Price Control for Northern Ireland's Gas Transmission Networks GT17

Draft Determination

16 December 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 GT17 for the four high pressure gas conveyance licence holders in Northern Ireland, GNI (UK) Ltd, Premier Transmission Ltd (PTL), Belfast Gas Transmission Ltd (BGTL), and West Transmission Ltd (WTL) for the years from October 2017 to September 2022.

The price control will set out the amount the gas transmission companies will have to run their businesses and invest in the gas network. The key decisions for the companies are on operating expenditure, replacement expenditure and the proposed rate of return.

Audience

Industry, consumers & statutory bodies.

Consumer Impact

The price control will set out the allowed transmission revenue for the holders of high pressure gas conveyance licences. The draft determination in this document sets out the basis on which we propose to determine the allowed revenue with consideration of the business plans submitted by the licence holders.

The impact of implementing the business plans submitted by the companies would be an approximate £5 real terms uplift in the annual bill. This compares to a £0.50 increase proposed in the draft determination. The UR allowance therefore results in a £4.50 saving compared to the company submissions.

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ACRONYMS AND GLOSSARY

ACRT	Annual/Cost Reporting Template
AGI	Above Ground Installation
ARR	Actual Required Revenue
BAU	Business as Usual
BGTL	Belfast Gas Transmission Limited
BGTP	Belfast Gas Transmission Pipeline
C&I Panel	Control & Instrumentation Panel
Capex	Capital expenditure
CAPM	Capital Asset Pricing Model. A model that describes the relationship between risk and expected return.
CBA	Cost Benefit Analysis
CC	Competition Commission
CJV	Contractual Joint Venture – Single market system operation for TSOs
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.
Co.	County
CPI	Consumer Price Index
e.g.	for example
EBITDA	Earnings before Interest, Taxes, Depreciation and Amortization
etc.	Et cetera (and so forth)
European Gas	Directive 2009/73/EC of the European Parliament of 13 July 2009

Directive	concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC
FFO	Funds from Operation
FOIA	Freedom of Information Act 2000
FRR	Forecast Required Revenue
FTE	Full Time Equivalent
GttW	Gas to the West. This is the name of the project aiming to extend the Natural Gas Network, to other areas of the province, namely Dungannon, Cookstown, Magherafelt, Enniskillen, Omagh and Strabrane
GB	Great Britain
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).
GNI	Gas Networks Ireland (parent company of GNI (UK))
GNI (UK)	Gas TSO operating in Northern Ireland
GT12	This is the name given to the price control period 2012/13 to 2016/17
GT12 actuals	The period 2012-13 to 2014-15 for which actual expenditure is available
GT17	This is the name given to the next price control for high pressure gas conveyance licence holders in Northern Ireland covering the years 2017-18 to 2021-22
IC	Interconnector
ISO	International Organisation for Standardisation
IT	Information Technology
km	Kilometre
m	Million
MEL	Mutual Energy Limited
mm	Millimetre
NI	Northern Ireland
NIE	Northern Ireland Electricity – now known as NIEN

NPB	Net Present Benefit
NPC	Net Present Cost
NWP	North-West Pipeline
OBR	Office of Budget Responsibility
Ofgem	Office of Gas and Electricity Markets. Regulates the electricity and gas markets in Great Britain.
Opex	Operating Expenditure
p.a.	Per annum (per year)
PC10	Price Control for NI Water for the years 2010-2013
PC15	Price Control for NI Water for the years 2015-2021
PLC	Programmable Logic Controllers
PMICR	Post-Maintenance Interest Coverage Ratio
PTL	Premier Transmission Limited
REMIT	Regulation on Energy Market Integrity and Transparency
Repex	Replacement Expenditure
RIGs	Regulatory Instructions and Guidance
RPEs	Real Price Effects
RPI	Retail Price Index
SCADA	Supervisory Control and Data Acquisition
SEF	Social Enhancement Fund
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.
SNIP	Scotland to Northern Ireland Pipeline
SNP	South-North Pipeline
SONI	System Operator Northern Ireland (electricity network)
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	GNI (UK), PTL, BGTL and WTL. WTL is not a TSO (Transmission System Operator) as defined by the European Commission but it is referred to as a TSO in this document for simplicity.
UK	United Kingdom
UPS	Universal Power Supply
UR	Utility Regulator
WACC	Weighted Average Cost of Capital
WTL	West Transmission Limited

1 Executive Summary

Introduction

1.1 This document represents the draft determination for the GT17 price control process.

1.2 GT17 is the name given to the price control for the four high pressure gas networks in Northern Ireland (NI) relating to the period starting 1 October 2017 until 30 September 2022. The four gas conveyance licence holders for NI high pressure networks are:

- GNI (UK) Limited (GNI (UK));
- Premier Transmission Limited (PTL);
- Belfast Gas Transmission Limited (BGTL); and
- West Transmission Limited (WTL).

1.3 In this draft determination, we detail our proposals with respect to:

- Operating expenditure (opex) allowances;
- Maintenance/replacement (repex) allowances; and
- Weighted average cost of capital (WACC), where relevant.

1.4 A significant development in the regulatory regime will be the establishment of a single system operator for Northern Ireland on 1 October 2017. This will be a contractual joint venture (CJV) between the licence holders rather than a separate legal entity. Its operations will be funded through the existing licences. However, in determining proposed allowances for the CJV, we did so on the principle of the CJV being a single entity.

1.5 This draft determination follows the publication of the GT17 approach and business plan templates on 30 June 2016, and the submission of the completed business plans by the licence holders in September/October 2016.

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. We do so consistently with our fulfilment of the objectives set out in the European Gas Directive, and by having regard to a number of matters, as set out more fully in the Energy (Northern Ireland) Order 2003.

1.7 As GNI (UK), PTL, BGTL and WTL in their respective geographical areas, are the only monopoly providers of high pressure gas networks, a regulatory framework has been put in place to protect the consumers who use their services.

1.8 An important part of the regulatory framework is price controls. A price control is a method of setting the total allowed revenues a licence holder is allowed to earn (revenue cap), or maximum tariffs a licence holder is allowed to charge (price cap) during a given period (the price control period).

1.9 In summary, 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 licence holders can continue to finance the activities which are the subject of obligations placed on them; and
- Have due regard to all relevant factors.

1.10 It is our aim to do this by:

- Providing a strong foundation for the continued and long-term growth of gas networks and delivering service improvements to consumers;
- Challenging the conveyance licence holders 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 levels that are consistent with efficient operation.

Licence Holder-Specific Proposals

Detailed Approach

1.11 When assessing the appropriateness of the opex requests, we take the view that costs should be in line with past allowances / actual costs observed in the previous price control period. This is particularly true if there has been no material change in the level and type of activities that are required to operate the network.

