Price Control for Northern Ireland's Gas Distribution Networks

GD17

Draft Determination

16 March 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 draft 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 draft 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 will set 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 proposed rate of return.

Audience

Industry, consumers & statutory bodies.

Consumer Impact

The price control will set out the allowed distribution charges for the gas distribution companies. Distribution charges make up around 40% of the total domestic customer bill. The draft determination in this document sets out the basis on which we propose to determine the allowed distribution charges.

As part of our approach for the GD17 price control, we propose a range of measures designed to increase the number of consumers that can connect to the natural gas network and improve customer service for natural gas customers.

TABLE OF CONTENTS

ACRONYMS AND GLOSSARY

ACRT	Annual/Cost Reporting Template
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
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
DNO	Distribution Network Operator
Domestic Premises	Any premises at which the supply of gas is, or is to be, 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
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, Maghreafelt, Enniskillen, Omagh and Strabrane
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
NI	Northern Ireland
NIE	Northern Ireland Electricity
NIEH	Northern Ireland Energy Holdings
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.
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.
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	The profile adjustment is a mechanism for carrying forward allowed revenues to future years with the purpose of levelising prices over time.
PRS	Pressure Reduction Station. A pressure reduction equipment having an inlet pressure greater than 7 barg.
RAB	Regulatory Asset Base
Re	Regarding

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 draft 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 price control sets out the amount 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 pipelines and connections, proposed rate of return and volumes forecasts.

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

1.5 This document is a consultation for the GD17 period and we welcome responses. We will provide our conclusions on the price control in the Final Determination which we will issue later this year.

Our Statutory Duties and Regulatory Principles

1.6 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 Directive3, and by having regard to a number of matters, as set out more fully in the Energy (Northern Ireland) Order 2003.

1.7 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.

1.8 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;

[1] As detailed in section 3 Approach, Duration – UR Proposals, the first price control for SGN begins on 1 January 2018. Hence, the SGN price control period is for a period of 5 years only.

- 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.

1.9 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.

Approach

1.10 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.

1.11 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.

1.12 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.

1.13 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 proposed figures.

1.14 We have also carried out top down benchmarking with GB GDNs. At this point we have proposed figures based on our bottom up assessment but we intend refining further our indicative top down benchmarking through a process of further engagement upon how GDN special factor claims might be applied to the results of our benchmark modelling. The culmination of this engagement around our benchmark modelling will see us begin to monitor local GDNs' respective efficiency performances within our Annual/Cost Reporting publications.

1.15 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

1.16 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 forecast connections used in designing the network.

1.17 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.

1.18 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 will work with other UK regulators to have our proposals peer reviewed before the Final Determination.

1.19 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.

1.20 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.

1.21 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.

1.22 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)[2] domestic customers. In GD14 we had considered that there would be a large reduction in the incentive but we are proposing a more gradual reduction in the incentive up to 2022.
- 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.

1.23 GD17 has involved an improved level of consumer and stakeholder engagement. We intend to build on this beyond the Final Determination by setting up a working group to

[2] 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.

consider further development of consumer and stakeholder engagement, including design of consumer focused metrics/satisfaction surveys and incentives and consideration of how it should feed into future price control submissions and our Annual/Cost Reporting.

FE

1.24 A summary of the overall draft 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 Draft Determination (post efficiencies)	5.5	5.6	5.7	5.9	6.1	6.3	**35.2**
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 Draft Determination (post efficiencies)	13.0	12.9	13.1	13.3	13.7	13.9	**79.8**
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 Draft Determination	15.0	15.6	16.3	17.1	17.9	18.7	**100.7**
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 Draft Determination	12,491	12,345	12,200	12,037	12,303	12,365	**73,741**
Connections (p.a.)	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
FE Submission - Total	4,069	4,140	4,225	4,356	4,703	4,849	26,342
- 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	0	0	0	0	0	0	**0**
- Large and Contract I&C	3	3	3	3	3	3	**18**
GD17 Draft Determination	4,203	4,553	4,903	5,203	5,503	5,703	30,068
- 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	0	0	0	0	0	0	**0**
- Large and Contract I&C	3	3	3	3	3	3	**18**

Table 1: FE Draft Determination Allowances

1.25 For capex the draft determination allows capital investment of £79.80m following the application of the frontier shift compared to the FE submission of £89.30m. The reduction incorporates a reduced unit rate 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.

1.26 We have reviewed FE's proposals and economic assessment for developing its infill mains and carried out our own assessment. Our initial conclusion is that a significant amount of infill mains is justified although not the whole amount FE requested as some of the projects proposed do not pass an economic test. Our draft determination is to allow 660km of mains for GD17, which is a significant increase on GD14 levels and facilitate 74k more customer having access to gas outside their property.

1.27 For opex we have proposed £35.2m over GD17 after application of the frontier shift compared to FE's proposal of £47.9m.

1.28 We have carefully considered the GDN submissions on the connections incentive in the context of our proposal in GD14 to reduce this by 50% from 2017. 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. However we now propose to move away from the proposed 50% reduction. Our economic analysis which follows the GD14 approach has produced an incentive figure of £420 per applicable connection. Taking into account the strong representations from the GDNs we propose to allow a glide path from the current level of £573 per applicable connection in 2016 down to £420 in 2022.

1.29 For the target number of connections we have taken into account our increased infill mains allowance which will make gas available to more customers. We therefore propose to set a target for FE to connect 20k owner occupier 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.

1.30 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. While we have allowed increases in the area of maintenance and emergencies, the allowances are £1.8m less than FE proposed as our analysis indicated the potential for significant efficiencies in this area.

1.31 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.

1.32 Our initial WACC analysis has resulted in a real cost of debt for FE of 2.33% and a cost of equity of 6.3%. 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. The cost of debt reflects the fact that current market rates are low and FE has a significant level of debt to finance in GD17. Overall we have applied a pre-tax WACC of 4.3% in the draft determination. Given the level of uncertainty for FE in raising so much debt in GD17 we propose to include a pain gain adjustment to our cost of debt so that FE only takes 20% of the pain/gain if the actual cost of debt is over/under our allowance.

1.33 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 purposes of the draft determination we have applied a model using 2045 for the Forecast Horizon. However we would emphasise that we have not made a decision on this matter and we will consider further the implications of moving the Forecast Horizon alongside the interrelated issues of depreciation and the Profile Adjustment.

1.34 We considered the treatment of FE underrecoveries in GD14 and now propose to reduce the rate of return that applies from 2017. Our initial view is that applying a full rate of return is not in the public interest and the proposed change would align FE with other GDN licences.

1.35 The modelling we have applied in the draft determination produces a significant drop in domestic distribution tariffs of 21% compared to the FE submission. In comparison with GD14 distribution tariffs the draft determination produces a reduction of 25%. This would result in domestic customers in the FE area paying around £46 less per annum than currently. For I&C customers the difference would obviously be much larger.

1.36 However we would caution that a significant element of this difference derives from applying the 2045 Forecast Horizon and the figures above are not perfectly comparable as they do not factor in the impact of how FE chooses to charge its under recovery amount.

PNGL

1.37 A summary of the overall draft 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 Draft Determination - Post Efficiency	13.9	13.8	13.7	13.6	13.5	13.5	82.0
Capex - Post Efficiencies (£m, in Dec 2014 prices)	2017	2018	2019	2020	2021	2022	Total
PNGL Submission (incl. East Down) - Pre Efficiency	19.0	19.2	17.9	18.8	17.5	19.5	111.9
GD17 Draft Determination - Post Efficiency	15.5	15.8	14.3	15.9	14.6	15.0	91.1
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 Draft Determination - Post Efficiency	47.9	49.3	50.7	52.0	53.3	54.5	307.7
Properties Passed (p.a.)	2017	2018	2019	2020	2021	2022	Total
PNGL Submission (incl. East Down)	7,889	7,989	7,989	7,989	7,989	7,089	46,935
GD17 Draft Determination	5,882	5,882	5,882	5,882	5,882	5,882	35,294
Connections (p.a.)	2017	2018	2019	2020	2021	2022	Total
PNGL Submission (incl. East Down)	8,447	8,525	8,776	9,081	9,104	9,110	53,043
- Owner Occupied	4,145	4,145	4,238	4,433	4,452	4,428	25,840
- New Build	2,912	2,912	3,112	3,112	3,112	3,112	18,269
- NIHE	1,023	1,104	1,046	1,112	1,156	1,152	6,593
- Small and Medium I&C	364	360	376	420	381	414	2,315
- Large and Contract I&C	4	4	4	4	4	4	25
GD17 Draft Determination	9,303	9,230	9,039	8,998	8,853	8,582	54,005
- Owner Occupied	5,800	5,650	5,500	5,350	5,200	4,900	32,400
- New Build	2,112	2,112	2,112	2,112	2,112	2,112	12,672
- NIHE	1,023	1,104	1,046	1,112	1,156	1,152	6,593
- Small and Medium I&C	364	360	377	420	381	414	2,316
- Large and Contract I&C	4	4	4	4	4	4	24

Table 2: PNGL Draft Determination Allowances

1.38 For capex the draft determination allows capital investment of £91.1m following the application of the frontier shift compared to the PNGL submission of £111.9m. The reduction incorporates a reduced unit rate in some areas, particularly around meter costs, when we roll forward the basket of works rates into GD17

1.39 We have reviewed PNGL's proposals for developing its infill mains and carried out an economic assessment. Our initial 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 draft determination is to allow 362km of mains for GD17 and facilitate 35k more customer having access to gas outside their property.

1.40 For opex we have proposed £82.0m over GD17 after application of the frontier shift compared to PNGL's proposal of £106.9m.

1.41 As with FE we have taken into account the strong representations from the GDNs on the connections incentive and we propose to allow a glide path from the current level of £573 per applicable connection in 2016 down to £420 in 2022.

1.42 For the target number of connections we have taken into account PNGL arguments that its current level of connections is not sustainable. We therefore propose to set a target for PNGL to connect 32k owner occupier 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.

1.43 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.

1.44 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.

1.45 Our initial WACC analysis has resulted in a real cost of debt for PNGL of 2.26% and a cost of equity of 6.3%. 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 propose not to make any adjustment to reflect the very high PNGL TRV:totex ratio. The cost of debt reflects the fact that current market rates are low and PNGL has a significant level of debt to finance in GD17. Overall we have applied a pre-tax WACC of 4.3% in the draft determination. Given the level of uncertainty for PNGL in raising so much debt in GD17 we propose to include a pain gain adjustment to our cost of debt so that PNGL only takes 20% of the pain/gain if the actual cost of debt is over/under our allowance.

1.46 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 equity finance.

1.47 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. We have set out our initial analysis here and, as would be expected, this would result in an increase in short term tariffs. We will continue to consider this issue in advance of the Final Determination and would be interested in understanding respondents' views on the subject.

1.48 The modelling we have applied in the draft determination produces a significant drop in domestic distribution tariffs of 13% compared to the PNGL submission. In comparison with GD14 distribution tariffs the draft determination produces a reduction of 8%. This

would result in domestic customers in the PNGL area paying around £15 less per annum than currently. For I&C customers the difference would obviously be much larger.

SGN

1.49 A summary of the overall draft determination for SGN is presented in Table 3.

Opex (£m, in Dec 2014 prices)	2017	2018	2019	2020	2021	2022	Total
SGN Submission		2.6	2.8	2.3	2.5	2.8	13.0
GD17 Draft Determination		2.1	1.6	1.4	1.4	1.5	8.1
Capex - Post Efficiencies (£m, in Dec 2014 prices)	2017	2018	2019	2020	2021	2022	Total
SGN Submission		12.0	10.8	7.3	7.5	7.7	45.4
GD17 Draft Determination		11.5	9.7	5.9	5.9	5.9	38.9
Revenues (£m, in Dec 2014 prices)	2017	2018	2019	2020	2021	2022	Total
SGN Submission		2.5	3.4	4.0	4.3	4.6	18.8
GD17 Draft Determination		3.3	4.6	4.8	5.0	5.2	22.7
Volumes (therms m)	2017	2018	2019	2020	2021	2022	Total
SGN Submission		17,688	21,893	24,653	25,417	26,258	115,908
GD17 Draft Determination		24,873	34,264	34,885	35,520	36,137	165,679
Properties Passed (p.a.)	2017	2018	2019	2020	2021	2022	Total
SGN Submission	4,504	4,586	4,887	4,886	4,875	4,876	28,614
GD17 Draft Determination	5,720	5,738	6,072	6,032	6,092	6,069	35,723
Connections (p.a.)	2017	2018	2019	2020	2021	2022	Total
SGN Submission	210	531	875	1,172	1,484	1,647	5,919
- Owner Occupied	162	398	633	869	1,105	1,219	4,386
- New Build	0	0	37	59	81	95	273
- NIHE	41	99	158	217	276	305	1,096
- Small and Medium I&C	2	12	14	18	22	27	95
- Large and Contract I&C	5	22	32	9	0	1	69
GD17 Draft Determination	9	2,414	1,987	1,484	1,552	1,539	8,985
- Owner Occupied	0	1,294	1,294	809	809	809	5,015
- New Build	0	0	352	331	391	368	1,442
- NIHE	0	1,062	266	266	265	266	2,125
- Small and Medium I&C	0	38	46	69	87	96	336
- Large and Contract I&C	9	20	29	9	0	0	67

Table 3: SGN Draft Determination Allowances

1.50 For capex the draft determination allows capital investment of £38.9m following the application of the frontier shift compared to the SGN submission of £45.4m. The reduction incorporates a significantly reduced unit rate based on the outturn of our benchmarking results. We did not regard proposals to move away from local benchmark rates as justified.

1.51 We would highlight that we are still awaiting network design details from SGN which we expect to be fully provided by April. However based on the information we have, we have proposed in our draft determination to allow 416km of mains for GD17 and facilitate 36k customers having access to gas outside their property.

1.52 For opex we have proposed £8.1m over GD17 compared to SGN's proposal of £13m.

1.53 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 including those related to changing economic conditions and changing oil/gas price differentials. 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.

1.54 As with the other GDNs we have taken into account the strong representations from the GDNs on the connections incentive and we propose to allow a glide path from the current level of £573 per applicable connection in 2016 down to £420 in 2022. 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.

1.55 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 5k owner occupier customers over the duration of GD17. Our draft determination sets total volumes over GD17 at 166m therms compared to the submission of 116m therms from SGN. 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 recent network design work as a basis for understanding the available properties in the area.

1.56 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 fully factored in to the licence application figures.

1.57 We have set pre-tax WACC at 6.2% in line with the licence application figure.

1.58 The modelling we have applied in the draft determination produces a significant drop in domestic distribution tariffs of 14% compared to the SGN submission.

Next Steps

1.59 Responses to this consultation should be received on or before 12 noon on Tuesday 31 May 2016.

1.60 We will reconsider our determination in light of the responses received to our consultation on this GD17 draft determination document. We envisage that this will entail a further phase of bilateral engagement between ourselves and the GDNs, as well as engagement with other key stakeholders.

1.61 We will be holding a workshop for stakeholders on 10 May 2016. This will provide an opportunity for stakeholders to understand the proposals outlined in this consultation and to give an opportunity for questions.

1.62 Our GD17 final determination is due to be published on 15 September 2016 and will account for our findings from consideration of the consultation responses received and comments made as part of this engagement.

1.63 The publication of the GD17 final determination will be accompanied by a consultation on related licence modifications, with the consultation period scheduled to end on 14 October 2016.

2 Introduction

Purpose of this Document

2.1 This document represents the draft determination for the GD17 price control process.

2.2 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]

2.3 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, proposed rate of return and forecast volumes.

2.4 This draft determination details the proposals of the Authority (the Utility Regulator, 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 proposals on consumers, in particular the expected impact on distribution charges and consumer bills.

2.5 We note that the proposals detailed in this draft determination are of provisional nature and subject to change as a result of responses and further information we receive during the consultation period on this draft determination.

Our Statutory Duties and Regulatory Principles

2.6 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[3], and by having regard to a number of matters, as set out more fully in the Energy (Northern Ireland) Order 2003.

2.7 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.

2.8 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.

[3] 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.

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

2.10 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.

2.11 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.

2.12 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).

2.13 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.

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

2.15 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.

2.16 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.

2.17 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.

2.18 This will be 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 will be scrutinised by us. In doing so, we seek to ensure that gas distribution licence holders deliver best value for money for all consumers.

2.19 Our approach is based on best practice regulation of natural monopolies. Our task essentially consists of 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.

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

Market Overview

2.21 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.

2.22 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.

2.23 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.

2.24 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.

GD14 Review

2.25 On 20 December 2013, we published the final determination for the GD14 price control period.[4] This is the price control for FE and PNGL covering the period from 1 January 2014 to 31 December 2016.

2.26 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[5].

2.27 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.

2.28 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.

2.29 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.

[4] Utility Regulator: GD14 Price Control for Northern Ireland’s Gas Distribution Networks 2014-2016, Final Determination, 20 December 2013.
[5] 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.

GD17 Outlook

2.30 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[6], 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[7]
- 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 20146 and published in its final version on 14 May 2015[8]
- 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[9] as well as details on any customer satisfaction surveys and other stakeholder engagement undertaken[10]

2.31 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.

2.32 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:

---

[6] Utility Regulator: Price Control for Northern Ireland's Gas Distribution Networks GD17, Discussion Document on Our Overall Approach, 19 December 2014.
[7] Utility Regulator: Price Control for Northern Ireland's Gas Distribution Networks GD17, Update on Our Overall Approach, 17 April 2015.
[8] 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.
[9] 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.
[10] See Utility Regulator: Price Control for Northern Ireland's Gas Distribution Networks GD17, Update on Our Overall Approach, 17 April 2015, paragraph 4.10.

- 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[11], the PNGL network extension to East Down[12] and SGN building the Gas to the West network[13]

2.33 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[14], with end date of 31 December 2022 for all three NI GDNs
- Form of price control[15]: Revenue cap for PNGL, price cap for SGN and switch from price cap to revenue cap for FE[16]
- Forecasting horizon: PNGL set to end in 2046, potential change for FE with new proposed end date in 2045[17] and SGN set to end in 2057

Structure of this Document

2.34 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 proposed key decisions of this price control process
- Chapter 2 Introduction provides an overview over the purpose of this GD17 draft 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 on the strategic context and key focus areas as proposed by each GDN with respect to the GD17 price control period

[11] For further details see section 4 Price Control Submissions, GD17 Outlook, FE.
[12] For further details see section 4 Price Control Submissions, GD17 Outlook, PNGL.
[13] For further details see section 4 Price Control Submissions, GD17 Outlook, SGN.
[14] For further details see section 3 Approach, Duration – UR Proposals.
[15] For further details on the different forms of price control see section 3 Approach, Form of Price Control – UR Proposals below.
[16] For further details see Utility Regulator: firmus energy (Distribution) Limited Licence, Outcome of Consultation paper on moving to revenue cap regime, 16 September 2015.
[17] For further details see section 11 Outputs, Outcomes and Allowances, **Error! Reference source not ound.**, Forecasting Horizon.

- 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 proposed 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 proposed allowances for the GD17 price control period
- 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 proposals for 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[87]
- 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 proposed licence modifications
- Chapter 13 Next Steps and Further Issues clarifies details relating the consultation processes, provides an overview over the proposed next steps and summarises consequential changes as well as further issues we propose to address pursuant to the price control determination

2.35 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 for an overview over these annexes.

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

- Detailed Approach – UR Proposals
- FE – UR Proposals
- PNG – UR Proposals
- SGN – UR Proposals

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

2.38 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, this section will 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[18] as well as, where appropriate, the relevant alternative approach for such cases.

2.39 We consider that this structure will help increase the readability of this draft determination document through reducing duplication and enabling each GDN to quickly identify the sections of the document relevant to them.

[18] For an overview over key differences with respect to the regulatory treatment of the three NI GDNs see paragraph 2.32.

3 Approach

Price Control Process

Timelines and Stages

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

- Table 4 for milestones leading up to the publication of this GD17 draft determination; and
- Table 194 for the remaining milestones to be met after publication of this GD17 draft determination.

Key Milestones of GD17	
Key Points	**Proposed 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
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

Table 4: Price Control Process Key Milestones up to Publication of GD17 Draft Determination

3.2 On 19 December 2014, we published a discussion document on our overall approach for the GD17 price Control6, alongside with a draft template for the proposed GD17

business plan templates[19]. 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.

3.3 We received six responses[20] 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)

3.4 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 control7, 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 this GD17 draft determination document.

3.5 On 14 May 2015, we published the final GD17 business plan data templates with associated RIGs (regulatory instructions and guidance).8 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 3.4, they were furthermore granted an extension of the submission deadline which more than compensated for the delay.

3.6 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.[21]

[19] Utility Regulator: GD17 Business Plan Template, Draft, 19 December 2014.
[20] For further details see http://www.uregni.gov.uk/publications/gd_17_responses.
[21] 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.

3.7 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.

3.8 In addition, and in preparation of the publication of this 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 of this GD17 draft determination, and offered an opportunity to discuss these.

3.9 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.

3.10 We have considered the feedback received from the ongoing engagement with the GDNs and other key stakeholders in the present GD17 draft determination.

3.11 In preparation of the GD17 final determination, we require GDNs to resubmit their business plan templates, updated with 2015 actuals, by 30 June 2016. We note that this is not intended as an opportunity to resubmit a fully revised business plan. Rather, it is a pragmatic approach designed to allow us to account, in our final determination, for 2015 actuals rather than estimates.

3.12 In line with normal Annual/Cost Reporting timelines, this information would normally only become available on 30 September 2016, 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.

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

3.14 We will reconsider our determination in light of the responses received to our consultation on this GD17 draft determination document. We envisage that this will entail a further phase of bilateral engagement between ourselves and the GDNs, as well as engagement with other key stakeholders between June and September 2016.

3.15 Our GD17 final determination is due to be published on 15 September 2016 and will account for our findings from consideration of the consultation responses received and comments made as part of this engagement.

3.16 The publication of the GD17 final determination will be accompanied by a consultation on related licence modifications, with the consultation period scheduled to end on 14 October 2016.

3.17 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 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[22]. 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

[22] http://www.legislation.gov.uk/nisi/1996/275/contents.

decision on the proposed licence modifications to the CMA (Competition and Markets Authority).

3.18 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.[23]

3.19 In line with good regulatory practice, we plan to conduct a lessons learnt process to take place in the first 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

3.20 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.

3.21 Therefore, as detailed in our update on our overall approach to the GD17 price control7, we adopt and apply a number of principles during the price control period to ensure our approach is proportionate. These principles are:

- GDN's business plan templates as published on the 14 May 20158, 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.
- 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.

[23] For further details on the reasons for the different start dates, see paragraph 3.51.

- 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.

3.22 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.

3.23 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.

3.24 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.

3.25 We also propose to 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.

3.26 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.

3.27 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

3.28 During the consultation on our Discussion Document on our Overall Approach to GD17 we engaged with the following organisations on the area of consumer and stakeholder engagement:

- PNGL
- FE
- SGN
- Consumer Council for Northern Ireland (CCNI)
- Department for Enterprise, Trade and Investment (DETI)

3.29 It was agreed that it would be useful to have a roundtable discussion, with all parties present, which would see if a common ground could be established. Through roundtable discussion it became apparent that a lot of work was already undertaken by the GDNs in this area, with a different focus for each respective GDN. One common theme, for the GDNs, was the factors that influence the decision of consumers to connect to the natural gas network.

3.30 Given the limited time available for further development of stakeholder and consumer engagement into GDN business plans from publication of our update on our overall approach for the GD17 price control on 17 April 20157, it was not possible to include a separate and additional round of engagement to inform GD17 submissions using our preferred partnership approach.

3.31 Previous experience of including such engagement processes within network price control timelines strongly advise contributors start early, ideally two years in advance of business plan submission dates. This has been the lesson learned from both (i) PC13 and PC15 with NI Water, DRD, CCNI and ourselves as participants within what has become an established Consumer Engagement Oversight Group (CEOG) and (ii) RP6 the current price control for NIE Networks, whose consumer and stakeholder research has been overseen by a Consumer Engagement Advisory Panel (CEAP) of the company, DETI, CCNI and ourselves.

3.32 As part of the GD17 business plan submission requirements from GDNs we sought details of any consumer satisfaction surveys and other stakeholder engagement undertaken.

3.33 PNGL conducted a very comprehensive attempt towards consumer and stakeholder GD17 research, although consumers (and potential consumers) were drawn from PNGL's network area and as such, their research findings are therefore somewhat limited as regards applicability to their counterparts' network areas given distinct differences in socio-economic factors, for example. This research was aimed at reflecting more short term views in proximity to GD17 compared to the company's business as usual engagement over the years.

3.34 Much of the short term survey research was focused upon barriers to consumers connecting to gas alongside consumer willingness to support an extension to the gas network plus views on the free connections policy applying to domestic customers. Of note was a stakeholder consultation through use of a multi-method interview with 13 representatives of stakeholder organisations. Various strengths of view emerged regarding a continued free connection policy, the extension of the network where financially viable and targeting towards those in fuel poverty.

3.35 Whilst the PNGL research has been used to support the company's various submissions regarding network extension and connections growth, much of the analyses is focused on areas of the business which should enable the company to grow its gas business.

Such connections focused research is primarily the preserve of the company although as regulator we would need to appraise same in our assessment of the underpinning assumptions and research behind a company's business plan submission.

3.36 Of greater concern for consumers is the extent to which connections are successfully completed to the consumer's satisfaction and again, various elements of the company's other consumer research touch on these important issues. Given the maturity of the industry and age of network assets there does not appear to be much evidence of consumer dissatisfaction. Rather, the evidence we examined indicates a much improved situation for consumers in the current decade, compared to early years, with the percentage of connected consumers surveyed prepared to recommend installing PNG to a friend running in the high 90 percents.

3.37 In 2014 customers have been given additional protection with regards to the introduction of Gas Individual (Guaranteed) Standards of Service in Northern Ireland[24].

3.38 FE conducts various types of consumer and stakeholder research and engagement and provided examples. The former focused upon customer feedback from infill domestic connection zones and opined upon the reasons for customers not proceeding to gas connection despite an initial contact with FE. The latter focused upon local elected representatives and officials within their Ten Towns area.

3.39 SGN made representations with regards planned stakeholder engagement across a wide variety of channels of engagement thought necessary to enable their connected base to grow. An approach starting from scratch prompts an immediate requirement to avoid, "re-inventing 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 consumer research and stakeholder engagement.

3.40 We remain of the belief that the work undertaken during consultation of our Approach to GD17 provides a solid foundation to develop 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 commitment towards working together with other GDNs in a collaborative approach to research going forward during the GD17 period as stated within its GD17 submissions.

3.41 A key developmental output for GD17 is for the GDNs to engage with ourselves, CCNI and DETI so that we might focus explicitly upon how consumer and stakeholder engagement can influence and impact upon GD23 to agreed timelines, to ensure such deliberative research is progressed in time to influence GD23's decision points.

3.42 An important consideration will be the examination of the specific opportunity to pool consumer research resources so we might resource a greater consumer and stakeholder engagement effort which shall benefit GD23 and ultimately all consumers.

General Stakeholder Engagement

3.43 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

24 http://www.consumercouncil.org.uk/filestore/documents/Gas_Individual_GSS_Factsheet_Final_October_2014.pdf

account of stakeholders' views in making a final determination and secure a successful outcome of GD17.

3.44 As shown in Table 4: Price Control Process Key Milestones up to Publication of GD17 Draft 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.

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

Duration – UR Proposals

3.46 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

3.47 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.[25] 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.[26]

3.48 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.

3.49 We therefore indicated in our update on overall approach for the GD17 price control[27] our decision to adopt a duration of six years for the GD17 price control period.

3.50 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.

3.51 This is because the first operational commencement date, when gas is due be available in the G2W SGN towns, is the final quarter of 2017 and was consulted on as part of the SGN licence process which sets out that the first price control period for SGN starts on 1 January 2018. Any relevant capital and operational expenditure that was reasonably

[25] See Utility Regulator: GD14 Price Control for Northern Ireland's Gas Distribution Networks for 2014-2016, Final Determination, 20 December 2013, paragraph 3.19.
[26] 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.
[27] See Utility Regulator: Price Control for Northern Ireland's Gas Distribution Networks GD17, Update on Our Overall Approach, 17 April 2015, paragraph 2.6.

incurred as well as any revenues received prior to that date will be considered as part of the opening TRV**Error! Bookmark not defined.** for SGN.[28]

3.52 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.

Form of Price Control – UR Proposals

3.53 As indicated in paragraph 2.12 above, 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.

3.54 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.

3.55 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.

3.56 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[29] our intention to consult on whether to change this to a revenue cap as part of GD17.

3.57 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. [30] We reiterated our minded 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. [31] We thus asked FE to submit their GD17 business plan in line with the requirements of a revenue cap form of price control.

[28] For further details see Condition 4.4.5 of the SGN conveyance licence.
[29] For further details see Utility Regulator: GD14 Price Control for Northern Ireland's Gas Distribution Networks for 2014-2016, Final Determination, paragraph 16.17.
[30] See Utility Regulator: Price Control for Northern Ireland's Gas Distribution Networks GD17, Update on Our Overall Approach, 17 April 2015, paragraph 3.146.
[31] 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

3.58 On 18 June 2015, we published a consultation on changing the price control format for FE.[32] 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.

3.59 On 16 September 2015, we published, following due consideration of the responses received to that consultation, our decision to change the form of price control for FE from a price cap form of control to a revenue cap.[33] 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. We envisage to provide further information on these licence modifications as part of the preparation of the GD17 final determination, as relevant and appropriate

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 do not propose any changes to these arrangements for the GD17 price control period.

[32] Utility Regulator: Consultation on modifications to the Price Control conditions of the Firmus energy (Distribution) Limited Licence, 18 June 2015.
[33] Utility Regulator: Firmus energy (Distribution) Limited Licence, Outcome of Consultation paper on moving to revenue cap regime, 16 September 2016.

4 Price Control Submissions

GD14 Review

Overview

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

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

4.3 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.

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

4.5 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.

4.6 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 5: GD14 Review – FE

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

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

4.9 We have requested more detailed explanation from FE on why its figures are so volatile over different years but at this point we are not clear on the reasoning and discuss this further in paragraph 6.34

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 6: GD14 Review – PNGL

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

GD17 Outlook

Overview

4.11 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.

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

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

FE

4.14 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 serves over 25,000 customers and transport around 55 million therms of natural gas per year.[34]

4.15 In developing its network, FE has 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.[35]

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

- increasing connections off the network infrastructure already built; and
- further roll-out of their network infrastructure.[35]

4.17 To support their plans for network roll-out, FE has developed a detailed construction programme for the GD17 price control period as well as a high-level programme for the

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

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.[36]

4.18 FE has built their 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. [37]

4.19 With their infill programme, FE plans to achieve the following during the GD17 price control period:[38]

- 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

4.20 Furthermore, FE aims to achieve a penetration rate for its total licensed area of 65% (expressed as connections as a proportion of total properties passed by the network) by the end of 2045.[39]

4.21 FE considers that through implementing this infill programme, it 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

4.22 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.

4.23 Over the years, PNGL has 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 had been connected.[40]

4.24 For the GD17 price control period, PNGL proposes to make gas available to c.23,000 additional properties and to connect c.50,000 properties, including c.24,000 owner occupied ones.[41]

4.25 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*."[42]

4.26 We note that the GD17 business plan presented by PNGL and the figures detailed in paragraph 4.24 do not account for the extension of the PNGL licensed area to East

[36] See firmus energy: GD17 Business Plan, October 2015, p.30.
[37] See firmus energy: GD17 Business Plan, October 2015, p.11.
[38] See firmus energy: GD17 Business Plan, October 2015, pages 9, 10 and 29.
[39] See firmus energy: GD17 Business Plan, October 2015, p.32.
[40] PNGL: GD17 Business Plan, p. 3.
[41] PNGL: GD17 Business Plan, p. 7.
[42] PNGL: GD17 Business Plan, p. 8.

Down. The reason for this is that the decision to grant this extension was made on 10 December 2015[43], i.e. after the timeline for the submission of the GD17 business plan on 30 September 2015.

4.27 The proposed figures for properties passed and connections in East Down are shown in Table 7.

	2017	2018	2019	2020	2021	2022
Properties Passed (cumulative)	3,884	7,768	11,653	15,537	19,421	23,305
Connections (cumulative)	342	762	1,233	2,008	2,808	3,613
Volumes (therms)	191,198	410,952	665,545	1,080,817	1,473,581	1,895,682

Table 7: East Down – Properties Passed, Connections and Volumes as Proposed by PNGL

4.28 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 their proposal to develop their 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. [44] 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*."[43]

4.29 As part of the ongoing engagement with PNGL in preparation of this GD17 draft determination we have asked the company to provide us with details of the expected impact of the East Down project on GD17. We have included East Down figures within our analysis as we view East Down as being a fundamental part of the PNGL licence area. We note that we consider the GD17 draft determination to be a consultation on these matters and East Down is covered further from paragraph 11.101.

SGN

4.30 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.

4.31 On 6 February 2014 we published the G2W Applicant Information Pack (AIP).[45] 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

[43] 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.
[44] 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.
[45] Utility Regulator: Gas Network Extensions in Northern Ireland, Gas to the West: Applicant Information Pack, 6 February 2014.

and subsequent price control processes. This was to incentivise applicants to submit realistic bids.

4.32 With respect 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."[46] We also clarified that, "as with capex, a number of items could be adjusted under an uncertainty mechanism".[47]

4.33 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".

4.34 The Applicant Information Pack also clarified "that we intended to use the pattern of volumes and connections derived from the FMA study48 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 setting of the first price control, we would consider if these needed to be reflected in the development plan and price control values". [49]

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

4.36 Thus in advance of GD17, it is clear that UR 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.

4.37 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.

---

[46] Utility Regulator: Gas Network Extensions in Northern Ireland, Gas to the West: Applicant Information Pack, 6 February 2014, paragraph 3.44.

[47] See Utility Regulator: Gas Network Extensions in Northern Ireland, Gas to the West: Applicant Information Pack, 6 February 2014, paragraph 3.47.

[48] 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.

[49] 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.

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

4.39 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.

4.40 In its GD17 submission SGN has proposed significant changes in its opex figures compared to those it submitted in its 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.

5 Volumes and Connections

Detailed Approach – UR Proposals

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

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

5.3 On 16 September 2015, we published, our decision[16] 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.

5.4 The SGN network is still at the very early stages of its development, with no customers planned until the end of 2016 at earliest. 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.

5.5 We have noted the questions about long term forecast of gas use in our depreciation discussion in paragraph 10.80 and will consider this further in the Final Determination.

FE – UR Proposals

Connection Assumptions

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

5.7 Detailed information on OO connections can be found in section 6.

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

5.9 Our determined connection targets are set out in the table below.

Connections	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 8: Draft Determined Connections for FE

Draft Determination of Volumes

5.10 The below table shows FE draft determinated volumes.

Volumes (Therms)	2017	2018	2019	2020	2021	2022	Total
Domestic	10,151,055	11,645,555	13,273,055	15,024,055	16,889,055	18,849,055	85,831,830
Small & Medium	15,793,478	16,357,533	16,909,346	17,449,105	17,976,998	18,493,206	102,979,666
Contract	36,035,593	35,700,025	35,700,025	35,700,025	35,700,025	35,700,025	214,535,716
Total	**61,980,126**	**63,703,112**	**65,882,425**	**68,173,185**	**70,566,077**	**73,042,286**	**403,347,212**

Table 9 FE Draft Determination of Volumes

PNGL – UR Proposals

Connection Assumptions

5.11 Our draft determination allows for 49,670 connections during the GD17 period.

5.12 Detailed information on OO connections can be found in section 6.

5.13 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 draft determination, we have included 2000 new build properties per annum.

5.14 Our draft determined connection targets are set out in the table below

Connections	2017	2018	2019	2020	2021	2022	Total
Domestic – OO	5,670	5,390	5,120	4,860	4,600	4,200	29,840
Domestic – NB	2,000	2,000	2,000	2,000	2,000	2,000	12,000
Domestic – NIEH	1,000	1,000	1,000	1,000	1,000	1,000	6,000
Domestic – I&C	305	305	305	305	305	305	1,830
Total	**8,975**	**8,695**	**8,425**	**8,165**	**7,905**	**7,505**	**49,670**

Table 10: Draft Determined Connections for PNGL

Draft Determination of Volumes

5.15 The below table shows PNGL draft determinated volumes.

Volumes (Therms)	2017	2018	2019	2020	2021	2022	Total
Domestic	72,721,411	75,996,053	79,142,389	82,215,055	85,206,820	88,071,803	483,353,530
Tariff	27,987,562	28,483,416	28,999,975	29,570,275	30,092,297	30,613,831	175,747,357
Contract	48,365,392	48,490,392	48,615,392	48,740,392	48,865,392	48,990,392	292,067,354
Total	**149,074,365**	**152,969,861**	**156,757,756**	**160,525,722**	**164,164,509**	**167,676,026**	**951,168,241**

Table 11 PNGL Draft Determination of Volumes

SGN – UR Proposals

Assessment of SGN Volumes for GD17

Overview

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

5.17 We stated in our GD17 approach document that we will use the profiles included in the Application Information Pack (AIP) [45] as a starting point for setting SGN volumes.

5.18 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.

5.19 We set out in our AIP[45], 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.

5.20 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.*"

5.21 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.

5.22 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.

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

Domestic

5.24 SGN has presented a number of figures (a) in its GD17 business plan and (b) in its 2014 network design. We understand the business plan figures are unfinished and so we have relied upon the 2014 network design to arrive at our initial volume figures.

5.25 The number of existing houses in the network design was 41,365 and a further 15,809 new builds where also assumed giving a total number of domestic households over the lifetime of the project of 57,174. We have assumed that within the existing houses of 41,365 there are 5,312 NIHE households (taken from the AIP profile).

5.26 SGN used an 85% penetration rate in their November 2014 design review. We have included a 70% penetration rate for existing households which is based on the AIP profile in this draft determination. We will consider the 70% penetration rate further and we may consider using a penetration rate of 85% in our final determination.

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

5.28 SGN assumed a penetration rate of 90% on new builds in the network design. We have also included 90% within our draft determination.

5.29 The below table shows SGN connection numbers based on the above assumptions.

SGN connection numbers	Penetration rate	2017	2018	2019	2020	2021	2022	Total
Existing Owner Occupied Households	70%	-	1,294	2,588	3,397	4,206	5,015	16,500
Existing Housing Executive Households	100%	-	1,062	1,328	1,594	1,859	2,125	7,968
Total Existing Households		**-**	**2,357**	**3,916**	**4,991**	**6,065**	**7,140**	**24,469**
New Households	90%	**-**	**-**	**352**	**683**	**1,074**	**1,442**	**3,551**
Total Households		**-**	**2,357**	**4,269**	**5,673**	**7,140**	**8,582**	**28,020**

Table 12: SGN Connection Numbers

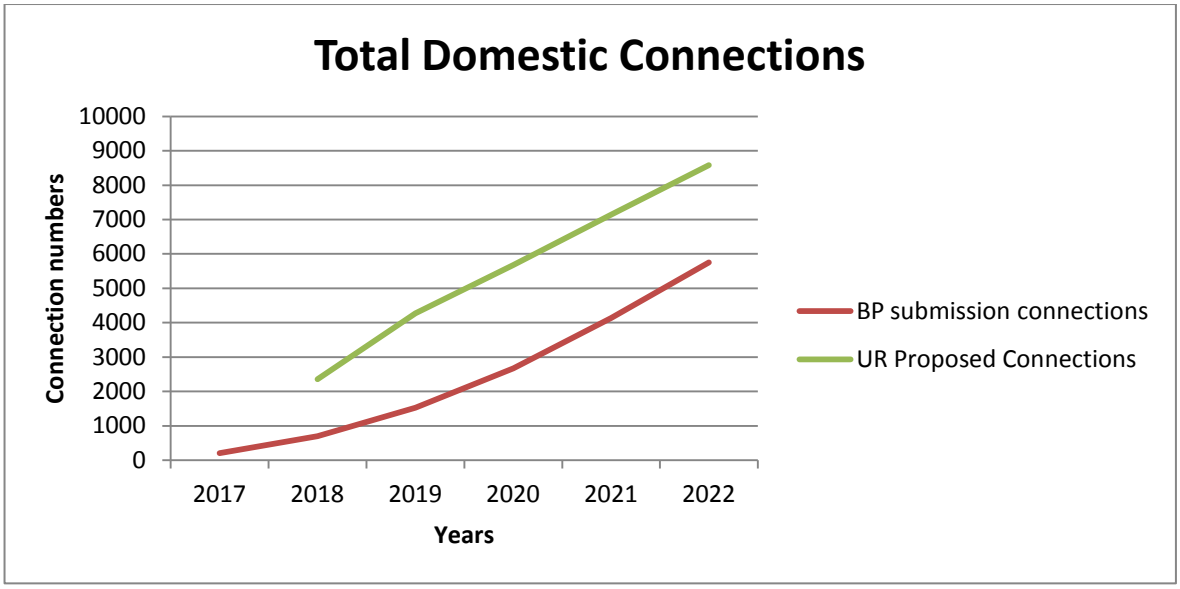


Figure 1: SGN Total Domestic Connections

5.30 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.

5.31 The below table shows SGN volumes based on the above assumptions.

Volumes (Therms)	2017	2018	2019	2020	2021	2022	Total
Existing	-	491,800	983,600	1,290,975	1,598,350	1,905,725	6,270,449
NIHE	-	403,712	504,640	605,568	706,496	807,424	3,027,840
New Build	-	-	133,808	259,368	408,227	547,994	1,349,396
Total	-	**895,512**	**1,622,047**	**2,155,910**	**2,713,073**	**3,261,143**	**10,647,685**

Table 13: SGN Volumes for Domestic Customers Based on Average Burn Assumptions

Small and Medium I&C

5.32 SGN are currently developing the detailed design of the network and further information on small and medium I&C customers will be available in April 2016 (see paragraph13.19 for further details). Due to the lack of detailed information, we have included in the draft determination the SGN business plan volumes to a total of 1.9m therms by year 40. This is likely to change in the final determination when the detailed design of the network is available.

