and the GDNs' business plan submissions.
Unit costs	Basket of works unit rates	Consistent with the GD17 capex determination, but excluding the application of real price effects.
Connection incentive	Variable	The relevant profile of connection incentive for each GDN used.

Key parameter	Value	Rationale
Operational costs	Variable	The analysis makes provision for variable opex associated with connections including asset maintenance, metering costs, repairs and emergencies and rates.
Ratio of I&C tariff to domestic tariff	90%	Based on FE GD14 tariff structure.

Table 100: Economics of Gas Mains – Key Parameters

7.22 In principle, we consider a package of new mains to be economic if it does not increase the current domestic tariff. In practice we have used a limit of 40p per therm for determining economic infill for GD17, given the varying tariffs over time.

7.23 In its response to the draft determination, PNGL indicated that we had made an error in our assessment that the infill proposed for GD17 would be broadly domestic and indicated that 10% of the properties it is proposing to passed in GD17 will be I&C properties. In light of this statement we reviewed a sample of the detailed schemes which PNGL had developed to support its development plans and confirmed that they are predominately domestic and include little or no I&C properties.

7.24 PNGL also challenged the test we use to determine an economic level of infill, suggesting that we should consider the average cost of delivery including past investment rather than the marginal cost of future development. The company was concerned that the application of our economic test had led us to conclude that the infill proposed by the company in its plan was uneconomic. We have considered the representations made by PNGL but concluded that it is right to continue to test the economic extent of infill based on a consistent marginal test for each price control period. This provides a balance between assessing the economics of individual properties or developments against the broader objective of extending the gas network, while ensuring the network is not extended to include small quantities of uneconomic development with the increase in tariff spread across a large number of economic connections. We noted that PNGL does not propose to pass every property in their network area because they judge some properties to be uneconomic and their connection would result in a small increase in tariff for all consumers and we agree with this principle. As a result, we have not changed our approach for GD17, but will consider further representations for GD23 if PNGL can provide further evidence as to why some of the properties concerned should be connected.

7.25 In its business plan, FE submitted summary information which suggested that gas burns for domestic properties would be higher than the average we assumed in the economic appraisal. Following our draft determination, FE identified the property type for a sample of properties in its area and the gas burn for these properties in 2014. Based on our analysis of this information we concluded that the consumptions set out on Table 101 are a reasonable basis for assessing the economic viability of infill in the firmus area.

Property type	Average annual gas consumption (therms)
1 Bed Apartment	155
2 Bed Apartment	202
Terrace House	356

Property type	Average annual gas consumption (therms)
Semi Detached House	322
Detached 4 Bedroom House	657
Large Dwelling 5+ Bedrooms	859
Weighted average for FE long term development plans	461

Table 101: Average Gas Consumption by Property Type (FE)

7.26 In its business plan submission, FE provided a development plan based on detailed assessments of 621 area projects where the company identified the cost of completing each area project and the number of properties passed by property type. As a result of the additional information provided on gas consumption, we have concluded that, the overall package of infill work proposed by FE is economic and we have broadly accepted the company's plans to complete this work over the GD17 and GD23 periods in a way which the company considers to be the most practical way of developing the network as a whole. Further detail of our conclusions on infill allowances for FE is provided in the section below beginning at paragraph 7.161.

7.27 In its business plan submission, PNGL proposed infill for 5,700 properties at the edge of the existing network. At the draft determination, we concluded that this infill was uneconomic. We have maintained this view in the final determination. Further detail of our conclusions on infill allowances for PNGL is provided in the section below beginning at paragraph 7.218.

7.28 The outcome of the analysis is an economic level of average investment per property and an estimate of the average length per property passed associated with that investment. Using the approach and key parameters described above, we have determined that the economic level of investment per property and the associated length of main per property for GD17 are as follows:

GDN	Price Control	Property type	£ per property passed	m per property passed
PNGL	GD14	Existing infill	515	7.73
FE	GD17	Existing infill	736	10.30
PNGL	GD17	Existing infill	359	5.16

Table 102: Economic Development Parameters for New Gas Mains

7.29 The primary drivers for an increase in £ per property passed and increase in metres per property passed for FE compared to GD14 are:

- A lower economic discount rate reflecting a lower return on capital.
- A higher domestic connection rate reflecting new information on historical levels of connection.
- A higher owner occupier consumption of 461 therms per property based on detailed information on gas consumption by property type provided by FE related to its detailed development plans.

7.30 The primary driver for the reduction in the economic £ per property passed and associated reduction in metres per property passed for PNGL is the absence of I&C properties in the remaining infill.

7.31 The economic length per property passed presented in Table 102 provides the lengths per property for the infill uncertainty mechanism described in Chapter 9.

Common Approach - Mains Laying Incentive and Uncertainty Mechanisms

Properties Passed Mechanism

7.32 All GDNs will be subject to a properties passed mechanism to incentivise them to continue to extend the network as proposed in the final determination.

7.33 In theory a GDN could fail to build a single metre of gas mains and not suffer any negative consequences, although we accept there is a general incentive to grow the industry. Therefore the draft determination included a target number of properties passed and failure to achieve the target would result in a penalty of £50 for every property below the target. Passing a larger number of properties than the target would result in a reward of £20 per additional property over the target.

7.34 In its response to the draft determination, FE commented on the unbalanced nature of the properties passed mechanism where the penalty for each property short of the properties passed target is 2.5 times the reward for each property in excess of the target. Having considered FE comments on the properties passed mechanism, we have maintained the position set out in the draft determination and retained an asymmetric mechanism to reflect the fact that GDNs have control over the number of properties passed and the penalty is not onerous.

7.35 In GD14 we applied the mechanism on an annual basis. The GDNs have argued that this should be amended to a cumulative mechanism over the price control period. In the draft determination, we noted that we would consider moving to a cumulative mechanism for properties passed, taking account of responses to the draft determination. None of the GDNs provided any analysis or opinion on whether the mechanism should be changed from an annual to cumulative mechanism.

7.36 We have considered the option of moving the application of the properties passed mechanism from an annual basis in GD14 to a cumulative basis in GD17 as follows:

- We considered but rejected the option of a cumulative mechanism applied during each year as this would reward or penalise any individual year's performance for the remainder of the price control, significantly altering the strength of the mechanism.
- We considered but rejected the option of a cumulative mechanism based on total performance over a price control for the following reasons:
    - A company which delivers properties passed late in the price control, but meets its targets for the price control as a whole, would not be subject to any penalty. Conversely, a company which delivers early would not be rewarded. As a result, a cumulative mechanism would not promote sustained continuous expansion of the network.
    - A cumulative mechanism applied at the end of a price control period, results in uncertainty for the company over the course of the price control.

- We noted the GDN's concern that the asymmetric nature of the incentives means that a company could be penalised even though its cumulative performance is ahead of target in each year of the price control. We considered two options to address this:
  - To introduce some form of short term rolling average to smooth this effect. This appeared overly complex and might not address the issue identified above in all circumstances.
  - To make the application of the annual incentive subject to cumulative performance such that an annual penalty would only be applied if cumulative performance was behind target and a reward would only be applied when cumulative performance was ahead of target. This latter approach has the advantage of being simple to apply on an annual basis.

7.37 We have concluded that the properties passed mechanism will continue to be applied on an annual basis subject to the condition that an annual penalty will not be applied where cumulative performance is ahead of target in that year and an annual reward will not be applied where cumulative performance is behind target in that year. This will ensure that the mechanism will target sustained delivery.

7.38 The properties passed incentive applies to the total of the following types of existing properties: owner occupied, NIHE and I&C properties. The target number of properties passed in GD17 for each GDN is shown in Table 103.

	2017	2018	2019	2020	2021	2022	GD17
FE	11,366	11,071	11,528	10,414	10,765	11,673	66,817
PNGL	1,041	1,956	5,370	5,263	4,913	3,439	21,982
SGN	0	1,711	7,925	6,570	4,660	4,554	25,420

Table 103: Properties Passed Targets for all GDNs

Infill and New Build Mains Uncertainty Mechanisms

7.39 In the final determination we have included an allowance for the construction of new mains to extend the gas network to serve both existing properties and new properties. We have adopted different approaches to determining the length of property passed for new build and infill development and for different areas:

- For new build properties we have based our assessment on the recent historical average for the length of main required to serve new development of 9.5m per property passed for all GDNs, compared to 5.9m per new build property passed in GD14.
- For existing properties in the FE licence area and the current PNGL licence area (excluding East Down), we applied an economic test and limited the determination to a basket of properties which could be delivered up to the average lengths per property passed set out in Table 102 above.
- For SGN and the PNGL East Down area, which have been subject to a separate economic test, we have determined average lengths per existing property passed of 11.50m per property passed and 11.52m per property passed respectively based on the designs presented by the GDNs.

7.40 We recognise that the number of properties passed and the length required to pass a property will vary in delivery. We will continue to apply the uncertainty mechanism to adjust for the actual numbers of properties passed and the actual length of properties passed up to a cap of the lengths per property set out above. Adjusting for the actual number of properties passed ensures that each GDN is funded for the outputs it delivers and protects consumers from under delivery. Adjusting for the actual length of main delivered up to a length per property cap, removes the risk of estimated lengths for both consumers and the GDNs and ensures that development is delivered within the parameters of the determination.

7.41 In GD14, the infill mechanism was applied to new build and infill development separately. In the draft determination we set our intention to maintain this approach for GD17 but noted that we would give further consideration to this approach for the final determination. None of the GDNs commented on this issue in their response to the final determination.

7.42 The infill mechanism exists to promote both efficient and economic delivery of infill mains. The key reasons for considering a change from a mechanism which makes a separate assessment of infill and new build to a combined mechanism are:

- It would allow the GDNs to balance the risk across a combined mechanism.
- It would reduce the need to allocate costs between new build and infill accurately when, in some cases, a scheme might include an element of both.

7.43 Having given further consideration to the issue, we have concluded that it is right to continue to apply the mechanism to new build and infill separately. In our view, applying the incentive separately will benefit consumers by ensuring economic delivery in both new build and infill and will ensure the efficient delivery costs are revealed which can inform future price controls. In the absence of any representation from the GDNs, we have decided to continue to apply the mechanisms separately in GD17.

7.44 In GD14, we applied this mechanism on an annual basis. The GDNs have argued that this should be amended to a cumulative approach over the price control period to prevent the application of the mechanism becoming a driver for the selection and management of capital delivery year on year. In the draft determination, we noted that we would give further consideration to this for the final determination, taking account of the response to the consultation on the draft determination. None of the GDNs provided any analysis or opinion on whether the mechanism should be changed from an annual to cumulative mechanism.

7.45 An annual infill mechanism has the advantage of promoting efficient and economic delivery in each year of the price control, securing efficient and economic delivery over the price control as a whole. However, it has the disadvantage that the GDNs must plan their programme of work to meet an annual target. In the past, where the GDNs had choices on the areas of infill to delivery, an annual target had the advantage of incentivising economic choices each year. As the industry has matured and the infill to be delivered has reduced, there is an argument to move to a cumulative target to allow GDNs the scope to select a mix of projects in any one year which promotes efficient delivery through good programme management. For example, the detailed plan of work for GD17 presented by FE in its business plan, on which our final determination is based, has been scheduled to allow the work to be delivered efficiently. The application of an annual infill mechanism based on an average length per property and average unit rate to this planned programme of work would result in a small incentive penalty. While the company could amend its programme to work within the average length per property and average unit rate in each year, this might result in a sub-optimal delivery programme. In view of these considerations, we have concluded that the infill mechanism for GD17 should be applied on a cumulative basis.

Economic project mechanism

7.46 In the draft determination, we set out our intention to consider an additional mechanism to manage unforeseen new connections to larger I&C customers. For the final determination, we have expanded on this concept as a more general economic project mechanism which formalises how we will assess and determine capital investment in major new opportunities or requirements which arise during the price control period, building on principles applied in GD14.

7.47 The business planning process and the determination ensures that each GDN is able to plan and finance the economic development of the network as far as this could be reasonably foreseen. The price control is also bounded by uncertainty and incentive mechanisms which afford both the company and consumers protection against change and provides incentives (positive and negative) to drive delivery and reward the company where it out-performs. However, it is possible that new projects will come to light which were not foreseen at the time of the determination, which are either economic or necessary, but which cannot be delivered by a prudent operator within the general uncertainty mechanisms and incentive mechanisms of the price control.

7.48 This price control mechanism provides a framework whereby a GDN can promote such projects.

7.49 This mechanism will not apply to the general development of the network to serve domestic and I&C consumers. Each GDN has a general funding and targets under the price control to serve this consumer base and there are uncertainty mechanisms available to allow economic development to take place. Each GDN has broad discretion on how to act under the price control and is expected to use this discretion to promote economic development. As a result, we expect the scheme to apply to a limit number of major projects only, such as a large new I&C connections.

7.50 To limit the application of the mechanism to major changes, we will apply a materiality threshold of £100k of total investment net of contributions and will only consider projects which exceed this value under this mechanism.

7.51 Where the company identifies a project which is new and is either economic or necessary, it should present a business case to the Utility Regulator which sets out:

- Why the scheme does not fall within the scope of the determination or is not adequately covered by the uncertainty mechanisms or the incentive mechanisms of the determination.
- The driver for the scheme and an explanation as to why the work must be carried out immediately and cannot form part of the next price control.
- A feasibility study setting out the proposed scope of works, the costs and revenues of the scheme, and a cost benefit analysis including a whole life cost analysis. All changes to the existing distribution network should be considered and the GDN should explain which elements of the upgrade it believes should be included in the economic appraisal and how this relates to its connection policy.

- The economic appraisal of the scheme should take full account of consequential benefits such as additional properties passed. In the case of a major new I&C connection, the submission should include a detailed technical assessment of the new load, including both peak and average consumption and evidence of the consumer's commitment to use gas.
- A net present value analysis of the project. The company should set out its reasoning for the period over which the NPV analysis is carried out which should reflect a reasoned assessment of the life of the project and the risks and opportunities associated with a longer or shorter period of analysis. Where there is a shortfall in the NPV calculated for the project, the GDN should set out the arrangements for these costs to be recovered as a contribution in line with the connections policy.
- The adjustments it considers necessary within the current price control and any residual adjustment which should be made in any future price control to allow the GDN to finance the scheme.

7.52 On receipt of such a proposal, the Utility Regulator will:

- Review the proposal to satisfy itself that the scheme does not fall within the scope of the determination or is not adequately covered by the uncertainty mechanisms or the incentive mechanisms of the determination.
- Assess the scope and costs of the proposed development including benchmarking capital costs and assessing the potential loads and income generated by the scheme.
- Review the net present value analysis calculations and, if necessary, ask the GDN to resubmit the net present value analysis and the assessment of any contribution necessary using criteria established by the Utility Regulator to ensure that the general consumer base are not asked to subsidise the project which benefits a few consumers disproportionately.
- Following a review of the costs and further engagement with the GDN, make a determination of the adjustments necessary to the price control and the provision to be made in any future price control to finance the scheme.

7.53 The adjustments made to the Price Control for an economic scheme under this mechanism will include the following:

- A determination of an adjustment to volume targets for a minimum of 6 years, equal to the consumption included in the economic appraisal.
- An adjustment to the capital allowances for the determined capital costs net of any contributions and net of any consequential benefits such as additional properties passed.
- The addition of a nominated output for the delivery of the scheme including a completion date.

7.54 Any scheme which meets the criteria for this mechanism is likely to develop over a period of time. We would expect each GDN to keep us informed of the development of such schemes and engage on the timing and scope of any proposals well in advance of them being made.

Common Approaches - Benchmark Rates for Capital Expenditure

Introduction

7.55 FE and PNGL have relied on recently tendered contract rates to price the capital works identified in their business plan submissions. As a new entrant, SGN relied on contract rates from similar operations in Scotland to estimate the cost of works in GD17, subject to reasoned adjustments.

7.56 We adopted three principle approaches to review and challenge the estimates prepared by the GDNs:

- We undertook simple high level benchmarking of costs and activities in the business plan submissions to identify areas where there were material differences between the estimates prepared by the GDNs.
- We undertook a bottom up assessment of detailed information provided by PNGL and FE to confirm the costing methodologies used and to confirm that the estimates reflected current contract rates. We took the opportunity to compare the costing methodologies of the three GDNs.
- We updated and applied the basket of works approach first used in GD14 to determine high level unit rates consistent with historic costs in Northern Ireland which could then be used to estimate the costs of future work.

7.57 We have provided a brief description of each of these assessments below. We have based much of the final determination on the unit rates derived from an analysis of a historical basket of works, with some smaller elements of the programme based on current contract rates for FE and PNGL.

Comparison of High Level Unit Rates

7.58 As a first step in our assessment of the business plan submissions we calculated average rates for the capital expenditure proposed by each GDN. While this simple approach does not reflect underlying explanatory factors (for example, size distribution by asset type), it does provide an indication of material differences in unit costs and areas of focus for our subsequent assessments.

Investment category	Average unit rates for capital investment in GD17 (£)			
	Units	PNGL	FE	SGN
7 Bar Mains	£/m	283	NA	NA
LP, 2Bar or 4Bar Mains				
Infill and spine mains	£/m	78	71	100
New build mains	£/m	56	52	40
Pressure Reduction	£/unit	3,830	4,888	15,571
Domestic Services				
Existing properties	£/service	795	871	1,091
New build properties	£/service	273	348	349
Domestic Meters	£/meter	209	170	87
I&C Services	£/service	1,316	2,479	3,381
I&C Meters	£/meter	1,403	1,267	9,136

Table 104: High Level Business Plan Capex Unit Rates for GD17

7.59 A key observation from this comparison is that SGN, a new entrant to the market, has proposed rates for infill/spine mains and pressure reduction which are materially higher than those of FE and PNGL who have been able to base their estimates on local current contract rates.

Inter GDN Comparison of Spine and Infill Mains Laying Rates

7.60 As part of their business plan submissions, FE and PNGL provided information on individual gas mains projects for the first two years of GD17 (2017 and 2018). SGN presented a plan to provide new gas mains to almost all existing properties in the main towns within its new licence area. The company provided network drawings and a priced schedule of works by town.

7.61 To understand how FE and PNGL had developed their estimates for infill gas mains, we asked both GDNs to provide detailed information for a sample of these projects, including drawings and priced schedules of works. We used this information to review the quantities of work, to understand how the works were costed and to benchmark the costs of spine and infill mains laying.

7.62 We were able to confirm that the lengths of infill and spine mains laying proposed by each GDN were reasonable for the properties passed. We were able to confirm that FE and PNGL had applied their current contract rates to cost the scope of works identified.

7.63 To compare the unit rates and methodologies used by each GDN to cost mains laying, we took the scope of works for a sample of projects from FE and PNGL and the total mains proposed by SGN and priced these using the business plan cost rates and methodologies of the other GDNs. Our objective was to provide a like for like comparison of mains laying rates taking account of differences in physical attributes such as diameter, pressure rating or surface type. The outcome of this analysis is shown below.

		GDN rates applied		
		PNGL	FE	SGN
GDN scope of works priced	**PNGL**		FE estimates 3% lower than PNGL	SGN estimates 38% higher than PNGL
	FE	PNGL estimates 1.0% higher than FE		SGN estimates 37% higher than firmus
	SGN	PNGL estimates 29% lower than SGN	FE estimates 31% lower than SGN	

Table 105: High level business plan capex unit rates for GD17

7.64 When compared on a like for like basis, taking account of physical attributes of diameter, surface type and pressure rating, a consistent picture emerges:

- The costing set out by FE and PNGL are broadly similar with PNGL costs marginally higher than FE costs for the sample of works considered.
- SGN's proposed costs of mains laying are consistently about 37% higher than those of FE and PNGL. SGN has set out reasons why its cost should be higher than those of FE and PNGL and these are reviewed in Section 7.87.

Basket of Works Approach to the Capex Determination

7.65 The bottom up approach adopted by the GDNs could provide a reasonable estimate of costs, provided they fully reflect the decisions made and opportunities available in delivery. However, the approach carries a number of risks to consumers which we must seek to address in our determination:

- The development of bottom up scopes of works and estimates might not truly reflect efficient design choices, cost allocations or opportunities for cost saving in delivery.
- Bottom up estimates might not adequately reflect or over estimate site specifics such as disruption and standing time, difficult ground conditions or restrictions on access, traffic management and the need for weekend working.
- Bottom up estimates might not adequately reflect general items such as management costs.
- The application of contract rates might not adequately reflect performance against commercial terms such as pain-gain payments.
- Using tendered rates to price a determination assumes that a particular procurement process is efficient and that tendered rates should be passed through to consumers.
- The application of current contract rates by each GDN foregoes the opportunity for benchmarking to identify efficient capital expenditure.

7.66 To address these issues, we have applied and adapted the basket of works approach first used in GD14.

7.67 The basket of works approach used in GD14 built on principles which were adopted by Ofgem in GDPRC1 and RIIO-GD1 price controls. The basket of works summarises total historical capex into broad categories of work with high level cost drivers such as length of mains or number of connections. Unit rates for the basket of works are calculated by dividing the total historical cost by the historical number of units for the cost driver.

7.68 For GD17, we have reviewed our approach to the basket of works and made a number of changes to reflect both improving historical cost information and the balance of unit rates in Northern Ireland. The primary changes made are:

- We analysed historical costs for a four year period, 2011 to 2014. Extending the duration of the analysis reduces the impact of year on year changes in the balance of work undertaken and the potential impact of accruals between years.
- The GD14 analysis was based on historical costs and drivers for PNGL. For GD17, we have based our analysis on the combined costs of FE and PNGL. Combining costs in this way provides a broader cost base and a comparative benchmark taking account of all costs incurred in the period.
- Further work has been done to align the relative level of unit costs with local experience of all-in costs or tendered rates. This was achieved by adjusting the GD17 rates profile within each main item in the basket of works to reflect local profiles and then adjusting the package of rates for each main item in the basket of works to reflect its historical costs. As a result, unit rates for I&C meters and services were increased and the unit rates for new build mains and domestic meters were reduced. Notwithstanding these adjustments, the GD17 unit rates as a whole reconcile to total historical costs.

7.69 We set out our proposals for unit rates developed from a basket of works in the draft determination and we shared our detailed calculations with the GDN's. As part of their overall response to the draft determination we asked that the GDNs:

- Comment on any errors in the data used or proposals made in the allocation of costs and activities.
- Identify any further disaggregation of the basket of works which would improve the analysis and explain the rationale for this, providing any additional data necessary to support additional disaggregation.
- Identify and explain any improvements in the ratios between the rates which would better reflect actual cost rates, recognising that a change in one rate will prompt a balancing change in other rates.
- Identify and quantify any company specific factors which should be considered in the application of the rates and, where appropriate, explain how these special factors were included in the historical capital investment used to develop the basket of works.
- Identify any areas where historical costs or activities might not adequately reflect future costs and activities and quantify the impact this would have on the company's estimated future costs.

7.70 In response to the draft determination, each GDN made general criticisms of the approach we adopted. For example:

- PNGL noted that the UR's use of synthetic unit rates restricts PNGL's ability to comment on UR's capex proposals other than at an overall level. However, the company's subsequent comments addressed issues of scope rather than a challenge to the determined rates.

- FE acknowledged that the intention of the basket of works concept was to ensure that company allowances are balanced across the full range of capex costs and therefore reflective of total costs. However the company expressed concerns about the impact of company specific outliers with a particular focus on the basket of works rates for domestic services which were lower than the company's historical experience and lower than current tendered costs.
- SGN commented that it did not believe that a top-down approach to benchmarking including the use of regression analysis, of Northern Ireland and potentially GB GDNs, is appropriate for a new 'Greenfield' business such as SGN. The company provided a number of additional papers arguing for the use of tendered rates, more latterly based on recent tendered rates for Strabane. Over time, the company's concern focused on unit rates for large diameter mains and domestic connections.

7.71 In principle, each company argued for the use of its own bottom up assessment and tendered rates. Having considered the company's general feedback we have concluded that the risks of a bottom up approach highlighted in paragraph 7.65 remain valid and we have continued to use a basket of works approach for the final determination subject to adjustments to reflect specific issues identified by the companies.

7.72 In response to the specific questions identified in paragraph 7.69 the GDNs identified the following issues:

- PNGL identified corrections to the historical data used in our analysis. The impact of this on the basket of works unit rates was marginal and would have resulted in a small reduction in the allowances for each GDN. However, for the final determination, we have maintained the unit rates used in the draft determination. We recognise that this provides additional headroom and flexibility for the GDNs which in managing the overall GD17 package.
- No GDN proposed a further disaggregation of the basket of works. We have continued to use the same basket of works items for the final determination.
- SGN raised concerns about the ratio between unit rates for mains used in the draft determination. The company considered that it resulted in inadequate rates for large diameter mains and that this was a particular disadvantage to the company as it developed the spine network for new areas.
- Both SGN and FE expressed concern about unit rates for domestic services, highlighting specific factors relating to differences between services installed in their areas and those in the PNGL area which dominated the calculation of the basket of works unit rate.
- SGN identified a company specific factor relating to the type of roads it would undertake construction in, highlighting the fact that the initial construction of spine mains in new areas required it to work in roads with a higher classification than other GDNs.

7.73 As a result of the company's feedback, we have adjusted the basket of work unit rates calculated for the final determination: for large diameter mains for all companies; for domestic services for SGN and FE; and, surface category for SGN only. These adjustments are explained in the following sections.

Basket of works (BoW) unit rate adjustment for large diameter mains.

7.74 SGN has made significant progress on its designs and plans for infill since its business plan submission and our draft determination. Through this work, the company has increased its estimate of the proportion of large diameter mains it will construct in GD17. The company expressed concern about the calculation of large diameter rates in our basket of work rates and noted that the relative proportion of large diameter mains in its plans meant that the issue had a particular impact on its funding. The company provided tendered rates for large diameter mains (only) from its recent procurement exercise for Strabane.

7.75 In light of the company's comments we reviewed the proportion of large diameter mains laying carried out by PNGL and FE in the period 2011 to 2014 which forms the basis of our basket of works unit rates. This confirmed that the investment planned by SGN had a higher proportion of large diameter mains than our basket of works. As a result we reviewed the basket of works rates for large diameter mains. We drew on our recent experience of determining rates for bulk mains for East Down which we based on recently tendered rates for Gas to the West. This approach was also used to determine rates for 7bar reinforcement mains for PNGL in GD17. We extended this methodology to provide amended basket of works rates for mains greater than 250 mm diameter. The revised rates are shown in Table 106.

Main diameter	Unit rate at draft determination	Revised rate at final determination	Uplift
315 mm	163	188	15%
355 mm	186	211	13%
400 mm	215	239	11%
450 mm	250	272	9%
600 mm	375	387	3%

Table 106: Revised Unit Rates for Large Diameter Mains

BoW unit rate adjustment for domestic services.

7.76 In response to our draft determination both FE and SGN expressed concern over our BoW rate for services to existing domestic properties of £736 per connection. FE highlighted differences in the construction of services in the PNGL area relating to both length and surface type. The company noted that the average cost of domestic service installation in its area over the period 2011 to 2014 was £880 per service compared to a proposed basket of works rate of £736 calculated as a weighted average of connections for FE and PNGL and dominated by PNGL connections. SGN highlighted concerns based on the difference in the proposed basket of works unit rates and the tendered rates it had obtained for work in Strabane.

7.77 In light of the issues raised by FE we asked both FE and PNGL to provide information on service tenure, length and postcode for the years 2014 and 2015. A summary of the data for owner occupier connections is shown in Table 107.

OO Service up to 50m in length							
Cum %	**0-5**	**5-10**	**10-15**	**15-20**	**20-25**	**25-30**	**30-35**
PNGL	17%	45%	76%	93%	97%	99%	100%
Belfast	25%	56%	82%	95%	98%	100%	
Exc Belfast	8%	31%	67%	89%	96%	99%	99%
FE	8%	43%	78%	91%	96%	98%	100%

Table 107 FE and PNGL Service Summary (cumulative)

7.78 Both GDN's have a similar average service length and ~75% of services are less than 15m in length. However services in Belfast, which account for over 50% of PNGL's installations in this period have, a markedly different profile to those outside Belfast and those in the FE area, with a significantly higher proportion of very short services. As well as the simple relationship between cost and length, this can open up opportunities to use lower cost techniques for construction.

7.79 In view of the difference between the services constructed in the PNGL area and services constructed in the FE area, we concluded that it would not be appropriate to apply a historical unit costs dominated by work in the PNGL area to FE. For the final determination, we have amended the BoW unit rates for FE to its historical run rate of £880 per connection. We have continued to apply the BoW unit rate of £736 in our final determination to PNGL.

7.80 The SGN area is similar to that of FE and we expect that the layout and development of its network will be similar to that in the FE area. SGN provided detailed information on the likely length of domestic services in its area which is similar to historical experience in the FE area. The company also provided information on current tendered rates which show that its unit costs are similar to FE. On the basis of this information, we have also applied the historical run rate for FE of £880 to SGN.

<u>BoW unit rate adjustment for surface category.</u>

7.81 During the consultation period SGN made representations that its revised infill proposals incorporated a special factor for road categories. As the revised infill proposal is approximately 40% in length of the original business plan submission there is higher percentage of mains laid in category 1&2 roads primarily due to the fact that the larger diameter feeder mains, often constructed in mains roads, are required in both cases. SGN provided information based on its current plans for development to show that the work planned for GD17 included 19% of main laying in category 1&2 roads compared to the Northern Ireland average of 11% meaning that SGN has an additional 8% extra main laying in category 1&2 roads compared to the Northern Ireland average.

7.82 We examined the information provided by SGN and compared it to FE's business plan and PNGL's revised business plan for East Down. As SGN's proposals currently stand we agree that over the GD17 period only, there is an increase in the proportion of category 1&2 roads.

7.83 We examined current contract rates for FE and PNGL to gauge an appropriate increase to our BoW unit rates for main laying due to the increased costs associated with working on category 1&2 roads. We calculate that there is approximately 17% uplift in rates on average and that this should apply to an additional 8% of SGN's proposed main laying programme over and above the normal parameters contained in the BoW unit rates described in section 7.81. We therefore apply a uniform 1.4% uplift to the BoW main laying rates over GD17 only for SGN.

GD17 final determination BoW unit rates

7.84 The outcome of the analysis is a set of unit rates which can be applied to the same high level categories of work and cost drivers in the future to determine an efficient overall capex allowance which is reflective of historical costs. The resulting basket of works unit rates for GD17 for each GDN are set out in the following tables:

- FE Table 108.
- PNGL Table 109.
- SGN Table 110.

Activity	Revised	Activity	Revised
Mains New Build 32mm	43	Domestic Meter	192
Mains New Build 50mm	45	Domestic Meter - Replacement	192
Mains New Build 63mm	47	I&C U6	192
Mains New Build 75mm	49	I&C U16	1,232
Mains New Build 90mm	51	I&C U25	1,531
Mains New Build 125mm	58	I&C U40	1,760
Mains New Build 180mm	70	I&C U65	4,224
Mains New Build 200mm	76	I&C U100	5,456
Mains New Build 250mm	91	I&C U160	7,040
Mains New Build 315mm	114	I&C U250	8,800
Mains New Build 355mm	130	I&C U400	19,360
Mains New Build 400mm	150	I&C U650	28,160
Mains New Build 450mm	174	I&C U1000	40,479
Mains New Build 600mm	262	I&C U1600	59,839
Mains Feeder/InFill 32mm	62	I&C U2500	84,479
Mains Feeder/InFill 50mm	65	I&C U6 - Replacement	192
Mains Feeder/InFill 63mm	67	I&C U16 - Replacement	1,232
Mains Feeder/InFill 75mm	70	I&C U25 - Replacement	1,531
Mains Feeder/InFill 90mm	73	I&C U40 - Replacement	1,760
Mains Feeder/InFill 125mm	83	I&C U65 - Replacement	4,224
Mains Feeder/InFill 180mm	101	I&C U100 - Replacement	5,456
Mains Feeder/InFill 200mm	108	I&C U160 - Replacement	7,040
Mains Feeder/InFill 250mm	130	I&C U250 - Replacement	8,800
Mains Feeder/InFill 315mm	**188**	I&C U400 - Replacement	19,360
Mains Feeder/InFill 355mm	**211**	I&C U650 - Replacement	28,160
Mains Feeder/InFill 400mm	**239**	I&C U1000 - Replacement	40,479
Mains Feeder/InFill 450mm	**272**	I&C U1600 - Replacement	59,839
Mains Feeder/InFill 600mm	**387**	I&C U2500 - Replacement	84,479
Domestic Services Existing	**880**		
Domestic Services New Build	332		
I&C Very Small (U6)	1,147		
I&C Small (U16-U40)	1,835		
I&C Medium (U65-U160)	4,013		
I&C Large (U250-U650)	8,214		
I&C Very Large (>U650)	10,727		

Table 108: GD17 Basket of Works Unit Rates for FE

Activity	Revised	Activity	Revised
Mains New Build 32mm	43	Domestic Meter	192
Mains New Build 50mm	45	Domestic Meter - Replacement	192
Mains New Build 63mm	47	I&C U6	192
Mains New Build 75mm	49	I&C U16	1,232
Mains New Build 90mm	51	I&C U25	1,531
Mains New Build 125mm	58	I&C U40	1,760
Mains New Build 180mm	70	I&C U65	4,224
Mains New Build 200mm	76	I&C U100	5,456
Mains New Build 250mm	91	I&C U160	7,040
Mains New Build 315mm	114	I&C U250	8,800
Mains New Build 355mm	130	I&C U400	19,360
Mains New Build 400mm	150	I&C U650	28,160
Mains New Build 450mm	174	I&C U1000	40,479
Mains New Build 600mm	262	I&C U1600	59,839
Mains Feeder/InFill 32mm	62	I&C U2500	84,479
Mains Feeder/InFill 50mm	65	I&C U6 - Replacement	192
Mains Feeder/InFill 63mm	67	I&C U16 - Replacement	1,232
Mains Feeder/InFill 75mm	70	I&C U25 - Replacement	1,531
Mains Feeder/InFill 90mm	73	I&C U40 - Replacement	1,760
Mains Feeder/InFill 125mm	83	I&C U65 - Replacement	4,224
Mains Feeder/InFill 180mm	101	I&C U100 - Replacement	5,456
Mains Feeder/InFill 200mm	108	I&C U160 - Replacement	7,040
Mains Feeder/InFill 250mm	130	I&C U250 - Replacement	8,800
Mains Feeder/InFill 315mm	**188**	I&C U400 - Replacement	19,360
Mains Feeder/InFill 355mm	**211**	I&C U650 - Replacement	28,160
Mains Feeder/InFill 400mm	**239**	I&C U1000 - Replacement	40,479
Mains Feeder/InFill 450mm	**272**	I&C U1600 - Replacement	59,839
Mains Feeder/InFill 600mm	**387**	I&C U2500 - Replacement	84,479
Domestic Services Existing	736		
Domestic Services New Build	332		
I&C Very Small (U6)	1,147		
I&C Small (U16-U40)	1,835		
I&C Medium (U65-U160)	4,013		
I&C Large (U250-U650)	8,214		
I&C Very Large (>U650)	10,727		

Table 109: GD17 Basket of Works Unit Rates for PNGL

Activity	Revised	Activity	Revised
Mains New Build 32mm	43	Domestic Meter	192
Mains New Build 50mm	45	Domestic Meter - Replacement	192
Mains New Build 63mm	47	I&C U6	192
Mains New Build 75mm	49	I&C U16	1,232
Mains New Build 90mm	51	I&C U25	1,531
Mains New Build 125mm	58	I&C U40	1,760
Mains New Build 180mm	70	I&C U65	4,224
Mains New Build 200mm	76	I&C U100	5,456
Mains New Build 250mm	91	I&C U160	7,040
Mains New Build 315mm	114	I&C U250	8,800
Mains New Build 355mm	130	I&C U400	19,360
Mains New Build 400mm	150	I&C U650	28,160
Mains New Build 450mm	174	I&C U1000	40,479
Mains New Build 600mm	262	I&C U1600	59,839
Mains Feeder/InFill 32mm	**62**	I&C U2500	84,479
Mains Feeder/InFill 50mm	**66**	I&C U6 - Replacement	192
Mains Feeder/InFill 63mm	**68**	I&C U16 - Replacement	1,232
Mains Feeder/InFill 75mm	**71**	I&C U25 - Replacement	1,531
Mains Feeder/InFill 90mm	**74**	I&C U40 - Replacement	1,760
Mains Feeder/InFill 125mm	**84**	I&C U65 - Replacement	4,224
Mains Feeder/InFill 180mm	**102**	I&C U100 - Replacement	5,456
Mains Feeder/InFill 200mm	**110**	I&C U160 - Replacement	7,040
Mains Feeder/InFill 250mm	**132**	I&C U250 - Replacement	8,800
Mains Feeder/InFill 315mm	**190**	I&C U400 - Replacement	19,360
Mains Feeder/InFill 355mm	**214**	I&C U650 - Replacement	28,160
Mains Feeder/InFill 400mm	**242**	I&C U1000 - Replacement	40,479
Mains Feeder/InFill 450mm	**276**	I&C U1600 - Replacement	59,839
Mains Feeder/InFill 600mm	**393**	I&C U2500 - Replacement	84,479
Domestic Services Existing	**880**		
Domestic Services New Build	332		
I&C Very Small (U6)	1,147		
I&C Small (U16-U40)	1,835		
I&C Medium (U65-U160)	4,013		
I&C Large (U250-U650)	8,214		
I&C Very Large (>U650)	10,727		

Table 110: GD17 Basket of Works Unit Rates for SGN

Special Factors

<u>FE Special Factors</u>

7.85 FE did not identify any special factors relating to capital costs in its business plan submission. In response to the draft determination, the company raised specific issues about domestic services which are addressed in paragraph 7.76 above.

<u>PNGL Special Factors</u>

7.86 PNGL did not identify any special factors relating to capital costs in their business plan submission. The company did not raise any special factors relating to unit rates in its response to the draft determination.

<u>SGN – Special Factors</u>

7.87 As a new entrant to the market, SGN does not have local contracts to assess future costs. Instead, the company used contract rates from similar operations in GB as a starting point for developing unit rates for GD17. It then identified five adjustments which were applied to arrive at the unit rates for mains laying in GD17:

- A 'regional price adjustment' (12% reduction) to reflect differences in labour costs between Scotland and Northern Ireland.
- A 'sparsity' adjustment (5% uplift) to reflect the impact of working in the remote areas of Gas to the West.
- A 'singleton' adjustment (2% uplift) to reflect the focus on new mains construction when the company's Scottish contract allows a contractor to achieve synergies across a wider range of service and maintenance works.
- A 'start up' adjustment (8% uplift) to reflect the additional costs of contractor mobilisation for a start up business and diseconomies of scale compared to the company's GB business.
- An efficiency factor (3% reduction) associated with economies of scale for delivering an accelerated programme of works with substantial completion of mains in all the main towns served by the end of GD17.

7.88 In its response to the draft determination, the company raised specific issues about unit rates for large diameter mains, domestic services and surface category. We have addressed these issues above.

7.89 We have also considered the adjustments set out by SGN in its business plan submission and the supporting information provided by the company and concluded that there is insufficient evidence to make further adjustments to the basket of works unit rates to reflect special factors relative to FE and PNGL. We have responded to each of the adjustments included in the company's submission below.

Regional Price Adjustment

7.90 The basket of works unit rates used in the draft determination are based on local historical costs and there is no need to apply a further regional price adjustment relative to GB. We have no plans to consider any regional wage variations within Northern Ireland.

Sparsity Adjustment

7.91 The company has identified a special factor to reflect the impact of working in the remote areas of Gas to the West. This ‘sparsity’ factor covers the following:

Additional costs due to sparsity effects	£/a
Additional travel costs from home to connected towns	140,000
Additional costs of travel from connected towns to asphalt suppliers	14,560
Additional travel time from connected towns to aggregate quarries	5,200
Additional travel times from connected towns to landfill sites	33,040
Total per annum	192,800
Total for GD17	***1,157,800 (2%)***

Table 111: SGN Special Factor Claim for Sparsity

7.92 SGN provided supporting information based on:

- A methodology used by Ofgem to assess sparsity for gas distribution price controls in GB. The company also noted other examples where economic regulators (including the Utility Regulator) had allowed special factors relating to sparsity.
- An assessment of times of travel to work in the Gas to the West area.
- A statement of the location of aggregate suppliers and land fill sites relative to the Gas to the West towns and relative travel distances.

7.93 The Ofgem sparsity factor applied by the company was used by Ofgem to determine costs relating to emergency response only. Other examples quoted by SGN also related to operational costs (opex), for example, responding to individual customers or the costs of operating small and widely distributed assets over a remote area. We have not identified a similar regulatory approach to sparsity for capital investment. Regulators in the water and energy sectors have considered regional variations in capital costs across GB due to local factors. This has largely resulted in a “London weighting” only to reflect physical and economic differences in London.