1.12 However, a significant change in the price control period arises in the form of the WTL network. This will raise certain costs such as maintenance and emergency response, but will simply spread other costs, such as intercompany recharges over a wider base.

1.13 With regard to those activities which in future will be delivered by the CJV, allowances will be reduced. We will not provide allowances to duplicate activity within the TSOs that in future will be the responsibility of the CJV.

1.14 As part of their business plans, licence holders submitted a list of repex projects for which they sought an allowance. In considering each project we followed a two stage approach. In the first stage we determined whether or not the project should be carried out during the price control period. For those projects that pass this first stage we then, in the second stage, considered what the appropriate allowance would be.

1.15 In making an assessment of the efficient level of allowances required to deliver individual projects our consultants benchmarked costs against other companies who have carried out similar work. We also aim to take account of, amongst other things, available cost data from Ofgem and the Commission for Energy Regulation (CER) in the final determination.

1.16 In line with regulatory practice and historic precedent, we have applied an efficiency challenge to both controllable opex and repex to account for frontier shift.

1.17 Frontier shift is calculated by applying the average annual productivity figure to the real price effects (RPEs) result. The real price effect is computed from discounting RPI from the weighted impact of nominal input prices.

1.18 In a simplified calculation, frontier shift can be determined as follows:

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

BGTL, PTL and WTL

1.19 PTL, BGTL and WTL are all part of the Mutual Energy Group (MEL). These companies are all subject to a 'mutualised' model.[1] In this model NI gas consumers absorb deviations between forecast and actual operating costs in return for an absence of equity.

Table 1: Total allowance for MEL (post efficiency) – March 2016 prices

Cost Category	BP Request - £m	2017-18 £m	2018-19 £m	2019-20 £m	2020-21 £m	2021-22 £m	Totals £m
Controllable Opex non-CJV	**33.9**	6.8	5.7	6.1	4.9	6.2	**29.7**
Controllable Opex CJV	**3.7**	0.6	0.6	0.6	0.5	0.5	**2.8**
Asset Replacement - Repex	**4.9**	0.3	0.7	0.3	0.5	0.1	**1.9**
Uncontrollable Costs	**45.7**	11.0	8.5	8.5	8.5	8.5	**45.0**
Capital Repayments	**81.7**	13.0	16.8	17.1	17.3	17.6	**81.7**
Total	**169.9**	**31.7**	**32.2**	**32.5**	**31.8**	**32.9**	**161.1**

Figures may not sum due to rounding

1.20 Table 1 sets out the proposed post efficiency allowances for the MEL businesses across the GT17 price control period.

1.21 For PTL and BGTL, rate of return on capital is excluded from the price control review process. Both these licence holders are entirely funded by debt finance in the form of a long-term bond. The repayments on this bond including principle and interest will be made in accordance with a predetermined schedule that has been previously agreed by the UR. There is therefore no provision in either of these licences to review the rate of return.

1.22 The WACC for WTL (1.98%) was established by the competitive process to award the Gas to the West (GttW) high pressure licence. This figure was based on prevailing market conditions in April 2014. At the time we made it clear that we would revise this figure if there was a significant shift in market conditions.

1.23 In their business plan WTL noted the significant reduction in the cost of debt since then. Applying the 2014 analysis to current debt figures indicates an equivalent WACC of 0.3%. We therefore propose for this draft determination that the rate of return figure for WTL should be 0.3%

[1] WTL are not mutualised in the sense of PTL and BGTL as yet. They do however operate a cost pass through mechanism for operating costs.

GNI (UK)

1.24 GNI (UK) is a subsidiary of Gas Networks Ireland, which is a subsidiary of Ervia, a utility infrastructure company owned by the government of the Republic of Ireland. GNI (UK) is subject to a traditional 'revenue cap' incentive framework which provides a strong incentive to manage costs. In order to reduce cash flow risk the licence contains two adjustment mechanisms:

- The ability to seek allowances for *unforeseen operating expenditure*.
- The ability to seek a forecast expenditure review should actual expenditure be greater than 15% above the allowance in any gas year.

1.25 We consider that these mechanisms are sufficient to provide GNI (UK) with adequate protection against risks. In particular, this includes unforeseen IT development costs related to the CJV, and/or capital maintenance projects for which no allowance is made at the time of the price control determination but which we subsequently allow during the price control period due to new information provided by GNI (UK).

Table 2: Total allowance for GNI (UK) (post efficiency) – March 2016 prices

Cost Category	BP Request - £m	2017-18 £m	2018-19 £m	2019-20 £m	2020-21 £m	2021-22 £m	Totals £m
Controllable Opex non-CJV	**22.1**	3.7	3.9	3.6	3.6	3.6	**18.4**
Controllable Opex CJV	**3.7**	0.5	0.5	0.5	0.5	0.5	**2.5**
Asset Replacement - Repex	**5.9**	0.1	0.2	0.0	0.0	0.0	**0.4**
Uncontrollable Costs	**9.1**	1.8	1.8	1.8	1.9	1.9	**9.1**
Capital Repayments	**56.2**	10.9	10.9	10.9	10.9	10.9	**54.3**
Total	**96.9**	**16.9**	**17.2**	**16.8**	**16.9**	**16.9**	**84.6**