5.33 Table 14 below shows the assumed volumes over the GD17 period.

Volumes (Therms)	2017	2018	2019	2020	2021	2022	Total
Small and Medium	-	2,058	39,325	125,798	204,436	272,559	644,176

Table 14: SGN Volumes for Small and Medium I&C Customers

Large I&C

5.34 The SGN business plan template does not separate large customers from contract customers. We have assumed that any customers between 25,000 therms and 75,000 therms are large customers with greater than 75,000 therms being contract customers. There are 49 large customers included in the SGN submission. SGN assumed that all customers would be connected but only burn to 80% of their potential giving 1,906,400 therms by the end of GD17.

5.35 We have arrived at the same figure by following a different approach. We consider that the potential burn per annum is 2,383,000 therms but then applied the AIP connection profile of year 1, 0%; year 2, 40%; year 3, 80%

5.36 Table 15 below shows the assumed volumes over the GD17 period.

Volumes (Therms)	2017	2018	2019	2020	2021	2022	Total
Profile	0%	40%	80%	80%	80%	80%	
Large	-	953,200	1,906,400	1,906,400	1,906,400	1,906,400	8,578,800

Table 15: SGN Volumes for Large I&C Customers

Contract I&C

5.37 SGN I&C contract volume included in the GD17 Business Plan was also submitted 80% of the potential load, on the basis that some customers would not burn the full forecast annual quantity for the full price control period.

5.38 SGN consider that it would not be prudent to include a 100% volume assumption in the GD17 period and consider 80% much more creditable. They consider there is a

significant risk of under recovery which would lead to an increase in tariffs at a critical time resulting in a significant detrimental impact.

5.39 The business plan has 25 users with greater than 75,000 therms adding to a total of 22.2m therms by year 2022.

5.40 As set out in paragraph 5.24 above we have based our proposals on the SGN network design figures. These assumed IC contract load of 37.6m therms. This included one company which we understand has since shut and we propose to remove this 3.4m therms leaving 34.2m therms.

5.41 The 34.2m therms includes 27.2m existing consumption and also identified 7.0m therms of additional load for plant expansion and CHP opportunities. We have assumed that 50% of the additional 7.0m therms will burn within the price control period. Therefore the total contract therms is 30.7m therms.

5.42 The AIP profile for contract customers is year 1, 25%; year 2, 75%; year 3, 100%. We have included in the draft determination the AIP profile based on the network design. We are assuming the 25% related to 2017 and this is in line with SGNs business plan. This figure will be used to calculate revenues in 2017 which will impact on the SGN opening asset value.

Volumes (Therms)	2017	2018	2019	2020	2021	2022	Total
Profile	25%	75%	100%	100%	100%	100%	
Contract	7,674,113	23,022,387	30,695,500	30,695,500	30,695,500	30,695,500	153,482,500

Table 16: SGN Volumes for Contract I&C Customers

Draft Determination of Volumes

5.43 The following Table summarises the analysis above and sets out the total draft determination figures for SGN, by category and by year.

Volumes (Therms)	2017	2018	2019	2020	2021	2022	Total
Domestic	-	896,512	1,622,047	2,155,910	2,718,073	3,261,143	10,647,685
Small & Medium	-	2,058	39,325	125,798	204,436	272,559	644,176
Large	-	953,200	1,906,400	1,906,400	1,906,400	1,906,400	8,578,800
Contract	7,674,113	23,022,387	30,695,500	30,695,500	30,695,500	30,695,500	145,808,387
Total	**7,674,113**[50]	**24,873,159**	**34,264,274**	**34,884,611**	**35,520,413**	**36,136,607**	**165,679,048**

Table 17: SGN Draft Determination Volumes Summary

5.44 As above we would highlight that the SGN business plan figures are not fully developed and we will consider further when SGN provide this data in April. However we can still see from the table that considerable difference arise from the assumptions made. The SGN figures do not assume the same profile as the AIP date. In some cases the AIP data was actually lower than the SGN business plan submission. However, overall, application of the AIP data increases the volumes and this is most clearly see in the case of Contract I&C customers.

[50] This figure is not included in total as it is outside the price control period.

5.45 As discussed in section 4, UR view the application of the principles set out at the time of the G2W licence competition as important element of this price control and this draft determination figures are in line with the principle.

5.46 Table 18 and Figure 2 below highlight the main areas of difference between the SGN business plan submission and the draft determination figures and we note that the SGN submission did not align with the AIP.

Therms	2017	2018	2019	2020	2021	2022	Total
GD17 Requested Volumes	-	17,688,188	21,893,163	24,652,573	25,416,611	26,257,894	115,908,428
Draft Determined Volumes	7,674,113	24,873,159	34,264,274	34,884,611	35,520,413	36,136,607	165,679,048
Variance Determination Increase / (Decrease)	7,674,113	7,184,971	12,371,111	10,232,038	10,108,802	9,878,713	49,770,635
Variance %	100%	41%	57%	42%	40%	38%	43%

Table 18: Differences between the SGN Business Plan Submission and the Draft Determination with Respect to Volumes

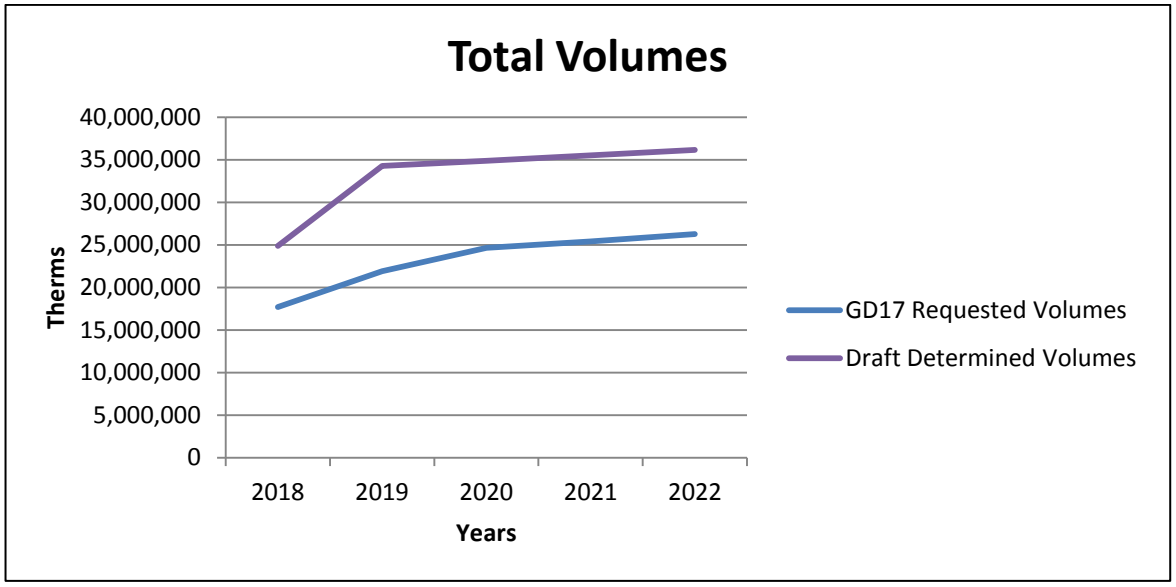


Figure 2: SGN Total Volumes

6 Opex

Detailed Approach – UR Proposals

Overview

6.1 This is the first price control for the GDNs where we have applied top down opex benchmarking as well as bottom up. We present initial figures from our indicative top down work in this draft determination but highlight that we will continue to work on the analysis with the GDNs before we conclude on our econometric modelling. Therefore, we have decided to apply the results of our bottom-up opex assessment in the figures used in the draft determination and this Chapter is largely focused on the bottom up analysis.

Top-Down Assessment

6.2 We have carried out top down benchmarking with GB GDNs, taking expert econometric advice from Dr Alan Fernihough of Queen's University, Belfast as well as Deloitte LLP. The latter has provided expert advice / input to the development of models which provide us with some indicative findings for this draft determination, see Annex 4 – GD17 Efficiency Advice, Relative efficiency of NI Gas Distribution Networks (Deloitte LLP).

6.3 Our modelled opex includes a number of data adjustments to both NI and GB GDN opex to ensure "like for like" comparison when benchmarking, see Annex 5 – Indicative findings from top-down benchmarking: GD17.

6.4 Our indicative findings for PNGL and FE support a reduction to company claimed opex within the 12% to 30% range across the GD17 period, taken from our preferred Model 3 and Model 5 respectively. Whilst both models include the use of a Composite Scale Variable (CSV) including customer numbers, volumes and network length we have specific modelling concerns remaining, hence these results remain indicative at the present time[51].

6.5 Further assessment of top-down disaggregated modelling might indicate further scope for efficiencies. This would likely be the case if we were to apply an asymmetric approach, reducing opex to a more efficient level in areas of the business where there are clear inefficiencies whilst not taking into account, or netting off, for areas where efficiencies are apparent.

6.6 We intend refining further our indicative top down benchmarking through a process of further engagement upon how GDN special factor claims might be applied to the results of our benchmark modelling. This will start with our draft determination consultation and extend beyond. The culmination of this engagement around our benchmark modelling will see us begin to monitor local GDNs' respective efficiency performances within our Annual/Cost Reporting publications.

[51] Whilst 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.

Bottom-up Assessment

Overview

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

6.8 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.

6.9 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.

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

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

6.12 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 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.

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

Emergency Costs

Overview

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

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

6.16 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.

6.17 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.

6.18 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.

6.19 Annex 8 provides further description of this work, the detail behind the individual GDN assessments and the approach applied.

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

Network Maintenance

Overview

6.21 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.

6.22 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 draft determination allowances are reported net of contributions. We will continue to review and benchmark contributions for the final determination.

6.23 We have adopted different approaches for FE and PNGL for the draft 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 draft determination. We reviewed the new items of work identified by PNGL for GD17 and made reasoned adjustments to arrive at a draft 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 draft 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.

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

Real Price Effects, Productivity and Frontier Shift

Overview

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

6.26 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).

6.27 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	

6.28 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

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

FE – UR Proposals

Overview

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

Top-Down Assessment

6.31 We intend refining further our indicative top down benchmarking through a process of further engagement upon how FE special factor claims might be applied to the results of our benchmark modelling. This will start with our draft determination consultation and extend beyond. The culmination of this engagement around our benchmark modelling will see us begin to monitor FE's efficiency performance within our Annual/Cost Reporting publications.

Bottom-up Assessment

6.32 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.

6.33 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. Furthermore we have not provided for additional allowances within GD17 that were justified as a result of the change of ownership.

6.34 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. Therefore we regard it as reasonable to use 2014 costs after adjusting for these one off costs.

6.35 For the FE business plan submission in terms of Opex in general, it has requested substantially more allowances, compared to GD14, as a result of the accelerated build programmes, which leads to substantially more connections.

6.36 As mentioned at the start of section 6.8, GD17 has a different reporting template compared to GD14. However, the fundamentals necessary to run the business are still the same.

6.37 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.

6.38 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 ACT. 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.

6.39 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.

6.40 Given these issues we have utilised the 2014 year as a base year for analysing costs for FE and unless stated otherwise used historic trend analysis for only 2013 and 2014.

6.41 In GD14 we found that the FE business plan submission contained costs associated with the supply part of the FE business. At this point we have not found this to be the case with the FE GD17 business plan submission but will analyse this further, alongside the FE Supply price control, before the final determination is made.

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

Table 19: FE 2014 Actuals versus FE GD17 Submission, £m

6.42 FE in its GD17 Business Plan submission 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, a year in which FE did not spend within the GD14 allowance. 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)

6.43 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 & Telecomms	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
AMPR (OO)	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 20: FE Operating Expenditure GD17 Submission, £k

Key Cost Lines

Overview

6.44 Table 20 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.

6.45 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.

6.46 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

6.47 As described above, due to Manpower being such an integral part of the price control, we will consider the number of FTE's necessary to run an efficient business.

6.48 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	56.5	56.5	56.5	56.5	56.5	56.5
FE actual	53.7	59	60						

Table 21: FE FTE's Requested, 204 Actual and GD17 Determination

6.49 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

6.50 Table 21 sets outs FE requested allowances for FTE's for both GD14 and GD17. It can be observed that FE actual number of FTE's for 2014 was below its 2014 requested allowance in GD14 but in line with our GD14 allowance.

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

6.52 However we are not of the same opinion, that the level of resources and the need to have FTE's in place from day one is appropriate.

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

6.54 From a Salary prospective, FE stated 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*'

6.55 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.

Connective Incentive/ AMPR (OO)

6.56 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.

6.57 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.

6.58 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 was becoming less relevant.

6.59 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.

6.60 Costs for 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).

6.61 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.

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

6.63 We will now in turn deal with the Mechanism principles, used to calculate the allowance.

Mechanism Principles

6.64 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

- 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

6.65 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*

6.66 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 cut the incentive in half.

6.67 The GDNs have set out in significant detail, covered in sections below, the issues they are facing with connections and the risks of a halving of the connections incentive. We have taken these representations into account and propose to reduce the existing allowance on a glide path, from £573 to £420, over the 6 year duration of GD17, as in Table 22.

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

Table 22: FE Actual Connection Numbers versus GD14 UR Determination

6.68 In arriving at the overall connections package we will look at two key figures. These are a connection target and an allowance. We will consider each of these in turn.

Connection Numbers

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

	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	1980*	2000*

(* - 2015-16 is Best Estimates)

Table 23: FE Actual Connection Numbers versus GD14 UR Determination

6.70 Table 23 shows how FE has performed in terms of actual owner occupied connection numbers versus price control targets.

6.71 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*'.

6.72 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.

Also we need to consider what level of properties that remain to be connected to the network. As

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%

6.73 Table 24 demonstrates, another potential c. 40,000 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. As FE has been developing its network for nearly a decade, the level of penetration is still only 20%. We discuss this further, on dealing with issue on "Non-Additionality".

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 24: FE Connection Numbers and Properties Passed

6.74 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 25 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.

	GD17 DD					
FE Connection No's (OO)	2017	2018	2019	2020	2021	2022
FE GD17 Submission	2466	2537	2622	2753	3100	3246
UR determination	2628	2950	3300	3600	3900	4100

Table 25: GD17 Determined OO Connection Numbers

6.75 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)[52][, the Heat Scheme and the Affordable Warmth grant scheme[53], in delivering on social goals.

Connection Allowance

6.76 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

[52] In line with a decision published by the Utility Regulator in June 2015, this scheme will operate until 31 March 2017. For further details on this decision, see: Utility Regulator: Northern Ireland Sustainable Energy Programme, Decision Paper on proposal to extend programme and reallocate costs between customer groups, June 2015. For further details on the scheme see: Utility Regulator: Framework Document for the Northern Ireland Sustainable Energy Programme 2016-2017, September 2015.

[53] 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.

- Shared corporate overheads

6.77 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.

6.78 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.

6.79 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 FTE's in the GD17 business plan submission are in line with the GD14 allowances. We will review this further for the GD17 final determination. We have re-allocated 50% of the Head of Sales distribution costs to the AMPR owner occupied category and this is line with GD14.

6.80 We have maintained the percentage used for the apportionment of overheads from GD14 for GD17 i.e. 15% to reflect the number of FTE's 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.

6.81 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 individually for each cost category on the business support.

6.82 As in GD14, we introduced 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.

6.83 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.

6.84 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.

6.85 In line with GD14 and to maintain consistency with the other GDN's we are implementing a risk-reward mechanism to provide strong incentives for FE to outperform its connection targets.

6.86 In order to reinforce FE's incentive to connect customers, we will reward FE if it exceeds the target connections i.e. we will increase the per connection allowance for additional

connections exceeding the target number of connections by the same proportion that the connections target is overachieved. Conversely, a penalty will apply if FE fails short of the target connections i.e. we will reduce the per connection allowance by the same proportion that the connections target is underachieved. This under or outperformance would be capped at +/-50%.

6.87 To demonstrate how the incentive mechanism might work, consider the following examples:

Outperformance – the connection allowance is £520 and the target (excluding non-additional) connections is 2,213, but PNGL outperforms by connecting 2,434 OO customers (excluding non-additional). As the connections outperformance is 10% (= 2,434 / 2,213 – 1), a unit connection allowance of £572 (= £520 x (1+10%)) will be payable for the 221 extra connections gained; the standard allowance of £520 would still apply to the original 2,213 connections. Total allowances would therefore equal £1,277,055 (i.e. (£520 x 2,213) + (£572 x 221)).

Underperformance – the connection allowance is £520 and the target (excluding non-additional) connections is again 2,213, but PNGL this time underperforms by connecting 1,991 OO customers. As the connections underperformance is 10% (= 2,213 / 1,991 – 1), the unit connection allowance payable will be £468 (= £520 x (1-10%)) for all connections (excluding non-additional). Total allowances in this case would equal £931,905 (i.e. £468 x 1,991).

6.88 All connections allowances claimed by GDN's must relate to properties which have a supplier and are burning gas. We plan to review the mechanisms in place to ensure this is appropriate. We expect the GDN's to be able to demonstrate that all connections have a supplier agreement in place and burn a minimum quantity of gas.

6.89 We note that the GDN's have raised concerns with the application of the owner occupied incentive mechanism as it applied in GD14. They have made the argument that the connection incentive should be calculated over the entire price control period rather than on an annual basis.

6.90 We would welcome views on this proposal and further analysis from the GDN's on this issue as part of their response to the GD17 draft determination.

Advertising & Market Development (non OO)

6.91 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.

6.92 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 £353,855. FE had 5.9 FTE's employed within the advertising and market development (non OO) category in 2014 and is proposing to reduce the level of FTE's to 3.4 FTE's in GD17.

6.93 We consider that the FE proposed reduction in FTE's 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 FTE's and using 2014 staff costs.

6.94 We have 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 consider that they will spend time on Advertising and Market development for non-

owner occupied connections. This is consistent with our approach in GD14 and consequently we have rolled forward the amount we re-allocated in GD14.

	2017	2018	2019	2020	2021	2022
FE requested allowances	239.7	239.7	239.7	239.7	239.7	239.7
UR DD before re-allocation	231.2	231.2	231.2	231.2	231.2	231.2
Re-allocation of Head of Sales to AMPR (OO)	12.8	12.8	12.8	12.8	12.8	12.8
UR Draft Determination	218.4	218.4	218.4	218.4	218.4	218.4
Variance	21.3	21.3	21.3	21.3	21.3	21.3

Table 26: Advertising and Marketing (non OO) Costs, Requested and Allowed, £k

Work Management

Overview

6.95 Work Management covers the following cost categories

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

Asset Management

6.96 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

6.97 FE asset management costs are in the main driven by its associated manpower costs. In the 2014 year PNGL had Asset Management costs of £139,017 and had 1.8 FTE's employed within the Asset Management cost category. FE has proposed an additional FTE specifically an additional engineer for Asset Management in the GD17 period.

6.98 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 already allowed for an increase in FTE's for asset management in GD14.

	2017	2018	2019	2020	2021	2022
FE requested allowances	131.3	131.3	131.3	131.3	131.3	131.3
UR Draft Determination	79.8	79.8	79.8	79.8	79.8	79.8
Variance	51.5	51.5	51.5	51.5	51.5	51.5

Table 27: Asset Management Costs, Requested and Allowed, £k

Operations Management

6.99 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.; and
- 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

6.100 FE operations management costs are in the main driven by its associated manpower costs. In the 2014 year FE had Operations Management costs of £186,806 and had 11.6 FTE's employed within the Operations Management cost category. FE has proposed that there should be 16.6 FTE's for Operations Management in the GD17 period.

6.101 We consider that an increase in FTE's is appropriate for Operations Management in the GD17 period given the extent of FE planned network development. We have provided for an increase of 2 FTE's when compared to the 2014 actual FTE, however this is still lower than FE requested FTE's.

	2017	2018	2019	2020	2021	2022
FE requested allowances	379.5	379.5	379.5	379.5	379.5	379.5
UR Draft Determination	281.8	281.8	281.8	281.8	281.8	281.8
Variance	97.7	97.7	97.7	97.7	97.7	97.7

Table 28: Operations Management Costs, Requested and Allowed, £k

Customer Management

6.102 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.

6.103 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 £254,373 and had 8.9 FTE's employed within the Customer Management cost category. FE has proposed a marginal increase in FTE's for Customer Management in the GD17 period i.e. from 8.9 FTE's in 2014 to 9.3 FTE's in the GD17 period.

6.104 We do not consider that an increase in FTE's for Customer Management from the 2014 figure is appropriate. However we have not re-allocated any FTE's from Customer Management to the advertising and market development owner occupied cost category as the FE allocation of FTE's between customer management activities and sales related activities appears consistent with our allowances in GD14. We intend to review this further for the GD17 final determination.

6.105 In addition, FE has proposed a significant increase in professional and legal costs from circa £13,000 in 2014 to circa £204,000 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)*".

6.106 We not consider that it is appropriate for consumers to fund these professional and legal costs since they appear to be related to the change in ownership of FE. We note that the other GDN's do not have 'professional and legal' fees costs under the Customer Management cost category.

	2017	2018	2019	2020	2021	2022
FE requested allowances	477.6	479.2	456.8	458.4	461.9	465.6
UR Draft Determination	252.6	252.6	252.6	252.6	252.6	252.6
Variance	225.0	225.0	225.0	225.0	225.0	225.0

Table 29: Customer Management costs, Requested and Allowed, £k

System Control

6.107 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).

6.108 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

6.109 FE system control costs are in the main driven by its associated manpower costs. In the 2014 year PNGL had manpower costs of £101,838 and had 3.1 FTE's employed within the System Control cost category. FE has proposed an additional 1.4 FTE for System Control in the GD17 period.

6.110 We do not consider that an increase in FTE's is necessarily required for System Control is required 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
FE requested allowances	211.8	211.8	211.8	211.8	211.8	211.8
UR Draft Determination	165.0	165.0	165.0	165.0	165.0	165.0
Variance	46.8	46.8	46.8	46.8	46.8	46.8

Table 30: System Control Costs, Requested and Allowed, £k

Emergency Costs

Overview

6.111 FE has requested a total allowance of £1.3 million in 2017 rising to £2.0 million in 2022, to cover the cost of the emergency call centre, emergency first response and repairs (although we note that this includes £2.13m over the period which has subsequently been removed/reallocated). For comparison, historical actual costs for 2013-2014 averaged around £0.8 million.

6.112 Table 31 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 31: Emergency Costs Submitted by FE

6.113 Table 32 summarises the draft determination allowances for FE under each emergency expenditure category.

	2017	2018	2019	2020	2021	2022	GD17 Total
Call centre (£k)	197	204	212	219	228	236	1,296
First response (£k)	668	719	769	820	879	934	4,789
Repair activities (£k)	53	56	59	62	66	69	366
Total (£k)	919	979	1,040	1,102	1,173	1,239	6,451

Table 32: Emergency Costs Allowed in the Draft Determination for FE

6.114 Figure 3 shows FE's GD17 allowances against the submission, historical actuals and the allowances for GD14.

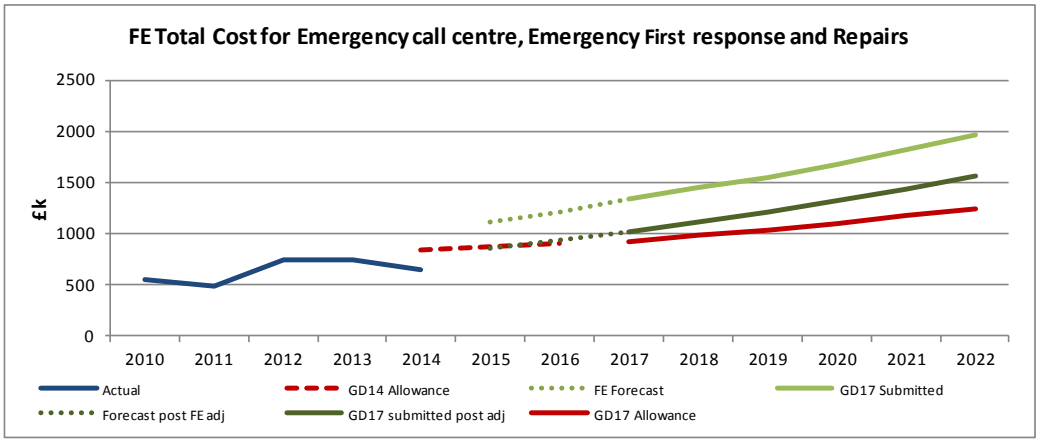


Figure 3: FE Total Cost for Emergency Activities

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

- Removal of £1.1m of professional and legal fees from emergency call centre costs.
- Call volume modelling was used to assess the cost for the call centre. This carried forward the call reduction targets applied in GD14 and resulted in an additional reduction of £140k 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.
- The number of estimated emergency jobs was adjusted to align with modelled call numbers to assess the cost for emergency first response activity. In addition a lower unit rate of £5 was applied to jobs closed without a visit. The combined effect resulted in an additional reduction of £1.1m 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.

Network Maintenance

Overview

6.116 In its Business Plan FE identified net costs of network maintenance rising from in £466k in 2015 to in £1 441k in 2022 (a 209% increase). The expenditure profile proposed by the company is shown in Figure 4.

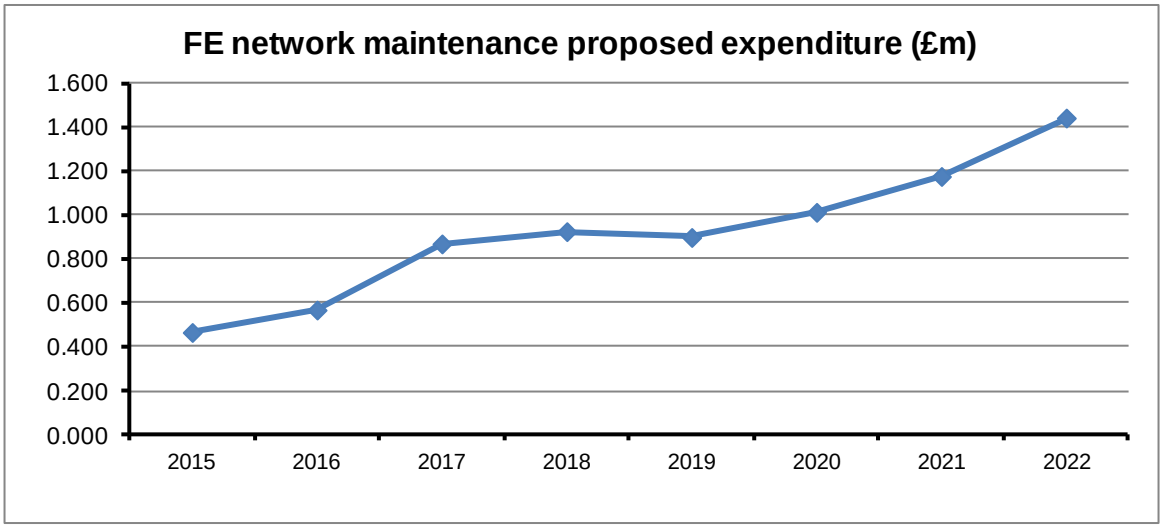


Figure 4: FE Proposed Network Maintenance Expenditure (£m)

6.117 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

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

6.119 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.

6.120 To address the opportunities for synergies in the FE cost estimates we have developed a benchmarking process for our draft determination 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.

6.121 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 £9.5 for the PNGL draft determination.

6.122 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.

6.123 A review of the detailed bottom up estimate prepared by FE revealed that there are 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.

6.124 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 33.

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 year previously.	147
10 year cycle – I&C For example: I&C MP regulator maintenance and meter component replacement.	Number of I&C connections made 10 year previously.	405
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).	2.58
Annual – I&C For example: annual costs of I&C meter calibration	Current number of I&C connections.	81
Annual - mains The annual cost of maintenance of gas mains valves and ancillaries	Length of mains.	81
One-off costs	Excluded from the analysis	
Fixed costs GIS costs, software licences and fees for base maps.	Per annum	165,219

Table 33: FE Network Maintenance Benchmarking Cost Drivers

6.125 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 27% lower than the benchmark calculated using unit rates derived from the FE bottom up cost estimate for GD14. For our draft determination, we applied a reduction of 25% to the variable costs estimated by FE to reflect this benchmarking exercise and added back the fixed and one-off costs proposed by the company. We will further review the one-off costs for the final determination.

6.126 The draft determination allowance for network maintenance costs in GD17 is £16.5 per weighted connection compared to £9.3 per weighted connection for PNGL.

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*
FE Business Plan variable costs (£k)	*624*	*686*	*692*	*806*	*1,003*	*1,269*
Draft determination - variable costs (£k)	468	515	519	605	752	952
One off costs (£k)	79	73	41	41	7	7
Fixed costs	165	165	165	165	165	165
Draft determination allowance (£k)	713	753	725	811	925	1,124

Table 34: FE GD17 allowance for network maintenance

Expenditure post GD17

6.127 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 connection 10 years previously, results in the cost per connection reducing to £11 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

6.128 FE has requested an allowance of circa £1300 pa in the GD17 period for 'other direct activities' and this has been accepted since it is below 2014 actual expenditure.

	2017	2018	2019	2020	2021	2022
FE requested allowances	1.3	1.3	1.3	1.3	1.3	1.3
UR Draft Determination	1.3	1.3	1.3	1.3	1.3	1.3
Variance	0	0	0	0	0	0

Table 35; Other Direct Activities Costs, Requested and Allowed, £k

Business Support Activities

Overview

6.129 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

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

6.131 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, 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 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.

6.132 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 £607,597. 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 £299,935 pa.

6.133 FE had 0.75 FTE's employed within IT & Telecoms cost category in 2014 and has proposed an increase in FTE's 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.

6.134 We have based the IT & Telecoms allowance for GD17 on 2014 FTE's but using 2014 staff costs and accepted the proposed professional and legal fees. We have not accepted the proposed increase in FTE's as we don't consider that consumers should fund the consequences of the change in ownership of FE.

6.135 We have re-allocated some of the costs under IT & Telecoms to the Advertising and Marketing (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 DD before re-allocation	245.1	245.1	245.1	245.1	245.1	245.1
Re-allocation to AMPR (OO)	44,9	44,9	44,9	44,9	44,9	44,9
UR Draft Determination	200.2	200.2	200.2	200.2	200.2	200.2
Variance	99.7	99.7	99.7	99.7	99.7	99.7

Table 36: IT & Telecoms Costs, Requested and Allowed, £k

Property Management

6.136 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.

6.137 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.

6.138 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.

6.139 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 will update the formula to take account of any information on 2016-17 rating valuations.

6.140 FE also has rent and rates costs in relation to its offices and these costs have been accepted for the draft determination. We will review these costs further for the final determination.

6.141 As per the treatment in GD14, the allowance for rates will be treated as pass-through, subject to FE demonstrating that it has taken appropriate actions to minimise valuations.

6.142 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.

6.143 We have re-allocated some of the costs under Office costs to the Advertising and Marketing (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 DD before re-allocation	732	796.1	824.9	855.4	887.3	920.5
Re-allocation to AMPR (OO)	2.3	2.3	2.3	2.3	2.3	2.3
UR Draft Determination	769.7	793.8	822.6	853.1	885.0	918.2
Variance	144.7	150.3	157.2	164.7	173.6	184.1

Table 37: Requested and Determined Property Management Allowances, £k

HR & Non-Operational Training

6.144 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.

6.145 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

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

6.147 In the 2014 year FE had HR & Ops training costs of £65,775. FE had 0.6 FTE's employed within HR and Ops training cost category in 2014 and has proposed an increase in FTE's of 0.6 in this area for the GD17 period.

6.148 We have based the HR and Ops training allowance for GD17 on the 2014 FTE's and rolled forward 2014 staff costs and 2014 professional and legal fees.

6.149 We have re-allocated some of the costs under HR and Ops training to the Advertising and Marketing (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 DD before re-allocation	65.7	65.7	65.7	65.7	65.7	65.7
Re-allocation to AMPR (OO)	5.0	5.0	5.0	5.0	5.0	5.0
UR Draft Determination	60.7	60.7	60.7	60.7	60.7	60.7
Variance	62.4	62.4	62.4	62.4	62.4	62.4

Table 38: HR & Non-Operational Costs, Requested and Allowed, £k

Audit Finance & Regulation

6.150 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.

6.151 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.

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

6.153 In the 2014 year FE had Audit Finance and Regulation costs of £416,321. FE had 7.4 FTE's employed within Audit Finance and Regulation cost category in 2014 and has proposed an increase of circa 1 FTE's in this area for the GD17 period. Part of this proposed increase relates to a 0.5 FTE for a regulatory analyst.

6.154 We have based the Audit Finance and Regulation allowance for GD17 on the 2014 FTE's and using 2014 staff costs and 2014 costs for professional and legal fees and accepted FE proposals for stationary, communications and billing costs.

6.155 We have re-allocated some of the costs under Audit Finance and Regulation to the Advertising and Marketing (OO) cost category 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 DD before re-allocation	478.2	478.2	478.2	478.2	478.2	478.2
Re-allocation to AMPR (OO)	61.9	61.9	61.9	61.9	61.9	61.9
UR Draft Determination	381.9	381.9	381.9	381.9	381.9	381.9
Variance	221.5	221.5	221.5	221.5	221.5	221.5

Table 39: Audit Finance & Regulation Costs, Requested and Allowed, £k

Insurance

6.156 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.

6.157 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.

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

6.159 The total insurance costs requested by PNGL 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.

6.160 In the absence of adequate justification warranting the magnitude of the claimed increases in business insurance, we have continued 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 are reasonable and therefore we have granted the requested costs.

6.161 Our determined allowances for 2017 - 2022 are shown in the table below along with FE requested allowances and the variance between the two. We have apportioned an element of the insurance allowance to be recovered through the Connection Incentive Mechanism.

6.162 We have re-allocated some of the costs under Insurance to the Advertising and Marketing (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 DD before re-allocation	164.4	170.7	178.2	186.1	194.5	203.1
Re-allocation to AMPR (OO)	0.64	0.64	0.64	0.64	0.64	0.64
UR Draft Determination	164.3	170.6	178.1	186.0	194.4	203.0
Variance	104.6	98.3	90.8	82.9	74.5	65.9

Table 40: FE Insurance Costs, Requested and Allowed, £k

Procurement

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

6.164 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.

6.165 FE procurement costs are driven by staff costs and professional and legal fees. In the 2014 year FE had procurement costs of £18,304. FE had 0.25 FTE's employed within the Procurement cost category in 2014 and has marginal increases in FTE's and professional and legal fees.

6.166 We have based the Procurement cost allowance for GD17 on the 2014 FTE's and using 2014 staff costs and rolled forward 2014 professional and legal fees.

6.167 We have re-allocated some of the costs under Procurement to the Advertising and Marketing (OO) cost category 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 DD before re-allocation	18.3	18.3	18.3	18.3	18.3	18.3
Re-allocation to AMPR (OO)	1.1	1.1	1.1	1.1	1.1	1.1
UR Draft Determination	17.2	17.2	17.2	17.2	17.2	17.2
Variance	10.7	10.7	10.7	10.7	10.7	10.7

Table 41: FE Procurement Costs, Requested and Allowed, £k

CEO & Group Management

6.168 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.

6.169 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.

6.170 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 FTE's for GD17 is similar to actual FTE in 2014.

6.171 We have rolled forward 2014 actual staff costs. We have also rolled forward 2014 actual costs for professional and legal fees as well as stationary, communications and billing costs.

6.172 We have re-allocated some of the costs under CEO & Group Management to the Advertising and Marketing (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 DD 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 Draft 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 42: CEO and Group Management Costs, Requested and Allowed, £k

Stores & Logistics

6.173 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.

6.174 FE has not requested an opex allowance for stores and logistics and therefore we have not provided for one. FE had opex of £27,234 for this cost category in 2014.

Trainees & Apprentices

6.175 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).

6.176 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.

6.177 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 £133,351 in each year of GD17. FE actually spent £66,019 on trainees and apprentices in 2014. The requested increase in allowances is driven from an increase of FTE's from 1FTE in 2014 to 2 FTE's in GD17 and by a circa 50% increase in professional and legal fees.

6.178 We have based our GD17 allowances on the actual number of FTE's in 2014 and rolled this forward the associated costs into GD17. We have not accepted the professional and legal fees into the GD17 period as we consider this expenditure was not justified within the FE GD17 business plan.

	2017	2018	2019	2020	2021	2022
FE requested allowances	133.4	133.4	133.4	133.4	133.4	133.4
UR Draft Determination	20.4	20.4	20.4	20.4	20.4	20.4
Variance	113	113	113	113	113	113

Table 43: Trainee's and Apprentice's Costs, Requested and Allowed, £k

Non-Controllable Opex

6.179 The only costs shown under non-controllable opex are FE licence fees. We have accepted FE 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
FE requested allowances	60	60	60	60	60	60
UR Draft Determination	60	60	60	60	60	60
Variance	0	0	0	0	0	0

Table 44: Non-controllable Opex Costs, Requested and Allowed, £k

Capitalised Opex

6.180 For the purpose of the GD17 draft determination we have accepted FE capitalisation rates, however we expect to review this further for the final determination.

Summary of Bottom-up Assessment Findings

6.181 Table 45 summaries the GD17 draft 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	79.8	79.8	79.8	79.8	79.8	79.8	479.1
Operations Management	281.8	281.8	281.8	281.8	281.8	281.8	1,691.0
Emergency Call Centre	197.2	204.4	211.6	219.1	227.6	235.5	1,295.6
Customer Management	252.6	252.6	252.6	252.6	252.6	252.6	1,515.9
System Control	165.0	165.0	165.0	165.0	165.0	165.0	990.2
Emergency	668.4	718.6	768.8	820.2	879.1	933.9	4,789.3
Metering	307.3	324.5	312.5	349.5	398.7	484.4	2,177.2
PRE Repairs	53.2	56.1	59.0	62.2	65.7	69.4	365.8
Maintenance	405.6	428.4	412.4	461.4	526.2	639.5	2,873.8
Other Direct Activities	1.3	1.3	1.3	1.3	1.3	1.3	7.7
IT & Telecomms	200.2	200.2	200.2	200.2	200.2	200.2	1,201.1
Property Man	769.7	793.8	822.6	853.1	885.1	918.2	5,042.5
HR & Non-Ops Training	60,7	60.7	60.7	60.7	60.7	60.7	364.5
Audit, Fin and Regulation	381.9	381.9	381.9	381.9	381.9	381.9	2,291.3
Insurance	164.3	170.6	178.1	186.0	194.4	203.0	1,096.4
Procurement	17.2	17.2	17.2	17.2	17.2	17.2	103.2
CEO & Group Management	146.7	146.7	146.7	146.7	146.7	146.7	880.2
AMPR (OO)	1,072.5	1,150.5	1,237.5	1,269.0	1,316.2	1,291.5	7,337.2
AMPR (non-OO)	218.4	218.4	218.4	218.4	218.4	218.4	1,310.2
Trainee's & Apprentices	20.4	20.4	20.4	20.4	20.4	20.4	122.4
Non Controllable Costs	60,0	60,0	60,0	60,0	60,0	60,0	360.0
Total	**5,524,706**	**5,733,392**	**5,888,946**	**6,106,805**	**6,379,339**	**6,661,755**	36,294,944

Table 45: Pre Efficiency Draft Determination (excluding AMPR re-allocated costs), £k

Triangulation of Top-Down and Bottom-up Assessment Findings

6.182 After comparing the various indicative results from our top-down opex benchmarking to our bottom-up opex assessment we recognise there is a requirement for further engagement with local GDNs to decide how we shall apply special factors (both positive and negative) before we conclude on our econometric modelling. For this draft determination, we have decided to apply the results of our bottom-up opex assessment.

Real Price Effects, Productivity and Frontier Shift

Overview

6.183 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: Draft Determination GD17.

Net Impact

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

PNGL – UR Proposals

Overview

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

Top-Down Assessment

6.186 We intend refining further our indicative top down benchmarking through a process of further engagement upon how PNGL special factor claims might be applied to the results of our benchmark modelling. This will start with our draft determination consultation and extend beyond. The culmination of this engagement around our benchmark modelling will see us begin to monitor PNGL's efficiency performance within our Annual/Cost Reporting publications.

Bottom-up Assessment

Overview PNGL OPEX – Pre Efficiency – September 2014 Prices

6.187 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.

6.188 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 have actual costs for one year of GD14.

6.189 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	2017	2018	2019	2020	2021	2022	Average GD17
	Actual	PNGL GD17 submission						
Opex, £m	14.5	16.9	17.3	17.5	17.7	18.0	18.3	17.6
OO connections	7751	4000	4000	4000	4000	4000	4000	4000

Table 46: PNGL GD17 Submission, £m

6.190 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)

6.191 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	571.1	552.0	552.6	553.2	3,322.7
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 & Telecomms	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	1,903.9	1,897.9	1,898.0	1,898.2	11,379.4
Stores and Logistics	29.8	29.8	27.6	29.8	29.8	29.8	176.7
AMPR (OO)	2,201.3	2,211.5	2,220.1	2,214.9	2,216.3	2,217.2	13,281.5
AMPR (non-OO)	263.5	267.8	271.7	268.0	268.2	268.3	1,607.7
Non Controllable Costs	115.5	115.5	115.5	115.5	115.5	115.5	693,215
Total	**16,881.5**	**17,289.8**	**17,465.4**	**17,653.0**	**17,987.7**	**18,270.4**	**105,548.1**

Table 47: PNGL Operating Expenditure GD17 Submission, £k

Key Cost Lines

Overview

6.192 Table 47 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), or due to other specific circumstances calling for individual treatment, irrespective of their magnitude.

6.193 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 47.

Manpower

6.194 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 Determination	124.2	125.7	124.8	120.8	120.8	120.8	120.8	120.8	120.8
PNGL actual	118.8	124.4	127.3						

Table 48: PNGL FTE's Requested, 2014 Actual and GD17 Determined

6.195 Table 48 sets outs PNGL's requested allowances for FTE's for both GD14 and GD17. It can be observed that PNGL's actual number of FTE's for 2014 was significantly below its 2014 requested allowance in GD14 as well as our GD14 FD allowance.

6.196 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 FTE's necessary to run the business are included in all FTE's, whether agency staff or otherwise, and see no reason why we should not use 2014 as a suitable base figure.

6.197 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.

6.198 We therefore have based the levels of FTE's on actual 2014 levels, with a small increase in relation to Customer Management, due to continuing cumulative connection numbers.