7.94 To provide a bottom up estimate of the impact of sparsity, SGN estimated the additional costs of travel time to and from construction sites. This was based on an additional paid half hour travel time for all staff per day. The analysis recognised the opportunities to employ local contractors, local sub-contractors, and staff based in the local area, but made no allowance for this.

7.95 The analysis is based on a series of assumptions and does not take account of the opportunities for workers living in the Gas to the West area that currently travel to work in other areas to reduce their travel time by working locally. It does not make any assessment of regional wage variation across Northern Ireland or the opportunities to employ local contractors who may be able to offer more competitive prices. In the absence of any assessment of counter costs, we have not included any allowance for this special factor in the final determination.

7.96 The company has identified aggregate quarries and landfill sites in Northern Ireland and estimated an additional travel distances of:

- to asphalt suppliers 18.2 km.
- to aggregate quarries 6.5 km.

- to landfill sites 41.3 km.

7.97 The total estimated cost of additional travel time is £52,720 per annum which we estimate as an additional 1% of the annual cost of construction. We recognise the potential for additional costs but do not consider this level of additional cost material. It is possible that further research of the market may identify suitable local suppliers which would reduce or remove this estimated additional cost.

Singleton Adjustment

7.98 SGN highlighted the volume discounts negotiated in the contract used to develop its GD17 rates from bundling packages of work types across multi-utility construction. The company noted that it would not be able to achieve such discounts in a contract focused primarily on gas network construction.

7.99 The basket of works unit rates used in the final determination are based on local contracts for the construction of similar gas networks. SGN has the same opportunity to procure similar types of contract or to consider alternatives which drive greater efficiency. In view of this, we have concluded that it is not appropriate to apply a '*singleton'* uplift to the basket of works unit rates.

Start up Adjustment

7.100 SGN has estimated that it will require four depots to deliver capital works in its licence area, compared with one depot required to support the same level of works in the FE and PNGL areas. In our view, FE operates over a wide ranging area from the south-east to the north-west, covering 10 towns. We see no reason why SGN could not manage its works with a similar cost of depots to that incurred by the FE supply chain.

7.101 The company has also made the argument that, as a new entrant, it will incur additional costs of establishing new contracts and building working relationships with its supply chain. The company has recently been awarded a licence for gas distribution in the area following a competitive process. The competitive process included an opportunity for the company to bid initial mobilisation costs and include any other start up cost it considered necessary. In the application process we noted that we would determine capital costs in line with standard regulatory price control processes and the company made no mention or allowance for additional new entrant or mobilisation costs associated with capital delivery. In addition, we would not allow incumbent companies additional costs associated with a new supplier. In view of this, we have not included any start up adjustment in our determination.

Economies of Scale

7.102 The rates for mains laying in the draft determination are based on the costs of mains laying by two GDNs over a four year period. The average rate of investment per company included in the analysis is £4.3m per annum. We have determined an allowance for spine and infill mains laying for SGN in GD17 of £4.0m per annum. We have not assessed any economies of scale for this marginal difference.

Common Approaches - Street Works Legislation

7.103 In GB, there are two main pieces of legislation which set out the rules and regulations that apply whenever utilities or similar organisations undertake capital works in public roads. They are the Traffic Management Act (TMA) and the New Roads and Street Works Act (NRSWA). Equivalent legislation has not yet been implemented in Northern Ireland, but it is possible that the Assembly might proceed with implementation in due course. The terms and the timing of any such future legislation and the impact it would have on the costs incurred by GDNs remains uncertain.

7.104 In light of this on-going uncertainty, we have continued the approach to TMA costs adopted in GD14:

- We have made a provision in the draft determination of 10% of the cost of mains and services against future TMA costs which are reflected in the determination of tariffs.
- We will make an adjustment through the uncertainty mechanism at the time of the next price control to reflect the actual level of expenditure due to the implementation of traffic management legislation. This adjustment will take account of the impact on return on capital associated with any reduced or increased costs.

7.105 This approach allows for the implementation of legislation during the course of the price control without a material impact on tariffs and provides a symmetrical protection to both the GDNs and consumers against this future uncertainty.

Common Approaches - Capex Real Price Effects and Frontier Shift

7.106 We have applied a frontier shift to capital investment in GD17 to reflect movements in capital expenditure input costs relative to RPI and the on-going efficiency gains attributable to productivity improvements. We have not applied a frontier shift to our projection of costs beyond GD17.

7.107 We have assessed particular elements of cost, drawing on our previous experience and current regulatory practice.

7.108 The price of a company's various inputs may differ over time. Price controls have normally been indexed by the Retail Price Index (RPI) to account for broad changes in prices. However, being a measure of general inflation, not all types of cost changes will be reflected in the range of prices used to calculate the RPI. To account for this it is common practice to calculate and make adjustments for the difference, either positive or negative, between particular input price changes for a company or industry and the RPI measure of inflation. This is described as *real price effects* (RPEs).

7.109 The concept of frontier shift is wider than simple productivity assumptions. Within this report, the UR has adopted the methodology we first introduced at PC13 for NI Water, which aligns closely with the Competition Commission (CC) determination for Northern Ireland Electricity at RP5 and more recent Competition and Markets Authority (CMA) decisions. This process combines nominal input price forecasts with productivity expectations and RPI inflation:

Frontier shift in real terms = input price increase minus
forecast RPI (measured inflation) minus
productivity increase

7.110 As a result of updates in our data since DD, there is a small overall change to the RPEs and frontier shift for capex. This is illustrated in the table below.

Capex	2015	2016	2017	2018	2019	2020	2021	2022
Frontier shift FD	0.2	-0.5	-0.4	-0.9	-0.8	-0.7	-0.7	-0.7
Frontier Shift FD (Cumulative %)	-0.20%	0.30%	0.70%	1.50%	2.30%	3.00%	3.60%	4.20%
Frontier shift DD	0	-0.5	-0.8	-1	-0.8	-0.6	-0.6	-0.6
Frontier shift DD (Cumulative %)	0.00%	0.60%	1.40%	2.40%	3.20%	3.80%	4.30%	4.90%

Table 112: Real Price Effects for Capex – Change from the DD

7.111 A further detailed explanation of the precise make up of our overall RPEs and assumed productivity increase is contained in Annex 6 – Real Price Effects and Frontier Shift: Final Determination GD17.

General Approach by Investment Categories

General Approach - 7 Bar Mains

7.112 We have assessed the need for 7 bar mains on a project by project basis.

General Approach - LP, 2 Bar or 4 Bar Mains

New Build Mains

7.113 In GD14, we provided an allowance for PNGL to provide mains to new developments up to a length per property passed of 5.9m and a unit rate per length of main of £56/m (equivalent to £330 per property). The allowance was subject to a retrospective adjustment to reflect the actual length of main provided up to a limit of 5.9m, but allowing the company to benefit from out-performance on unit cost. A similar allowance was provided for FE in a combined allowance for new build and infill mains and properties passed.

7.114 Based on reported information for 2013 and 2014, the length of new build main per property passed is significantly higher than envisaged for GD14, at approximately 9m and 11m per property passed for PNGL and FE respectively.

7.115 For GD17, the GDNs have asked for allowance for new build properties passed based on 10.42m, 10.2m and 5.5m per property passed for PNGL, FE and SGN respectively. Both FE and PNGL have suggested that a higher proportion of developments with semi detached and detached housing will drive an increase in the length of mains per property passed required to serve new developments.

7.116 Taking account of current lengths per property passed as experienced by FE and PNGL, we have provided an allowance for new build mains based on an average length per property passed of 9.5 m. We have used the basket of works unit rates to estimate an allowance for new build mains. These estimates take account of the specific proportion of mains identified by each company. The difference between the average rates requested for new build mains and the average unit rates allowed in the final determination are:

GDN	Average rate for new build mains (£/m)	
	Business Plan	Final Determination
FE	51.50	47.23
PNGL	56.09	46.48
SGN	40.09	47.08

Note Final determination figures post frontier shift

Table 113: Average Rates for New Build Mains

Spine and Infill Mains

7.117 We have determined an allowance for the number of properties passed and the length of spine and infill mains in the existing FE and PNGL areas by applying the economic test described in 7.18 above. The detailed outcome of this analysis is described in the individual sections for the relevant GDNs below. In summary:

- We concluded that the investment proposed by PNGL did not meet the economic test and made no allowance for further infill in the draft determination. The infill mechanisms will allow the company to deliver economic infill where this can be identified.
- We identified an economic package of infill for FE of 66,817 properties passed at a length per property passed of 10.30m.

7.118 The development of the gas network in both the SGN area and the PNGL East Down area were subject to separate economic appraisals and the developments have been supported by either government grant or the transfer of some costs to a postalised tariff. We have not subjected the development of the gas network in these areas to a further economic test and the determination allows for the wholesale construction of gas mains within the towns served. We have based our target length of main per property passed on the designs, property counts and lengths of mains prepared by the GDNs, subject to adjustments to the SGN figures to reflect further work undertaken by the company on design development.

7.119 For PNGL and FE, we have not distinguished between spine and infill mains in our assessment and targets. We have taken account of the relative size of mains when estimating the costs of mains and the average unit costs for infill and spine mains for each company.

7.120 Since the draft determination, SGN has continued to develop more detailed designs for infill in its area and refined the extent of infill it plans to carry out in GD17. As part of this work the company has identified the need to lay a greater proportion of larger diameter spine mains in GD17 than it had assumed in its business plan. Applying the updated unit rates to this work gives blended unit rates for infill as shown in Table 114. SGN has asked that the final determination takes account of the uncertainty associated with the continuing development of its designs. In this respect, the use of a single blended rate for mains in the infill uncertainty mechanism would leave the company and consumers exposed to the risk that the work completed in GD17 does not reflect the current designs and, in particular, the assumptions we have made in the final determination on the proportion of different mains diameter. Therefore, for SGN, we have introduced unit rates for different pipe size bands which will be applied in the infill uncertainty mechanism. This will allow the uncertainty mechanism to reflect the development of the design over time.

7.121 We used the basket of works unit rates to estimate an allowance for spine and infill mains. These estimates take account of the specific proportion of mains identified by each company. The average rates requested for infill mains and the average unit rates allowed in the final determination are:

GDN	Average rate for spine and infill mains (£/m)	
	Business Plan	Final Determination
FE	71.13	67.76
PNGL – Current area	77.81	66.81
PNGL – East Down	71.06	71.59
SGN	100.49	
SGN - mains up to 90 mm diameter		67.06
SGN - mains greater than 90mm and up to 200 mm diameter		89.64
SGN - mains greater than 200 mm diameter		160.61

Final determination figures post frontier shift

Table 114: Average Rates for Spine and Infill Mains

Replacement Mains

7.122 We have made no allowance for replacement mains in the determination. We have assumed that the costs of any 3rd party requirement to relocate mains or repair mains will be balanced by contributions received and there will be no net cost to consumers.

General Approach - Pressure Reduction

Pressure Reducing Stations – Growth and Reinforcement

7.123 We have reviewed the forecast activity volumes and costs associated with the construction of new PRS installations for FE and PNGL which are minimal. We have granted allowances for the additional PRSs identified by these GDNs in their business plan submissions. We have applied the current contract rates of the respective GDNs to cost this work.

7.124 For the draft determination, we challenged the number of PRS installations proposed by SGN in its initial designs and included an allowance based on the average number of similar installations per km of main in the PNGL area. Since its business plan submission, SGN has continued to develop its network design including amending the balance of medium pressure and low pressure network to provide the most economic design. However, there is still further design development work to do and the number, type and location of pressure reducing stations is likely to change as the design develops. For the final determination, we have maintained the approach we adopted for the draft determination and included an allowance based on the average number of similar installations per km of main in the PNGL area.

7.125 The unit rates proposed by SGN for pressure reducing stations were materially higher than the existing contract rates available to FE and PNGL. We based our allowance for this work on the average contract rates of FE and PNGL for similar installations.

7.126 SGN has yet to complete its detailed design development and the number, type and location of pressure reducing stations remains uncertain. For the final determination, we considered including the number of PRSs in the uncertainty mechanism for SGN only. We concluded that this would be unnecessarily complex in that any mechanism would have to anticipate and define a wide range of possible outcomes in terms of the type of network adopted and unit size of PRS. In our view, an allowance based on the number of PRS on the average number of similar installations per km of main in the PNGL area is a conservative assumption which offers the company an opportunity to outperform as it develops its design. Therefore, we have decided not to include the PRS in the uncertainty mechanism based on the number of PRS. Any out-performance or over run against the PRS allowance will be subject to the capex sharing mechanism for SGN described in the section beginning at paragraph 11.2 and will inform our decisions on future price controls.

7.127 As noted above, SGN is continuing to develop its network design to achieve the most economic balance of medium pressure and low pressure network. These decisions could have a material impact on the overall cost of service and the balance of current and future costs. As it finalises its designs, and before committing to the development of the network, the company should provide us with an updated network design and economic appraisal which considers the balance of low pressure and medium pressure network and demonstrates that it has optimised the whole life cost of network over the long term taking account of the full development of the network.

Pressure Reducing Stations – Replacement

7.128 PNGL included end-of-life replacement of PRS installations which will reach 20 years of age in GD17. This decision has been made on age alone and no detailed assessment has been made of partial replacement which could optimise the whole life cost of these installations. We have allowed this small level of replacement investment in GD17. The work has been costed using current contract rates which include the provision of civils works, chambers, covers and reinstatement as well as the pipes, valves, fittings and monitoring equipment.

7.129 FE has included end-of-life replacement of PRS installations which will reach 10 years in GD17. In view of the fact that PNGL has maintained similar installations over a 20 year period, we have not allowed for end-of-life replacement of PRS installations beginning at 10 years as proposed by FE.

7.130 For GD17 we have concluded that we should not include PRS end of life replacement in an uncertainty mechanism. There is an opportunity for the GDNs to investigate options for partial replacement of plant and equipment to prolong the life of these installations without wholesale replacement of chambers, covers and pipework. This will become progressively more important over time as the number reaching the end-of-life will increase. We expect the GDNs to investigate these opportunities in GD17 and be in a position to demonstrate that they have optimised the balance of maintenance and plant replacement for subsequent price controls.

General Approach - Domestic Services

7.131 We used basket of works unit rates to estimate allowances for domestic services at each new connection. No allowance has been made for replacement domestic services. The unit rates for new domestic services distinguish between services on new developments and services to existing domestic properties.

General Approach - Domestic Meters

Domestic Meters – Growth

7.132 We used basket of works unit rates to estimate allowances for domestic meters at each new connection. The basket of works unit rates for domestic meters are a blended rate for credit meters and PAYG meters which reflects the mix of meters installed over the period 2011 to 2014.

Domestic Meters – End-of-life Replacement

7.133 PNGL included the costs of end-of-life replacement of domestic meters which have been in use for 20 years in its business plan. This activity would begin in 2017 with cost in GD17 estimated at £6.84m.

7.134 FE included the cost of end-of-life replacement of domestic meters which have been in use for 15 years. This would begin in 2021 with cost in GD17 estimated at £0.21m.

7.135 Neither company provided an economic case to support the replacement of meters on the basis of age. PNGL noted the synergies between meter replacement and cycles of battery replacement, regulator maintenance and replacement. The company also noted that the meters had a 20 year manufacturer's guarantee.

7.136 In the absence of any supporting information from the GDNs, we developed a high level financial appraisal of the life-cycle costs of domestic meters taking account of battery replacement, regulator maintenance and replacement and meter replacement. This indicated that there may be a cost advantage in deferring meter replacement until 30 years, assuming that they remain capable of recording consumption with reasonable accuracy over this extended life. We have concluded that it is appropriate to allow funding for a 20 year cycle of replacement of domestic meters.

7.137 In view of the fact that PNGL has maintained domestic meters over a 20 year life cycle, we have not allowed for end-of-life replacement of domestic meters at 15 years as requested by FE.

7.138 The level of investment in replacement meters is significant and there is both uncertainty over the number of meters to be replaced and an opportunity for the company to defer the replacement of meters to a subsequent price control, benefiting from the price control cost sharing mechanism. Therefore we have considered a number of approaches to uncertainty and incentives for this new strand of investment as follows:

- We could choose not to apply a volume driver to meter replacement. This would provide the company with a pre-determined amount of investment, with the company carrying the risk and benefit of having over or under-estimated the number of meters to be replaced. It would allow the company to benefit from deferring meter replacement into a subsequent price control. If it did so, consumers would benefit from the longer economic life of meters revealed in the process.

- We could choose to apply a volume driver to meter replacement, whereby the price control would be adjusted for the number of meters replaced which have exceeded a 20 year life. This would ensure that consumers only pay for the work done. However, it would provide no incentive to the company to defer the replacement of meters and consumers would not benefit in the long term from an extended economic life of meters.

- We could choose a hybrid of the above, where the price control is adjusted for the actual number of meters replaced which have exceeded their 20 year life, but an additional incentive is introduced for extending the meter life beyond 20 years to reflect the long term benefit to consumers of extending meter life.

7.139 In its response to the draft determination, PNGL stated that it did not consider that a volume driver for domestic meter replacements is required. The company contended that its forecast of the number of domestic meter replacements included within its GD17 submission is based on the data held within its asset register which records the meter installation date. The company was content to carry the risk and benefit of having over or under-forecast the number of meters to be replaced across GD17. In its response, PNGL stated that National Grid's approach to end of life domestic meter replacement was 20 years for credit meters and 10 year for pre-payment meters. In previous submissions, the company had drawn attention to the fact that the certification period for its meter stock was 20 years.

7.140 When considering whether or not we should apply an uncertainty mechanism to end of life replacement of existing meters, we have noted any variation in the numbers of meters replaced compared to the final determination estimate could arise from either:

- an error in the data reported to us in its submissions which is revealed as the company begins to replace meters at end of life; or
- a decision by the company to extend the life of the meters in the short term which would only provide a material benefit to consumers if the extended life is applied in subsequent price controls and over the long term.

7.141 As a result, we believe that any decision not to apply an uncertainty mechanism must be linked to the company revealing that meters can be retained over a longer than 20 year life and that this decision is sustainable in the long term. In view of this we have concluded that it is appropriate to apply an uncertainty mechanism to the number of end of life meter replacement in GD17. This will be based on the number of meters replaced which are 20 years old or more, addressing the uncertainty in the accuracy of the company's records. However, we would not implement the mechanism to the extent that the following circumstances apply:

- The deferral of meter replacement is as a result of extending the meter life beyond 20 years.
- The company demonstrates that the extended meter life revealed in GD17 is applied to assess investment need in subsequent price controls. When assessing the impact of any deferral in GD17 on the extended life of mains, we will round up to the nearest year.

7.142 We used basket of works unit rates allowances for domestic meters as the basis for estimating the cost of replacement meters. The basket of works unit rates for domestic meters are a blended rate for credit meters and PAYG meters which reflects the mix of meters installed over the period 2011 to 2014. For replacement meters, we have adjusted the unit rate to reflect the mix of credit and PAYG meters which are being replaced to a unit rate of £151 per meter replaced pre application of RPE. This will be applied in the uncertainty mechanism.

General Approach – I&C Services

7.143 We used the basket of works unit rates to estimate allowances for new I&C services. No allowance has been made for replacement I&C services.

General Approach – Industrial and Commercial Meters

Industrial and Commercial meters – Growth

7.144 We used basket of works unit rates to estimate an allowance for I&C meters for each new connection.

Industrial and Commercial Meters – Replacement

7.145 PNGL included costs in its business plan for end-of-life replacement of all I&C meters which have been in use for 20 years. This activity would begin in 2017 with cost in GD17 estimated at £6.31m. FE included the cost of end-of-life replacement of I&C meters which have been in use for 15 years. This would begin in 2021 with cost in GD17 estimated at £0.05m. Neither company provided an economic case to support the replacement of meters on the basis of age.

7.146 In view of our conclusions on domestic meters, we included funding for a 20 year cycle of replacement of U6 I&C meters in the draft determination for PNGL. We did not include end-of-life replacement for larger I&C meters at 20 years as proposed by PNGL in the draft determination. We asked the company to assess options for managing these high value assets and their associated whole life costs to allow us to reach an informed decision for the final determination. We asked that the company should consider replacement on age, targeted replacement of key components or the continued maintenance of the plant over a longer life.

7.147 In its response to the draft determination, PNGL provided three key pieces of evidence:

- A commentary on the type of I&C meter by size, noting that meters up to U40 are similar to U6 I&C meters in that they are a sealed unit which must be replaced as a whole or not at all.
- Information on the cost of meter replacement within the meter rig for U65 and above meters.
- An assessment of the costs of a programme of testing and recertification of meters removed on a 20 year end of life cycle to allow them to be reused. The costs and benefits of this programme were of the same order without accounting for the uncertainty over the extended life of the meter.

7.148 In view of the information provided by the company, we have concluded that the final determination should include an allowance based on:

- End of life replacement at 20 years for I&C meters less than U65.
- End of life replacement at 20 years for I&C meters U65 and larger based on replacement of the meter but retention of the remainder of the meter rig installation.

7.149 We have set out our thoughts on the introduction of uncertainty mechanisms for domestic meter replacement in paragraph 7.138. We have reached the same conclusion for I&C meters. We will apply an uncertainty mechanism to end of life meter replacement based on the number of meters replaced which are 20 years old or more, addressing the uncertainty in the accuracy of the company’s records. However, we would not implement the mechanism to the extent that the following circumstances apply:

- The change in the deferral of meter replacement is as a result of extending the meter life beyond 20 years.
- The company demonstrates that the extended meter life revealed in GD17 is applied to assess investment need in subsequent price controls.

7.150 In view of the fact that PNGL has maintained I&C meters over a 20 year life cycle, we have not allowed for end-of-life replacement of I&C meters at 15 years as requested by FE.

7.151 Following more detailed information on the costs of replacing meters in meter rigs for U65 meter and above, we have used the following rates for meter replacement in the GD17 final determination:

- For U6 I&C meter replacement, we have used a unit rate which reflects the high proportion of credit meters in this category.
- For U16 to U40 meters we have used the basket of works unit rates for the full replacement of the meter, ancillary equipment and housing.
- For U65 meters and above, we have used unit rates provided by PNGL for replacing the meter and closely associated components within the existing meter rig, subject to a reduction in the management fee and capitalised on costs by 5% to align with the allocation of costs between work types.

7.152 The resulting unit rates for end of life meter replacement are set out in Table 115.

Domestic Meter Credit - End of Life	130
Domestic Meter PAYG - End of Life	210
I&C U6 - End of Life	130
I&C U16 - End of Life	1,232
I&C U25 - End of Life	1,531
I&C U40 - End of Life	1,760
I&C U65 - End of Life	1,408
I&C U100 - End of Life	1,761
I&C U160 - End of Life	2,751
I&C U250 - End of Life	3,123
I&C U400 - End of Life	2,910
I&C U650 - End of Life	4,008
I&C U1000 - End of Life	4,918
I&C U1600 - End of Life	7,277
I&C U2500 - End of Life	10,273

Table 115: Final Determination Unit Rates for End of Life I&C Meter Replacement

General Approach – Other Capex

7.153 We have considered and challenged the 'Other Capex' proposed by the companies on a case by case basis. Our assessment and conclusions are described in the detailed sections for each company below.

General Approach – Traffic Management Act

7.154 Our overall approach to possible future implementation of additional traffic management legislation in Northern Ireland is set out at paragraph 7.103 above and summarised below:

- We have made a provision in the determination of 10% of the cost of mains and services against future TMA costs which is reflected in the determination of tariffs.
- We will make an adjustment using the uncertainty mechanism at the time of the next price control to reflect the actual level of expenditure due to the implementation of traffic management legislation. This adjustment will take account of the impact on return on capital associated with any reduced or increased costs.

General Approach – PNGL – East Down

7.155 PNGL's business plan submission for GD17 excluded the extension of gas mains into East Down which was the subject of a separate decision in principle.

7.156 We have applied the GD17 basket of works unit rates to the company's designs for East Down to estimate the cost of construction of new spine and infill mains and associated connections. The total determined costs for these works are included in the summary table below.

7.157 In December 2015 we wrote to PNGL identifying appropriate allowances for the bulk mains required in East Down. These mains largely run between the relevant towns and are made up of a mixture of sizes and pressures ranging from 7 bar 450mm mains to 4bar 125mm mains. Given the separate nature of these costs they have not been included in the summary tables below.

FE – Overview

7.158 FE's business plan included capital investment of £89.30m in GD17 in Dec 2014 prices. The final determination allows capital investment of £91.18m following the application of the frontier shift in the years 2017 to 2022.

7.159 An explanation of the changes made to the capital programme for the final determination is given in the summary table below with more detailed information provided in the subsequent sections.

Item	Base Year Prices (£m) BPT	FD	Var	Explanation
7 Bar Mains	**0.00**	**0.00**	**0.00**	
				No expenditure in business plan.
LP, 2Bar or 4Bar Mains	**50.05**	**48.60**	**-1.45**	
Infill	47.45	46.39	-1.06	*Allowance is based on business plan lengths, applied to the BoW rates.*
New Build	2.60	2.21	-0.39	*The length per property given at 9.5m and unit rate reduced.*
Pressure Reduction	**0.32**	**0.09**	**-0.23**	
				MP Inlet (growth) has been allowed. End of life BINS replacement has been removed based on a assumed life of 20 years.
Domestic Services	**21.52**	**23.81**	**2.29**	
New Build	1.67	1.59	-0.08	*The unit rate has been reduced.*
Existing	19.85	22.22	2.37	*The number of properties has been increased. The unit rate set to £880.*
Domestic Meters	**4.72**	**6.79**	**2.07**	
New	4.51	5.76	1.25	*The number of meters and unit rate have been increased.*
Replacement	0.21	0.00	-0.21	*Replacement expenditure has been removed based on a assumed life of 20 years.*
Other Exchange	0.00	1.03	1.03	*None in business plan, transfer from Opex*
I&C Services	**2.68**	**1.77**	**-0.90**	
				The unit rates have been reduced for very small and small services. The unit rates for medium and large services have been increased.
I&C Meters	**1.42**	**1.40**	**-0.01**	
New	1.37	1.40	0.04	*The unit rates for U6, U16, U65, U400 & U650 meters have been increased. All other unit rates have been reduced.*
Replacement	0.05	0.00	-0.05	*Replacement expenditure has been removed on a assumed life of 20 years.*
Exchange	0.00	0.00	0.00	*No expenditure in business plan.*
Other Capex	**1.13**	**3.67**	**2.54**	
				Addition of the Foyle River reinforcement, IUS replacement included, Telemetry partly included .
TMA	**7.46**	**7.42**	**-0.04**	
				The variance equates to 10% of total net final determination adjustment for mains and services.
Sub Total	**89.30**	**93.56**	**4.26**	
Post FS Adjustment	**0.00**	**-2.39**	**-2.39**	
Final Determination	**89.30**	**91.18**	**1.87**	

Table 116 FE Summary for GD17

FE – Detailed Assessment

FE – 7 Bar Mains

<u>FE – Reinforcement</u>

7.160 FE does not plan to lay any 7 bar mains during the GD17 price control period.

FE – Low and Medium Pressure Mains

<u>FE Infill Mains – Growth</u>

7.161 For GD17, FE prepared detailed plans to extend the gas network to the natural boundaries of the towns in its licence area, passing an additional 92,344 existing properties. The company proposed to pass 67,304 (73%) of these properties in GD17 with the remainder passed in the early years of the next price control.

7.162 FE provided detailed plans for the development of gas mains in each town comprising 621 individual projects. Each project assessment included a detailed layout of mains, a schedule of works priced using current tendered rates and an economic assessment of the project. The company has prepared a detailed programme of work to provide a logical and efficient build.

7.163 We reviewed a sample of the projects prepared by the company and concluded that the property counts and lengths of mains identified were reasonable and were able to confirm that the works identified were priced using current contract rates.

7.164 The annual rates of investment, properties passed and length of mains laid proposed by FE are summarised below.

Other Mains: Growth	2017	2018	2019	2020	2021	2022	GD17
Properties passed (no)	11,397	11,120	11,645	10,573	10,882	11,687	67,304
Length (m)	113,119	111,715	110,309	108,727	111,307	111,901	667,078
FE submission (£k)	7,804	7,580	7,628	7,951	7,886	8,602	47,451
m per property passed	9.93	10.05	9.47	10.28	10.23	9.57	9.91
£ per property passed	685	682	655	752	725	736	705

Table 117: Annual Infill Investment Proposed by FE

7.165 In Section 7.18, above we describe the economic test which we applied to determine whether further development of the gas network to serve existing areas is economic. Since the draft determination we have revised our assessment of the economic level of infill in the FE area to take account of additional information provided by the company on levels of gas consumption in the types of domestic properties it plans to pass to complete the infill development of its area. As a result, we concluded that it is economic to pass additional properties up to an average of £736 per property and 10.30m per property passed; an increase from £620 per property and 8.92m per property passed at the draft determination.

7.166 We concluded that the programme of infill work proposed by FE for the GD17 period is economic. We have therefore accepted the company's planned programme of work as the basis for the final determination. We have calculated allowances for infill mains for GD17 by applying the appropriate basket of works unit rate for each pipe size of the GDN's workload as proposed in its business plan submission, our allowances are shown in Table 118.

Other Mains: Growth	2017	2018	2019	2020	2021	2022	GD17
Properties passed (no)	11,366	11,071	11,528	10,414	10,765	11,673	66,817
Length (m)	113,119	111,715	110,309	108,727	111,307	111,901	667,078
UR final determination (£k) Pre RPE	7,902	7,695	7,613	7,629	7,741	7,807	46,388
m per property passed	9.95	10.09	9.57	10.44	10.34	9.59	9.98
£ per property passed	695	695	660	733	719	669	694

Table 118: FE Final Determination Other Mains: Growth

7.167 The detailed infill development plans prepared by FE for its business plan submission covered all infill for existing properties which the company considered viable over the long term including infill it plans to carry out after GD17. We used base construction costs provided by the company to make an initial estimate of the likely out-turn costs of this work. We included an allowance for capitalised opex and applied an adjustment factor to reflect both frontier shift and efficient unit rates based on our assessment of investment in the GD17 period. This provided us with a preliminary estimate of investment post GD17 which is set out in Table 119 below.

Other Mains GD23: Growth	2023	2024	2025	2026	2027	2028	GD23
Properties passed (no)	8,373	7,191	6,417	2,890	0	0	24,871
Length (m)	82,812	77,803	76,017	41,462	0	0	278,094
UR estimate (£k)	6,279	5,603	5,736	3,300	0	0	20,917
m per property passed	9.89	10.82	11.85	14.35	0	0	11.18
£ per property passed	750	779	894	1,142	0	0	841

Table 119: FE Other Mains GD23

7.168 In part, the company has prioritised its work so that some of the more expensive schemes necessary to complete its current plans will be carried out post GD17 in terms of both cost per property passed and cost per metre.

7.169 Combining our estimates for the company's planned programme of work both in GD17 and beyond provides an estimate for the total package of work which is presented in Table 120.

Other Mains GD17 & GD23: Growth	GD17	GD23	Total
Properties passed (no)	66,817	24,871	91,688
Length (m)	667,078	278,094	945,172
UR final determination (£k) Pre RPE	46,388	20,917	67,305
m per property passed	9.98	11.18	10.30
£ per property passed	694	841	734

Table 120: FE Other Mains GD17 and GD23

7.170 While some of the work scheduled for individual years post GD17 and the package of work as a whole post GD17 does not meet our economic test, the total combined package of work proposed by the company does meet our economic test. Having concluded that the totality of the long term package of work developed by the company is economic, we do not plan to undertake a further economic test for the GD23 determination in respect of the completion of this package of work. This will ensure that the company can deliver the work in the most economic way without any concern over the marginal economic viability of the work left to be completed in GD23.

7.171 We have concluded that infill investment in the FE area would be economic up to £736 per property (see Table 102). While some of the work scheduled for individual years post GD17 and the package of work as a whole post GD17 does not meet our economic test, the total combined package of work proposed by the company does meet our economic test. Having concluded that the totality of the long term package of work developed by the company is economic, we do not plan to undertake a further economic test for the GD23 price control in respect of the completion of the total package of work, provided there is no material change in the estimated costs or consumption of the remaining schemes. This will ensure that the company can deliver the work in the most economic way without the need to consider the marginal economic viability of the work left to be completed in GD23. We have set an upper limit on the average length of infill mains for property passed of 10.20m for the purpose of infill uncertainty mechanism described in Chapter 9 which reflects our current estimate of the long term economic average.

7.172 For GD23, we expect FE to provide an update on the infill projects it plans to carry out in GD23, identifying those projects which were included in the long term package of works in the GD17 business plan submission and any additional projects. We would expect FE to review the remaining projects which formed part of the GD17 package of projects, identify any outliers in respect of cost per property and justify why they should be included in a subsequent determination. We would expect the company to provide the information necessary to allow us to determine whether any additional schemes, which were not included in the GD17 submission, are economic.

FE – New Build Mains – Growth

7.173 The provision of gas mains to serve new developments proposed by FE is summarised in Table 121.

New Build Mains: Growth	2017	2018	2019	2020	2021	2022	GD17
Properties passed (no)	896	797	800	800	800	800	4,893
Length (m)	9,689	8,160	8,160	8,160	8,160	8,160	50,489
FE submission (£k)	526	417	416	415	414	412	2,601
m per property passed	10.81	10.24	10.20	10.20	10.20	10.20	10.32
£ per property passed	587	523	520	519	518	515	531

Table 121: FE Proposed New Build Mains and Outputs

7.174 Based on NISRA estimates of future household growth in the FE area, we concluded that 800 new properties is a reasonable assessment of future growth to include in the final determination.

7.175 In its business plan submission, FE proposed a length for infill mains of 10.32 m per property passed. In the draft determination we proposed an average length per property of 9.5 m per property passed, reflecting the combined experience of FE and PNGL. FE did not comment on this in its response and we have maintained this position for the final determination. The final determination allowance is based on a basket of works unit rate for new build of 48.48 £/m consistent with our draft determination. This is a weighted average rate which takes account of the mix of the diameters of mains required to serve new development which was identified by the company in its business plan submission.

7.176 The profile of connections and investment in the final determination is shown in Table 122.

New Build Mains: Growth	2017	2018	2019	2020	2021	2022	GD17
Properties passed (no)	800	800	800	800	800	800	4,800
Length (m)	7,600	7,600	7,600	7,600	7,600	7,600	45,600
UR final determination (£k) Pre RPE	370	365	366	371	368	370	2,211
m per property passed	9.50	9.50	9.50	9.50	9.50	9.50	9.50
£ per property passed	463	457	458	463	461	462	461

Table 122: FE Final Determination New Build Mains and Outputs

FE – District Governors and Pressure Reduction Stations

FE – PRS – Growth

7.177 We reviewed the forecast of activity volumes and costs associated with the construction of PRS installations. The levels are consistent with historical performance and are at a slightly reduced level from that submitted in GD14. We therefore accepted the forecasted costs as presented in Table 123.

District governors & PRS: Growth	2017	2018	2019	2020	2021	2022
FE submission (No.)	2	4	7	7	5	5
UR final determination (No.)	2	4	7	7	5	5
UR final determination (£k) Pre RPE	7	13	24	23	8	19

Table 123: FE Pressure Reducing Stations: Growth

FE – PRS – Replacement

7.178 FE proposed replacing approximately 20% of their governor stock by the end of the GD17 price control. PNGL plan to maintain similar installations over a 20 year life. In view of this and the fact that none of the plant which FE proposes to replace in GD17 will have been in place for 20 years, we have not allowed investment for the end-of-life replacement PRS installations proposed by FE.

FE – Domestic Service Connections

7.179 FE business plan proposed to connect 26,324 domestic customers over the GD17 price control period, 4,800 each for new build and NIHE properties, the remaining 16,724 for owner occupier properties, shown in Table 124.

Domestic Services: Growth	2017	2018	2019	2020	2021	2022
New Domestic Service (New Build)	800	800	800	800	800	800
New Domestic Service (OO)	2,466	2,537	2,622	2,753	3,100	3,246
New Domestic Service (NIHE)	800	800	800	800	800	800
FE submission (£k)	3,314	3,382	3,453	3,558	3,853	3,962

Table 124 FE Submission Domestic Services: Growth

7.180 Our draft determination concluded that the company's projection of new build and NIHE connections were reasonable. We increased the target number of existing owner occupier connections in the GD17 price control to 20,450 to reflect the increased planned mains laying programme in GD17 and the additional properties passed in our draft determination. In its response to the draft determination, FE commented on the significant increase in connections relative to its business plan submission. We have considered the company's comments and concluded that our targets are commensurate with the increase in infill over GD17 and historical rates of connections over the life of the company and by PNGL.

7.181 For the final determination we have retained the number of connections from our draft determination.

7.182 We have applied the appropriate basket of works unit rate to calculate the allowance for the final determination. The unit rate for domestic services other than new build has been increased to £880 as described in section 7.76. The profile of connections and investment in the final determination is shown in Table 125.

Domestic Services: Growth	2017	2018	2019	2020	2021	2022
New Domestic Service (New Build)	800	800	800	800	800	800
New Domestic Service (OO)	2,600	2,950	3,300	3,600	3,900	4,100
New Domestic Service (NIHE)	800	800	800	800	800	800
UR final determination (£k) Pre RPE	3,258	3,566	3,874	4,138	4,402	4,578

Table 125: FE Final Determination Domestic Services: Growth

FE – Industrial and Commercial Service Connections

7.183 FE forecast 150 I&C connections in each year of GD17 totalling 900 over the GD17 period. We have accepted the number of I&C connections proposed by FE. Our allowances are calculated by applying the appropriate basket of works unit rate. The profile of I&C connections the company's business plan estimate and the final determination allowance are shown in Table 126.

I&C Services: Growth	2017	2018	2019	2020	2021	2022
I&C Very Small (U6)	55	55	55	55	55	55
I&C Small (U16-U40)	74	74	74	74	74	74
I&C Medium (U65-U160)	18	18	18	18	18	18
I&C Large (U250-U650)	3	3	3	3	3	3
I&C Very Large (>U650)	0	0	0	0	0	0
FE submission (£k)	447	448	448	446	445	443
UR final determination (£k) Pre RPE	296	296	296	296	296	296

Table 126: FE Final Determination I&C services: Growth

FE – Domestic Meters

FE Domestic Meters – Growth

7.184 FE's business plan included a domestic meter for each new connection. The number and cost of domestic meters proposed by FE is shown in Table 127.

Domestic Meters: Growth	2017	2018	2019	2020	2021	2022
Domestic Total	4,066	4,137	4,222	4,353	4,700	4,846
FE submission (£k)	698	711	725	746	805	827

Table 127: FE Submission Domestic Meters: Growth

7.185 The number of domestic meters in the final determination reflects the increased target number of owner occupier connections (see paragraph 7.180 above). We have applied the appropriate basket of works unit rate to calculate the allowances for the final determination. The profile of connections and investment in the final determination is shown in Table 128.

Domestic Meters: Growth	2017	2018	2019	2020	2021	2022
Domestic Total	4,200	4,550	4,900	5,200	5,500	5,700
UR final determination (£k) Pre RPE	805	872	939	997	1,054	1,093

Table 128: FE Final Determination Domestic Meters: Growth

FE Domestic Meters – Replacement

7.186 FE proposed to replace domestic meters after fifteen years as shown in Table 129.

Domestic Meters: Replacement	2017	2018	2019	2020	2021	2022
Domestic Total	0	0	0	0	449	978
FE submission (£k)	0	0	0	0	66	145

Table 129: FE Submission Domestic Meters: Replacement

7.187 PNGL currently maintains its meter stock beyond this age, proposing to replace domestic meters after twenty years. In view of this we have excluded the end-of-life replacement of meters proposed by FE from the final determination.

7.188 FE replaces meters for reasons other than end-of-life and the costs associated with these were included in the business plan under opex costs. For the final determination, we have transferred these costs from opex to capex as a lump sum for each year as shown in Table 130.

Domestic Meters: Replacement	2017	2018	2019	2020	2021	2022
Domestic Total	0	0	0	0	0	0
Transfer of meter costs from Opex (£k)	128	144	160	178	199	219
UR final determination (£k) Pre RPE	128	144	160	178	199	219

Table 130: Final Determination Domestic Meters: Replacement

FE – Industrial and Commercial Meters

FE – Industrial and Commercial Meters – Growth

7.189 FE forecast 150 I&C connections in each year of GD17 totalling 900 over the GD17 period. A new meter is included on each connection. We have accepted the number of I&C meters proposed by FE. Our allowances are calculated by applying the appropriate basket of works unit rate. The profile of I&C meters, the company's business plan estimate and the final determination allowance are shown in Table 131.

I&C Meters: Growth	2017	2018	2019	2020	2021	2022
I&C Total	150	150	150	150	150	150
FE submission (£k)	235	237	225	224	224	223
UR final determination (£k) Pre RPE	239	248	229	229	229	229

Table 131: FE Final Determination I&C Meters: Growth

FE – Industrial and Commercial Meter Replacement

7.190 As with domestic meters FE propose to begin replacing I&C meters after fifteen years of life. The number and cost of replacement I&C meters proposed by FE are shown in Table 132.