Figures may not sum due to rounding

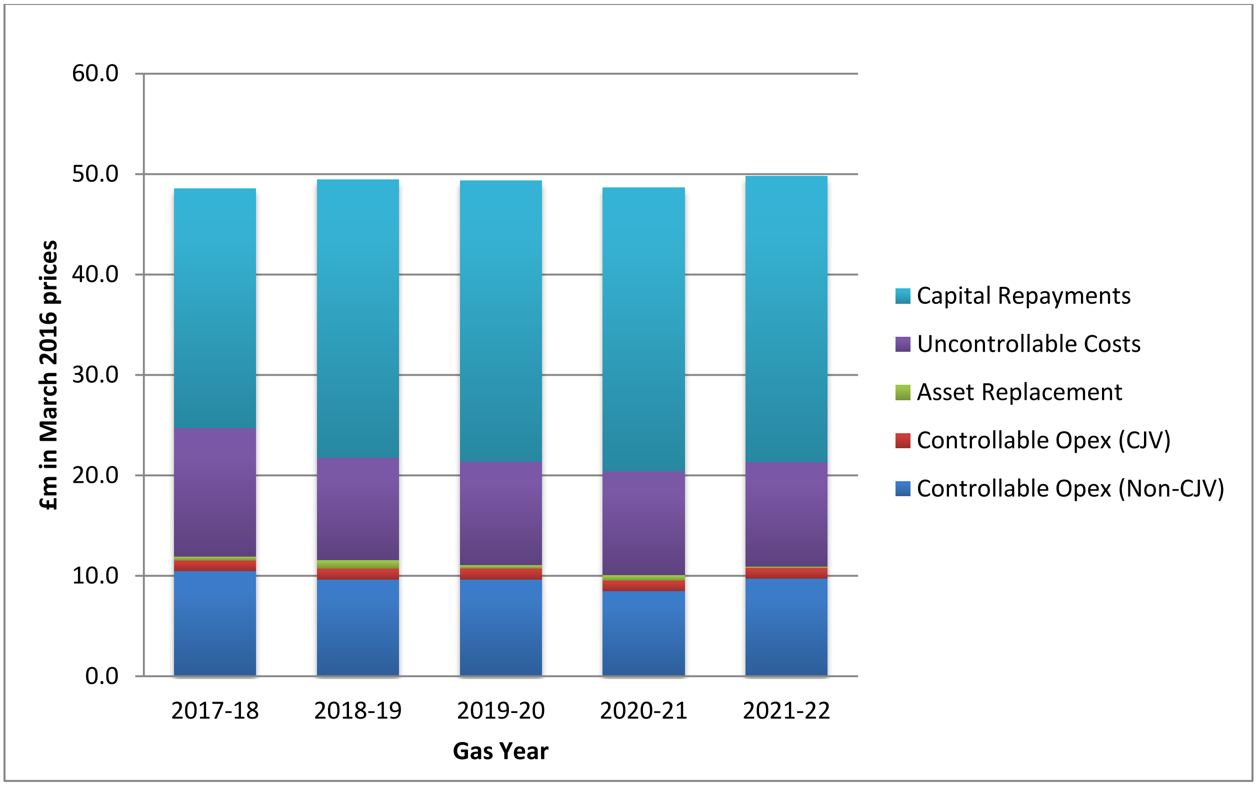
1.26 Table 2 sets out the proposed post efficiency allowances for GNI (UK) across the GT17 price control period.

1.27 Based on an assessment considering both the output from the competitive process to award the GttW high pressure conveyance licence, the CAPM approach and regulatory practice from other price controls, we propose the WACC should be set at a rate of 2.0% for this draft determination.

Industry

1.28 On an industry basis the overall allowance is approximately £49.2m p.a. in real terms against a request of £53.4m. As shown in Figure 1, the figures forecast that the postalised tariff revenues should remain fairly constant in real terms throughout the period.

Figure 1: Revenue allowance for gas industry by cost category – March 2016 prices



1.29 For domestic gas tariffs in Northern Ireland, the consumer bill is made up of the distinct cost elements shown in Table 3:

Table 3: Supply price split by cost element – April 2016

Cost Category	Greater Belfast	Ten Towns
Transmission network costs	11.8%	9.7%
Distribution network costs	38.9%	48.3%
Wholesale gas costs	38.8%	32.7%
Supply retail costs	10.5%	9.4%
Total	**100%**	**100%**

Figures may not sum due to rounding

1.30 Assuming domestic usage of 12,500 kWh, the average gas bill is currently around £500 per annum.[2] From the table above it can be seen that approximately 10% (+£50) of this is related to the transmission network.

1.31 The impact of implementing the business plans submitted by the companies would be an approximate £5 uplift in the annual bill. This compares to a £0.50 increase proposed in the draft determination. The UR allowance therefore results in a £4.50 saving compared to the company submissions.

Next Steps and Further Issues

1.32 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 12 noon on 17 February 2017 and should be addressed to:

Veronika Gallagher

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 veronika.gallagher@uregni.gov.uk

1.33 We expect to publish the final determination, following due consideration of any responses received to this draft determination, in April 2017.

1.34 We envisage publishing, alongside the final determination, a consultation on draft licence modifications. The purpose of these licence modifications is to:

- Align price control review dates for all licence holders included in this price control;
- Formally introduce Regulatory Instructions and Guidance into the licence. This new condition will match that included in the conveyance licence of distribution companies;
- Include conditions within the GNI (UK) licence to facilitate appeals to the Competition and Markets Authority; and
- Clarify the conditions under which GNI (UK) can request a determination to be reopened.

1.35 In our approach document we stated that as part of the price control we would make a decision as to whether or not there needed to be a review of the governance of the MEL, with the review to take place in the next price control period. The last review of the relevant governance arrangements was carried out in 2008. As a matter of best regulatory practice the UR intends to carry out a review of existing arrangements during the GT17 price control period.

[2] Whilst 12,500 kWh is the standard used for comparisons, consumption in NI tends to be lower than this. As such, the average bill may be overestimated for NI consumers.

1.36 As noted in our approach we consider that the value of the Social Enhancement Fund (SEF) in providing appropriate incentives to managers is not clear. Having taken note of the response received from Mutual Energy, however, we consider the future of this mechanism and the funds already retained by it should form part of our proposed governance review.

1.37 In the meantime we propose that no further monies are allocated to the fund and that all future operating cost savings are returned directly to consumers at the end of the gas year. This will be achieved by setting the 'z'[3] factor to zero each year. We intend to give this proposal effect immediately, commencing with the 2016-17 gas year reconciliation process.

1.38 It is also our intention to develop the annual cost reporting process further providing information on company performance during the price control period including publication of key cost and output metrics.

[3] The 'z' factor is a figure between 0 and 1 to be determined by the UR in the PTL licence. It relates to the amount of approved surplus or outperformance which can be allocated to the SEF.

2 Introduction

Purpose of this Document

2.1 This document represents the draft determination for the GT17 price control process.

2.2 GT17 is the name given to the price control for the four high pressure gas networks in Northern Ireland (NI) relating to the period starting 1 October 2017 until 30 September 2022. The four gas conveyance licence holders for NI high pressure networks are:

- GNI (UK) Limited (GNI (UK));
- Premier Transmission Limited (PTL);
- Belfast Gas Transmission Limited (BGTL); and
- West Transmission Limited (WTL).

2.3 GNI (UK) is a subsidiary of Gas Networks Ireland, which is a subsidiary of Ervia, a utility infrastructure company owned by the government of the Republic of Ireland. GNI (UK) is subject to a traditional 'revenue cap' incentive framework.

2.4 PTL, BGTL and WTL are all part of the Mutual Energy Group (MEL). These companies are all subject to a 'mutualised' model. In this model NI gas consumers absorb deviations between forecast and actual operating costs in return for an absence of equity funding / returns from the business.

2.5 In this draft determination, we detail our proposals with respect to:

- Operating expenditure (opex) allowances;
- Maintenance / replacement (repex) allowances; and
- Weighted average cost of capital (WACC), where relevant.

2.6 In setting out proposals for an efficient level of opex for the review period, we differentiate between:

- Uncontrollable expenditure the level of which is fully outside the control of the licence holder; and
- Controllable operating expenditure, i.e. any operating expenditure not classified as uncontrollable.

2.7 Allowances for uncontrollable opex are forecast at the time of the price control review and will be adjusted later on to match actual costs. For controllable opex, the potential impact of these allowances for the licence holders will vary, depending on whether they operate a 'revenue cap' or 'mutualised' model.