6.199 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.

Connective Incentive/ AMPR (OO)

6.200 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.

6.201 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.

6.202 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 was becoming less relevant.

6.203 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.

6.204 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).

6.205 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.

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

6.207 We will now in turn deal with the Mechanism principles, used to calculate the allowance.

Mechanism Principles

6.208 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

6.209 We have developed a model around the above formulae using estimates, where necessary, for some key assumptions within the formulae.

6.210 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

6.211 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 49: GD17 Connection Incentive Assumptions

6.212 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 cut the incentive in half.

6.213 The GDNs have set out in significant detail, covered in sections below, the issues they are facing with connections and the risks of a halving of the connections incentive. We have taken these representations into account and propose to reduce the existing allowance on a glide path, from £573 to £420, over the 6 year duration of GD17, as shown in Table 50.

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

Table 50: Connection Incentive Glide Path

6.214 In arriving at the overall connections package we will look at two key figures. These are a connection target and an allowance. We will consider each of these in turn.

Connection Numbers

6.215 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 5 which has been provided by PNGL gives a summary of PNGL view on factors it considers influenced connections numbers since 2010.

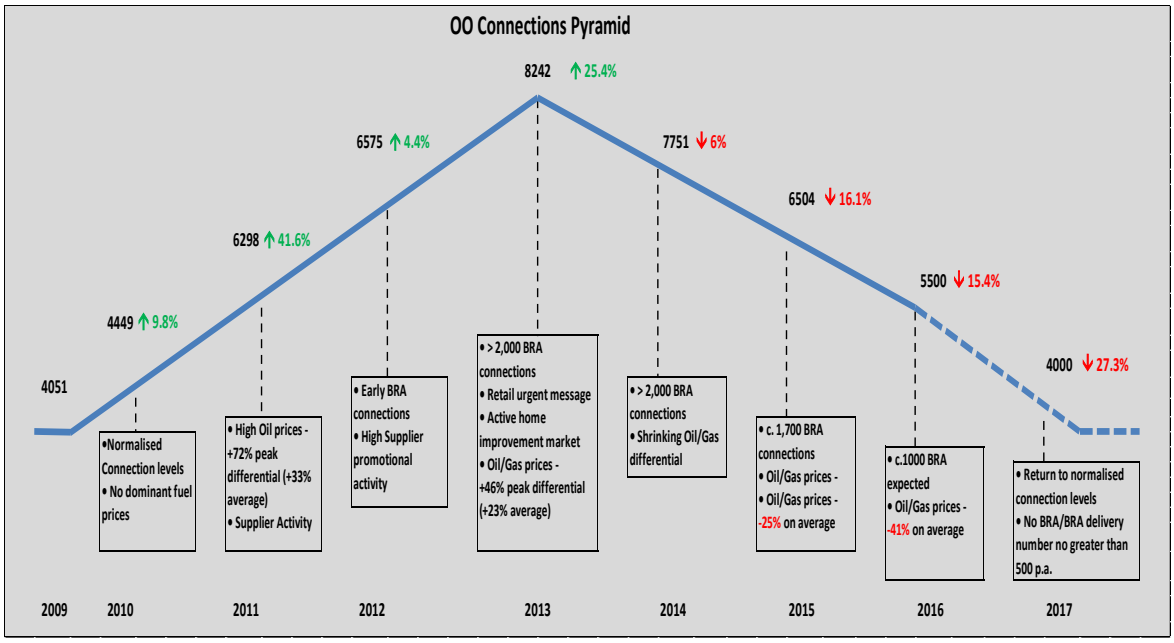


Figure 5: PNGL Graphical Representation of Issues Influencing Connection Numbers

6.216 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'.

6.217 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*'.

6.218 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".

6.219 On this basis PNGL has proposed an annual owner occupied connections target of 4000. We note that some of these arguments have put forward in previous price controls by PNGL and we have set out in Table 51 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

Table 51: PNGL Actual OO Connection Numbers v PNGL Requested Targets and UR Determined Targets

6.220 We have considered the PNGL arguments but do not believe they justify PNGL's proposal to reduce the connections target to 4000 pa. We consider using a 15 year average gives 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 disagree 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 consider using average data from the last 15 years as being relevant for consideration in arriving at a target for connection numbers.

6.221 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.

6.222 Using the 15 year average from 2000 to 2014 gives a figure of 5800 which is 700 less than the target in GD14. We consider that this gives an appropriate target for 2017 but recognise that over GD17 the ability to maintain this level is likely to diminish. This is particularly true in the context of a reduction in the level of new infill mains and the associated opportunity to get new connections from recently passed properties.

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 52: PNGL Connection Numbers and Properties Passed

6.223 Also we need to consider what level of properties remains to be connected to the network. As the

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%

6.224 Table 52 above 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.

6.225 Therefore, we are setting a figure based on the 15 year average connection rate, 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.

PNGL Connection Nos. - OO	2017	2018	2019	2020	2021	2022
PNGL Submission	4,145	4,145	4,238	4,433	4,452	4,428
GD17 Draft Determination	5,800	5,650	5,500	5,350	5,200	4,900

Table 53: OO Connection Numbers and Allowances

6.226 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)[54], the Heat Scheme and the Affordable Warmth grant scheme[55], in delivering on social goals.

[54] In line with a decision published by the Utility Regulator in June 2015, this scheme will operate until 31 March 2017. For further details on this decision, see: Utility Regulator: Northern Ireland Sustainable Energy Programme, Decision Paper on proposal to extend programme and reallocate costs between customer groups, June 2015. For further details on the scheme see: Utility Regulator: Framework Document for the Northern Ireland Sustainable Energy Programme 2016-2017, September 2015.

[55] 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.

Connection Allowance

6.227 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

6.228 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.

6.229 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.

6.230 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 FTE's and in addition a portion of the Sales Director and Finance Director costs.

6.231 We have 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.

6.232 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 draft determination allowances for business support cost categories.

6.233 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.

6.234 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.

6.235 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 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.

6.236 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.

6.237 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 PNGL area while still facilitating a substantial amount of resources to be available for continuing the growth of the industry.

6.238 In line with GD14 and to maintain consistency with the other GDNs we are implementing a risk-reward mechanism to provide strong incentives for PNGL to outperform its connection targets.

6.239 In order to reinforce PNGL’s incentive to connect customers, we will reward PNGL if it exceeds the target connections i.e. we will increase the per connection allowance for additional connections exceeding the target number of connections by the same proportion that the connections target is overachieved. Conversely, a penalty will apply if PNGL fails short of the target connections i.e. we will reduce the per connection allowance by the same proportion that the connections target is underachieved. This under or outperformance would be capped at +/-50%.

6.240 To demonstrate how the incentive mechanism might work, consider the following examples:

Outperformance – the connection allowance is £520 and the target (excluding non-additional) connections is 3,786, but PNGL outperforms by connecting 4,164 OO customers (excluding non-additional). As the connections outperformance is 10% (= 4,164 / 3,786 – 1), a unit connection allowance of £572 (= £520 x (1+10%)) will be payable for the 378 extra connections gained; the standard allowance of £520 would still apply to the original 3,786 connections. Total allowances would therefore equal £2,184,991 (i.e. (£520 x 3,786) + (£572 x 378)).

Underperformance – the connection allowance is £520 and the target (excluding non-additional) connections is again 3,786, but PNGL this time underperforms by connecting 3,407 OO customers. As the connections underperformance is 10% (= 3,407 / 3,786 – 1), the unit connection allowance payable will be £468 (= £520 x (1-10%)) for all connections (excluding non-additional). Total allowances in this case would equal £1,594,453 (i.e. £468 x 1,165).

6.241 All connections allowances claimed by GDNs must relate to properties which have a supplier and are burning gas. We plan to review the mechanisms in place to ensure this is appropriate. 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.

6.242 We note that the GDNs have raised concerns with the application of the owner occupied incentive mechanism as it applied in GD14. They have made the argument that the connection incentive should be calculated over the entire price control period rather than on an annual basis.

6.243 We would welcome views on this proposal and further analysis from the GDNs on this issue as part of their response to the GD17 draft determination.

Advertising & Market Development (non OO)

6.244 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.

6.245 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 £262,851. PNGL had 5.3 FTE's 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.

6.246 We have based the advertising and market development (non-OO) cost allowance for GD17 on the 2014 FTE's and using 2014 staff costs.

6.247 We have re-allocated some of the costs under CEO and Group Management to the Advertising and Market development (non-OO) cost category as we consider that PNGL's sales director will spend time on Advertising and Market development for non-owner occupied connections. This is consistent with our approach in GD14.

	2017	2018	2019	2020	2021	2022
PNGL requested allowances	263.5	267.8	271.7	268.0	268.2	268.3
UR DD before re-allocation	266.3	266.3	266.3	266.4	266.4	265.6
Re-allocation from CEO and Group Management	91.5	91.5	91.5	91.5	91.5	91.5
UR Draft Determination	357.8	357.8	357.8	357.9	357.9	357.9
Variance (+)	94.3	90	86.1	89.9	89.7	88.8

Table 54: Advertising and Marketing (non OO) Costs, Requested and Allowed, £k

Work Management

Overview

6.248 Work Management covers the following cost categories

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

Asset Management

6.249 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

6.250 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 £215,423 and had 4 FTE's employed within the Asset Management cost category. PNGL has proposed an additional FTE specifically an additional engineer for Asset Management in the GD17 period.

6.251 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 we do not consider that an additional FTE is required in the GD17 period as this is already included in the PNGL costs base.

	2017	2018	2019	2020	2021	2022
PNGL requested allowances	251.6	255.3	262.7	256.6	257.0	257.7
UR Draft 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 55: Asset Management Costs, Requested and Allowed, £k

Operations Management

6.252 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.; and
- 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

6.253 PNGL's operations management costs are in the main driven by its associated manpower costs. In the 2014 year PNGL had Asset Management costs of £414,834

and had 19.6 FTE's employed within the Operations Management cost category. PNGL have proposed that there should be 22.2 FTE's for Operations Management in the GD17 period.

6.254 We do not consider that an increase in FTE's is necessarily required for Operations Management in the GD17 period and therefore our proposed allowance is based on 2014 actual FTE numbers. This is consistent with our approach in GD14.

	2017	2018	2019	2020	2021	2022
PNGL requested allowances	542.7	550.8	571.1	552.0	552.6	553.2
UR Draft Determination	484.5	484.1	483.9	483.8	483.7	483.6
Variance	58.2	66.7	87.2	68.2	68.9	69.6

Table 56: Operations Management costs, Requested and Allowed, £k

Customer Management

6.255 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.

6.256 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 £737,190 and had 34.4 FTE's employed within the Customer Management cost category. PNGL has proposed that there should an incremental increase in FTE's for Customer Management in the GD17 period i.e. from 37 FTE's in 2017 to 39.2 FTE's in 2022.

6.257 We consider that an increase in FTE's 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 FTE's proposed by PNGL is necessary. We have therefore based our allowance on PNGL's projected 2015 figure for FTE's of circa 36 FTE's.

6.258 We have 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. This is consistent with our approach in GD14 and therefore the amount we have re-allocated is consistent with that in GD14 uplifted by RPI.

	2017	2018	2019	2020	2021	2022
PNGL requested allowances	830.0	851.9	865.9	869.5	878.2	886.8
UR DD before re-allocation	819.6	820.0	820.6	821.2	821.6	822.1
Re-allocation to AMPR (OO)	370.9	370.9	370.9	370.9	370.9	370.9
UR Draft Determination	448.7	449.1	449.7	450.3	450.7	451.2
Variance	381.2	402.7	416.1	419.2	427.4	435.6

Table 57: Customer Management Costs, Requested and Allowed, £k

System Control

6.259 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).

6.260 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

6.261 PNGL's system control costs are in the main driven by its associated manpower costs. In the 2014 year PNGL had customer management costs of £128,682 and had 5.3 FTE's employed within the System Control cost category. PNGL has proposed an additional FTE for System Control in the GD17 period.

6.262 We do not consider that an increase in FTE's is necessarily required for System Control in the GD17 period and therefore our proposed 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 Draft 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 58: System Control Costs, Requested and allowed, £k

Operations Management

6.263 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.; and

- 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

6.264 PNGL's operations management costs are in the main driven by its associated manpower costs. In the 2014 year PNGL had Asset Management costs of £414,834 and had 19.6 FTE's employed within the Operations Management cost category. PNGL have proposed that there should be 22.2 FTE's for Operations Management in the GD17 period.

6.265 We do not consider that an increase in FTE's is necessarily required for Operations Management in the GD17 period and therefore our proposed allowance is based on 2014 actual FTE numbers. This is consistent with our approach in GD14.

	2017	2018	2019	2020	2021	2022
PNGL requested allowances	542.7	550.8	571.1	552.0	552.6	553.2
UR Draft Determination	484.5	484.1	483.9	483.8	483.7	483.6
Variance	58.2	66.7	87.2	68.2	68.9	69.6

Table 59: Operations Management costs, Requested and Allowed, £k

Customer Management

6.266 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.

6.267 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 £737,190 and had 34.4 FTE's employed within the Customer Management cost category. PNGL has proposed that there should an incremental increase in FTE's for Customer Management in the GD17 period i.e. from 37 FTE's in 2017 to 39.2 FTE's in 2022.

6.268 We consider that an increase in FTE's 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 FTE's proposed by PNGL is necessary. We have therefore based our allowance on PNGL's projected 2015 figure for FTE's of circa 36 FTE's.

6.269 We have 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. This is consistent with our approach in GD14 and therefore the amount we have re-allocated is consistent with that in GD14 uplifted by RPI.

	2017	2018	2019	2020	2021	2022
PNGL requested allowances	830.0	851.9	865.9	869.5	878.2	886.8
UR DD before re-allocation	819.6	820.0	820.6	821.2	821.6	822.1
Re-allocation to AMPR (OO)	370.9	370.9	370.9	370.9	370.9	370.9
UR Draft Determination	448.7	449.1	449.7	450.3	450.7	451.2
Variance	381.2	402.7	416.1	419.2	427.4	435.6

Table 60: Customer Management Costs, Requested and Allowed, £k

System Control

6.270 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).

6.271 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

6.272 PNGL's system control costs are in the main driven by its associated manpower costs. In the 2014 year PNGL had customer management costs of £128,682 and had 5.3 FTE's employed within the System Control cost category. PNGL has proposed an additional FTE for System Control in the GD17 period.

6.273 We do not consider that an increase in FTE's is necessarily required for System Control in the GD17 period and therefore our proposed 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 Draft 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 61: System Control Costs, Requested and Allowed, £k

Emergency Costs

Overview

6.274 PNGL has requested a total allowance of £2.3 million in 2017 rising to £2.6 million 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 £2.2 million.

6.275 Table 62 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 62 – Emergency Costs Submitted by PNGL

6.276 Table 63 summarises the draft 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 63 - Emergency Costs Allowed in the Draft Determination for PNGL

6.277 Figure 6 shows PNGL's GD17 allowances against the submission, historical actuals and the allowances for GD14.

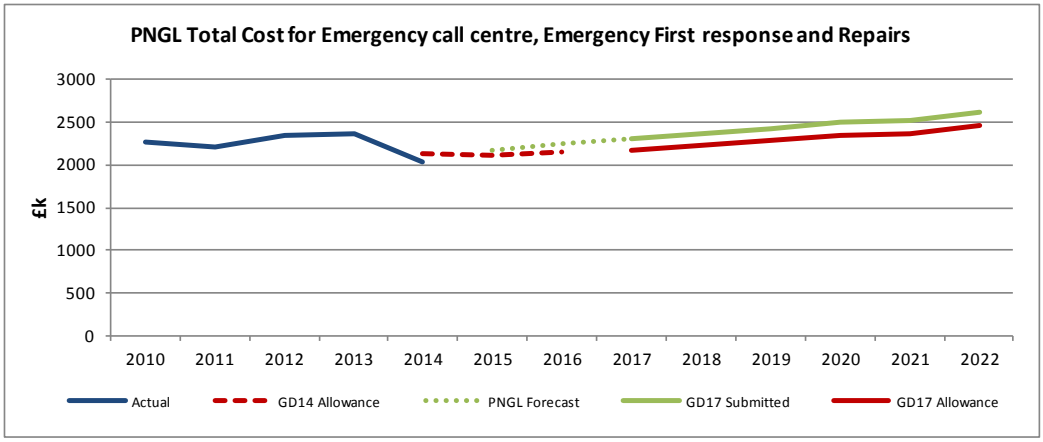


Figure 6 – PNGL Total Cost of Emergency Activities

6.278 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 £0.86m.
- 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.

Network Maintenance

Overview

6.279 In its Business Plan, PNGL identified net costs of network maintenance over GD17 averaging £2,715k per annum.

6.280 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 identify 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.

6.281 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.

6.282 PNGL proposed expenditure for GD17 is set out in Table 64.

	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
Total (£k) net	2,552	2,672	2,649	2,723	2,807	2,884
New items						
Valve accessibility project	375	375	375	375	377	373
Steel riser project	123	123	123	123	123	123
PRS cover maintenance	0	0	0	40	140	90
Total (£k) net	498	498	498	538	640	586
Total (£k) net excluding new items	2,054	2,174	2,152	2,186	2,168	2,298
PES profit element (£k)	116	153	145	142	145	160
Total (£k) net excluding new items and PES profit	1,938	2,021	2,006	2,043	2,023	2,139
Total (£k) net including new items, excluding PES profit	2,436	2,519	2,504	2,581	2,662	2,724

Table 64: PNGL Network Maintenance Proposals (Adjusted for PES Profit Element)

Assessment of Network Maintenance Expenditure Excluding New Items

6.283 Projected network maintenance expenditure for GD17 proposed by PNGL is shown in Figure 7 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.

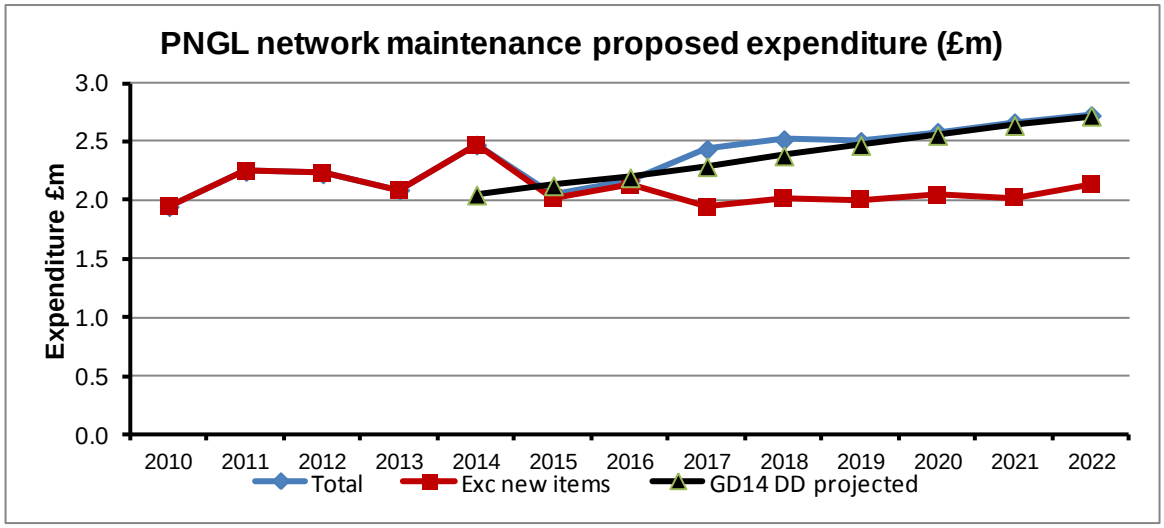


Figure 7: PNGL Proposed Network Maintenance

6.284 Excluding new items, 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

6.285 PNGL identified three new items of network maintenance expenditure which are identified in Table 64. In this section we set out our initial conclusion on these three items.

Valve Accessibility Project

6.286 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.

6.287 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%).

6.288 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.

6.289 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.

6.290 We note that the company's approach is 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.

6.291 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.

6.292 In view of this advice, we have based our draft determination on the following:

- We have 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.

6.293 The level of defects identified by the company in its sample inspection represents a population of valves up to 18 years old. There is no evidence on whether these defects were inherent in the initial design and installation, occurred shortly after installation, have developed over the period, or occurred more recently. To develop and support a clear risk based approach, we suggest that the company considers undertaking a small sample of inspections to better understand when defects occur to inform the development of a planned schedule of inspection and maintenance.

6.294 Given that 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. We suggest that the company consider 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.

Steel Riser Project

6.295 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.

6.296 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 draft determination.

PRS Cover Maintenance

6.297 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.

6.298 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.

6.299 For the final determination we will consider any further information provided by the company which confirms the need for this work within an overall plan for maintenance of pressure reducing stations.

Summary of Expenditure for GD17

	2017	2018	2019	2020	2021	2022
PNGL Proposed maintenance opex excluding new items (£k)	2,054	2,174	2,152	2,186	2,168	2,298
Less PES profit margin (£k)	-116	-153	-145	-142	-145	-160
New items (£k)						
Valve accessibility project	129	129	129	129	129	129
Steel riser project	123	123	123	123	123	123
PRS cover maintenance	0	0	0	0	20	70
Draft determiantion allowance (£k)	2,190	2,272	2,258	2,295	2,294	2,460

Table 65: PNGL GD17 Allowance for Network Maintenance

Expenditure post GD17

6.300 We have included an allowance for network maintenance activities post GD17 based on £9 per weighted connection based on our draft determination for GD17 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

6.301 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

6.302 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

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

6.304 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.

6.305 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 £485,449. PNGL had 4.5 FTE's employed within IT & Telecoms cost category in 2014 and has not proposed any increase in FTE's in this area for the GD17 period.

6.306 We have based the IT & Telecoms allowance for GD17 on the FTE's as submitted by PNGL but using 2014 staff costs and 2014 costs for stationary, communications and billing.

6.307 We have re-allocated some of the costs under IT & Telecoms to the Advertising and Marketing (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.

6.308 Our allowances (before taking into account re-allocation to Advertising and marketing (OO) for GD17 are similar to the three year average over the 2012 -2014 period at circa £488,829

	2017	2018	2019	2020	2021	2022
PNGL requested allowances	604.3	588.1	591.9	590.9	592.0	618.3
UR DD 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 Draft 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 66: IT& Telecoms Costs, Requested and Allowed, £k

Property Management

6.309 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.

6.310 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

6.311 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.

6.312 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 we are retaining it for GD17. The network rates allowances have therefore been calculated accordingly. For the final determination we will update the formula to take account of any information on 2016-17 rating valuations.

6.313 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.

6.314 PNGL also has rent and rates costs in relation to its offices and these costs have been accepted for the draft determination. We will review these costs further for the final determination to ensure any recharges are taken account of.

6.315 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.

6.316 We have re-allocated some of the costs under Office costs to the Advertising and Marketing (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 DD before re-allocation	2,482.9	2,540.5	2,606.1	2,670.1	2,777.7	2,841.2
Re-allocation to AMPR (OO)	32.8	32.8	32.9	32.8	32.9	32.8
UR Draft Determination	2,450.1	2,507.7	2,573.2	2,637.3	2,744.8	2,808.4
Variance	91.0	226.2	223.5	234.7	218.9	203.9

Table 67: Property Management Costs, Requested and Allowed, £k

HR & Non-Operational Training

6.317 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.

6.318 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

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

6.320 PNGL In the 2014 year PNGL had HR & Ops training costs of £227,790. PNGL had 2.4 FTE's employed within HR and Ops training cost category in 2014 and has not proposed any increase in FTE's in this area for the GD17 period.

6.321 We have based the HR and Ops training allowance for GD17 on the FTE's as submitted by PNGL but using 2014 staff costs and 2014 costs for professional and legal fees as well as 2014 materials costs.

6.322 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 £195,535.

6.323 We have re-allocated some of the costs under HR and Ops training to the Advertising and Marketing (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 DD 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 Draft 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 68: HR & Non-Operational Costs, Requested and Allowed, £k

Audit Finance & Regulation

6.324 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.

6.325 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.

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

6.327 In the 2014 year PNGL had Audit Finance and Regulation costs of £941,853. PNGL had 12.7 FTE's employed within Audit Finance and Regulation cost category in 2014 and has proposed an increase of circa 0.8 FTE's in this area for the GD17 period.

6.328 We have based the Audit Finance and Regulation allowance for GD17 on the 2014 FTE's and using 2014 staff costs and 2014 costs for professional and legal fees as well as 2014 stationary, communications and billing costs.

6.329 We have re-allocated some of the costs under Audit Finance and Regulation to the Advertising and Marketing (OO) cost category 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 DD 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 Draft 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 69: Audit Finance & Regulation Costs, Requested and Allowed, £k

Insurance

6.330 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.

6.331 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.

6.332 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.

6.333 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%. We do not have sufficient evidence to justify such an increase.

6.334 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. However, this does not provide a sufficient rationale for why premiums

are expected to increase over time. We also note that the historical trend for actual insurance costs has not increased year - on - year, indeed it has reduced since 2012.

6.335 In the absence of adequate justification warranting the magnitude of the claimed increases in business insurance, we have continued with the approach of granting a business insurance allowance based on a 3-year average of the actual costs incurred during 2012 – 2014.

6.336 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.

6.337 PNGL's requested allowance for car insurance is marginally under £1,500 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 draft determination to an assumed fleet of around 65 cars.

6.338 Finally, for building insurance costs, we have granted allowances on the basis of a two year average of the actual costs for 2013-14.

6.339 Our determined allowances for 2017 - 2022 are shown in Table 70 below along with PNGL's requested allowances and the variance between the two. We have apportioned an element of the insurance allowance to be recovered through the Connection Incentive Mechanism.

6.340 We have re-allocated some of the costs under Insurance to the Advertising and Marketing (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 DD 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 Draft Determination	789	789	789	789	789	789
Variance	112	132	113	173	193	214

Table 70: Insurance Costs, Requested and Allowed, £k

Procurement

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

6.342 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.

6.343 PNGL procurement costs are driven by staff costs. In the 2014 year PNGL had procurement costs of £72,313. PNGL had 2.4 FTE's employed within the Procurement cost category in 2014 and has not proposed any increases in this area for the GD17 period.

6.344 We have based the Procurement cost allowance for GD17 on the 2014 FTE's and using 2014 staff costs.

6.345 We have re-allocated some of the costs under Procurement to the Advertising and Marketing (OO) cost category 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	1883.6	1897.6	1903.9	1897.9	1898.0	1898.2
UR DD before re-allocation	1228.2	1228.3	1228.3	1228.3	1228.3	1228.3
Re-allocation to AMPR (OO)	251.0	251.0	251.0	251.0	251.0	251.0
UR Draft Determination	977.2	977.3	977.3	977.3	977.3	977.3
Variance	906.4	920.3	926.6	920.6	920.7	920.9

Table 71: CEO and Group Management Costs, Requested and Allowed, £k

Stores & Logistics

6.346 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.

6.347 We have accepted PNGL requested allowances for stores and logistics for GD17 as they are below the three year historical average (2012-2014).

	2017	2018	2019	2020	2021	2022
PNGL requested allowances	29.8	29.8	27.7	29.8	29.8	29.8
UR Draft Determination	29.8	29.8	27.7	29.8	29.8	29.8
Variance	0	0	0	0	0	0

Table 72: Stores and Logistics Costs, Requested and Allowed, £k

Other Area

Trainees & Apprentices

6.348 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).

6.349 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.

6.350 PNGL has not proposed any costs under this category and this is consistent with PNGL historical information. Therefore UR does not propose to provide for any costs under this category.

Non-Controllable Opex

6.351 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 Draft Determination	115.5	115.5	115.5	115.5	115.5	115.5
Variance	0	0	0	0	0	0

Table 73: PNGL Non-controllable Opex Costs, Requested and Allowed, £k

Capitalised Opex

6.352 For the purpose of the GD17 draft determination we have accepted PNGL capitalisation rates, however we expect to review this further for the final determination.

East Down

6.353 In relation to East Down we have previously informed PNGL that we did not plan to allow an 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.

6.354 Further detail is provided on East Down from paragraph 11.101.

Summary of Bottom-up Assessment Findings

6.355 Table 74 summaries the GD17 draft 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	484.5	484.0	483.9	483.8	483.7	483.5	2,903.6
Emergency Call Centre	444.6	451.0	461.3	471.9	475.3	490.3	2,794.6
Customer Management	448.7	449.1	449.7	450.3	450.7	451.2	2,700.0
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	964.8	1,001.2	994.7	1,011.1	1,010.8	1,083.9	6,066.7
PRE Repairs	446.7	457.6	469.8	482.3	491.0	505.0	2,852.7
Maintenance	1,225.0	1,271.2	1,262.9	1,283.8	1,283.4	1,376.2	7,702.7
IT & Telecomms	438,9	437,9	438,2	438,2	438,1	439,2	2,630.8
Property Man	2,450.1	2,507.7	2,573.2	2,637.3	2,744.8	2,808.4	15,721.7
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	27.6	29.8	29.8	29.8	176.7
AMPR (OO)	2,137.3	1,968.4	1,842.5	1,684.7	1,567.8	1,378.8	10,579.6
AMPR (non-OO)	357.8	357.8	357.8	357.9	357.9	357.9	2,147.3
Non Controllable Costs	115.5	115.5	115.5	115.5	115.5	115.5	693.2
Total	**14,065.6**	**14,079.2**	**14,064.8**	**14,074.4**	**14,089.9**	**14,219.0**	**84,593.2**

Table 74: Pre Efficiency Draft Determination (excluding AMPR re-allocated Costs), £k

Triangulation of Top-Down and Bottom-up Assessment Findings

6.356 After comparing the various indicative results from our top-down opex benchmarking to our bottom-up opex assessment we recognise there is a requirement for further

engagement with local GDNs to decide how we shall apply any special factors (both positive and negative) before we conclude on our econometric modelling. For this draft determination, we have decided to apply the results of our bottom-up opex assessment.

Real Price Effects, Productivity and Frontier Shift

Overview

6.357 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: Draft Determination GD17.

Net Impact

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

6.359 This is shown in Table 2: PNGL Draft Determination Allowances

SGN – UR Proposals

Overview

6.360 For SGN we did not set any efficiencies for opex given our judgement that its licence application figures included efficiency.

Top-Down Assessment

6.361 Once we begin to receive outturn opex data from SGN we shall consider when would be an appropriate time to include SGN in our benchmark modelling.

Bottom-up Assessment

Overview

6.362 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:

6.363 The structure of this section reflects three main periods:

- The mobilisation period i.e. the period up to First Operational Commencement Date (FOCD), this is currently envisaged to be Q4 2017.
- The period between First Operational Commencement Date (FOCD) ie Q4 2017 and SGN's GD17 price control period which starts 1 January 2018.
- SGN's GD17 price control period which covers the period 1 January 2018 to 31 December 2022.

6.364 We will now in turn go over each section of the request made and make a consideration of the comments made.

Mobilisation Period

SGN Proposals

6.365 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.

6.366 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.

6.367 The FOCD for the G2W project is scheduled to be Q4 2017 when the high pressure pipeline is complete, providing access to all the towns in the SGN licence area.

6.368 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*".

6.369 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".

6.370 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.

6.371 Table 3 provides an overview for SGN's rationale 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 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 75: SGN Rationale for Increased Mobilisation Allowances

IT costs – SGN G2W Application

6.372 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

6.373 Within their 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 Draft Determination.

6.374 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.

6.375 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*".

6.376 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.

6.377 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

6.378 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

6.379 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.

6.380 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 Draft Determination

6.381 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. The Utility Regulator considers 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.

6.382 Consequently we are not providing any additional transition cost allowances for the draft determination.

Sales and Marketing – SGN G2W Licence Application

6.383 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

6.384 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*".

6.385 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.

6.386 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*".

6.387 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*".

6.388 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*".

6.389 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*".

6.390 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.

6.391 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

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'

6.392 We have considered SGN's points on economic conditions and third party funding together since SGN consider the points are related.

6.393 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.

6.394 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.

6.395 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

6.396 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.

6.397 In order to assist us we have considered Figure 8 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.

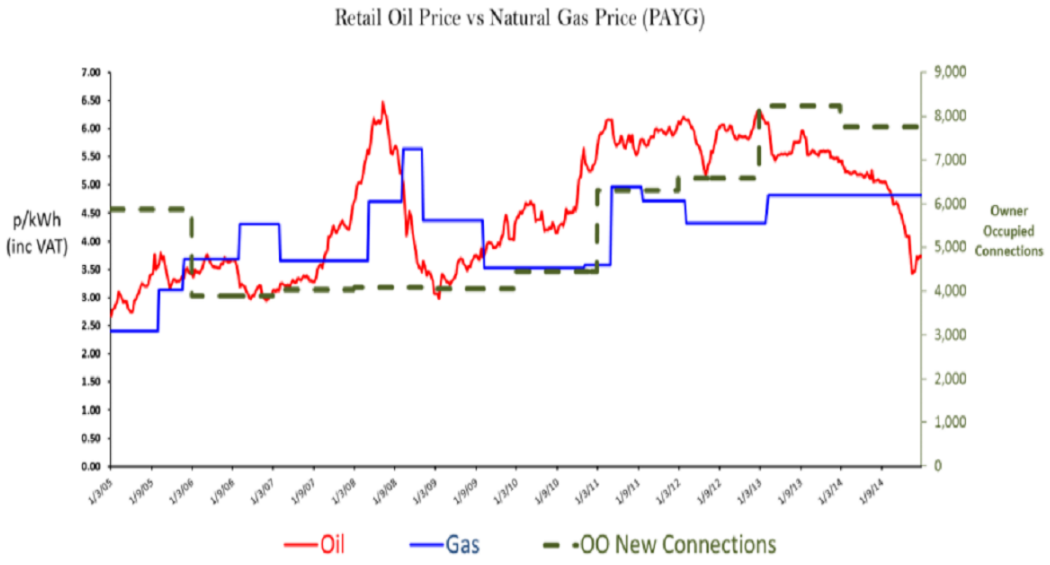


Figure 8: Oil and Gas Price in PNGL Area

6.398 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 example our draft determination provides for an SGN distribution tariff that is 8ppt lower than that for PNGL.

6.399 In addition to the number above we note that the OO gas connection numbers in the FE area (not presented in Figure 8) 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.

6.400 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 8 above.

6.401 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.

6.402 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.

6.403 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.

6.404 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.

6.405 We have considered the arguments and challenges SGN faces in connecting customers further in Advertising & Market Development (OO Properties).

Sales and Marketing – Utility Regulator Draft Determination

6.406 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.

6.407 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 4.33 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*".

6.408 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.

6.409 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

6.410 We do not accept SGN's rationale for the proposed increase in mobilisation costs of circa £2.7m versus its G2W licence application figures.

6.411 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).

6.412 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.

The period between First Operational Commencement Date (FOCD) ie Q4 2017 and SGN's GD17 price control period which starts 1 January 2018.

Delay in the start of GD17 – SGN GD17 Business Plan

6.413 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 Draft Determination

6.414 As set out in paragraph 6.369 above the AIP was clear that all costs before the FOCD should be included within mobilisation costs.

6.415 Therefore all costs up to Q4 2017 are included within the SGN mobilisation licence application figure and all costs from 2018 will be included in GD17 opex. This leaves a gap from FOCD to 1 January 2018.

6.416 Also, the Strabane area is scheduled to have its first gas customer by Q4 2016, which will incur some costs.

6.417 Therefore we propose to allow additional costs in the period 1 October 2017 to 31 December 2017, to reflect the costs of operating the network post FOCD. We propose to allow 25% of operational cost for 2018 to cover this period. This amounts to circa £385k.

6.418 This will be subject to FOCD occurring on 1 October 2017 and if this date changes the figure will be adjusted accordingly in the Uncertainty Mechanism.

6.419 We would also highlight that other adjustments will be made in relation to Strabane costs and revenues. The treatment of these costs and revenues 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 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".

SGN Price Control opex costs (2018 – 2022)

Overview

6.420 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.

6.421 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 76. At time of writing we are not convinced that the SGN response as shown in this table has correctly identified the appropriate opex figures from the G2W application to facilitate a meaningful comparison to their GD17 BP submission. We consider that this may arise, due to the timing of the FOCD and the costs associated with this. We will review this further for the GD17 final determination.

SGN G2W Application (GD17 Period)

6.422 The mobilisation and pre GD17 costs within the SGN G2W application amounted to £1,003,360. The SGN GD17 costs amounted to £7,592,826 and therefore the total amount in the SGN G2W application was £8,596,187 for both mobilisation and GD17 opex costs.

	2017	2018	2019	2020	2021	2022	Total
Senior management	194.295	198.677	199.825	199.148	197.122	196.264	**1,185.335**
Operations	56.414	56.414	56.414	56.414	54.399	54.399	**334.453**
Marketing and Admin	53.392	72.532	84.621	93.687	102.754	111.820	**518.806**
Emergency Call Centre	0.028	5.066	8.401	10.975	13.519	16.048	**54.036**
Emergency	31.020	58.386	78.461	93.885	104.009	118.327	**484.086**
PRE Repairs	4.267	6.584	8.118	9.302	10.001	11.164	**49.436**
Maintenance	36.301	74.460	65.964	69.085	72.370	75.843	**394.024**
IT and Telecomms	19.878	19.878	19.878	19.878	19.878	19.878	**119.269**
Property Management	34.251	34.251	34.251	34.251	34.251	34.251	**205.508**
Insurance	18.311	18.311	18.311	18.311	18.311	18.311	**109.868**
CEO & Group Management	33.294	33.294	33.294	33.294	33.294	33.294	**199.765**
AMPR (OO)	211.252	330.222	397.716	398.551	380.074	359.658	**2,077.472**
Rates and licence	100.014	269.326	308.745	347.993	387.160	447.533	**1,860.770**
Total	**792.718**	**1,322.620**	**1,391.723**	**1,283.584**	**1,344.008**	**1,434.073**	**7,592.826**

Table 76: SGN Opex Application for GD17 Period for G2W in GD17 Business Plan Template format (Dec 2014 Prices), £k

SGN GD17 Business Plan Submission

6.423 The SGN business plan submission for the GD17 period shows significant cost increases versus the SGN G2W licence application - from £7,592,826 to £13,046,242. Adding in SGN's increase in mobilisation costs from £1,003,360 to £3,683,410, the total

change in SGN's G2W application to the GD17 business plan submission is from £8.572m to £16.729m (dec 2014 prices).

6.424 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.

6.425 Table 77 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 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 Telecomms	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**
AMPR (OO)	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	**2,569.9**	**2,818.4**	**2,344.4**	**2,501.3**	**2,812.0**	**13,046 .0**

Table 77: SGN GD17 Business Plan Submission for the GD17 Period, £k

6.426 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.

6.427 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'*.

6.428 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.

6.429 We propose 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 consider that this is the most appropriate proxy in order to uplift relevant costs.

6.430 For transparency we discuss below the GD17 draft determination allowances for SGN in comparison to the SGN G2W application. We have uplifted the following cost categories

in comparison to the SGN G2W application by 7%. The calculation for this is shown in Table 78 and reflects the 7% increase in domestic customers as compared to the G2W AIP.

- Manpower and MSA/SLA costs under operations management
- Emergency Call Centre
- Emergencies
- PRE repairs
- Maintenance

6.431 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.

6.432 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 DD	% change
Owner occupied and NIHE	6840	7140	
New build	1206	1442	
Total domestic connections	8046	8582	Circa +7%

Table 78: Change in Domestic Connection Numbers (GD17 vs. G2W Assumptions)

6.433 We did not include other customer groups within the connection numbers analysis as we were not able to reconcile SGN's GD17 Business Plan submission on connection numbers for small and medium I & C's to the applicable year.

6.434 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

6.435 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 have 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.

Advertising & Market Development (OO Properties)

6.436 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*'.

6.437 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.

6.438 For the GD17 draft determination we have 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 80.

6.439 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.

6.440 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.

6.441 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. Consequently this is a change from the 25% non-additional assumption used in the AIP.

6.442 The profile number of target owner occupied connections and associated allowance for SGN is set out in Table 79.

	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 draft determination	1294	1294	809	809	809	5015

Table 79: SGN vs. UR View on GD17 'OO' Connection Numbers

6.443 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 80.

	2018	2019	2020	2021	2022
UR determination target	1294	1294	809	809	809
Incentive allowance (£)	520	500	470	450	420
GD17 allowance (£k)	672.9	647.0	380.2	364.0	339.7

Table 80: SGN GD17 Owner Occupied Connection Incentive Allowance

6.444 This represents an increase of £0.4m compare to the connections incentive in the AIP.

AMPR (Advertising Marketing and PR) for owner occupied domestic OO connections

6.445 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.

6.446 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*'.

6.447 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*'.

6.448 Consequently we consider no re-allocation of costs is required to the owner occupied cost category.

Connection Incentive Allowance Application

6.449 In line with GD14 and to maintain consistency with the other GDN's we are implementing a risk-reward mechanism to provide stronger incentives for SGN to outperform its connection targets.

6.450 In order to reinforce SGN's incentive to connect customers, we will reward SGN if it exceeds the target connections i.e. we will increase the per connection allowance for additional connections exceeding the target number of connections by the same proportion that the connections target is overachieved. Conversely, a penalty will apply if SGN falls short of the target connections ie we will reduce the per connection allowance by the same proportion that the connections target is underachieved. This under or outperformance would be capped at +/-50%.

6.451 To demonstrate how the incentive mechanism might work, consider the following examples:

- *Outperformance* – the connection allowance is £520 and the target connections is 1,294, but SGN outperforms by connecting 1,423 OO customers. As the

connections outperformance is 10% (= 1,423 / 1,294 – 1), a unit connection allowance of £572 (= £520 x (1+10%)) will be payable for the 129 extra connections gained; the standard allowance of £520 would still apply to the original 1,294 connections. Total allowances would therefore equal £746,897 (i.e. (£520 x 1,294) + (£572 x 129)).

- *Underperformance* – the connection allowance is £520 and the target connections is again 1,294, but SGN this time underperforms by connecting 1,165 OO customers. As the connections underperformance is 10% (= 1,165 / 1,294 – 1), the unit connection allowance payable will be £468 (= £520 x (1-10%)) for all connections. Total allowances in this case would equal £545,033 (i.e. £468 x 1,165).