I&C Meters: Replacement	2017	2018	2019	2020	2021	2022
I&C Total	0	0	0	0	85	133
FE submission (£k)	0	0	0	0	19	30

Table 132: FE Submission I&C Meters: Replacement

7.191 As with domestic meters, we note that PNGL currently maintain their meter stock beyond fifteen years age, proposing to begin replacing meters at twenty years. In view of this we have excluded the end-of-life replacement meters proposed by FE from the final determination.

FE – Other Capex

7.192 FE submitted costs for IT transformation in 2017. We did not include this allowance in the draft determination. The remaining costs including a small amount for transport were included in the draft determination.

7.193 We consulted further with FE regarding their IT transformation costs. FE confirmed that the proposed investment is to replace an aged bespoke IT system developed by FE's then parent company BGE. As part of our gas supply price control SPC17 we asked Gemserv to assess FE Supply IT transformations proposals. Gemserv confirmed that the proposed costs proposed by FE Supply were reasonable and were subsequently included in the SPC17 price control.

7.194 As the proposed costs relating to the distribution business are in line with those of the supply business we have included the allowance in our determination. By making this allowance for the distribution business we do not envisage circumstances where additional funding for specific new IT systems would be provided for the foreseeable future.

7.195 As part of our consultation process FE requested an allowance of £190k for telemetry be considered for inclusion in the final determination. We have reviewed the plans and estimates provided by the company and concluded:

- That the amount identified for the continuing replacement of daily metered supply points (£41k), which represents the on-going replacement of assets which began the GD14 price control period, is appropriate. The full amount requested is included in the final determination, subject to the application of the frontier shift.
- FE identified 18 locations on their existing network where it wishes to install pressure monitoring because concerns exist over possible low pressure on the network. We concluded that this work is necessary to manage the network and included the full amount requested (£34k) in the final determination, subject to the application of the frontier shift.
- The company requested a further allowance for and estimated ten low pressure monitoring sites which it had not yet identified. We have not included these in the final determination. We will consider funding for further sites which have been identified in GD23.

- An allowance of (£97k) requested by the company to convert 40 non daily metered supply points to daily metered supply points should not be included in the final determination. At present, there is no requirement under the company's network code to have to record these supplies consumption daily.

7.196 Our allowance for telemetry amounts to £75k over the GD17 period.

7.197 FE has identified a need to reinforce the supply to the cityside of Derry/Londonderry. This work was identified as a ring fence allowance and did not form part of the GD17 draft determination. In parallel with our work on the GD17 price control, we have continued to engage with the company on the need for an estimated cost of the Foyle River crossing, and we have accepted the need for a second crossing of the Foyle.

7.198 For the purpose of determining robust tariffs in the GD17 final determination, we have included a ring fenced allowance for the Foyle River crossing which reflects our current understanding of the company's proposals. This includes:

- A ring fenced allowance of £0.45m in 2016 for the planning and procurement of the successful delivery of a river crossing to secure the proposed increase in capacity for the cityside. The final amount will be determined through the GD14 uncertainty mechanism. Once confirmed, we will not make any further allowances for the completion of this planning and procurement work.

- A ring fenced allowance of £2.46m in GD17. This is an estimate of the construction of the river crossing and connecting mains based on the company's current estimate of the river crossing and our current estimate of a reasonable benchmark cost for the connecting mains.

7.199 We will continue a separate strand of engagement to determine a reasonable allowance and control mechanisms which we will communicate to the company separately. The allowance for the river crossing will be determined following a procurement exercise carried out by FE. The allowance for connecting mains will be determined on estimate of length and benchmark unit rates and will be adjusted to reflect the actual length laid. The necessary adjustments will be made in the GD23 final determination, subject to the delivery of the crossing.

7.200 FE's submission and our allowance are shown in Table 133.

Other Capex	2017	2018	2019	2020	2021	2022
FE submission (£k)	564	114	114	114	114	114
UR final determination (£k) Pre RPE	3,049	129	128	128	119	119
IT transformation	514	114	114	114	114	114
Transport	50	0	0	0	0	0
Foyle River crossing	2,464	0	0	0	0	0
Telemetry	21	16	14	14	5	5

Costs exclude 2016 investment of £0.45m post frontier shift for the Foyle River crossing

Table 133 FE Final Determination Other capex

FE – Traffic Management Act

7.201 As in previous price controls, we have allowed a ring fenced allowance for TMA equivalent to 10% of the allowances for main laying and service laying activities.

FE – Summary of Findings

7.202 In Table 134 we set out a summary of the FE's capex submission and our total capex allowance pre and post frontier shift for the final determination.

FE Final Determination	2017	2018	2019	2020	2021	2022	GD17
FE Business Plan Submission (£k)							
7 Bar Mains	0	0	0	0	0	0	0
LP, 2Bar or 4Bar Mains	8,330	7,996	8,044	8,366	8,300	9,015	50,052
Pressure Reduction	19	37	42	47	44	134	323
Domestic Services	3,314	3,382	3,453	3,558	3,853	3,962	21,521
Domestic Meters	698	711	725	746	872	972	4,724
I&C Services	447	448	448	446	445	443	2,678
I&C Meters	235	237	225	224	243	252	1,416
Other Capex	564	114	114	114	114	114	1,133
TMA	1,211	1,186	1,198	1,241	1,264	1,355	7,455
Total	14,818	14,111	14,249	14,742	15,135	16,247	89,302
UR Final Determination pre RPE (£k)							
7 Bar Mains	0	0	0	0	0	0	0
LP, 2Bar or 4Bar Mains	8,273	8,060	7,979	8,000	8,110	8,177	48,598
Pressure Reduction	7	13	24	23	8	19	95
Domestic Services	3,258	3,566	3,874	4,138	4,402	4,578	23,815
Domestic Meters	933	1,016	1,100	1,175	1,253	1,312	6,789
I&C Services	296	296	296	296	296	296	1,774
I&C Meters	239	248	229	229	229	229	1,403
Other Capex	3,049	129	128	128	119	119	3,672
TMA	1,183	1,192	1,215	1,243	1,281	1,305	7,419
Total	17,236	14,520	14,844	15,232	15,697	16,034	93,565
UR Final Determination post FS (£k)							
7 Bar Mains	0	0	0	0	0	0	0
LP, 2Bar or 4Bar Mains	8,217	7,937	7,792	7,761	7,816	7,830	47,353
Pressure Reduction	7	13	24	22	8	18	92
Domestic Services	3,236	3,512	3,783	4,014	4,242	4,383	23,170
Domestic Meters	927	1,001	1,074	1,140	1,208	1,256	6,605
I&C Services	294	291	289	287	285	283	1,729
I&C Meters	238	244	223	222	221	219	1,367
Other Capex	3,028	128	125	124	114	114	3,633
TMA	1,175	1,174	1,186	1,206	1,234	1,250	7,225
Total	17,121	14,300	14,496	14,778	15,129	15,353	91,176

Table 134: FE Final Determination Capex Allowance

FE – Capital Expenditure Assumptions Post GD17

7.203 We made the following assumptions to include a reasonable allowance of capital expenditure post GD17 for the purpose of modelling GD17 tariffs:

- FE did not identify any reinforcement post GD17 and no allowance has been made in our long term projections.
- We have included the infill proposed by FE in its business plan submission which we have prorated to the GD17 period allowances in our final determination. The adjustments made in the final determination reflect our assessment of economic infill taking account of the additional consumption data provided by FE, which have had a minor impact on our post GD17 assumptions.
- We have included an allowance for mains to serve new development based on an average of 800 new build properties per annum and a length of 9.5 metres of gas main per property.
- We have included the costs of meters and services associated with infill and new development based on connection profiles which reflect long term development projections and the impact of additional properties passed.
- The company did not identify any new pressure reducing stations in its submission post GD17 however we have included a nominal number of two per year in our long term capital assumptions.
- We have allowed for the replacement of domestic meters, I&C meters and pressure reducing stations on a 20 year life.
- We have continued the level of other capex proposed by the company in its submission for GD17, excluding IT replacement and the Foyle River crossing.
- We have continued an allowance for TMA costs at 10% of mains and services.

7.204 We have not applied real price effects or frontier shift to estimated expenditure post GD17.

PNGL – UR Proposals

PNGL – Overview

7.205 PNGL's revised business plan included capital investment of £112.85m in GD17 in Dec 2014 prices. The final determination allows capital investment of £92.55m following the application of the frontier shift in the years 2017 to 2022.

7.206 An explanation of the changes made to the capital programme for the final determination is given in the summary table below with more detailed information provided in the subsequent sections.

7.207 PNGL's business plan submission did not include the development of the East Down area which was the subject of a separate submission and licence revision. Investment in infill mains and connections for this area has been assessed in the GD17 determination. The development of gas services in East Down was subject to a DfE (formally DETI) economic assessment and an element of it will be included under Postalised Distribution Pipelines (PDPs).

7.208 Investment in bulk mains identified in the section beginning paragraph 7.209 will be included under Postalised Distribution Pipelines (PDP) in their entirety. These have not been included in the capital investment numbers reported below. Our assessment of the infill mains, new build mains and connections has been included in the figures reported below. Some part of these costs are also allocated to Postalised Distribution Pipelines for the purpose of tariff calculation, as set out in Chapter 11.

	Base Year Prices (£m)			
Item	**BPT**	**FD**	**Var**	**Explanation**
7 Bar Mains	**1.41**	**1.13**	**-0.29**	
				The scope of works has been accepted. The unit rates have been reduced by around 20%.
LP, 2Bar or 4Bar Mains	**16.26**	**5.44**	**-10.82**	
Infill	5.80	0.00	-5.80	*Infill expenditure has been removed based on the outcome of the economic appraisal.*
New Build	10.46	5.44	-5.03	*The length per property and unit rate have been reduced.*
Pressure Reduction	**0.73**	**0.60**	**-0.13**	
				IP Inlet growth expenditure has been removed in 2022. MP Inlet growth and BINS end of life replacement expenditure has been allowed.
Domestic Services	**28.67**	**28.16**	**-0.52**	
New Build	4.81	3.99	-0.82	*The number of properties has been reduced. The unit rate has been increased.*
Existing	23.86	24.17	0.31	*The number of properties has been increased. The unit rate has been reduced.*
Domestic Meters	**23.23**	**18.87**	**-4.36**	
New	12.36	8.59	-3.76	*The unit rate has been reduced. The number of properties has been reduced.*
Replacement	6.84	6.96	0.12	*The unit rate has been increased.*
Other Exchange	4.04	3.32	-0.72	*The unit rate has been reduced.*
I&C Services	**2.41**	**3.07**	**0.66**	
				There has been a minor reallocation of services from small, medium and large to very small. The unit rate for very small and small services has been increased. The unit rate for medium and large services has been reduced.
I&C Meters	**10.69**	**8.11**	**-2.58**	
New	2.18	2.19	0.01	*There have been a minor adjustments to the number of meters across the majority of sizes. The unit rate for U6, U16 & U400 meters has been increased. All others have been reduced.*
Replacement	6.31	3.80	-2.51	*All meter replacement expenditure included, other I&C meters above U40 at reduced rates.*
Exchange	2.20	2.12	-0.08	*The unit rate for U16 & U400 meters has been increased. All others have been reduced.*
Other Capex	**3.18**	**1.43**	**-1.75**	
				The innovation programme has been removed from plan.
TMA	**4.88**	**3.78**	**-1.10**	
				The variance equates to 10% of total net final determination adjustment for mains and services.
Sub Total	**91.46**	**70.58**	**-20.87**	
Post FS Adjustment	**0.00**	**-1.86**	**-1.86**	
Final Determination	**91.46**	**68.73**	**-22.73**	*Excluding East Down*
East Down		**23.82**		*East Down infill mains and connections*
Final Determination		**92.55**		*Including East Down infill mains and connections*

Table 135: PNGL Summary for GD17

PNGL – 7 Bar Mains and East Down Bulk Mains

PNGL – East Down Bulk Mains

7.209 As part of its licence extension application, PNGL submitted costs in relation to East Down which included the bulk mains costs. These mains run largely between the relevant towns and are made up of a mixture of sizes and pressures ranging from 7 bar 450mm mains to 4 bar 125mm mains.

7.210 We have based our final determination on a recently tendered 7 bar main similar in nature, which results in an allowance of £11.13m in 2016, £5.79m in 2017 and 6.46m in 2018 (all Sept 2015 prices).

7.211 In addition, we will set an allowance for elements of the project relating to significant engineering barriers which concentrate on crossing rivers and main roads. For our draft determination we proposed to ring fence an amount of £100k for each element which consisted of four river crossings in Lisburn, Drumaness, two in Downpatrick; and A1 and M1 road crossings. During the consultation period we received the tendered costs for three crossings from PNGL and we determined an allowance of £297,304.01 (April 2016 prices) in line with our expectations. The remaining ring fenced amount equal to that in our draft determination will be subject to further consideration once more detail for the remaining crossings becomes available.

7.212 These costs will be subject to a risk sharing mechanism based on a 65:35 customer/GDN split. Given the separate nature of these costs and the fact that they will be allocated in their entirety as Postalised Distribution Pipelines, we have not included them in the summary tables that follow.

PNGL – Reinforcement

7.213 PNGL identified one 7 bar reinforcement project ‘Ballysallagh to Craigantlet’ in its ‘Network Reinforcement’ paper submitted in June 2015 consisting of a 315mm pipeline approximately 5km in length which will maintain sufficient pressure in the Bangor and Newtownards areas as new connections are made and demand increases.

7.214 Projects to reinforce the Bangor and Newtownards area were previously allowed in the 1999-2000 period but never delivered. Some of these costs have already been paid for by customers leading to concerns about customers paying twice. This matter was considered by the CC in 2012 and further consulted on by us in GD14. The GD14 final determination set out our decision in sections 10.36-10.39. This decided that the full costs of these pipelines would be allowed again and no adjustments would be made in respect of previous rewards paid to PNGL for these pipelines.

7.215 In its business plan submission, PNGL provided summary network modelling information and existing pressure records to support its proposal and advised us that its analysis and design was based on conditions experienced in the winter of 2010-11. It also includes interruptible supply loads (which the company noted had minimal impact) and takes account of local experience of diversity on peak demand. We included an allowance for the work in our draft determination but asked PNGL to review its design for a 1 in 20 year design event recurrence interval with interruptible supply loads switched off to confirm the need for the project.

7.216 PNGL responded to our consultation with a paper demonstrating the impact of interruptible customers and provided the peak mean hourly pressure at the IPRS feeding North Down. Based on the information we received, we have included an allowance in our final determination. To calculate the appropriate unit rate we used a recent tender for a 7 bar main similar in nature which was also the basis for setting the allowance for PNGL's 7 bar bulk mains to supply East Down. Applying the same principles resulted in a reduction from the business plan submission of £1.4m to the draft determination allowance of £1.1m pre RPE. This was accepted as reasonable by PNGL in its response to the draft determination and has been maintained for the final determination. The investment profile for the final determination is shown in Table 136.

7 bar mains: Reinforcement	2017	2018	2019	2020	2021	2022
PNGL submission (£k)	0	0	0	1,412	0	0
UR final determination (£k) Pre RPE	0	0	0	1,126	0	0

Table 136: PNGL 7 bar Mains: Reinforcement

7.217 This allowance is allocated specifically for the completion of this project for which PNGL has undertaken a detailed technical assessment to establish the need and to establish that the proposed solution is the optimum way of meeting that need. As such, we have included it as a nominated output for PNGL in GD17. If the company decides that the main is not needed or the investment can be deferred to a later date, we would apply an adjustment under the uncertainty mechanism to the price control to either remove the investment or defer it to a later date so that consumers pay for the service delivered. If the company decides, following further technical assessment, that an alternative solution should be provided, we will review the proposed solution and make a decision on whether the GD17 allowance should be amended to reflect that solution.

PNGL – Low and Medium Pressure Mains

<u>PNGL Infill mains – Growth</u>

7.218 In its GD17 business plan submission PNGL requested an allowance to pass approximately 5730 existing properties in its existing licence area (excluding East Down). These properties represent the remainder of what PNGL considers reasonable to connect on its network. The investment proposed for its existing is summarised in Table 137

	2017	2018	2019	2020	2021	2022	GD17
Properties Passed (no)	1,105	1,105	1,105	1,105	1,105	205	5,730
Length (m)	14,365	14,365	14,365	14,365	14,365	2,665	74,490
PNGL submission (£k)	1,001	988	1,181	1,100	1,191	334	5,796
m per property passed	13.00	13.00	13.00	13.00	13.00	13.00	13.00
£ per property passed	906	895	1,069	995	1,078	1,628	1,011

Table 137: PNGL Proposed Infill Investment – excluding East Down

7.219 PNGL developed detailed assessments for approximately half these properties and projected the results of that analysis to estimate the cost of passing all 5,730 properties. Each project assessment included a detailed plan of mains, a schedule of works priced using current tendered rates and an economic assessment of the project.

7.220 We reviewed a sample of the projects prepared by the company and concluded that the property counts and lengths of mains identified were reasonable and were able to confirm that the works identified were priced using current contract rates.

7.221 In Section 7.18 above we described the economic test which we applied to determine whether further development of the gas network to serve existing areas within Greater Belfast is economic. We concluded that it is economic to pass additional properties up to an average of £359 per property and 5.16 m per property passed. Neither the overall package of development proposed for GD17, nor the package of work proposed for any individual year met this test. Inspection of the individual projects revealed that the most beneficial project had a cost per property passed of £619.

7.222 Based on our economic assessment of PNGL's proposals we conclude that none of PNGL's infill within Greater Belfast is warranted. In response to this conclusion in our draft determination, PNGL made three key points relating to:

- The inclusion of contractor management costs and capitalised on costs to the costs used in our economic appraisal.
- The number of I&C properties included in the economic appraisal.
- The application of our economic appraisal to future work in isolation as opposed to including past and future investment in a combine appraisal.

7.223 We considered and responded to these issues in the section beginning paragraph 7.23. We have maintained the position set out in the draft determination and excluded this investment from the final determination on the basis that it has not been shown to be economic. We will consider further representations for GD23 if PNGL can provide further evidence to demonstrate that this investment is economic. It is also open to PNGL to propose a change during GD17 if it can demonstrate that this or other infill work is economic.

7.224 PNGL also plans to undertake infill in the East Down area in GD17 to pass an estimated 21,982 properties. The infill investment proposed for East Down is shown in Table 138.

	2017	2018	2019	2020	2021	2022	GD17
Properties Passed (no)	1,041	1,957	5,370	5,262	4,913	3,439	21,982
Length (m)	11,992	22,546	61,883	60,636	56,615	39,632	253,304
PNGL submission (£k)	902	1,673	4,545	4,454	4,161	2,921	18,656
m per property passed	11.52	11.52	11.52	11.52	11.52	11.52	11.52
£ per property passed	867	855	846	847	847	849	849

Table 138: PNGL Proposed Infill Investment – East Down

7.225 We have not applied an economic test for infill mains in East Down as DfE (formerly DETI) considered this under its appraisal when making its decision to support the East Down extension.

7.226 For the final determination, we have reviewed the plans and workload estimates which PNGL prepared for East Down and concluded that they were a reasonable assessment of properties passed and length of main. We have calculated allowances for infill mains for GD17 by applying the appropriate basket of works unit rate for each pipe size of the GDN's workload as proposed in their business plan submission, our allowances are shown in Table 139.

Other Mains: Growth	2017	2018	2019	2020	2021	2022	GD17
Properties passed (no)	1,041	1,957	5,370	5,262	4,913	3,439	21,982
Length (m)	12,184	25,399	62,024	60,747	54,205	38,576	253,134
UR final determination (£k) Pre RPE	864	1,800	4,548	4,466	4,056	2,932	18,665
m per property passed	11.70	12.98	11.55	11.54	11.03	11.22	11.52
£ per property passed	830	920	847	849	826	852	849

Table 139 PNGL Final Determination Other Mains: Growth

7.227 In view of our conclusions above, the infill allowance for GD17 is based on work in the East Down area only. In view of the different conclusions reached on the economics of infill in the East Down area and the remainder of PNGL's licence area, we will have set out an uncertainty mechanism in Section 9 which distinguishes between the two areas. We expect the company to report work on infill in the two areas separately during the GD17 period.

PNGL New Build Mains – Growth

7.228 The extent of new gas mains to serve new development proposed by PNGL for its licence area (excluding East Down) is summarised in Table 140.

New Build Mains: Growth	2017	2018	2019	2020	2021	2022	GD17
Properties passed (no)	2,900	3,000	3,000	3,000	3,000	3,000	17,900
Length (m)	30,223	31,265	31,265	31,265	31,265	31,265	186,546
PNGL submission (£k)	1,863	1,896	1,664	1,550	1,678	1,813	10,464
m per property passed	10.42	10.42	10.42	10.42	10.42	10.42	10.42
£ per property passed	642	632	555	517	559	604	585

Table 140: PNGL Proposed New Build Mains and Outputs (excluding East Down)

7.229 The company has estimated new development rates of 3,000 properties per annum. This is higher than levels of development in the period 2011 to 2014. The company has suggested that the housing market is expected to pick up as it recovers from a period of depressed activity. We have considered the average rates of medium term household growth by NISRA. This suggests household growth rates of 0.5% per annum which equates to 1,600 properties per annum. For the final determination, we have included 2,000 new build properties per annum within Greater Belfast.

7.230 The extent of new gas mains to serve new development proposed by PNGL the East Down area is summarised in Table 141.

New Build Mains: Growth	2017	2018	2019	2020	2021	2022	GD17
Properties passed (no)	32	63	114	114	114	114	550
Length (m)	187	370	672	672	672	672	3,244
PNGL submission (£k)	11	22	40	40	40	40	192
m per property passed	5.90	5.90	5.90	5.90	5.90	5.90	5.90
£ per property passed	348	348	348	348	348	348	348

Table 141: PNGL Proposed New Build Mains and Outputs (East Down)

7.231 For East Down we accepted the rates of new development proposed by the company as a reasonable estimate.

7.232 The allowance in the final determination is based on an average of 9.5 m per property, reflecting the combined experience of PNGL and FE. The final determination allowance is based on a basket of works unit rate for new build of 47.72 £/m. The profile of connections and investment in the final determination is shown in Table 142.

New Build Mains: Growth	2017	2018	2019	2020	2021	2022	GD17
Properties passed (no)	2,032	2,063	2,114	2,114	2,114	2,114	12,550
Length (m)	19,302	19,595	20,081	20,081	20,081	20,081	119,223
UR final determination (£k) Pre RPE	922	930	965	957	957	957	5,689
m per property passed	9.50	9.50	9.50	9.50	9.50	9.50	9.50
£ per property passed	454	451	457	453	453	453	453

Table 142: PNGL Final Determination New Build Mains and Outputs

7.233 We note that both the company business plan submission and our final determination are estimates of future development which will be driven by broader economic circumstances. This uncertainty is addressed by the uncertainty mechanism for new build infill mains which adjusts the determination for the actual number of new build properties passed, allowing the company to respond to the new development which takes place.

PNGL – District Governors and Pressure Reduction Stations

PNGL – PRS Reinforcement

7.234 PNGL's business plan included a submission on 'Network Reinforcement' where PNGL propose to reinforce their network with three district governors namely Lisburn Road MPRS, Village MPRS, and Holywood Road MPRS. We have reviewed and accepted both the need for this work and the company's estimates. We have not included the proposed expenditure for year 2022 which did not have a specific output.

7.235 The allowances included in the final determination are set out in Table 143.

District governors & PRS: Reinforcement	2017	2018	2019	2020	2021	2022
PNGL submission (No.)	0	1	2	0	0	0
UR final determination (No.)	0	1	2	0	0	0
UR final determination (£k) Pre RPE	0	84	161	0	0	0

Table 143: PNGL Pressure Reducing Stations: Reinforcement

7.236 This allowance is allocated specifically for the completion of the projects for which PNGL has undertaken a detailed technical assessment to establish the need and to establish that this is the optimum way of meeting that need. As such, we have included it as a nominated output for PNGL in GD17. If the company decides that a security of supply scheme is not needed or the investment can be deferred to a later date, we would apply a retrospective adjustment to the price control to either remove the investment or defer it to a later date so that consumers pay for the service delivered. If the company decides, following further technical assessment, that an alternative solution should be provided, we will review the proposed solution and make a decision on whether the GD17 allowance should be amended to reflect that solution.

PNGL – PRS Replacement

7.237 PNGL propose to replace approximately 18% of their governors by the end of GD17. This is based on a twenty year end-of-life replacement. We have allowed these governor replacements for the final determination as shown in Table 144.

District governors & PRS: Replacement	2017	2018	2019	2020	2021	2022
PNGL submission (No.)	0	9	33	65	50	31
UR final determination (No.)	0	9	33	65	50	31
UR final determination (£k) Pre RPE	0	17	63	115	96	64

Table 144: PNGL Pressure Reducing Stations: Replacement

PNGL – Pressure reducing stations – East Down

7.238 In its business plan submission, PNGL did not identify PRS associated with infill mains (growth) in its existing licence area. Historically, the company has reported costs of PRS associated with infill mains as part of the cost of infill mains. We have concluded that the cost of PRS are adequately covered in the basket of works unit rates for the company and have made no further specific provision in the final determination.

PNGL – Service Connections

PNGL – Domestic service connections

7.239 PNGL plan to connect 47,600 domestic customers within Greater Belfast over the GD17 price control period, 17,600 of new build, 6,000 NIHE properties, with the remaining 24,000 owner occupier properties. A further 2,611connections are proposed in East Down from PNGL's revised proposals. The total number of connections for each tenure is shown in Table 145.

Domestic Services: Growth	2017	2018	2019	2020	2021	2022
New Domestic Service (New Build)	2,821	2,846	3,086	3,112	3,112	3,112
New Domestic Service (OO)	4,047	4,083	4,197	4,343	4,447	4,533
New Domestic Service (NIHE)	1,006	1,022	1,046	1,095	1,137	1,166
PGNL submission (£k)	4,770	4,817	4,936	5,046	5,197	5,079

Table 145 PNGL Submission Domestic Services: Growth

7.240 We have concluded that the company's projections of NIHE connections were reasonable. We have increased the target number of existing owner occupier connections in GD17 to 28,500, reduced by 5% from our draft determination. We have reduced the number of new build connections in the existing PNGL area to 2,000 per annum in line with our draft determination (see paragraph 7.229) and accepted the company's estimate for new build connections in East Down.

7.241 We have applied the basket of works unit rates to calculate the appropriate allowance for the final determination. We have maintained PNGL's unit rate for domestic connections other than new build from our draft determination as the historic average of FE and PNGL. The profile of connections and investment in the final determination is shown in Table 146. This table provides a total for PNGL including East Down. The associated uncertainty mechanism for domestic services described in Chapter 9 will apply to PNGL as a whole.

Domestic Services: Growth	2017	2018	2019	2020	2021	2022
New Domestic Service (New Build)	2,021	2,046	2,086	2,112	2,112	2,112
New Domestic Service (OO)	5,000	4,900	4,800	4,700	4,600	4,500
New Domestic Service (NIHE)	1,006	1,022	1,046	1,095	1,137	1,166
UR final determination (£k) Pre RPE	5,094	5,041	4,998	4,969	4,927	4,874

Table 146 PNGL Final Determination Domestic Services: Growth

PNGL – Industrial and Commercial Service Connections

7.242 PNGL forecast 305 I&C connections in each year of GD17 totalling 1,830 over the GD17 period for its licence area excluding East Down. In its revised estimates for East Down, the company 595 I&C connections over the GD17 period rising from 11 in 2017 to 191 in 2022. We have accepted the number of I&C connections proposed by PNGL. Our allowances are calculated by applying the appropriate basket of works unit rate. The combined profile of I&C connections the company's business plan estimate and the final determination allowance are shown in Table 147.

I&C Services: Growth	2017	2018	2019	2020	2021	2022
I&C Very Small (U6)	164	174	205	243	268	284
I&C Small (U16-U40)	131	136	150	168	180	187
I&C Medium (U65-U160)	16	17	18	19	20	21
I&C Large (U250-U650)	4	4	4	4	4	4
I&C Very Large (>U650)	0	0	0	0	0	0
PNGL submission (£k)	416	428	466	516	549	551
UR final determination (£k) Pre RPE	528	548	615	697	751	785

Table 147 PNGL Final Determination I&C services: Growth

PNGL – Domestic Meters

PNGL – Domestic Meters - Growth

7.243 PNGL's business plan and East Down submission included a domestic meter at each new connection. The numbers and cost of domestic meters proposed by PNGL are shown in Table 148.

Domestic Meters: Growth	2017	2018	2019	2020	2021	2022
Domestic Total	7,875	7,951	8,330	8,549	8,696	8,810
PNGL submission (£k)	2,062	2,064	2,137	2,193	2,227	2,278

Table 148 PNGL Submission domestic meters: Growth including East Down

7.244 We have adjusted the number of domestic meters in the final determination to reflect the increased target number of owner occupier connections and reduced the number of new build connections. We have applied the basket of works unit rates to calculate the appropriate allowance for the final determination. The profile of connections and investment in the final determination is shown in Table 149.

Domestic Meters: Growth	2017	2018	2019	2020	2021	2022
Domestic Total	8,027	7,968	7,933	7,906	7,849	7,778
UR final determination (£k) Pre RPE	1,539	1,528	1,521	1,516	1,505	1,491

Table 149 PNGL Final Determination Domestic Meters: Growth

PNGL – Domestic Meters Replacement

7.245 PNGL proposed to replace domestic meters after twenty years of service. We took advice from our consultants Rune Associates on PNGL's meter replacement strategy and prepared an economic appraisal of the life cycle costs of meter replacement taking account of battery replacement, regulator maintenance and meter replacement. We concluded that there was scope for PNGL to consider options for deferring replacement. Such a decision would require careful consideration and further asset management work by PNGL and our view remains that it is appropriate to allow funding for a 20 year cycle of replacement of domestic meters.

7.246 In addition to end-of-life replacement meters, PNGL requested an allowance for replacing meters for other reasons. These could be at customer request or faults with meters among various other reasons. We have continued to include the allowance for this work in the final determination as the proposed replacement numbers reflect past experience.

7.247 PNGL's proposed investment in replacement domestic meters is shown in Table 150.

Domestic Meters: Replacement	2017	2018	2019	2020	2021	2022
Domestic Total End of Life	6,490	6,490	6,490	6,490	6,490	13,791
PNGL submission (£k)	799	793	785	787	787	2,889
Domestic Total Other Replacement	2,886	2,886	2,886	2,886	2,886	2,886
PNGL submission (£k)	680	674	667	669	669	677

Table 150: PNGL Submission Domestic Meters: Replacement

7.248 The profile of replacement meters and investment in the final determination is shown in Table 151. We have re-profiled PNGL's end-of-life replacement meters to match the profile of meter installation rather than the smoothed profile proposed by PNGL. We have applied the basket of works unit rates to estimate the appropriate allowance for the final determination. We amended the rates for end-of-life meter replacement to reflect the proportion of credit and PAYG meters in which will be replaced.

Domestic Meters: Replacement	2017	2018	2019	2020	2021	2022
Domestic Total End of Life	1,119	4,159	5,803	9,769	11,597	13,792
UR final determination (£k) Pre RPE	158	588	820	1,380	1,638	2,379
Domestic Total Other Replacement	2,886	2,886	2,886	2,886	2,886	2,886
UR final determination (£k) Pre RPE	553	553	553	553	553	553

Table 151: PNGL Final Determination Domestic Meters: Replacement

7.249 End of life replacement meters will be subject to an uncertainty mechanism under which the estimated replacement rates shown above will be corrected for the number and size of meters which PNGL replace over the GD17. To provide an incentive for PNGL to defer replacement and extend the life of the meter stock, we will not implement the uncertainty mechanism to the extent that the change is as a result of extending the meter life and that this extended life will inform future price controls see paragraph 7.141 above.

PNGL – Industrial and Commercial Meters

PNGL – Industrial and Commercial Meters Growth

7.250 PNGL's business plan and East Down submission included an I&C meter at each new connection. A new meter is included on each connection. We have accepted the number of I&C meters proposed by PNGL. Our allowances are calculated by applying the appropriate basket of works unit rate. The profile of I&C meters, the company's business plan estimate and the final determination allowance are shown in Table 131.

I&C Meters: Growth	2017	2018	2019	2020	2021	2022
I&C Total	316	330	377	434	472	496
UR final determination (£k) Pre RPE	372	381	412	449	473	488

Table 152 PNGL Final Determination I&C Meters: Growth

PNGL – Industrial and Commercial Meters Replacement

7.251 PNGL propose to replace all I&C meters after twenty years of service. The company did not provide an economic case to support the replacement of meters on the basis of age. In addition to end-of-life replacement meters, PNGL have requested an allowance for replacing meters for other reasons which include customer requested exchange or meter faults. The I&C meter replacement work included in the business plan is summarised in Table 153.

I&C Meters: Replacement	2017	2018	2019	2020	2021	2022
I&C Total End of Life	792	792	792	792	792	1,164
PNGL submission (£k)	941	941	935	934	934	1,623
I&C Total Other Replacement	111	111	111	111	111	111
PNGL submission (£k)	363	363	360	360	360	395

Table 153: PNGL Submission I&C Meters: Replacement

7.252 We took advice from our consultants Rune Associates on PNGL's I&C meter replacement strategy. Taking account of this advice and our economic appraisal of domestic meter replacement, we included the replacement of U6 I&C meters in the draft determination. We have re-profiled PNGL's U6 end-of-life replacement meters to match the profile of meter installation rather than the smoothed profile proposed by PNGL.

7.253 In view of the higher replacement cost estimated by PNGL for larger I&C meters and the opportunities for extending the life of these assets by maintenance and partially replacement of key components, we did not include the end-of-life replacement for larger meters at 20 years as proposed by PNGL.

7.254 In PNGL's consultation response the company assessed options for managing these high value assets and their associated whole life costs. Their response considered replacement on age, targeted replacement of key components or the continued maintenance of the plant over a longer life.

7.255 PNGL provided the cost of replacing the physical meter and other associated key components necessary to restore rotary and turbine meters to an as new condition. We have accepted these costs as reasonable only reducing the management fee and capitalised opex uplift by 5%in total to bring into line with their business plan. These rates are shown in Table 115.

7.256 Based on the information provided by PNGL we have reached the following conclusions for the final determination:

- U6 – U40 diaphragm meters can be replaced after 20 years with a reduced BoW of £130 for U6 meters, using the full BoW rates for U16 – U40 meters.
- U65 and above rotary and turbine meters have targeted replacement of key components after 20 years using the rates shown in Table 115.

7.257 The profile of replacement meters and investment in the final determination is shown in Table 154.

I&C Meters: Replacement	2017	2018	2019	2020	2021	2022
I&C Total End of Life	355	673	735	977	1,219	1,163
UR final determination (£k) Pre RPE	316	533	567	713	837	832
I&C Total Other Replacement	111	111	111	111	111	111
UR final determination (£k) Pre RPE	353	353	353	353	353	353

Table 154 PNGL Final Determination I&C Meters: Replacement

7.258 End of life replacement meters will be subject to the uncertainty mechanism under which the calculated replacement rates shown above will be corrected for the number and size of meters which PNGL replace over the GD17.

PNGL – Other Capex

7.259 PNGL submitted an allowance for the construction of compressed natural gas filling stations which has been discussed in Chapter 8 in the final determination and the allowance for this project has been removed from the first three years of the GD17 price control. The remaining costs for IT and telecoms, system operations, land, buildings, furniture and fittings have been accepted for the final determination as they remain in line with allowances for GD14. PNGL's submission and the final determination allowance are shown in Table 155.

Other Capex	2017	2018	2019	2020	2021	2022
PNGL submission (£k)	819	819	829	239	239	239
UR final determination (£k) Pre RPE	239	239	239	239	239	239

Table 155 PNGL Final Determination Other Capex including East Down

PNGL – Traffic Management Act

7.260 As in previous price controls, we have given a ring fenced allowance for TMA equivalent to 10% of the allowances for main laying and service laying activities.

PNGL – Summary of Findings

7.261 In Table 156 we set out a summary of the PNGL's capex submission and our total capex allowance pre and post frontier shift for the final determination.

PNGL Final Determination	2017	2018	2019	2020	2021	2022	GD17
PNGL Business Plan Submission & Revised East Down Submission (£k)							
7 Bar Mains	0	0	0	1,412	0	0	1,412
LP, 2Bar or 4Bar Mains	2,864	2,884	2,845	2,649	2,870	2,147	16,260
Pressure Reduction	0	101	224	115	96	196	732
Domestic Services	4,769	4,771	4,842	4,837	4,838	4,615	28,673
Domestic Meters	3,524	3,496	3,512	3,521	3,521	5,656	23,230
I&C Services	406	406	404	403	403	385	2,408
I&C Meters	1,663	1,663	1,652	1,650	1,650	2,408	10,685
Other Capex	819	819	829	239	239	239	3,182
TMA	804	806	809	930	811	715	4,875
East Down	1,276	2,584	5,696	5,077	3,958	2,799	21,389
Total	16,124	17,531	20,813	20,833	18,386	19,159	112,847
UR Final Determination pre RPE (£k)							
7 Bar Mains	0	0	0	1,126	0	0	1,126
LP, 2Bar or 4Bar Mains	1,786	2,730	5,513	5,423	5,013	3,889	24,354
Pressure Reduction	0	101	224	115	96	64	600
Domestic Services	5,094	5,041	4,998	4,969	4,927	4,874	29,903
Domestic Meters	2,250	2,669	2,894	3,449	3,696	4,423	19,381
I&C Services	528	548	615	697	751	785	3,923
I&C Meters	1,041	1,267	1,332	1,515	1,663	1,673	8,491
Other Capex	239	239	239	239	239	239	1,432
TMA	741	832	1,113	1,221	1,069	955	5,931
Total	11,679	13,427	16,928	18,753	17,453	16,901	95,141
UR Final Determination post FS (£k)							
7 Bar Mains	0	0	0	1,092	0	0	1,092
LP, 2Bar or 4Bar Mains	1,774	2,689	5,384	5,261	4,832	3,724	23,663
Pressure Reduction	0	100	219	111	92	61	584
Domestic Services	5,060	4,964	4,881	4,820	4,748	4,667	29,141
Domestic Meters	2,235	2,628	2,826	3,346	3,562	4,235	18,833
I&C Services	524	540	601	676	724	751	3,815
I&C Meters	1,034	1,248	1,301	1,470	1,603	1,602	8,257
Other Capex	237	235	233	232	230	229	1,395
TMA	736	819	1,087	1,185	1,030	914	5,771
Total	11,600	13,223	16,531	18,193	16,821	16,183	92,552

Table 156: PNGL Final Determination Capex Allowance

PNGL – Capital Expenditure Assumptions Post GD17

7.262 We made the following assumptions to include a reasonable allowance of capital expenditure post GD17 for the purpose of modelling GD17 tariffs:

- PNGL identified further reinforcement which it believes will be needed in 2025 and 2026. We have included this investment in our projections. We expect the company to review and confirm the need for this investment in a subsequent price control

- Based on our economic test of infill investment proposed by PNGL in GD17, we have made no further allowance for infill investment in our long term projections.
- We have included an allowance for mains to serve new development based on an average of 2,112 new build properties per annum and a length of 9.5 metres of gas main per property.
- We have included the costs of meters and services associated with existing properties and new development based on the connection profiles included in Section 7.239.
- The company did not identify any new pressure reducing stations in its submission post GD17 and none have been included in our long term capital assumptions.
- We have allowed a rising trend for the replacement of domestic meters, I&C meters and pressure reducing stations on a 20 year life.
- We have continued the constant trend in investment for non end-of-life replacement meters.
- We have continued the level of other capex proposed by the company in its submission for GD17, excluding exceptional items.
- We have continued an allowance for TMA costs at 10% of mains and services.

7.263 We have not applied real price effects or frontier shift to estimated expenditure post GD17.

SGN – UR Proposals

SGN – Overview

7.264 SGN's business plan included capital investment of £54.39m in GD17 in Dec 2014 prices. The final determination allows capital investment of £44.75m following the application of the frontier shift in the years 2017 to 2022.

7.265 An explanation of the changes made to the capital programme for the final determination is given in Table 157 below with more detailed information provided in the subsequent sections.