2.8 In the case of GNI (UK), the allowance represents a fixed amount the licence holder will recover from consumers. Any variation between this allowance and actual opex is absorbed by the licence holder. In this instance the consumer is exposed to no operating cost risk. Instead this risk is borne entirely by the shareholders of the licence holder and is reflected in the rate of return. This provides the licence holder with a very clear incentive to effectively manage costs.

2.9 In the case of MEL, the allowance represents merely a forecast of future outcomes. Actual allowances that the licence holder will recover from consumers will vary with actual expenditure. The licence holders, in this case PTL, BGTL and WTL, are exposed to none of the potential opex risk. Instead this risk is borne entirely by the NI gas consumer.

2.10 However, we continue to determine an efficient level of operating costs as if a ‘revenue cap’ was in place during what has previously been described as a ‘shadow’ price control. The licence holders then have a reputational incentive to manage costs effectively in line with the determined ‘shadow’ allowance.

2.11 In addition, management incentives may be set to align with these allowances as a means of effective operating cost control. Performance against the ‘shadow’ allowances also provides the Utility Regulator (UR) with a metric to judge whether existing licence conditions continue to facilitate our statutory duties.

2.12 A significant development in the regulatory regime will be the establishment of a single system operator for Northern Ireland on 1 October 2017. This will be a contractual joint venture (CJV) between the licence holders rather than a separate legal entity.

2.13 Its operations will be funded through the existing licences. However, in determining proposed allowances for the CJV, we did so on the principle of the CJV being a single entity.

2.14 This price control review does not set allowances for capital expenditure (capex) to add to the capacity of the existing pipeline network. Two of the licence holders (PTL and BGTL) purchased existing assets, the Scotland Northern Ireland Pipeline and Belfast Gas Transmission Pipeline respectively. They are therefore not required to fund capital formation.

2.15 In the case of the other two licence holders; GNI (UK) which built both the North West and South North Pipelines along with their associated spurs, and WTL which will build the GttW network, capital allowances are set in accordance with a completely separate methodology outside the price control process.

2.16 However, maintenance / replacement expenditure (repex) to replace or upgrade existing equipment is considered. It will be treated in the same way as controllable opex.

2.17 As with opex and repex, the cost of capital has a different treatment depending on the particular licence holder. In the case of both GNI (UK) and WTL, we are required to review the rate of return at each review. For PTL and BGTL, the rate of return on capital is excluded from the price control process.

2.18 Table 4 provides an overview of the key outputs of the GT17 price control process for each licence holder.

Table 4: Price control output by licence holder

Price Control Item	GNI (UK)	Premier Transmission	Belfast Gas Transmission	West Transmission
Controllable operating expenditure (non CJV)	Allowance fixed at review	Allowance forecast at review but actual allowance matches actual costs		
Controllable operating expenditure (CJV)	Allowance fixed at review	Allowance forecast at review but actual allowance matches actual costs		
Uncontrollable operating expenditure	Allowance forecast at price control review but actual allowance matches actual costs			
Maintenance / repex expenditure	Allowance fixed at review	Allowance forecast at review but actual allowance matches actual costs		
Weighted average cost of capital	Allowance fixed at review	Not applicable	Not applicable	Allowance fixed at review

2.19 This draft determination details the proposals of the UR with respect to the GT17 price control period on:

- Price control allowances;
- Incentive mechanisms; and
- Outputs.

2.20 It also considers the expected impact of these proposals on consumers.

2.21 We note that the proposals detailed in this draft determination are provisional in nature. As such, they are subject to change as a result of responses and further information we receive during the consultation period. We will provide our conclusions on the price control in the final determination to be issued next year.

Our Statutory Duties and Regulatory Principles

2.22 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 NI. We do so consistently with our fulfilment of the objectives set out in the European Gas Directive[4], and by having regard to a number of matters, as set out more fully in the Energy (Northern Ireland) Order 2003.

2.23 High pressure gas networks are natural monopolies. It does not make economic sense for a number of businesses to build, maintain and operate high pressure gas networks in the same geographic area.

[4] 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. The objective of this Directive is the creation of a fully operational market in natural gas. Respect for public service requirements is a fundamental requirement of the Directive, and definition of common minimum standards, which take into account the objectives of common protection, security of supply, environmental protection and equivalent levels of competition in all Member States is of importance. Measures implemented by the Member States should achieve the objectives of social and economic coherence, to include, in particular, the provision of adequate economic incentives.

2.24 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:

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

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

2.26 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 analysis of cost and service to establish the level of performance.

2.27 As GNI (UK), PTL, BGTL and WTL in their respective geographical areas, are the only monopoly providers of high pressure gas networks, 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 underperforms or operates less efficiently than its peers. We also set targets for improvement.

2.28 An important part of this regulatory framework are price controls. A price control is a method of setting the total allowed revenues a licence holder is allowed to earn (revenue cap), or maximum tariffs a licence holder is allowed to charge (price cap)[5], during a given period (the price control period).

2.29 As part of a price control, we establish a clearly defined set of outputs that the licence holders must deliver. We also put in place reporting that allows 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 licence holders the flexibility they need to deliver them in the most effective way.

2.30 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 transmission costs and consumer tariffs, on the environment and greenhouse gas emissions and on customer service.

2.31 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 licence holders can continue to finance the activities which are the subject of obligations placed on them; and
- Have due regard to all relevant factors.

2.32 It is our aim to do this by:

- Providing a strong foundation for the continued and long-term operation of the NI high pressure gas networks, delivering value for money to consumers;

[5] Price caps are not applicable to holders of high pressure conveyance licences in NI.

- Challenging the licence holders 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 are set at the minimum levels that are consistent with the efficient operation.

2.33 The price controls for each of the companies considered are complex, and comprise different elements. In this context, we interpret our obligation to further our principal objective and fulfil our duties as a requirement to do so taking all of the elements of each price control together. This means, the overall price control needs to be considered in the round.

2.34 Certain aspects of each company's price control may make particular contributions to the fulfilment of certain aspects of our objective and duties, but no part of the control should be considered in isolation. We aim to ensure that the balance which we are required to strike, having regard to all of the different elements of our objective and duties, is struck in setting each price control as a totality.

2.35 Our approach to price controls 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.

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

Market Overview

2.37 The Scotland to Northern Ireland (SNIP) pipeline connects to the GNI (UK) system at Twynholm in Scotland and has a maximum operating pressure of 75 barg. The pipeline is almost 135 km long, runs towards the coast near Stranraer and crosses the Irish Sea to terminate at Ballylumford Power Station, Islandmagee. The SNIP is owned and operated by PTL.