6.452 All connections allowances claimed by GDN's must relate to properties which have a supplier and are burning gas. We expect the GDN's to be able to demonstrate that all connections have a supplier agreement in place and burn a minimum quantity of gas. We will further discuss with GDN's how this should be defined.

6.453 We note that the GDN's have raised concerns with the application of the owner occupied incentive mechanism as it applied in GD14. They have made the argument that the connection incentive should be calculated over the entire price control period rather than on an annual basis.

6.454 We would welcome further analysis from the GDN's as part of their response to the GD17 draft determination.

Advertising & Market Development (Non OO)

6.455 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.

6.456 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.

6.457 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 81.

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, semianrs
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) – up front 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 81: SGN GD17 Proposed Allowances for Sales and Marketing Activities

6.458 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 £0.058m as shown in Table 82.

	2017	2018	2019	2020	2021	2022	Total (£k)
SGN G2W application	8.0	9.0	11.0	12.0	11.0	7.0	58.0

Table 82: SGN Advertising and Marketing Costs (G2W Bid) for non OO Customers, £k

6.459 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.

6.460 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'*.

6.461 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 ie costs used in assisting non-OO in converting from existing fuel source to natural gas.

6.462 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

6.463 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*'.

6.464 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

6.465 We note that SGN within its GD17 business plan submission has increased the number of FTE's they consider that they require when compared to their G2W licence application and this is shown in Table 83.

	2017	2018	2019	2020	2021	2022
SGN G2W application	19	19	19	17	17	17
SGN GD17 BP submission	13.7	19.8	21	20	20	20

Table 83: SGN FTE's G2W BP Submission vs. GD17 BP Submission

6.466 While it is a matter for SGN to decide the number and mix of staff it employs our GD17 allowances are based on the FTE's as submitted by SGN in its G2W licence application.

Summary of Bottom-up Assessment Findings

6.467 Table 84 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.

6.468 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.

6.469 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.

6.470 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'*.

6.471 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.

6.472 However there are some areas we have proposed that an adjustment is appropriate.

6.473 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 for domestic owner occupied properties has no non additional assumption in order to take into account the challenges facing SGN.

6.474 The allowances we have set for SGN assume that SGN connects to all towns as set out in the licence by the start of 2018. We may change the profile of cost allowances for SGN for the GD17 final determination if this does not occur and will consider how to reflect this in the Uncertainty Mechanism.

6.475 We are not convinced that the SGN has correctly identified the appropriate opex figures from their G2W application to facilitate a meaningful comparison to their GD17 business plan submission. We consider that this may arise, due to the timing of the FOCD and the costs associated with this. This draft determination has been completed on the basis that SGN have referred to the correct opex figures in their G2W application. We will review this further for the GD17 final determination and make any appropriate adjustments.

	2017	2018	2019	2020	2021	2022	Total
Senior management	194.295	198.677	199.825	199.148	197.122	196.264	**1,185.335**
Operations	60.363	60.363	60.363	60.363	58.207	58.207	357.865
Marketing and Admin	53.392	72.532	84.621	93.687	102.754	111.820	**518.806**
Emergency Call Centre	30	5.420	8.989	11.743	14.465	17.171	**57.819**
Emergency	33.191	62.473	83.953	100.457	111.289	126.610	**517.972**
PRE Repairs	4.565	7.045	8.687	9.954	10.701	11.946	**52.897**
Maintenance	38.843	79.672	70.582	73.921	77.436	81.152	**421.605**
IT and Telecomms	19.878	19.878	19.878	19.878	19.878	19.878	**119.269**
Property Management	34.251	34.251	34.251	34.251	34.251	34.251	**205.508**
Insurance	18.311	18.311	18.311	18.311	18.311	18.311	**109.868**
CEO & Group Management	33.294	33.294	33.294	33.294	33.294	33.294	**199.765**
AMPR (OO)	211.252	475.440	475.440	297.360	296.940	296.940	**2,403.940**
AMPR (OO)	8.059	9.067	11.081	12.089	11.081	7.052	**58.429**
Rates and licence	100.014	269.326	308.745	347.993	387.160	447.533	**1,860.770**
Total	**598.487**	**1,543.190**	**1,589.579**	**1,395.319**	**1,440.000**	**1,503.269**	**8,069.845**

Table 84: SGN Draft Determination Opex for the GD17 Period, £k

7 Capex

Detailed Approach – UR Proposals

Overview

7.1 This chapter of the draft determination summarises the capital expenditure proposed by the three GDNs in their business plans and set outs our initial conclusions on reasonable levels of capital expenditure for GD17.

7.2 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.

7.3 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 draft determination.

7.4 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 draft 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.

7.5 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.

7.6 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.

They have been identified separately. The overall investment proposed by the GDNs for GD17 and our draft 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 85: Capital Investment Proposed by the GDNs for GD17

Investment category	Capital investment allowances for GD17 (£m)				
	PNGL	PNGL East Down	FE	SGN	Total
7 Bar Mains	1.126	0.000	0.000	0.000	1.126
LP, 2Bar or 4Bar Mains	5.439	17.642	44.921	29.974	97.976
Pressure Reduction	0.600	0.000	0.095	0.568	1.263
Domestic Services	30.380	2.545	20.189	5.737	58.851
Domestic Meters	19.454	0.733	6.789	1.645	28.622
I&C Services	3.071	0.729	1.774	1.330	6.905
I&C Meters	4.678	0.330	1.403	1.867	8.277
Other Capex	1.432	0.000	0.733	2.371	4.536
TMA	4.002	2.092	6.688	3.704	16.486
Totals (*Dec 2014 price base*)	**70.181**	**24.071**	**82.592**	**47.197**	**224.041**
Frontier shift	-2.365	-0.775	-2.790	-1.501	-7.432
Totals included in DD	**67.816**	**23.296**	**79.802**	**45.695**	**216.610**

Note *Investment before partial allocation of East Down investment to postalised tariffs. East Down costs exclude 2016 investment of £2.03m post frontier shift*

Table 86: Capital Investment Included in the GD17 Draft Determination

Overall Structure of Capital Expenditure Submissions and Assessment

7.7 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 pressures 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 87: Investment Category Descriptions

7.8 We have used this structure to present both our assessment and challenge to the GDNs proposals and our conclusions and the allowances included in this draft 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

7.9 In this section we outline five key areas where we have adopted a common approach to inform our draft 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 the on-going productivity improvements.

Common Approach – Economics Level of Infill Mains

7.10 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.

7.11 The development of the gas network in both the SGN area and the PNGL East Down areas 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.

7.12 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 burnin gas.

7.13 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	380 therms/a	Consistent with the average therms per property currently reported by the GDNs 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 GDN's 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.
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 88: Economics of Gas Mains – Key Parameters

7.14 In principle, we consider a package of new mains to be economic if it does not increase the current domestic tariff. Given the varying tariffs over time, in practice we have used a limit of 40p per therm for determining economic infill for GD17.

7.15 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	620	8.92
PNGL	GD17	Existing infill	359	5.16

Table 89: Economic Development Parameters for New Gas Mains

7.16 The primary drivers for an increase in £ per property passed and increase in metres per property passed for FE compared to GD17 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.

7.17 These are countered by a reduction in the average therms per property from 410 therms per annum to 380 therms per annum, which reduces the assumed revenue from new connections.

7.18 PNGL has proposed infill for small numbers of domestic properties at the edge of the existing network. 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.

7.19 Overall we view the role of an economic assessment as important in delivering a sustainable long term industry, although we recognise that an amount of judgement is required. We will finalise our approach taking account of views expressed in the consultation on the draft determination.

Common Approach - Mains Laying Incentive and Uncertainty Mechanisms

Properties Passed Mechanism

7.20 All GDNs will be subject to a properties passed mechanism to incentivise them to continue to extend the network as proposed in the draft determination. 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 includes a target number of properties passed and failure to achieve the targeted number of properties passed will result in a penalty of £50 for every property below the target. Passing a larger number of properties than the target will result in a reward of £20 per additional property over the target.

7.21 We have retained an asymmetric mechanism to reflect the fact that the GDNs have control over the numbers of properties passed and the penalty is not onerous.

7.22 In GD14, we have 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. We will consider this for the final determination, taking account of the response to the consultation on the draft determination.

7.23 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 90.

	2017	2018	2019	2020	2021	2022	GD17
FE	11,691	11,545	11,400	11,237	11,503	11,565	68,941
PNGL	3,770	3,770	3,770	3,770	3,770	3,770	22,620
SGN	5,720	5,738	5,720	5,701	5,701	5,701	34,281

Table 90: Properties Passed Targets for all GDNs

Infill and New Build Mains Uncertainty Mechanisms

7.24 In the draft determination we include 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 area (excluding East Down), we applied an economic test and limited the determination to a basket of properties which could be delivered up to an average length of 8.92m per property passed.
- 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 11.75m per property passed and 10.67m per property passed respectively based on the designs presented by the GDNs.

7.25 We recognise that the number of properties passed will vary and the length required to pass a property will vary in delivery. We plan to continue to apply the retrospective 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 the GDN is funded for the actual outputs delivered, protecting consumers from under delivery but allowing the GDNs to continue to develop the network where this is economic. 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 GDN and ensures that development is delivered within the parameters of the determination.

7.26 We plan to continue to apply the mechanism to new build and infill development separately. We will give further consideration in the final determination on their interaction. In GD14, we have 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. We will consider this for the final determination, taking account of the response to the consultation on the draft determination.

7.27 We have not set out a detailed mechanism in this draft determination on how we woudl manage unforeseen new connections to larger I&C customers. We plan to consider this further in the final determination and build on the principles from GD14.

Common Approaches - Benchmark Cost Rates for Capital Expenditure

Introduction

7.28 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.

7.29 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 works.

7.30 We have provided a brief description of each of these assessments below. We have based much of the draft 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

7.31 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 91: High Level Business Plan Capex Unit Rates for GD17

7.32 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

7.33 As part of their business plan submissions, FE and PNGL provided information on individual gas mains projects for the first two years of GD17 (2017and 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.

7.34 To understand how FE and PNGL had developed their estimates for infill gas mains, we asked both GDN's 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.

7.35 We were able to confirm that the lengths of infill and spine mains laying proposed by each GDN were reasonable for the properties passed. SGN has advised us that it is continuing to develop its plans and that it will provide more detailed information for us to consider for the final determination. We have made some adjustments to the SGN's property counts in anticipation of the outcome of this work. We were able to confirm that FE and PNGL had applied their current contract rates to cost the scope of works identified.

7.36 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 92: High level business plan capex unit rates for GD17

7.37 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 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 7.46.

Basket of Works Approach to the Capex Determination

7.38 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.

7.39 To address these issues, we have applied and adapted the “basket of works” approach first used in GD14.

7.40 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.

7.41 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.

7.42 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 are shown below:

Synthetic Rates			
Activity	New	Activity	New
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	163	I&C U400 - Replacement	19,360
Mains Feeder/Infill 355mm	186	I&C U650 - Replacement	28,160
Mains Feeder/Infill 400mm	215	I&C U1000 - Replacement	40,479
Mains Feeder/Infill 450mm	250	I&C U1600 - Replacement	59,839
Mains Feeder/Infill 600mm	375	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 93: GD17 Basket of Works Unit Rates

7.43 Subject to their agreement to share data, additional supporting information on the calculation of the unit rates will be provided to the GDNs to inform their response to the draft determination. As part of their overall response to the draft determination we ask 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.

7.44 We will consider the GDNs responses to the basket of works and make adjustments to the basket of works or allowances for special factors in the final determination where we consider this appropriate.

Special Factors

FE and PNGL Special Tactors

7.45 FE and PNGL did not identify any special factors relating to capital costs in their business plan submissions.

SGN – Special Factors

7.46 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's 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.

7.47 In our determination, we have applied the basket of works unit rates which come from our analysis of capital expenditure by FE and PNGL over a four year period. This reflects local cost information which was not available to SGN.

7.48 We have considered the adjustments set out by SGN in its submission and further supporting information provided by the company and concluded that there was insufficient evidence to adjust 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

7.49 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 relative to GB. We have not yet considered any regional wage variations within Northern Ireland.

Sparsity Adjustment

7.50 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 quarries	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 94: SGN Special Factor Claim for Sparsity

7.51 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.

7.52 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.

7.53 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.

7.54 The analysis is based on a series of assumptions and does not take account of the opportunities for workers 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 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 draft determination.

7.55 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

7.56 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

7.57 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.

7.58 The basket of works unit rates used in the draft 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 work unit rates.

Start up Adjustment

7.59 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.

7.60 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

7.61 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 £4.6m per annum. We have not assessed any economies of scale for this marginal difference.

Common Approaches - Street Works Legislation

7.62 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.

7.63 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 a retrospective adjustment 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.

7.64 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

7.65 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.

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

7.67 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).

7.68 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

7.69 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: Draft Determination GD17.

7.70 The calculation of the frontier shift for capital expenditure is summarised in Table 95 below.

Capex	Weight	2014	2015	2016	2017	2018	2019	2020	2021	2022
Labour (direct and contracted)	56%	1.5%	2.6%	3.4%	3.7%	3.6%	3.7%	3.9%	3.9%	3.9%
Materials	19%	1.0%	1.5%	0.5%	1.6%	2.0%	3.0%	3.5%	3.5%	3.5%
Equipment/Plant	4%	1.5%	1.1%	1.7%	2.3%	2.3%	2.3%	2.3%	2.3%	2.3%
Other	21%	2.4%	1.0%	2.0%	2.9%	3.2%	3.2%	3.2%	3.2%	3.2%
Total nominal input price inflation		1.6%	2.0%	2.5%	3.1%	3.2%	3.4%	3.6%	3.6%	3.6%
RPI		2.4%	1.0%	2.0%	2.9%	3.2%	3.2%	3.2%	3.2%	3.2%
Productivity growth		1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
Frontier shift		0.0%	0.0%	-0.5%	-0.8%	-1.0%	-0.8%	-0.6%	-0.6%	-0.6%
Frontier Shift		0.0%	0.0%	0.5%	0.8%	1.0%	0.8%	0.6%	0.6%	0.6%
Frontier Shift (Cumulative)		0.0%	0.0%	0.6%	1.4%	2.4%	3.2%	3.8%	4.3%	4.9%

Table 95: Real Price Effects for Capex

General Approach by Investment Categories

General Approach - 7 Bar Mains

7.71 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

7.72 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.

7.73 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.

7.74 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.

7.75 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 draft determination are:

GDN	Average rate for new build mains (£/m)	
	Business Plan	Draft Determination
PNGL	56.09	47.71
FE	51.50	48.48
SGN	40.09	48.70

Note: average unit rates in Dec 2014 prices before the application of frontier shift

Table 96: Average Rates for New Build Mains

Spine and Infill Mains

7.76 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 7.10 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 68,941 properties passed at a length per property passed of 8.92 m

7.77 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 by the company on design development. 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.

7.78 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 draft determination are:

GDN	Average rate for spine and infill mains (£/m)	
	Business Plan	Draft Determination
PNGL – Current area	77.81	68.38
PNGL – East Down	71.06	71.86
FE	71.13	69.47
SGN	100.49	72.77

Note: average unit rates in Dec 2014 prices before the application of frontier shift

Note: the unit rate for SGN reflects the higher quantity of spine mains required to serve larger new towns

Note: East Down figures include a proportion of PDP included in unit rates

Table 97: Average Rates for Spine and Infill Mains

Replacement Mains

7.79 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

7.80 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.

7.81 We have 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. SGN has advised us that it is reviewing its initial designs and will provide updated information well in advance of the final determination.

7.82 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.

Pressure Reducing Stations – Replacement

7.83 PNGL included end-of-life replacement of PRS installations which will reach 20 year 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.

7.84 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.

7.85 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

7.86 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

7.87 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

7.88 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. 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.

7.89 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.

7.90 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.

7.91 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.

We will include a decision on uncertainty and incentive mechanisms for meter replacement in the final determination having considered the response to the consultation.

7.92 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.

7.93 We used basket of works unit rates to estimate 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.

General Approach – I&C Services

7.94 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

7.95 We used basket of works unit rates to estimate an allowance for I&C meters for each new connection.

Industrial and Commercial Meters – Replacement

7.96 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.

7.97 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 partial replacement of key components, we have not included the end-of-life replacement for larger meters at 20 years as proposed by PNGL. We expect 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. This should consider replacement on age, targeted replacement of key components or the continued maintenance of the plant over a longer life. We will consider the evidence the company presents before reaching our final determination.

7.98 In view of our conclusions on domestic meters, we have included funding for a 20 year cycle of replacement of U6 I&C meters in the draft determination for PNGL.

7.99 We have set out our initial thoughts on the introduction of uncertainty and incentive mechanisms for meter replacement in paragraph 7.91 above. We will include a decision on uncertainty and incentive mechanisms for meter replacement in the final determination having considered the response to the consultation.

7.100 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.

7.101 We used basket of works unit rates to estimate allowances for estimating the cost of replacement I&C meters. For U6 I&C meter replacement, we have used a unit rate which reflects the high proportion of credit meters in this category.

General Approach – Other Capex

7.102 For the draft determination, we have reviewed the expenditure proposed by the companies and excluded the following major items of investment:

- Innovation funding for gas filling stations proposed by PNGL, where we concluded that there was not yet sufficient justification to support the case for investment.
- IT and systems upgrade proposed by FE, which, in our view was funded in a previous price control.

7.103 We will continue to review and challenge the business as usual other capex investment for the final determination.

General Approach – Traffic Management Act

7.104 Our overall approach to possible future implementation of additional traffic management legislation in Northern Ireland is set out at paragraph 7.62 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 a retrospective adjustment 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

7.105 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.

7.106 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.

7.107 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 – UR Proposals

FE - Overview

7.108 FE's business plan included capital investment of £89.30m in GD17 in Dec 2014 prices. The draft determination allows capital investment of £79.80m following the application of the frontier shift.

7.109 An explanation of the changes made to the capital programme for the draft determination is given in the summary table below with more detailed information provided in the subsequent sections.

Item	Base Year Prices (£m)			Explanation
	BPT	DD	Var	
7 Bar Mains	**0.00**	**0.00**	**0.00**	
				N/A - no expenditure in Business Plan.
LP, 2Bar or 4Bar Mains	**50.05**	**44.92**	**-5.13**	
Infill	*47.45*	*42.71*	*-4.74*	*Allowance is based on the least cost properties to serve up to an average of 8.92 m/pp (68,941 properties). Unit rate redued to 69.5 £/m*
New Build	*2.60*	*2.21*	*-0.39*	*The length per property reduced to 9.5 m/pp, unit rate reduced to 48.5 £/m.*
Pressure Reduction	**0.32**	**0.09**	**-0.23**	
				MP Inlet (growth) included. End of life BINS replacement at 15 years removed.
Domestic Services	**21.52**	**20.19**	**-1.33**	
New Build	*1.67*	*1.59*	*-0.08*	*Unit rate reduced to £332.*
Existing	*19.85*	*18.59*	*-1.25*	*Number of connections increased to 25,250. Unit rate reduced to £736.*
Domestic Meters	**4.72**	**6.79**	**2.07**	
New	*4.51*	*5.76*	*1.25*	*The number of meters increased to 30,050. Unit rate increased to £192.*
Replacement	*0.21*	*0.00*	*-0.21*	*Replacement expenditure has been removed based on a minimum life of 20 years.*
Other Exchange	*0.00*	*1.03*	*1.03*	*Exchange meters transferred from opex section.*
I&C Services	**2.68**	**1.77**	**-0.90**	
				Basket of works unit rates applied.
I&C Meters	**1.42**	**1.40**	**-0.01**	
New	*1.37*	*1.40*	*0.04*	*Basket of works unit rates applied.*
Replacement	*0.05*	*0.00*	*-0.05*	*Replacement expenditure has been removed based on a minimum life of 20 years.*
Exchange	*0.00*	*0.00*	*0.00*	*N/A - no expenditure in Business Plan.*
Other Capex	**1.13**	**0.73**	**-0.40**	
				IT project has been removed from plan.
TMA	**7.46**	**6.69**	**-0.77**	
				The variance equates to 10% of total net draft determination adjustment for mains and services.
Sub Total	**89.30**	**82.59**	**-6.71**	
Post RPE Adjustment	**0.00**	**-2.79**	**-2.79**	
Draft Determination	**89.30**	**79.80**	**-9.50**	

Table 98: FE Summary for GD17

FE - Detailed Assessment

FE - 7 Bar Mains

FE - Reinforcement

7.110 FE does not plan to lay any 7 bar mains during the GD17 price control period.

FE - Low and Medium Pressure Mains

FE Infill Mains – Growth

7.111 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 67,273 (73%) of these properties in GD17 with the remainder passed in the early years of the next price control.

7.112 FE provided detailed plans for the development of gas mains in each town comprising 621 individual projects. Each project assessment included a detailed layouts 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.

7.113 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.

7.114 The annual rates of investment, properties passed and length of mains laid proposed by FE are summarised below.

	2017	2018	2019	2020	2021	2022	GD17
Investment (£m)	7.804	7.580	7.628	7.951	7.886	8.602	47.451
Properties passed (nr)	11,366	11,120	11,645	10,573	10,882	11,687	67,273
Mains Laid (km)	113	112	110	109	111	112	667
m per property passed	9.95	10.05	9.47	10.28	10.23	9.57	9.92
£ per property passed	687	682	655	752	725	736	705

Table 99: Annual Infill Investment Proposed by FE

7.115 In Section 7.10, above we described the economic test which we applied to determine whether further development of the gas network to serve existing areas is economic. We concluded that it is economic to pass additional properties up to an average of £620 per property and 8.92m per property passed. Neither the overall package of development proposed for GD17, nor the package of work proposed for any individual years, met this test.

7.116 As an alternative, we considered a basket of projects which could be delivered at least cost per property passed. We ranked the proposed schemes by cost per property and identified the basket of works which could be delivered up to the limit of our economic test. The results of this ranking is summarised in Table 100. The package of infill included in the draft determination for GD17 consists of 68,941 properties passed in GD17 at an average of 8.92 m/pp.

Percentile	Properties passed	Length of main (km)	Investment £m	£/pp	m/pp
20%	18469	118	8.3	451	6.40
40%	36938	282	19.7	533	7.64
50%	46172	367	25.9	561	7.95
60%	55406	462	32.7	590	8.34
70%	64641	561	39.7	615	8.68
80%	73875	673	47.9	648	9.11
90%	83110	788	57.1	687	9.48
100%	92344	967	74.8	810	10.47

Table 100: FE Infill Schemes Ranked by Cost per Property

7.117 An inspection of the projects affected by this change revealed that the key driver for cost per property was length per property served. As a consequence of our draft determination, schemes with shorter lengths per property are deemed to be economic. However, it is likely that longer lengths per property served correlates to larger properties with higher gas burns which could be economic. We have asked FE to provide further information on gas burns for different property types to test this and we will use this information to inform our final determination. Pending the outcome of this work, we have included the remaining investment proposed by FE in GD23 to pass all 92,344 properties included in its plans.

7.118 We have calculated our allowances by pro rataing the GDN's submission by pipe size and by mains driver to our determined length and applying the appropriate basket of works unit rate for each pipe size, thereby retaining the overall balance of the GDN's workload as proposed in their business plan submission.

FE - New Build Mains – Growth

7.119 The provision of gas mains to serve new development proposed by FE is summarised in Table 101.

New Build Mains: Growth	2017	2018	2019	2020	2021	2022
Properties passed (no)	896	797	800	800	800	800
Length (m)	9,689	8,160	8,160	8,160	8,160	8,160
FE submission (£k)	526	417	416	415	414	412

Table 101: FE Proposed New Build Mains and Outputs

7.120 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 draft determination.

7.121 The expenditure allowance in the draft determination is based on an average of 9.5 m per property, reflecting the combined experience of FE and PNGL. The draft determination allowance is based on a basket of works unit rate for new build of 48.48 £/m. We recognise the potential for the average length per property passed to vary if the mix of new development changes. The profile of connections and investment in the draft determination is shown in Table 102.

New Build Mains: Growth	2017	2018	2019	2020	2021	2022
Properties passed (no)	800	800	800	800	800	800
Length (m)	7,600	7,600	7,600	7,600	7,600	7,600
UR draft determination (£k) Pre RPE	370	365	366	371	368	370

Table 102: FE Draft Determination New Build Mains and Outputs

FE Low and Medium Pressure Mains – Draft determination summary

Other Mains: Growth	2017	2018	2019	2020	2021	2022
Properties passed (no)	11,691	11,545	11,400	11,237	11,503	11,565
Length (m)	104,258	102,964	101,668	100,210	102,588	103,135
UR draft determination (£k) Pre RPE	7,283	7,092	7,017	7,005	7,127	7,187

Table 103: FE Draft Determination Other Mains: Growth

FE - District Governors and Pressure Reduction Stations

FE – PRS - Growth

7.122 We reviewed the forecast activity volumes and costs associated with the construction of PRS installations. The levels are consistent with historical performance and reduced from that submitted in GD14. We therefore accept the forecast costs as presented in Table 104.

District governors & PRS: Growth	2017	2018	2019	2020	2021	2022
FE submission (No.)	2	4	7	7	5	5
UR draft determination (No.)	2	4	7	7	5	5
UR draft determination (£k) Pre RPE	7	13	24	23	8	19

Table 104: FE Pressure Reducing Stations: Growth

FE – PRS - Replacement

7.123 FE proposed replacing approximately 20% of their governor's by the end of GD17. In view of the fact that PNGL plan to maintain similar installations over a 20 year period, we have not allowed investment for end-of-life replacement PRS installations proposed by FE.

FE - Domestic Service Connections

7.124 FE plan to connect 26,324 domestic customers over the GD17 price control period, 4,800 each of new build and NIHE properties, with the remaining 16,724 owner occupier properties as shown in Table 105.

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 105: FE Submission Domestic Services: Growth

7.125 We have concluded that the company's projections of new build and NIHE connections were reasonable. We have increased the target number of existing owner occupier connections in GD17 to 20,450 to reflect the planned mains laying programme in GD17 and the additional properties passed.

7.126 We have applied the basket of works unit rates to estimate the appropriate allowance for the draft determination. The profile of connections and investment in the draft determination is shown in Table 106.

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 draft determination (£k) Pre RPE	2,770	3,027	3,285	3,506	3,727	3,874

Table 106: FE Draft Determination Domestic Services: Growth

FE - Industrial and Commercial Service Connections

7.127 FE forecast 150 I&C connections in each year of GD17 totalling 900 over the GD17 period. The profile showing the size of each connection and the total requested allowance is shown in Table 107.

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

Table 107: FE Submission I&C Services: Growth

7.128 We have accepted the numbers of I&C connections proposed by FE. Our allowances are calculated by applying the appropriate basket of works unit rates. The profile of connections and investment in the draft determination for I&C services is shown in Table 108.

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
UR draft determination (£k) Pre RPE	296	296	296	296	296	296

Table 108: FE Draft Determination I&C services: Growth

FE - Domestic Meters

FE Domestic Meters – Growth

7.129 FE's business plan included a domestic meter at each new connection. The numbers and cost of domestic meters proposed by FE are shown in Table 109.

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 109: FE Submission Domestic Meters: Growth

7.130 We have increased the number of domestic meters in the draft determination to reflect our decision to increase the target number of owner occupier connections (see paragraph 7.125 above). We have applied the basket of works unit rates to estimate the appropriate allowance for the draft determination. The profile of connections and investment in the draft determination is shown in Table 110.

Domestic Meters: Growth	2017	2018	2019	2020	2021	2022
Domestic Total	4,200	4,550	4,900	5,200	5,500	5,700
UR draft determination (£k) Pre RPE	805	872	939	997	1,054	1,093

Table 110: FE Draft Determination Domestic Meters: Growth

FE Domestic Meter Replacement

7.131 FE proposed to replace domestic meters after fifteen years as shown in Table 111.

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 111: FE Submission Domestic Meters: Replacement

7.132 PNGL currently operate their meter stock past this age, proposing to replace domestic meters at twenty years. In view of this we have excluded the end-of-life replacement of meters proposed by FE from the draft determination.

7.133 FE replace meters for reasons other than end-of-life and the costs associated with these were included in its business plan under opex costs. For the draft determination, we

have transferred these costs from opex to capex as a lump sum for each year as shown in Table 112.

Domestic Meters: Replacement	2017	2018	2019	2020	2021	2022
Domestic Total	0	0	0	0	0	0
Transfer of meter costs from Opex (£k) Pre RPE	128	144	160	178	199	219
UR draft determination (£k) Pre RPE	128	144	160	178	199	219

Table 112: Daft Determination Domestic Meters: Replacement

FE - Industrial and Commercial Meters

FE - Industrial and Commercial Meters – Growth

7.134 FE's business plan included an I&C meter at each new connection. The numbers and cost of I&C meters proposed by FE are shown in Table 113.

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

Table 113: FE Submission I&C Meters: Growth

7.135 We have accepted the numbers of I&C connections proposed by FE. We have applied the basket of works unit rates to estimate the appropriate allowance for the draft determination. The profile of connections and investment in the draft determination is shown in Table 114.

7.136 Our allowances have been calculated by applying the appropriate basket of works unit rate to the number of I&C meters of the size proposed by FE in their business plan

I&C Meters: Growth	2017	2018	2019	2020	2021	2022
I&C Total	150	150	150	150	150	150
UR draft determination (£k) Pre RPE	239	248	229	229	229	229

Table 114: FE Draft Determination I&C Meters: Growth

FE - Industrial and Commercial Meter Replacement

7.137 As with domestic meters FE propose to begin replacing I&C meters after fifteen years of life. The numbers and cost of replacement I&C meters proposed by FE are shown in Table 115.

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 115: FE Submission I&C Meters: Replacement

7.138 As with domestic meters, we note that FE currently operate their meter stock past fifteen years age, proposing to begin replacing meters at twenty years. In view of this we have

excluded the end-of-life replacement of meters proposed by FE from the draft determination.

FE - Other Capex

7.139 FE submitted allowances for IT transformation in 2017 of £500k. We have removed this allowance as funding has been provided for this previously. The remaining costs including a small amount for transport are included in the draft determination and we will give further consideration to this in the final detemination. FE's submission and our allowance is shown in Table 116.

Other Capex	2017	2018	2019	2020	2021	2022
FE submission (£k)	564	114	114	114	114	114
UR draft determination (£k) Pre RPE	164	114	114	114	114	114

Table 116 FE Other capex

FE - Traffic Management Act

7.140 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

7.141 In Table 117 we set out a summary of the FE's capex submission and our total capex allowance pre and post RPE for the draft determination.

FE Draft 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 Draft Determination pre PRE (£k)							
7 Bar Mains	0	0	0	0	0	0	0
LP, 2Bar or 4Bar Mains	7,653	7,457	7,383	7,375	7,496	7,556	44,921
Pressure Reduction	7	13	24	23	8	19	95
Domestic Services	2,770	3,027	3,285	3,506	3,727	3,874	20,189
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	164	114	114	114	114	114	733
TMA	1,072	1,078	1,096	1,118	1,152	1,173	6,688
Total	13,134	13,249	13,526	13,836	14,274	14,573	82,592
UR Draft Determination post PRE (£k)							
7 Bar Mains	0	0	0	0	0	0	0
LP, 2Bar or 4Bar Mains	7,548	7,278	7,148	7,097	7,170	7,184	43,425
Pressure Reduction	7	13	23	22	8	18	91
Domestic Services	2,731	2,955	3,180	3,374	3,565	3,683	19,489
Domestic Meters	920	992	1,065	1,131	1,199	1,247	6,553
I&C Services	292	289	286	285	283	281	1,715
I&C Meters	236	242	222	220	219	218	1,357
Other Capex	162	111	110	110	109	108	709
TMA	1,057	1,052	1,061	1,076	1,102	1,115	6,463
Total	12,953	12,931	13,096	13,314	13,653	13,855	79,802

Table 117: FE Draft Determination Capex Allowance

FE – Capital Expenditure Assumptions Post GD17

7.142 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 did not include in the GD17 period in our determination. The long term profile of connections also takes account of this. As noted above, we have carried out an economic test of this investment and concluded it is not economic. We have asked FE to provide further information on estimated gas consumption for the associated properties which may demonstrate that some or all of this infill is economic. We will adjust the final determination to reflect our assessment of economic infill taking account of this additional data.

- 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 by extending the connection profiles shown in section 7.124 taking account of 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 and none have been included 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 exceptional items.
- We have continued an allowance for TMA costs at 10% of mains and services.

7.143 We have not applied real price effects of frontier shift to estimated expenditure post GD17.

PNGL – UR Proposals

PNGL – Overview

7.144 PNGL's business plan included capital investment of £91.46 m in GD17 in Dec 2014 prices. The draft determination allows capital investment of £67.82m following the application of the frontier shift.

7.145 An explanation of the changes made to the capital programme for the draft determination is given in the summary table below with more detailed information provided in the subsequent sections.

7.146 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. They have been identified separately. The main issues to note that are specific to East Down are that it was subject to a DETI economic assessment and an element of it will be included under Postalised Distribution Pipelines (PDPs). This is covered in more detail in section 7.148.

We have identified the East Down elements of the project in each section below. We have also included a specific section to cover costs of the East Down bulk mains. As covered in section 7.148 it is proposed that the costs of bulk mains will be included in the Postalised Distribution Pipelines (PDP) and would be subsequently be included in the asset base of a transmission licence. However the costs included here form part of our draft determination for consultation.

Item	Base Year Prices (£m)			Explanation
	BPT	DD	Var	
7 Bar Mains	**1.41**	**1.13**	**-0.29**	
				The scope of works has been included. The unit rates for 7 bar mains has been reduced.
LP, 2Bar,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*	*Number of new build properties reduced from 3000 to 2000 per annum. The length 9.5m unit rate reduced to 48 £/m.*
Pressure Reduction	**0.73**	**0.60**	**-0.13**	
				IP Inlet growth expenditure has been removed.
Domestic Services	**28.67**	**30.38**	**1.71**	
New Build	*4.81*	*3.99*	*-0.82*	*New build connections reduced from 3000 to 2000 per annum. Unit rate increased to £332*
Existing	*23.86*	*26.39*	*2.53*	*Number of connections increased to 35,840 in GD17. The unit rate reduced to £736.*
Domestic Meters	**23.23**	**19.45**	**-3.78**	
New	*12.36*	*9.19*	*-3.17*	*New connections increase by 240. Unit rate reduced to £192.*
Replacement	*6.84*	*6.96*	*0.12*	*Unit rate increased to £151.*
Other Exchange	*4.04*	*3.32*	*-0.71*	*Unit rate reduced to £192.*
I&C Services	**2.41**	**3.07**	**0.66**	
				Basket of works unit rates applied.
I&C Meters	**10.69**	**4.68**	**-6.01**	
New	*2.18*	*2.19*	*0.01*	*Basket of works unit rates applied.*
Replacement	*6.31*	*0.37*	*-5.94*	*U6 meter replacement included at £130. Replacement of larger I&C meters removed pending development of supporting business case.*
Exchange	*2.20*	*2.12*	*-0.08*	*Basket of works unit rates applied.*
Other Capex	**3.18**	**1.43**	**-1.75**	
				The innovation programme has been removed from plan.
TMA	**4.88**	**4.00**	**-0.87**	
				The variance equates to 10% of total net draft determination adjustment for mains and services.
Sub Total	**91.46**	**70.18**	**-21.28**	
Frontier shift	**0.00**	**-2.36**	**-2.36**	
Draft Determination	**91.46**	**67.82**	**-23.64**	

Table 118: PNGL Summary for GD17

PNGL – 7 Bar Mains and East Down Bulk Mains

PNGL – East Down Bulk Mains

7.147 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 pressure ranging from 7 bar 450mm mains to 4 bar 125mm mains.

7.148 We have based our determination on a recent competitive tender for a 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).

7.149 In addition, we propose to set an allowance for elements of the project relating to significant engineering barriers which concentrate on crossing rivers and main roads. We propose to ring fence an amount of £100k for each element which are made up of rivers in Lisburn, Drumaness, two in Downpatrick, and the A1 and M1 road crossings. The ring fenced amount will be subject to further consideration once more detail is available.

7.150 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 we have not included them in the summary tables that follow. The issue of treatment of East Down costs is covered in more detail from paragraph 11.101.

PNGL – Reinforcement

7.151 PNGL identified one 7bar (intermediate pressure mains) reinforcement project consisting of a 7 bar main approximately 5km in length to maintain pressure in the Bangor and Newtownards areas as new connections are made.

7.152 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.

7.153 PNGL provided summary network modelling information and existing pressure records to support its proposal and advised us that its analysis and design is based on conditions experienced in the winter of 2010-11, includes interruptible supply loads (which the company noted had minimal impact) and takes account of local experience of diversity on peak demand. In advance of the final determination, we ask that the company 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.

7.154 As above, we have based our determination on a recent competitive tender for a 7 bar main similar in nature which was used for setting an allowance for PNGL's 7 bar bulk main 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.

7.155 This allowance is allocated specifically for this project and as such is a nominated output for PNGL in GD17.

7 bar mains: Reinforcement	2017	2018	2019	2020	2021	2022
PNGL submission (£k)	0	0	0	1,412	0	0
UR draft determination (£k) Pre RPE	0	0	0	1,126	0	0

Table 119: PNGL 7 bar Mains: Reinforcement

7.156 If the company decides that the main 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.

PNGL – Low and Medium Pressure Mains – Excluding East Down

PNGL Infill mains – Growth (Excluding East Down)

7.157 In its GD17 business plan submission PNGL requested an allowance to pass approximately 5700 existing owner occupier properties. These properties represent the remainder of what PNGL considers reasonable to connect on its network.

7.158 PNGL developed detailed assessments for half these properties and projected the results of that analysis to estimate the cost of passing all 5700 properties. Each detailed project assessment included a detailed plan of mains, a schedule of works priced using current tendered rates and an economic assessment of the project.

7.159 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.

7.160 The annual rates of investment, properties passed and length of mains laid proposed by PGNL are summarised below.

	2017	2018	2019	2020	2021	2022	GD17
Investment (£m)	1.001	0.988	1.181	1.100	1.191	0.334	5.796
Properties passed (nr)	1,105	1,105	1,105	1,105	1,105	205	5,730
Mains Laid (km)	14	14	14	14	14	3	74
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 120 Annual Infill Investment Proposed by PGNL

7.161 In Section 7.10 above we described the economic test which we applied to determine whether further development of the gas network to serve existing areas 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 years met this test. Inspection of the individual projects revealed that the most beneficial project had a cost per property passed of £619.

7.162 Based on our economic assessment of PNGL's proposals we conclude that none of PNGL's infill is warranted and we have not made any allowance for future infill in the draft determination. The uncertainty and incentive mechanism relating to properties passed will continue to apply to PNGL, allowing the company to complete further infill projects where these are economic.

PNGL New Build Mains – Growth (Excluding East Down)

7.163 The extent of new gas mains to serve new development proposed by PNGL is summarised in Table 121.

New Build Mains: Growth	2017	2018	2019	2020	2021	2022
Properties passed (no)	2,900	3,000	3,000	3,000	3,000	3,000
Length (m)	30,223	31,265	31,265	31,265	31,265	31,265
PNGL submission (£k)	1,863	1,896	1,664	1,550	1,678	1,813

Table 121: PNGL Proposed New Build Mains and Outputs

7.164 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 draft determination, we have included 2,000 new build properties per annum.

7.165 The expenditure allowance in the draft determination is based on an average of 9.5m per property, reflecting the combined experience of PNGL and FE. The draft determination allowance is based on a basket of works unit rate for new build of 47.71 £/m. The profile of connections and investment in the draft determination is shown in Table 122.

New Build Mains: Growth	2017	2018	2019	2020	2021	2022
Properties passed (no)	2,000	2,000	2,000	2,000	2,000	2,000
Length (m)	19,000	19,000	19,000	19,000	19,000	19,000
UR draft determination (£k) Pre RPE	907	901	914	905	905	905

Table 122: PNGL Draft Determination New Build Mains and Outputs

PNGL – Low and Medium Pressure Mains –East Down

PNGL Low and Medium Pressure Mains – East Down

7.166 We have not applied an economic test for infill mains in East Down as DETI considered this under its appraisal when making its decision to support gas to East Down.

7.167 We have reviewed the length of main proposed by PNGL for East Down and accepted the company's proposals as shown in Table 123. The only adjustment we made was to increase the allowance for new build properties to 9.5m/pp in order to maintain equality with other proposals within this draft determination as displayed in Table 124.

		GD17					
East Down Mains	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
New Build (m)	0	672	672	672	672	672	672
Other (m)	19,414	49,414	49,414	35,607	35,607	35,607	35,607
PNGL East Down submission (£k)	1,831	3,866	3,866	2,409	2,409	2,409	2,409

Table 123: PNGL Submission East Down Mains

		GD17					
East Down Mains	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
New Build (m)	0	1,064	1,064	1,064	1,064	1,064	1,064
Other (m)	19,414	49,414	49,414	35,607	35,607	35,607	35,607
UR draft determination (£k) Pre RPE	1,856	3,926	3,926	2,448	2,448	2,448	2,448

Table 124: PNGL Draft Determination East Down Mains

7.168 We have calculated our allowances from the GDN's submission by applying the appropriate basket of works unit rate for each pipe size.

PNGL – District Governors and Pressure Reduction Stations

PNGL – PRS Reinforcement

7.169 We have reviewed PNGL's paper 'Network Reinforcement' where PNGL propose to reinforce their network with three district governors. We have accepted these proposals and the company's estimates. We have not included the expenditure proposed for year 2022 which did not have a specific output. The allowances included in the draft determination are set out in Table 125.

District governors & PRS Reinforcement	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
PNGL submission (No.)	0	1	2	0	0	0
UR draft determination (No.)	0	1	2	0	0	0
UR draft determination (£k) Pre RPE	0	84	161	0	0	0

Table 125: PNGL Pressure Reducing Stations: Reinforcement

PNGL – PRS Replacement

7.170 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 draft determination as shown in Table 126.