Item	Base Year Prices (£m) BPT	FD	Var	Explanation
7 Bar Mains	**0.00**	**0.00**	**0.00**	
				No expenditure in business plan.
LP, 2Bar or 4Bar Mains	**37.88**	**24.87**	**-13.01**	
Infill	37.56	24.33	-13.22	*Revised development plan reduced length of mains proposed. Infill pushed back a year and reprofiled, uplift for cat2 roads applied to basket of works rates.*
New Build	0.32	0.53	0.22	*The length per property and the unit rate have been increased, reprofiled and pushed back a year.*
Pressure Reduction	**4.91**	**0.63**	**-4.28**	
				In line with PNGL reprofile for new mains and larger sizes based on design data
Domestic Services	**5.10**	**5.58**	**0.48**	
New Build	0.10	0.38	0.29	*The property number has been increased and the unit rate reduced, reprofiled and pushed back a year.*
Existing	5.00	5.19	0.19	*The property number has been increased and the unit rate set to £880.*
Domestic Meters	**1.11**	**1.35**	**0.24**	
New	1.11	1.35	0.24	*The number of of meters has been increased and the unit rate reduced slightly, reprofiled and pushed back a year.*
Replacement	0.00	0.00	0.00	*No expenditure in business plan.*
Other Exchange	0.00	0.00	0.00	*No expenditure in business plan.*
I&C Services	**0.99**	**3.88**	**2.90**	
				The number of small, medium and large services has been increased. Very small services have been added and very large services removed. The unit rate has been reduced for small services and increased for medium and large, reprofiled and pushed back a year.
I&C Meters	**1.58**	**3.95**	**2.37**	
New	1.58	3.95	2.37	*U6 meters have been added. The number of meters in sizes up to U160 has been increased. The unit rate for U25, U40 and U650 meters has been reduced. All others have been increased, reprofiled and pushed back a year.*
Replacement	0.00	0.00	0.00	*No expenditure in business plan.*
Exchange	0.00	0.00	0.00	*No expenditure in business plan.*
Other Capex	**2.83**	**2.37**	**-0.46**	
				Primarily ring fenced amount for SPED's.
TMA	**0.00**	**3.43**	**3.43**	
				This is 10% of the total final determination allowance for mains and services.
Sub Total	**54.39**	**46.07**	**-8.32**	
Post FS Adjustment	**0.00**	**-1.32**	**-1.32**	
Final Determination	**54.39**	**44.75**	**-9.64**	

Table 157: SGN Summary for GD17

SGN – Detailed Assessment

SGN – 7 Bar Mains

SGN – 7 Bar Mains - Reinforcement

7.266 SGN does not plan to lay any 7 bar mains during the GD17 price control period.

SGN – Low and Medium Pressure Mains

SGN Infill Mains – Growth

7.267 The level of investment on infill mains proposed by SGN in its business plan submission is summarised in Table 158.

	2017	2018	2019	2020	2021	2022	GD17
Properties Passed (no)	4,054	4,586	4,554	4,553	4,542	4,543	26,832
Length (m)	70,484	92,235	76,905	45,970	45,970	45,970	377,534
SGN submission (£k)	7,048	9,175	7,668	4,564	4,564	4,564	37,583
m per property passed	17.39	20.11	16.89	10.10	10.12	10.12	14.07
£ per property passed	1,739	2,001	1,684	1,002	1,005	1,005	1,401

Table 158 Annual Infill Investment Proposed by SGN

7.268 This submission was based on an early assessment of the likely development necessary to complete the infill in the main towns served. At that time, the company was considering an accelerated programme which would have completed the bulk of infill in the main towns served, on the basis of efficiency of delivery and momentum in terms of generating connections. At the draft determination, we noted the need for the company to continue to develop its plans for infill to allow us to arrive at robust conclusions for the final determination.

7.269 As part of on-going engagement following the draft determination, SGN made a number of submissions which improved the quality of information in infill mains and presented a revised plan for infill of only part of the main towns served in the GD17 period with further infill proposed for subsequent price controls. The plan for infill was also delayed by one year to reflect re-profiled delivery of the high pressure and intermediate pressure gas mains being constructed separately under the ‘Gas to the West’ project.

7.270 The revised plan presented by the company is set out in Table 159.

	2017	2018	2019	2020	2021	2022	GD17
Revised Properties Passed (no)	1,044	2,480	6,085	6,538	4,651	4,554	25,352
Length (m)	12,549	27,268	69,335	64,875	53,775	52,808	280,610

Excludes 69 properties served directly from IP mains

Table 159 Revised Infill Plan Proposed by SGN

7.271 In its revised plan, the company provided information on properties passed and length of mains to be installed, but did not update its estimates of the costs of the mains. Instead, the company challenged the unit rates we used to prepare the draft determination. The company concluded that the unit rates we used in the draft determination were adequate for small diameter mains and focused its attention on:

- The difference between our benchmark unit rates for large diameter mains comparing them to rates it had recently obtained from tendered costs for distribution mains in Strabane.
- The quantity of higher classification road it expects to work on during the initial development of a new network.

7.272 We have responded to these issues in the section beginning paragraph 7.81 above and amended our unit rates for the final determination to reflect our conclusions.

7.273 We reviewed network drawings prepared by the company as part of its revised designs and concluded that the relationship between length and size of mains and properties passed was reasonable and broadly consistent with earlier estimates prepared during the development of the Gas to the West project.

7.274 We have accepted the revised plan put forward by the company as a reasonable basis for the GD17 final determination. We have applied the basket of works unit rates to calculate the appropriate allowance for the final determination. The profile of investment included in the final determination is shown in Table 160. The high early cost per property reflects the installation of spine mains which generally pass few properties during the initial development of the network.

Other Mains: Growth	2017	2018	2019	2020	2021	2022	GD17
Properties passed (no)	1,047	2,487	6,101	6,556	4,663	4,566	25,420
Length (m)	12,549	27,268	69,336	64,875	53,775	52,808	280,612
UR final determination (£k) Pre RPE	1,435	3,269	6,189	5,323	3,935	4,184	24,335
m per property passed	11.99	10.97	11.36	9.90	11.53	11.56	11.04
£ per property passed	1,371	1,315	1,014	812	844	916	957

Includes 69 properties served directly from IP mains

Table 160 SGN Final Determination Other Mains: Growth

7.275 This revised plan marks a substantial reduction in the proposed numbers of properties passed in the GD17 period. However, we have continued to include connection targets based on the licence application process which form the basis for the award of the distribution licence. It is for the company to decide the extent of network development in GD17 necessary to achieve these targets. The actual length of network laid will be subject to the infill uncertainty mechanism which provides the basis for allowances to be adjusted to reflect the economic development of the network.

7.276 Beyond GD17 we have assumed that the remainder of the network will be built out in the GD23 period to the length and boundaries presented by SGN during the consultation period. SGN advised that the network is proposed to extend to 41,807 existing properties requiring 479 km of mains giving 11.46 m/pp over the proposed network compared to 11.04 m/pp in GD17.

7.277 We have not applied an economic test for infill mains in SGN's case as DfE (formally DETI) considered this under its appraisal when making its decision to support Gas to the West. As a result, we do not plan to subject the work necessary to complete infill of the main towns served in a subsequent price control, provided there is no material change in the estimated costs or consumption of the remaining work. This will ensure that the company can deliver the work in the most economic way without the need to consider the marginal economic viability of the work left to be completed in GD23. Should the company identify further areas outwith the main towns, we would expect the company to provide the information necessary to allow us to determine whether they are economic. We have set an upper limit on the average length of infill mains for property passed of 11.50m for the purpose of infill uncertainty mechanism described in Chapter 9 which reflects the information provided by the company on the infill development of the main towns served.

SGN New Build Mains – Growth

7.278 The extent of the new gas mains to serve new development proposed by SGN in its original business plan submission is summarised in Table 161.

New Build Mains: Growth	2017	2018	2019	2020	2021	2022	GD17
Properties passed (no)	0	0	333	333	333	333	1,331
Length (m)	0	0	1,831	1,831	1,831	1,831	7,322
SGN submission (£k)	0	0	73	73	73	73	294
m per property passed			5.50	5.50	5.50	5.50	5.50
£ per property passed			221	221	221	221	221

Table 161: SGN Proposed New Build Mains and Outputs

7.279 We have consulted with SGN since the publication of our draft determination on the determined volumes for each customer sector. We have estimated new development connections based on this work. The final determination is based on 1,154 new build properties spread over the last four years of GD17.

7.280 We have maintained the allowance for new build properties of 9.5 m/pp to align with recent experience in Northern Ireland, consistent with the final determination for PNGL and FE.

7.281 The final determination allowance is based on a basket of works unit rate for new build of 48.70 £/m. The profile of connections and investment in the final determination is shown in Table 162.

New Build Mains: Growth	2017	2018	2019	2020	2021	2022	GD17
Properties passed (no)	0	0	282	264	313	294	1,154
Length (m)	0	0	2,677	2,512	2,978	2,796	10,962
UR final determination (£k) Pre RPE	0	0	130	122	145	136	534
m per property passed			9.50	9.50	9.50	9.50	9.50
£ per property passed			463	463	463	463	463

Table 162 SGN Final Determination New Build Mains and Outputs

SGN – District Governors and Pressure Reduction Stations

SGN – PRS – Growth

7.282 We have reviewed the forecast activity volumes and costs associated with the construction of PRS installations presented in SGN's business plan submission. We note that both the unit cost and the proposed number of installations are high in comparison to the other GDN's operating in Northern Ireland. SGN's business plan submission is shown in Table 163. The company's initial estimate of investment in PRS was £4.91m.

District governors & PRS: Growth	2017	2018	2019	2020	2021	2022
SGN submission (No.)	53	46	57	55	53	51
SGN submission (£k)	1,043	765	829	807	756	705

Table 163: SGN Submission Pressure Reducing Stations: Growth

7.283 Since the draft determination, the company has continued to develop its designs for the distribution network. In respect of PRS, it has:

- Reduced the quantity of infill main to be provided in GD17.
- Undertook further assessments of where it was economic to use medium pressure networks or introduce local PRS to move to a low pressure network. As a result, it has increased the quantity of medium pressure development, reducing the need for PRS.
- It has developed its design in more detail, rationalising the number of PRS necessary to serve the area.

7.284 However, the company has yet to complete this work and was not in a position to provide a detailed update on the number of PRS it expects to install in GD17. SGN provided the numbers of properties passed for each governor they designed. Using this information we were able to identify an increased number of DPG's compared to our draft determination. We were also able to more accurately count the number of smaller PRS's proposed. The balance from our calculation in section 7.285 was allocated to small governor bins.

7.285 In order to set an appropriate allowance for SGN over the GD17 period we have maintained the approach adopted for the draft determination and assessed SGN's forecast against PNGL and FE historical network development and used local contract rates as the basis for setting an appropriate unit rate. Average rates of governor installation are 3.2 per km of main for PNGL and 6.2 per km of main for FE. We have allowed for a governor installation for every 3.2km of main using the revised mains lengths based on the PNGL network.

7.286 The unit rates used by SGN to estimate the costs of governors are significantly higher than the current contract rates available to FE and PNGL. For the final determination, we have applied the average contract rates available to FE and PNGL to determine an allowance for governors, allowing for uplifts to these rates for capitalised opex and management fees where appropriate. Our allowance for the GD17 period is shown in Table 164.

District governors & PRS: Growth	2017	2018	2019	2020	2021	2022
UR final determination (No.)	4	8	21	20	17	16
UR final determination (£k) Pre RPE	28	61	155	145	120	118

Table 164 SGN Final Determination Pressure Reducing Stations: Growth

7.287 We have concluded that it is not appropriate to apply an uncertainty mechanism based on the actual number of PRS installed (see section beginning paragraph 7.126 above).

SGN – Domestic Service Connections

7.288 SGN's business plan estimate of the numbers and costs of domestic service connections in GD17 is shown in Table 165.

Domestic Services: Growth	2017	2018	2019	2020	2021	2022
New Domestic Service (New Build)	0	0	37	59	81	95
New Domestic Service (OO)	162	398	633	869	1,105	1,219
New Domestic Service (NIHE)	41	99	158	217	276	305
SGN submission (£k)	185	454	736	1,012	1,289	1,424

Table 165: SGN Submission Domestic Services: Growth

7.289 For the final determination, we have amended the number and profile of domestic connections to reflect the numbers and profiles included in the Gas to the West licence competition altered due to the delay in network rollout and the determined volumes for each customer sector.

7.290 We have applied the basket of works unit rates to calculate the appropriate allowance for the final determination. The unit rate for domestic services other than new build has been increased to £880 as described in the general approach section. The profile of connections and investment in the final determination is shown in Table 166.

Domestic Services: Growth	2017	2018	2019	2020	2021	2022
New Domestic Service (New Build)	0	0	282	264	313	294
New Domestic Service (OO)	186	140	1,174	951	634	904
New Domestic Service (NIHE)	156	39	945	266	266	242
UR final determination (£k) Pre RPE	302	157	1,959	1,158	896	1,106

Table 166 SGN Final Determination Domestic Services: Growth

SGN – Industrial and Commercial Service Connections

7.291 SGN forecasted 164 I&C connections in their business plan over the GD17 price control period. The profile showing the size of each connection and the total requested allowance is shown in Table 167. This has been profiled by SGN to connect the largest I&C customers early within the price control period with smaller I&C customers increasingly connecting in the latter years.

I&C Services: Growth	2017	2018	2019	2020	2021	2022
I&C Very Small (U6)	0	0	0	0	0	0
I&C Small (U16-U40)	1	5	6	11	13	16
I&C Medium (U65-U160)	1	7	8	7	9	11
I&C Large (U250-U650)	2	7	22	9	0	0
I&C Very Large (>U650)	3	15	10	0	0	1
SGN submission (£k)	68	330	336	100	61	91

Table 167: SGN Submission I&C Services: Growth

7.292 As for domestic service we have re-profiled I&C service connections to match the number and profile connection numbers proposed in the Gas to the West licence competition and the Gas to the West design. We have used the determined volumes to calculate the number of connections in each customer sector. In Table 167 SGN have requested a number of services >U650, however we have not allowed any of this size as SGN have not requested any allowance for meters > U650.

7.293 The allowance for the final determination is calculated by applying the appropriate basket of works unit rate for each I&C service type. The allowance for the final determination is shown in Table 168.

I&C Services: Growth	2017	2018	2019	2020	2021	2022
I&C Very Small (U6)	16	7	152	67	95	95
I&C Small (U16-U40)	28	11	267	117	167	167
I&C Medium (U65-U160)	12	9	113	88	87	87
I&C Large (U250-U650)	2	5	24	19	0	0
I&C Very Large (>U650)	0	0	0	0	0	0
UR final determination (£k) Pre RPE	134	106	1,315	801	764	764

Table 168 SGN Final Determination I&C Services: Growth

SGN – Domestic Meters

<u>SGN – Domestic Meters – Growth</u>

7.294 SGN's business plan estimate of the numbers and costs of domestic meters in GD17 is shown in Table 169.

Domestic Meters: Growth	2017	2018	2019	2020	2021	2022
Domestic Total	203	497	829	1,145	1,462	1,619
SGN submission (£k)	39	96	161	222	283	314

Table 169: SGN Submission Domestic Meters: Growth

7.295 We have altered the number of domestic meters in the final determination to reflect our determined number of connections (see paragraph 7.288). We have applied the basket of works unit rates to calculate the appropriate allowance for the final determination. The profile of domestic meters and investment in the final determination is shown in Table 170.

Domestic Meters: Growth	2017	2018	2019	2020	2021	2022
Domestic Total	343	179	2,401	1,481	1,213	1,440
UR final determination (£k) Pre RPE	66	34	460	284	233	276

Table 170 SGN Final Determination Domestic Meters: Growth

<u>SGN – Domestic Meter – Replacement</u>

7.296 SGN does not plan to replace any domestic meters during the GD17 price control period.

SGN – Industrial and Commercial Meters

<u>SGN – Industrial and Commercial Meters – Growth</u>

7.297 SGN's estimate of the numbers and costs of Industrial and Commercial meters in GD17 is shown in Table 171.

I&C Meters: Growth	2017	2018	2019	2020	2021	2022
I&C Total	7	34	46	27	22	28
SGN submission (£k)	139	676	546	79	46	98

Table 171: SGN Submission I&C Meters: Growth

7.298 We have amended the numbers and size profile of meters to reflect the decisions made on I&C connections described above.

7.299 We have applied the basket of works unit rates to calculate the appropriate allowance for the final determination. The profile of connections and investment in the final determination is shown in Table 172.

I&C Meters: Growth	2017	2018	2019	2020	2021	2022
I&C Total	58	32	556	291	349	349
UR final determination (£k) Pre RPE	136	147	1,368	937	683	683

Table 172 SGN Final Determination I&C Meters: Growth

SGN – Industrial and Commercial Meter Replacement

7.300 SGN does not plan to replace any I&C meters during the GD17 price control period.

SGN – Other Capex

7.301 SGN have requested capex for IT of £1.22m across the GD17 period including a system investment set-up cost of £724k. It is important to point out that the Gas to the West Applicant pack specifically stated that there would be no allowance in capex for IT.

7.302 Consequently we are not providing any additional IT cost allowances for the final determination over and above the SGN licence application figures.

7.303 SGN submitted an allowance for significant engineering barriers which concentrate on crossing rivers in several towns when constructing the spine mains of its distribution network. There is a high degree of uncertainty over the cost of the major river crossings which cannot be resolved until the company has undertaken further investigation of options, site investigation and design works. This uncertainty is over and above that allowed for in the general uncertainty mechanisms included for mains laying in the determination. In view of this, have included a ring fenced allowance in the price control for these crossings to be determined when the works have been designed and tenders received. These estimated costs have been allowed and ring fenced for the six specific river crossings in Strabane, Enniskillen, and Omagh identified in the company's business plan submission. The ring fenced allowances will be applied to the following three areas:

- Costs associated with the design and construction of the crossings.
- Allowance associated with the design and construction of mains not previously identified but necessary to tie the crossings into the remaining network.
- Allowance associated with upsizing and downsizing of mains leading to crossing points.

7.304 The allowances above will be based on the appropriate basket of works unit rates applied to the estimated lengths of mains.

7.305 The remaining costs for engineering barriers (public realm, road schemes, governors, and customer driven changes) have been removed for the final determination. By way of explanation for removing the additional engineering barrier costs we concluded that:

- The effects of public realm works are embedded in the base years of our basket of works unit rates.
- The effects of new road schemes are embedded in the base years of our basket of works unit rates.
- Extending mains in order to site governors will be corrected within the uncertainty mechanism.
- Customer driven demand to pipe sizes will be corrected within the uncertainty mechanism.

7.306 SGN's submission and the final determination allowance are shown in Table 173.

Other Capex	2017	2018	2019	2020	2021	2022
SGN submission (£k)	475	470	470	470	470	470
UR final determination (£k) Pre RPE	395	395	395	395	395	395

Table 173: SGN Final Determination Other Capex

SGN – Pre 2018 Capex

7.307 Prior to the price control commencement on 1 January 2018, capital expenditure will be incurred in bringing a gas conveyance network to the area of Strabane in the SGN network. Thus as part of our final determination we have allowed a total capex allowance of £2.69m in relation to 2016 and 2017. This total is included as part of the 2018 OAV (see section 9.16).

7.308 It should be noted that the OAV will be corrected to reflect actual outputs delivered prior to the price control commencement as part of the GD23 price control in line with the Uncertainty Mechanism in Chapter 9.

SGN – Traffic Management Act

7.309 As in previous price controls we have given a ring fenced allowance for TMA equivalent to 10% of the allowances for main laying and service laying activities.

SGN – Summary of Findings

7.310 In Table 174 we set out a summary of the GDN's capex submission and our total capex allowance pre and post frontier shift for the final determination.

SGN Final Determination	2017	2018	2019	2020	2021	2022	GD17
SGN Business Plan Submission (£k)							
7 Bar Mains	0	0	0	0	0	0	0
LP, 2Bar or 4Bar Mains	7,048	9,175	7,742	4,637	4,637	4,637	37,875
Pressure Reduction	1,043	765	829	807	756	705	4,905
Domestic Services	185	454	736	1,012	1,289	1,424	5,099
Domestic Meters	39	96	161	222	283	314	1,115
I&C Services	68	330	336	100	61	91	986
I&C Meters	139	676	546	79	46	98	1,584
Other Capex	475	470	470	470	470	470	2,826
TMA	0	0	0	0	0	0	0
Total	8,996	11,966	10,819	7,328	7,542	7,740	54,391
UR Final Determination pre RPE (£k)							
7 Bar Mains	0	0	0	0	0	0	0
LP, 2Bar or 4Bar Mains	1,435	3,269	6,319	5,446	4,080	4,320	24,869
Pressure Reduction	28	61	155	145	120	118	626
Domestic Services	302	157	1,959	1,158	896	1,106	5,578
Domestic Meters	66	34	460	284	233	276	1,353
I&C Services	134	106	1,315	801	764	764	3,884
I&C Meters	136	147	1,368	937	683	683	3,954
Other Capex	395	395	395	395	395	395	2,371
TMA	187	353	959	740	574	619	3,433
Total	2,682	4,522	12,930	9,906	7,745	8,283	46,068
UR Final Determination post FS (£k)							
7 Bar Mains	0	0	0	0	0	0	0
LP, 2Bar or 4Bar Mains	1,425	3,219	6,171	5,283	3,933	4,137	24,167
Pressure Reduction	28	60	151	140	116	113	608
Domestic Services	300	155	1,913	1,124	863	1,059	5,414
Domestic Meters	65	34	450	275	224	264	1,313
I&C Services	133	104	1,284	777	737	732	3,767
I&C Meters	135	145	1,336	909	659	654	3,837
Other Capex	392	389	386	383	381	378	2,310
TMA	186	348	937	718	553	593	3,335
Total	2,664	4,454	12,626	9,610	7,465	7,931	44,750

Table 174: SGN Final Determination Capex Allowance

SGN – Capital Expenditure Assumptions post GD17

7.311 We made the following assumptions to include a reasonable allowance of capital expenditure post GD17 for the purpose of modelling GD17 tariffs:

- SGN did not identify any reinforcement post GD17 and no allowance has been made in our long term projections.

- SGN revised their network design and lengths of mains required to serve the eight towns in their licence area. We have distributed the remaining mains post GD17 equally across the six years of GD23.
- We have used the volumes model to estimate the number of new build properties and calculated the length of mains required based on 9.5 m/pp in line with GD17.
- We have included the costs of meters and services associated with domestic and I&C connections based on the connection profiles included in Section 7.288.
- We reduced new pressure reducing stations in SGN's submission post GD17 in line with our GD17 determination for the remaining length of mains and accounted for the identified numbers of DPG's and RRI's based on the information provided by SGN.
- We have included a small number of replacement exchange meters based on the increasing customer base post GD17.
- We have allowed for the replacement of domestic meters, I&C meters and pressure reducing stations on a 20 year life.
- We have continued the average level of GD17 other capex proposed by the company in its submission post GD17, excluding exceptional items unaltered from our draft determination.
- We have continued an allowance for TMA costs at 10% of mains and services.

7.312 We have not applied real price effects or frontier shift to estimated expenditure post GD17.

8 Innovation

Summary of Key Changes from Draft Determination to Final Determination

8.1 We have updated this chapter following on from the GD17 draft determination, following due consideration of the responses received to same 6. Key changes made in this context include:

- Update with respect to a reduction of the applicable materiality threshold from £150k proposed in the GD17 draft determination to £100k in the final determination
- Update of section Innovation Incentive Mechanisms to reflect our consideration of related consultation feedback on the GD17 draft determination
- Update of section Detailed Approach – UR Decisions, Innovation Initiatives, Development of Infrastructure for CNG Vehicles with respect to the status of that initiative and our related GD17 decisions

Detailed Approach – UR Decisions

Overview

8.2 This chapter comments on our overall views on innovation and the principles we propose for funding and furthering it during the course of the GD17 price control period.

8.3 It also provides our views on specific innovation initiatives presented by the GDNs. As some of these initiatives relate to and/or have the potential to impact on more than one GDN, we have considered it more appropriate to discuss them in a general rather than in GDN-specific sections.

Innovation Funding Principles

8.4 It is our view that successful innovation is best driven by the GDNs operating under an appropriate price control framework. Such a framework should allow them to make decisions on what innovation investments to make taking into account the impact these investments will have on reducing costs and improving outputs. The GDNs will then be rewarded through the price control framework for resulting outperformance to the end of the GD17 price control period, and consumers will benefit in the long run from improved services and lower prices.

8.5 We consider that this approach should remain the principal mechanism for delivering innovation. It provides maximum flexibility to the GDNs to make innovation decisions, aligns the benefits for consumers and GDNs and avoids the risk of a regulator being asked to pick winners from a list of potential innovation projects.

8.6 Also, with this price control being for duration of six years, the GDNs have the opportunity to make innovation early in GD17 and benefit from the outperformance to the end of GD17.

8.7 Generally, the purpose of innovation is to reduce cost and/or achieve an improvement of outputs that generates more revenue. Therefore, we would normally expect that any innovation costs will be funded from the overall price control package, and not from specific innovation allowances and increased prices. That said, we are conscious that in some cases funding of innovations through increased prices may be appropriate, e.g. in the case of major innovation projects that require significant upfront investment and where the payback period for the project is relatively long, perhaps spanning future price control periods for example.

8.8 We note that we regard the bar as being set high in terms of evidence required in support of a request for funding of innovation projects through specific innovation allowances and increased prices. In particular, our assessment criteria will include, but may not be limited to, the following information which we expect to be provided by the GDN requesting such funding:

- Quantified and robust cost benefit analysis
- Detailed and robust project plan for the innovation project
- Credible and binding commitments from any project partners to participate in/contribute to funding the project, as well as proposed contingency arrangements in case any of the project partners should fall short of their obligations
- Justification of why funding through the overall price control package is considered not appropriate/sufficient and why funding through specific innovation allowances and increased prices is requested
- Explanation of how the GDN has arrived at its chosen bid for innovation and how this interacts with other innovation investments planned under the normal price control regime
- Explanation of how the innovation bid was identified/prioritised and justified in consultation with consumers and other stakeholders
- Explanation of why there exists a barrier towards innovation which requires some form of regulator action to progress, and the consequences of the innovation not happening
- Details on what deliverables/benefits may be expected for local consumers from the research/development/trials
- Detailed risk assessment as well as details on and justification of proposed treatment of risk and reward
- Description of how the innovation, if successful, could be efficiently rolled out within the GDN and/or other NI or GB GDNs
- Justification of how the proposed innovation is different to anything that has occurred previously, whether within the GDN, another NI or GB GDN or within the wider industry

We note that we may consider additional, project-specific assessment criteria, where relevant and appropriate.

8.9 Where GDNs consider it appropriate to request funding of innovation projects through specific allowances and increased prices, details on the related allowances requested, as well as any supporting documentation, should, in principle, be included in the business plan submissions made by the GDNs at the onset of a price control.

8.10 However, we recognise that in certain circumstances this may present difficulties or not be possible. We deal with such circumstances through the uncertainty mechanism. We note that any request under the uncertainty mechanism will have to meet the criteria set out in paragraph 8.8 above and exceed a materiality threshold of £100k.

8.11 We note that we have changed this materiality threshold from £150k proposed in the draft determination to £100k (i.e. to the same level as had been used for the GD14 final determination) to reflect feedback received from the three GDNs in response to our GD17 draft determination. This threshold will be the same for each of the three GDNs.

Innovation Incentive Mechanisms

GDN Proposals

8.12 In our Update on Overall Approach for the GD17 Price Control11 we encouraged the GDNs to provide, as part of their business plan submissions, ideas for innovations that could make their businesses more efficient or offer enhanced serviced to customers.

8.13 In their GD17 business plan submission, SGN proposed three incentive mechanisms to provide an innovation stimulus in the NI natural gas market:

- Network Innovation Competition
- Discretionary Reward Scheme
- Innovation Roll-Out Mechanism

All three incentive mechanisms have been inspired from similar arrangements implemented under the RIIO price control regime in GB and are described in more detail in Table 175 below.

	Network Innovation Competition	Discretionary Rewards Scheme	Innovation Roll-Out Mechanism
Funding Objective	• Key projects of a commercial, operational or technical nature with a potential to deliver low carbon, environmental or financial benefits to customers • Focus on core outputs, e.g. network development, additional connections or enhanced customer satisfaction	Projects demonstrating excellence and innovation in the following areas: • Contracts with third parties to improve operational performance and efficiency • Packages with third parties to increase connections, including for the fuel poor • Customer satisfaction • Social and environmental improvements	Innovations with positive Cost Benefit Analysis (CBA)
Funding Mechanism	• Competition for up to £2m of funding a	• Competition every two years for up to	• Agreed funding cap per GDN, e.g. 1% of total

	Network Innovation Competition	Discretionary Rewards Scheme	Innovation Roll-Out Mechanism
	year, or 2% of total NI GDN average allowed revenue[84] • Funding recovered through postalised transmission charges • Funding of selected projects to cover bid development costs	£2m of funding a year, or 1% total NI GDN average allowed revenue[84] • Funding recovered through postalised transmission charges • Funding to be allocated ex-post	allowed revenue over price control period to be recovered over project lifecycle • Funding recovered through transportation charges • Adjustments to revenue through re-opener mechanism
Selection of Funding Projects	• Initial screening process identifies projects to be presented to expert panel • Expert panel to recommend to the Authority which, if any, projects should receive funding	Expert panel to recommend to the Authority which, if any, projects should receive funding	Authority based on CBA
Other Considerations	Knowledge sharing between GDNs and third parties to maximise returns through broader roll-out of successful projects and learn from any unsuccessful ones	Less cost than network innovation competition, but weaker incentive due to increased funding insecurity for GDNs	Potential distortions to innovation affordability for different GDNs due to different stages in network lifecycle and different levels of allowed revenue for GDNs

Table 175: Innovation Incentive Mechanisms Proposed by SGN

8.14 In its GD17 business plan submission, SGN recommended that a combination of either the network innovation competition and the innovation roll-out mechanism, or the discretionary reward scheme and the innovation roll-out mechanism, should be implemented for the GD17 price control period.

8.15 Following our proposal in the draft determination not to progress the proposed mechanisms we received responses from GDNs and the CCNI. The consultation responses noted in particular the following:

- The lack of incentives for innovation of any type is an opportunity missed as it restricts the prospect of innovative measures to address problems specific to Northern Ireland's unique network areas
- The high hurdles for any allowances for innovation projects could have the effect of discouraging innovation, including in particular with respect to higher risk, higher cost saving to consumer projects, as well as increasing the costs of submissions due to the time and resource required relative to level of funding

[84] These are the figures suggested by SGN in their business plan submission. We note that based on this GD17 final determination, the average annual allowed revenue across all NI GDNs is approximately £70m, i.e. 2% equals approximately £1.43m.

- A competition for funding of flagship innovation projects of a commercial, operational or technical nature would raise the standard of projects submitted versus individual GDN submissions on an ad hoc basis, and raise the profile of innovation and its benefits
- An Innovation Roll Out mechanism in NI, whereby GDNs can take up best practice through funding provided, would maximise the benefits from individual GDN's successful projects

8.16 In preparing this final determination document, we have given consideration to each of these proposed innovation incentive mechanisms individually, to the practical experience gained in GB with these mechanisms, and to their overall strategic fit for the NI natural gas market in general as well as the GD17 price control period in particular. We have also taken into account the responses to the draft determination.

Network Innovation Competition

8.17 In GB, the network innovation competition has been introduced under the RIIO price control framework to fund larger, more complex projects. Where relevant and appropriate, these projects can be delivered in partnership with the wider energy industry, such as energy suppliers, universities or technology providers. The projects should allow GDNs to understand what they need to do to provide the environmental benefits, cost reductions and security of supply as GB moves to a low carbon economy. To date, three competitions rounds have been run for the gas market, in 2013, 2014 and 2015. Altogether, nine projects have been selected for funding, covering a range of areas:[85]

- BioSNG Demonstration Plant (2013): To construct a demonstration plant investigating the techno-economic feasibility of the thermal gasification of waste to produce pipeline quality renewable gas
- Low Carbon Gas Preheating (2013): To test new and emerging pre-heating technologies and associated operating systems
- Robotics (2013): To develop new robotic technologies that operate inside live gas networks, in order to repair leaking joints, manage risk of pipe fracture in larger diameter pipes and repair and replace pipeline assets
- Opening Up the Gas Market (2013): To establish whether gas which sits outside the British standards could be used safely and efficiently
- In Line Robotic Inspection of High Pressure Installations (2014): To design and develop a robotic device to inspect complex below-ground pipework at high pressure above ground installations
- Customer Low Cost Connections (2015): To minimise the cost and time of connections with particular focus on unconventional gas connections
- City CNG (2015): To design and build the UK's first scalable city based Compressed Natural Gas (CNG) fuelling station
- Commercial BioSNG Demonstration Plant (2015): To develop a commercially viable plant that converts household waste into synthetic biogas

[85] See Ofgem: 2015 Network Innovation Competitions, Ofgem: Making Britain's Energy Networks Better; and Ofgem: RIIO-GD1 Annual Report 2013-14, 19 March 2015.

- Real-time Networks (2015): To create a new method of modelling energy within the GB gas network

8.18 We consider that the projects funded in GB as part of the network innovation competition are, at least in parts, relevant to NI GDNs as well. We note in particular that connections facilitating the injection of alternative forms of gas into the natural gas network and CNG fuelling stations are topics covered both in the GB projects listed and in the GDNs' business plans[86]. We encourage the NI GDNs to avail, where reasonable and appropriate, of relevant information and learnings relating to the GB projects to inform their innovation and investment decisions.

8.19 With respect to SGN's suggestion to introduce a network innovation competition in NI, we have decided not to do so for the reasons outlined below.

8.20 We are not convinced that a competition is necessary or beneficial in delivering innovation in the gas industry in NI. Due to the size of the NI market, the administrative effort involved in setting up a funding competition compared to the level of competition that it would be likely to generate would be questionable. There may also be merit in a co-operative approach to innovation and it is not clear why the price control framework which allows the GDNs to propose well argued business cases for projects is not sufficiently robust for consumers and flexible for the GDNs to support innovations.

8.21 We also note that we consider the key focus of the GD17 price control period for the GDNs should be on developing the networks and increasing connections. This final determination assumes, for all three GDNs, major network development to take place:

- FE plan to conduct a major infill programme
- PNGL plan to extend their network to East Down
- SGN will build the Gas to the West network

We consider that there should be alignment between the key focus areas of the price control and the incentive mechanisms used. Thus, the incentive mechanisms for GD17 provide opportunities for the GDNs to consider what innovations to apply in order to maximise connections and network delivery.

8.22 To be clear, we still welcome innovation initiatives where reasonable and economically efficient. However, we consider that at this stage, it is not appropriate to provide further incentives for innovation.

8.23 In summary, we consider that implementing a network innovation competition incentive mechanism would constitute a policy change with considerable practical implications that would require full consultation and involvement of both TSOs and GDNs. We consider such a policy change to be outside the scope of the GD17 price control. We also note that at this stage, we see no requirement for such a policy change as we consider the key focus of the GDNs should be on achieving network growth. Therefore, we are, for the time being and as already stated in the GD17 draft determination, not minded to progress this matter further.

Discretionary Reward Scheme

8.24 In GB, the Discretionary Reward Scheme (DRS) was introduced as part of the gas distribution price control for 2008-2013 (GDPCR1). It also applies under the RIIO-GD1 arrangements and runs every three years. The aim of the DRS is to encourage GDNs to

[86] For further details see section Innovation Initiatives below.

deliver outputs that contribute to environmental and social objectives beyond those funded at the price control. By rewarding exceptional outcomes that can be regarded as best practice and replicated across the industry, the scheme aims to drive innovation; it is not intended to fund GDN activities.[87]

8.25 In 2015, the first DRS assessment under the RIIO-GD1 price control took place. As part of this assessment, a range of activities by GB GDNs were rewarded, including the following:

- Social Initiatives
- Environmental Outputs
- CO Safety Outputs
- Collaboration

8.26 We consider that the initiatives rewarded under the GB discretionary reward scheme may, at least in parts, be of interest to NI GDNs as well. We encourage the NI GDNs to avail, where reasonable and appropriate, of relevant information on the best practice shown as part of these initiatives and to consider applying it, where relevant and appropriate, to their own businesses.

8.27 With respect to SGN's suggestion to introduce a discretionary reward scheme in NI we have decided not to do so for the same reasons as outlined in paragraphs 8.20 to 8.21 above for the network innovation competition.

8.28 In summary, we consider that implementing a discretionary reward scheme incentive mechanism would constitute a policy change with considerable practical implications that would require full consultation and involvement of both TSOs and GDNs. We consider such a policy change to be outside the scope of the GD17 price control. We also note that at this stage, we see no requirement for such a policy change as we consider the key focus of the GDNs should be on achieving network growth. Therefore, we are, for the time being and as already stated in the GD17 draft determination, not minded to progress this matter further.

Innovation Roll-Out Mechanism

8.29 In GB, the innovation roll-out mechanism was implemented under the RIIO-GD1 arrangements. It is a revenue adjustment mechanism to facilitate the roll-out of proven innovations with demonstrable and cost effective low-carbon and/or environmental benefits ahead of the next price control, subject to a materiality threshold. RIIO-GD1 provides two reopener windows at which revenue adjustments pursuant to the innovation roll-out mechanism can be made, if and as appropriate.[88]

8.30 We consider that the arrangements detailed in paragraphs 8.8 to 8.10 regarding the treatment of requests for funding of innovations through specific allowances allows for the roll-out and implementation of innovations ahead of the next price control, provided the conditions specified in these paragraphs are met.

[87] See Ofgem: Decision on Ofgem's governance arrangements for the Gas Discretionary Reward Scheme under RIIO-GD1, 25 November 2013; Ofgem: Decision on RIIO-GD1 Gas Discretionary Reward Scheme 2013-2015.

[88] See Ofgem: RIIO-GD1: Final Proposals – Supporting Document – Outputs, incentives and innovation, 17 December 2012; Ofgem: Consultation on the assessment of benefits from the roll-out of proven innovations through the Innovation Roll-out Mechanism, 7 January 2015.

8.31 We consider furthermore that the arrangements detailed in paragraph 8.10 have a similar effect to that of an innovation roll-out mechanism as proposed by SGN. In line with our proposal detailed in the GD17 draft determination, we therefore consider that an innovation roll-out mechanism as proposed by SGN is not required as a complement to our innovation funding principles.

Summary

8.32 As detailed above, we have decided, in line with our proposal detailed in the GD17 draft determination, not to introduce any innovation incentive mechanism as part of the GD17 price control.

8.33 However, we welcome innovation initiatives from the GDNs, where reasonable and economically efficient. We will also take account of any government led initiatives e.g. biogas.

8.34 We are conscious that robust assessment criteria for funding of innovation projects may impact on the time and resource GDNs need to invest if they wish to request funding. However, we consider that this is appropriate, proportionate and necessary to provide protection to consumers who would bear risk and cost of such innovation projects. We also note that our assessment criteria do not exclude or restrict innovation measures to address problems specific to Northern Ireland's network areas or to create opportunities for natural gas connections. Nor do they preclude the submission and consideration of higher risk projects with higher cost saving potentials. That said, we consider that the riskier a proposed innovation project is and the higher the associated costs consumers will be asked to bear, the more diligent and detailed the upfront assessment needs to be.

8.35 As detailed in paragraphs 8.30 and 8.31, we consider that our treatment of requests for funding of innovation projects through specific innovation allowances has a similar effect as the innovation roll-out mechanism proposed by SGN and allows for the roll-out and implementation of innovations. We therefore consider that a separate innovation roll-out mechanism for NI is not required.

Innovation Initiatives

8.36 In their business plan submission, the GDNs highlighted a number of innovation projects and initiatives, including the following:

- Development of infrastructure for compressed natural gas (CNG) vehicles
- Biomethane Injection
- Northern Ireland Inventory Product
- These projects and initiatives are discussed in further detail below.

8.37 The GDNs also set out a number of operational innovations for their own business as well as for consumers. Some of these have already been implemented, others are being trialled, or are planned to be undertaken during GD17. As detailed above, we consider that such activities are covered by the overall price control package. We therefore do not grant any specific innovation allowances for such operational innovations.

Development of Infrastructure for CNG Vehicles

8.38 In their business plan submissions, FE and PNGL presented a joint innovation project. Together with the project partners Gas Networks Ireland (GNI) and the Technology

Centre for Biorefining and Bioenergy, they have applied to the European Union (EU) for funding of a cross-border CNG impact study. The project was aimed at the development of a network of 17 public CNG filling stations along the TEN-T (Trans-European Transport Network) core road network[89]. Four of these filling stations were to be located in NI (of which one in the FE licensed area and three in the PNGL licensed area), the other 13 in the Republic of Ireland. The project was aimed at examining the impacts from increased levels of CNG filling stations on the operation of the gas transmission and distribution networks by examining CNG equipment and user behaviour.

8.39 FE and PNGL received notification, after the GD17 business plans had been submitted, that the EU funding request was declined. However, the Innovation & Networks Executive Agency (INEA), who is responsible for managing the Connecting Europe Facility funding scheme, noted the relevance of the project and encouraged the project partners to make a revised submission for the next funding round.