2.38 The Belfast Gas Transmission Pipeline (BGTP) comprises a further 26 km of pipeline with a maximum operating pressure of 75 barg and runs from Ballylumford via Carrickfergus to Belfast, where it supplies the Greater Belfast demand.

2.39 The North-West Pipeline (NWP) extends a further 112 km of 450 mm pipeline from Carrickfergus to supply the power station at Coolkeeragh. The NWP is owned and operated by GNI (UK) Ltd.

2.40 A 450 mm pipeline connecting the Interconnector System to the NWP was built in 2006. This pipeline, called the South-North Pipeline (SNP), is 156 km long and extends from the IC2 (interconnector 2)[6] landfall at Gormanston, Co. Meath in Ireland to Ballyalbanagh on the NWP, approximately 12 km west off the Carrickfergus AGI[7] (above-ground installation). This pipeline facilitates supplies to towns and industries in the corridor from Newry to Belfast.

[6] IC2 is a 195 km sub-sea pipeline that runs from Beattock in southwest Scotland to Gormanston, Co. Meath, Ireland.
[7] Before gas is delivered to end users, the pressure is reduced at AGI stations.

2.41 The towns and industries along the NWP are currently supplied by flow from SNIP, the BGTP and the NWP via Ballyalbanagh. However, if needed, the SNP will be able to support the SNIP pipeline with flows from Gormanston in meeting increased demand levels in Northern Ireland.

Structure of this Document

2.42 This document is structured in a number of different chapters, each addressing a different aspect of the price control.

- Chapter 1 - Executive Summary provides an overview of the key findings and proposed key decisions of this price control process.
- Chapter 2 - Introduction provides an overview of the purpose of this GT17 draft determination, our statutory duties and regulatory principles as well as the NI high pressure gas market.
- Chapter 3 - Approach provides an overview of the price control process and key aspects of same.
- Chapter 4 - Operating Expenditure (Opex) details the opex allowances requested by each licence holder, our assessment of same, as well as our proposed pre-efficiency allowances for GT17.
- Chapter 5 - Replacement Expenditure (Repex) details the allowances requested by each licence holder, our assessment of same, as well as our proposed pre-efficiency allowances for GT17.
- Chapter 6 - Efficiency Analysis shows our proposed real price effects, frontier shift efficiency challenge and post efficiency allowances.
- Chapter 7- Incentives and Innovation details our view with respect to incentive and adjustment mechanisms as well as to the funding of innovation initiatives.
- Chapter 8 - Financial Aspects discusses different issues relating to the finance implications of the price control, including rate of return, financeability and repayments.
- Chapter 9 - Outputs and Allowances summarises key aspects of the price control proposals relating to GT17 outputs, impact on consumer bills and environmental impacts.
- Chapter 10 - Next Steps and Further Issues clarifies details relating the consultation processes, provides an overview of the proposed next steps and summarises consequential changes as well as further issues we propose to address pursuant to the determination.

2.43 These chapters are complemented by a set of appendices and annexes. For further details see sections Appendices and Annexes respectively.

2.44 Where relevant and appropriate, the chapters of the GT17 draft determination document are structured in a consistent way as follows:

- Detailed Approach – UR Proposals;
- MEL – UR Proposals; and
- GNI (UK) – UR Proposals.

2.45 The detailed approach section provides, 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 licence holders.

2.46 The licence holder-specific sections detail the implications arising for each licence holder from applying our detailed approach. This may include details on values, parameters, targets and/or outputs.

2.47 We consider that this structure will help increase the readability of this draft determination document through reducing duplication and enabling each licence holder to quickly identify the sections of the document relevant to it.

3 Approach

Price Control Process

Timelines and Stages

3.1 The key milestones of this GT17 price control process are summarised in:

- Table 5 for milestones leading up to the publication of this GD17 draft determination; and
- Table 37 for the remaining milestones to be met after publication of this GD17 draft determination.

Table 5: Key milestones up to publication of GT17 draft determination

Key Milestones	Date
Approach document[8] and business plan template[9] published	30 June 2016
Consultation on approach closed	19 August 2016
Licence holders information submission	September / October 2016
Publication of draft determination	16 December 2016

Price Control Principles

3.2 In addressing the key areas of this price control, we were mindful of the need to keep the regulatory burden to a minimum while addressing the information asymmetry that exists between us and the companies. We adopted and applied a number of principles to ensure that our approach is proportionate. These principles are:

- Areas of high expenditure will receive substantially more scrutiny and analysis than low value items, along with new additional operating expenditure where we shall expect to have presented the net impacts from such increases and any decrements.

[8] Utility Regulator: Price Control for Northern Ireland's Gas Transmission Networks GT17, Proposed Approach, 30 June 2016.
[9] Business Plan Reporting Template.

- Comparisons will be used where appropriate to ensure that allowances are efficient and that targets are reasonable but challenging.
- Where possible, any allowances set shall be closely aligned to clearly defined outputs and relevant drivers.
- The price control will be based on a standard RPI-X framework, which will incentivise the licence holders to control their costs through the setting of efficiency targets and adjustment of allowances at subsequent price controls.
- Allowances will not be given for profit margins to any affiliated business to which contracts have been awarded.
- Allowances will not be given for contingency elements within budgets.

3.3 We will adopt a light touch approach if:

- There is evidence to show that the licence holder is comparatively efficient.
- Past costs are a strong indicator of future costs.

3.4 We will adopt a more detailed approach if:

- The licence holder is comparatively inefficient.
- Past costs are a weak indicator of future costs.
- Cost lines are increasing and are of a material nature.
- Data is available for more detailed statistical analysis.

3.5 We would expect licence holders to provide the data necessary to support a robust assessment of expenditure and outputs. Where there is insufficient data, we would adopt an approach to funding which is prudent but conservative until the company can develop a robust approach based on sound data.

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

3.7 We will continue to ensure that the information we require from the licence holders is proportionate but sufficient to:

- Allow licence holders to communicate their business plans to us in a clear and effective manner.
- Ensure that we can submit the plans to effective and focused scrutiny.

3.8 We note that we:

- Reserve the right to appoint, where appropriate, an examiner to review the recording of relevant information by the licence holders;
- Reserve the right to request, where appropriate, an audit of specified information relating to the GT17 price control, including specification of the terms on which an auditor is to be appointed by the licence holders for that purpose and of the nature of the audit to be carried out by that person.

3.9 For the purposes of clarity all financial figures in this document are given in March 2016 prices unless otherwise stated.

Stakeholder Engagement

3.10 In June of this year we published an approach document setting out how we intended to conduct the price control review, inviting responses from stakeholders on our proposals.

3.11 We received three responses from MEL, GNI (UK) and the Consumer Council for Northern Ireland (CCNI). While all three broadly supported the approach we have set out, each raised specific issues for us to consider.