District governors & PRS Replacement	2017	2018	2019	2020	2021	2022
PNGL submission (No.)	0	9	33	65	50	31
UR draft determination (No.)	0	9	33	65	50	31
UR draft determination (£k) Pre RPE	0	17	63	115	96	64

Table 126: PNGL Pressure Reducing Stations: Replacement

PNGL – Service Connections

PNGL – Domestic service connections (excluding East Down)

7.171 PNGL plan to connect 47,600 domestic customers over the GD17 price control period, 17,600 of new build, 6,000 NIHE properties, with the remaining 24,000 owner occupier properties as shown in Table 127.

Domestic Services: Growth	2017	2018	2019	2020	2021	2022
New Domestic Service (New Build)	2,800	2,800	3,000	3,000	3,000	3,000
New Domestic Service (OO)	4,000	4,000	4,000	4,000	4,000	4,000
New Domestic Service (NIHE)	1,000	1,000	1,000	1,000	1,000	1,000
PGNL submission (£k)	4,769	4,771	4,842	4,837	4,838	4,615

Table 127: PNGL Submission Domestic Services: Growth

7.172 We have concluded that the company's projections of and NIHE connections was reasonable. We have increased the target number of existing owner occupier connections in GD17 to 29,840. We have reduced the number of new build connections to 2,000 per annum (see paragraph 5.13 above).

7.173 We have applied the basket of works unit rates to estimate the appropriate allowance for the draft determination. The profile of connections and investment in the draft determination is shown in Table 128.

Domestic Services: Growth	2017	2018	2019	2020	2021	2022
New Domestic Service (New Build)	2,000	2,000	2,000	2,000	2,000	2,000
New Domestic Service (OO)	5,670	5,390	5,120	4,860	4,600	4,200
New Domestic Service (NIHE)	1,000	1,000	1,000	1,000	1,000	1,000
UR draft determination (£k) Pre RPE	5,576	5,370	5,171	4,980	4,788	4,494

Table 128: PNGL Draft Determination Domestic Services: Growth

PNGL – Domestic service connections - East Down

7.174 PNGL estimate of domestic connections for East Dow is shown in Table 129.

Domestic Services: Growth	2017	2018	2019	2020	2021	2022
New Domestic Service (New Build)	112	112	112	112	112	112
New Domestic Service (OO)	145	145	238	433	452	428
New Domestic Service (NIHE)	23	104	46	112	156	152
East Down submission (£k)	155	211	234	410	452	434

Table 129: ED Submission Domestic Services: Growth

7.175 We have applied an upward adjustment for owner occupier connections based on our analysis giving a total of 2,560. We have retained PNGL's proposals for new build and NIHE connections.

7.176 We have applied the basket of works unit rates to estimate the appropriate allowance for the draft determination. The profile of connections and investment in the draft determination are shown in Table 130

Domestic Services: Growth	2017	2018	2019	2020	2021	2022
New Domestic Service (New Build)	112	112	112	112	112	112
New Domestic Service (OO)	130	260	380	490	600	700
New Domestic Service (NIHE)	23	104	46	112	156	152
UR draft determination (£k) Pre RPE	150	305	351	481	594	665

Table 130: ED Draft Determination Domestic Services: Growth

PNGL – Industrial and Commercial Service Connections

7.177 PNGL forecasts to connect 305 I&C services in each year of GD17 totalling 1,830 over the GD17 period. The profile showing the size of each connection and the total requested allowance is shown in Table 131.

I&C Services: Growth	2017	2018	2019	2020	2021	2022
I&C Very Small (U6)	156	156	156	156	156	156
I&C Small (U16-U40)	128	128	128	128	128	128
I&C Medium (U65-U160)	17	17	17	17	17	17
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)	406	406	404	403	403	385

Table 131: PNGL Submission I&C Services: Growth

7.178 We have accepted the company's proposals and applied the basket of works unit rates to estimate the appropriate allowance for the draft determination. The profile of connections and investment in the draft determination is shown in Table 132.

I&C Services: Growth	2017	2018	2019	2020	2021	2022
I&C Very Small (U6)	157	157	157	157	157	157
I&C Small (U16-U40)	128	128	128	128	128	128
I&C Medium (U65-U160)	16	16	16	16	16	16
I&C Large (U250-U650)	4	4	4	4	4	4
I&C Very Large (>U650)	0	0	0	0	0	0
UR draft determination (£k) Pre RPE	512	512	512	512	512	512

Table 132: PNGL Draft Determination I&C services: Growth

PNGL – Industrial and Commercial Service Connections - East Down

7.179 PNGL forecasts to connect 510 I&C services over the GD17 price control period. The profile showing the size of each connection and the total requested allowance is shown in Table 133.

I&C Services: Growth	2017	2018	2019	2020	2021	2022
I&C Very Small (U6)	42	39	50	80	53	75
I&C Small (U16-U40)	19	18	23	37	25	35
I&C Medium (U65-U160)	2	1	2	3	2	3
East Down submission (£k)	51	48	62	98	66	93

Table 133: ED Submission I&C services: Growth

7.180 We have accepted the company's proposals and applied the basket of works unit rates to estimate the appropriate allowance for the draft determination. The profile of connections and investment in the draft determination is shown in Table 134.

I&C Services: Growth	2017	2018	2019	2020	2021	2022
I&C Very Small (U6)	42	39	50	80	53	75
I&C Small (U16-U40)	19	18	23	37	25	35
I&C Medium (U65-U160)	2	1	2	3	2	3
UR draft determination (£k) Pre RPE	90	84	108	171	114	162

Table 134: ED Draft Determination I&C services: Growth

PNGL – Domestic Meters

PNGL – Domestic Meters - Growth

7.181 PNGL's business plan included a domestic meter at each new connection. The numbers and cost of domestic meters proposed by PNGL are shown in Table 135.

Domestic Meters: Growth	2017	2018	2019	2020	2021	2022
Domestic Total	7,800	7,800	8,000	8,000	8,000	8,000
PNGL submission (£k)	2,045	2,029	2,060	2,065	2,065	2,090

Table 135 PNGL Submission Domestic Meters: Growth

7.182 We have adjusted the number of domestic meters in the draft determination to reflect our proposal to increase the target number of owner occupier connections and reduce the number of new build connections. We have applied the basket of works unit rates to

estimate the appropriate allowance for the draft determination. The profile of connections and investment in the draft determination is shown in Table 136.

Domestic Meters: Growth	2017	2018	2019	2020	2021	2022
Domestic Total	8,670	8,390	8,120	7,860	7,600	7,200
UR draft determination (£k) Pre RPE	1,662	1,609	1,557	1,507	1,457	1,380

Table 136: PNGL Draft Determination Domestic Meters: Growth

PNGL – East Down – Domestic Meters Growth

7.183 The number of domestic connections and meters included in PNGL's plans for East Down are shown in Table 137.

Domestic Meters: Growth	2017	2018	2019	2020	2021	2022
Domestic Total	279	361	395	656	719	692
East Down submission (£k)	61	79	86	144	157	151

Table 137 ED Submission domestic meters: Growth

7.184 We have adjusted the number of domestic meters in the draft determination to reflect our proposal to increase the target number of owner occupier connections over the GD17 period. We have applied the basket of works unit rates to estimate the appropriate allowance for the draft determination. The profile of connections and investment in the draft determination is shown in Table 138.

Domestic Meters: Growth	2017	2018	2019	2020	2021	2022
Domestic Total	265	476	538	714	868	964
UR draft determination (£k) Pre RPE	51	91	103	137	166	185

Table 138: ED Draft Determination Domestic Meters: Growth

PNGL – Domestic Meters Replacement

7.185 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 prepare an economic appraisal of the life cycle costs of meter replacement taking account of battery replacement and 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 initial view is that it is appropriate to allow funding for a 20 year cycle of replacement of domestic meters. This provides a strong incentive for PNGL to defer replacement where appropriate. We re-profiled PNGL's end-of-life replacement meters to match the profile of meter installation rather than the smoothed profile proposed by PNGL.

7.186 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 included an allowance for this work in the draft determination and will consider further in the final determination.

7.187 We have applied the basket of works unit rates to estimate the appropriate allowance for the draft determination. We amended the rates for meter replacement to reflect the proportion of credit and PAYG meters in which will be replaced.

7.188 PNGL's proposed investment in domestic meters is shown in Table 139. The profile of connections and investment in the draft determination is shown in Table 140.

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 139: PNGL Submission Domestic Meters: Replacement

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 draft 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 draft determination (£k) Pre RPE	553	553	553	553	553	553

Table 140: PNGL Draft Determination Domestic Meters: Replacement

PNGL – Industrial and Commercial Meters Growth

7.189 PNGL's business plan included an I&C meter at each new connection. The numbers and cost of I&C meters proposed by PNGL are shown in Table 141.

I&C Meters: Growth	2017	2018	2019	2020	2021	2022
I&C Total	305	305	305	305	305	305
PNGL submission (£k)	359	359	357	356	356	391

Table 141: PNGL Submission I&C Meters: Growth

7.190 We have accepted the numbers of new I&C meters proposed by PNGL. We have applied the basket of works unit rates to estimate the appropriate allowance for the draft determination. The profile of connections and investment in the draft determination is shown in Table 142.

I&C Meters: Growth	2017	2018	2019	2020	2021	2022
I&C Total	305	305	305	305	305	305
UR draft determination (£k) Pre RPE	365	365	365	365	365	365

Table 142: PNGL Draft Determination I&C Meters: Growth

PNGL – Industrial and Commercial Meters Growth - East Down

7.191 The number of I&C meters included in PNGL's plan for East Down are shown in Table 143.

I&C Meters: Growth	2017	2018	2019	2020	2021	2022
I&C Total	63	59	76	119	80	113
East Down submission (£k)	21	20	26	41	27	39

Table 143: ED Submission I&C Meters: Growth

7.192 We have accepted the numbers of new I&C meters proposed by PNGL. We have applied the basket of works unit rates to estimate the appropriate allowance for the draft determination. The profile of connections and investment in the draft determination is shown in Table 144.

I&C Meters: Growth	2017	2018	2019	2020	2021	2022
I&C Total	63	59	76	119	80	113
UR draft determination (£k) Pre RPE	41	38	49	77	52	73

Table 144: ED Draft Determination I&C Meters: Growth

PNGL – Industrial and Commercial Meters Replacement

7.193 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. These could be for changes in demand, or faults with meters, amongst various other reasons. The I&C meter replacement work included in the business plan is summarised in Table 145.

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 145: PNGL Submission I&C Meters: Replacement

7.194 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 have 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.

7.195 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 have not included the end-of-life replacement for larger meters at 20 years as proposed by PNGL. We expect 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. This should consider replacement on age, targeted replacement of key components or the continued maintenance of the plant over a longer life. We will consider the evidence the company presents before reaching our final determination.

7.196 We have applied the basket of works unit rates to estimate the appropriate allowance for the draft determination. The profile of connections and investment in the draft determination is shown in Table 146.

I&C Meters: Replacement						
I&C Total End of Life	186	360	399	544	702	654
UR draft determination (£k) Pre RPE	24	47	52	71	91	85
I&C Total Other Replacement	111	111	111	111	111	111
UR draft determination (£k) Pre RPE	353	353	353	353	353	353

Table 146: PNGL Draft Determination I&C Meters: Replacement

PNGL - Other Capex

7.197 PNGL submitted an allowance for the construction of compressed natural gas filling stations which has been discussed under Chapter 8 in this draft 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 telcoms, system operations, land, buildings, furniture and fittings have been accepted for the draft determination. PNGL's submission and our draft determination allowance is shown in Table 147. We will consider this allowance further in the final determination.

Other Capex	2017	2018	2019	2020	2021	2022
PNGL submission (£k)	819	819	829	239	239	239
UR draft determination (£k) Pre RPE	239	239	239	239	239	239

Table 147: PNGL Other Capex

PNGL - Traffic Management Act

7.198 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

7.199 In Table 148 we set out a summary of the PNGL's capex submission and our total capex allowance pre and post RPE for the draft determination.

PNGL Draft Determination	2017	2018	2019	2020	2021	2022	GD17
PNGL Business Plan 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
Total	14,848	14,947	15,117	15,756	14,429	16,360	91,457
East Down	4,155	4,224	2,817	3,101	3,112	3,126	20,534
UR Draft Determination pre PRE (£k)							
7 Bar Mains	0	0	0	1,126	0	0	1,126
LP, 2Bar or 4Bar Mains	907	901	914	905	905	905	5,439
Pressure Reduction	0	101	224	115	96	64	600
Domestic Services	5,576	5,370	5,171	4,980	4,788	4,494	30,380
Domestic Meters	2,374	2,749	2,930	3,440	3,649	4,312	19,454
I&C Services	512	512	512	512	512	512	3,071
I&C Meters	742	765	770	789	809	803	4,678
Other Capex	239	239	239	239	239	239	1,432
TMA	700	678	660	752	621	591	4,002
Total	11,050	11,316	11,419	12,858	11,619	11,920	70,181
East Down	4,673	4,876	3,349	3,623	3,690	3,860	24,071
UR Draft Determination post PRE (£k)							
7 Bar Mains	0	0	0	1,083	0	0	1,083
LP, 2Bar or 4Bar Mains	895	880	884	871	866	861	5,257
Pressure Reduction	0	99	217	111	92	61	579
Domestic Services	5,500	5,241	5,007	4,792	4,580	4,272	29,392
Domestic Meters	2,341	2,683	2,837	3,311	3,490	4,100	18,761
I&C Services	505	500	496	493	490	487	2,969
I&C Meters	732	746	745	759	774	763	4,520
Other Capex	235	233	231	230	228	227	1,384
TMA	690	662	639	724	594	562	3,870
Total	10,897	11,044	11,055	12,373	11,113	11,333	67,816
East Down	4,609	4,759	3,243	3,487	3,529	3,669	23,296

Table 148: PNGL Draft Determination Capex Allowance

PNGL – Capital Expenditure Assumptions Post GD17

7.200 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 2,000 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 new development based on the connection profiles included in Section 7.171.
- 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 for the replacement of domestic meters, U6 I&C meters and pressure reducing stations on a 20 year life. We have deferred the replacement of U16 and greater I&C meters post GD17.
- 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.

7.201 We have not applied real price effects of frontier shift to estimated expenditure post GD17.

SGN – UR Proposals

SGN - Overview

7.202 SGN's business plan included capital investment of £54.39m in GD17 in Dec 2014 prices. The draft determination allows capital investment of £45.70m following the application of the frontier shift.

An explanation of the changes made to the capital programme for the draft determination is given in the summary table below with more detailed information provided in the subsequent sections.

Item	Base Year Prices (£m)			Explanation
	BPT	DD	Var	
7 Bar Mains	**0.00**	**0.00**	**0.00**	
				N/A - no expenditure in Business Plan.
LP, 2Bar or 4Bar Mains	**37.88**	**29.97**	**-7.90**	
Infill	*37.56*	*29.31*	*-8.25*	*Length of mains increased by 25 km, unit rate per metre reduced to 72.8 £/m.*
New Build	*0.32*	*0.67*	*0.35*	*New build properties passed increased to 1442. Length per property passed increased to 9.5 m. Unit rate increased to 48.7 £/m.*
Pressure Reduction	**4.91**	**0.57**	**-4.34**	
				Number of PRS reduced to 119, unit rates reduced to the average of contract rates for PNGL and FE.
Domestic Services	**5.10**	**5.74**	**0.64**	
New Build	*0.10*	*0.48*	*0.38*	*Number of connections increased to 1442, unit rate reduced to 332.*
Existing	*5.00*	*5.26*	*0.25*	*Connections increased to 7140, unit rate reduced to £736.*
Domestic Meters	**1.11**	**1.65**	**0.53**	
New	*1.11*	*1.65*	*0.53*	*Number of connections increased to 8,582, unit rate reduced to £192.*
Replacement	*0.00*	*0.00*	*0.00*	*N/A - no expenditure in Business Plan.*
Other Exchange	*0.00*	*0.00*	*0.00*	*N/A - no expenditure in Business Plan.*
I&C Services	**0.99**	**1.33**	**0.34**	
				I&C connections increased from 164 to 403. Basket of works unit rates applied.
I&C Meters	**1.58**	**1.87**	**0.28**	
New	*1.58*	*1.87*	*0.28*	*I&C connections increased from 164 to 403. Basket of works unit rates applied.*
Replacement	*0.00*	*0.00*	*0.00*	*N/A - no expenditure in Business Plan.*
Exchange	*0.00*	*0.00*	*0.00*	*N/A - no expenditure in Business Plan.*
Other Capex	**2.83**	**2.37**	**-0.46**	
TMA	**0.00**	**3.70**	**3.70**	
				This is 10% of the total draft determination allowance for mains and services.
Sub Total	**54.39**	**47.20**	**-7.19**	
Post RPE Adjustment	***0.00***	***-1.50***	***-1.50***	
Draft Determination	***54.39***	***45.70***	***-8.70***	

Table 149: PNGL Summary for GD17

SGN - Detailed Assessment

SGN - 7 Bar Mains

SGN - 7 Bar Mains - Reinforcement

7.203 SGN does not plan to lay any 7 bar mains during the GD17 price control period.

SGN - Low and Medium Pressure Mains

7.204 The annual rates of investment, properties passed and length of mains laid proposed by SGN are shown in

	2017	2018	2019	2020	2021	2022	GD17
Investment (£m)	7.048	9.175	7.668	4.564	4.564	4.564	37.582
Properties passed (nr)	4,504	4,586	4,554	4,553	4,542	4,543	27,283
Mains Laid (km)	70	92	77	46	46	46	378
m per property passed	15.65	20.11	16.89	10.10	10.12	10.12	13.84
£ per property passed	1,565	2,001	1,684	1,002	1,005	1,005	1,378

7.205 Table 150.

	2017	2018	2019	2020	2021	2022	GD17
Investment (£m)	7.048	9.175	7.668	4.564	4.564	4.564	37.582
Properties passed (nr)	4,504	4,586	4,554	4,553	4,542	4,543	27,283
Mains Laid (km)	70	92	77	46	46	46	378
m per property passed	15.65	20.11	16.89	10.10	10.12	10.12	13.84
£ per property passed	1,565	2,001	1,684	1,002	1,005	1,005	1,378

Table 150: SGN Submission Low and Medium Pressure Main: Growth

SGN Infill Mains – Growth

7.206 We have not applied an economic test for infill mains in SGN's case as DETI considered this under its appraisal when making its decision to support Gas to the West and East Down.

7.207 We have reviewed the length of main proposed by SGN and made adjustments to reflect the difference between the estimated total number of properties passed in the Business Plan submission and earlier estimates prepared during the development of the Gas to the West project

7.208 SGN has continued to develop its designs and provided additional explanation of this difference. Based on this additional information and in anticipation of further detailed information, we have included the following adjustments to domestic property numbers and lengths of mains for GD17

- We have added an additional 5,356 additional properties passed within the current design area will be served by the mains already identified by SGN in its Business Plan submission. We have assumed that additional mains will be required to pass 50% of these properties. We have included an additional allowance of 2,678 properties at 9.4 m/pp giving a total of 25.2 km over the GD17 period using the SGN average basket of works unit rate of £73 /m.

- On the advice of SGN, we have added an additional 1000 properties passed by medium pressure mains within its Business Plan designs for GD17.

7.209 We have calculated our allowances from the GDN's submission by pipe size and by mains driver and applying the appropriate basket of works unit rate for each pipe size.

Infill Mains: Growth	2017	2018	2019	2020	2021	2022
Properties passed (no)	5,720	5,738	5,720	5,701	5,701	5,701
Length (m)	75,183	98,385	82,033	49,035	49,035	49,035
UR draft determination (£k) Pre RPE	5,556	7,374	6,094	3,427	3,429	3,428

Table 151: SGN Draft Determination Low and Medium Pressure Main: Growth

7.210 Beyond GD17 and in the absence of any detailed information we have made further preliminary allowances for the following in GD23

- SGN advised that Moneymore, Ballymagorry and Artigarvin are not served in the initial design. We have allowed 2 IPRS, 1,379 properties at 9.4m/pp and 1km of potential spine mains over the first three years of GD23
- We estimate 1,000 properties closely associated with the existing designed network allowing 9.4m/pp and 6 MPRS to serve them in year one of GD23
- There are 5,851 properties which we are unable to identify but have allowed 9.4 m/pp and an additional 2.5 m/pp for spine mains and 15 MPRS to serve them spread over the six years of GD23. It should be noted however that at 11.9 m/pp these properties would likely be uneconomic to supply

7.211 SGN is continuing to develop the detail of its designs and estimates of mains length and property counts and has provided updates of this information to inform the draft determination. We expect the company with a further substantive update on the design and property counts by the end of April 2016 to allow us to take the improved information into account for the final determination.

SGN New Build Mains – Growth

7.212 The extent of the new gas mains to serve new development proposed by SGN is summarised in Table 152.

New Build Mains: Growth	2017	2018	2019	2020	2021	2022
Properties passed (no)	0	0	333	333	333	333
Length (m)	0	0	1,831	1,831	1,831	1,831
SGN submission (£k)	0	0	73	73	73	73

Table 152: SGN Proposed New Build Mains and Outputs

7.213 The company has estimated new development rates of 333 properties per annum. For the draft determination. Our draft determination is based on 361 new build properties per annum for each of the last four years of GD17 which aligns with the .

7.214 We have increased the allowance for new build properties to 9.5 m/pp to align with recent experience in Northern Ireland, consistent with the draft determination for PNGL and FE.

7.215 The draft 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 draft determination is shown in Table 153.

New Build Mains: Growth	2017	2018	2019	2020	2021	2022
Properties passed (no)	0	0	352	331	391	368
Length (m)	0	0	3,344	3,145	3,715	3,496
UR draft determination (£k) Pre RPE	0	0	163	153	181	170

Table 153: SGN Draft Determination new Build Mains and Outputs

SGN - District Governors and Pressure Reduction Stations

SGN – PRS - Growth

7.216 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 154.

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 154: SGN Submission Pressure Reducing Stations: Growth

7.217 In order to set an appropriate allowance for SGN over the GD17 period we have 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 . SGN request an allowance for a governor installation equivalent to 1.2 per km of main on their network. We have proratаed the governor type profile in SGN's business plan to allow for a governor installation for every 3.2km of main.

7.218 The unit costs used by SGN to estimate the costs of governors is significantly higher than the current contract rates available to FE and PNGL. For the draft determination, we have applied the average contract rates available to FE and PNGL to determine an allowance for governors for, allowing for uplifts to these rates for capitalised opex and management fees where appropriate. Our allowance for the GD17 period is shown in Table 155.

District governors & PRS: Growth	2017	2018	2019	2020	2021	2022
UR draft determination (No.)	20	17	22	21	20	19
UR draft determination (£k) Pre RPE	121	89	96	94	88	82

Table 155: SGN Draft Determination Pressure Reducing Stations: Growth

7.219 SGN's network design is at an early stage and the detail is currently being developed. As part of the work, SGN has advised us that it will review and provide an update on the numbers of governors required. As part of this work we expect the company to balance to costs of district governors to move to a low pressure system against the costs of extending the 2bar system to minimise the whole life cost of its design. This should take account of the frequency and costs of maintaining the governors, and consumer

regulators. We will consider the revised designs and estimates for the final determination.

SGN - Domestic Service Connections

7.220 SGN's estimate of the numbers and costs of domestic service connections in GD17 is shown in Table 156.

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 156: SGN Submission Domestic Services: Growth

7.221 For the draft 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.

7.222 We have applied the basket of works unit rates to estimate the appropriate allowance for the draft determination the profile of connections and investment in the draft determination is shown in Table 157.

Domestic Services: Growth	2017	2018	2019	2020	2021	2022
New Domestic Service (New Build)	0	0	352	331	391	368
New Domestic Service (OO)	0	1,294	1,294	809	809	809
New Domestic Service (NIHE)	0	1,062	266	266	265	266
UR draft determination (£k) Pre RPE	0	1,735	1,266	902	921	914

Table 157: SGN Draft Determination Domestic Services: Growth

SGN - Industrial and Commercial Service Connections

7.223 SGN forecast 164 I&C connections over the GD17 price control period. The profile showing the size of each connection and the total requested allowance is shown in Table 158. This is 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 158: SGN Submission I&C Services: Growth

7.224 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. In Table 158 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. Our allowance for the draft determination is shown in Table 159.

I&C Services: Growth	2017	2018	2019	2020	2021	2022
I&C Very Small (U6)	0	9	12	17	23	24
I&C Small (U16-U40)	0	17	20	31	38	43
I&C Medium (U65-U160)	0	12	14	21	26	29
I&C Large (U250-U650)	9	20	29	9	0	0
I&C Very Large (>U650)	0	0	0	0	0	0
UR draft determination (£k) Pre RPE	74	254	345	235	200	223

Table 159: SGN Draft Determination I&C Services: Growth

7.225 Our allowances for the draft determination are calculated by applying the appropriate basket of works unit rate for each I&C service type.

7.226 We have made an allowance for very small I&C connections and decreased appropriately the overall proportion of small and medium connections to compensate. We ask that SGN provide additional information on the relative property types that exist within its network area should this become available in advance of the final determination.

SGN - Domestic Meters

SGN - Domestic Meters - Growth

7.227 SGN's estimate of the numbers and costs of domestic meters in GD17 is shown in Table 160.

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 160: SGN Submission Domestic Meters: Growth

7.228 We have increased the number of domestic meters in the draft determination to reflect our proposal to increase the target number of connections (see paragraph 7.224 above). We have applied the basket of works unit rates to estimate the appropriate allowance for the draft determination. The profile of connections and investment in the draft determination is shown in Table 161.

Domestic Meters: Growth	2017	2018	2019	2020	2021	2022
Domestic Total	0	2,356	1,912	1,406	1,465	1,443
UR draft determination (£k) Pre RPE	0	452	367	270	281	277

Table 161: SGN Draft Determination Domestic Meters: Growth

SGN - Domestic Meter - Replacement

7.229 SGN do not plan to replace any domestic meters during the GD17 price control period.

SGN - Industrial and Commercial Meters

SGN - Industrial and Commercial Meters - Growth

7.230 SGN's estimate of the numbers and costs of domestic service connections in GD17 is shown in Table 162.

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 162: SGN Submission I&C Meters: Growth

7.231 We have amended the numbers and size profile of meters to reflect the decisions made on I&C connections described above.

7.232 We have applied the basket of works unit rates to estimate the appropriate allowance for the draft determination. The profile of connections and investment in the draft determination is shown in Table 163.

I&C Meters: Growth	2017	2018	2019	2020	2021	2022
I&C Total	9	58	75	78	87	96
UR draft determination (£k) Pre RPE	215	516	493	235	193	215

Table 163: SGN Draft Determination I&C Meters: Growth

SGN - Industrial and Commercial Meter Replacement

7.233 SGN do not plan to replace any I&C meters during the GD17 price control period.

SGN - Other Capex

7.234 SGN have requested capex for IT of £1.218m 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

7.235 Consequently we are not providing any additional IT cost allowances for the draft determination over and above the SGN licence application figures.

7.236 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. These estimated costs have been allowed and ring fenced for six specific river crossings in Strabane, Enniskillen, and Omagh. The remaining costs for engineering barriers (public realm, road schemes, governors, and customer driven changes) have been removed for the draft 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

7.237 SGN's submission and our draft determination allowance are shown in Table 164.

Other Capex	2017	2018	2019	2020	2021	2022
SGN submission (£k)	475	470	470	470	470	470
UR draft determination (£k) Pre RPE	395	395	395	395	395	395

Table 164: SGN Other Capex

7.238 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, we intend to adjust the price control to allow a reasonable pre-estimate of the costs of these crossings to be determined when the works have been designed and tenders received.

SGN - Traffic Management Act

7.239 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

7.240 In Table 165 we set out a summary of the GDN's capex submission and our total capex allowance pre and post RPE for the draft determination.

SGN Draft 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 Draft Determination pre PRE (£k)							
7 Bar Mains	0	0	0	0	0	0	0
LP, 2Bar or 4Bar Mains	5,556	7,374	6,256	3,580	3,609	3,598	29,974
Pressure Reduction	121	89	96	94	88	82	568
Domestic Services	0	1,735	1,266	902	921	914	5,737
Domestic Meters	0	452	367	270	281	277	1,645
I&C Services	74	254	345	235	200	223	1,330
I&C Meters	215	516	493	235	193	215	1,867
Other Capex	395	395	395	395	395	395	2,371
TMA	563	936	787	472	473	473	3,704
Total	6,924	11,751	10,005	6,181	6,160	6,177	47,197
UR Draft Determination post PRE (£k)							
7 Bar Mains	0	0	0	0	0	0	0
LP, 2Bar or 4Bar Mains	5,479	7,197	6,057	3,445	3,452	3,421	29,052
Pressure Reduction	119	87	93	90	84	78	550
Domestic Services	0	1,693	1,225	868	881	869	5,536
Domestic Meters	0	441	355	259	269	263	1,587
I&C Services	73	248	334	226	192	212	1,284
I&C Meters	212	504	478	226	184	205	1,808
Other Capex	390	386	383	380	378	376	2,292
TMA	555	914	762	454	452	450	3,587
Total	6,828	11,469	9,686	5,948	5,892	5,873	45,695

Table 165: SGN Draft Determination Capex Allowance

SGN – Capital Expenditure Assumptions post GD17

7.241 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 advised that Moneymore, Ballymagorry and Artigarvin are not served in the initial design. We have allowed 2 IPRS, 1,379 properties at 9.4m/pp and 1km of potential spine mains over the first three years of GD23
- We estimate 1,000 properties closely associated with the existing designed network allowing 9.4m/pp and 6 MPRS to serve them in year one of GD23
- We have included an allowance to pass additional properties to serve the total number of properties included in the Gas to the West designs. An additional 5,851 properties to but have included at 9.4m/pp and an additional 2.5 m/pp for spine mains and 15 MPRS to serve them spread over the six years of GD23
- We have included an allowance for mains to serve new development based on an average of 400 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 domestic and I&C connections based on the connection profiles included in Section 7.220.
- We reduced new pressure reducing stations in SGN's submission post GD17 in line with our GD17 determination.
- We have allowed for the replacement of domestic meters, U6 I&C meters and pressure reducing stations on a 20 year life. We have allowed for the replacement of U16 and above I&C meters 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.
- We have continued an allowance for TMA costs at 10% of mains and services.

7.242 We have not applied real price effects of frontier shift to estimated expenditure post GD17.

8 Innovation

Detailed Approach – UR Proposals

Overview

8.1 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.

8.2 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

8.3 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 from resulting outperformance to the end of GD17 period, and customers will benefit in the long run from improved services and lower prices.

8.4 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.

8.5 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.

8.6 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.

8.7 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 and 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.

8.8 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.

8.9 However, we recognise that in certain circumstances this may present difficulties or not be possible. We would propose to deal with such circumstances through the Uncertainty Mechanism. We propose that any request under the uncertainty mechanism would have to meet the criteria set out in paragraph 8.7 above and exceed a materiality threshold of £150k.

Innovation Incentive Mechanisms

GDN Proposals

8.10 In our Update on Overall Approach for the GD17 Price Control7 we encouraged the GDNs to provide, as part of their business plan submissions, ideas or innovations that could make their businesses more efficient or offer enhanced serviced to customers.

8.11 In their GD17 business plan submission, SGN have 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 166 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 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 year, or 2% of total NI GDN average allowed revenue[56] • Funding recovered through postalised transmission charges • Funding of selected projects to cover bid development costs	• Competition every two years for up to £2m of funding a year, or 1% total NI GDN average allowed revenue[56] • Funding recovered through postalised transmission charges • Funding to be allocated ex-post	• Agreed funding cap per GDN, e.g. 1% of total 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 pro-jects identifies pro-jects to be presented to expert panel • Expert panel to recommend to the Authority which, if any, projects should	Expert panel to recommend to the Authority which, if any, projects should receive funding	Authority based on CBA

[56] These are the figures suggested by SGN in their business plan submission. We note that based on this GD17 draft determination, the average annual allowed revenue across all NI GDNs is approximately £70m, i.e. 2% equals approximately £1.43m.

	Network Innovation Competition	Discretionary Rewards Scheme	Innovation Roll-Out Mechanism
	receive funding		
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 166: Innovation Incentive Mechanisms Proposed by SGN

8.12 In their 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.

8.13 In preparing this draft 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.

Network Innovation Competition

8.14 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, iin 2013, 2014 and 2015. Altogether, nine projects have been selected for funding, covering a range of areas:[57]

- 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

[57] See Ofgem: 2015 Network Innovation Competitions; Ofgem: Making Britain's Energy Networks Better; Ofgem: RIIO-GD1 Annual Report 2013-14, 19 March 2015.

- 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
- Real-time Networks (2015): To create a new method of modelling energy within the GB gas network

8.15 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[58]. We encourage the NI GDNs to avail, where reasonable and appropriate, of relevant information and learnings relating to the GB projects to inform our innovation and investment decisions.

8.16 With respect to SGN's suggestion to introduce a network innovation competition in NI we propose not to do so for the reasons outlined below.

8.17 We are not convinced that a competition is necessary or beneficial in delivering innovation in the gas industry in NI. The industry size is smaller than GB and the level of competition that would be generated 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 suffieiently robust for consumers and flexible for the GDNs to support innovations.

8.18 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 draft determination assumes, for all three GDNs, major network development to take place:

- FE propose to conduct a major infill programme
- PNGL plan to extend their network to East Down
- SNG will build the Gas to the West network

Whilst this does not necessarily contradict the simultaneous running of innovation projects and initiatives, 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 should draw the focus of the GDNs to making connections and enhancing network infill, rather than on any other initiatives that might distract from such focus.

8.19 To be clear, by saying this we do not mean that GDNs should not pursue innovation. On the contrary, we welcome innovation initiatives where reasonable and economically efficient. However, we consider that at this stage it is not appropriate to provide further incentives to further innovation.

[58] For further details see section Innovation Initiatives below.

8.20 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, not minded to progress further.

Discretionary Reward Scheme

8.21 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 run every three years. The aim of the DRS is to encourage GDNs to 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.[59]

8.22 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

8.23 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 consider applying it, where relevant and appropriate, to their own businesses.

8.24 With respect to SGN's suggestion to introduce a discretionary reward scheme in NI we propose not to do so for the same reasons as outlined in paragraphs 8.17 to 8.18 above for the network innovation competition.

8.25 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, not minded to progress this further.

Innovation Roll-Out Mechanism

8.26 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

[59] 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.

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.[60]

8.27 We consider that our proposals detailed in paragraphs 8.7 to 8.9 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.

8.28 We consider that our proposals detailed in paragraph 8.9 have a similar effect to that of an innovation roll-out mechanism as proposed by SGN. We therefore consider that an innovation roll-out mechanism as proposed by SGN is not required as complement to our innovation funding principles.

Summary

8.29 As detailed above, we propose not to introduce any innovation incentive mechanism as part of the GD17 price control.

8.30 However, we welcome innovation initiatives from the GDNs where reasonable and economically efficient.

Innovation Initiatives

8.31 In their business plan submission, the GDNs have 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.

8.32 The GDNs have also set out a number of operational innovations for their own business as well as for customers. Some of these have already been implemented, others are being trialled,or are planned to be undertaken during GD17. As detailed in section 8 Innovation, Detailed Approach – UR Proposals, Innovation Funding Principles, we consider that such activities are covered by the overall price control package. We therefore do not propose to grant any specific innovation allowances for such operational innovations.

Development of Infrastructure for CNG Vehicles

8.33 In their business plan submissions, FE and PNGL have 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[61]. Four of these filling stations were to

[60] 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.

[61] 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.

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.

8.34 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 are responsible for managing the Connecting Europe Facility funding scheme, have noted the relevance of the project and encouraged the project partners to make a revised submission for the next funding round.

8.35 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.

8.36 Based on the information provided to us, it seems 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. 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).

8.37 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.

8.38 The submission deadline for proposals under the new funding round was 16 February 2016. It is expected that in July 2016 a decision on selected projects will be taken and applicants informed, with the signature of grant agreements as of September 2016.

8.39 In their 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.

8.40 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.

8.41 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.

8.42 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

8.43 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.

8.44 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 hurdles for such allowances are high and that, in particular, the requirements detailed in paragraph 8.7would 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 8.7 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.

8.45 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 like to see more detail on what aspect of the proposal is innovative.

8.46 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 propose to reconsider the project once certain minimum requirements including (but not necessarily limited to) the ones listed below have been fulfilled and supporting documentation has been provided:

- Positive decision on EU funding request
- 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)

8.47 If, at the time of the GD17 final determination, we consider that there is a reasonable probability for the project to comply with the requirements detailed in paragraphs 8.44 and 8.45, we may consider the granting of ring-fenced and potentially conditional allowances at that stage.

8.48 However, seeing the EU funding and GD17 project timelines, there is a reasonable prospect that at the time of drafting of the GD17 final determination the CNG infrastructure project may still not be sufficiently advanced to allow for a final decision on whether related allowances should be granted or not. For this case, we propose to

reconsider the project once more at a later stage 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 8.9.

Biomethane Injection

8.49 In their business plan submission, SGN has indicated its intention to develop other innovations over the GD17 price control period such as:

- Supporting alternative forms of gas
- 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 have not included any specific project suggestions and/or related funding requests in their business plan submission, but have indicated their interest in working other GDNs and ourselves to develop proportionate funding arrangements that could be introduced during the price control period.

8.50 PNGL have mentioned in their business plan submission the potentials exploring biomethane potentials in conjunction with the development of infrastructure for CGN vehicles initiative.

8.51 In their business plan submission, FE has highlighted the potentials associated with the injection of biomethane into the natural gas grid.

8.52 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.

8.53 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.

8.54 FE also highlight 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.

8.55 FE consider 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.

8.56 We welcome the interest by FE in furthering biomethane injection projects.

8.57 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 the hurdles for such allowances are high. In particular, in addition to compliance with the requirements detailed in paragraph 8.7, it would need to be ensured 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 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)

8.58 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 propose to 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, and to allow for a subsequent ring-fenced adjustment under the uncertainty mechanism, as appropriate, if the circumstances described in paragraph 8.9 for such cases and those described in paragraph 8.57 are fulfilled.

Northern Ireland Inventory Product

8.59 In their business plan submission, FE refer 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.

8.60 FE consider 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.

8.61 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 propose not to grant any related specific innovation allowances.

9 Uncertainty Mechanism

Detailed Approach – UR Proposals

9.1 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 section 2 Introduction, Our Statutory Duties and Regulatory Principles.

9.2 This chapter summarises these mechanisms and, where appropriate, references the sections of this document where the rationale and operation of the mechanisms are described in more detail.

9.3 The primary mechanism 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).

9.4 Adjustments fall into one of three 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 x the forecast driver for that item e.g. connections/properties passed (Opex) or metres per connection (Capex). Any difference in outputs (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 – Any difference between the allowance in the determination and the actual costs incurred will result in a retrospective adjustment at the time of GD23.
- Ring fenced – This will require further justification from the licence holder that the costs are necessary and efficient, otherwise the full amount will not be allowed.

9.5 The adjustments will 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.

9.6 The determined unit rates/unit allowances applied in the uncertainty mechanism will be post efficiency.

GD14 Review and Adjustments – UR Proposals

FE

9.7 GD14 included an uncertainty mechanism for FE similar to the mechanism that has been proposed below for this GD17 price control period.

9.8 In respect of the FE GD14 uncertainty mechanism the draft 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)	1,542,745	**(4,238,188)**
Capex 15 Year Life	(9,914)	144,198	98,232	**232,516**
Capex 5 Year Life	0	0	0	**0**
Opex	(603,995)	(265,008)	(296,639)	**(1,165,642)**
Total Annual Uncertainty Adjustments	**(6,187,312)**	**(328,340)**	**1,344,338**	**(5,171,314)**

Table 167: FE Draft Uncertainty Mechanisms Adjustments

9.9 All the above adjustments are added or removed from the closing Total Regulatory Value (TRV) for 2016 appropriately, giving a draft TRV at 1st January 2017 for FE of £143.4m [£av. 2014].

PNGL

9.10 GD14 included an uncertainty mechanism for PNGL similar to the mechanism that has been proposed below for this GD17 price control period.

9.11 In respect of the FE GD14 uncertainty mechanism adjustments the draft 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)	6,214,576	**6,214,576**
GD14 Depreciation Actual/Forecast Adjustment (2014 – 2016)	(276,765)	**(276,765)**
GD14 Capex Return Actual/Forecast Adjustment (2014 – 2016)	(254,255)	**(254,255)**
GD14 Opex Actual/Forecast Adjustment (2014 – 2016)	(1,070,982)	**(1,070,982)**
GD14 Q & CC Movement Actual/Forecast Adjustment (2014 – 2016)	(265,799)	**(265,799)**
Total Annual Uncertainty Actual/Forecast Adjustments	**4,346,774**	**4,346,774**

Table 168: PNGL Draft Uncertainty Mechanism Adjustments

9.12 All the above adjustments are added or removed from the closing Total Regulatory Value (TRV) for 2016 appropriately, giving a draft TRV at 1st January 2017 for PNGL of £596.3m [£Sep 2014].

GD17– UR Proposals

FE

9.13 In respect of GD17 FE **capex** allowances, the proposed items subject to an uncertainty adjustment are those shown in the table below:

Capex Item	Determination Basis
Traffic Management Act	Ring fenced
Pressure Reduction Stations	Output based on actual numbers installed
7 bar & Feeder Mains	No outputs for FE in GD17 although we will consider further treatment of larger IC connections
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 8.92 metres and determined unit rate. Additional incentive and penalties will apply as outlined in section 7.20.
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.
Security of Supply Mains	No outputs for FE in GD17
Domestic/I&C Meters	Output based on connections and determined unit rates.
Domestic/I&C Services	Output based on connections and determined unit rates.
IT	Not applicable.

Table 169: FE Capex Uncertainty Mechanism

9.14 The determined rates for the capex uncertainty mechanisms are:

- The basket of works unit rates set out in Table 93 following the application of the frontier shift set out in Table 95.
- Except for infill mains and new build mains where the blended basket of works unit rates set out in Table 97 and Table 96 respectively will apply.

For example, the calculation of the determined unit rates for domestic meter installation is shown in Table 170. 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 (%)	1.38%	2.40%	3.18%	3.77%	4.35%	4.93%
Frontier multiplication factor	0.98623	0.97599	0.96816	0.96231	0.95650	0.95073
Uncertainity mechanism determined unit rate	189.08	187.12	185.62	184.49	183.38	182.27

Table 170: Example calculation of determined unit rates for domestic meter installation

9.15 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	Pass through for Network Rates.
Non Controllable Costs	Pass through for Licence Fees.
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 (as adjusted for over/under performance with respect to target owner occupier connections. This is illustrated in the FE section 6.56.