8.40 On 25 January 2016, we were provided with a draft cost benefit analysis (CBA) which was expected to form the basis for the new funding request. This report comprises of a description of the project and its main benefits, a description of the counterfactual scenarios against which the costs and benefits of the project are assessed, a Social CBA assessing the costs and benefits to society of the project, and a Financial CBA which estimates the grant funding needed.

8.41 Based on the information provided to us, it appears that the project scope has changed compared to the initial project. It now also comprises, in addition to the network of 17 CNG filling stations, a linked biogas injection facility in the Republic of Ireland. The draft CBA notes furthermore that, if the project was to go ahead, the construction of the CNG filling stations would start in 2016 and would be expected to be completed by 2018; the biogas injection facility would be set up in 2017. Different scenarios have been presented with respect to vehicle uptake, one with 18 CNG vehicles associated with each station by 2025 (central scenario) and one with 30 (targets met scenario).

8.42 Based on the draft CBA provided and the assumptions contained therein, the social CBA would be positive. The overall financial NPV for the overall project is negative. Up to 50% of this shortfall could be eligible for funding if the project was approved, with the funding for the remaining shortfall to be covered by other means.

8.43 The submission deadline for proposals under the new funding round was 16 February 2016. In July 2016, a decision on selected projects was taken and applicants were informed of the results. FE and PNGL informed us at this stage that EU funding for the CNG project had been granted, but not for the full amount requested. The GDNs informed us that further talks were scheduled with INEA on this matter for August/September 2016.

8.44 We note that in line with the timeline published by INEA, the signature of grants is expected to take place in September 2016[90]. We have also been informed by FE that, if the project is to progress, there is a requirement for all participating parties to commit to the project by November 2016.

[89] For a map of the North Sea-Mediterranean corridor of the Trans-European Transport Network, see http://ec.europa.eu/transport/infrastructure/tentec/tentec-portal/site/maps_upload/corridors_png/C8_northsea_med.pdf.

[90] Innovation and Networks Executive Agency: Connecting Europe Facility, 2015 Transport Calls, Funding Opportunities.

8.45 In their brochure on projects under the 2015 CEF Transport Calls, INEA noted, with respect to the CNG project, the following: "*The Action's relevance is excellent, aiming at deploying a network of 17 CNG fuelling stations in both the Republic of Ireland (RoI) and Northern Ireland (NI) along the Core Network Corridor. Its maturity is very high as thorough studies have been carried out. The Action's impact is very good with a thorough CBA already finalised. Its quality is very good being very well structured and organised in all aspects*."[91]

8.46 In its business plan submission, FE did not include any specific request for allowances related to this project. However, they noted that they were keen to develop this opportunity further.

8.47 PNGL included in their business plan submission a request for other capex relating to this project to cover their share of the project cost after consideration of EU funding. In August 2016, PNGL provided an update to its initial request to account for the impact of exchange rate changes.

8.48 We welcome the work done by FE and PNGL in developing this innovation opportunity as well as the co-operation between these two NI GDNs in this area.

8.49 We consider that the project, if successful, would provide a range of benefits to the GDNs, consumers and the NI society as a whole, including e.g.:

- Better understanding of impact of CNG filling stations on the network
- Increased network usage entailing potential for reduction of conveyance charges
- Experience in managing the development, planning and operation of a CNG filling station network
- Fuel-cost reductions and security of supply through enhanced choice of transportation fuels
- Reduced carbon emissions, improved air quality and reduced noise pollution

8.50 The project might also offer potential for additional opportunities, e.g. installation of additional back to base CNG refuelling facilities for customers with a locally operating fleet.

8.51 Based on the above considerations, we are of the view that in principle, and subject to operational, technical, health and safety, economical and due diligence pre-requisites being met, a CNG infrastructure project may warrant the granting of project-specific allowances due to its size, potentially high upfront investment cost (especially in the case of special injection points being required) and potentially relatively long payback period. We note, however, that the requirements detailed in paragraph 8.8 would need to be fulfilled. We note that more specifically, with regards to this particular project, we consider that the information to be provided in line with the requirements detailed in paragraph 8.8 would need to address aspects such as analysis on stranded asset risk and risk sharing, including proposals for part-funding through private investment at risk. Our initial view is that consumers are being asked to take on significant risk and the GDNs have proposed that they take on none themselves. In addition we would like to see more detail on what aspect of the proposal is innovative.

[91] Innovation and Networks Executive Agency: Connecting Europe Facility, Transport, 2015 Call for Proposals, Proposal for the selection of projects.

8.52 We consider that the CNG infrastructure project is not sufficiently advanced to warrant the granting of specific ring-fenced allowances at this stage. However, we will reconsider the project once certain minimum requirements including the ones listed below have been fulfilled and supporting documentation has been provided:

- Satisfactory solution of funding gap between requested and recommended EU funding, and signature of grant;
- Positive CBA not only for the project as a whole, but also with respect to each NI GDN individually;
- Clarity on risk sharing;
- Evidence confirming that the anticipated numbers of vehicles per CNG filling station and volumes can be met, including:
    - Evidence of firm customer commitment with contingency arrangements in case any of the key customers should fall short of their commitments; and
    - Sensitivity analysis considering the impact of the roll-out of other alternative fuel charging facilities (e.g. further development of network of charging points for electric cars).

8.53 We note in particular that there are over 300 charging points for electric vehicles in Northern Ireland[92] which have been financed partly through grant funding (with a significant part of this funding being provided by the Office for Low Emission Vehicles (OLEV)), partly by NIEN (Northern Ireland Electricity Networks) outside their regulatory asset base, without any related price control allowances. We are of the view that consideration should be given as to whether similar funding arrangements could be used to finance any funding shortfall of the CNG project after consideration of the INEA grant. We note that we would expect FE and PNGL to provide analysis on the relevance of this approach. We would also take government views into account on transport policy.

8.54 We indicated in the GD17 draft determination that if at the time of drafting of the GD17 final determination the CNG infrastructure project still is not sufficiently advanced to allow for a final decision on whether related allowances should be granted or not, we would reconsider the project once more at a later stage during the GD17 price control period, once all relevant information has become available.

8.55 In light of the ongoing uncertainty regarding the funding arrangements and the need for further related information and analysis, we have therefore decided not to grant any allowances with respect to the CNG project at this stage. We will, however, follow-on from our proposed proceeding in the GD17 draft determination and reconsider the project once more during the GD17 price control period, once all relevant information has become available. Depending on the outcome of our assessment, we may allow for a ring-fenced adjustment under the uncertainty mechanism then, provided the circumstances described in paragraph 8.10 and the requirements in paragraphs 8.51, 8.52 and 8.53 apply.

Biomethane Injection

8.56 In its business plan submission, SGN indicated their intention to develop other innovations over the GD17 price control period such as:

- Supporting alternative forms of gas

[92] This figure does not include the ca. 60 home charging points paid for by the home owners.

- Opening up of competition in the gas market by widening the gas quality range
- Support of long-term utilisation of the gas network through the development of hybrid technologies

SGN did not include any specific project suggestions and/or related funding requests in their business plan submission, but indicated their interest in working with other GDNs and ourselves to develop proportionate funding arrangements that could be introduced during the price control period.

8.57 PNGL mentioned in its business plan submission the potentials relating to biomethane in conjunction with the development of the infrastructure for CGN vehicles initiative.

8.58 In its business plan submission, FE highlighted the potentials associated with the injection of biomethane into the natural gas grid.

8.59 Anaerobic digestion sites have the potential to produce biomethane. Biomethane has different qualities from natural gas. However, subject to biomethane being processed in such a way that it becomes compliant with the applicable gas quality standards for natural gas networks, and/or to such standards being modified to also cover (processed) biomethane, there is a potential for biomethane to be injected into and conveyed through natural gas systems.

8.60 Through injection of biomethane into the NI natural gas grid, the gas supply in NI could be made more environmentally friendly and sustainable, reducing the dependency on gas deliveries through the interconnectors, increasing network usage and thus ultimately offering a potential for reduction of conveyance charges.

8.61 FE also highlighted the potential for biomethane projects to be combined with other projects for customer connections in relative geographic proximity, thus enabling additional consumers to benefit from gas connections which would not have been economically viable on their own.

8.62 FE considers there is demand for biomethane injection in Northern Ireland and have identified a number of potential customers. However, FE also recognise that the discussions are at an early stage and that more preparatory work is required. FE have therefore not included any requests for allowances related to biomethane injection projects in their business plan submission. However, they have indicated that they may wish to submit a related business case at a later stage, once discussions with potential customers and other relevant parties have progressed sufficiently.

8.63 We welcome the interest by FE in furthering biomethane injection projects.

8.64 We consider that in principle, and subject to operational, technical, health and safety, economical and due diligence pre-requisites being met, a biomethane injection project may warrant the granting of project-specific allowances due to its size, risk, potentially high upfront investment cost and potentially relatively long payback period. We note, however, that in addition to compliance with the requirements detailed in paragraph 8.10, it would need to ensure that the legal and regulatory framework in NI could support such projects. More specifically, this will involve (but not necessarily be limited to) the following:

- Clarification of how any pressure issues relating to the injection of biomethane into the grid as well as associated health and safety risk will be addressed
- Compliance with gas quality standards which may or may not need to be amended to facilitate such a project (e.g. Wobbe index, oxygen content)

- Clarification of any health and safety issues relating to the growth of microorganisms as a result of the biomethane production will be addressed
- Implementation of relevant operations procedures, including (but not limited to) procedures for the following:
    - Odourisation of biomethane
    - Curtailment of gas in the event of quality breaches
    - Metering
    - Management of emergencies linked to connected systems such as the biogas production and injection facilities
- Update of connection policy to reflect connection charging arrangements for biogas injection facilities
- Development and implementation of a methodology for biogas access charging
- Analysis and resolution of associated licence, network code and connection agreement issues (which may depend on the design of the biomethane injection facility and the way in which responsibilities are allocated between the producer and the GDN)

8.65 We consider that the work on and planning of a biomethane injection project is not sufficiently advanced to warrant the granting of specific ring-fenced allowances at this stage. However, we will consider a related business case with supporting documentation, should FE or any other NI GDN wish to present one to us during the GD17 price control period. We will allow for a subsequent ring-fenced adjustment under the uncertainty mechanism, as appropriate, if the circumstances described in paragraph 8.10 for such cases and those described in paragraph 8.64 are fulfilled.

Northern Ireland Inventory Product

8.66 In its business plan submission, FE refers to the Northern Ireland inventory project. As part of this initiative, a solution was trialled in 2007/2008 whereby gas was bought when prices were lower and stored in the transmission pipeline for use at times when gas prices were higher. The trial was operationally successful. However, as price stability in the natural gas market increased, continuing the project became less interesting from an economic perspective.

8.67 FE considers a natural gas inventory product such as the one trialled before to be a viable future innovative solution should there be a return to volatile gas commodity prices. However, as the market conditions required for such a product to be economically successful do not currently prevail, FE have not included in their business plan any concrete plans for such a project.

8.68 We consider that prevailing market conditions are not appropriate for the implementation of a natural gas inventory product such as the one referred to by FE. We therefore have not granted any related specific innovation allowances.

9 Uncertainty Mechanism

Summary of Key Changes from Draft Determination to Final Determination

9.1 We have updated this chapter following on from the GD17 draft determination, following due consideration of the responses received to same[6]. Key changes made in this context include:

- Reduction of the applicable materiality threshold from £150k proposed in the GD17 draft determination to £100k in the final determination, and with clarification on the treatment of costs relating to the NIED (Northern Ireland European Development) project.
- The uncertainty mechanism adjustments for PNGL have been updated to reflect capital creditor and working capital adjustments necessary in the opening TRV for GD17.
- The uncertainty mechanism adjustments for FE have been updated to include an allowance for the 2016 year in relation to the best estimate of costs for the Foyle river crossing and a minor adjustment to the 2014 ring-fenced IT allowance reflecting actual spend.
- For GD17, we will take account of cumulative performance in the application of the properties passed incentive (see section beginning paragraph 7.32).
- In GD17, we will apply the uncertainty mechanisms for infill and new build mains on a cumulative basis over the price control (see section beginning paragraph 7.39).
- For GD17, we have included a process for an ‘economic project mechanism’, building on our practice in GD14, which allows GDNs to bring forward major projects which are necessary or economic over the course of the price control (see section beginning paragraph 7.46).
- We have concluded that we should not apply an uncertainty mechanism to pressure reduction stations in GD17.
- We have introduced a Capex Risk Sharing adjustment to be applied at the last stage of the Uncertainty Mechanism for SGN.

Detailed Approach and Methodology – UR Decisions

9.2 We have included a number of mechanisms within this determination to reduce the risk to GDNs or to incentivise them to deliver outputs consistently with our statutory duties as described in Chapter 2.

9.3 This chapter summarises these mechanisms and methodologies and, where appropriate, references the sections of this document where the rationale and operation of the mechanisms are described in more detail.

9.4 The primary methodology that we use is termed the “uncertainty mechanism”. This will be implemented at the time of the GD23 price control, by adjusting determined allowances for differences between actual and allowed costs or outputs (for example, connection activity).

9.5 Adjustments fall into one of six categories as set out in our determination, namely:

- Output based – we determine a unit price (Capex) or unit allowance (Opex). The value included in the cost base is the determined unit price/unit allowance (e.g. cost of meter/connections incentive) x the forecast driver for that item (e.g. number of connections). Any difference in the driver (e.g. higher connections) between the determination and outturn will result in an adjustment at the time of GD23 (i.e. determined unit rate/unit allowance x actual driver output less determined unit rate/unit allowance x forecast driver output).
- Pass through – A forecast of this amount has been included in the final determination but any difference between the allowance in the determination and the actual costs incurred will result in an adjustment at the time of GD23.
- Ring fenced – This item has been included in the final determination but will be removed through an adjustment in GD23 unless the Utility Regulator determines that the costs (or adjusted costs) are necessary and efficient.
- Nominated output – an allowance included for the delivery of a specific project proposed by the GDN after undertaking a detailed technical assessment to identify a need and the optimum way of meeting that need. If the GDN subsequently decides that the work is not necessary or can be deferred to a later date, we will either remove the investment form the price control or reprofile the allowance to reflect actual delivery. If the company decides that an alternative solution will deliver the same output, we will review the proposal and determine whether the original allowance should be maintained or the allowance adjusted to reflect a change of output.
- Materiality Threshold – this covers additional projects which are not included within the final determination but are subsequently approved by the Utility Regulator and cost above £100k. Further detail is provided from paragraph 9.36 below.
- Capex Risk Sharing (SGN only) – to be applied at the last stage of the Uncertainty Mechanism for SGN once all other adjustments have been calculated. Whilst we have retained the capex roller sharing mechanism within the licence condition turned off for SGN, we have decided to introduce a 75:25 capex sharing mechanism for the company and consumer respectively. This means SGN will take 75% of the risk of under/over recoveries and customers will take 25%.

9.6 The methodology ensures adjustments also include the impact of the allowed cost of capital from the date of the difference in expenditure to the date that the adjustment is made. For example, the GD14 adjustments are grossed up for applicable return to the end of 2016, prior to inclusion into the opening Total Regulatory Value (TRV) for GD17. These adjustments will follow methodology used to calculate the GD14 adjustments described below and provided by spreadsheet to the GDNs. The only difference will be to the scope of some of the items but they are described below.

9.7 For each area of the programme, we identify whether the uncertainty mechanism applicable in GD17 is:

- **Continuing** – continuation of a mechanism which applied in GD14.
- **Amended** – continuation of a mechanism which applied in GD14 subject to a change in the way the mechanism will be applied in GD17.
- **New** – a new mechanism introduced for the GD17 period.

9.8 The determined unit rates/unit allowances applied in the uncertainty mechanism will be post efficiency.

GD14 Uncertainty Mechanism Review and Adjustments – UR Decisions

FE

9.9 GD14 included an uncertainty mechanism for FE similar to the mechanism that has been proposed below for this GD17 price control period.

9.10 In respect of the FE GD14 uncertainty mechanism the adjustments (including rate of return) are proposed as follows:

FE Uncertainty Adjustment Categories (£av. 2014)	2014 Actual	2015 Forecast	2016 Forecast	Total Actual/Forecast
Capex 40 Year Life	(5,573,403)	(207,530)	1,977,833	**(3,803,100)**
Capex 15 Year Life	(9,914)	144,198	98,232	**232,516**
Capex 5 Year Life	(4,873)	0	0	**(4,873)**
Opex	(603,995)	(265,008)	(296,639)	**(1,165,642)**
Total Annual Uncertainty Adjustments	**(6,192,185)**	**(328,340)**	**1,779,426**	**(4,741,099)**

Table 176: FE Final Uncertainty Mechanisms Adjustments

9.11 All the above adjustments are added or removed from the closing Total Regulatory Value (TRV) for 2016 appropriately, giving a TRV at 1st January 2017 for FE of £143.8m (£av. 2014).

PNGL

9.12 GD14 included an uncertainty mechanism for PNGL similar to the mechanism that has been proposed below for this GD17 price control period.

9.13 In respect of the PNGL GD14 uncertainty mechanism adjustments the adjustments (including rate of return) are proposed as follows:

PNGL Uncertainty Adjustments (£Sep 2014)	Up to 2016 Forecast	Total Actual/Forecast
PNGL12 Overall Finalised Actual Adjustment (2012 – 2013)	8,159,057	**8,159,057**
GD14 Depreciation Actual/Forecast Adjustment (2014 – 2016)	(322,533)	**(322,533)**
GD14 Capex Return Actual/Forecast Adjustment (2014 – 2016)	(254,255)	**(254,255)**
GD14 Opex Actual/Forecast Adjustment (2014 – 2016)	(1,124,476)	**(1,124,476)**
GD14 Q & CC Movement Actual/Forecast Adjustment (2014 – 2016)	(208,967)	**(208,967)**
Total Annual Uncertainty Actual/Forecast Adjustments	**6,248,826**	**6,248,826**

Table 177: PNGL Draft Uncertainty Mechanism Adjustments

9.14 The above figures include necessary corrections in relation to capital creditors and working capital from 2007 to 2014. This is required to ensure the opening TRV for the GD17 period is up to date. We regard use of the uncertainty mechanism as the most transparent way to make such corrections and note that any similar adjustments would apply this principle symmetrically.

9.15 All the above adjustments are added or removed from the closing Total Regulatory Value (TRV) for 2016 appropriately, giving a TRV at 1st January 2017 for PNGL of £595.8m (£Sep 2014).

SGN 2018 Opening Asset Value (OAV)

9.16 As the SGN price control period starts from 1 January 2018, we have compiled the pre price control allowances required in forming a 2018 OAV. This OAV has been assessed at £3.76m (Dec £2014).

9.17 This figure comprises pre price control Capex of £2.69m, plus Opex of £1.56m minus £550k pre price control revenues (i.e. pre price control related volumes multiplied by the SGN 2016 and 2017 tariffs), all thereafter adjusted for at the licence[93] LIBOR + 0.5% rate of return (net c£57k). The SGN 2018 OAV elements are detailed further in Chapters 5, 6 and 7.

9.18 It should be noted that all relevant costs incurred in 2016 and 2017 will be subject to the Uncertainty Mechanism. Therefore the TRV will be updated as part of the GD23 price control.

GD17Uncertainty Mechanism – UR Decisions

FE

9.19 In respect of GD17 FE **capex** allowances, the items subject to an uncertainty adjustment, whether it is output, pass through or ring fenced based, and the elements that will be adjusted are those shown in the tables below. The tables also include a reference to the section of the paper where additional elements of the mechanism e.g.

[93] Per condition 4.4.5(d)

cap and collar, are detailed.

Capex Item	Uncertainty mechanism applicable in GD17	Status
Traffic Management Act	Ring fenced as set out in Chapter 7.	Continuing
Pressure Reduction Stations	Not applicable in GD17	Amended
7 bar & Feeder Mains	Not applicable in GD17	
Other Mains: Existing Domestic and I&C	Output based on actual number of properties passed, annual average number of metres of infill laid per property passed up to a cap of 10.30 metres and determined unit rate. Applied on a cumulative basis in GD17 (see section beginning paragraph 7.39). Additional incentive and penalties will apply as outlined in section 7.32.	Amended
Infill Mains: New Build Domestic	Output based on actual number of properties passed, annual average number of metres of infill laid per property passed up to a cap of 9.5 metres and determined unit rate. Applied on a cumulative basis in GD17 (see section beginning paragraph 7.39).	Amended
Security of Supply Mains	Ring fenced – Foyle River crossing as described from paragraph 7.197.	New
Domestic/I&C Meters	Output based on connections and determined unit rates.	Continuing
Domestic/I&C Meters – end of life replacement.	Not applicable in GD17	
Domestic/I&C Services	Output based on connections and determined unit rates.	Continuing
IT	Not applicable in GD17	
Company specific issues	None for GD17	
Additional projects	The economic project mechanism described at paragraph 7.46 will apply to new projects which are shown to be either economic or necessary.	New
Materiality Threshold	Subject to future UR determinations	Continuing

Table 178: FE Capex Uncertainty Mechanism

9.20 The determined rates for the capex uncertainty mechanisms are:

- the basket of works unit set out in Table 108 following the application of the frontier shift set out in Table 112,
- except for infill mains and new build mains where the blended basket of works unit rates set out in Table 114 and Table 113 respectively.

For example, the calculation of the determined unit rates for domestic meter installation is shown in Table 179. These rates are expressed in Dec 2014 prices and will be adjusted for inflation where appropriate using RPI.

	2017	2018	2019	2020	2021	2022
Basket of works unit rate	191.72					
Frontier shift (%)	0.7%	1.5%	2.3%	3.0%	3.6%	4.2%
Frontier multiplication factor	0.99330	0.98480	0.97653	0.97015	0.96381	0.95751
Uncertainity mechanism determined unit rate	190.43	188.80	187.22	185.99	184.78	183.57

Table 179: Example calculation of determined unit rates for domestic meter installation

9.21 In respect of GD17 FE **opex** allowances, the proposed items subject to uncertainty adjustment are those shown in the table below:

Opex Item	Determination Basis	
Property Mgt	Network Rates based on turnover as set out in section 6	New
Licence Fees	Pass through.	Continuing
Advert. & Market Dev. (OO) (Connections Incentive Mechanism - inclusive of sales/support staff and related overheads)	Output based on Owner Occupier connections (excluding assessed non-additional connections) and determined unit rates, in conjunction with target connections. This is illustrated in the FE section 6.115.	Amended
Supplier of Last Resort	Ring-fenced	New
Materiality Threshold	Subject to future UR determinations.	Continuing

Table 180: FE Opex Uncertainty Mechanism

9.22 The determined rates for the opex uncertainty mechanism are:

- Network Rates, Licence Fees and Supplier of Last Resort are set out in Table 55;
- Connections Incentive per connection allowance is set out in Table 31.

9.23 It should be noted that the opex allowances, as set in chapter 6 are set pre-efficiency. They will be updated to reflect the frontier shift as below, before being applied to the Uncertainty Mechanism

Opex	2015	2016	2017	2018	2019	2020	2021	2022
Frontier shift FD	0.0	-0.4	-0.4	-0.8	-0.8	-0.7	-0.7	-0.7
Frontier Shift FD (Cumulative %)	0.0%	0.5%	0.8%	1.6%	2.4%	3.1%	3.7%	4.4%

Table 181: Opex Frontier Shift

PNGL

9.24 In respect of GD17 PNGL **capex** allowances the items subject to an uncertainty adjustment, whether it is output, pass through or ring fenced based, and the elements that will be adjusted are those shown in the tables below. The tables also include a reference to the section of the paper where additional elements of the mechanism e.g. cap and collar, are detailed.

Capex Item	Uncertainty mechanism applicable in GD17	Status
Traffic Management Act	Ring fenced as set out in Chapter 7.	Continuing
Pressure Reduction Stations	Not applicable in GD17	Amended
7 bar & Feeder Mains	Nominated output. The following project has been included as a nominated output – Ballysallagh to Craigantlet reinforcement as described from paragraph 7.213 of the final determination.	
Other Mains: Existing Domestic and I&C	Output based on actual number of properties passed, annual average number of metres of infill laid per property passed up to a cap of 5.16 metres excluding East Down and 11.52m for East Down and determined unit rate. Applied on a cumulative basis in GD17 (see section beginning paragraph 7.39). Additional incentive and penalties will apply as outlined in section 7.32.	Amended
Infill Mains: New Build Domestic	Output based on actual number of properties passed, annual average number of metres of infill laid per property passed up to a cap of 9.5 metres and determined unit rate. Applied on a cumulative basis in GD17 (see section beginning paragraph 7.39).	Amended
Security of Supply Mains	Nominated output. The following projects have been approved – Lisburn Road MPRS, Village MPRS, Holywood Road MPRS as described from paragraph 7.234 of the final determination	New
Domestic/I&C Meters	Output based on connections and determined unit rates.	Continuing
Domestic/I&C Meters – end of life replacement.	Output based on the actual number of meters replaced which are 20 years old or more. The mechanism will be disapplied to the extent that a deferral reveals a longer meter life which can be applied in the long term (see section beginning paragraph 7.133 and paragraph 7.149)	New
Domestic/I&C Services	Output based on connections and determined unit rates.	Continuing
IT	Not applicable in GD17	
Company specific issues	None for GD17	
Additional projects	The economic project mechanism described at paragraph 7.46 will apply to new projects which are shown to be either economic or necessary.	New
Materiality Threshold	Subject to future UR determinations	Continuing

Table 182: PNGL Capex Uncertainty Mechanism

9.25 The determined rates for the capex uncertainty mechanisms are:

- the basket of works unit set out in Table 109 following the application of the frontier shift set out in Table 112,
- except for infill mains and new build mains where the blended basket of works unit rates set out in Table 114 and Table 113 respectively will apply,

- except for replacement I&C meters at end of life where the unit rates in Table 115 will apply following the application of the frontier shift set out in Table 112.

9.26 An example of the application of frontier shift when calculating the determined unit rates for the uncertainty mechanism is shown in paragraph 9.20 above.

9.27 In respect of GD17 PNGL **opex** allowances, the proposed items subject to uncertainty adjustment are those shown in the table below:

Opex Item	Determination Basis	
Property Mgt	Network Rates based on turnover as set out in PNGL paragraph 6.434.	Continuing
Non Controllable Costs	Pass through for Licence Fees.	Continuing
Advert. & Market Dev. (OO) (Connections Incentive Mechanism - inclusive of sales/support staff and related overheads)	Output based on Owner Occupier connections (excluding assessed non-additional connections) and determined unit rates, in conjunction with target connections. This is illustrated in the PNGL section 6.311.	Amended
Supplier of Last Resort	Ring-fenced.	New
Materiality Threshold	Subject to future UR determinations.	Continuing

Table 183: PNGL Opex Uncertainty Mechanism

9.28 The determined rates for the opex uncertainty mechanism are:

- Network Rates, Licence Fees and Supplier of Last Resort are set out in Table 83;
- Connections Incentive per connection allowance is set out in Table 61.

9.29 It should be noted that the opex allowances, as set in chapter 6 are set pre-efficiency. They will be updated to reflect the frontier shift as below, before being applied to the Uncertainty Mechanism

Opex	2015	2016	2017	2018	2019	2020	2021	2022
Frontier shift FD	0.0	-0.4	-0.4	-0.8	-0.8	-0.7	-0.7	-0.7
Frontier Shift FD (Cumulative %)	0.0%	0.5%	0.8%	1.6%	2.4%	3.1%	3.7%	4.4%

Table 184: Opex Frontier Shift

SGN

9.30 In respect of GD17 SGN **capex** allowances, the items subject to an uncertainty adjustment, whether it is output, pass through or ring fenced based, and the elements that will be adjusted are those shown in the tables below. The tables also include a reference to the section of the paper where additional elements of the mechanism e.g. cap and collar, are detailed.

Capex Item	Uncertainty mechanism applicable in GD17	Status
Traffic Management Act	Ring fenced as set out in Chapter 7	New
Pressure Reduction Stations	Not applicable in GD17	
7 bar & Feeder Mains	Not applicable in GD17	
Other Mains: Existing Domestic and I&C	Output based on actual number of properties passed, annual average number of metres of infill laid per property passed up to a cap of 11.50 metres and determined unit rate. Applied on a cumulative basis in GD17 (see section beginning paragraph 7.39). Additional incentive and penalties will apply as outlined in section 7.32.	New
Infill Mains: New Build Domestic	Output based on actual number of properties passed, annual average number of metres of infill laid per property passed up to a cap of 9.5 metres and determined unit rate. Applied on a cumulative basis in GD17 (see section beginning paragraph 7.39).	New
Security of Supply Mains	Not applicable in GD17	
Domestic/I&C Meters	Output based on connections and determined unit rates.	New
Domestic/I&C Meters – end of life replacement.	Not applicable in GD17	
Domestic/I&C Services	Output based on connections and determined unit rates.	New
IT	Not applicable in GD17	
Company specific issues	Special engineering difficulties as described in the section beginning paragraph 7.303 above – ring fenced.	New
Additional projects	The economic project mechanism described at paragraph 7.46 will apply to new projects which are shown to be either economic or necessary. For avoidance of doubt this may include consequential changes to volumes.	New
Materiality Threshold	Subject to future UR determinations	New
Capex Risk Sharing	75:25 capex risk sharing adjustment for company and consumer respectively. This means SGN will take 75% of the risk of under/over recoveries and customers will take 25%.	New

Table 185: SGN Capex Uncertainty Mechanism

9.31 The determined rates for the capex uncertainty mechanisms are:

- the basket of works unit set out in Table 110 following the application of the frontier shift set out in Table 112,
- except for infill mains and new build mains where the blended basket of works unit rates set out in Table 114 and Table 113 respectively will apply.

9.32 An example of the application of frontier shift to the when calculating the determined unit rates for the uncertainty mechanism is shown in paragraph 9.20 above.

9.33 In respect of GD17 SGN **Opex** allowances, the proposed items subject to uncertainty adjustment are those shown in the table below:

Opex Item	Determination Basis	
Property Mgt	Pass through for Network Rates.	New
Licence Fees	Pass through	New
Advert. & Market Dev. (OO) (Connections Incentive Mechanism - inclusive of sales/support staff and related overheads)	Output based on Owner Occupier connections (excluding assessed non-additional connections) and determined unit rates, in conjunction with target connections. This is illustrated in the SGN section 6.582.	New
Supplier of Last Resort	Ring-fenced	New
Materiality Threshold	Subject to future UR determinations.	New

Table 186: SGN Opex Uncertainty Mechanism

9.34 The determined rates for the opex uncertainty mechanism are:

- Network Rates, Licence Fees and Supplier of Last Resort are set out in Table 94;
- Connections Incentive per connection allowance is set out in Table 88.

9.35 It should be noted that all relevant costs incurred in 2016 and 2017 will be subject to the Uncertainty Mechanism. Therefore the TRV will be updated as part of the GD23 price control.

Materiality Thresholds

9.36 In line with our approach as part of GD14 price control, we will have a materiality threshold for costs not foreseen at the time of the price control determination, but incurred as part of the GDN operations during the price control period. GDNs can request approval of such costs from us, provided they are above the materiality threshold and sufficiently justified with a robust business case. We would only expect to approve such costs where they are linked to new outputs and do not part of normal operational work.

9.37 The materiality threshold is set at £100k (i.e. at the same level as had been used for the GD14 final determination) per project for the duration of the GD17 price control period. We note that this is a change to the materiality threshold of £150k proposed in the draft determination to reflect feedback received from the three GDNs in response to our GD17 draft determination. This materiality threshold is the same for each of the three GDNs.

9.38 Consideration will also be made for any issues arising that could not reasonably have been foreseen, or for which realistic estimates with respect to the associated costs could not reasonably be made, at the time of the price control determination and which are reasonably outside the control of the GDNs, such as European Directives or equivalent local legislation which the GDNs are required to implement. Whilst we will still require a robust business case for any projects or initiatives to deal with such issues from the GDNs, we note that we may also consider them, as relevant and appropriate, if the materiality threshold is not met.

9.39 We note in particular that we consider the NIED (Northern Ireland European Development) project to be one of those for which paragraph 9.38 will be applicable. This project is aimed at the implementation of European network codes in Northern Ireland to improve access arrangements in the European gas market. Whilst this will imply significant changes to the current code arrangements, systems and procedures for transmission system operators, it will also impact on GDNs. However, whilst it is clear that there will be an impact for GDNs, it has at the time of this price control determination not been reasonably possible to quantify this impact. We therefore wish to clarify our position that we will consider any robust business cases submitted in respect to the NIED project, and that we will not apply the materiality threshold to them.

9.40 In taking decisions on granting of additional allowances we will consider the balance between the unforeseen costs and any cost reductions or revenue gains achieved during the price control period.

Rate of Return Adjustment – PNGL & FE

9.41 As well as the adjustments that will be made with respect to opex and capex described above we will also make adjustments for rate of return.

9.42 The methodology for making these adjustments is described in detail in Annex 14 and in Chapter 10.

9.43 The methodology for these calculations has been discussed at length with the GDNs and will be based on the spreadsheet set out in Annex 15.

Tax Allowance Adjustment – SGN

9.44 As part of the SGN licence we are required to set an annual tax allowance for the business due to WACC being set on a vanilla basis.

9.45 The GD17 allowance is determined at nil per annum and is subject to an uncertainty mechanism adjustment to reflect changes to the statutory corporation tax rates.

9.46 The methodology of making the adjustment follows that described in the Detailed Approach and Methodology section above and will be treated as an output item with the calculations adjusted only to reflect updated statutory corporation tax rates. As the tax allowance has been determined at zero in GD17 this adjustment will have no impact over the GD17 period but we regard it as important to establish this principle in the GD17 uncertainty mechanism.

10 Financial Aspects

Summary of Key Changes from Draft Determination to Final Determination

10.1 There are only minor changes to our calculation of PNGL's and FE's allowed rates of return. The final determination calculations are 4.26% for PNGL and 4.32% for FE.

10.2 We have updated our allowances for the cost of debt to reflect the latest Office for Budget Responsibility (OBR) inflation forecasts and to take account of FE's and PNGL's comments and evidence on debt-related transaction costs.

10.3 We have updated the proposed GD23 cost of debt adjustment mechanism after consideration of responses to the draft determination and discussions with the companies. A revised methodology for this mechanism is detailed in Annex 14. The main difference from the proposition put forward at the time of the draft determination is that we propose to adjust the allowances in this final determination in line with observed changes in market interest rates, rather than PNGL's and FE's out- or under-performance against the allowed cost of debt.

10.4 We have updated and expanded our financeability analysis and have concluded that an efficient GDN will be able to finance its licence activities during the GD17 period.

Detailed Approach – UR Decisions

Overview

10.5 This chapter sets out the financial inputs into the UR's price control calculations. The chapter is mostly focused on PNGL and FE as the SGN inputs are largely set by the outcome of the Gas to the West licence application competition.

Rate of Return

10.6 The financial model provides for PNGL and FE to earn a return on their allowed expenditures up until the point of recovery of those expenditures from customers. The value of this return is calculated as a weighted average of the costs of the equity and debt finance that the companies have to pay to investors.

10.7 In calculating the allowed cost of equity, the UR, like most economic regulators, uses the Capital Asset Pricing Model (CAPM) to determine the returns that shareholders require in exchange for their equity investments. CAPM estimates the required return to be a function of the risk-free rate (R_f), the expected return on the market portfolio (R_m) and a firm-specific measure of risk (beta of β_e) as follows:

$$\text{Return on equity} = R_f + \beta_e \, . \, (R_m - R_f)$$

10.8 In paragraphs 10.20 to 10.40 we explain how we have put numbers to each of the parameters in this formula.

10.9 The interest that PNGL and FE pay on their debts is directly observable, and in the first instance we propose to align the allowed cost of debt to these amounts. However, both companies will need to refinance the entirety of their existing debts during the GD17 period, meaning that there is some uncertainty about the interest that PNGL and FE will pay from mid-2017 and mid-2019 respectively.

10.10 In assembling the companies' new price controls, we have considered how far it is feasible to factor best available forecasts of the companies' post-refinancing costs of debt into the GD17 allowed return. We note that there is an inevitable uncertainty about what these costs will be and that over- or under-estimating future interest payments will result in the networks earning excess returns or sub-normal returns for several years until the GD23 reset of price controls. Elsewhere in the UK's regulated industries, there have been criticisms of such 'windfall' gains and losses, with the likes of the National Audit Office and the UK government highlighting that it is unfair for regulation to be set up in such a way as to produce outcomes in which prices are likely to be significantly higher or significantly lower than they need to be in order to cover companies' actual costs of debt.

10.11 Against this background, we consider that it is in the best interests of both consumers and investors that we should provide for an ex post adjustment to the GD17 allowed cost of debt. PNGL and especially FE have argued against this approach primarily on the grounds that a more conventional fixed ex ante allowance for interest costs will provide strong incentives for the companies to minimise their borrowing costs when they conduct their refinancings, and that the Utility Regulator will then be able to capture the benefit of lower costs for consumers at the next review of price controls, GD23. We understand this position, but we are not persuaded by the argument. It is important to highlight (i) that this final determination is being issued during a period of considerable volatility in market interest rates and (ii) that both companies are to refinance the whole of their borrowings in the first half of the 2017-22 period. The risk and consequences of setting a fixed cost of debt allowance too high or too low in this review are therefore unusually pronounced and the Utility Regulator does not consider that it is appropriate to inject a sizeable, largely uncontrollable element into PNGL's and FE's future profits when there exist regulatory options which will serve to protect both customers and investors from such risk.

10.12 We have considered a number of mechanisms for dealing with the uncertainty around future interest rates, as set out in the draft determination, and have engaged in further discussions with the companies during the last three months. Following this work, and in line with representations made by the parties, we have revised our proposed design of the ex post adjustment mechanism so that it passes through observed changes in market interest rates rather than PNGL's and FE's company-specific out- or under-performance against the Utility Regulator's forecasts of actual borrowing costs. A detailed description of the mechanism is set out in Annex 14.

Financeability

10.13 In carrying out its functions, the Utility Regulator is required to carry out our functions in the manner we consider is best calculated to further our principal objective, having regard to the need to secure that licence holders are able to finance their licence obligations (amongst other things). This duty has underpinned our approach to the whole of our cost of capital assessment, and to the assembly of PNGL's and FE's price controls more generally, but we also give a self-contained assessment of financeability in paragraphs 10.60 to 10.80.

Rate of Return

10.14 The values that the Utility Regulator proposed for the GD17 allowed rate of return in its draft determination are set out in Table 187.

Parameter	UR draft determination PNGL	UR draft determination FE
Gearing	0.55	0.55
Risk-free rate	1.25%	
Expected market return	6.5%	
Asset beta	0.40	
Debt beta	0.10	
Equity beta	0.77	
Post-tax cost of equity	5.3%	
Tax rate	20%	
Pre-tax cost of equity	6.6%	
Cost of debt	2.26%	2.33%
Rate of return	4.3%	4.3%

Table 187: Allowed rates of return – draft determination

10.15 PNGL and FE both said in their responses to the draft determination that the above rates of return are too low. A detailed review of the arguments that they made is set out in Annex 13. Key points include:

- beta – PNGL and FE both argued that the UR's attempt to position the GD17 beta logically next to regulatory precedent was flawed because the precedents cited in the draft determination had been misrepresented and rendered out-of-date by recent market data. Both companies also took issue with the Utility Regulator's assessment of their riskiness;
- tax – PNGL and FE both argued for the tax wedge adjustment to the cost of equity to be increased from the 1 / (1 – t) uplift that the Utility Regulator provided for in the draft determination;
- cost of debt – PNGL and FE provided a series of comments on the component parts of the cost of debt calculation, and concluded that the Utility Regulator had significantly under-estimated the allowance that they required.

10.16 Conversely other responses have been more supportive of our approach or questioned whether our proposed WACC was too high. Specifically CCNI referenced work it had done with its consultants Reckon, to question whether the beta provided for in the DD was over generous. It argued that, given there was no evidential basis for FE and PNG being more risky than GB comparators, it would have expected the beta to be set in the middle of a 0.30 to 0.40 range identified in the draft determination at 0.35.

10.17 In reaching this final determination, we have paid careful attention to these representations and sought to address the points that have been made either in this chapter or in Annex 13.

10.18 We also asked UKRN to undertake a review of our draft determination and received a number of helpful points in feedback. The UKRN report is attached as Annex 7 to this document.

10.19 Our final determination of allowed returns for the GD17 period is set out below.

Gearing

10.20 We noted in our draft determination that other regulatory determinations for UK regulated networks have provided for gearing of between 45% and 65%. We have decided to use a point estimate of 55% at the middle of this range.

10.21 We note that the final pre-tax WACC figure is not especially sensitive to gearing and we have also considered the issue of gearing levels in our financeability analysis.

Risk-free rate and expected market return

10.22 We have decided to retain our draft determination estimate of the risk-free rate of 1.25%, to be consistent with the estimate that the Competition & Markets Authority (CMA) used in its recent price control determination for Bristol Water.