GNI (UK)

3.12 In their response GNI (UK) raised two issues. The first of these related to the allocation of CJV allowances between the licence holders. The licence holders have not finalised contractual responsibility for the various resources required to deliver the outputs of the CJV.

3.13 GNI (UK) raised concerns over which TSO staff would carry out the CJV function. In preparing the draft determination we have split the total allowance for such resources evenly between GNI (UK) and MEL. Other costs are split based on how the costs were divided in the business plan submissions.

3.14 GNI (UK) also commented on our proposed approach to expenditure related to the replacement of existing assets. While it welcomed our proposal to treat such repex in the same way as controllable opex, GNI (UK) noted that accurately predicting the cost of these bespoke intermittent projects was difficult.

3.15 GNI (UK) suggested that detailed design work for an individual project to establish a robust cost estimate could account for as much as one fifth of that project's final cost. On this basis GNI (UK) proposed that for those projects which the UR considers are justified, an allowance for this design work should be granted at the time of the price control review. A further adjustment would then be required to allowances during the price control period when accurate cost estimates have been established.

3.16 We do not accept that the design work required to deliver these projects could account for one fifth of final costs. The projects relate to replacement of existing equipment not the design of entirely new pipelines or AGIs. In most cases, projects will be carried out on a number of similar assets delivering some economies of scale. Indeed it is possible that this spreading of costs will not be limited to GNI (UK) assets but will extend to assets owned by the parent company in the Republic of Ireland.

3.17 Our view would be that design costs might at the very most account for no more than 5% of total project costs.[10] We therefore consider that general allowances for asset management and compliance and other overheads are sufficient to fund such design activity.

3.18 We do, however, recognise that establishing robust cost estimates for replacement expenditure at the time of the price control review might be difficult. If the scale of the projects we determine are justified is sufficient, we may consider some form of specific mechanism for these allowances as part of our final determination.[11] For the draft determination, however, we will focus on whether or not a particular project or suite of projects is justified to proceed.

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[10] In the PC10 and PC15 Cost Base submissions from NI Water, design costs for standard projects typically ranged from 2% to 5%.

[11] See section *7 Incentives and Innovation, GNI (UK) – UR Proposals* for further details.

Mutual Energy Limited

3.19 In their response MEL raised a number of issues. With regard to our proposal to give consideration to removing the Social Enhancement Fund (SEF) from the regulatory regime, MEL stated that any change to the financial arrangements set out in their licences could trigger significant financier assurance costs. These would ultimately be borne by consumers.

3.20 As an alternative they suggest that we simply commit to setting the Z factor contained within the licence to zero for the price control period. We consider this to be an acceptable and practical alternative to licence modification.

3.21 MEL also stated their desire to use some of the monies in the SEF to fund costs associated with the issuance of the bond that will be used to fund WTL network assets. We would have concerns that such an approach would significantly delay the benefit of these monies accruing to consumers. We propose to consider options for use of the monies in the SEF to date as part of a proposed governance review for MEL.

3.22 In response to the MEL comment on CJV mobilisation costs, we can confirm that setting an allowance for this activity prior to October 2017 will not form part of this price control process. This issue is being considered separately.

3.23 Mutual Energy also expressed concern with regard to recharging between themselves and GNI (UK) for CJV related resources which were being funded by the other's price control allowance[12]. We have taken this concern onboard and propose a practical approach using an adjustment to the treatment of uncontrollable costs.

3.24 We also note the MEL comment on the likelihood of significant unforeseen developments at EU level that might trigger large system development costs. We consider that the risk is mitigated by the 'cost-pass through' arrangements for MEL and Condition 2.2.4 (j) for GNI (UK) which provides for unforeseen expenditure.

3.25 Regarding the setting of allowances for repex, MEL made many of the same comments as GNI (UK). However, the differing treatment of controllable operating costs for the Mutual Group creates less uncertainty associated with estimating project costs.

3.26 MEL also stated that they do not see any value in jointly procuring services such as the Maintenance and Emergency Response Contract (MERC) with GNI (UK). They added that the option had previously been examined but was found not to be viable due to the need to retain legal responsibility.

3.27 While we recognise that there might be difficulties in joint procurement, our analysis suggests that for certain activities, in particular grid control, there is potential to deliver significant benefit to consumers.

3.28 Similar comments have been made with regard to the Emergency Call Centre contract in both GD14 and GD17[13]. We have therefore set the proposed allowances for this activity based on what we consider an efficient procurement process would deliver. We would encourage licence holders to consider afresh how they might work together to realise these efficiencies.

[12] GT17 Proposed Approach paragraph 2.28.

[13] GD17 Final Determination Annex 8 paragraphs 1.16 – 1.26

3.29 In their response, MEL stated that catch up to the frontier assessment of their costs should not be based on a comparison with larger companies which benefit from economies of scale. We believe that it is appropriate to take account of economies of scale when setting allowances. Hence, our approach with regard to joint procurement.

3.30 Any comparison should account for scale economies. In our view the appropriate scale comparison would be with a licence holder responsible for a network of similar scale to that funded by this price control. Where this is not possible comparisons with GB, RoI or other data may be used. However, judgement will be used where necessary to account for the scale impact.

3.31 MEL made two other comments regarding the forecasting of uncontrollable costs related to the Transportation Agreement, and the use of a services company to procure certain resources for the three separate licence holders. We agree with these comments and continue to mitigate the former by working with the CER in Dublin.

Consumer Council for Northern Ireland (CCNI)

3.32 CCNI expressed support for actions we have already taken such as the introduction of a common cost reporting and business plan submission template. The CCNI also expressed support for aligning the review periods for the various licence holders.

3.33 CCNI further supported our intention to review the SEF mechanism and our intention to consider the need for a wider governance review. Should we determine that such a review is justified then this will be conducted during the price control period as a separate project. No monies in the SEF have been previously used for any purpose. We propose to consider what use the £5m balance might be put to as part of the MEL governance review.

3.34 In response to a number of comments regarding stakeholder engagement we can confirm that in preparing this draft determination we met with the CCNI prior to publication. We plan to engage with the wider industry and consumer representatives during the consultation process in line with our approach document.

3.35 It is not our practice, however, to publish individual TSO business plans. Going forward we intend to develop the annual cost reporting process further which may involve the publication of key cost and output metrics.

3.36 In terms of our plans for the MEL governance review, we consider any such review should be carried out after the publication of the final determination, during the GT17 price control period. We would welcome further engagement with CCNI to discuss this review.

Duration – UR Proposals

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

a) The advantage of giving planning security to the licence holders 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.

b) 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.

3.38 At present the duration of the review period varies between licence holders. In the case of GNI (UK) the review period is defined as being every fifth year commencing on 1 October 2007. The next review period will therefore commence on 1 October 2017.