Table 171: FE Opex Uncertainty Mechanism

9.16 Other items are referenced in the main document, such as Innovations, Supplier of Last Resort etc., which are subject to the Uncertainty Mechanism. It should be noted that:

- Innovations will be dealt with by being "Ring Fenced", and for the avoidance of doubt, no specific cost allowances are included at this stage, based on their uncertainty.
- Supplier of Last Resort will be dealt with by being "Ring Fenced". For the avoidance of doubt, no specific cost allowances are included at this stage; however we would be minded to include a ring fenced amount in the Final Determination after discussion with stakeholders.
- If an item occurs, that is not included within GD17 allowances and is approved, it will be adjusted for in GD23, subject to size and scale of the issue.

PNGL

9.17 In respect of GD17 PNGL **capex** allowances, the proposed items subject to uncertainty adjustment are those shown in the table below:

Capex Item	Determination Basis
Traffic Management Act	Ring fenced
Pressure Reduction Stations	Output for new PRS based on actual numbers installed.
7 bar & Feeder Mains	Nominated output for defined projects. See section beginning 7.151. We will consider further treatment of larger IC connections
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 10.67m for East Down and determined unit rate. Additional incentive and penalties will apply as outlined in section 7.20.
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.
Security of Supply Mains	None identified in GD17.
Domestic/I&C Meters	Output based on connections and determined unit rates.

Capex Item	Determination Basis
Domestic/I&C Services	Output based on connections and determined unit rates.
Capex over and under spend	We will retrospectively allow approved capex into the cost base at the time of the next review e.g. as a result of Energy Efficiency improvements.

Table 172: PNGL Capex Uncertainty Mechanism

9.18 The calculation of the determined rates for use in the the capex uncertainty mechanisms is described at paragraph 9.14 above.

9.19 For the final determination we will consider introducing a separate uncertainty and incentive mechanisms for replacement meters.

9.20 In respect of GD17 PNGL o**pex** 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 6.309
Non Controllable Costs	Pass through for Licence Fees.
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 (as adjusted for over/under performance with respect to target owner occupier connections. This is illustrated in the FE section 6.200.

Table 173: PNGL Opex Uncertainty Mechanism

9.21 Other items are referenced in the main document, such as Innovations, Supplier of Last Resort etc., which are subject to the Uncertainty Mechanism. It should be noted that:

- Innovations will be dealt with by being “Ring Fenced”, and for the avoidance of doubt, no specific cost allowances are included at this stage, based on their uncertainty.
- Supplier of Last Resort will be dealt with by being “Ring Fenced”. For the avoidance of doubt, no specific cost allowances are included at this stage; however we would be minded to include a ring fenced amount in the FD after discussion with stakeholders.
- If an item occurs, that is not included within GD17 allowances and is approved, it will be adjusted for in GD23, subject to size and scale of the issue.

SGN

9.22 In respect of GD17 SGN **capex** allowances, the proposed items subject to uncertainty adjustment are those shown in the table below:

Capex Item	Determination Basis
Traffic Management Act	Ring fenced
Pressure Reduction Stations	Output based on actual numbers installed
7 bar & Feeder Mains	No outputs for SGN 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 11.75 metres and determined unit rate. Additional incentive and penalties will apply as outlined in section 7.20.
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.
Security of Supply Mains	No outputs for SGN in GD17
Domestic/I&C Meters	Output based on connections and determined unit rates.
Domestic/I&C Services	Output based on connections and determined unit rates.
Capex over and under spend	Additional Development Area (ADA) projects submitted by SGN and approved by us will be allowed into the cost base at the time of the next review as well as approved projects to deal with Energy Efficiency. Similarly any projects within the price control which do not go ahead will be removed from the cost base.
Volumes in relation to Additional Development Areas (ADAs)	Output based on additional volumes times the determined Pi rate. Volume determination updated to reflect actual burn of ADAs.

Table 174: SGN Capex Uncertainty Mechanism

9.23 The calculation of the determined rates for use in the the capex uncertainty mechanisms is described at paragraph 9.14 above.

9.24 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.
Non Controllable Costs	Pass through for Licence Fees.
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 (as adjusted for over/under performance with respect to target owner occupier connections. This is illustrated in the SGN section 6.436..

Table 175: SGN Opex Uncertainty Mechanism

9.25 For SGN we will give further consideration in our final determination to how a change in the FOCD will be dealt within the uncertainty mechanism.

9.26 Other items are referenced in the main document, such as Innovations, Supplier of Last Resort etc., which are subject to the Uncertainty Mechanism. It should be noted that:

- Innovations will be dealt with by being "Ring Fenced", and for the avoidance of doubt, no specific cost allowances are included at this stage, based on their uncertainty.
- Supplier of Last Resort will be dealt with by being "Ring Fenced". For the avoidance of doubt, no specific cost allowances are included at this stage; however we would be minded to include a ring fenced amount in the FD after discussion with stakeholders.
- If an item occurs, that is not included within GD17 allowances and is approved, it will be adjusted for in GD23, subject to size and scale of the issue.

Materiality Thresholds

9.27 In line with our approach as part of GD14 price control, we will have a materiality threshold for costs not foreseen at 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 not part of normal operational work. Consideration will also be made for any issues arising that are reasonably outside the control of the GDNs - such as European Directives or equivalent local legislation which the GDNs are required to implement. The materiality threshold is set at £150,000 per project for the duration of the GD17 price control period. This is an increase on the threshold in GD14 when it was £100k

9.28 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.

10 Financial Aspects

Detailed Approach – UR Proposals

Overview

10.1 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

10.2 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 take from their investors.

10.3 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 or β_e) as follows:

$$\text{Return on equity} = R_f + \beta_e \,.\, (R_m - R_f)$$

10.4 In paragraphs 10.18 to 10.38 we explain how we have put numbers to each of the parameters in this formula.

10.5 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.

10.6 In assembling this draft determination, 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.

10.7 Against this background, we consider that it is in the best interests of both consumers and investors that we should provide for PNGL's and FE's actual post-refinancing costs to flow through into the allowed return when these costs become known. We have thought about a number of options for dealing with this issue, as set out in Annex 7, and would be keen to understand respondents' views on the potential approaches.

10.8 Our current thinking is that we should put in place a mechanism in which:

- the allowed returns for the GD17 period will initially incorporate our best current forecasts of the average annual interest rates that PNGL and FE will face during the 2017-22 period; and
- the returns will be subsequently adjusted, to capture any deviation that there would otherwise be from this forecast, once the companies have completed their refinancings.

10.9 In order to avoid a situation in which the allowed cost of debt becomes a pass-through item, with the undesirable incentive properties that this brings, we propose to design the adjustment mechanism in such a way that 80% of any over- or under-forecast of the post-refinancing cost of debt passes through to prices and the remaining 20% is retained by PNGL's and FE's shareholders. Our intention is that this sharing rule will give the companies strong incentives to minimise the costs that they pay on their new borrowings, to the long-term benefit of customers in the GD23 period and beyond.

10.10 While the very specific aspects of the mechanism may be somewhat novel to UK regulation, the general principles of pain/gain sharing and adjusting debt allowances to reflect more updated actual costs of debt are well established.

10.11 We will need to hold further discussions with the companies about the precise mechanics underpinning the adjustment mechanism prior to publishing our final determination. We will also need to set out our best current estimates of the costs of debt (i.e. the reference point for the sharing mechanism) in our decision. Our provisional estimate is set out in paragraphs 10.42 to 10.50.

Financeability

10.12 In carrying out its functions, the Utility Regulator is required to have regard to the need to secure that licence holders are able to finance their activities. Our assessment of financeability is set out in paragraphs 10.56 to 10.69.

FE and PNGL– UR Proposals

Rate of Return

Submissions

10.13 PNGL and FE made initial submissions on the GD17 rate of return in June 2015. The figures put forward by the companies are set out in Table 176. FE subsequently updated its calculations in September 2015. The revised figures are shown in the final column of the table.

Parameter	PNGL June 2015	FE June 2015	FE September 2015
Gearing	0.60 to 0.65	0.55	0.55
Cost of debt	2.6% to 2.7%	2.0% to 2.3%	3.05% to 3.3%
Risk-free rate	1.75% to 2.1%	1.25% to 1.5%	.25% to 1.5%
Expected market return	6.75% to 7.1%	6.5% to 7.0%	6.5% to 7.0%
Asset beta	0.40 to 0.45	0.40 to 0.50	0.40 to 0.50
Debt beta	-	0.1	0.1
Equity beta	1.00 to 1.29	0.77 to 0.99	0.77 to 0.99
Post-tax cost of equity	6.8% to 8.5%	5.3% to 6.9%	5.3 to 6.9%
Tax rate	20%	27%	27%
Pre-tax cost of equity	8.5% to 10.6%	7.3% to 9.4%	7.3% to 9.4%
Rate of return	4.9% to 5.5%	4.4% to 5.4%	5.0% to 6.0%

Table 176: PNGL and FE Allowed Rate of Return Submissions

10.14 In evaluating these submissions, and in considering the issues around the GD17 rate of return more generally, we have taken advice from the economic consultancy First Economics. The consultant's report is attached as Annex 7 to this paper.

10.15 Our draft determination is as follows.

Gearing

10.16 The weights that are accorded to equity and debt within the allowed rate of return calculation typically reflect a notional or efficient level of gearing. Other regulatory determinations for UK regulated networks have provided for gearing of between 45% and 65%. We propose to use a point estimate of 55% at the middle of this range.

10.17 We apply this figure to both PNGL and FE. We recognise that this is slightly lower than the PNGL proposal and PNGL's recent actual levels of gearing. The PNGL gearing figure has been at levels between 55% and 65% in recent years and is largely driven by decisions that PNGL has made, including its dividend policy. However, 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

10.18 The return that investors demand in exchange for holding riskless assets can be assessed by examining the yields on government gilts. At March 2016, real yields (after allowing for RPI-measured inflation) are negative, as has been the case for several years.

10.19 The emergence of below-inflation risk-free returns has come partly as a result of the recent financial crisis and policymakers' responses to subsequent recessions, including very low interest rates and programmes of quantitative easing. There is naturally some uncertainty about how long current market conditions will persist for.

10.20 Most UK regulators have been allowing for a positive RPI-stripped risk-free rate when setting forward-looking price controls. As set out in First Economics' report, figures used in recent decisions range from 0.5% to 1.5%. We propose to use a figure 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.

Expected Market Return

10.21 The other generic or non-firm-specific parameter within the CAPM 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*."

10.22 Most UK regulators, with the exception of Ofwat, have factored the CC/CMA's guidance on the 6.5% upper limit into recent price control decisions. Given the clear steer from the CC/CMA on this matter, we also propose to use a value of 6.5%.

Beta

10.23 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 company 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).

10.24 The comparators are set out in Table 177 and in Figure 9. As a cross-check on these numbers, First Economics has also looked at empirical estimates of beta for the remaining listed network businesses in the UK. The calculations show that average asset betas over the last five years have typically been slightly below the figures in the table.

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 177: Asset Beta Estimates

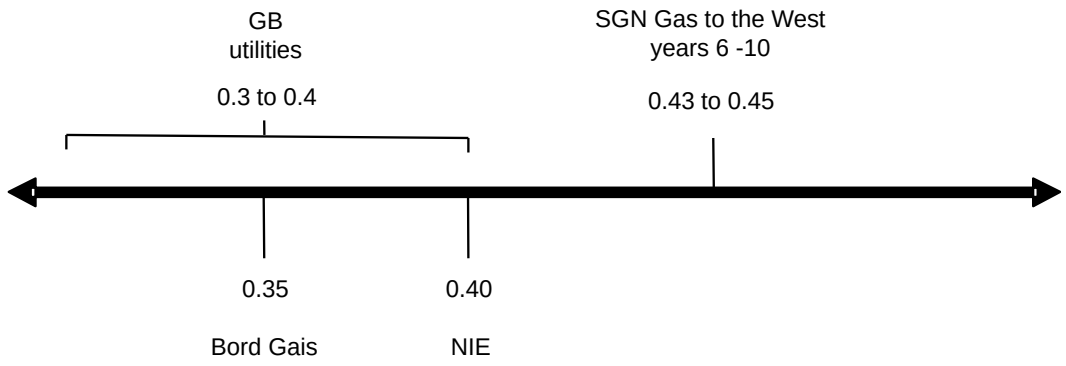


Figure 9: Asset Beta Range

10.25 The key determinant of a firm's positioning in the above spectrum is the risk that the firm presents to investors. We have therefore sought to understand how PNGL's and FE's risk profiles compare to the other regulated networks.

10.26 In a number of respects, the networks are very similar. For example, most regulated companies nowadays have revenues caps like the caps that we are proposing 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.

10.27 Our analysis suggests that there are really two main areas in which PNGL and/or FE are distinguishable from other regulated networks:

- first, PNGL manages 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 of an impact on the percentage return that PNGL is able to give its investors, thus offering equity providers a more stable and more predictable return than is the case with other regulated utilities; and
- second, PNGL and FE have both said in their submissions how they are relatively 'immature' businesses and that they face atypical uncertainty around customer numbers and volume growth.

10.28 On the first of these matters, we have previously increased our estimates of beta for firms that manage large amounts of expenditure when measured as a percentage of their capital base (e.g. SONI). Other regulators, including the CC/CMA, have done the same. There is therefore a case, on the grounds of consistency, for factoring a

downward adjustment into our estimate of PNGL's beta, as a company that finds itself in the reverse position. However, we have found it very difficult to judge what an appropriate quantification of the effect of PNGL's very low totex-to-TRV ratio might be. PNGL appears to be the only regulated network of this character, which means that there is not a readily available source of direct regulatory precedent. We note that the CC/CMA made a formulaic adjustment to account for Bristol Water's relatively high totex-to-TRV ratio, but it cautioned that its formula might not be applicable to other companies. We, therefore, think that we have to be cautious and place limited weight, in quantitative terms, on this factor, although we can note that it may be necessary to tackle the issue of quantification more explicitly at future price reviews.

10.29 This leaves the question of maturity or immaturity as the key driver of PNGL's and FE's positioning in Figure 9. We had considerable difficulties with the companies' submissions in this area, where the majority of the arguments made identified factors which differentiate PNGL and FE from other utilities (e.g. penetration rates, forecast volume growth, the form of the price control model) but without following through to show how these factors mean that there is greater uncertainty around the return of and on the capital that equity providers have put into these businesses. First Economics gives detailed comments on this matter in its report.

10.30 We have therefore conducted our own analysis to understand what kind of unanticipated shocks could cause PNGL's and FE's shareholders to lose money (or, more strictly, more money than a typical network company could lose in the day-to-day running of its business). The scenarios that we had to construct are very extreme. By way of an illustration, we modelled what would happen to tariffs at GD17 if the risk factors that PNGL and FE identified were to crystallise in a very unfavourable way and the networks were to see zero connection growth and zero volume growth from 2017 onwards (NB: base case forecasts are for 38% (PNGL) and 77% (FE) growth in volumes as a result of connections in the remaining recovery period). Our modelling showed that network tariffs would need to increase by 4.37% for PNGL and 1.95% for FE, implying increases in final prices of 1.68% and 0.73% The magnitude of these numbers do not seem unmanageable and tend to suggest that the companies have attained sufficient critical mass that they ought to be capable of recovering the costs of their investment in most circumstances.

10.31 To extend the thought experiment still further, we found that it is only if PNGL and FE were to suffer a catastrophic loss of customers that there could be any serious questions about stranding. It is difficult for us to see why such a collapse would occur, or crucially, why the risk of a collapse occurring is any higher in Northern Ireland than it is in Great Britain. PNGL in its submissions did paint a scenario in which efforts to meet the UK's carbon emissions reduction target results in a terminal decline of the gas industry. However, we note that Ofgem has not attached any real weight to this eventuality in its WACC analysis (Ofgem concluded that the GB gas distribution networks were, if anything, slightly less risky investments than the GB electricity distribution networks). Furthermore, it is not clear why the effects of decarbonisation would be more pronounced in Northern Ireland in comparison to the rest of the UK. PNGL has argued that gas tariffs are higher in NI than GB and, thus the NI gas industry would be more vulnerable from decarbonised alternatives. However we would note that standard domestic tariffs are not dissimilar between NI and GB and are currently lower in NI. In addition, progress on decarbonisation is likely to be dependent on government policy and support. Given that DETI and UR retain a principle objective to promote the gas industry and the NI Executive has recently approved a significant subvention to extend

gas to the west of NI, there is a strong argument that this risk is lower in NI than GB. This issue is also covered from paragraph 10.77.

10.32 PNGL has also put forward an argument that the inclusion of a profile adjustment in its regulatory model defers revenue, thus increasing risk compared to other utilities and requires a higher beta, which they calculate as a 0.03 uplift. We recognise that the application of the profile adjustment does defer revenue for the NI GDNs and have considered this argument. We have reviewed Ofgem's consideration of this issue when it analysed the implications of adjusting the timing of cash flows in RIIO-ED1. We have noted the work done by Europe Economics and Ofgem's conclusion that duration of cashflows would not be a material factor in setting the appropriate cost of equity in RIIO – ED1.

10.33 Taking these points together, we provisionally conclude that we should place limited weight on the companies' arguments about immaturity. We also think that we need to clearly position PNGL and FE 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 legitimate uncertainty about the recovery of investments.

10.34 The positioning of PNGL and FE relative to the 0.30 to 0.40 range for conventional network utilities requires the exercise of judgment. For this draft determination, we use a value of 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 the GDNs at the top of the betas that regulators have judged appropriate for low-risk network utility businesses.

10.35 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

10.36 Table 178 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 at 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% *

Note: an asterisk indicates a recalculated value. The figure for NIE is taken from table 13.13 of the CC inquiry report.

Table 178: Calculation and Comparison of the Allowed Cost of Equity

10.37 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.

10.38 We are content that this is a logical picture to present.

Tax rate

10.39 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 the prevailing statutory corporation tax rate. 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%.

10.40 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. The Utility Regulator will apply the Northern Ireland corporation tax main rate effective for the majority of each regulatory year of this price control within the WACC to all GDN's. We will need to hold further discussions with the companies about the precise mechanics underpinning this adjustment prior to publishing our final determination.

10.41 We note that FE argued in its submission that we should use an effective tax rate of approximately 27% in our calculations. We do not accept this proposition on the grounds that FE's analysis of tax is over-simplistic and does not capture all of the factors that will cause the effective tax rate to differ from the statutory rate. Our proposed approach is consistent with the uplift applied by the CC/CMA in previous decisions.

Cost of Debt

10.42 In line with the methodology set out in paragraphs 10.5 to 10.11, our provisional cost of debts are our best current estimates of the average interest rates that PNGL and FE will pay over the GD17 period, plus an allowance for transaction costs.

10.43 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.

10.44 We build up our estimate of the post-refinancing costs of debt as follows:

- first, we observe that the current yield on BBB rated debt in secondary markets is approximately 4.4%;
- we allow 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 allow 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 provide 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; and
- finally, we allow for refinancing related transaction costs. In the case of PNGL we provide for fees in line with the costs incurred in the company's last debt raising exercise. In the case of FE, we provide for a small mark-down to reflect the benefit of raising slightly higher quantum of debt.

10.45 Table 179 brings these calculations together into an overall forecast of the nominal cost of debt.

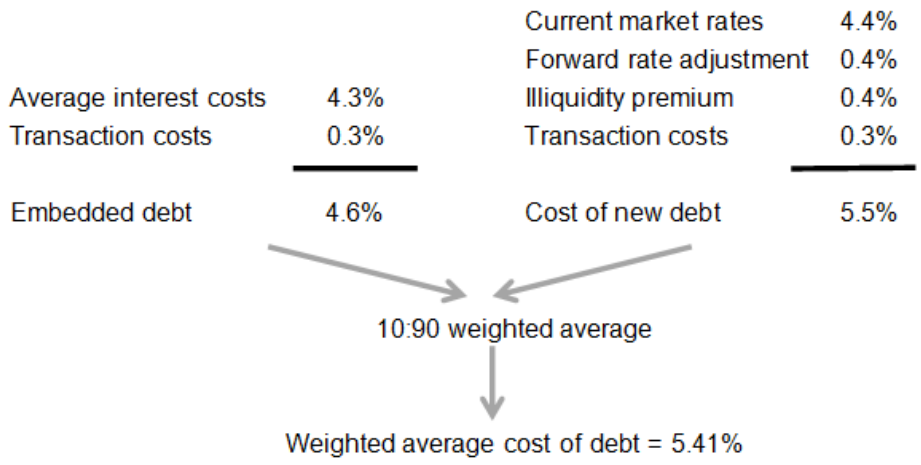
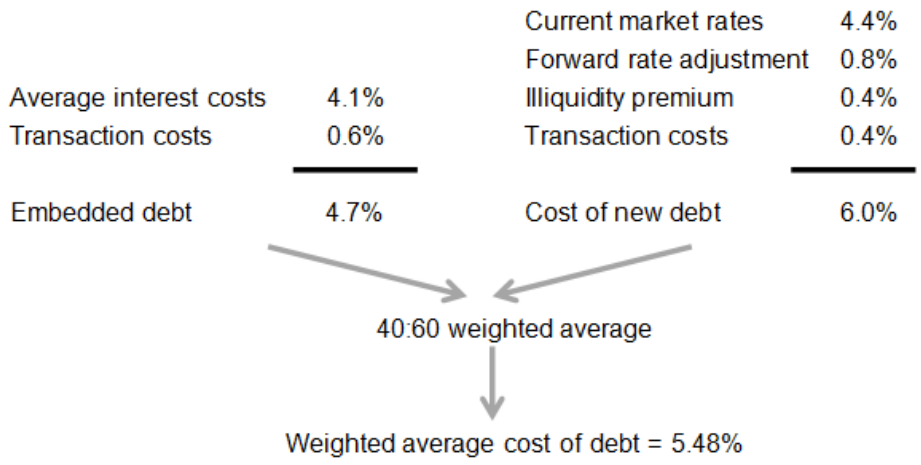
Company	Average nominal cost of debt, GD17
PNGL	
FE	

Table 179: Cost of Debt Calculations

10.46 All of the above figures are best estimates at the cut-off date for First Economics' report, 31 December 2015 and will need to be updated prior to our final determination to reflect prevailing market conditions and to allow consideration of any further detail that emerges about PNGL's and FE's refinancing plans.

10.47 We convert the nominal costs of debt in Table 179 into their real equivalents by adjusting for forecast GD17 inflation as projected by the Office for Budget Responsibility in its latest published forecasts. This gives a real cost of debt of 2.26% for PNGL and 2.33% for FE.

10.48 Table 180 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%	2.3%

Table 180: Calculation and Comparison of the Allowed Cost of Debt

10.49 Our provisional estimate of PNGL's and FE's cost of debt is lower than the other allowed costs of debt. This reflects 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 rates of interest for several more years.

10.50 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 would be below 2.3% by as early as 2017/18.

Overall Rate of Return

10.51 Table 181 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	55%	55%
Pre-tax cost of equity	6.3%	6.3%
Cost of debt	2.26%	2.33%
Overall rate of return	4.21%	4.25%

Table 181: Computed Rates of Return

10.52 Based on these calculations, we propose to factor a rate of return of 4.3% into PNGL's and FE's price controls at the outset of the GD17 period.

10.53 Our starting GD17 rates of return are lower than the ranges put forward by PNGL and FE (see Table 176: PNGL and FE Allowed Rate of Return Submissions) 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 (although, as noted above, our estimate of beta is within the range put forward by FE);
- in the case of FE, made a more conventional tax adjustment when calculating the pre-tax cost of equity; and
- made slightly lower central forecasts of the networks' likely costs of debt. We have also excluded a premium that PNGL factored into its calculations for hedging costs, recognising that uncertainty about the future cost of debt will be dealt with via a regulatory adjustment mechanism.

10.54 As noted in paragraphs 10.8 and 10.40, 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.

Peer Review

10.55 The UR is a member of the UK Regulatory Network (UKRN) Cost of Capital working group. The purpose of the UKRN is to improve the level of co-ordination and consistency across its members. It is our intention to have the WACC peer reviewed and this will provide useful feedback prior to the final determination. This process will also increase awareness of the position of UR lying firmly within the UK regulatory regime.

Financeability

10.56 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[62] (amongst other things).

10.57 This duty is framed similarly to the financing duties of other UK regulators and can broadly be taken to mean that the price control ought to be set at a level which would allow an efficient company to finance its licensed activities. It is therefore necessary for us to consider financeability as an integral part of a price review.

10.58 In assessing whether our draft 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.

10.59 The key determinant of the companies' ability to access equity finance is the allowed return on equity. As noted in paragraphs 10.18 to 10.38, 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.

10.60 As far as borrowing is concerned, it will be important for PNGL and FE to maintain investment-grade credit quality. One determinant of the companies' credit worthiness in the eyes of lenders will be the level of cashflows that the networks generate under our price control proposals. 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.

10.61 PNGL has a licence condition to maintain an investment grade credit rating. An investment grade credit rating is a rating of BBB- or above (Fitch or Standard & Poor's) or Baa3 (Moody's). We are not prescriptive on which credit rating agency is used by PNGL.

10.62 In Table 182 and Table 183 we present the results of some modelling that we have produced to understand the projected level of two important 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. These are the same metrics we considered in GD14 although we recognise there are other ratios that lenders and rating agencies consider. We have taken into account the considerations of the CC in RP5 in arriving at appropriate targets for the

[62] 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.

financial ratio which looked at an interest cover ratio of at least 1.4 times and gearing of no more than 70% in order to obtain a BBB credit rating.

10.63 The modelling applies TRV's, capex, opex, volumes and rate of return based on proposals in this paper.

	2017	2018	2019	2020	2021	2022
Adjusted interest cover	1.46	1.49	1.49	1.52	1.40	1.43
Gearing	55.6%	55.0%	54.4%	53.6%	52.7%	51.9%

Table 182: Modelling Results for PNGL

	2017	2018	2019	2020	2021	2022
Adjusted interest cover	1.41	1.40	1.40	1.40	1.40	1.40
Gearing	56.6%	57.2%	57.2%	57.2%	57.2%	57.2%

Table 183: Modelling Results for FE using 2045 Forecasting Horizon

10.64 The figures show that the ratios for both companies are within the target thresholds. 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 and FE ought to be capable of maintaining quite substantial amounts of debt finance during the GD17 period.

10.65 We are also aware that the analysis above would produce more challenging financial ratios if we were to apply different gearing assumptions for PNGL – including those close to its current level of gearing. As stated earlier the current level of gearing for PNGL has been determined by its decisions, including those in relation to dividend policy.

10.66 Our approach 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.

10.67 Our approach is consistent with recent regulatory decisions including the CC/CMA decision in RP5 and Ofgem's recent decisions.

10.68 Based on our assessment of the options open to an efficient company and the combination of a reasonable return of equity and the financial ratios in Table 182 and Table 183 indicate to us that PNGL and FE ought be able to finance their activities through a mix of equity and debt equity finance.

10.69 We will update our analysis in advance of the Final Determination and will consider views and analysis included in consultation responses.

Depreciation

10.70 This section is based on our views on depreciation profiles of the GDNs under current arrangements. We discuss in paragraphs 10.89 to 10.96 on the Profile Adjustment the option of making significant changes to current arrangements. Should we decide that such changes are appropriate we would expect that a full review of depreciation profiles, as part of implementing those changes would be required. We have not included in this section the options that might be included in such a review and this section should be read accordingly.

10.71 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.

10.72 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 184.

Asset Categories	PNGL	FE	SGN
Mains	40	40	
Services	35	40	
Meters	15	15	
Other	40	5	
All Assets			35

Table 184: Proposed Asset Lives

10.73 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 same way. This means that various templates and financial models can then be aligned and comparability increases across the 3 GDNs.

10.74 We are currently minded 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).

10.75 As this is the first price control for SGN it simply means that the proposed asset lives will be applied on all assets from start-up.

10.76 FE would not be impacted by the proposal. This leaves PNGL for whom services would change from 35 to 40 years and the other category would become 5 years. To minimise any impact on PNGL we would propose 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.

10.77 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.

10.78 The relevant department in NI is DETI 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.

10.79 This context is obviously different from GB and we would have to consider whether the policy framework is in place to justify a significant change to the depreciation profile that would match the GB context. We have engaged with DETI on its review of the Strategic Energy Framework and will continue to do so.

10.80 Even if this is an issue which needs to be addressed, given the structure of the NI licences, it may be more appropriate to consider future volume assumptions than to adjust depreciation profiles. We are keen to hear views on this issue.

Tax

10.81 In the GD17 approach document the UR said it would consider how tax should be treated in the rate of return, after evaluating the current tax payments of the individual GDN's.

10.82 The UR has historically taken an approach with PNGL and FE which applies a tax wedge adjustment to the cost of equity, calibrated in line with the statutory rate of corporation tax i.e. an uplift to the cost of equity of 1 / (1 – tc), where tc is the statutory rate of corporation tax.

10.83 PNGL in particular are coming to the end of a period of zero tax payments largely driven by accelerated capital allowances, and are forecasting tax becoming payable during the GD17 period. Tax payments for FE will also follow in future price controls.

10.84 A change in how the UR makes allowances for tax with the price controls for PNGL and FE would involve making a calculation for any pre-funding received and would involve significant computational difficulties, including how the profile adjustment has impacted on allowances.

10.85 We are therefore minded to maintain the historical approach to tax for PNGL and FE within the rate of return while the profile adjustment remains in place.

10.86 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 FE and PNGL 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 1990's. 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.

10.87 In line with best regulatory practice we are minded to use this approach for SGN. This will require further discussion with SGN and company specific tax forecasts to be prepared prior to the final determination. For the draft determination calculations we have used the same approach as PNGL and FE and will update in the Final Determination.

10.88 We are keen to hear views on this issue.

Profile Adjustment

10.89 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.

10.90 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.

10.91 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.

10.92 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 considers it appropriate to set out the options for GD17.

10.93 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.

10.94 These indicate that the impact on distribution tariffs in GD17 would be an increase of 14% and 20% for FE and PNGL respectively.

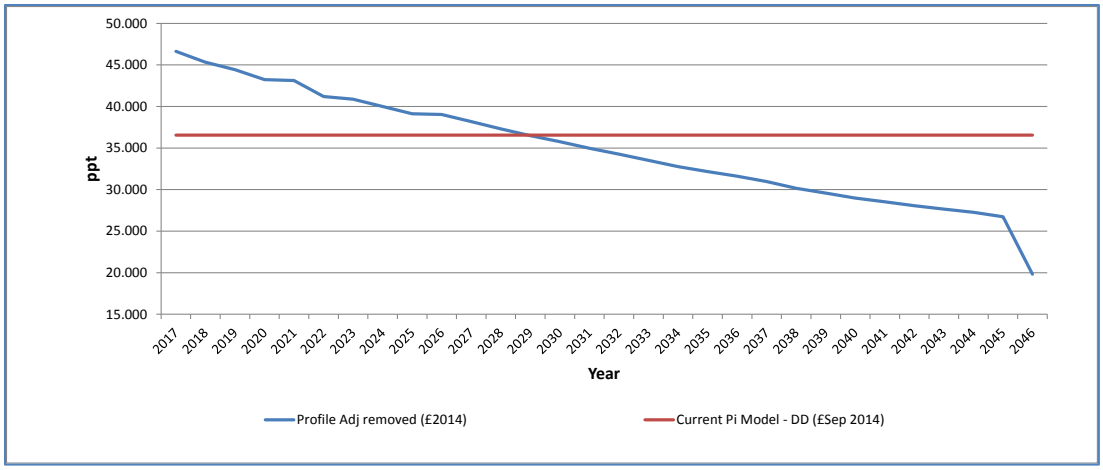


Figure 10: Impact of Removal of the Profile Adjustment on Distribution Tariffs – PNGL

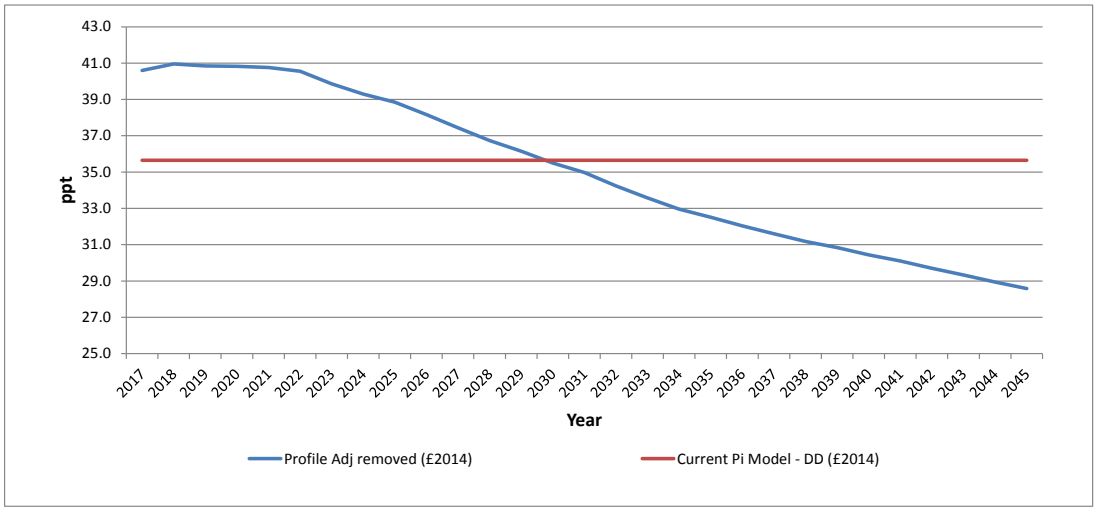


Figure 11: Impact of Removal of the Profile Adjustment on Distribution Tariffs – FE

10.95 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. 4% and 6% for FE and PNGL.

10.96 We plan to progress further analysis in this area, along with the interlinked areas of depreciation and adjusting the Forecast Horizon and are keen to hear views on this issue.

11 Outputs, Outcomes and Allowances

UR Proposals

Risk Sharing Mechanism

Introduction

11.1 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, say, 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.

11.2 For GD17 we wish to consult on aligning the mechanisms and possibly simplifying them.

Current Approaches

11.3 PNGL had a Capex efficiency roller 'switched on' for the PC03 Price Control, a supplemental document forms part of the PNGL12 Final Determination[63] to describe this in detail.

11.4 Currently, this roller works outside the published Conveyance Licence. Capex under-spends occurring efficiently[64] will be removed from the TRV on a 5 year rolling basis i.e. PNGL will retain 5 years' financing costs on the efficiency equating to 4 years of return and 5 years of depreciation.

11.5 Capex over-spends occurring efficiently[64] are treated symmetrically, so PNGL forego 5 years' financing costs on the efficiency equating to 4 years of return and 5 years of depreciation.

11.6 FE has a capex rolling incentive mechanism built into the formulae in their Conveyance Licence[65]. This can be found 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.

11.7 SGN has a capex rolling incentive mechanism built into the formulae in its Conveyance Licence[66]. This can be found under condition 4.6.11.

11.8 We made our intentions clear whilst issuing the final Conveyance Licence to SGN that this roller is likely to be 'switched off' as part of the GD17 price control (at a minimum). This will be done by setting the designated parameters h and d in condition 4.11.1 to 0 (zero).

[63] This can be found in Utility Regulator: Phoenix Natural Gas Limited Price Control Review 2022-2013, Final Decisions, January 2012, p. 103 to 104.
[64] In all cases, efficiency will need to be demonstrated by PNGL.
[65] http://www.uregni.gov.uk/uploads/licenses/2016-02-04_firmus_(Gas_Conveyance)_-_final.pdf .
[66] http://www.uregni.gov.uk/uploads/publications/Scotia_Gas_Networks_Northern_Ireland_Ltd_Grant.pdf .

11.9 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.

11.10 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.

11.11 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

11.12 For the NIE RP6 price control the CC/CMA put in place a much simplified set of risk sharing arrangements.

11.13 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.

11.14 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.

11.15 The mechanism applies to both opex and capex.

11.16 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.

11.17 The sharing figures for Ofgem's recent RIIO price controls have varied between 50% and 70%.

11.18 Our current thinking is that a simplified mechanism of 50:50 sharing could be a reasonable proposition and this would be applied to FE and PNGL in GD17. We would be keen to hear respondents' views on this option and any alternatives.

Impact on Consumer Bills

11.19 The modelling we have applied in the draft determination produces a significant drop in domestic distribution tariffs of 21%, 13% and 14% compared to the FE, PNGL and SGN submissions respectively.

11.20 In comparison with current GD14 distribution tariffs the draft determination produces a reduction of 25% and 8% for FE and PNGL respectively. This would result in domestic customers paying around £46 and £15 less per annum than currently. For I&C customers the difference would obviously be much larger.

11.21 The SGN distribution tariff is being set for the first time and therefore no current retail bill for comparison purposes is available.

	GD17 DD P1 tariff	GD17 distribution tariff V submission	GD17 V GD14 distribution tariff	Customer impact per annum
FE	35.65	-21%	-25%	-£46
PNGL	36.55	-13%	-8%	-£15
SGN	32.07	-14%	-	-

Table 185 Impact on domestic customer bills

11.22 However we would caution that a significant element of the FE difference derives from applying the 2045 Forecast Horizon and the figures above are not perfectly comparable as they do not factor in the impact of how FE chooses to charge its under recovery amount.

Customer Service

11.23 As indicated in section 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 our ongoing focus on how GDNs are meeting their respective consumers' interests and needs.

11.24 The customer service development objective will require delivery of new customer service metrics and customer satisfaction surveys as an output of GD17. The prize is to design and introduce 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.

11.25 Given our previous experience of development work using a partnership model across both the local water and electricity sectors we envisage the following timetable will 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.

11.26 During the draft determination stage we would propose we re-convene the gas industry partnership group to discuss the above timetable, with a view to settling on an agreed timeline of milestones for delivery of this development objective.

11.27 Such a working group on consumer and stakeholder engagement will also likely begin its examination of 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) has undertaken an international literature review entitled, "Customer engagement methods and examples of best practice". The literature review defines different sorts of engagement as either provider or regulator focused and examines an international long list of alternatives, many of which include some degree of expert, consumer and negotiated settlements. The review recommends the adoption of the "IAP2[67]" taxonomy as relevant to regulated utilities such as NIE Networks. We shall consider this further on the basis of NIE Networks' RP6 Business Plan submission (including elements of the CEAP research programme undertaken by PIMR).
- 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 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[68], they could be different surveys (in whole or in part) designed specifically to address local utility consumer concerns, or they could be a combination of both.

11.28 Ideally, some form of Net Promoter Scoring question should be included within any consumer questionnaire to enable benchmarking across local utility providers and their 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 has 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).

11.29 Through such a development objective for GD17 we shall set the agenda towards delivery of improved customer service delivery through the price control period and beyond. Further, once out-turn data against the new metrics establishes the GDNs' baselines over time we shall be in an informed position to consider improved monitoring of our GDN's performance. This shall help inform our Annual/Cost Reporting of GDN

[67] The Public Participation Spectrum of the International Association of Public Participation defines two extremes of (i) one-way engagement of the provision of information from an agency to the community and (ii) decision-making resting with the community.
[68] For further details, see e.g. Ofgem: RIIO-GD1 Gas Distribution Price Control – Regulatory Instructions and Guidance: Version 1.1, 30/05/2014.

performance as well as inform subsequent consideration of whether targeted improvement(s) are warranted in certain areas of GDN delivery.

11.30 Another possibility from improved performance monitoring may be evidence-based proposals for the introduction of certain incentive mechanisms concerning specific elements of the customer service experience in future price controls.

11.31 Finally, it is our belief SGN has the potential to benefit the most from our GD17 development objective to deliver greater partnership in the delivery of consumer research and stakeholder engagement. SGN can benefit in the immediate term from any lessons learned, avoidance of "re-inventing the wheel" and being part of a wider partnership grouping who can pool the research effort and resources into delivering be-spoke research of relevance to all three companies at once (which should help avoid much of the nugatory triplication of research that would otherwise occur).

Shrinkage

11.32 In October 2012, Directive 2012/27/EU on Energy Efficiency[69] 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.

11.33 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 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.*"

11.34 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. Therfore energy efficiency considerations were re-assessed as part of the present price control process.

11.35 We consider that one area that requires further focus is that of shrinkage.

11.36 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.

[69] Directive 2012/27/EU: http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2012:315:0001:0056:EN:PDF

- 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.

11.37 Theft of gas occurs when unaccounted for and/or unrecorded gas is utilised. It can occur upstream of downstream of the emergency control valve and is caused by tampering with gas apparatus.[70] 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.

11.38 In its GD17 business plan submission, SGN has 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*"[71].

11.39 More specifically, SGN proposes an incentive payment of £500 for each uncovered instance of theft of gas, either at a point downstream or upstream of the emergency control valve, which leads to a recovery of monies associated with stolen gas by either the relevant GDN or the relevant supplier.

11.40 SGN considers 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.

11.41 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.

11.42 In line with the Reasonable and Prudent Operator licence condition[72], 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[73], 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.

[70] 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.

[71] SGN: GD17 Business Plan, September 2015, p. 75.

[72] 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. See chapter 12 for further details.

[73] See Condition 2.4 in the FE and SGN conveyance licences and Condition 2.5 in the PNGL conveyance licence.

11.43 We consider that these obligations already put a strong obligation on the GDNs to ensure any issues impacting on the safety of their networks are addressed.

11.44 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[74]
- 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.

11.45 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.

11.46 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 have 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.[75]

11.47 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 propose, however, to continue monitoring gas theft-related matters during the course of GD17. We propose to 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.

[74] See Section M, paragraph 2.13 of the PNGL and FE Network Codes.
[75] See Ofgem: Decision on incentive arrangements for Gas Distribution Networks on gas theft during conveyance and for unregistered sites, 14 October 2014.

We propose 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 propose to 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 11.52.

11.48 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.

11.49 In line with their respective network codes, the GDNs determine on an annual basis a shrinkage factor for their respective networks.[76] This shrinkage factor is used to attribute shrinkage to gas flows and related suppliers, and ultimately through the supplier tariffs to customers.