10.23 The expected market return has also been considered at length in recent UK price reviews. The CMA, and its predecessor the Competition Commission (CC), have expressed the view that it is untenable to think of a real expected market return of more than 6.5%. The following excerpt is taken from the CC's 2014 report on NIE's price control:

"The interpretation of the evidence on market returns remains subject to considerable uncertainty. The CC said in recent regulatory inquiries that 7 per cent is an upper limit for the expected market return, based on the approximate historical average realized return for short holding periods. We think that it may be appropriate to move away from this upper limit based on historical realized returns and place greater reliance on ex ante estimates derived from historical data which tend to support an upper limit of 6.5 per cent."

10.24 Given the clear steer from the CMA/CC on this matter, we also propose to use a value of 6.5%.

10.25 The UKRN report notes that both of the above values lie within ranges that are consistent with decisions made by other UK regulators.

Beta

10.26 The betas of listed firms can be estimated empirically using stock market data. In this price review, however, we are concerned with two companies that do not have a stock market listing. We have therefore sought to understand the betas that regulators have factored into other companies' allowed rates of return and to position PNGL and FE logically against these comparators. We have also taken account of the beta that SGN identified in its successful application for the new Gas to the West licence, as evidence of perceptions of riskiness obtained through a competitive process. The unit of comparison that we use is a firm's assumed asset beta (a hypothetical measure of the beta that a firm would have at zero gearing).

10.27 The comparators are set out in table Table 188 and in Figure 10.

Regulator / company	Asset beta
Ofgem, gas distribution networks	0.38
Ofgem, electricity distribution networks	0.38
CC, NIE	0.40
Ofwat, water and sewerage networks	0.30
SGN Gas to the West years 6-10	0.43 to 0.45
Commission for Energy Regulation Bord Gais	0.35

Table 188: Asset beta estimates

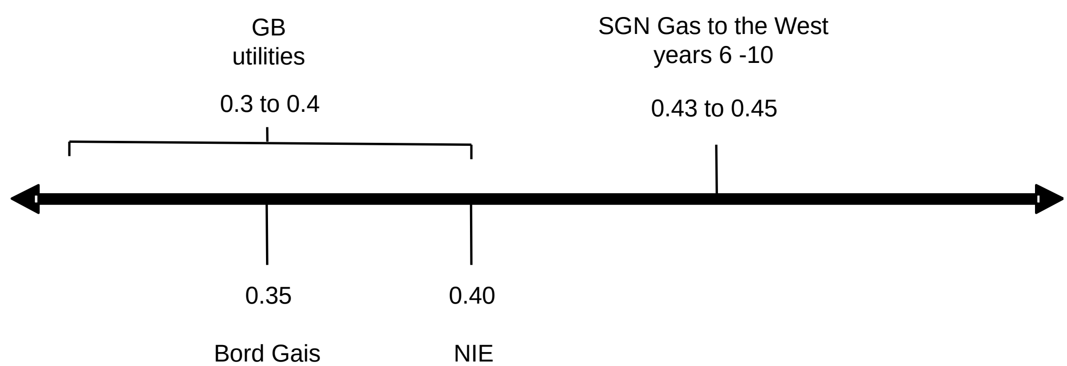

Figure 10: Asset beta range

10.28 As noted above, PNGL and FE both disagreed that these were valid reference points for us to factor into our determination, at least without first making significant upward adjustments. We do not agree with this assessment for the reasons set out in Annex 13. We have therefore sought to understand how PNGL's and FE's risk profiles compare to the other regulated networks and to position the two businesses logically within the above spectrum.

10.29 In the draft determination document we explained that in many respects the networks are very similar. For example, most regulated companies nowadays have revenues caps like the caps that we are putting to put in place for PNGL and FE, which limit companies' in-period exposure to unforeseen changes in volumes. There are also similarities across sectors between the overall strength of opex/capex/totex incentives and the amounts of money that are tied to output or service quality schemes across different price controls, even if the detailed design of such incentives differs from industry to industry.

10.30 Our analysis suggested that there are really two main areas in which the risks around PNGL's and FE's future equity returns might be distinguishable from other regulated networks:

- first, PNGL and FE both argued in their submissions that they are relatively 'immature' businesses and that they face atypical uncertainty around customer numbers and volume growth; and
- second, PNGL and FE manage comparatively low amounts of ongoing expenditure in comparison to the capital that investors have put into the business. All other things being equal, this ought to mean that any cost shocks, if they occur, have less impact on the percentage return that they are able to give their investors, thus

offering equity providers a more stable and more predictable return than is the case with other regulated utilities.

10.31 The UKRN review also highlighted the second of these factors, and suggested that we should consider also how the skew in allowed revenues towards the recovery of the TRV might affect the companies' exposure to risks around the long-term demand for gas during any transition to a low carbon economy.

10.32 On the first of the above matters, we explained in the draft determination how both PNGL and FE have passed the point in their development where the recovery of shareholders' investments is dependent on the companies acquiring new customers. We put forward quantified analysis in support of this assessment. Neither PNGL nor FE sought to challenge our calculations. The UKRN also did not take any issue with this conclusion in its review. Accordingly, we do not accept the very general and qualitative arguments that the companies have made about their supposed immaturity.

10.33 In relation to the second matter, the UKRN was clear in its advice that low totex-to-TRV ratios indicate a lower exposure to systematic risk. We have reviewed again whether we should make an explicit downward adjustment to the GD17 beta to account for this lower risk, but continue to find it difficult to produce a robust and defensible quantification of the effect.

10.34 We note URKN's comments on risks around the long term uncertainty in gas distribution, its reference to Ofgem's work on this in RIIO GD1 and its assessment that the flip side of a relatively large TRV might be a marginally greater exposure to volume decline and asset stranding, specifically in a scenario where there is a rapid transition to a low carbon economy. We consider the scale of the risk here to be small, given the Northern Ireland government's policy of promoting the use of gas, and expect that it would be considered by investors to be of lesser importance than the lower sensitivity of profits to cost risk that also comes from having a relatively large TRV. However we have taken into account UKRN comments in making changes to our approach to volumes which is discussed in Chapter 5.

10.35 Taking these points together, we conclude that it is not necessary for us to provide for an atypically high beta in this determination. If anything, there is a case for a small mark-down in beta relative to our comparator companies, to reflect the lower sensitivity that returns will exhibit in the face of cost shocks, although we note again that the difficulties that we have with quantification make us reluctant to propose a specific deduction.

10.36 We have therefore decided to position the GD17 beta as follows.

10.37 First, we need to place PNGL and FE clearly apart from the beta that SGN put forward for years 6-10 in its Gas to the West application, as a reference point for a business that will have a price cap rather than a revenue cap and where there is more pronounced uncertainty about the long-term recovery of investments.

10.38 Second, we have concluded, on the basis that there is no material difference in the riskiness of the Northern Ireland gas networks in comparison to other regulated utilities, that the GD17 asset beta should logically sit within the 0.38 to 0.40 range formed by Ofgem's RIIO-GD1/ED1 beta and the CC's estimate of NIE's beta.

10.39 Our chosen point estimate from this range is 0.40. This gives recognition, in particular, to the fact that there are differences with PNGL's and FE's regulatory model from the standard model, e.g. the Profile Adjustment, and notwithstanding the analysis that we have summarised above, the possibility that investors may not be wholly familiar with these differences. While we regard this as a small and potentially short term factor, our initial view is that a cautious approach is appropriate and this therefore warrants placing PNGL and FE at the top of the range that regulators have judged appropriate for low-risk network utility businesses.

10.40 At gearing of 55% and assuming a debt beta of 0.1, the calculated equity beta is 0.77. We note that this estimate is within the range put forward by FE, albeit at the bottom end.

Overall cost of equity

10.41 Table 189 brings our proposed figures for the risk-free rate, expected market return, beta and gearing into an overall calculation of the allowed cost of equity. We also provide a comparison to other recent regulatory determinations. (NB: because these other determinations all provided for slightly different levels of gearing, we show in the final row of the table how the calculations would compare if all regulators were to have used a common 65% gearing ratio.)

Parameter	GB GDNs	NIE	GB electricity DNOs	GB water and sewerage companies	PNGL / FE
Risk-free rate	2.0%	1.5%	1.5%	1.25%	1.25%
Expected market return	7.25%	6.5%	6.5%	6.75%	6.5%
Asset beta	0.38	0.40	0.38	0.30	0.40
Cost of equity @ 55% gearing	**-**	**-**	**-**	**-**	**5.3%**
Cost of equity at 45% gearing		5.0%			
Cost of equity at 62.5% gearing				5.7%	
Cost of equity at 65% gearing	6.7%	6.3% *	6.0%	6.0% *	6.3% *

Table 189: Calculation and comparison of the allowed cost of equity

Note: an asterisk indicates a recalculated value. The figure for NIE is taken from table 13.13 of the CC inquiry report.

10.42 The table shows that the allowed cost of equity for PNGL and FE sits above the returns that Ofgem and Ofwat gave regulated networks in their most recent determinations. It sits below the RIIO-GD1 allowed cost of equity reflecting the steps forward that there have been in thinking about the expected market return.

10.43 We are content that this is a logical picture to present.

Tax

10.44 The allowed cost of equity in the financial model is a pre-tax cost of equity which is intended to cover both the annual return to shareholders and the tax payable on that return. The pre-tax cost of equity is conventionally uplifted by a factor of 1 / (1 – t), where t is the prevailing statutory corporation tax rate. PNGL and FE both argued for an alternative to this approach, but we do not accept their submissions on this matter for the reasons set out in Annex 13.

10.45 At the start of the GD17 period, the tax rate will be 20%. This means that the 5.3% cost of equity can be translated into a pre-tax cost of equity of 6.6%. There is an expectation that the tax rate may move lower over the GD17 period, in part due to the decision to devolve corporate tax to the Northern Ireland Assembly. We therefore intend to adjust the TRV at the GD23 to 'true-up' the difference between the revenue that the networks are provided with under this final determination and the revenue that they would have been entitled to had the Utility Regulator provided in its calculations for the average out-turn tax rate over the period 2017-22.

10.46 Our methodology will be to update the 20% figure with the average tax rate that applies during GD17. Where two different tax rates apply in a single calendar year we will calculate the weighted average in that calendar year. The average of the calendar years will then be used to calculate an overall average for GD17. This will then be used to amend the rate of return and calculate an updated set of revenues for the GDNs and the difference between this and the revenues determined in this final determination will be reflected in an adjustment to the TRV at the start of GD23. This methodology is incorporated within the Rate of Return Adjustment spreadsheet which is included as Annex 15.

Cost of debt

10.47 In line with the methodology set out in paragraphs 10.9 to 10.12, our 'baseline' cost of debts are built around the best current estimates of the average interest rates that PNGL and FE will pay over the GD17 period, plus an allowance for transaction costs.

10.48 The calculations start with the interest that PNGL and FE will pay on existing debts prior to their intended refinancings. The average rates are 4.3% for PNGL and 4.1% for FE. We add an annualised amount of the fees that the companies incurred when entering into their borrowing arrangements, giving an all-in embedded cost of debt of 4.6% and 4.7% respectively.

10.49 In making baseline estimates of the post-refinancing costs of debt, we have had to consider how far it is appropriate to reflect the marked movements in market interest rates that have occurred during recent months. Market interest rates have, in particular, been significantly affected by the Brexit vote at the end of June 2016 and by policymakers' responses to the uncertainty that this has caused. We could simply factor the latest market data into our 'baseline' calculation, as the best available benchmark for the interest rates that companies will face over the next few years. However, our assessment is that this will result in us placing undue weight on data drawn from a period of considerable turbulence. Reflecting on previous occasions when there have been sharp movements in interest rates (e.g. 2008), there is a danger of concluding prematurely that interest rates have moved to a new equilibrium, only to then be surprised by ongoing developments in the market. In the circumstances, we prefer not to be too swayed by short-term data and have chosen instead to retain the baselines that we set out in our draft determination. These calculations, which made use of data up to January 2016, were built up as follows:

- first, we observed that the yield on BBB rated 10+ year debt in secondary markets at the start of this year was approximately 4.4%;
- we allowed for a small move up in interest rates of 0.4% and 0.8% by mid-2017 and mid-2019, consistent with forward gilt market rates;
- we next allowed for the possibility that PNGL and FE may have to pay a small premium in comparison to other borrowers, reflecting possible illiquidity of their

bonds as compared to more actively traded GB utility debt. We provided for an illiquidity premium of 0.4% to mirror the premium that we have observed in the pricing of PNGL's debt since the resolution of the 2012 Competition Commission inquiry;

- finally, we allowed for refinancing-related transaction costs in line with the costs incurred in the companies' last debt-raising exercises.

10.50 In this final determination, we have made small adjustments to the transaction costs allowances in line with the representations made by the companies in their responses to the draft determination, but have otherwise left the calculations unchanged. Table 190 brings these calculations together into an overall baseline for the nominal cost of debt.

Company	Average nominal cost of debt, GD17			
PNGL			Current market rates	4.4%
			Forward rate adjustment	0.4%
	Average interest costs	4.3%	Illiquidity premium	0.4%
	Transaction costs	0.3%	Transaction costs	0.4%
	Embedded debt	4.6%	Cost of new debt	5.6%
	10:90 weighted average			
	Weighted average cost of debt = 5.5%			
FE			Current market rates	4.4%
			Forward rate adjustment	0.8%
	Average interest costs	4.1%	Illiquidity premium	0.4%
	Transaction costs	0.6%	Transaction costs	0.6%
	Embedded debt	4.7%	Cost of new debt	6.2%
	40:60 weighted average			
	Weighted average cost of debt = 5.6%			

Table 190: Cost of debt calculations

10.51 We convert the nominal costs of debt in Table 191 into their real equivalents by adjusting for forecast average GD17 RPI inflation of 3.07% per annum, as projected by the Office for Budget Responsibility's in its latest published forecasts.[94] This gives a real cost of debt of 2.36% for PNGL and 2.45% for FE.

10.52 Table 191 compares this figure to other recent regulatory decisions.

	GB GDNs, 2016/17	NIE	GB electricity DNOs, 2016/17	GB water and sewerage companies	PNGL / FE
Allowed cost of debt	2.38%	3.1%	2.42%	2.59%	~2.4%

Table 191: Calculation and comparison of the allowed cost of debt

10.53 Our provisional estimate of PNGL's and FE's cost of debt is in line with other allowed costs of debt. This is in spite of the opportunity that PNGL and FE have to refinance the whole of their existing borrowings at historically low rates of interest during the GD17 period, whereas other companies will have to go on servicing legacy debt at comparatively higher rate of interest for several more years.

10.54 It should also be noted that Ofgem's indexed costs of debt for the GB GDNs and electricity DNOs are likely to fall in the coming years. If we apply current debt market trends they are likely to be below 2.3% from 2017/18.

Overall rate of return

10.55 Table 192 combines our calculations of the cost of equity and the cost of debt into an overall rate of return for the GD17 period.

Regulator / company	PNGL	FE
Gearing	0.55	0.55
Pre-tax cost of equity	6.6%	6.6%
Cost of debt	2.36%	2.45%
Overall rate of return	4.26%	4.32%

Table 192: Computed rates of return

10.56 Based on these calculations, we propose to factor rates of return of 4.26% and 4.32% into PNGL's and FE's price controls at the outset of the GD17 period.

10.57 No further rounding of these figures beyond 2 decimal places is proposed.

10.58 Our starting GD17 rates of return are lower than the figures sought by PNGL and FE because we have:

- aligned our estimate of the expected market return to the 6.5% figure recommended recently by the CC/CMA;
- taken a different view from the companies about riskiness of future returns and beta (although, as noted above, our estimate of beta is within the range put forward by FE);
- made a more conventional tax adjustment when calculating the pre-tax cost of equity; and

[94] For 2021 and 2022, where there is no OBR forecast, we use an annual RPI inflation rate of 3.2%, consistent with the OBR forecast for 2018-20.

- made slightly lower central forecasts of the networks' likely costs of debt.

10.59 As noted in paragraphs 10.12 and 10.46, the return may subsequently be adjusted up and down within period in light of changes to the statutory corporation tax rate and any over- or under-forecasting of the post-refinancing costs of debt. Details of this adjustment mechanism are given in Annex 14.

Financeability

10.60 Article 14 of the Energy (Northern Ireland) Order 2003 requires us to carry out our functions in the manner we consider is best calculated to further our principal objective, having regard to the need to secure that licence holders are able to finance their licence obligations[95] (amongst other things).

10.61 This duty is framed similarly to the financing duties of other UK regulators and can broadly be taken in practice to mean that the price control ought to be set at a level which would allow an efficient network company to finance its licensed activities. It is therefore necessary for us to consider financeability as an integral part of a price review.

10.62 The main responses to the draft determination section on financeability came from FE and PNGL. They generally argued that the financeability analysis was flawed and better quality analysis would show that GD17 was not financeable. Their specific arguments included that:

- The analysis should target a higher credit rating;
- Actual gearing levels should be used;
- More ratios and downside scenarios should be included in the analysis;

10.63 Furthermore as a response to the financeability issues that they identified they proposed solutions including a higher rate of return and removal of the Profile Adjustment. We set out below our updated financeability assessment and deal with many of the GDN issues. We have also addressed the responses in our paper under Annex 13.

10.64 In assessing whether this determination leaves PNGL and FE in a position where they will be able to finance their activities during the GD17 period, we have considered the ability that the companies will have to utilise both equity and debt finance.

10.65 The key determinant of the companies' ability to access equity finance is the allowed return on equity. As noted in paragraphs 10.20 to 10.43, we have built returns by considering the level of returns that investors are likely to be able to get from other equity investments and by positioning the return offered by PNGL and FE logically against these alternative investments. Our proposed return is slightly higher, on a like-for-like basis, than the return that Ofgem factored into its recent RIIO-GD1 and RIIO-ED1 price control calculations. Accordingly, we are satisfied that both PNGL and FE ought to be capable of securing equity finance on an ongoing basis throughout the next six years.

10.66 As far as borrowing is concerned, it will be important for PNGL and FE to maintain investment-grade credit quality.[96] One determinant of the companies' credit worthiness

[95] Activities which are the subject of obligations imposed by or under Part II of the Gas (Northern Ireland) Order 1996 or the Energy (Northern Ireland) Order 2003.

[96] An investment grade credit rating is a rating of BBB- or above (Fitch or Standard & Poor's) or Baa3 (Moody's). PNGL has a licence condition to maintain an investment grade rating. We are not prescriptive on which credit rating agency is used by PNGL.

in the eyes of lenders will be the level of cashflows that the networks generate under our price controls. A second key factor will be the amount of borrowing that the companies attempt to take on. We influence the first of these things, but the second is firmly in the hands of PNGL and FE.

10.67 In Table 193 and Table 194 we present the results of some modelling that we have produced to understand the projected level of key financial ratios if PNGL and FE select a gearing that is in line with the 55% figure that we use in our cost of capital calculations. The modelling assumes that the companies set prices, carry volumes and incur costs (i.e. opex, capex and interest costs) in line with the allowances feeding into the calculation of allowed revenues, as set out in the earlier sections of this document.

10.68 The modelling has been updated since the draft determination to expand the range of ratios examined. We have taken into account both evidence from rating agency reports and the considerations of the Competition Commission in its 2014 report for NIE in arriving at appropriate thresholds for the post-maintenance interest cover ratio (PMICR)[97] of at least 1.4 times and gearing of no more than 70%, in order to obtain a BBB credit rating.

	2017	2018	2019	2020	2021	2022
PMICR	**1.40**	**1.46**	**1.51**	**1.50**	**1.39**	**1.41**
Gearing	**54.0%**	**52.0%**	**51.0%**	**52.0%**	**52.0%**	**51.0%**
FFO/Interest Cover	**2.12**	**2.26**	**2.37**	**2.47**	**2.53**	**2.63**
FFO/Net Debt	**6.0%**	**7.0%**	**7.0%**	**8.0%**	**8.0%**	**9.0%**
RCF/Capex	**0.94**	**0.27**	**0.59**	**0.59**	**1.49**	**-0.16**

Table 193: Modelling results for PNGL

	2017	2018	2019	2020	2021	2022
PMICR	**1.38**	**1.38**	**1.32**	**1.33**	**1.35**	**1.36**
Gearing	**56.2%**	**56.3%**	**56.1%**	**55.7%**	**55.3%**	**54.7%**
FE PMICR	**1.00**	**1.00**	**1.00**	**1.00**	**1.00**	**1.00**
FFO/Interest Cover	**2.50**	**2.34**	**2.30**	**2.32**	**2.35**	**2.39**
FFO/Net Debt	**8.2%**	**7.3%**	**7.1%**	**7.2%**	**7.4%**	**7.6%**
RCF/Capex	**0.41**	**0.46**	**0.47**	**0.49**	**0.51**	**0.54**

Table 194: Modelling results for FE

10.69 In the case of PNGL, gearing remains fairly modest throughout the GD17 period and PMICR sits above a 1.4 threshold that two of the rating agencies have indicated would normally be expected of a company with an investment-grade credit rating. This demonstrates an internal consistency between the gearing and cost of debt estimates that we inserted into our cost of capital calculations and shows that PNGL ought to be capable of maintaining quite substantial amounts of debt finance during the GD17 period.

10.70 In the case of FE, gearing levels are similarly modest but PMICR is much tighter against the above-mentioned 1.4 threshold. FE has also said that we need to pay attention to an

[97] PMICR = EBITDA adjusted for issues such as under recoveries, deferred revenue and cash taxes less regulatory depreciation all divided by cash interest.

alternative measure of interest cover[98] that currently appears in its covenants with lenders. We do not think that it is appropriate to place undue weight on this measure. The PMICR measure that we put most focus on is the one we have used in GD14 and is based on the metrics provided by the credit rating agencies. After responses to the draft determination we had further discussions with the credit rating agencies on their view of the PMICR and they re-iterated that they were comfortable with its application and use in our analysis. We are not aware of the background to the specific discussions between FE and its current lender. We remain of the view that the PMICR referenced by the credit rating agencies and which investors in PNGL have been comfortable for many years is appropriate to focus on in GD17.

10.71 We do note that this alternative interest cover metric falls below the threshold at which FE's parent is currently required to take certain remedial actions under its agreement with lenders. This is something FE will need to consider in detail with its lenders.

10.72 FE argued in its response to the draft determination, and in subsequent correspondence and meetings, that the weak interest cover reflected in Table 194 shows that the UR is providing for a rate of return that is too low and, consequently, an inadequate amount of revenues. We disagree with this assessment.

10.73 First, notwithstanding that projected financial ratios are one of several factors that rating agencies and lenders consider, the figures above do not factor in potentially significant mitigating factors and it may well be that, when other parties come to calculate interest cover, they will arrive at significantly higher figures than we present in Table 194 and Table 195. Two[99] potentially important considerations here are that:

- the figures ignore the additional revenue FE will receive as a result of under recoveries which have been built up historically (see Chapter 11). This currently stands at c£15m (Av £2014). FE has some flexibility on how it will collect that revenue but it is reasonable to assume that this will add significantly to revenues between 2017 and 2019 and so is an additional tool which FE can use to improve the ratios;

- the actual post-refinancing cost of debt comes out lower than the allowed cost that is feeding into our modelling (as identified in Table 190). Although we have said above that it would be premature to reflect current market interest rates into GD17 allowed revenues, an objective assessment at the time of writing would be that the balance of probabilities are skewed towards lower rather than higher interest rates over the next six years.

10.74 If we just capture the latter point within the modelling and apply the current market cost of debt, our analysis shows that FE's interest cover ratios come out above threshold values, as shown in Table 196 below. Our discussions with credit rating agencies have confirmed that using market debt would be a reasonable approach to this analysis. We do recognise that the assumption in this modelling would mean there was a subsequent correction in TRV in 2023 which would have to be considered by investors as it would

[98] FE PMICR = EBITDA adjusted for working capital less capex plus loan drawdowns divided by cash interest.

[99] We would also note that both PNGL and FE allowances include £5.9m and £7.4m associated with street works legislation. Should no legislation be passed, no such costs will materialise and, while this will come out in the GD23 uncertainty mechanism, it provides the GDNs with further financeability flexibility in GD17. In relation to GD23 adjustments we would expect that an efficient company will factor this into its long term decisions on its capital structure.

lead to changes to FE ratios from 2023. However we note that the nature of the FE business model tends to mean that flexibility increases over the longer term, i.e. significant increase in scope of dividend payments. In effect the impact of this will be to bring forward revenues from the GD23 period into GD17. We have also included the PNGL comparable table and, as expected, its ratios also improve.

	2017	2018	2019	2020	2021	2022
PMICR	**1.92**	**2.03**	**2.15**	**2.17**	**1.92**	**1.98**
Gearing	**54.1%**	**51.3%**	**49.5%**	**49.4%**	**49.3%**	**47.9%**
FFO/Interest Cover	**2.90**	**3.14**	**3.36**	**3.57**	**3.54**	**3.76**
FFO/Net Debt	**7.4%**	**8.4%**	**9.2%**	**10.1%**	**9.9%**	**10.8%**
RCF/Capex	**0.98**	**1.13**	**0.91**	**0.88**	**0.89**	**1.02**

Table 195: Modelling results for PNGL

	2017	2018	2019	2020	2021	2022
PMICR	**1.68**	**1.63**	**1.49**	**1.48**	**1.47**	**1.47**
Gearing	**57.1%**	**58.7%**	**59.9%**	**60.8%**	**61.5%**	**62.0%**
FE PMICR	**1.90**	**1.82**	**1.76**	**1.71**	**1.67**	**1.63**
FFO/Interest Cover	**3.04**	**2.77**	**2.62**	**2.59**	**2.58**	**2.58**
FFO/Net Debt	**9.0%**	**7.8%**	**7.2%**	**7.0%**	**7.0%**	**7.0%**
RCF/Capex	**0.25**	**0.28**	**0.27**	**0.29**	**0.31**	**0.34**

Table 196: Modelling results for FE

10.75 Following on from the analysis summarised in Table 195 and Table 196, we have conducted some additional sensitivity analysis to look at a downside scenario. This scenario consists of increasing actual capex and opex costs by 15% compared to the FD and ignoring the impact of risk sharing. Unsurprisingly this results in a reduction in the average PMICR for PNGL to 1.76 and FE to 1.30.

10.76 While these scenarios depict some of the possible out-turns that PNGL may encounter, the UR considers them to be of limited interest from a financeability point of view because they assume that all under-performance is financed through debt issuance. The UR does not consider that this is necessarily the correct assumption. The risks here are risks that equity holders are being paid to bear via the allowed return on equity and it is just as reasonable to assume that equity rather than debt will flex to accommodate downside scenarios. If one holds debt constant in the scenarios we have constructed, key financial ratios remain broadly unchanged.

10.77 Second, and more importantly, we do not accept that modelling of interest cover can show that allowed revenues have been set too low. As noted in paragraph 10.66, such ratios are a function of two main inputs: the allowed revenues provided in this price control determination; and the capital structure that FE chooses to put in place. FE's reading of Table 194 has focussed almost exclusively on the first of these things. In our view, a more appropriate response would be to question the amounts of indebtedness and interest expense that are being modelled.

10.78 We note with a more modest selection of gearing at, say, 45%, interest cover ratios for both PNGL and FE achieve threshold values.[100] This demonstrates that the cashflows in this final determination are sufficient to enable efficient companies – i.e. companies that select a prudent capital structure – to finance themselves through a balanced mix of debt and equity financing. It is our view, therefore, that the calculation of allowed revenues cannot be said to be inadequate or 'wrong' for reasons of financeability.

10.79 In conclusion, we are of the view that both PNGL and FE are capable of financing their activities during the GD17 period via a prudent choice of capital structure. Our role is to ensure that the companies have an adequate return of equity and debt to manage their finances over the long run and to leave the detailed management of those finances to the companies. In the event that the revenues in this determination fall short of providing sufficient cashflows to support either companies' existing indebtedness, we would consider this to be a consequence of the companies seeking to borrow too much and expect there to be an adjustment to the mix of debt and equity such that the capital structure becomes consistent with the cashflows on offer. We note the return on equity provided for in this determination will support any such restructuring.

Depreciation

10.80 We discussed in the draft determination, in paragraph 10.89 to 10.96 on the Profile Adjustment, the option of making significant changes to licence arrangements which would have had a potential large knock on impact on depreciation. We detail our views on the Profile Adjustment below but as we have not made significant changes to the Profile Adjustment we have not carried out a full review of depreciation profiles. Therefore this section is based on current arrangements.

10.81 During GD14 we decided not to align depreciation rates across the GDNs. We concluded that given the minimal benefit and the effort required we would look at the issue again as part of GD17.

10.82 GD17 brings an additional GDN (SGN) in addition to PNGL and FE and therefore we are potentially faced with 3 different depreciation policies applying to the GD17 period as set out in Table 197.

Asset Categories	PNGL	FE	SGN
Mains	40	40	
Services	35	40	
Meters	15	15	
Other	40	5	
All Assets			35

Table 197: Proposed Asset Lives

10.83 Although the overall impact of aligning depreciation approaches within the GDNs will have minimal impact, it does provide practical benefits if we are to treat each GDN in the

[100] We note that the weighted average cost of capital calculation is insensitive to a choice of gearing within this sort of range, which means that such a recalibration would have no knock-on implications for allowed revenues resulting. This is consistent with an intuition that the cost of capital (based on CMA estimates of the risk-free rate and expected market return, a beta that sits within the range originally suggested by FE, and a very cautious forecast of interest rates) and allowed revenues have been calibrated appropriately for companies of PNGL's and FE's fundamental character, and are capable of supporting a range of possible capital structures – within certain limits.

same way. This means that various templates and financial models can then be aligned and comparability increases across the 3 GDNs.

10.84 The draft determination proposed to use the FE categories as this provides the broadest range of asset lives i.e. long – 40 years (mains and services), medium – 15 years (meters) and short – 5 years (e.g. IT).

10.85 PNGL disagreed with our proposal in its response to the draft determination. While it noted the benefit of the decrease in its IT depreciation profile it disagreed with the extension of its services profile arguing it would increase its recovery period.

10.86 As PNGL has noted the changes to the asset lives proposed would increase and decrease different elements and so is somewhat balanced. We note PNGL comments on services but can find no evidential reason why services should not be depreciated over the same period as mains. There seems to be a strong engineering and regulatory basis to align the two. Also 40 years follows our approach to economic assessment of gas extensions and therefore is a reasonable basis to set the asset lives for mains and services.

10.87 We have therefore determined that the asset lives of all three GDNs should be aligned to the FE current profiles.

10.88 As this is the first price control for SGN it simply means that the determinate asset lives will be applied on all assets from start-up.

10.89 FE is not impacted by the proposal. This leaves PNGL for whom services change from 35 to 40 years and the other category would become 5 years. To minimise any impact on PNGL we will make no adjustment to prior year expenditures i.e. the DAV values will remain unaffected (although we will consolidate the 2 existing 40 year asset life categories). For any new expenditure on services or other assets the new categories will apply from the beginning of GD17 only.

10.90 We have also considered the depreciation profile applied to the GB GDNs including the decision of Ofgem to front load the profile in RIIO – GD1. We have reviewed the Ofgem decision and discussion of future gas scenarios. We have also noted the comments from UKRN, Annex 7, in its peer review of our draft determination.

10.91 We are still of the view that on the question of long term uncertainty in the gas industry the context and policy environment is very different in NI. The relevant department in NI is DfE and it retains a principle objective to promote the gas industry and this also applies to UR. This objective is reflected in the NI Executive decision to provide a subvention of up to £32m for the extension of the gas network to the west of NI.

10.92 We have engaged with DfE since the draft determination and there is nothing to suggest that this different policy context is likely to change soon.

10.93 However we put significant weight on the UKRN comments and found the process of working closely with other UK regulators on GD17 very positive. While the differing policy context is evident, the similarities between the GB and NI gas industries are strong and we noted these in arriving at our rate of return decisions. We therefore think it prudent to take a cautious approach on this matter and follow Ofgem actions in taking into account long term uncertainty in the gas industry.

10.94 As noted in the draft determination, given the structure of the NI licences, it is more appropriate to consider future volume assumptions than to adjust depreciation profiles.

This is a more direct adjustment and is consistent with licence structure. Therefore our decision to address long term uncertainty is implemented through changes in the long volume assumptions and the detail is set out in Chapter 5.

10.95 As with Ofgem the outcome of our actions is to bring forward revenues for the GDNs into this period. This increases prices for consumers but reduces risks for the industry in the long run.

10.96 The impact on customers is not insignificant with a tariff impact in the order of 10% over GD17. However on balance we think it is in the interests of NI customers to take action now to reduce long term risks. We will update our volume forecasts and consider this issue again in GD23.

Tax

10.97 The rates of return for PNGL and FE, as set out in Table 192, are pre-tax rates of return, which combine remuneration for interest costs, equity returns and a simple 1 / 1 – t tax wedge adjustment into a single allowance. This reflects the UR's historical practice of setting pre-tax rates of return in all previous price control determinations and the difficulties that there would be in switching to an alternative approach at this point in the companies' licence periods.

10.98 SGN is in a different position to the other GDNs as it is at the start of its life. An alternative approach to that applied to PNGL and FE is a stand-alone allowance for tax, set in line with a company's projected tax payments. Ofwat was the first regulator to make company specific, period specific tax allowances in the 1990s. Since then, Ofgem, ORR and the Utility Regulator (with NIEN) have switched to modelled tax allowances and the CAA (with NATS), the Utility Regulator (with NI Water) and the WICS have all opted for this approach when regulating companies for the first time.

10.99 We said in our draft determination that we were minded to use this approach for SGN. We had previously been clear with the applicants for the Gas to the West licences that we would want to review the treatment of tax at each price review in line with best regulatory practice.[101] Insofar as a majority of regulated companies in the UK receive a stand-alone allowance for tax as part of each price control determination, and insofar as this approach has clear advantages in terms of the annual match that it brings between the costs that a company incurs and the revenue entitlement that the company accrues, we consider that it is desirable to put SGN on to a standard regulatory footing from the outset of its licence period.

10.100 In the short term, SGN, as a new company incurring significant upfront capital investment, will pay zero corporation tax. Accordingly, we have determined that tax allowances are set at zero for GD17. Tax will be subject to an uncertainty mechanism adjustment at the start of GD23 to deal with changes to statutory corporation tax rates and this is discussed further in Chapter 9.

10.101 One consequence of our approach to tax is that it becomes necessary to restate SGN's GD17 allowed rate of return. As part of the Gas to the West licence competition, we asked all bidders to state their required returns in terms of a pre-tax cost of capital. With tax now being dealt with as a separate line item in the allowed revenue calculation, we need to convert SGN's bid cost of capital into 'vanilla' form – i.e. excluding any allowance for tax.

[101] Paragraph 3.30
http://www.uregni.gov.uk/uploads/publications/Gas_to_the_West_Applicant_Information_Pack.pdf

10.102 SGN explained in its licence application that it derived its 6.2% pre-tax cost of capital bid by converting Ofgem's 3.78% starting RIIO-GD1 vanilla cost of capital for the GB GDNs into pre-tax terms, using a simple 1 / 1 – t tax wedge adjustment to give a value of 4.3%, and then adding a further uplift of 1.9% to account for the additional risk in a greenfield project. This detail helps us to 'back out' the appropriate vanilla WACC, as follows:

- First, we can assume that an efficient licence would seek to maintain an investment-grade credit rating. Insofar as the Ofgem cost of capital already factors in investment-grade debt costs, this implies that the 1.9% uplift represents additional return to equity providers, rather than additional interest expense. Further, since the 1.9% is an uplift to a pre-tax cost of capital, we can partition this uplift into an additional after-tax return on equity of 1.52% and an allowance for tax of 0.38%; and
- Second, the partitioning of the 'base' 4.3% return is as set out in SGN's own calculations – i.e. a 3.78% vanilla cost of capital and a 0.52% allowance for tax.

10.103 Combining the two non-tax elements, we find that SGN's bid 6.2% pre-tax cost of capital converts into a vanilla WACC of 5.3%. This 5.3% is the figure that we factor into SGN's GD17 allowed revenues.

10.104 We originally shared this calculation with SGN in May 2016 and received a number of points in response. We have responded to these points in Annex 13.

Profile Adjustment

10.105 In the GD17 approach the UR said it would review the need to retain a profile adjustment within the licences, or whether NI is ready to move to a more conventional GB regulatory type of practice.

10.106 A profile adjustment is currently calculated within PNGL and FE licences and this has the effect of smoothing prices to customers over the long term. The total revenue received by the GDN's is the same in NPV terms but enables prices to be spread across increasing volumes which come with additional connections and keeps prices lower for today's customers. This calculation has also been built into the SGN licence to be applied in its first price control in 2018.

10.107 This means that allowed revenue and prices in any given year are determined as much by the UR assessment of revenue requirements and volumes at the end of the revenue recovery period as by the price control building blocks and volumes in any given year. For example, a one off increase or reduction in the UR opex allowance in 2017 would not feed one for one into an increase or reduction in revenues in 2017, unlike the position in most other regulated industries.

10.108 However there are disadvantages from the Profile Adjustment. It adds a certain level of complexity to the regulatory model and is not consistent with the standard regulatory model in the UK. While these disadvantages are clearly outweighed in the early years of a greenfield investment this becomes less obvious as the project progresses. At some point it is likely to make sense to move to a more standard model. UR considered it appropriate to set out the options for GD17.

10.109 If the profile adjustment was to be removed this would lead to higher prices today and lower prices at the end of the GDN revenue recovery periods. The charts below set out the impact removal of the profile adjustment would have on the PNGL and FE distribution tariffs.

10.110 These indicate that the impact on distribution tariffs in GD17 would be an increase of 6% and 12% for FE and PNGL respectively.

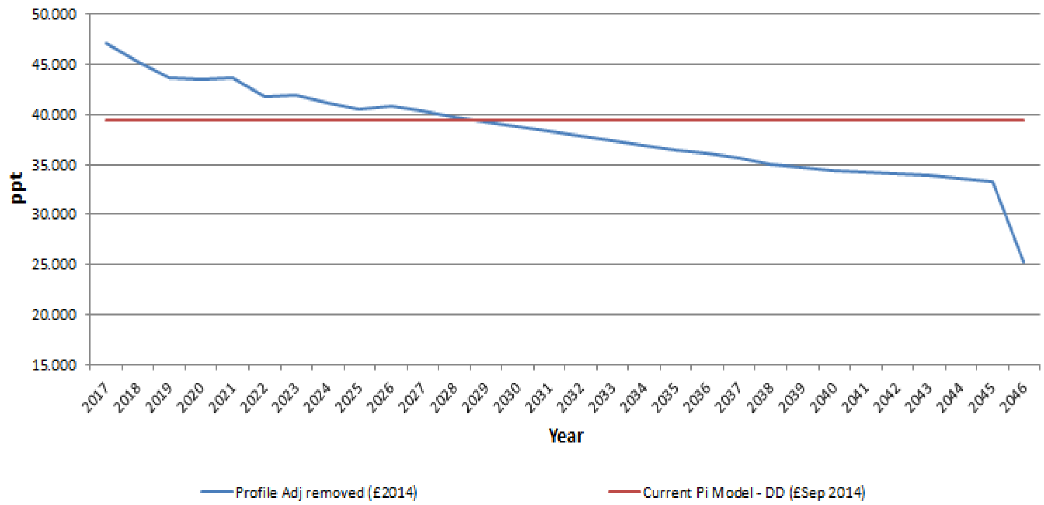

Figure 11: Impact of Removal of the Profile Adjustment on Distribution Tariffs – PNGL

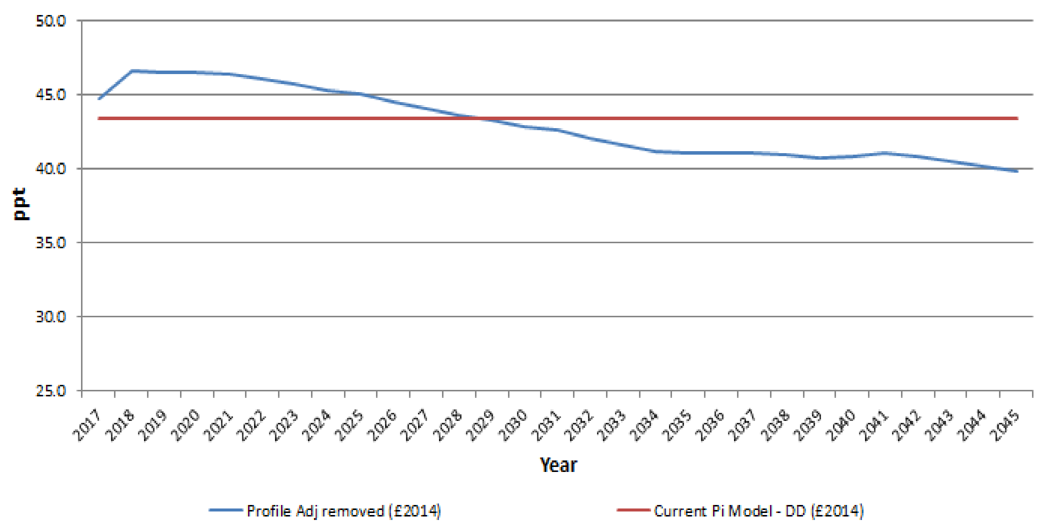

Figure 12: Impact of Removal of the Profile Adjustment on Distribution Tariffs – FE

10.111 This would in turn impact directly on the final retail tariffs which customers are charged. We estimate the impact on a domestic customer to be an increase of approx. 3% and 4% for FE and PNGL.