3.39 In the case of PTL and BGTL the licence holder must submit a forecast of controllable operating expenditure every third year for approval by the UR. The next review period will also commence on 1 October 2017. However, licence changes to the PTL and BGTL licences would be needed to align the duration of the shadow price control period to that of GNI (UK). We propose that the next review date will be 1 October 2022.

3.40 We have discussed this with all four licence holders and they were content to provide forecast costs data up to 30 September 2022. However, we do not propose to pre-determine the length of review period in the licence. Instead the formulation in the WTL licence would seem preferable. It states that the date of the subsequent price control review will be determined by the UR at the time of the previous review.

3.41 In the case of WTL, the licence holder must also submit a forecast of controllable operating expenditure every third year for approval by the UR. We will review the relevant condition in the company licence and consult on any changes that may be necessary to align the review period such that it will also commence on 1 October 2017.

3.42 This alignment of price control review periods will permit more effective comparisons between licence holders as allowances are set under the same set of market conditions. It will facilitate a consistent approach to similar issues by the UR. It will also lead to greater efficiency on the part of the UR as all relevant licence holders will have their reviews carried out at the same time.

3.43 All proposed licence changes will be published for consultation alongside the final determination.

4 Operating Expenditure (Opex)

Detailed Approach – UR Proposals

Overview

4.1 When assessing the appropriateness of the opex requests, we take the view that costs should be in line with past allowances / actual costs observed in the previous price control period. This is particularly true if there has been no material change in the level and type of activities that are required to operate the network.

4.2 However, a significant change in the price control period arises in the form of the West Transmission network. This will raise certain costs such as maintenance and emergency response, but will simply spread other costs, such as intercompany recharges over a wider base.

4.3 Opex is split by controllable and uncontrollable expenditure. Uncontrollable expenditure is that which is fully outside the control of the licence holder. In other price controls, for gas distribution, electricity and water, business rates are no longer typically considered to be uncontrollable. While they are included in uncontrollable opex in this draft determination, the appropriateness of this will be considered as part of the final determination.

4.4 With regard to those activities which in future will be delivered by the CJV, allowances will be reduced. We will not provide allowances to duplicate activity within the TSOs that in future will be the responsibility of the CJV. We note that the assessment of CJV development cost will be ongoing during this consultation period. Finalisation of these figures may impact on the final determination.

4.5 All costs shown in this section are pre-efficiency and are in £ millions

Bottom-up Assessment

Overview

4.6 For GT17 we adopted a common cost reporting template for the TSOs. The purpose of this was to provide comparability, certainty and an understanding of cost movements over time.

4.7 When developing the cost reporting template, we consulted with the licensees and provided guidance on what should be included in the cost lines of the new reporting template. This allows us to have consistent and comparable views of the cost submitted by all the licensees.

4.8 Opex is grouped into three main areas: Controllable non-CJV, CJV and uncontrollable. This can be seen in Table 6 below. Repex is covered separately in the following chapter. For more information on what is included within each cost line displayed in the tables in this opex section, please see the TSO Business Plan Reporting Requirements.

4.9 In the bottom-up analysis we looked at each individual line separately and the justification for such costs. The overall allowance reflects the sum of the individual parts.

MEL – UR Proposals

Overview

4.10 We considered the submissions from PTL, BGTL and WTL separately and made separate determinations for each. These are shown in *Appendix 1: Proposed Pre-efficiency Opex Allowances*. Here we present opex proposals on an overall level for MEL.

4.11 The bottom-up approach has been the method used to arrive at the draft determination for MEL. The tables below show:

- The total requested from the licence holder for the full 5 years;
- The proposed determination for each year of the price control; and
- The total determination for the full 5 years.

4.12 Where reductions to the submitted amount are being proposed, a reason for this is given. No comments have been made on cost lines that we do not propose making reductions to in this draft determination.

Bottom-up Assessment

Overview

Table 6: MEL – Draft determination for pre-efficiency opex

Cost Category	BP Request - £m	2017-18 £m	2018-19 £m	2019-20 £m	2020-21 £m	2021-22 £m	DD Total £m
Controllable Opex non-CJV							
Administration	**7.6**	1.3	1.3	1.5	1.4	1.4	**6.9**
Staff Costs (excluding CJV)	**4.4**	0.8	0.8	0.8	0.8	0.8	**4.0**
Planned Maintenance	**14.2**	3.3	2.4	2.9	1.9	3.2	**13.8**
Unplanned Maintenance	**1.7**	0.3	0.3	0.3	0.3	0.3	**1.7**
System Operation	**6.1**	1.1	1.0	0.8	0.7	0.7	**4.3**
CJV							
CJV Costs (for MEL)	**3.7**	0.6	0.6	0.6	0.6	0.6	**2.9**
Uncontrollable Opex							
Uncontrollable Costs	**45.7**	11.0	8.5	8.5	8.5	8.5	**45.0**
Total	**83.3**	**18.5**	**15.0**	**15.4**	**14.2**	**15.5**	**78.5**

Figures may not sum due to rounding

4.13 Our draft determination proposes allowing £78.5m for the GT17 period for total opex (prior to efficiency). This represents 94% of the submission of £83.3m. The CJV line refers purely to the MEL element of the single system allowance. Total CJV costs are reported separately in this chapter.

4.14 In the draft determination, reductions have been made in all of the areas shown in Table 6 above with the exception of unplanned maintenance. The reasons for the reductions in the controllable non-CJV opex and the uncontrollable opex are described below.

Controllable Non-CJV Expenditure

Table 7: MEL – Draft determination for administration

Cost Category	BP Request - £m	2017-18 £m	2018-19 £m	2019-20 £m	2020-21 £m	2021-22 £m	DD Total £m
Pipeline Insurance	**3.1**	0.5	0.5	0.5	0.5	0.5	**2.7**
Intra-company Recharge	**1.9**	0.3	0.3	0.3	0.3	0.3	**1.5**
Other Overheads	**0.4**	0.1	0.1	0.1	0.1	0.1	**0.4**
Mutualisation Costs	**2.3**	0.5	0.4	0.5	0.5	0.5	**2.3**
Total	**7.6**	**1.3**	**1.3**	**1.5**	**1.4**	**1.4**	**6.9**

Figures may not sum due to rounding

4.15 In MEL's submission, the pipeline insurance cost was given as £3.1m over the GT17 period. Of this £3.1m, £571k relates solely to WTL. It is our view that the WTL element is high given the small amount of additional pipeline. We reduced the WTL pipeline insurance to £214k which is in line with the insurance cost per km of the existing GNI (UK) pipeline network.

4.16 We consider the cost of the GNI (UK) pipeline insurance to be an appropriate comparison since the pipelines are on land and include a number of Above Ground Installations (AGI) throughout the network.

4.17 Within intra-company recharge, we considered board member fees to be high. The MEL annual report for 2016 shows a salary of £77k for the chair and £34k for other non-executives. Compared to other boards, these salaries seem excessive. We have reduced the allowance for this element. The result is a determination of £1.5m for intra-company recharge against a submission amount of £1.9m.