11.50 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.

11.51 We consider that these current arrangements are suboptimal for a number of reasons:

- In line with the distribution network codes, shrinkage quantities shall be recovered from the suppliers[77]. 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 have 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.

11.52 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.

11.53 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 propose 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. To facilitate this exercise,

[76] See firmus energy Distribution Limited: Network Code, 1st October 2015, Section D, paragraph 4.3 and Phoenix Natural Gas Limited: Distribution Network Code, 1st October 2015, Section D, paragraph 4.3. At the time of writing, the SGN Network Code has been drafted but is still pending publication.
[77] See firmus energy Distribution Limited: Network Code, 1st October 2015, Section D, paragraph 4.6 and Phoenix Natural Gas Limited: Distribution Network Code, 1st October 2015, Section D, paragraph 4.6. At the time of writing, the SGN Network Code has been drafted but is still pending publication.

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.

11.54 As set out in paragraph 13.13 we expect the GDNs to produce a report on this matter in 2017.

Supplier of Last Resort (SOLR)

11.55 This area refers to circumstances where the UR revokes a gas supplier's licence (the defaulting supplier) and then subsequently gives a direction[78] to another gas supply company (the SoLR supplier) to supply gas to the customers of the defaulting supplier. In a SoLR event, the UR's intention is to direct a supplier within each distribution network area to be the SoLR supplier.

11.56 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 these costs may be largely outside their control (e.g. costs of purchasing short-term gas for the defaulting supplier's customers.

11.57 We are currently 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. At the time of a SoLR event, the SoLR suppliers will need to submit information to the UR on any costs they have incurred. The UR 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.

11.58 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 a "Ring Fenced" cost within the uncertainty mechanism. We note 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.

11.59 There are two options for how the UR could build SoLR costs into the GD17 price control: Based on normal practice, any allowances granted, if a SoLR event did occur, would wait until the time of the next price control. Dependant on the scale and size of the event occurring, the UR may consider some other interim measures, such as adjusting the tariff, if the GDN can demonstrate the financial effect that it would have on its business.

11.60 Specific monetary allowances for SoLR events could be included in the GD17 FD which would be subject to the uncertainty mechanism at the time of the next price control. In

[78] Gas (Supplier of Last Resort) Regulations (Northern Ireland) 2009: http://www.legislation.gov.uk/nisr/2009/412/made/data.pdf

this case there would be no requirement for any exceptional review throughout the price control period.

11.61 We note that no specific allowances have been included in this DD for a SoLR event however this will be reconsidered for the FD if option two is preferred.

11.62 We are continuing to work with the gas industry to develop SoLR processes and to find pragmatic solutions. We welcome views on these proposals in order to form our final decisions.

FE – UR Proposals

Under-Recoveries

Introduction

11.63 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.

11.64 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.

11.65 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.

11.66 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 woudl 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.

11.67 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.

11.68 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.

11.69 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.

11.70 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

11.71 The forecast 'Z' under-recovery amount at the end of 2016 is c£13.0m (£av. 2014). This is made up of c£2.6m of actual under recovery and £10.3m of interest applied. 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.

11.72 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.

11.73 We have considered the current position and the arguments made by FE. Our view is that the current licence is not in the public interest and we would propose to modify it. This is because the 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. We are not aware of a strong policy reason for doing so and note that this approach was not taken in the PNGL or SGN distribution licences.

11.74 Furthermore we think the history of the FE build up of 'Z' under-recoveries demonstrates the risk of perverse incentives. The principle behind facilitating 'Z' under-recoveries was to deal with difficult periods where, for example, the price of oil was cheaper than the price of gas. The period when FE built up its 'Z' under-recovery had historically low gas prices relative to oil. The current licence conditions provide customers with no protection from a situation where the licensees actual cost of capital is less than the licence allowed cost of capital.

11.75 We have considered FE arguments against making a change. 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.

11.76 We would also note that FE have been given a number of years notice that this change was likely and the proposal brings FE in line with PNGL and SGN. In addition we would highlight that changes to the licence are a normal part of the regulatory process. FE themselves have argued for a significant change to the licence to move the forecasting horizon to 2045.

11.77 We disagree with FE that this would add a layer of complexity. The licence contains all the formulae necessary for the calculation and brings FE in line with SGN and PNGL. The arrangements only apply to 'Z' under recoveries which were only intended for short term unusual circumstances.

11.78 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 2020 based on current tariffs therefore, the horizon for recovery currently is fairly short. This also means that the change of rate of return is unlikely to impact FE's return significantly.

11.79 We therefore propose that the rate of return to be applied to FE under recoveries will move to LIBOR plus 2%.

11.80 We would be keen to hear respondents' views on this issue.

Options

11.81 As well as reducing the rate of return to be applied to 'Z' under-recoveries we are also considering whether other licence changes should be applied in how it interacts with the TRV. Assessing the options available to us in GD17, the most realistic and feasible ones are 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.

11.82 Option (a) assumes that 'Z' under-recoveries will continue to be treated outside the TRV, therefore, published tariffs will remain above those determined in the most recent price control decision, until these are fully recovered in 2020 (the current estimated date).

11.83 This would be in line with the current licence arrangements and would mean that the impact that 'Z' currently has on tariffs would continue until 2019.

11.84 Under Option (b) 'Z' under-recoveries will be included in the opening TRV, whilst being depreciated over the remaining 29 years of the licence forecast horizon period.

11.85 Under this option, current 'Z' under-recoveries at the end of 2016 are discounted at a specified rate of return to gain a current value that is appropriate to receive the full 4.3% rate of return attached to the TRV. This would mean that the impact of 'Z' on tariffs is spread out over a longer period. At 2% discounting, the levelised price faced would be c36.29ppt,. This is c1.8% above the current DD scenario respectively.

11.86 The initial view of UR is to retain the current approach to 'Z' outside the TRV but we are keen to hear views on this issue.

Forecasting Horizon

11.87 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.

11.88 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[79] and the final business plan templates were consistent with this.

11.89 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.

11.90 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.[80] The submission did not follow the template. We would note that this has made consideration of the submission more complex than we had anticipated and we do not expect such proposals to make substantial changes to the licence framework to be made in such a manner. The approach contrasts to that on moving from a price cap to a revenue cap where the principles were set out in GD14, before further discussion in the discussion document on overall approach for the GD17 price control6 in December 2014, the update on overall approach for the GD17 price control7 in April 2015 and a standalone consultation on the issue in 2015[32,33].

11.91 However as part of a package of measures of changing the FE regulatory model, including changing to a price cap and changing the under recovery arrangements we regard it as appropriate to consider the issues around moving the FE forecasting horizon to 2045.

11.92 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

[79] 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.
[80] See firmus energy: GD17 Business Plan, October 2015, p. 13.

11.93 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[81]. We did not find the FE analysis transparent in this respect and we have set out below our intial work on the impact on customers of the propose change.

Typical Domestic Charge (Pence per Therm)	GD14 Final Determination (FD)	GD17 BPT Submission	GD17 DD
30 Years	47.6p	48.7p	38.5p
40 Years		45.2p	35.6p

Table 186: Customer Impact of Moving from 30 to 40 year Forecasting Horizon

11.94 The impact on customers from moving from 30 to 40 years is that customers up to 2035 are better off by approximately 3ppt but customers after 2035 will be much worse off and we plan to complete further analysis on this prior to the FD.

11.95 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.

11.96 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.

11.97 The fact that we depreciate the mains and services over 40 years suggests there is some justification for considering a move to 40 years.

11.98 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. This is discussed more fully in section 10 - Profile Adjustment.

11.99 We have factored the 2045 Forecast Horizon into our modelling in the draft determination. However this does not reflect a decision on this matter and we plan to carry out further analysis before a decision is taken in the Final Determination.

Designated Parameters and Determination Values

[81] For further details see section 4 Price Control Submissions, GD17 Outlook, FE.

.

11.100 Table 187 and Table 188 show the proposed designated parameters and determination values respectively for FE.

Designated Parameter	Value
r_t	0.043
n	2017
f_t	0.5
q	2045
RPI	256.0
w	6
g	0
h	1
d	1
l	Please see section 10
δ_t	0
$x_{O,t}$	0
$x_{U,t}$	Please see section 11
α_t	0.4

Table 187: FE – 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=2017**	**t=2018**	**t=2019**	**t=2020**	**t=2021**	**t=2022**
Volume (therms)	$V_{E,i,t}$	**61,980**	**63,703**	**65,882**	**68,178**	**70,566**	**73,042**
Capital Expenditure	$C_{E,t}$	**12,877**	**12,856**	**13,019**	**13,237**	**13,574**	**13,785**
Operating Expenditure	$O_{E,t}$	**5,426**	**5,581**	**5,689**	**5,861**	**6,083**	**6,312**
Annual Depreciation	$D_{E,t}$	**4,191**	**4,572**	**4,945**	**5,348**	**5,728**	**6,061**
Cash Flow (calculated in accordance with Condition 4.6.6)	$F_{E,t}$	**-3,269**	**-2,803**	**-2,360**	**-1,995**	**-1,761**	**-1,377**
Revenue Per Unit	$P_{E,i,t}$ **(IV) (V) (Vi)**	**21.04**	**21.04**	**21.04**	**21.04**	**21.04**	**21.04**
Revenue Per Unit	$P_{E,i,t}$ **(II) (III)**	**24.29**	**24.29**	**24.29**	**24.29**	**24.29**	**24.29**
Revenue Per Unit	$P_{E,i,t}$ **(I)**	**35.65**	**35.65**	**35.65**	**35.65**	**35.65**	**35.65**
Depreciated Asset Value (calculated in accordance with Condition 4.6.7)	$DAV_{E,t}$	**113,927**	**122,210**	**130,284**	**138,174**	**146,019**	**153,744**
Total Regulatory Value (calculated in accordance with Condition 4.6.8)	$TRV_{E,m}$						**200,318**

Table 188: FE – Proposed Determination Values

East Down

11.101 On 16th October 2015, we granted[82] an extension to the PNGL Licence to facilitate the Conveyance of gas to the area of East Down.

11.102 This extension comprised of 13 new towns[83] 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.

11.103 Chapters 6 and 7 of this paper have incorporated all costs for East Down and these are the subject of consultation in line with all other costs proposed in this paper .In addition, because of the background to the project an adjustment will be required to the PNGL TRV which is explained in this section.

11.104 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[84] 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.

11.105 This explains why the economic consideration for infill mains discussed from paragraph 7.10 does not apply for East Down and, indeed the SGN area.

11.106 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.£28.8m but this will be subject to adjustment once outturn costs are finalised.

11.107 We have therefore included all costs within the GD17 price control and removed an amount from the TRV to reflect the transfer to the transmission licence asset base. The current modelling assumes that this transfer will take place in 2020 although in reality this may be earlier and we will adjust the figures accordingly.

11.108 This will work by adding the capex in the years this is incurred and removing at the point transfer is made. The removal will take account of depreciation. The exception will be the 2016 mains build, which will be added in 2017 (so excluded from the opening GD17 TRV) after being adjusted for depreciation for the 2016 year.

11.109 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.

[82] 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

[83] Namely Annahilt, Ballygowan, Ballynahinch, Castlewellan, Crossgar, Downpatrick, Dromore, Drumaness, Dundrum, Hillsborough, Newcastle, Saintfield and The Spa.

[84] http://www.detini.gov.uk/1011.pdf

Designated Parameters and Determination Values

11.110 Table 189 and Table 190 show the proposed designated parameters and determination values respectively for PNGL.

Designated Parameter	Value
r_t	0.043
m	2017
n	2022
q	2046
RPI	257.6

Table 189: 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*	72,721	75,996	79,142	82,215	85,207	88,072
$V_{E,i,t}$	*i = 2*	27,988	28,483	29,000	29,570	30,092	30,614
$V_{E,i,t}$	*i =3 & 4*	48,365	48,490	48,615	48,740	48,865	48,990
$C_{E,t}$		11,811	13,823	14,303	15,866	14,648	15,008
$CC_{E,t}$		-6,213	-6,548	-6,628	-6,889	-6,686	-6,746
$O_{E,t}$		13,895	13,786	13,666	13,587	13,515	13,551
$D_{E,t}$		15,288	16,035	16,596	16,462	17,105	17,686
$F_{E,t}$		22,116	21,826	22,453	21,847	23,378	25,879
$Q_{E,t}$		-3,702	-3,481	-3,264	-3,053	-2,850	-2,667
$P_{E,i,t}$	*i = 1*	0.3655	0.3655	0.3655	0.3655	0.3655	0.3655
$P_{E,i,t}$	*i = 2*	0.3289	0.3289	0.3289	0.3289	0.3289	0.3289
$P_{E,i,t}$	*i = 3 & 4*	0.2511	0.2511	0.2511	0.2511	0.2511	0.2511
$R_{E,t}$		47,930	49,322	50,673	52,015	53,311	54,562
$DAV_{E,t}$		428,471	434,753	432,574	403,969	402,876	400,199
$TRV_{E,m}$							648,023
$PA_{E,m}$							257,236
$N_{E,i,j,t}$		not used	not used	not used	not used	not used	not used
$H_{E,i,j,t}$		not used	not used	not used	not used	not used	not used

Table 190: PNGL – Proposed Determination Values

Designated Parameters and Determination Values

11.111 Table 191 and Table 192 show the proposed designated parameters and determination values respectively for SGN.

Designated Parameter	Value
r_t	0.062
n	2018
f_t	0.5
m	2022
q	2057
RPI	256.0
w	5
g	0
h	0
d	0
l	See section 10
δ_t	0
$x_{O,t}$	0
$x_{U,t}$	See section 11
α_t	0.4

Table 191: SGN – Proposed Designated Parameters

		All Value(s) in £000's and indexed to RPI 2014				
Description (for Conveyance Categories *i* and Formula Years *t*)	**Determination Values**	**2018**	**2019**	**2020**	**2021**	**2022**
Volume (therms)	$V_{E,i,t}$	24,873	34,264	34,885	35,520	36,137
Capital Expenditure	$C_{E,t}$	11,402	9,630	5,913	5,858	5,839
Operating Expenditure	$O_{E,t}$	2,129	1,580	1,387	1,432	1,495
Annual Depreciation	$D_{E,t}$	566	911	1,149	1,383	1,617
Cash Flow (calculated in accordance with Condition 4.6.6)	$F_{E,t}$	-10,295	-6,669	-2,560	-2,346	-2,193
Revenue Per Unit	$P_{E,i,t}$ (i)	32.07	32.07	32.07	32.07	32.07
Revenue Per Unit	$P_{E,i,t}$ (ii)(iii)(iv)	31.43	31.43	31.43	31.43	31.43
Revenue Per Unit	$P_{E,i,t}$ (v)(vi)	12.30	12.30	12.30	12.30	12.30
Depreciated Asset Value (calculated in accordance with Condition 4.6.7)	$DAV_{E,t}$	17,664	26,383	31,147	35,621	39,843
Total Regulatory Value (calculated in accordance with Condition 4.6.8)	$TRV_{E,m}$					39,346

Table 192: SGN – Proposed Determination Values

Under-Recoveries

11.112 As detailed in 11.79 we also propose the same approach is applied to SGN underrecoveries i.e. LIBOR plus 2%.

12 Licence Implications

Legal and Regulatory Framework

12.1 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.

12.2 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 as well as licence formulae, designated parameters, determination values and charging methodology. 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.

12.3 On 6 February 2015, the Gas and Electricity Licence Modifications and Appeals Regulations (Northern Ireland) 2015[85] came into effect. These regulations have impacted on the way price control decisions need to be implemented and can be appealed.[86]

12.4 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 determined values need to be updated in the respective licence conditions, in line with the price control final determinations. Additional licence modifications may or may not be required, depending on the price control decisions.

12.5 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. 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.

12.6 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;

[85] http://www.legislation.gov.uk/nisr/2015/1/contents/made.

[86] 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.

- 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.

12.7 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

12.8 As detailed in the Legal and Regulatory Framework section above, licence modifications are required to update the relevant designated parameters and determination values[87] in 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.

12.9 Table 193 provides an overview over the different types of licence modifications we propose to make as part of the GD17 price control process and their relevance for the different GDNs. Some of these licence modifications are discussed in detail below in the GDN-specific sections of this chapter, including a summary of their reasons and effects.

12.10 We also note that any wording and comments with respect to the proposed licence modifications included in this GD17 draft determination are of indicative nature and for information purposes; they are subject to change depending on the decisions taken as part of the GD17 final determination. Therefore, whilst we do welcome comments and views on the proposed licence modifications, this document does not constitute a formal licence modification notice. As outlined in Table 194: GD17 Next Steps we intend to issue such notice in a timely manner to the publication of the GD17 final determination, having considered any representations made in response to this GD17 draft determination and any other developments that may occur in the meantime, as relevant and appropriate.

[87] 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.

Type of Licence Modification	Relevance		
	FE	PNGL	SGN
Update of designated parameters and determination values	X	X	X
Change from price cap to revenue cap	X		
Extension of forecasting horizon and treatment of Under-recoveries	X		
Future treatment of profile adjustments[88]	X	X	
Use of opex and capex rollers	X	X	X
Licence alignment between GDNs pursuant to the Gas to the West project	X	X	
Licence modifications pursuant to the extension of the PNGL licensed area to East Down		X	
Licence Modifications pursuant to our decision paper on Modifications necessary due to The Gas and Electricity Licence Modification and Appeals Regulations (Northern Ireland) 2015[86]			X
Correction of licence errors			X

Table 193: Overview over Types of Licence Modifications Proposed

FE – UR Proposals

Overview

12.11 As indicated in section 12 Licence Implications, Overview over Licence Modification Proposals, we consider making modifications to the firmus energy conveyance licence with respect to the following:

- Update of designated parameters and determination values
- Change from price cap to revenue cap
- Extension of forecasting horizon and treatment of under-recoveries
- Future treatment of profile adjustments[88]
- Use of opex and capex rollers
- Licence alignment between GDNs pursuant to the Gas to the West project

12.12 This section provides details on the following proposed licence modifications, including a summary of their reasons and effects.

- Update of designated parameters and determination values
- Licence alignment between GDNs pursuant to the Gas to the West project

For these areas, Annex 1: FE Licence – Proposed Modifications shows the proposed licence modifications as tracked changes. As mentioned before, this drafting is for

[88] We note that dependent on the decisions taken in preparing the GD17 final determination, after due consideration of the responses received to this consultation on the GD17 draft determination, there may or may not be a need to introduce licence modifications with respect to the future treatment of profile adjustments.

illustrative purposes only and subject to change between now and the formal licence modification notice to be published together with the GD17 final determination.

12.13 We envisage to provide further information on those proposed licence modifications which are not discussed in detail in this GD17 draft determination to the GDNs as part of the preparation of the GD17 final determination, as relevant and appropriate.

Update of Designated Parameters and Determination Values

12.14 We propose to update Condition 4.9: Current Designated Parameters and Determination Values with the values determined as part of this GD17 price control for designated parameters and determination values. The provisional values for the designated parameters and determination values are shown in section 11 Outputs, Outcomes and Allowances, of this document but are subject to change as part of the GD17 final determination.

12.15 This change is required to bring the GD17 final determination into effect and ensure consistency between the GD17 final determination and the FE conveyance licence. Furthermore, by us making such a modification to the FE licence, in line with the Gas (Northern Ireland) Order 2003, FE have a mechanism to bring forward an appeal to the CMA against the licence modification and the underlying GD17 final determination.

Licence Alignment between GDNs Pursuant to the Gas to the West Project

Overview

12.16 As part of the Gas to West project and our preparatory work on the SGN conveyance licence, we identified a number of necessary changes to the FE and PNGL licences. There were multiple reasons for these change requirements, including lack of clarity or inaccuracies in the current drafting of these licences, new licence requirements arising from changes to the legal and regulatory framework the GDNs are operating in, shortfalls of the current licences in certain areas as well as the general need to treat the NI GDNs in a fair and equal manner. Whilst these issues were addressed in the SGN conveyance licence, the FE and PNGL licences were not updated at the time. However, we noted in our Gas to the West Licence Consultation[89] our intention to include, for some of the licence conditions contained in the SGN conveyance, equivalent licence conditions in the FE and PNGL conveyance licences in due course.

12.17 We propose to implement the outstanding updates to the FE and PNGL licences together with the licence modifications to bring into effect the GD17 determination. This section therefore details our related proposals with respect to updates to the FE licence, the reasons for them and their effect.

Definitions

12.18 We propose to add the definitions for "*high pressure pipe-line*" and "*low pressure pipe-line*" contained in Condition 1.1.6: Interpretation and Construction, Definitions, of the SGN conveyance licence into Condition 1.1.6: Interpretation and Construction, Definitions of the FE conveyance licence.

12.19 We consider that this proposed change is a consequential change to the proposed licence modifications detailed in the sections below as some of the wording proposed to be introduced into the FE licence refers to these terms.

[89] Utility Regulator: Gas to the West Licence Consultation, 18 December 2014.

12.20 We furthermore propose to amend the definition for "*related undertaking*" in Condition 1.1.6: Interpretation and Construction, Definitions of the FE conveyance licence by replacing the words "*as defined by Article 268 of the Companies (Northern Ireland) Order 1986*" with "*within the meaning of section 421A of the Financial Services and Markets Act 2000*".

12.21 We consider that this proposed change, which aligns the definitions for "*related undertaking*" in the SGN and FE conveyance licences, is required because the proposed licence modifications detailed in section 12 Licence Implications, FE – UR Proposals, Licence Alignment between GDNs Pursuant to the Gas to the West Project, Trading with Associated Businesses refer to this term and the reference in the definition of "related undertaking" currently contained in the FE conveyance licence is out of date; the Companies (Northern Ireland) Order 1986 has been replaced.

Independence of the Licensed Business

12.22 We propose to replace the wording of Condition 1.16.1(b): Independence of the Licensed Business, Application in the FE conveyance licence with the wording of Condition 1.16.1(c): Independence of the Licensee, Application of the SGN conveyance licence.

12.23 We furthermore propose to add the definition of "*Relevant Affiliate*" contained in Condition 1.16.7: Independence of the Licensee, Additional Definitions of the SGN conveyance licence to Condition 1.16.7: Independence of the Licensed Business, Additional Definitions of the FE conveyance licence.

12.24 We consider that the revised wording in Condition 1.16.1 provides additional clarity, in particular with respect to the application of the threshold of 100,000 connected premises. The revised wording clarifies that, in situations where any affiliate or related undertaking of the Licensee is carrying out the activities of an Associated Business, this threshold applies to premises connected (whether individually or in aggregate) by the Licensee and/or any Relevant Affiliate of the Licensee to any gas conveyance network consisting of low pressure pipe-lines which is owned or operated by the Licensee or any Relevant Affiliate of the Licensee.

Whilst the Condition currently contained in the FE conveyance licence was intended to work in the same way as described in the revised wording, this was not immediately obvious.

12.25 We recognise that Condition 1.16.1 does not currently apply to FE as the circumstances described in this condition do not apply. Therefore, we consider that the proposed change has no immediate impact. However, it was noted as part of the process of granting the Gas to the West low pressure conveyance licence, that the additional clarity with respect to the wording of this condition was required. Furthermore, it was recognised that, if the enhanced, clearer wording was included in the SGN licence, it should for reasons of equality and consistency also be included in the relevant licence conditions of other NI distribution licence holders.

12.26 The proposed modification of Condition 1.16.7 is a consequential change to that proposed for Condition 1.16.1, required to define the term of "Relevant Affiliate" used therein.

Regulatory Instructions and Guidance

12.27 We propose to introduce Condition 1.21: Regulatory Instructions and Guidance from the SGN conveyance licence (after consideration of the modification proposed in paragraph

12.148 of this document to correct a reference error in the licence wording) as new Condition 1.26 in the FE conveyance licence. Any references contained in this condition to specific sub-paragraphs of this condition will be renumbered accordingly (e.g. from 1.21.x to 1.26.x).

12.28 We first introduced RIGs as part of the Annual/Cost Reporting for the 2013 reporting year in 2014. These RIGs have been updated the following year for the Annual/Cost Reporting for the 2014 reporting year. They have also formed the basis for the RIGs for the GD17 business plan submission.

12.29 We consider that by introducing this new licence condition into the FE conveyance licence, additional clarity is provided for both ourselves and the Licensee with regards to the arrangements concerning the provision of information under RIGs:

- The new licence condition provides us with the powers not only to request information, but also to require the Licensee to have adequate systems, processes and procedures in place to ensure such information can be provided.
- The new licence condition provides protection to the Licensee by assuring that new RIGs or modifications to existing RIGs may only be issued following a consultation process and after due consideration of any responses received.
- The new licence conditions also provides protection to the Licensee in that it allows for any new information requested or information requested to a greater level of detail to be estimated.

12.30 We consider that the additional clarity provided by this licence condition is desirable for both the Licensee as well as ourselves as it provides a better picture of the respective responsibilities.

12.31 We note furthermore that in drafting the Annual/Cost Reporting and business plan RIGs, we have sought alignment with the relating Ofgem templates and documentation where relevant and appropriate. It hence is consequent to also seek alignment, where relevant and appropriate, with the regulatory and governance arrangements supporting this reporting framework. This includes introduction of the relevant licence condition on which such a reporting framework is based, with NI-specific modifications as relevant and appropriate and as included in the drafting of the proposed new licence condition.

12.32 Ofgem introduced the RIGs to achieve improved consistency of reporting across the licensees, including with respect to reporting structures and definitions used. On this basis, comparability of data across businesses was enhanced and benchmarking between GDNs became more meaningful. As we move towards aligning price controls, where reasonable and appropriate, across NI GDNs and increase the use of comparative analysis and benchmarking, RIGs, and this associated licence condition, become more important.

12.33 Finally, we consider that the introduction of the proposed new licence condition in the FE licence also furthers consistency between the NI low pressure conveyance licences. In the Gas to the West Applicant Information Pack we had noted our intention to include in the Gas to the West licence a condition to oblige the Licensee to co-operate with cost reporting.[90] This condition later became Condition 1.21: Regulatory Instructions and Guidance of the SGN licence. We consider, however, that in order to ensure that the NI

[90] See Utility Regulator: Gas Network Extensions in Northern Ireland, Gas to the West: Application Information Pack, 6 February 2014, paragraph 3.71.

GDNs are regulated on an equivalent basis a related condition should be included in the FE and PNGL conveyance licences as well. We indicated in the Gas to the West Licence Consultation[89] our intention to do so and are now proposing to follow-up on this matter.

Resolution of Disputes

12.34 We propose to substitute Condition 2.2.6: Conveyance Charges, Other Terms for the Conveyance of Gas and the provision of Conveyance services, Resolution of disputes in the FE conveyance licence with the corresponding Condition 2.2.6 in the SGN conveyance licence.

12.35 We furthermore propose to substitute Condition 2.3.8: Connection Charges and Obligation to permit a Connection, Resolution of disputes by the Authority in the FE conveyance licence with the corresponding Condition 2.3.9 in the SGN conveyance licence. Any references contained in this condition to the condition itself will be renumbered accordingly (e.g. from 2.3.9 to 2.3.8).

12.36 As part of our preparatory work on the SGN conveyance licence as part of the Gas to the West project we noted that the arrangements for resolution of disputes contained in the existing NI conveyance licences were inconsistent, complex, difficult to understand and represented neither current nor intended practice. This was true for both disputes relating to conveyance services and connections. We therefore redrafted the related licence conditions and included them as Condition 2.2.6 and Condition 2.3.9 in the SGN conveyance licence.

12.37 We consider that in the interest of clarity, to ensure equivalent regulatory treatment of the NI GDNs and to facilitate a consistent dispute resolution process across NI the FE and PNGL conveyance licences should be updated to reflect the reworded conditions. We indicated in the Gas to the West Licence Consultation[89] our intention to do so and are now proposing to follow-up on this matter.

Connection Charges and Obligation to Permit a Connection

12.38 We propose to introduce Condition 2.3.8: Connection Charges and Obligation to permit a Connection, Statements for the purposes of standards of performance from the SGN conveyance licence as new Condition 2.3.16 into the FE conveyance licence.

12.39 We propose to introduce Condition 2.3.15: Connection Charges and Obligation to permit a Connection, Accuracy of quotations from the SGN conveyance licence as new Condition 2.3.17 into the FE conveyance licence.

12.40 We propose to introduce Condition 2.3.17: Connection Charges and Obligation to permit a Connection, In this Condition from the SGN conveyance licence as new Condition 2.3.18 into the FE conveyance licence.

12.41 We consider that these licence changes are required pursuant to the Gas (Individual Standards of Performance) Regulations (Northern Ireland) 2014[91]. In these regulations, the terms complex connection, excluded connection and public accuracy scheme are defined with reference to the conveyance licence. It is therefore necessary to include such references in the conveyance licence.

[91] Gas (Individual Standards of Performance) Regulations (Northern Ireland) 2014.

12.42 The relevant licence conditions have already been included in the SGN conveyance licence at the time of its grant in February 2015. For consistency and compliance with the regulations we propose to update the FE conveyance licence accordingly.

Co-operation with Other GDNs

12.43 We propose to introduce Condition 2.4.12: Network Code, Performance of Obligations from the SGN conveyance licence as new Condition 2.4.13 into the FE conveyance licence. Any references contained in this condition to the condition itself will be renumbered accordingly (e.g. from 2.4.12 to 2.4.13).

12.44 We propose to introduce Condition 2.25: Common Branding from the SGN conveyance licence as new Condition 2.16 into the FE conveyance licence.

12.45 We propose to introduce Condition 2.26: Common Network Tariff from the SGN conveyance licence as new Condition 2.17 into the FE conveyance licence.

12.46 In the Gas to the West Applicant Information Pack[92] we had noted our intention to include in the Gas to the West licence conditions to oblige the Licensee to co-operate with other GDNs in:

- producing a single low pressure network code together with a consistent switching system and consistent switching processes;
- delivering a common branding approach in relation to promoting natural gas in NI; and
- delivering a common low pressure network tariff in NI.

12.47 These conditions later became Condition 2.4.12: Network Code, Performance of Obligations, Condition 2.25: Common Branding and Condition 2.26: Common Network Tariff from the SGN conveyance licence. However, co-operation may be difficult to achieve (and would be impossible to enforce) if the obligation to co-operate is only on one, not on all the parties supposed to be co-operating. We therefore consider that to achieve the objective of true co-operation amongst the GDNs in the relevant areas and to ensure equivalent regulatory treatment of the NI GDNs, a related condition should be included in the FE and PNGL conveyance licences as well. We indicated in the Gas to the West Licence Consultation[89] our intention to do so.

12.48 With respect to co-operation in delivering a common branding approach and a common low pressure network tariff in NI, we note that GDNs have also been encouraged already as part of our GD14 final determination[93] to work together in a number of areas, including:

- Advertising and Marketing/Consumer Research;
- Conveyance Charges;
- Connection Policies; and
- Emergencies and Major Incidents.

[92] See Utility Regulator: Gas Network Extensions in Northern Ireland, Gas to the West: Application Information Pack, 6 February 2014, paragraphs 3.68, 3.69 and 3.72.
[93] See Utility Regulator: GD14 Price Control for Northern Ireland's Gas Distribution Networks for 2014-2016, Final Determination, 20 December 2013, paragraphs 16.9 and 16.39 to 16.43.

12.49 Whilst we are aware that co-operation between the NI GDNs is ongoing, we consider that further progress can be made. We consider that the proposed licence modifications may help to achieve such further progress over time. However, we consider that it is important to focus on the most relevant aspect at this point, which is from our point of view the common branding.

12.50 We note that we are aware that achieving communality may take time, in particular with respect to single network code and common tariff. For example 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 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. We consider that this has been reflected in the proposed licence conditions in so far as both Condition 2.4.12: Network Code, Performance of Obligations and Condition 2.26: Common Network Tariff from the SGN conveyance licence put a general obligation on the GDNs to co-operate in the relevant area in addition to the need to comply with specific related directions which may be issued by the Authority, e.g. once we have a more detailed plan for progressing such projects.

12.51 We note that in their response to the Gas to the West Licence consultation, FE have indicated a concern that common branding might impact negatively on the brand recognition and reputation they have built up over the past years and adversely impact on the development of the gas industry within their network area. We have considered this carefully, but after doing so do not agree that this would be the case. The purpose of the proposed common branding licence condition is to further (and not hamper) the development of the natural gas industry in the FE licensed area and in Northern Ireland as a whole, and to prevent consumers getting confused by the different brands. We consider that GDNs can achieve further efficiencies and improve recognition by consumers by aligning and/or sharing promotional material and/or activities, thus increasing the effect/reducing the cost for each GDN.

Reasonable and Prudent Operator

12.52 We propose to introduce Condition 2.27: Reasonable and Prudent Operator from the SGN conveyance licence as new Condition 2.18 into the FE conveyance licence.

12.53 In the Gas to the West Applicant Information Pack[94] we had noted our intention to include in the Gas to the West licence a condition obliging the licence holder to act as a reasonable and prudent operator and maintain the network for its economic engineering life. This condition later became Condition 2.27: Reasonable and Prudent Operator in the SGN conveyance licence. However, to ensure equivalent regulatory treatment of the NI GDNs, a related condition should be included in the FE and PNGL conveyance licences as well. We indicated in the Gas to the West Licence Consultation[89] our intention to do so and are now proposing to follow-up on this matter.

[94] See Utility Regulator: Gas Network Extensions in Northern Ireland, Gas to the West: Application Information Pack, 6 February 2014, paragraph 3.70.

12.54 The proposed new licence condition formalises how we would expect any low pressure conveyance licence holder to run their business. That said, we still consider the introduction of the proposed new licence condition to be of importance as by formalising the requirements of a reasonable and prudent operator in the licence they become enforceable.

Trading with Associated Businesses

12.55 We propose to introduce Condition 2.30: Trading with Associated Businesses from the SGN conveyance licence as new Condition 2.19 into the FE conveyance licence. Any references contained therein to other conditions will be renumbered accordingly (e.g. from 1.2.14 to 1.2.12).

12.56 We furthermore propose to amend Condition 1.2.12: Separate Accounts for Separate Businesses, Associated Undertakings of the FE conveyance licence as follows: Replace in sub-paragraphs (a) and (b) of this Condition the words "*(or its parents or subsidiaries)*" with "*(or an affiliate or related undertaking of the Licensee)*".

12.57 The proposed new licence condition prohibits cross subsidies to or from businesses operated by the Licensee or any of its affiliates or related undertakings. This reflects our intention that the Licensee shall not benefit from cross-subsidies arising from transactions with associated businesses, nor provide such benefits to associated businesses. There are in addition requirements to ensure that contracts entered into by the Licensee comply with the prohibition on cross subsidy.

12.58 The proposed modification to Condition 1.2.12: Separate Accounts for Separate Businesses, Associated Undertakings of the FE conveyance licence is a consequential change to the introduction of the proposed new Condition 2.19: Trading with Associated Businesses and required to ensure licence consistency.

12.59 When we included Condition 2.30: Trading with Associated Businesses in the SGN conveyance licence, we considered that to ensure equivalent regulatory treatment of the NI GDNs, a related condition should be included in the FE and PNGL conveyance licences as well. We indicated in the Gas to the West Licence Consultation[89] our intention to do so and are now proposing to follow-up on this matter.

Asset Management

12.60 We propose to introduce Condition 3.7: Asset Management from the SGN conveyance licence as new Condition 3.8A into the FE conveyance licence. Any reference contained in this condition to the condition itself will be renumbered accordingly (e.g. from 3.7.1 to 3.8A.1).

12.61 We consider that in order to ensure the efficient and economic operation of the network, the Licensee needs to have in place an asset management system.

12.62 We have noted, in previous price control determinations, our concerns at the lack of implementation of a comprehensive asset management system by the GDNs. Whilst by the time of the GD14 final determination both FE and PNGL had presented plans for implementation of such a system during the GD14 price control period, we were uneasy about whether this objective would indeed be reached and about the amount of time it took to get to such a stage.

12.63 On this background, and to prevent similar issues arising in the future, we decided to introduce Condition 3.7: Asset Management in the SGN conveyance licence. We consider that to ensure all NI GDNs have appropriate asset management systems in

place and are being regulated on an equivalent basis, a related condition should be included in the FE and PNGL conveyance licences as well. We indicated in the Gas to the West Licence Consultation[89] our intention to do so and are now proposing to follow-up on this matter.

Complaints Handling Procedure – The Code

12.64 We propose to modify Condition 2.8A.2: Complaints Handling Procedure, The Code of the FE conveyance licence by removing the words "*who is connected to or requests a connection to the Licensee's Network*" as well as the words "*in providing such a connection*".

12.65 By making this modification, the scope of the complaints procedure a GDN needs to have in place pursuant to Condition 2.8A: Complaints Handling Procedure gets extended. Based on the current licence wording, the complaints procedure shall enable any person who is connected or requests a connection to the Licensee's network to bring and have promptly dealt with a complaint in respect of the Licensee's activities in providing such a connection. With the proposed revised wording, complaints can also be raised:

- by persons other than those connected or requesting a connection to the Licensee's networks;
- if they relate to any of the Licensee's activities, even if these activities are not activities in providing a connection.

12.66 We consider that this enhanced scope is appropriate. In practice, GDN activities can impact not only on persons connected or requesting a connection. For example, any person passing or living/working near roadworks associated with the laying of gas pipelines could be impacted by the side-effects of the roadworks and wish to raise a relating complaint, even if he or she does not have or request a natural gas connection. If they wish to do so, they should have the option to bring forward and have promptly dealt with their complaint by the party they consider to be at the source of it: the Licensee.

12.67 Similarly, there may be situations where a complaint is related to the Licensee's activities, but not directly to the provision of a connection. This could for example be the case if someone considers one of the Licensee's marketing activities to be inappropriate[95] and wishes to raise a relating complaint. If they do, they should have the option to bring forward and have promptly dealt with their complaint by the party they consider to be at the source of it: the Licensee.

12.68 We also consider that the proposed modification to the FE conveyance licence leads to an alignment of Condition 2.8A.2: Complaints Handling Procedure, The Code in the FE licence with the corresponding Condition 2.14.3 of the SGN licence. It thus furthers the consistency between the NI low pressure conveyance licences and equality in the treatment of licence holders.

12.69 We note that the definition of complaint in the FE Complaints Code of Practice is already compliant with the enhanced scope for complaints as entailed by the new proposed wording. We therefore consider that the practical implications of the proposed licence modifications for FE should be limited.

[95] We note that we do not wish to insinuate this might be the case, but have merely chosen this scenario as an example.

Timelines for Periodic Reviews

12.70 We propose to modify Condition 4.4.7 of the FE conveyance licence as follows: Replace in sub-paragraph (a) the figure "*12*" with "*18*".Experience has shown that the period of 12 months originally stipulated in the FE conveyance licence is too short to carry out a full price control review. This is all the more true if, as now is the case, price control cycles for NI GDNs are being aligned and business plans and representations from a number of NI GDNs need to be considered concurrently. We consider that 18 months is a more sensible period reflective of the time that from our experience a price control process from business plan submission to start of the new price control period actually takes.

12.71 In the Gas to the West Applicant Information Pack we had noted our intention to require business plan submissions for periodic price reviews 18 months before the implementation date. This was then implemented by means of Condition 4.4.7 of the SGN conveyance licence. We consider, however, that to ensure equivalent regulatory treatment of the NI GDNs, a related modification should be made to the FE conveyance licence as well. This is all the more important as we intend to benchmark GDNs against each other as part of the price control process, where relevant and appropriate and thus need to have their price control cycles aligned.

PNGL – UR Proposals

Overview

12.72 As indicated in section 12 Licence Implications, Overview over Licence Modification Proposals, we will consider making modifications to the Phoenix Natural Gas conveyance licence with respect to the following:

- Update of designated parameters and determination values
- Future treatment of profile adjustments[88]
- Use of opex and capex rollers
- Licence alignment between GDNs pursuant to the Gas to the West project
- Licence modifications pursuant to the extension of the PNGL licensed area to East Down

12.73 This section provides details on the following proposed licence modifications, including a summary of their reasons and effects.

- Update of designated parameters and determination values
- Licence alignment between GDNs pursuant to the Gas to the West project

For these areas, Annex 2: PNGL Licence – Proposed Modifications shows the proposed licence modifications as tracked changes. As mentioned before, this drafting is for illustrative purposes only and subject to change between now and the formal licence modification notice to be published together with the GD17 final determination

12.74 In the interest of transparency, we have also included some views on the proposed licence modifications pursuant to the extension of hte PNGL licensed area to East Down in this section. We note, however, that these proposals are not yet sufficiently detailed to be tracked as proposed licence modifications in Annex 2: PNGL Licence – Proposed Modifications.

12.75 We envisage to provide further information on those proposed licence modifications which are not discussed in detail in this GD17 draft determination to the GDNs as part of the preparation of the GD17 final determination, as relevant and appropriate.

Update of Designated Parameters and Determination Values

12.76 We propose to update Condition 2.3.22: Conveyance Charges, Other terms for the Conveyance of Gas and the provision of Conveyance services, Current Designated Parameters with the values determined as part of this GD17 price control for designated parameters.

12.77 We furthermore propose to update Condition 2.3.24: Conveyance Charges, Other terms for the Conveyance of Gas and the provision of Conveyance services, Current Determination Values with the values determined as part of this GD17 price control for determination values.

12.78 The provisional values for the designated parameters and determination values are shown in section 11 Outputs, Outcomes and Allowances of this document but are subject to change as part of the GD17 final determination.

12.79 This change is required to bring the GD17 final determination into effect and ensure consistency between the GD17 final determination and the PNGL conveyance licence. Furthermore, by us making such a modification to the PNGL licence, in line with the Gas (Northern Ireland) Order 2003, PNGL have a mechanism to bring forward an appeal to the CMA against the licence modification and the underlying GD17 final determination.

Licence Alignment between GDNs Pursuant to the Gas to the West Project

Overview

12.80 As part of the Gas to West project and our preparatory work on the SGN conveyance licence, we identified a number of necessary changes to the FE and PNGL licences. There were multiple reasons for these change requirements, including lack of clarity or inaccuracies in the current drafting of these licences, new licence requirements arising from changes to the legal and regulatory framework the GDNs are operating in, shortfalls of the current licences in certain areas as well as the general need to treat the NI GDNs in a fair and equal manner. Whilst these issues were addressed in the SGN conveyance licence, the FE and PNGL licences were not updated at the time. However, we noted in our Gas to the West Licence Consultation[96] our intention to include, for some of the licence conditions contained in the SGN conveyance, equivalent licence conditions in the FE and PNGL conveyance licences in due course.