10.112 We have considered responses to the draft determination.

10.113 FE supports the removal of the profile adjustment in the context of financeability in its response to the draft determination. PNGL noted there is no strong reason on a pure financeability basis to accelerate the removal of the profile adjustment at this time.

However wider external industry bodies were in support of retaining the profile adjustment.

10.114 Overall we have concluded that we will retain the Profile Adjustment in GD17. This is after taking into account the strong level of responses that supported this position. We have also noted that the impact of the volume adjustment discussed in the depreciation section above already serves to bring significant revenues forward and increase tariffs. The impact will also bring forward the date of when the Profile Adjustment peaks.

11 Outputs, Outcomes and Allowances

Summary of Key Changes from Draft Determination to Final Determination

11.1 We have updated this chapter following on from the GD17 draft determination, following due consideration of the responses received to same[6]. Key changes made in this context include:

- Update of Supplier of Last Resort (SoLR) with respect to cost recovery arrangements in case of a supplier of last resort event;
- Introduction of a capex risk sharing mechanism for SGN.

UR Decisions

Risk Sharing Mechanism

Introduction

11.2 At present capex efficiency rollers exist in varying forms for all GDN's, however, for some the roller is 'switched on' and for others it is 'switched off'. The concept of an efficiency 'roller' is to provide an incentive to the GDNs. Thus if the GDN outperforms and spends less than the allowance it is allowed to keep this for a rolling period of five years, before the benefit is removed from the GDN and customers will then benefit from the efficiency. Conversely overspends can be treated in a symmetric manner where the GDN gets no compensation for overspend for a rolling period.

11.3 For GD17 we consulted on aligning the mechanisms and possibly simplifying them.

Current Approaches

11.4 PNGL had a Capex efficiency roller 'switched on' for the PC03 Price Control, a supplemental document forms part of the PNGL12 Final Determination [102] to describe this in detail.

11.5 Currently, this roller works outside the published Conveyance Licence. Capex under-spends occurring efficiently [103] were removed from the TRV on a 5 year rolling basis i.e. PNGL retained 5 years' financing costs on the efficiency equating to 4 years of return and 5 years of depreciation which was equivalent to an incentive rate of 35:65 for company:consumer.

11.6 Capex over-spends occurring efficiently were also treated symmetrically, so PNGL forego 5 years' financing costs on the efficiency equating to 4 years of return and 5 years of depreciation.

[102] This can be found in Utility Regulator: Phoenix Natural Gas Limited Price Control Review 2022-2013, Final Decisions, January 2012, p. 103 to 104.
[103] In all cases, efficiency will need to be demonstrated by PNGL

11.7 FE had a capex rolling incentive mechanism built into the formulae in their Conveyance Licence [104] for GD14 under condition 4.6.11. This roller was 'switched on' as part of the GD14 price control by setting the designated parameters h and d in condition 4.9 to 1. For the purposes of rewarding efficiency, the formula could be viewed as overly complex and simplification of the mechanism would be to the benefit of all parties.

11.8 SGN has a capex rolling incentive mechanism built into the formulae in its Conveyance Licence [105]. This can be found under condition 4.6.11.

11.9 We made our intentions clear whilst issuing the final Conveyance Licence to SGN that this roller was likely to be 'switched off' as part of the GD17 price control (at a minimum). This would be done by setting the designated parameters h and d in condition 4.11.1 to 0 (zero).

11.10 Since the formula is identical to that contained in the FE Licence it may be overly complex and simplification of the mechanism would be to the benefit of SGN as well as UR.

11.11 While the licences facilitate an opex roller mechanism these have not been turned on as, given the extent of the Uncertainty Mechanism, it has not been judged to be necessary.

11.12 UR is content that the principles of incentives set out above are reasonable for GD17. However there may be merit in enshrining those principles in a more simplified mechanism and we have considered some alternative approaches.

Alternative Approaches

11.13 For the NIE RP6 price control the CC/CMA put in place a much simplified set of risk sharing arrangements.

11.14 Any efficient cost savings leading to an under-spend, or unavoidable additional costs leading to an over-spend, will be shared between NIE and consumers on a 50:50 basis. This serves as a protection for both company and consumers and incentivises NIE to strive for efficiency savings as their RAV can increase for money not actually spent. The mechanism applies to both opex and capex.

11.15 The UR view is that this more simplified mechanism warrants consideration, including application to both capex and opex. The current approach described above for PNGL and FE, where capex is retained for a rolling five years would lead to a sharing ratio between GDN and customer of about 35:65.

11.16 The sharing figures for Ofgem's recent RIIO price controls have varied between 50% and 70%.

11.17 Responses on this area stated the following:

- PNGL – agreed with the UR that, *"the current principles of risk sharing i.e. a 5-years capex rolling incentive mechanism for PNGL, are reasonable for GD17"* and should be maintained for GD17. They also suggest they would be content to investigate a simplified 50:50 risk sharing mechanism as part of the next price control GD23;
- FE – stated they looked forward to, "further engagement with the UR around the detail" of simplifying the sharing mechanism and state FE "accepts the continuation

[104] http://www.uregni.gov.uk/uploads/licenses/2016-02-04_firmus_(Gas_Conveyance)_-_final.pdf .
[105] http://www.uregni.gov.uk/uploads/publications/Scotia_Gas_Networks_Northern_Ireland_Ltd_Grant.pdf
.

of the [Capital Rolling Incentive] in its current form" i.e., current value of 1 equates to "ON"; and

- SGN – hoped that engagement would enable, "an appropriate solution that enables SGN Natural Gas to achieve some benefit and protection around the use of opex and capex rollers" whilst, "not[ing],...it is the intention of the UR to have these rollers 'switched off' for the GD17 period", SGN stated they, "welcome[d] this approach".

11.18 We have concluded that there is no strong agreement on the need to make such significant changes to the licence at this point. We have therefore proposed to retain the risk sharing mechanisms as per the draft determination with the PNGL and FE capex mechanisms turned on and based on sharing over 5 years. The SGN capex and all opex sharing mechanisms are turned off. This is reflected in our decisions on Designated Parameters [106]:

- FE's "h" switched on for the Capital Rolling Incentive (see paragraph 4.4.11 of the GD17 Annex 1 – FE Licence – Proposed Modifications); and
- SGN's "h" switched off for the Capital Rolling Incentive.

11.19 While SGN welcomed our draft determination approach to switch its sharing mechanisms off, it subsequently wrote to the Utility Regulator requesting a 50:50 capex sharing mechanism.

11.20 We would note that UR turned off the sharing mechanisms in the early years of both PNGL and FE so our approach is consistent. However we do generally support a role for capex sharing mechanisms and would plan to graduate to this position for SGN. Therefore while we retain the sharing mechanisms within the licence condition turned off, we have decided to introduce a 75:25 capex sharing adjustment for company and consumer respectively (once all other adjustments have been calculated as part of the uncertainty mechanism). This means that SGN will take 75% of the risk of under/over recoveries and customers will take 25%. This sharing will be implemented through the uncertainty mechanism as reference in Chapter 9.

Impact on Consumer Bills

11.21 The modelling we have applied in the final determination produces a significant drop in domestic distribution tariffs of 4%, 6% and 22% compared to the FE, PNGL and SGN submissions respectively.

11.22 In comparison with current GD14 distribution tariffs the final determination produces a reduction of 8% and 1% for FE and PNGL respectively. If we convert the reduction in tariffs into the impact on customers' overall bills, this results in domestic customers paying around £16 and £1 less per annum than currently. For I&C customers the difference would obviously be much larger.

11.23 The SGN distribution tariff is being set for the first time and therefore no current tariff for comparison purposes is available.

[106] PNGL has an 'off licence' arrangement which was introduced from PNGL12 and includes a roller for capex so that there are no associated text / formulae in the licence formulae.

	GD17 FD P1 tariff	GD17 distribution tariff v submission	GD17 v GD14 distribution tariff	Customer Saving per annum (v submission)
FE (Av. £2014)	43.35	-4%	-8%	£6.47
PNGL (Sep £2014)	39.51	-6%	-1%	£10.39
SGN (Av. £2014)	28.83	-22%	N/A	£33.20

Table 198: Impact on Domestic Customer Bills

11.24 However we would caution that the figures above are not perfectly comparable for FE as they do not factor in the impact of how FE chooses to charge its under recovery amount.

Customer Service

11.25 As indicated in Chapter 3 - Consumer and Stakeholder Engagement, we shall progress this workstream during the GD17 price control period to ensure both customer service measures and consumer satisfaction surveys are in place to ensure we maintain our focus on improving how GDNs meet their respective consumers' interests and needs.

11.26 Our customer service development objective will require delivery of new customer service metrics and customer satisfaction surveys as an output of GD17. The first stage will be the re-constitution of our partnership model of consumer engagement with CCNI, GDNs and DfE and ourselves forming a new working group who shall draw up an agreed timetable for the introduction of new metrics, consumer surveys as well a shared research programme to inform GD23.

11.27 The development of our agreed timetable will be a developmental objective for the first 6 months of the GD17 period and we shall work to develop this through our preferred partnership model and working group (GDNs, the CCNI, DfE and the UR).

11.28 The prize will be to design new regulatory metrics and surveys which provide our local GDN's with "actionable data", since gaining insight, without taking action, is of no real value. With such a guiding principle in mind the new partnership grouping should also avoid the highest risk pitfalls in regulation where situations develop where either (i) what gets targeted or measured by a regulator gets done and/or (ii) the Law of Unintended Consequences begins to bear bitter fruit.

11.29 Given our previous experience of development work using a partnership model across both the local water and electricity sectors we envisage the agreed timetable ought to deliver:

- New consumer metrics and customer satisfaction surveys for trial in Year 2 of GD17 or 2018;
- Introduction and incorporation of the above new measures within a revised Regulatory Instructions and Guidance pack; so that
- Performance in 2019 can be reported going forward in our Annual/Cost Reporting publication.

11.30 Such a working group on consumer and stakeholder engagement will from time to time examine some or all of the following:

- Increased focus on complaints data, especially complaints escalated to CCNI and UR and opportunities for lessons learnt.

- Review of the appropriateness and relevance of the Guaranteed and Overall Standards of Service already in place and implementation of a process of amendment where relevant and appropriate. This will require consultation with other organisations such as CCNI and DETI.
- Consideration of future consumer and stakeholder engagement models and appropriateness for the local gas scene. This will likely build upon part of CEAP workstream under the RP6 price control of NIE Networks where the specialist consumer research consultant, Perceptive Insight Market Research (PIMR) undertook an international literature review entitled, "Customer engagement methods and examples of best practice" [107]. The literature review defined different sorts of engagement as either provider or regulator focused and examined an international long list of alternative models, many of which included some degree of expert, consumer and/or negotiated settlement. The review recommended the adoption of the "IAP2 " taxonomy as relevant to regulated utilities such as NIE Networks.
- Review of customer service metrics used in NI and GB and, where relevant and appropriate, standardisation of such metrics across NI in gas and across our other regulated sectors.
- Introduction of customer satisfaction surveys to be conducted by the GDNs on a regular basis. These surveys could be based on those in place in GB and/or designed specifically to address local utility consumer concerns.

11.31 Ideally, some form of Net Promoter Scoring question should be included within any consumer questionnaire to enable benchmarking across local utility providers and consumers. The CEOG partnership working model applying to NI Water through the existing price control PC15 established a Customer Measures / Customer Satisfaction working Group (CM/SAT) chaired by the Utility Regulator. Like the CEOG, the CM/SAT includes representation from the company, CCNI, DRD and ourselves. Our chairing of such a group helped set the agenda for delivery on the PC15 development objective to introduce (i) more customer focused consumer measures and (ii) a new customer satisfaction survey (which includes a Net Promoter Style question to enable benchmarking of NI Water against other similar providers, other regulated utilities and other service providers not just nationally, but internationally).

11.32 In targeting our consumer engagement developmental objective for GD17 we shall set the agenda towards delivery of improved customer service delivery through the GD17 price control period and beyond. Further, once out-turn data against the new metrics establishes the GDNs' baselines, over time we shall be able to take an informed position when considering how we might improve our monitoring of GDN performance. This will help inform our Annual/Cost Reporting of GDN performance as well as our subsequent consideration of whether targeted improvement(s) are warranted in certain areas of GDN delivery.

11.33 Furthermore, improved performance monitoring will also open up the potential to consider better evidence-based proposals for the introduction of potential incentive mechanisms for customer service in future price controls.

[107] http://www.nienetworks.co.uk/documents/Future_Plans/4-NIE-Networks-Phase-4-literature-review-and-final

Asset Management Development Objective

11.34 The delivery of gas to consumers is an asset intensive process. It requires investment in distributions systems comprising pressure pipe networks, flow and pressure regulation, supply connections and supply meters and governors. Investment is also required in indirect assets necessary for the effective management of the system including IT systems, offices, vehicles, maintenance and testing equipment and other facilities. In Northern Ireland our gas distribution networks are relatively new. The focus of past investment has been the initial development of networks and this is likely to continue into the future as the network expands to serve new consumers. However, as time passes, the need for investment in maintaining and replacing these assets will increase.

11.35 In our approach to GD17, we noted that we expect the monopoly service providers we regulate to demonstrate effective long term stewardship of the asset base which has been and continues to be funded by consumers. We asked each GDN to provide a Plan for Asset Maintenance which sets out its approach to asset maintenance planning and explains how it has assessed the changes in operational practice and the investment required to maintain or enhance serviceability to consumers during GD17. We asked each GDN prepare its plan in the context of their current stage of development and the long term needs for information and processes which will deliver asset management excellence over the life of its assets.

11.36 During GD17, we expect the GDNs to continue to review and develop their plans for asset management. While this is an essential part of service delivery, we also expect the GDNs to focus on the information and processes necessary to inform decisions on asset investment and asset maintenance expenditure during GD17 and in future price controls to deliver the necessary level of service at a least whole life cost. In particular, the GDNs should look forward to key decisions they expect the Utility Regulator to make in the GD23 price controls and ensure that the information necessary to inform such decisions have been collected and analysed over the GD17 period to provide robust information in the business planning process that all parties are familiar with in a timely way.

11.37 To monitor delivery of this objective during GD17, we will introduce asset management development reporting into the Annual Cost Reporting to require the GDNs to update their Asset Management Capability Assessment and Plans for Asset Maintenance and report on progress against the delivery of these plans, with a particular focus on the needs of the GD23 price control.

Shrinkage

11.38 In October 2012, Directive 2012/27/EU on Energy Efficiency[108] established a common framework of measures for the promotion of energy efficiency within the European Union in order to ensure the achievement of the 20% headline target on energy efficiency by 2020 and to pave the way for further energy efficiency improvements beyond that date.

11.39 In article 15 (2), this directive placed an obligation on the member states to ensure that by 30 June 2015:

(a) "*an assessment is undertaken of the energy efficiency potentials of the gas and electricity infrastructure, in particular regarding transmission, distribution, load*

[108] Directive 2012/27/EU: http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2012:315:0001:0056:EN:PDF

management and interoperability, and connection to energy generating installations, including access possibilities for micro energy generators; and

(b) *concrete measures and investments are identified for the introduction of cost-effective energy efficiency improvements in the network infrastructure, with a timetable for their introduction.*"

11.40 Following-on from this obligation, we conducted an energy efficiency review, based on related submissions from relevant gas and electricity companies in Northern Ireland. With respect to GDNs, the report concluded that at the time of writing they were compliant with energy efficiency considerations, and that the price control process should serve as a means for ensuring ongoing focus on energy efficiency of the networks and addressing any related initiatives that may become relevant in the future. Therefore, energy efficiency considerations were re-assessed as part of the present price control process.

11.41 We consider that one area that requires further focus is that of shrinkage.

11.42 Shrinkage represents the difference in volume between the gas entering the gas distribution network and the total volume of gas used by customers. Shrinkage is comprised of the following three elements:

- Leakage: uncombusted gas emissions to the environment from GDN infrastructure such as emissions from mains and services, emissions from above ground installations, emissions related to venting and emissions related to interference and damage.
- Theft of gas: natural gas consumptions by end users that are unaccounted for and/or are utilising unrecorded natural gas.
- Own use gas: gas that is used for operational purposes but which does not pass through a meter, e.g. gas used for the purposes of preheating at pressure reduction stations.

11.43 Theft of gas occurs when unaccounted for and/or unrecorded gas is utilised. It can occur upstream or downstream of the emergency control valve and is caused by tampering with gas apparatus.[109] Theft of gas is illegal. It represents a safety risk which is taken seriously by all GDNs. Furthermore, theft of gas results in financial damage as the stolen gas is not being paid for by the party that uses it. Rather, the cost for the stolen gas is being passed on to all consumers as part of shrinkage cost.

11.44 In its GD17 business plan submission, SGN proposed the introduction of "*an incentive package to drive instances of theft down by demonstrating a proactive stance to investigating not only known theft occurrences but also to uncover unknown theft activity*"[110].

11.45 More specifically, SGN proposed an incentive payment of £500 for each uncovered instance of theft of gas, either at a point downstream or upstream of the emergency

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[109] Theft upstream of the point of offtake at any meter point, or at or downstream of the point of offtake where there is no registered user for the meter point and the meter point has been isolated, is in the responsibility of the GDNs. Theft at or downstream of a point of offtake at a meter point is in the responsibility of the supply business, except in cases where there is no registered user for the meter point and the meter point has been isolated.

[110] SGN: GD17 Business Plan, September 2015, p. 75.

control valve, which leads to a recovery of monies associated with stolen gas by either the relevant GDN or the relevant supplier.

11.46 SGN considered that such an incentive mechanism would facilitate GDNs enhancing co-operation with third parties on tackling theft and establishing a NI-wide theft database for joint use by other utilities and the NI authorities.

11.47 When assessing the SGN proposals with respect to a theft reduction incentive, we have considered the strength of existing obligations on GDNs to tackle theft as well as the mechanisms already put in place to do so.

11.48 In line with the Reasonable and Prudent Operator licence condition[111], GDNs need to perform their functions exercising "*that degree of skill, diligence, prudence and foresight which would reasonably and ordinarily be exercised by a skilled and experienced operator complying with applicable law and engaged in the same type of undertaking and under the same or similar circumstances and conditions*." In line with the Network Code licence condition[112], GDNs need to ensure that the transportation arrangements for the conveyance of gas through distribution pipelines facilitate "*the secure, safe, reliable, efficient and economic development and operation and maintenance of the network with due regard to the environment*". In addition to this, general and gas-specific Health & Safety legislation and regulations apply.

11.49 We consider that these obligations already put a strong obligation on the GDNs to ensure that any issues impacting on the safety of their networks are addressed.

11.50 Furthermore, we also consider that there is evidence that GDNs take this obligation seriously. All the GDNs have confirmed to us that the following applies to them (or in the case of SGN who are just in the process of setting up their operations will apply in due course):

- The Network Code contains obligations on suppliers to read and inspect meters and to report to the relevant GDN any evidence of broken seals or any tampering or interference of theft or attempted theft of gas[113]
- Revenue protection policy available, revenue protection team in place and systems and process to help identify and address gas theft issues implemented
- GDNs working together in the area of revenue protection, sharing experience and best practice and learning from operations in other NI natural gas networks
- Co-operation with other relevant third parties such as suppliers and, where relevant and appropriate, the PSNI. Two of the GDNs are also (or are planning to become) associated members of the UKRPA (United Kingdom Revenue Protection Association), benefitting from an exchange of experience of lessons learnt with a wider industry base, including meter manufacturers and network businesses from other regions and/or industries.

[111] See Condition 2.27 in the SGN conveyance licence. We note that this condition does not currently form part of the FE and PNGL licences, but that we propose to introduce it there as part of the licence alignments between GDNs pursuant to the Gas to the West project. For further details see our consultation on licence modifications pursuant to the GD17 final determination and other regulatory decisions, 15 September 2016, referenced in section Annexes, Consultation Responses and Supplementary Documents, Supplementary Documents.

[112] See Condition 2.4 in the FE and SGN conveyance licences and Condition 2.5 in the PNGL conveyance licence.

[113] See Section M, paragraph 2.13 of the FE, PNGL and SGN Network Codes.

11.51 In the Annual/Cost Reporting for the 2014 reporting year, we introduced new reporting requirements for the GDNs to better understand the issue of gas theft in Northern Ireland. The figures show that both FE and PNGL have successfully investigated a number of suspected incidents of theft. We note, however, that there are some differences between the GDNs with respect to the number of suspected and confirmed theft incidents (even when accounting for differences in customer base size) as well as with respect to the recovery of the monies from these incidents.

11.52 Notwithstanding the above, we note the work conducted by Ofgem in reviewing arrangements to incentivise network operators to investigate theft. We recognise the argument that theft investigations cost money and that the money recovered as a result does not always outweigh the cost of the investigation. We also note that, as part of their consultation on proposed incentive arrangements for GDNs on theft in the course of conveyance and unregistered sites, Ofgem decided not to implement any new incentive mechanisms for the time being. Instead, they decided to enhance the related reporting requirements to gather relevant information as a basis for future reviews into theft investigation-related incentive mechanisms and related decision taking.[114]

11.53 Having considered the above, we are not convinced at this stage that the introduction of an additional incentive mechanism related to gas theft investigations is required or appropriate to address the tackling of gas theft in Northern Ireland. We will, however, continue to monitor gas theft-related matters during the course of GD17. We will do so by continuing, and where relevant and appropriate enhancing, related reporting as part of the Annual/Cost Reporting submissions by the GDNs. In particular, we would expect the GDNs to provide a report including a professional estimate of leakage and own use gas as a basis for estimation of shrinkage due to theft. We consider that this report should be provided by no later than end of 2017.This will enable the building-up of a relevant information base to inform future related analysis and decision taking. We will build on this information base when reconsidering the suitability of the arrangements for tackling gas theft as part of the overall review into shrinkage proposed to take place during the GD17 price control period, as further detailed in paragraph 11.59.

11.54 We also note that, with respect to the funding of counter-theft activities by the GDNs, we consider that this is covered by the opex allowances for manpower and professional and legal fees, subject, again, to the proposed review into shrinkage and any additional incentive mechanisms that may or may not be decided as part thereof.

11.55 In line with their respective network codes, the GDNs determine on an annual basis a shrinkage factor for their respective networks.[115] This shrinkage factor is used to attribute shrinkage to gas flows and related suppliers, and ultimately through the supplier tariffs to customers.

11.56 Regulatory arrangements for gas supply and distribution should ensure that shrinkage as well as the associated negative impact on energy efficiency, on the environment and the associated cost that is ultimately to be borne by natural gas customers is minimised.

11.57 We consider that the current arrangements are suboptimal for a number of reasons:

[114] See Ofgem: Decision on incentive arrangements for Gas Distribution Networks on gas theft during conveyance and for unregistered sites, 14 October 2014.
[115] See section D, paragraph 4.3 of the FE, PNGL and SGN Network Codes.

- In line with the distribution network codes, shrinkage quantities shall be recovered from the suppliers[116]. This limits the incentives for GDNs to minimise shrinkage even though many of the shrinkage causes are under their control.
- Similarly, in recent supply price controls, shrinkage has been treated as a pass-through cost, thus limiting the incentives for suppliers subject to such price controls to minimise shrinkage, even though some shrinkage causes may be under their control (e.g. theft downstream from the meter point).
- We asked the GDNs for specific shrinkage-related information as part of the Annual/Cost Reporting for the 2014 reporting year, the GD17 Business Plan submissions and related information requests. Based on the information received from the GDNs, we consider that further analysis is required to ensure the methodologies used for establishing shrinkage factors across the GDNs are consistent and adequate, and that differences in shrinkage over time are considered, as appropriate.

11.58 We recognise that further work is required to ensure the regulatory arrangements with respect to shrinkage for GDNs and suppliers, including any related incentive-mechanisms as relevant, are appropriate.

11.59 However, we consider that such work is beyond the scope of the GD17 draft and final determinations, bearing in mind the complexity and number of stakeholders involved. Instead, we will reconsider shrinkage and the appropriateness of introducing related changes to regulatory arrangements (such as licences or network codes) and/or incentive mechanisms during the GD17 price control period. To facilitate this exercise, we will continue to collect shrinkage-related data from the GDNs as part of the Annual/Cost Reporting. We may review the level of detail of the information requested, as appropriate. We will also bear in mind any related Ofgem decisions and their relevance and applicability for NI in the light of differences of the overall regulatory framework. Should we, as part of our ongoing analysis into this matter, consider a change of policy with respect to the treatment of shrinkage, related regulatory arrangements and/or the introduction of related incentives, we will consult on this in line with best regulatory practice and duly consider any responses received before taking a related decision. We envisage that any such decision will also clarify how any associated financial impact for the GDNs will be considered. This could be as part of an adjustment under the GD17 uncertainty mechanism and/or under GD23.

11.60 As set out in paragraph 13.9 we expect the GDNs to produce a report on this matter no later than end of 2017.

Supplier of Last Resort (SoLR)

11.61 This area refers to circumstances where we revoke a gas supplier's licence (the defaulting supplier) and then subsequently give a direction[117] to another gas supply company (the SoLR supplier) to supply gas to the customers of the defaulting supplier. In a SoLR event, our intention is to direct a supplier within each distribution network area to be the SoLR supplier.

11.62 We recognise that in such a case, the SoLR supplier is likely to incur costs directly related to the role of being a SoLR supplier and that these costs may be largely outside

[116] See section D, paragraph 4.6 of the FE, PNGL and SGN Network Codes.
[117] Gas (Supplier of Last Resort) Regulations (Northern Ireland) 2009: http://www.legislation.gov.uk/nisr/2009/412/made/data.pdf

their control (e.g. costs of purchasing short-term gas for the defaulting supplier's customers).

11.63 We have been working with the gas industry to develop full processes to deal with a SoLR event. An agreed principle is that SoLR suppliers will be reimbursed for any reasonable costs incurred by the SoLR supplier as a result of the SoLR event. Some of the costs would be recoverable directly from the customers affected by the SoLR event through their tariff prices; however it may not be reasonable to charge some costs directly to the SoLR customers. Any such charges would be dealt with under the SoLR cost recovery mechanism.

11.64 At the time of a SoLR event, the SoLR suppliers will need to submit information to us on any costs they have incurred that they wish to recoup through the SoLR cost recovery mechanism. We will review the submitted costs and will determine the level of "allowed costs" for each SoLR supplier. Each GDN will then be required to pay the "allowed costs" to the SoLR supplier within their distribution network area. Full details of this process will be set out in an industry procedure for SoLR events.

11.65 In the GD17 draft determination we proposed that if a SoLR event occurs where GDNs are required to pay the "allowed costs" to the relevant SoLR suppliers, then the GDNs will recover the "allowed costs" through their price control under the uncertainty mechanism. The amount of the "allowed costs" will be treated as "ring-fenced" costs within the uncertainty mechanism. We noted that the "materiality threshold" will not be applicable for these costs. The relevant amount will be subsequently included in the asset base of the GDN and the rate of return determined under each future price control will apply.

11.66 The GD17 draft determination, we proposed two options to address this problem:

- Option 1: Based on normal practice, any allowances granted, if a SoLR event did occur, would be considered as part of the uncertainty mechanism update at the time of the next price control. However we added that if a SoLR event did occur the UR would consider interim measures, such as tariff adjustments, depending on the scale and size of the event occurring, if the GDNs could demonstrate the financial effect the event would have on their business.
- Option 2: Inclusion of specific monetary allowances in the GD17 final determination, subject to the uncertainty mechanism at the time of the next price control, removing the potential need for any exceptional review throughout the price control period.

11.67 We noted as part of our GD17 draft determination that we had not included any specific allowances for a SoLR event, but would reconsider this as part of the final determination if the second option was preferred.

11.68 Some concern has been raised in responses to the GD17 draft determination and also through other discussions with the gas industry that option 1 could leave the GDNs exposed if the financial impact of the SoLR event was significant and the event occurred early on during a price control period, as the GDNs would then potentially need to wait for long time for reimbursement of their costs incurred. A similar risk was raised in relation to option 2 as the GDNs could be exposed if the costs included in the GD17 price control were not sufficient to cover the actual costs required for the cost recovery mechanism if a SoLR event did occur.

11.69 Following further engagement with the gas industry, we have decided to implement the second option. More specifically, we have included, within the opex allowances, a ring-fenced allowance for SoLR events that will be subject to adjustment under the uncertainty mechanism. The “materiality threshold” will not be applicable for these costs

11.70 Based on estimates of the expected costs that may be incurred in a SoLR event we have included £150k for FE, £300k for PNGL and £75k for SGN in the opex costs within the GD17 price control.

11.71 In addition to this if a SoLR event does occur during the price control period and the actual costs incurred by the GDNs are significantly higher than the allowances included in the GD17 price control, then the UR will consider interim measures, such as tariff adjustments, if the GDNs can demonstrate that waiting for an adjustment under the uncertainty mechanism at the end of the price control period would be inappropriate,

11.72 We note that in their responses to the GD17 draft determination, all three GDNs suggested that the arrangements relating to the recovery of SoLR costs should be embedded in the conveyance licences. They have suggested that this should be done through the inclusion of arrangements for a limited and special review within the GDNs’ conveyance licences.

11.73 We have considered this request and concluded that such a licence modification is not necessary. As detailed in chapter 9 Uncertainty Mechanism and further discussed in our consultation on licence modifications pursuant to the GD17 final determination and other regulatory decisions[118], we consider that the uncertainty mechanism should be referenced in the GDNs’ conveyance licences. Through embedding the uncertainty mechanism into the GDNs’ conveyance licences, it will mean that there will be a mechanism for implementing items covered by the uncertainty mechanism, such as SoLR costs, clearly referenced in the GDNs’ licences.

11.74 We consider that these arrangements for costs associated with SoLR events are pragmatic, appropriate and proportionate while providing assurance that efficiently incurred costs relating to a SoLR event can be recovered in due course. They avoid the administrative burden associated with special reviews whilst providing a buffer to prevent the potential for financing issues arising as a result of a SoLR event.

FE – UR Decisions

Under-Recoveries

Introduction

11.75 FE is set a determined tariff in each year but has some discretion in setting actual tariffs. In the PCR02 period covering 2009 to 2013, FE decided to set tariffs significantly below allowances and built up ‘Z’ under recover-revenues.

11.76 The licence is somewhat inconsistent in the treatment of the rate of return to be applied to ‘Z’ under recovery. Condition 4.2.17 clearly foresees the circumstances where it might be necessary to change the rate of return on ‘Z’ in order “*to provide an incentive or disincentive (as the case may be) in respect of the accumulation of such under-recovery or over-recovery of revenue*”. A set of formulae is then put in place to facilitate this principle within the licence.

[118] This document is referenced in Annexes, Consultation Responses and Supplementary Documents, Supplementary Documents.

11.77 However the subsequent Condition 4.10.4 limited the adjustment to zero that could be made to the ‘Z’ under-recovery rate of return until the year 2034, thus, restricting any movement from the full rate of return. The subsequent fixing of the rate of return in 4.10.4 is not explained in the licence or policy documents and is incongruous with the earlier conditions and formulae. However we have been applying the full rate of return, 7.5% to ‘Z’ under recoveries.

11.78 The reasoning behind the inclusion of under-recoveries in the licence was to allow FE flexibility as it built its customer base e.g. to manage times when oil would be cheaper than gas. However the period during which FE has built up this large under recovery was one where gas prices were largely cheaper than oil and at times over 30% cheaper. This raised questions as to the motive of building up such large under recoveries.

11.79 This was because pricing below the cap could facilitate FE to outperform volume targets while also earning a 7.5% rate of return on the ‘Z’ under-recovery. Indeed this appears to be precisely the type of perverse incentive which the formulae discussed in 4.2.17 of the licence was meant to deal with.

11.80 By the GD14 price control, FE had a cumulative under-recovery of £19.4m at the end of 2012 (2012 prices). The ‘Z’ under-recovery approach had contributed to a significant volume outperformance in PCR02 of c29.5m therms over the 5 year period.

11.81 We considered whether we should modify the licence in GD14 to clarify that the principles in 4.2.17 would apply. However we decided to wait until GD17 to take any action. This was to provide a lengthy notice period to FE that the licence was likely to be modified and also allowed time for FE to eliminate the ‘Z’ under-recovery amount.

11.82 We set out very clearly in GD14 that we would visit the rate attached to ‘Z’ under-recoveries as part of the GD17 price control, as we believed “*the 7.5% return is providing a perverse incentive for FE to under-recover revenues” and we noted that “we are minded to review the allowed return on under-recoveries in GD17 to ensure there are no perverse incentives and if this requires a licence modification we will consider this at that time*”.

Current Position

11.83 The forecast ‘Z’ under-recovery amount at the end of 2016 is c£15.0m (£av. 2014). We recognise that this has provided a significant benefit to FE at a time when no volume or totex risk applies to the ‘Z’ under-recovery amount.

11.84 FE has argued the following points in relation to any change in the rate of return on ‘Z’ under-recoveries:

- The risks associated with ‘Z’ under-recoveries are not materially different to that associated with other capital invested, whereby, they do not differentiate between the funding of capital investment or deferred revenues as both require funded;
- Such a change would be at odds with prior commitments to investors, who have invested on the basis of a full rate of return applying to ‘Z’ under-recoveries and such a change could affect FE financeability;
- Changing the rate would add a layer of complexity that would be at odds with previous decision made by the Utility Regulator regarding a ‘dual’ pot TRV, attracting different rates of return in relation to PNGL;
- FE would have to unwind ‘Z’ under-recoveries at a faster rate if a lower return was applied, causing pricing instability in the short term.

11.85 In its response to the draft determination FE repeated many of these points and added that it does not believe the Libor plus 2% rate or the UR position that the licence change is in the public interest were justified. Other parties such as CCNI and MNI felt that a modification was required in line with the UR proposals.

11.86 We have considered the current position and the arguments made by FE.

11.87 We do not agree with the proposition that the current arrangements were put in place for good policy reasons at the time and therefore we should not proceed with the modifications. The suggestion that the under recovery mechanism is the equivalent of the Profile Adjustment does not withstand scrutiny. The purpose of the Profile Adjustment is to smooth tariffs for NI gas customers over the long term which ensures customers over different generations pay the same price for gas. As we have stated the role of under recovery is very different and is in place as an extreme measure to deal with difficult circumstances such as gas being very uncompetitive with oil. By its nature it can result in different generations of customers paying different prices over time. Therefore it must be treated differently from the Profile Adjustment.

11.88 Indeed this is why the firmus licence includes clear principles on the need to control the rate of return to apply to under recoveries. As we have explained the current licence is inconsistent whereby, on the one hand it identifies the requirement to adjust the rate of return on ‘Z’ under-recoveries and provides the formulae to do so and on the other hand it prevents those formulae from being applied. The purpose of the proposed licence modification was to bring clarity to the licence.

11.89 We also think it is very important to note that both PNGL and SGN, the two most similar licences to FE, never allowed the full rate of return on under recoveries. The strong policy reasons for doing so, in line with the principles in the FE licence, must apply to FE.

11.90 Our view remains that the current licence is not in the public interest and we would propose to modify it.

11.91 We continue to think that the history of the FE build up of ‘Z’ under-recoveries demonstrates the risk of perverse incentives. The period when FE built up its ‘Z’ under-recovery had historically low gas prices relative to oil. Now FE finds itself having to raise prices to recover its under recovery at a time when gas prices are less competitive.

11.92 In relation to regulatory uncertainty we would highlight that the change is forward looking only and will only apply from 2017. FE will retain the 7.5% return on ‘Z’ under-recovery built up in the period to 2017, which, as at the end of 2016, is estimated to make up c80% of the ‘Z’ under-recovery amount. We have reviewed FE’s arguments on this point and on the amount of notice given which concluded that good regulation would retain the full rate of return.

11.93 We have considered the context of the FE licence drafting and the perverse incentive created by the licence as described above. We have also taken into account that FE has been aware of UR concerns on under recoveries for many years and could have reduced the amount in 2016 to £2-3m but it is at £15m. We also note that the delay in our taking action means the effect on FE is less than £800k. We remain of the view that best practice regulation requires a licence modification to break the link with under recoveries and the rate of return.

11.94 We disagree with FE that the modification would add a layer of complexity. Indeed we view FE’s idea of two under recovery pots to be overly complex. The proposed licence modification sets out the formulae necessary for the calculation and brings FE in line with SGN and PNGL.

11.95 We also disagree with FE's point about the need to unwind 'Z' under recoveries at a faster rate. We estimate that they will be eliminated by 2019 based on current tariffs therefore, the horizon for recovery currently is fairly short.

11.96 We remain of the view that LIBOR plus 2% remains a reasonable rate to allow. This is consistent with the PNGL and SGN licences and reflects the fact that we view under recoveries as something which should be a short term arrangement that should not be incentivised in the licence.

11.97 However in order to facilitate a glide towards the new rate we will apply LIBOR plus 4% in 2017 and LIBOR plus 3% in 2018. This will have some moderate benefit for FE and should see under recoveries largely dealt with by the time the enduring rate of LIBOR plus 2% is applied in 2019.

Implementation Options

11.98 As well as reducing the rate of return to be applied to 'Z' under-recoveries we also considered whether other licence changes should be applied in how it interacts with the TRV. We considered options as follows:

a) Continue with 'Z' under-recoveries being treated separately from the TRV

b) Account for a discounted version for estimated 'Z' under-recoveries at 2016 year end and include as part of the TRV. The discount would roll forward 'Z' at LIBOR plus 2% and discounted using the licence rate of return.

11.99 The initial view of UR was to retain the current approach to 'Z' outside the TRV (Option a above). We note that FE and CCNI supported this option. We think that it is proportionate to retain the current approach and not make a further modification to the licence.

Forecasting Horizon

11.100 As a greenfield project it would not have been appropriate to apply standard regulatory practice to FE and calculate tariffs over the price control period, say 6 years. This would have lead to very high tariffs in early price control periods (when the bulk mains were built) and great difficulty in attracting customers.

11.101 Therefore it was necessary to calculate tariffs, and thus smooth costs, over a much longer timeframe. Thus the FE licence conditions included a Profile Adjustment term which acted to levelise tariffs and profile costs over a long period – up to the forecasting horizon of 2035. This is fixed in the licence[119] and the final business plan templates were consistent with this.

11.102 FE indicated it wished to look at the potential to move the period from 2035 to 2045 after the business plan template had been consulted on. We made clear that we expected all submissions to be consistent with the template. However we were content for FE to present an alternative option using 2045 and set out clearly the impact this would have on customers over all periods.

[119] See Condition: 4.4: Review Process & Disapplication Notice, Terms Relevant to Reviews and Condition 4.9: Current Designated Parameters and Determination Values of the FE conveyance licence with respect to parameter q.

11.103 In its business plan submission, FE has proposed to extend this period until 2045 and to include any accumulated under-recoveries in the depreciated asset value.[120] The submission did not follow the template.

11.104 However as part of a package of measures of changing the FE regulatory model, including changing to a revenue cap and changing the under recovery arrangements we regard it as appropriate to consider the issues around moving the FE forecasting horizon to 2045.

11.105 In proposing this change, FE has considered the following:

- With PNGL having a forecasting horizon in 2046 and SGN in 2057, changing the FE forecasting horizon to end in 2045 would improve comparability between networks in future price controls and reduce price differentials between territories that arise out of differences in the regulatory frameworks for the GDNs
- It reflects the alterations made to the PNGL licence at the time the PNGL form of price control was changed from a price cap to a revenue cap control
- It allows for the profile adjustment to be unwound over a longer period of time, and over greater volumes, leading to greater inter-generational fairness
- It allows for prices for FE customers that are lower compared to a situation where such a change was not made and that are thus more apposite to further growing connection numbers
- It provides greater security around the long-term nature of the FE business and sends a strong signal to business customers that connecting to the network is a sensible long-term choice

11.106 The impact of moving from 2035 to 2045 is that significant costs are transferred to customers in the 2035-2045 period. FE has indicated in its submission that costs overall will drop by 8%, if the 2045 period is adopted. However there is very limited recognition that this will advantage some customers and disadvantage others. Furthermore, the FE submission did not disentangle the effect of the proposed prolongation of the forecasting horizon by ten years from the effect of other proposed changes such as inclusion of under-recoveries in the depreciated asset value and/or the planned significant infill programme[121]. We did not find the FE analysis transparent in this respect and we have set out below our work on the impact on customers of the propose change.

[120] See firmus energy: GD17 Business Plan, October 2015, p. 13.
[121] For further details see section 4 Price Control Submissions, GD17 Outlook, FE.
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Typical Domestic Charge (Pence per Therm)	GD14 Final Determination (FD)	GD17 BPT Submission	GD17 FD
30 Years	47.6p	48.7p	45.3p
40 Years		45.2p	43.4p

Table 199: Customer Impact of Moving from 30 to 40 year Forecasting Horizon

11.107 The impact on customers from moving from 30 to 40 years is that customers up to 2035 are better off by approximately 1.9ppt but customers after 2035 will be relatively worse off, because the large drop in tariffs they would have seen does not occur.

11.108 We would note that since the decision to use 30 years for FE (ending in 2035) we have set 40 years for the PNGL licence to 2046 and 40 years for the SGN licence to 2057.

11.109 The basis for setting the figure should take into account over what period customers should benefit from the assets being paid for, as well as a view on the level of uncertainty that a longer time frame might bring.

11.110 The fact that we depreciate the mains and services over 40 years suggests there is some justification for considering a move to 40 years.

11.111 We have further discussed this matter with interested parties and considered responses to the draft determination. We note that FE did question the impact on financeability of moving to 40 years but did not request a return to 30 years. Other parties including MEUC, MNI and CCNI were largely supportive of the proposal.

11.112 We have decided to retain the forecast horizon at 2045.

Designated Parameters and Determination Values

11.113 Table 200 and Table 201 show the proposed designated parameters and determination values respectively for FE.

Designated Parameter	Value
r_t	0.0432
n	2022
m	2016
f_t	0.5
q	2045
RPI	256.0
w	5
g	0
h	1
d	1
l	33

Table 200: FE – Proposed Designated Parameters

Description (for Conveyance Categories *i* and Formula Years *t*)	Determination Values		All Values in £(000's) and Indexed to RPI 2014					
			t=2017	t=2018	t=2019	t=2020	t=2021	t=2022
Volume (therms)	$V_{E,it}$	*i* = 1	11,228	12,780	14,462	16,267	18,185	20,197
	$V_{E,it}$	*i* = 2	8,336	8,850	9,352	9,844	10,325	10,796
	$V_{E,it}$	*i* = 3	6,380	6,374	6,368	6,362	6,355	6,349
	$V_{E,it}$	*i* = 4	1,161	927	927	927	927	927
	$V_{E,it}$	*i* = 5	13,375	13,361	13,361	13,361	13,361	13,361
	$V_{E,it}$	*i* = 6	21,500	18,152	18,152	18,152	18,152	18,152
Capital Expenditure	$C_{E,t}$		17,021	14,216	14,412	14,692	15,041	15,264
Operating Expenditure	$O_{E,t}$		6,334	6,293	6,446	6,656	6,929	7,205
Annual Depreciation	$D_{E,t}$		4,378	4,797	5,209	5,650	6,069	6,356
Cash Flow (calculated in accordance with Condition 4.4.6)	$F_{E,t}$		-5,538	-2,697	-2,163	-1,723	-1,369	-854
Revenue Per Unit	$P_{E,i,t}$	*i* = 1	0.4335	0.4335	0.4335	0.4335	0.4335	0.4335
	$P_{E,i,t}$	*i* = 2	0.3046	0.3046	0.3046	0.3046	0.3046	0.3046
	$P_{E,i,t}$	*i* = 3	0.2730	0.2730	0.2730	0.2730	0.2730	0.2730
	$P_{E,i,t}$	*i* = 4	0.2168	0.2168	0.2168	0.2168	0.2168	0.2168
	$P_{E,i,t}$	*i* = 5	0.2558	0.2558	0.2558	0.2558	0.2558	0.2558
	$P_{E,i,t}$	*i* = 6	0.2324	0.2324	0.2324	0.2324	0.2324	0.2324
Total Conveyance Revenue	$R_{E,t}$		17,818	17,813	18,694	19,624	20,601	21,615
Depreciated Asset Value (calculated in accordance with Condition 4.4.7)	$DAV_{E,t}$		118,306	127,726	136,929	145,970	154,942	163,849
Total Regulatory Value (calculated in accordance with Condition 4.4.8)	$TRV_{E,m}$							202,350

Table 201: FE – Proposed Determination Values

East Down

11.114 On 16th October 2015, we granted[122] an extension to the PNGL Licence to facilitate the Conveyance of gas to the area of East Down.

11.115 This extension comprised of 13 new towns[123] for development and required the grant of capital expenditure in excess of £58m in order to make gas available to around 27,000 properties over time.

11.116 Chapters 6 and 7 of this paper have incorporated all costs for East Down.In addition, because of the background to the project an adjustment will be required to the PNGL TRV which is explained in this section.

11.117 The extension to East Down (as well as Gas to the West) was subject to an economic appraisal by DETI in 2012 and endorsement by the NI Executive in 2013. This was reflected in the a DETI consultation[124] which sets out the basis for the project falling under a policy whereby relevant pipelines are determined to be Postalised Distribution Pipelines (PDPs) and are included within the postalised transmission tariff. This approach follows those which have previously been applied in all three GDN areas and is explained in more detail in the referenced consultations.

11.118 This explains why the economic consideration for infill mains discussed from paragraph 7.18 does not apply for East Down and, indeed the SGN area.

11.119 Given the policy context, a sum of mains will be transferred into the asset base of a transmission licence and out of the distribution licence. This figure will be calculated to ensure that the there will be no negative impact on PNGL distribution tariffs and is currently calculated to be c.£28.7m (£Sep 2014) but this will be subject to adjustment once outturn costs are finalised.

11.120 To break this figure into individual years we get the following costs:

- 2016: £12.02m
- 2017: £6.98m
- 2018: £8.81m
- 2019: £0.92m

11.121 For FD modelling purposes, in addition to the normal process of setting our Determination Value for $TRV_{E,2022}$ (i.e. TRV in the final year at the end of GD17), we have included within TRV the following adjustments:

- an increase in opening DAV in 2017, 2018 and 2019 to reflect the 2016 – 2019 PDP (note that no depreciation will be applied to the PDP given that PNGL are not to receive any income associated with this expenditure during the phase of construction);

[122] http://www.uregni.gov.uk/uploads/publications/2015-10-15_Consultation_Notice_to_Extend_the_Licence_Area_and_Modify_Licence_of_PNGL_-_East_Down.pdf

[123] Namely Annahilt, Ballygowan, Ballynahinch, Castlewellan, Crossgar, Downpatrick, Dromore, Drumaness, Dundrum, Hillsborough, Newcastle, Saintfield and The Spa.

[124] http://www.detini.gov.uk/1011.pdf

- a reduction in opening DAV in 2020 of £28,732,262 following receipt of the offsetting PDP payment; and,
- an addition to the profile adjustment equal to the PDP above in paragraph 11.120 for 2017, 2018 and 2019. This is necessary due to the fact that, in accordance with PNGL's licence formula, the profile adjustment automatically reduces by the PDP each year, therefore, this addition is required to maintain the profile adjustment accordingly until receipt of the offsetting PDP payment.

11.122 For the purposes of the GD17 model, the applicable rate of return has not been included in any of our FD modelling. This will be recovered as part of the PDP payment.

11.123 This ensures that all adjustments will occur fully within the GD17 price control period and prices are completely unaffected in line with the policy of no impact on distribution tariffs.

11.124 In circumstances where no PDP payment is feasible, the reduction in opening DAV in 2020 of £28,732,262 would not be made and we would determine an appropriate WACC to be applied to the PDP in consultation with PNGL and other interested parties, which will be based on what the market can bear at that time, including the feasibility of 100% debt finance. We will need to consider the prevailing situation in consultation with all interested parties before determining if a reopener is required.

11.125 In addition all allowances are contingent on PNGL delivering on connecting each of the towns as set out in the development plan and we will reconsider those allowances in any case in which such connection does not take place.

Designated Parameters and Determination Values

11.126 Table 202 and Table 203 show the proposed designated parameters and determination values respectively for PNGL.

Designated Parameter	Value
r_t	0.0426
m	2016
n	2022
q	2046
RPI	257.6

Table 202: PNGL – Proposed Designated Parameters

Determination Value		All Values in £(000's) and Indexed to RPI 2014					
		t=2017	t=2018	t=2019	t=2020	t=2021	t=2022
$V_{E,i,t}$	i = 1	78,885	82,121	85,375	88,665	91,966	95,217
$V_{E,i,t}$	i = 2	21,631	21,885	22,162	22,466	22,789	23,123
$V_{E,i,t}$	i = 3	29,598	29,723	29,848	29,973	30,098	30,223
$V_{E,i,t}$	i = 4	18,768	18,768	18,768	18,768	18,768	18,768
$C_{E,t}$		10,468	10,927	15,615	18,200	16,828	16,189
$CC_{E,t}$		-5,989	-6,066	-6,847	-7,278	-7,049	-6,943
$O_{E,t}$		14,737	14,422	14,331	14,281	14,179	14,286
$D_{E,t}$		14,748	15,224	15,835	16,563	17,290	17,930
$F_{E,t}$		25,896	27,822	25,265	23,180	24,848	28,339
$Q_{E,t}$		-3,203	-2,954	-2,729	-2,506	-2,274	-2,070
$P_{E,i,t}$	i = 1	0.3951	0.3951	0.3951	0.3951	0.3951	0.3951
$P_{E,i,t}$	i = 2	0.3556	0.3556	0.3556	0.3556	0.3556	0.3556
$P_{E,i,t}$	i = 3	0.3349	0.3349	0.3349	0.3349	0.3349	0.3349
$P_{E,i,t}$	i = 4	0.1685	0.1685	0.1685	0.1685	0.1685	0.1685
$R_{E,t}$		51,932	53,343	54,769	56,219	57,679	59,125
$DAV_{E,t}$		421,864	426,373	427,189	400,858	401,760	400,019
$TRV_{E,m}$							592,436
$PA_{E,m}$							201,430

Table 203: PNGL – Proposed Determination Values

SGN – UR Decisions

Designated Parameters and Determination Values

11.127 Table 204 and Table 205 show the proposed designated parameters and determination values respectively for SGN.

Designated Parameter	Value
r_t	0.053
n	2022
m	2017
f_t	0.5
q	2057
RPI	256.0
w	5
g	0
h	0
d	0
l	33
δ_t	0
$X_{O,t}$	0
$X_{U,t}$	0
α_t	0.4

Table 204: SGN – Proposed Designated Parameters

			All Values in £(000's) and Indexed to RPI 2014				
Description (for Conveyance Categories *i* and Formula Years *t*)	Determination Values		t=2018	t=2019	t=2020	t=2021	t=2022
Volume (therms)	$V_{E,it}$		5,055	21,811	28,333	31,391	32,804
Capital Expenditure	$C_{E,t}$		4,428	12,553	9,554	7,421	7,884
Operating Expenditure	$O_{E,t}$		843	2,156	1,971	1,694	2,015
Annual Depreciation	$D_{E,t}$		256	717	1,078	1,371	1,676
Tax Allowance	$T_{E,t}$		0	0	0	0	0
Cash Flow (calculated in accordance with Condition 4.6.6)	$F_{E,t}$		-4,482	-11,506	-6,985	-3,875	-4,252
Revenue Per Unit	$P_{E,i,t}$	*i* = 1	0.2883	0.2883	0.2883	0.2883	0.2883
	$P_{E,i,t}$	*i* = 2	0.2883	0.2883	0.2883	0.2883	0.2883
	$P_{E,i,t}$	*i* = 3	0.2785	0.2785	0.2785	0.2785	0.2785
	$P_{E,i,t}$	*i* = 4	0.1585	0.1585	0.1585	0.1585	0.1585
	$P_{E,i,t}$	*i* = 5	0.1585	0.1585	0.1585	0.1585	0.1585
	$P_{E,i,t}$	*i* = 6	0.1585	0.1585	0.1585	0.1585	0.1585
	$P_{E,i,t}$	*i* = 7	0.1200	0.1200	0.1200	0.1200	0.1200
Depreciated Asset Value (calculated in accordance with Condition 4.6.7)	$DAV_{E,t}$		6,883	18,719	27,195	33,245	39,453
Total Regulatory Value (calculated in accordance with Condition 4.6.8)	$TRV_{E,m}$						40,786

Table 205: SGN – Proposed Determination Values

Under-Recoveries

11.128 As detailed in 11.96 we also propose the same approach is applied to SGN underrecoveries i.e. LIBOR plus 2%.

12 Licence Implications

Summary of Key Changes from Draft Determination to Final Determination

12.1 We have completely revised this Chapter since the publication of the GD17 draft determination 6. Key changes made in this context include:

- Removal of all sections referring to any specific licence modification proposals for FE, PNGL and/or SGN; instead, our licence modification proposals now form part of a separate consultation on licence modifications pursuant to the GD17 final determination and other regulatory decisions[125] which is being published alongside this GD17 final determination
- Some smaller updates to the Legal and Regulatory Framework and Overview over Licence Modification Proposals sections below

12.2 We note that in drafting said consultation paper on licence modifications pursuant to the GD17 final determination and other regulatory decisions, we have accounted for any comments received on our licence modifications proposals in form of responses to our GD17 draft determination and/or as part of further stakeholder engagement in preparation of the licence modification consultation.

Legal and Regulatory Framework

12.3 As detailed in section 2 Introduction, Our Statutory Duties and Regulatory Principles, gas distribution networks are natural monopolies. The lack of competition in the market entails a need for other mechanisms to ensure consumers pay fair prices for the services offered by GDNs. This is typically done through price controls.

12.4 For each GDN, details of the price control process are prescribed in the licence. The relevant licence conditions cover e.g. aspects such as review process, licence formulae, charging methodology, designated parameters and determination values[126]. Taken together, these define how price controls need to be conducted, and the price control elements that need to form part of a determination. They also define how ultimately consumer prices will be impacted.

12.5 On 6 February 2015, the Gas and Electricity Licence Modifications and Appeals Regulations (Northern Ireland) 2015[127] came into effect. These regulations have

[125] This document is referenced in section Annexes, Consultation Responses and Supplementary Documents, Supplementary Documents.

[126] Designated parameters include e.g. formula years, rate of return and price base. Determination values include e.g. volumes, capital and operating expenditure, annual depreciation, cash flow, revenues per unit of gas, depreciated asset value and total regulatory value. The exact number and type of designated parameters and determination values can vary between licences and they may comprise of more than those listed here.

[127] http://www.legislation.gov.uk/nisr/2015/1/contents/made.

impacted on the way price control decisions need to be implemented and can be appealed.[128]

12.6 In particular, one consequence of these regulations is that, in order to preserve the right of licence holders to challenge price control decisions through their referral to the CMA, those decisions now need to be brought into effect through licence modifications. More specifically, for each GDN the relevant designated parameters and determination values need to be updated in the respective licence conditions, in line with the price control final determination. Additional licence modifications may or may not be required, depending on the price control decisions.

12.7 One further consequence of the Gas and Electricity Licence Modifications and Appeals Regulations (Northern Ireland) 2015 is that the provisions of the Gas (Northern Ireland) Order 1996 which relate to the process through which licence modifications may be made by the Authority (including those required to bring into effect price control decisions) have been amended. As under the previous process, prior to making a licence modification, we need to give notice of at least 28 days of the proposed modification. With respect to the licence modifications we consider requisite to bring into effect our GD17 price control, we have given this notice in form of our consultation on licence modifications pursuant to the GD17 final determination and other regulatory decisions[125] published alongside this GD17 final determination. We must give due consideration to any representations made during this period and publish our decision and the licence modification, stating the reasons for it and its effects. However, the effective date for the licence modification must be at least 56 days after the publication of the licence modification decision.

12.8 In addition, we no longer need the consent of the licence holder to make a modification to their licence. In consequence of that, we no longer require a power to refer a licence to the CMA if consent is withheld. Licence modification decisions are automatically effective. However, any licence modification decision may be appealed to the CMA by:

- the licence holder concerned;
- any other licence holder materially affected by the decision;
- a qualifying body or association representing a licence holder concerned or a licence holder materially affected by the decision; or
- the Consumer Council for Northern Ireland.

12.9 If an appeal is brought to the CMA, the CMA will in a first step decide whether to give permission for the appeal to proceed or not. If permission is granted, the CMA has a period of 4 months, or in the case of licence modifications relating to price controls 6 months, in which to determine the appeal. These timelines can be extended to 5 months, respectively 7 months for licence modifications relating to price controls, if required.

Overview over Licence Modification Proposals

12.10 As detailed in the Legal and Regulatory Framework section above, licence modifications are required to update the relevant designated parameters and determination values in

[128] For further details see e.g.: Utility Regulator: Changes to Gas and Electricity Licences with regards to Appeals to the CMA, Decision Paper on Modifications necessary due to The Gas and Electricity Licence Modifications and Appeals Regulations (Northern Ireland) 2015, 4 August 2015.

the GDNs' licences and bring into effect the GD17 price control decisions. Furthermore, we propose to make additional licence modifications that are consequential to other decision papers published by the Authority or required to address known licence errors and some key inconsistencies between the licences held by the GDNs. This is on the basis that licences relating to the same activities ought to include similar provisions, except where there is a reason for a difference of treatment. In particular, including in the FE and PNG licences a number of provisions which were incorporated in the new SGN licence will ensure that all of the licences are brought up to date with the latest regulatory thinking on a range of key issues. This ensures fairness and equality between licensees on those matters, and secures that equivalent regulatory powers are available to us (and thus an equivalent level of protection is provided for consumers) in respect of each network.

12.11 Table 206 provides an overview over the different types of licence modifications we propose to make and their relevance for the different GDNs. For further details, please refer to our consultation on licence modifications pursuant to the GD17 final determination and other regulatory decisions[125] published alongside this GD17 final determination.

Type of Licence Modification	Relevance			Background
	FE	PNGL	SGN	
Update of designated parameters and determination values	X	X	X	GD17
Change from price cap to revenue cap	X			FE form of control
Treatment of Under-recoveries	X			GD17
Extension of forecasting horizon	X			GD17
Post-tax WACC			X	GD17
Uncertainty Mechanism reference	X	X		GD17
Licence alignment between GDNs pursuant to the Gas to the West project	X	X		Gas to the West project
Licence modifications pursuant to the extension of the PNGL licensed area to East Down		X		Gas to the East project
Licence Modifications pursuant to our decision paper on Modifications necessary due to The Gas and Electricity Licence Modification and Appeals Regulations (Northern Ireland) 2015			X	LMA
Correction of licence errors and inconsistencies	X	X	X	Various

Table 206: Overview over Types of Licence Modifications Proposed

12.12 Proposed drafting for these licence modifications is contained in:

- Annex 1: FE Licence – Proposed Modifications
- Annex 2: PNGL Licence – Proposed Modifications; and
- Annex 3: SGN Licence – Proposed Modifications

13 Next Steps and Further Issues

Summary of Key Changes from Draft Determination to Final Determination

13.1 We have updated this chapter following on from the GD17 draft determination, following due consideration of the responses received to same[6]. Key changes made in this context include an update on the Further Issues with additional issues considered to be beyond the scope of the GD17 price control determination.

Next Steps

13.2 Table 207 provides an overview over the next steps and associated timelines for the GD17 price control process.

Key Milestones of GD17	Date
Stakeholder engagement	September/October 2016
Closure of consultation on licence modifications related to GD17	14 October 2016
Decision on licence modifications relating to GD17	1 November 2016
Start of GD17 price control period	1 January 2017
Completion of lessons learnt report	Q4 2017

Table 207: GD17 Next Steps

Consequential Changes

13.3 We consider that a number of consequential changes will be required as a result of the GD17 final determination. These will include the following:

- Modifications to the FE, PNGL and SGN licences to bring into effect the GD17 final determination and follow through on any additional licence modification proposals mentioned in chapter 12 Licence Implications and further detailed in our consultation on licence modifications pursuant to the GD17 final determination and other regulatory decisions[125].
- Alignment of the Annual/Cost Reporting templates and associated regulatory instructions and guidance with the GD17 final determination, where relevant and appropriate
- Review of the GDN connection policies to ensure alignment with the GD17 final determination, where relevant and appropriate

13.4 We note that this list is not necessarily exhaustive and that the need for further consequential changes may arise.

Further Issues

13.5 As part of this GD17 final determination we have identified a number of issues that we consider to be beyond the scope of the GD17 price control determination. Broadly speaking, these issues can be categorised as follows:

- Issues to be considered during the GD17 price control period but after the GD17 final determination
- Issues to be considered as part of subsequent price controls

13.6 The issues to be considered during the GD17 price control period but after the GD17 final determination comprise of the following.

- Consumer engagement and customer satisfaction
- Shrinkage review
- Review of conveyance charges
- Delivery of a common branding approach in relation to promoting natural gas in NI
- Revision of Annual/Cost reporting templates and associated RIGs
- Asset maintenance excellence

13.7 Consumer engagement and customer satisfaction: As detailed in Chapter 11 and given our previous experience of development work using a partnership model across both the local water and electricity sectors we envisage the following timetable ought to deliver:

- New consumer metrics and customer satisfaction survey to be trialled in Year 2 of GD17 or 2018;
- Introduction and incorporation of the above new measures within a revised Regulatory Instructions and Guidance pack; so that
- Performance in 2019 can be reported going forward in our Annual/Cost Reporting publication.

13.8 Our customer service development objective will require delivery of new customer service metrics and customer satisfaction surveys as an output of GD17. The first stage will be the re-constitution of our partnership model of consumer engagement with CCNI, GDNs, DfE and ourselves forming a new working group who shall draw up an agreed timetable for the introduction of new metrics, consumer surveys as well a shared research programme to inform GD23. The development of our agreed timetable will be a developmental objective for the first 6 months of the GD17 period and we shall work to develop this through our preferred partnership model and working group (GDNs, the CCNI, DfE and the UR).

13.9 Shrinkage review: As detailed in Chapter 11 we plan to reconsider shrinkage and the appropriateness of introducing related changes to regulatory arrangements (such as licences or network codes) and/or incentive mechanisms during the GD17 price control period. We note that relevant incentive mechanisms, if deemed appropriate, could relate to shrinkage as a whole and/or to certain aspects of it (e.g. minimisation of theft-related losses). To facilitate this exercise, we will continue to collect shrinkage-related data from the GDNs as part of the Annual/Cost Reporting. In particular, we would expect the GDNs to provide a report including a professional estimate of leakage and own use gas as a basis for estimation of shrinkage due to theft. We consider that this report should be provided by no later than end of 2017.

13.10 Review of conveyance charges: It was recognised in meetings we had with FE and PNGL on achieving a common understanding and charging methodology across all conveyance charge classes, that this was a complex matter that required further work, including a review not only of the NI gas distribution market, but also of the NI electricity market. Taking into consideration the impact even small changes in methodology can have on consumer prices, consumer bills and the development of the NI natural gas market as a whole, it was agreed that there was a requirement for further detailed analysis as well as potentially for public consultation. With regards to the overall timeframe, this project was considered to be a mid-term project which would need to be continued during the GD17 price control period.

13.11 Delivery of a common branding approach in relation to promoting natural gas in NI: As natural gas is a homogenous product, we expect significant overalp in marketing benefits with respect to the three GDNs. It is our view that the GDNs have not maximised this potential. Whilst we do not propose to dictate details, we expect issues of common branding approach are addressed. This will in a first step require development of a common branding approach. The common branding approach will subsequently need to be implemented and complied with.

13.12 Revision of Annual/Cost reporting templates and associated RIGs: We will revise and, where relevant, amend the Annual/Cost Reporting templates and associated regulatory instructions and guidance to reflect the decisions from our GD17 determination as well as, where relevant and appropriate, any changes Ofgem are making to their reporting framework. The purpose of any such amendments will be to align the reporting structures so as to ensure data is captured at the relevant level of detail to support ongoing analysis and decision taking and allow monitoring of performance against price control allowances, outputs and other outcomes. We note that we are also considering bringing forward the timelines for Annual/Cost Reporting to align with those defined in the GDNs' licences for the submission of financial statements and auditor's reports.[129] In practice, this would mean that Annual/Cost Reporting for a reporting year would need to be submitted by 30 June of the following year, rather than, as has been current practice to date, by 30 September. We consider that this would still allow GDNs to align the Annual/Cost Reporting data with their accounts whilst avoiding unnecessary delay in our review of the GDNs' performance.

13.13 Asset management excellence: As set out in Chapter 11 to monitor delivery of this objective during GD17, we will introduce asset management development reporting into the Annual Cost Reporting to require the GDNs to update their Asset Management Capability Assessment and Plans for Asset Maintenance and report on progress against the delivery of these plans, with a particular focus on the needs of the GD23 price control.

13.14 The issues to be considered as part of subsequent price controls comprise of the following:

- Connections Incentive review
- Single low pressure network code

[129] See Condition 1.2: Separate Accounts for Separate Businesses in the FE and SGN licences and Condition 1.3: Separate Accounts for Separate Businesses in the PNGL licence.

13.15 Connections Incentive review : We consider that it is important that we review the rationale for the connection incentive as well as the performance of each of the GDN's in connecting owner occupied properties. We consider that a mid-point review, during GD17 would be appropriate point to do this in 2020. We consider that this review would assist in developing our approach for consideration for the rationale for any connection incentive for the GD23 price control period.

13.16 Single low pressure network code: It is our view that co-operation and consistency with respect to network codes is an important aspect of the development and maintenance of an efficient, economic and co-ordinated gas industry in Northern Ireland and should hence be enforceable. We note that it is not our intention to oblige the GDNs at this stage to put in place a single low pressure network code. However, we note that, subject to a related consultation process, we may consider a related direction in the future.

Change in Ownership Structure

13.17 It is possible that any GDN could end up under common ownership. Under the terms of their licences, any change of ownership must be approved by us.

13.18 Our expectation, in particular if any GDN came under common ownership, is that there may be synergies and other cost savings that can be achieved.

13.19 As a consequence, it may be appropriate to re-open this price control for any change of ownership, depending on the exact timing. If the businesses come under common ownership we would seek to ensure that the resulting synergy cost savings are shared between the GDNs and consumers.

Appendices

Appendix 1: Map of FE Licensed Area

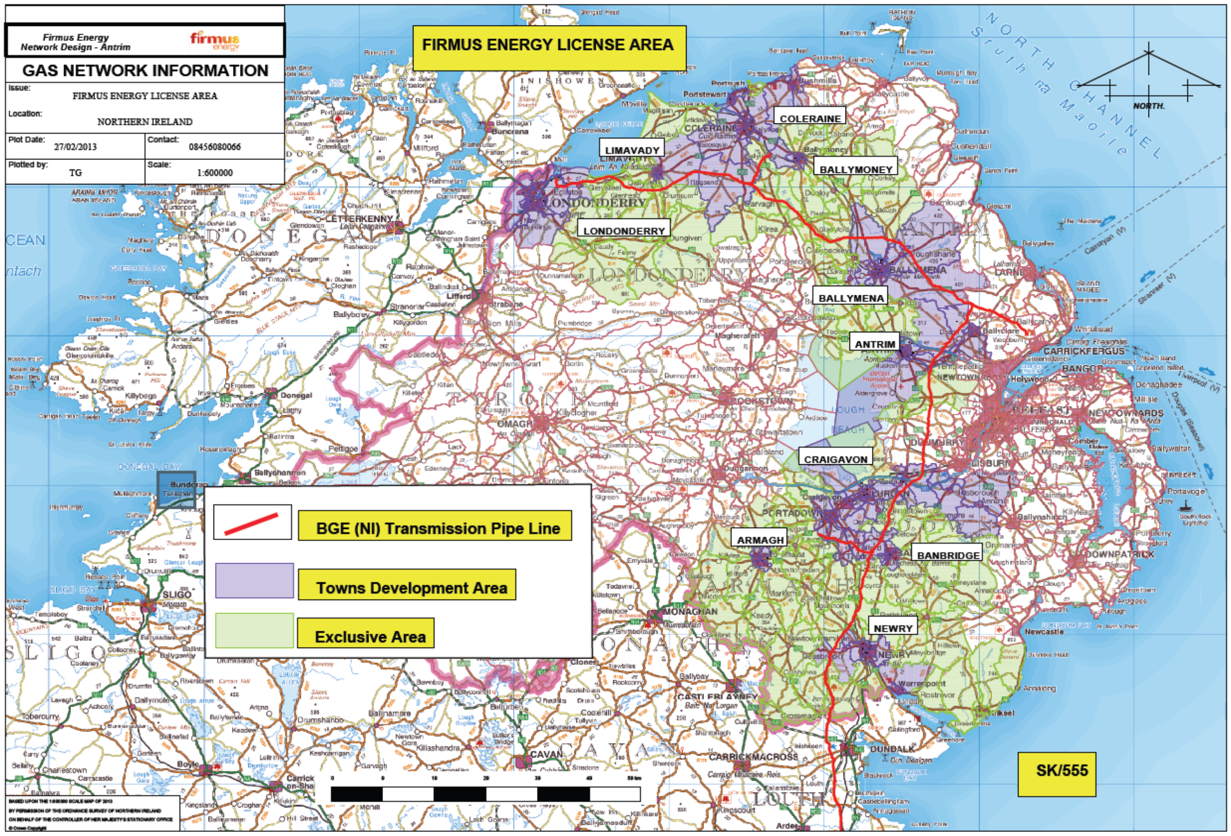

Figure 13: Map of FE Licensed Area

Appendix 2: Map of the PNGL Licensed Area

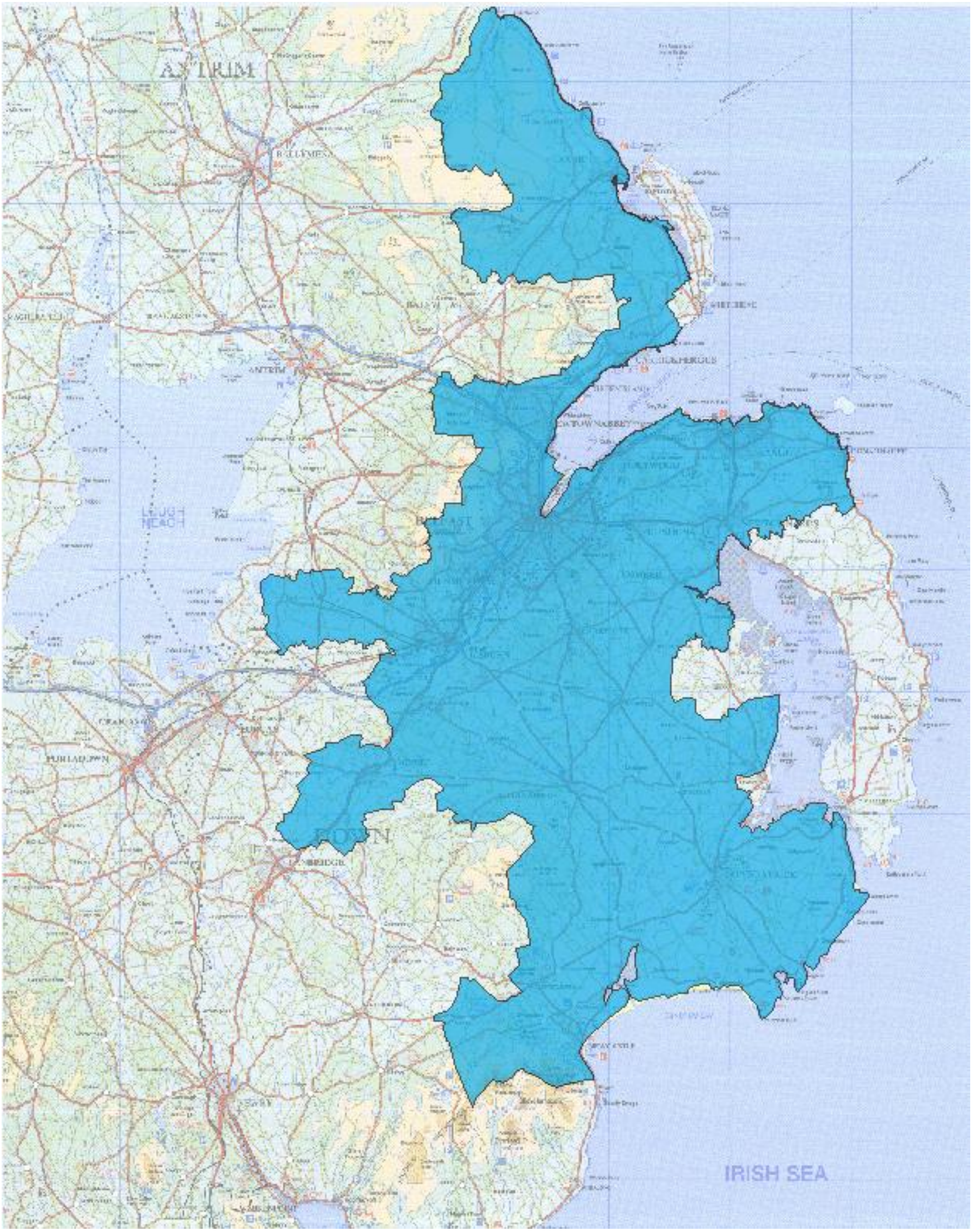

Figure 14: Map of PNGL Licensed Area

Appendix 3: Map of SGN Towns to Connect

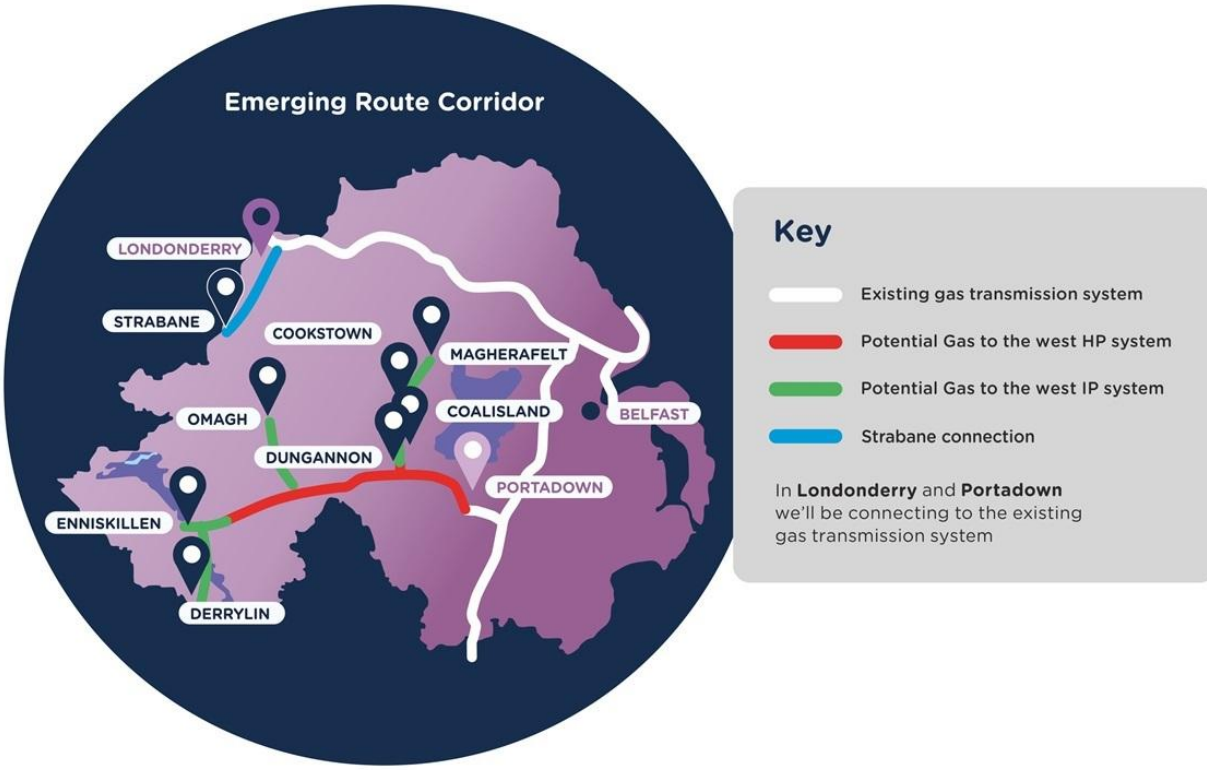

Figure 15: Map of SGN Towns to Connect

Annexes, Consultation Responses and Supplementary Documents

Annexes

Table 208: Annexes to GD17 Draft Determination provides an overview over the annexes to this GD17 final determination.

Annex Number	Annex Name
Annex 1	FE Licence – Proposed Modifications
Annex 2	PNGL Licence – Proposed Modifications
Annex 3	SGN Licence – Proposed Modifications
Annex 4	GD17 DD GD17 Efficiency Advice (Deloitte LLP)
Annex 5	GD17 DD Indicative Findings from Top-Down Benchmarking
Annex 6	GD17 DD Real Price Effects & Frontier Shift
Annex 7	UKRN Peer Review
Annex 8	Emergency Costs
Annex 9	Opex Backcasting Methodology
Annex 10	PI Models – FE
Annex 11	PI Models – PNGL
Annex 12	PI Models - SGN
Annex 13	Draft Determination Consultation Report
Annex 14	Rate of Return Adjustment Mechanism
Annex 15	Rate of Return Adjustment Mechanism Model

Table 208: Annexes to GD17 Draft Determination

Consultation Responses

Table 209: Non-confidential Responses to GD17 Draft Determination provides an overview over the non-confidnetial responses received to the GD17 draft determination.

Document	Document Link
FE Response to GD17 Draft Determination	Firmus energy: Response to the GD17 Draft Determination, May 2016
PNGL Response to GD17 Draft Determination	Phoenix Natural Gas Ltd. Response to the Utility Regulator: Price Control for Northern Ireland's Gas Distribution Networks, GD17 Draft Determination, May 2016
SGN Response to GD17 Draft Determination	SGN: GD17 Draft Determination Consultation Response, 31 May 2016
CCNI Response to GD17 Draft Determination	The Consumer Council: Response to UR's Price Control for NI's Gas Distribution Networks GD17, May 2016
Manufacturing NI Response to GD17 Draft Determination	Manufacturing Northern Ireland: Manufacturing NI's response to the "Price Control for Northern Ireland's Gas Distribution Networks (GD17) Draft Determination"
NEA Response to GD17 Draft Determination	NEA: National Energy Action Northern Ireland's response to the Northern Ireland Authority for Utility Regulation Price Control for Northern Ireland's Gas Distribution Networks GD17, May 2016
Ninga Response to GD17 Draft Determination	Ninga: Re: Draft determination for gas distribution network operators (GD17)
Fermanagh and Omagh District Council Response to GD17 Draft Determination	Fermanagh and Omagh District Council: Response to GD17 Draft Determination, 24 May 2016
AGSNI Response to GD17 Draft Determination	AGSNI: Response to GD17 Draft Determination, Gas distribution network price control
MEUC Response to GD17 Draft Determination	Major Energy Users' Council: Response to GD17 Consultation Document, 31 May 2016

Table 209: Non-confidential Responses to GD17 Draft Determination

Supplementary Documents

Table 210: Supplementary Consultation and Decision Papers provides an overview over further supplementary documents to this GD17 final determination, which are not contained in the lists of annexes and responses to the GD17 draft determination in Table 208: Annexes to GD17 Draft Determination and Table 209: Non-confidential Responses to GD17 Draft Determination respectively.

Document	Document Link
GD17 Draft Determination	Utility Regulatory: Price Control for Northern Ireland's Gas Distribution Networks GD17, Draft Determination, 16 March 2016
Consultation paper on licence modifications pursuant to the GD17 final determination and other regulatory decisions	Utility Regulatory: Licence Modifications Pursuant to the GD17 Final Determination and other Regulatory Decisions, 15 September 2016
Decision on extending the PNGL licensed area to East Down	Utility Regulator: Decision Paper on the Extension to the Conveyance Licence Area and Modification of the Conveyance Licence of Phoenix Natural Gas Limited – East Down, 10 December 2015
Consultation on extending the PNGL licensed area to East Down	Utility Regulator: Notice to Extend the Conveyance Licence Area and Modification of the Conveyance Licence of Phoenix Natural Gas Limited – East Down, 16 October 2016
Outcome of consultation on moving firmus energy to a revenue cap regime	Utility Regulator: firmus energy (Distribution) Limited Licence, Outcome of Consultation paper on moving to a revenue cap regime, 16 September 2015
Consultation on moving firmus energy to a revenue cap regime	Utility Regulator: Consultation on modifications to the Price Control conditions of the firmus Energy (Distribution) Limited Licence, 18 June 2015
LMA Decision Paper	Utility Regulator: Changes to Gas and Electricity Licences with regards to Appeals to the CMA, Decision Paper on Modifications necessary due to The Gas and Electricity Licence Modifications and Appeals Regulations (Northern Ireland) 2015, 4 August 2015
Gas to the West Licence Decision	Utility Regulator: Gas to the West Licence Decision, 11 February 2015
Gas to the West Licence Consultation	Utility Regulator: Gas to the West Licence Consultation, 18 December 2014

Table 210: Supplementary Consultation and Decision Papers