12.81 We propose to implement the outstanding updates to the FE and PNGL licences together with the licence modifications to bring into effect the GD17 determination. This section therefore details our related proposals with respect to updates to the PNGL licence, the reasons for them and their effect.

Definitions

12.82 We propose to add the definitions for "*high pressure pipe-line*" and "*low pressure pipe-line*" contained in Condition 1.1.6: Interpretation and Construction, Definitions of the SGN conveyance licence into Condition 1.1.6: Interpretation and Construction, Definitions of the PNGL licence.

[96] Utility Regulator: Gas to the West Licence Consultation, 18 December 2014.

12.83 We consider that this proposed change is a consequential change to the proposed licence modifications detailed in the sections below as some of the wording proposed to be introduced into the PNGL licence refers to these terms.

12.84 We furthermore propose to amend the definition for "*related undertaking*" in Condition 1.1.6: Interpretation and Construction, Definitions of the PNGL conveyance licence by replacing the words "*as defined by Article 268 of the Companies (Northern Ireland) Order 1986*" with "*within the meaning of section 421A of the Financial Services and Markets Act 2000*".

12.85 We consider that this proposed change, which aligns the definitions for "*related undertaking*" in the SGN and PNGL conveyance licences, is required because the proposed licence modifications detailed in section 12 Licence Implications, PNGL – UR Proposals, Licence Alignment between GDNs Pursuant to the Gas to the West Project, Trading with Associated Businesses refer to this term and the reference in the definition of "related undertaking" currently contained in the PNGL conveyance licence is out of date; the Companies (Northern Ireland) Order 1986 has been replaced.

Independence of the Licensed Business

12.86 We propose to modify the wording of Condition 1.16.1: Independence of the Licensed Business, Application in the PNGL conveyance licence so as to align it with the wording of Condition 1.16.1: Independence of the Licensed Business, Application of the FE conveyance licence after consideration of the changes suggested to that in paragraph 12.22 of this document.

12.87 We furthermore propose to add the definition of "*Relevant Affiliate*" contained in Condition 1.16.7: Independence of the Licensee, Additional Definitions of the SGN conveyance licence to Condition 1.16.7: Independence of the Licensed Business, Additional Definitions of the FE conveyance licence.

12.88 We recognise that Condition 1.16.1 currently applies to PNGL and that it would continue to apply under the new proposed wording.. However, it was noted as part of the process of granting the Gas to the West low pressure conveyance licence, that the additional clarity with respect to the wording of this condition was required. Furthermore, it was recognised that, if the enhanced, clearer wording was included in the SGN licence, it should for reasons of equality and consistency also be included in the relevant licence conditions of other NI distribution licence holders.

12.89 The proposed modification of Condition 1.16.7 is a consequential change to that proposed for Condition 1.16.1, required to define the term of "Relevant Affiliate" used therein.

Regulatory Instructions and Guidance

12.90 We propose to introduce Condition 1.21: Regulatory Instructions and Guidance from the SGN conveyance licence (after consideration of the modification proposed in paragraph 12.148 of this document to correct a reference error in the licence wording) as new Condition 1.26 in the PNGL conveyance licence. Any references contained in this condition to specific sub-paragraphs of this condition will be renumbered accordingly (e.g. from 1.21.x to 1.26.x).

12.91 We first introduced RIGs as part of the Annual/Cost Reporting for the 2013 reporting year in 2014. These RIGs have been updated the following year for the Annual/Cost Reporting for the 2014 reporting year. They have also formed the basis for the RIGs for the GD17 business plan submission.

12.92 We consider that by introducing this new licence condition into the PNGL conveyance licence, additional clarity is provided for both ourselves and the Licensee with regards to the arrangements concerning the provision of information under RIGs:

- The new licence condition provides us with the powers not only to request information, but also to require the Licensee to have adequate systems, processes and procedures in place to ensure such information can be provided.
- The new licence condition provides protection to the Licensee by assuring that new RIGs or modifications to existing RIGs may only be issued following a consultation process and after due consideration of any responses received.
- The new licence conditions also provides protection to the Licensee in that it allows for any new information requested or information requested to a greater level of detail to be estimated.

12.93 We consider that the additional clarity provided by this licence condition is desirable for both the Licensee as well as ourselves as it provides a better picture of the respective responsibilities.

12.94 We note furthermore that in drafting the Annual/Cost Reporting and business plan RIGs, we have sought alignment with the relating Ofgem templates and documentation where relevant and appropriate. It hence is consequent to also seek alignment, where relevant and appropriate, with the regulatory and governance arrangements supporting this reporting framework. This includes introduction of the relevant licence condition on which such a reporting framework is based, with NI-specific modifications as relevant and appropriate and as included in the drafting of the proposed new licence condition.

12.95 Ofgem introduced the RIGs to achieve improved consistency of reporting across the licensees, including with respect to reporting structures and definitions used. On this basis, comparability of data across businesses was enhanced and benchmarking between GDNs became more meaningful. As we move towards aligning price controls, where reasonable and appropriate, across NI GDNs and increase the use of comparative analysis and benchmarking, RIGs, and this associated licence condition, become more important.

12.96 Finally, we consider that the introduction of the proposed new licence condition in the PNGL licence also furthers consistency between the NI low pressure conveyance licences. In the Gas to the West Applicant Information Pack we had noted our intention to include in the Gas to the West licence a condition to oblige the Licensee to co-operate with cost reporting.[90] This condition later became Condition 1.21: Regulatory Instructions and Guidance of the SGN licence. We consider, however, that in order to ensure that the NI GDNs are regulated on an equivalent basis a related condition should be included in the FE and PNGL conveyance licences as well. We indicated in the Gas to the West Licence Consultation[89] our intention to do so and are now proposing to follow-up on this matter.

Resolution of Disputes

12.97 We propose to substitute Condition 2.3.6: Conveyance Charges, Other Terms for the Conveyance of Gas and the provision of Conveyance services, Resolution of disputes in the PNGL conveyance licence with the corresponding Condition 2.2.6 in the SGN conveyance licence. Any references contained in this condition to the condition itself will be renumbered accordingly (e.g. from 2.2 to 2.3 and from 2.2.6 to 2.3.6).

12.98 We furthermore propose to substitute Condition 2.4.9: Connection Charges and Obligation to permit a Connection, Resolution of disputes by the Authority in the PNGL conveyance licence with the corresponding Condition 2.3.9 in the SGN conveyance licence. Any references contained in this condition to the condition itself will be renumbered accordingly (e.g. from 2.3.9 to 2.4.9).

12.99 As part of our preparatory work on the SGN conveyance licence as part of the Gas to the West project we noted that the arrangements for resolution of disputes contained in the existing NI conveyance licences were inconsistent, complex, difficult to understand and represented neither current nor intended practice. This was true for both disputes relating to conveyance services and connections. We therefore redrafted the related licence conditions and included them as Condition 2.2.6 and Condition 2.3.9 in the SGN conveyance licence.

12.100 We consider that in the interest of clarity, to ensure equivalent regulatory treatment of the NI GDNs and to facilitate a consistent dispute resolution process across NI the FE and PNGL conveyance licences should be updated to reflect the reworded conditions. We indicated in the Gas to the West Licence Consultation[89] our intention to do so and are now proposing to follow-up on this matter.

Connection Charges and Obligation to Permit a Connection

12.101 We propose to introduce Condition 2.3.8: Connection Charges and Obligation to permit a Connection, Statements for the purposes of standards of performance from the SGN conveyance licence as new Condition 2.4.19 into the PNGL conveyance licence. Any references contained in this condition to the other conditions in the licence will be updated accordingly (e.g. from Condition 2.3.1 in the SGN licence to 2.4.1 in the PNGL licence and from 2.3.7 in the SGN licence to 2.4.8 in the PNGL licence).

12.102 We propose to introduce Condition 2.3.15: Connection Charges and Obligation to permit a Connection, Accuracy of quotations from the SGN conveyance licence as new Condition 2.4.20 into the PNGL conveyance licence.

12.103 We propose to introduce Condition 2.3.17: Connection Charges and Obligation to permit a Connection, In this Condition from the SGN conveyance licence as new Condition 2.4.21 into the PNGL conveyance licence.

12.104 We consider that these licence changes are required pursuant to the Gas (Individual Standards of Performance) Regulations (Northern Ireland) 2014[91]. In these regulations, the terms complex connection, excluded connection and public accuracy scheme are defined with reference to the conveyance licence. It is therefore necessary to include such references in the conveyance licence.

12.105 The relevant licence conditions have already been included in the SGN conveyance licence at the time of its grant in February 2015. For consistency and compliance with the regulations we propose to update the PNGL conveyance licence accordingly.

Co-operation with Other GDNs

12.106 We propose to introduce Condition 2.4.12: Network Code, Performance of Obligations from the SGN conveyance licence as new Condition 2.5.13 into the PNGL conveyance licence. Any references contained in this condition to the condition itself will be renumbered accordingly (e.g. from 2.4.12 to 2.5.13).

12.107 We propose to introduce Condition 2.25: Common Branding from the SGN conveyance licence as new Condition 2.16 into the PNGL conveyance licence.

12.108 We propose to introduce Condition 2.26: Common Network Tariff from the SGN conveyance licence as new Condition 2.17 into the PNGL conveyance licence.

12.109 In the Gas to the West Applicant Information Pack[92] we had noted our intention to include in the Gas to the West licence conditions to oblige the Licensee to co-operate with other GDNs in:

- producing a single low pressure network code together with a consistent switching system and consistent switching processes;
- delivering a common branding approach in relation to promoting natural gas in NI; and
- delivering a common low pressure network tariff in NI.

12.110 These conditions later became Condition 2.4.12: Network Code, Performance of Obligations, Condition 2.25: Common Branding and Condition 2.26: Common Network Tariff from the SGN conveyance licence. However, co-operation may be difficult to achieve (and would be impossible to enforce) if the obligation to co-operate is only on one, not on all the parties supposed to be co-operating. We therefore consider that to achieve the objective of true co-operation amongst the GDNs in the relevant areas and to ensure equivalent regulatory treatment of the NI GDNs, a related condition should be included in the FE and PNGL conveyance licences as well. We indicated in the Gas to the West Licence Consultation[89] our intention to do so.

12.111 With respect to co-operation in delivering a common branding approach and a common low pressure network tariff in NI, we note that GDNs have also been encouraged already as part of our GD14 final determination[97] to work together in a number of areas, including:

- Advertising and Marketing/ Consumer Research;
- Conveyance Charges;
- Connection Policies; and
- Emergencies and Major Incidents.

12.112 Whilst we are aware that co-operation between the NI GDNs is ongoing, we consider that further progress can be made. We consider that the proposed licence modifications may help to achieve such further progress over time. However, we consider that it is important to focus on the most relevant aspect at this point, which is from our point of view the common branding.

12.113 We note that we are aware that achieving communality may take time, in particular with respect to single network code and common tariff. For example 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 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

[97] See Utility Regulator: GD14 Price Control for Northern Ireland's Gas Distribution Networks for 2014-2016, Final Determination, 20 December 2013, paragraphs 16.9 and 16.39 to 16.43.

need to be continued during the GD17 price control period. We consider that this has been reflected in the proposed licence conditions in so far as both Condition 2.4.12: Network Code, Performance of Obligations and Condition 2.26: Common Network Tariff from the SGN conveyance licence put a general obligation on the GDNs to co-operate in the relevant area in addition to the need to comply with specific related directions which may be issued by the Authority, e.g. once we have a more detailed plan for progressing such projects.

12.114 With respect to the proposed common branding licence condition we note that its purpose is to further the development of the natural gas industry and to prevent consumers getting confused by the different brands. We consider that GDNs can achieve further efficiencies and improve recognition by consumers by aligning and/or sharing promotional material and/or activities, thus increasing the effect/reducing the cost for each GDN.

Reasonable and Prudent Operator

12.115 We propose to introduce Condition 2.27: Reasonable and Prudent Operator from the SGN conveyance licence as new Condition 2.18 into the PNGL conveyance licence.

12.116 In the Gas to the West Applicant Information Pack[94] we had noted our intention to include in the Gas to the West licence a condition obliging the licence holder to act as a reasonable and prudent operator and maintain the network for its economic engineering life. This condition later became Condition 2.27: Reasonable and Prudent Operator in the SGN conveyance licence. However, to ensure equivalent regulatory treatment of the NI GDNs, a related condition should be included in the FE and PNGL conveyance licences as well. We indicated in the Gas to the West Licence Consultation[89] our intention to do so and are now proposing to follow-up on this matter.

12.117 This licence condition formalises how we would expect any low pressure conveyance licence holder to run their business. That said, we still consider the introduction of the proposed new licence condition to be of importance as by formalising the requirements of a reasonable and prudent operator in the licence they become enforceable.

Trading with Associated Businesses

12.118 We propose to introduce Condition 2.30: Trading with Associated Businesses from the SGN conveyance licence as new Condition 2.19 into the PNGL conveyance licence. Any references contained therein to other conditions will be renumbered accordingly (e.g. from 1.2.14 to 1.3.14).

12.119 We furthermore propose to introduce Condition 1.2.14: Separate Accounts for Separate Businesses, Associated Undertakings from the SGN conveyance licence as new Condition 1.3.14 into the PNGL conveyance licence. Any references contained therein to this or other conditions will be renumbered accordingly (e.g. from 1.2.9(c) to 1.3.8(c) and from 1.2.14 to 1.3.14).

12.120 The proposed new Condition 2.18: Trading with Associated Businesses prohibits cross subsidies to or from businesses operated by the Licensee or any of its affiliates or related undertakings. This reflects our intention that the Licensee shall not benefit from cross-subsidies arising from transactions with associated businesses, nor provide such benefits to associated businesses. There are in addition requirements to ensure that contracts entered into by the Licensee comply with the prohibition on cross subsidy.

12.121 The proposed new Condition 1.3.14: Separate Accounts for Separate Businesses, Associated Undertakings is a consequential change to the introduction of the proposed

new Condition 2.18: Trading with Associated Businesses and required to ensure licence consistency.

12.122 When we included Condition 2.30: Trading with Associated Businesses in the SGN conveyance licence, we considered that to ensure equivalent regulatory treatment of the NI GDNs, a related condition should be included in the FE and PNGL conveyance licences as well. We indicated in the Gas to the West Licence Consultation[89] our intention to do so and are now proposing to follow-up on this matter.

Asset Management

12.123 We propose to introduce Condition 3.7: Asset Management from the SGN conveyance licence as new Condition 2.15 into the PNGL conveyance licence. Any reference contained in this condition to the condition itself will be renumbered accordingly (e.g. from 3.7.1 to 2.15.1).

12.124 We consider that in order to ensure the efficient and economic operation of the network, the Licensee needs to have in place an asset management system.

12.125 We have noted, in previous price control determinations, our concerns at the lack of implementation of a comprehensive asset management system by the GDNs. Whilst by the time of the GD14 final determination both FE and PNGL had presented plans for implementation of such a system during the GD14 price control period, we were uneasy about whether this objective would indeed be reached and about the amount of time it took to get to such a stage.

12.126 On this background, and to prevent similar issues arising in the future, we decided to introduce Condition 3.7: Asset Management in the SGN conveyance licence. We consider that to ensure all NI GDNs have appropriate asset management systems in place and are being regulated on an equivalent basis, a related condition should be included in the FE and PNGL conveyance licences as well. We indicated in the Gas to the West Licence Consultation[89] our intention to do so and are now proposing to follow-up on this matter.

Complaints Handling Procedure – The Code

12.127 We propose to modify Condition 2.8A.2: Complaints Handling Procedure, The Code of the PGNL conveyance licence by removing the words "*who is connected to or requests a connection to the Licensee's Network*" as well as the words "*in providing such a connection*".

12.128 By making this modification, the scope of the complaints procedure a GDN needs to have in place pursuant to Condition 2.8A: Complaints Handling Procedure gets extended. Based on the current licence wording, the complaints procedure shall enable any person who is connected or requests a connection to the Licensee's network to bring and have promptly dealt with a complaint in respect of the Licensee's activities in providing such a connection. With the proposed revised wording, complaints can also be raised:

- by persons other than those connected or requesting a connection to the Licensee's networks;
- if they relate to any of the Licensee's activities, even if these activities are not activities in providing a connection.

12.129 We consider that this enhanced scope is appropriate. In practice, GDN activities can impact not only on persons connected or requesting a connection. For example, any

person passing or living/working near roadworks associated with the laying of gas pipelines could be impacted by the side-effects of the roadworks and wish to raise a relating complaint, even if he or she does not have or request a natural gas connection. If they wish to do so, they should have the option to bring forward and have promptly dealt with their complaint by the party they consider to be at the source of it: the Licensee.

12.130 Similarly, there may be situations where a complaint is related to the Licensee's activities, but not directly to the provision of a connection. This could for example be the case if someone considers one of the Licensee's marketing activities to be inappropriate[98] and wishes to raise a relating complaint. If they do, they should have the option to bring forward and have promptly dealt with their complaint by the party they consider to be at the source of it: the Licensee.

12.131 We also consider that the proposed modification to the PNGL conveyance licence leads to an alignment of Condition 2.8A.2: Complaints Handling Procedure, The Code in the PNGL licence with the corresponding Condition 2.14.3 of the SGN licence. It thus furthers the consistency between the NI low pressure conveyance licences and equality in the treatment of licence holders.

12.132 We note that the pursuant to this proposed modification the PNGL Code of Practice may need to be amended to account for this enhanced scope of complaints.

Timelines for Periodic Reviews

12.133 We propose to modify Condition 2.3.13: Conveyance Charges, Other Terms for the Conveyance of Gas and the provision of Conveyance services, Reviews Generally of the PNGL conveyance licence as follows: Replace in sub-paragraph (a) the figure "*15*" with "*18*".

12.134 Experience has shown that the period of 15 months originally stipulated in the PNGL licence is too short to carry out a full price control review. This is all the more true if, as now is the case, price control cycles for NI GDNs are being aligned and business plans and representations from a number of NI GDNs need to be considered concurrently. We consider that 18 months is a more sensible period reflective of the time that from our experience a price control process from business plan submission to start of the new price control period actually takes.

12.135 In the Gas to the West Applicant Information Pack we had noted our intention to require business plan submissions for periodic price reviews 18 months before the implementation date. This was then implemented by means of Condition 4.4.7 of the SGN conveyance licence. We consider, however, that to ensure equivalent regulatory treatment of the NI GDNs, a related modification should be made to the PNGL conveyance licence as well. This is all the more important as we intend to benchmark GDNs against each other as part of the price control process, where relevant and appropriate and thus need to have their price control cycles aligned.

Licence modifications pursuant to the extension of the PNGL licensed Aarea to East Down

12.136 As detailed in paragraph 4.28, we stated in our consultation paper on the extension of the PNGL licensed area to East Down that, should the extension of the PNGL licensed

[98] We note that we do not wish to insinuate this might be the case, but have merely chosen this scenario as an example.

area be granted, PNGL needed to deliver against their proposal to develop their 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.[44] 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*."[43]

12.137 Appendix 4: Draft PNGL Development Plan for East Down with Respect to Cumulative Properties Passed provides details on the development plan we are considering including in the PNGL licence. We note that this is for illustrative purposes only and the targets set ou in this draft development plan are subject to change. We note furthermore that in addition to this development plan, we propose to include related licence conditions, referencing this development plan and embedding the need to achieve the targets set out in this development plan in the licence. We propose to provide further information on these proposed licence conditions as part of the preparation of the GD17 final determination, as relevant and appropriate.

SGN – UR Proposals

Overview

12.138 As indicated in section 12 Licence Implications, Overview over Licence Modification Proposals, we will consider making modifications to the SGN conveyance licence with respect to the following:

- Update of designated parameters and determination values
- Use of opex and capex rollers
- Licence Modifications pursuant to our decision paper on Modifications necessary due to The Gas and Electricity Licence Modification and Appeals Regulations (Northern Ireland)
- Correction of licence errors

12.139 This section provides details on the following proposed licence modifications, including a summary of their reasons and effects.

- Update of designated parameters and determination values
- Licence Modifications pursuant to our decision paper on Modifications necessary due to The Gas and Electricity Licence Modification and Appeals Regulations (Northern Ireland)
- Correction of licence errors

For these areas, Annex 3: SGN Licence – Proposed Modifications shows the proposed licence modifications as tracked changes. As mentioned before, this drafting is for

illustrative purposes only and subject to change between now and the formal licence modification notice to be published together with the GD17 final determination.

12.140 We envisage to provide further information on those proposed licence modifications which are not discussed in detail in this GD17 draft determination to the GDNs as part of the preparation of the GD17 final determination, as relevant and appropriate.

Update of Designated Parameters and Determination Values

12.141 We propose to update Condition 4.11: Current Designated Parameters and Determination Values with the values determined as part of this GD17 price control for designated parameters and determination values. The provisional values for the designated parameters and determination values are shown in section 11 Outputs, Outcomes and Allowances, SGN – UR Proposals, Designated Parameters and Determination Values of this document but are subject to change as part of the GD17 final determination.

12.142 This change is required to bring the GD17 final determination into effect and ensure consistency between the GD17 final determination and the SGN conveyance licence. Furthermore, by us making such a modification to the SGN licence, in line with the Gas (Northern Ireland) Order 2003, SGN have a mechanism to bring forward an appeal to the CMA against the licence modification and the underlying GD17 final determination.

Licence Modifications due to The Gas and Electricity Licence Modification and Appeals Regulations (Northern Ireland)

12.143 On 1 May 2015, we published a consultation paper on Changes to Gas and Electricity Licences with regards to Appeals to the CMA[99]. This paper detailed our proposed licence modifications required with respect to gas and electricity licences pursuant to the Gas and Electricity Licence Modification and Appeals Regulations (Northern Ireland) 2015. The consultation paper was followed, on 4 August 2015, by the publication of our related decision paper[86].

12.144 The SGN conveyance licence was granted on 11 February 2015 and drafted so as to be consistent with these Regulations and provide the licence holder with appropriate appeals mechanisms. Therefore, no modifications to the SGN conveyance licence were required or made at the time the decision paper on Changes to Gas and Electricity Licences with regards to Appeals to the CMA was published.

12.145 However, as part of the consultation process, a number of changes have been made to licence conditions that are in equivalent form also contained in the SGN licence. We indicated in the decision paper that in the interest of licence consistency, we would consider aligning the SGN licence with these decisions in due course. We are now proposing to follow-up on this matter and, in particular, to make the changes listed in paragraphs 12.146 to 12.147 below.

12.146 We propose to modify Condition 4.4.13 by removing the following wording from sub-paragraph (c): "*which shall not be earlier than the Disapplication Date*". This will allow the licence holder to request and us to agree a disapplication date earlier than the date set out in the licence.

[99] See Utility Regulator: Changes to Gas and Electricity Licences with regards to Appeals to the CMA, Modifications necessary due to The Gas and Electricity Licence Modification and Appeals Regulations (Northern Ireland) 2015, April 2015.

12.147 We propose to modify Condition 4.4.14 of the SGN conveyance licence as follows:

- remove the word "*and*" at the end of condition 4.4.14(a);
- rename condition 4.4.14(b) into 4.4.14(c);
- add a new condition 4.4.14(b) to read as follows: "*may be withdrawn by the Licensee at any time prior to the Disapplication Date; and*".

We propose furthermore to modify Condition 4.4.11 of the SGN conveyance licence by adding the following words at the end of condition 4.4.11(b): "*and not withdrawn*".

These changes will allow for a Disapplication Notice to be withdrawn.

Correction of Licence Errors

12.148 A licence drafting error has been noted in Condition 1.21.5: Regulatory Instructions and Guidance, Requirements for new or more detailed information of the SGN conveyance licence. In paragraphs (a) and (b) reference is made to Condition 1.12.5. This reference is wrong and should be to Condition 1.21.5 instead. We propose to update the SNG licence accordingly.

12.149 A further licence drafting error has been noted in Condition 4.12: Definitions and Interpretation of the SGN conveyance licence: In the definition of Expenditure, sub-paragraph (iii) contains a reference to Conditions 2.5.2(a)(i) or 2.5.3(a)(i). This reference is wrong and should be to paragraphs 2.12.3(a)(ii) and 2.12.4(a)(i) respectively instead. We propose to update the SGN licence accordingly.

13 Next Steps and Further Issues

Submission of Consultation Responses

13.1 This is an open consultation paper. We invite stakeholders to express a view on any particular aspect of the paper or any related matter. Responses should be received on or before 12noon on Tuesday 31 May 2016 and should be addressed to:

Paul Harland
Finance and Network Assets
Queens House
14 Queen Street
Belfast
BT1 6ED
Tel: 028 9031 1575
Email: Gas_networks_responses@uregni.gov.uk with cc to paul.harland@uregni.gov.uk

Our preference would be for responses to be submitted by e-mail.

13.2 We note that we may make public any responses to this consultation on the GD17 draft determination. If you do not wish your response or name made public, please state this clearly by marking the response as confidential. Any confidentiality disclaimer that is automatically produced by an organisation's IT system or is included as a general statement in your fax or coversheet will be taken to apply only to information in your response for which confidentiality has been specifically requested.

13.3 Information provided in response to this consultation, including personal information, may be subject to publication or disclosure in accordance with the access to information regimes; these are primarily the Freedom of Information Act 2000 (FOIA) and the Data Protection Act 1998 (DPA). If you want the information that you provide to be treated as confidential, please be aware that, under the FOIA, there is a statutory code of practice with which public authorities must comply and which deals, amongst other things with obligations of confidence.

13.4 In view of this, it would be helpful if you could explain to us why you regard the information you have provided as confidential. If we receive a request for disclosure of the information we will take full account of your explanation, but we cannot give an assurance that confidentiality can be maintained in all circumstances. An automatic confidentiality disclaimer generated by your IT system will not, of itself, be regarded as binding on the Authority.

This document is available in accessible formats. Please contact Paul Harland on 028 9031 1575 or email: Gas_networks_responses@uregni.gov.uk with cc to paul.harland@uregni.gov.uk to request this.

Next Steps

13.5 Table 194 provides an overview over the next steps and associated timelines for the GD17 price control process.

Key Milestones of GD17	
Key Points	**Proposed Date**
Request GDNs to provide Business Plan templates updated with 2015 actuals	31 March 2016
Meetings with Credit Rating Agencies	26 to 27 April 2016
Stakeholder workshop on GD17 draft determination	10 May 2016
Closure of draft price control consultation	31 May 2016
Submission of updated Business Plan templates with 2015 actuals	30 June 2016
Stakeholder Workshop on GD17 final determination	August 2016 (exact date to be confirmed)
Publication of final determination of GD17 and consultation on related licence modifications	15 September 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
Issue of lessons learnt questionnaires to GDNs/key stakeholders	13 January 2016
Return of lessons learnt questionnaires by GDNs/key stakeholders	17 February 2016
Completion of lessons learnt report	31 March 2017

Table 194: GD17 Next Steps

13.6 We note in particular that we will be holding a workshop for stakeholders on 10 May 2016. This will provide an opportunity for stakeholders to understand the proposals outlined in this consultation and to give an opportunity for questions. If anyone wishes to attend the workshop, please contact:

Karen McConnell
Tel: 028 9031 1575
Email: Gas_networks_responses@uregni.gov.uk with cc to Karen.McConnell@uregni.gov.uk

Consequential Changes

13.7 We consider that a number of consequential changes will be required as a result of the GD17 final determination, once made. 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 detailed in chapter 12 Licence Implications.
- 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

13.8 We note that this list is not necessarily exhaustive and that the need for further consequential changes may arise as the GD17 determination is being finalised.

Further Issues

13.9 As part of this GD17 draft 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

13.10 Our initial view on the issues to be considered during the GD17 price control period but after the GD17 final determination comprise of the following.

- Consumer Engagement
- Shrinkage Review
- Review of Conveyance Charges
- Revision of Annual/Cost Reporting templates and associated RIGs

13.11 Consumer Engagement : As detailed in Section 11 Outputs, Outcomes and Allowances 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 will 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.

13.12 During the draft determination stage we would propose we re-convene the gas industry partnership group to discuss the above timetable, with a view to settling on an agreed timeline of milestones for delivery of this development objective.

13.13 Shrinkage Review: As As detailed in Section 11 Outputs, Outcomes and Allowances we propose 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), 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. 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 propose that this report should be provided by no later than end of 2017.

13.14 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.

13.15 Revision of Annual/Cost Reporting templates and associated RIGs: We propose to 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 would 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 allows a monitoring of performance against price control allowances, outputs and other outcomes. We note that we also 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.[100] 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 was 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.

Change in Ownership Structure

13.16 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.

13.17 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.

13.18 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.

SGN – Updated Network Design

13.19 SGN have informed us that an updated Network Design of the towns will be available for consideration by the end of April 2016.

13.20 We will consider, what changes may be necessary, if any, to reflect the best position possible for the final determination publication in September 2016. For any information to be considered in the final determination it will need to be provided in a timely manner.

[100] 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.

Appendices

Appendix 1: Map of FE Licensed Area

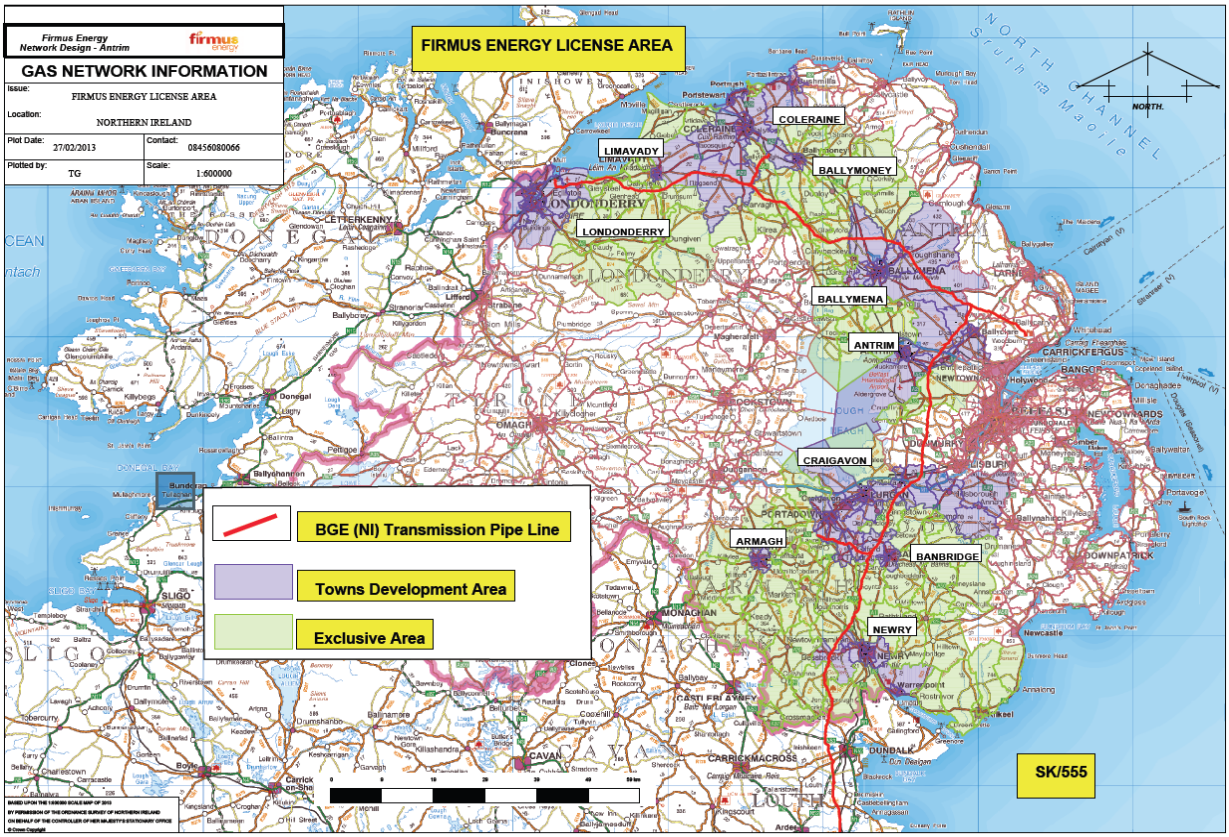


Table 195: Map of FE Licensed Area

Appendix 2: Map of the PNGL Licensed Area

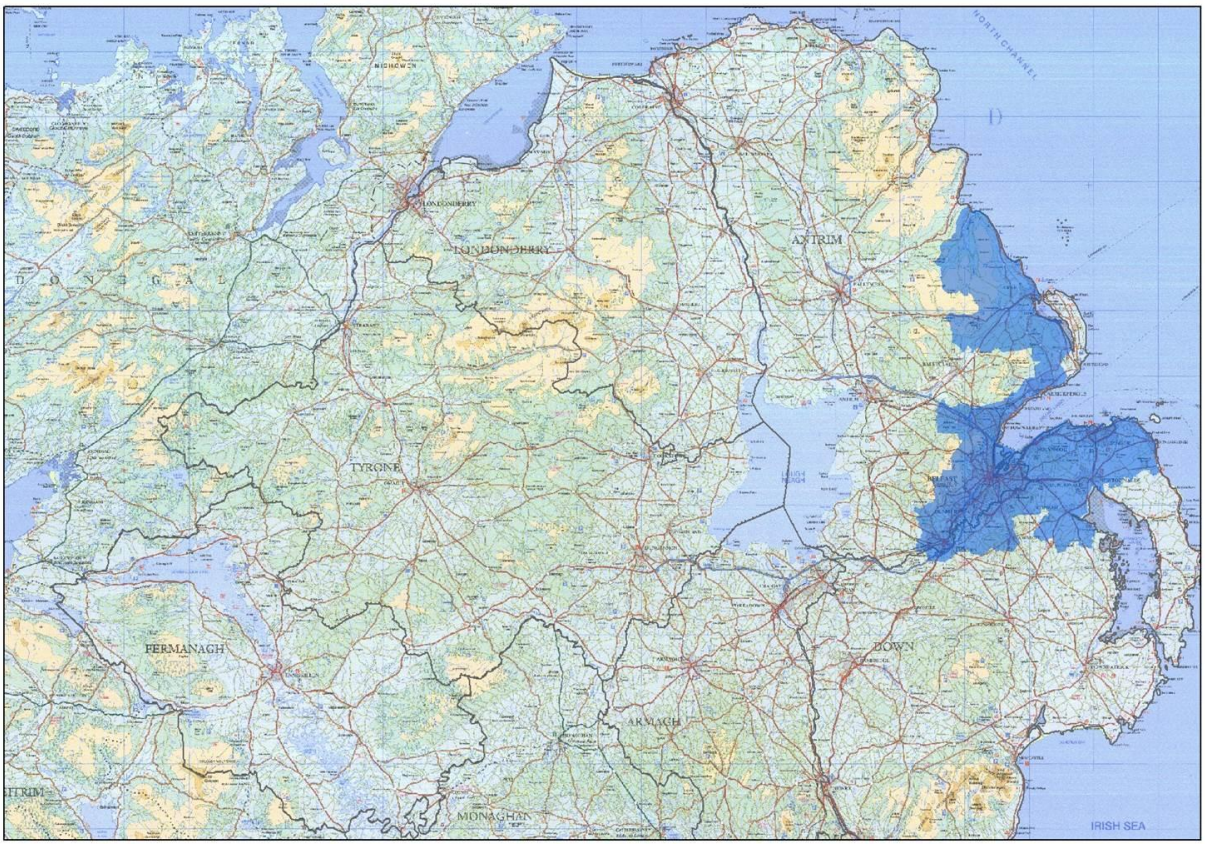


Table 196: Map of the PNGL Licensed Area

Appendix 3: Map of SGN Towns to Connect

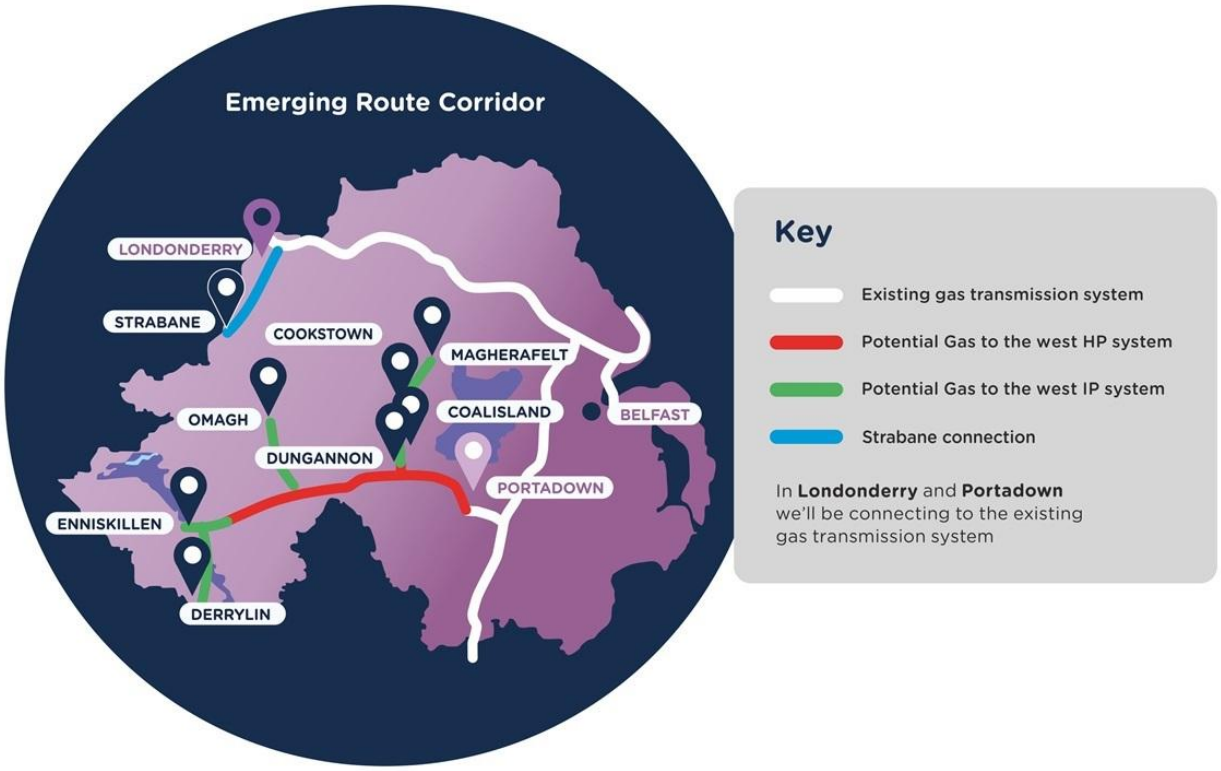


Table 197: Map of SGN Towns to Connect

Appendix 4: Draft PNGL Development Plan for East Down with Respect to Cumulative Properties Passed

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16
Ballynahinch, Drumaness and Spa	0	589	1,178	1,767	2,356	2,945	3,533	3,551	3,568	3,585	3,602	3,620	3,637	3,654	3,671	3,689
Crossgar, Saintfield and Ballygowan	0	594	1,188	1,782	2,376	2,970	3,564	3,581	3,598	3,616	3,633	3,651	3,668	3,686	3,703	3,720
Downpatrick	0	845	1,690	2,535	3,380	4,225	5,071	5,095	5,119	5,143	5,167	5,191	5,215	5,239	5,263	5,287
Dromore	0	464	928	1,392	1,857	2,321	2,785	2,799	2,813	2,826	2,840	2,854	2,868	2,882	2,895	2,909
Hillsborough and Annahilt	0	367	734	1,101	1,468	1,836	2,203	2,214	2,225	2,237	2,248	2,259	2,270	2,282	2,293	2,304
Newcastle, Castlewellan and Dundrum	0	1,025	2,050	3,075	4,100	5,125	6,150	6,180	6,210	6,240	6,270	6,300	6,330	6,360	6,390	6,420
TOTAL	0	3,884	7,768	11,653	15,537	19,421	23,305	23,419	23,533	23,647	23,760	23,874	23,988	24,102	24,216	24,330

	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046
	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24	Year 25	Year 26	Year 27	Year 28	Year 29	Year 30	Year 31
Ballynahinch, Drumaness and Spa	3,706	3,723	3,740	3,758	3,775	3,792	3,809	3,827	3,844	3,861	3,878	3,896	3,913	3,930	3,947
Crossgar, Saintfield and Ballygowan	3,738	3,755	3,773	3,790	3,808	3,825	3,843	3,860	3,877	3,895	3,912	3,930	3,947	3,965	3,982
Downpatrick	5,311	5,335	5,360	5,384	5,408	5,432	5,456	5,480	5,504	5,528	5,552	5,576	5,600	5,624	5,649
Dromore	2,923	2,937	2,951	2,965	2,978	2,992	3,006	3,020	3,034	3,047	3,061	3,075	3,089	3,103	3,117
Hillsborough and Annahilt	2,316	2,327	2,338	2,349	2,361	2,372	2,383	2,395	2,406	2,417	2,428	2,440	2,451	2,462	2,474
Newcastle, Castlewellan and Dundrum	6,450	6,480	6,510	6,539	6,569	6,599	6,629	6,659	6,689	6,719	6,749	6,779	6,809	6,839	6,869
TOTAL	24,443	24,557	24,671	24,785	24,899	25,013	25,126	25,240	25,354	25,468	25,582	25,696	25,810	25,923	26,037

Table 198: Draft PNGL Development Plan for East Down with Respect to Cumulative Properties Passed

Annexes

Overview

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	Cost of Capital
Annex 8	Emergency Costs
Annex 9	Opex Backcasting Methodology
Annex 10	PI Models – FE
Annex 11	PI Models – PNGL
Annex 12	PI Models - SGN

Table 199 provides an overview over the annex to this GD17 draft 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	Cost of Capital
Annex 8	Emergency Costs
Annex 9	Opex Backcasting Methodology
Annex 10	PI Models – FE
Annex 11	PI Models – PNGL
Annex 12	PI Models - SGN

Table 199: Annexes to GD17 Draft Determination