Table 8: MEL – Draft determination for staff costs (excluding CJV)

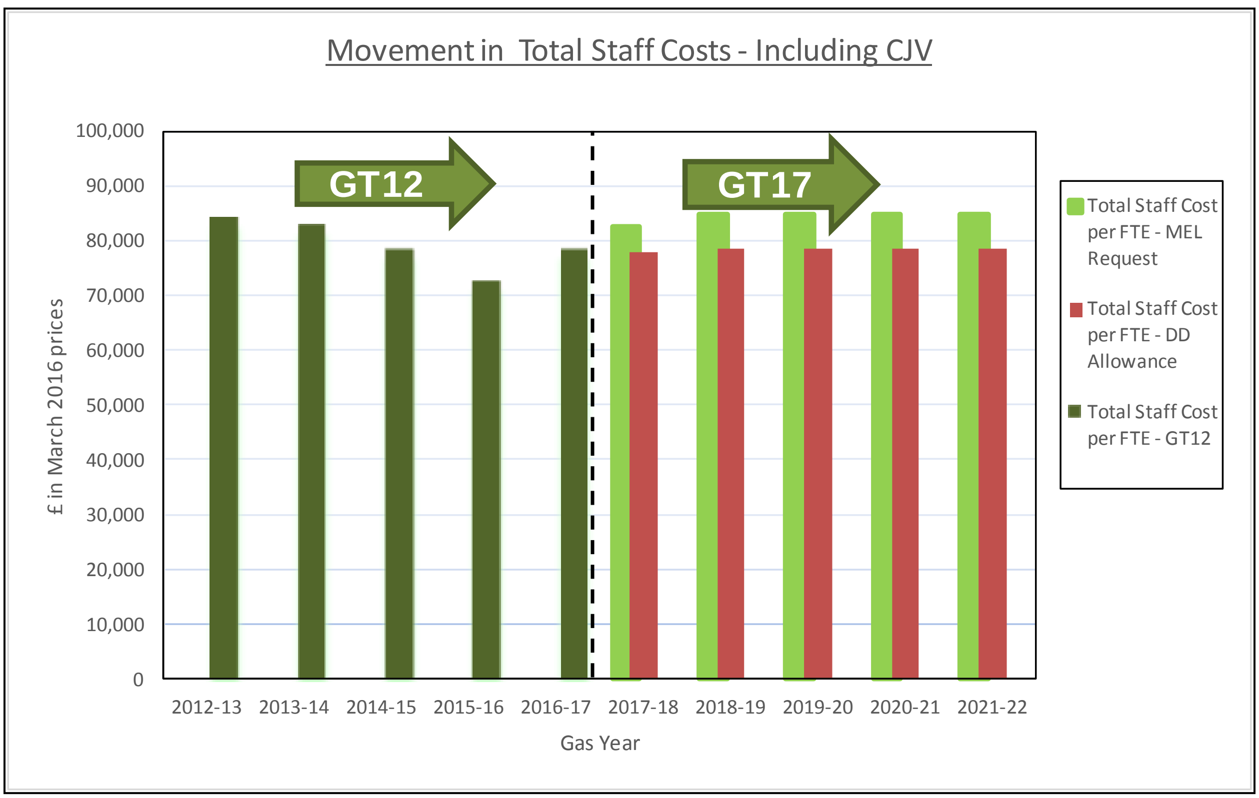
Cost Category	BP Request - £m	2017-18 £m	2018-19 £m	2019-20 £m	2020-21 £m	2021-22 £m	DD Total £m
Support Staff	**1.0**	0.2	0.2	0.2	0.2	0.2	**0.9**
Engineering Staff	**3.3**	0.6	0.6	0.6	0.6	0.6	**3.0**
Total	**4.4**	**0.8**	**0.8**	**0.8**	**0.8**	**0.8**	**4.0**

Figures may not sum due to rounding

4.18 In MEL's submission, a total of £4.4m (excluding CJV) was estimated for staff costs in the GT17 period. We compared MEL's direct salary costs per FTE to direct salary costs of other regulated companies. After adjusting for differences in regional rates, we found MEL's cost per FTE to be high. We also made comparisons where possible excluding senior management costs. On the basis of this analysis, we do not consider the forecast real price increases in GT17 to be necessary.

4.19 Figure 2 illustrates the amount requested versus allowance on a unit cost basis (including the CJV staff).

Figure 2: Total staff cost[14] per FTE – request versus allowance



[14] Total staff costs includes both direct (wages, bonus, pensions, social security etc) and indirect (training, car allowance, expenses etc) staff costs.

Table 9: MEL allowed FTEs

Staff Category	GT12 – Average Number of FTEs	GT17 – Average Requested FTEs	GT17 – Average Allowed FTEs
Non-CJV Staff	11.5	9.4	9.4
CJV Staff	0.0	4.0	3.0
Total Staff	**11.5**	**13.4**	**12.4**

4.20 Table 9 shows the manpower request and determination. We have provided allowances for all staff MEL requested for administration, engineering and support. The reduction of 1 FTE against the request of 13.4 is due to the CJV allowance.

4.21 Overall staff levels will increase by 1 FTE from the GT12 average. This reflects our view that an element of the CJV staff should be additional to the existing business.

Table 10: MEL – Draft determination for planned maintenance

Cost Category	BP Request - £m	2017-18 £m	2018-19 £m	2019-20 £m	2020-21 £m	2021-22 £m	DD Total £m
Asset Management	**1.0**	0.1	0.1	0.1	0.1	0.1	**0.6**
Emergency Response	**1.7**	0.3	0.4	0.4	0.3	0.4	**1.7**
Pipeline Inspection	**5.8**	2.1	0.8	1.2	0.2	1.6	**5.8**
Routine Maintenance	**5.7**	0.9	1.2	1.2	1.2	1.2	**5.6**
Total	**14.2**	**3.3**	**2.4**	**2.9**	**1.9**	**3.2**	**13.8**

Figures may not sum due to rounding

4.22 The allowance for asset management and compliance has been reduced from the submission amount to be more in line with actual expenditure in this area in the period 2012-13 to 2014-15. Likewise, the submission amount for some of the cost lines within emergency response and routine maintenance appeared high compared to actual spending in GT12.

4.23 Our determination allows an amount more closely in line with actual expenditure, plus an amount for the addition of WTL. The determination for pipeline inspection is equal to the submission. However, we may revisit this area before the final determination. Overall, our allowance for planned maintenance is 97% of the submitted amount.

Table 11: MEL – Draft determination for unplanned maintenance

Cost Category	BP Request - £m	2017-18 £m	2018-19 £m	2019-20 £m	2020-21 £m	2021-22 £m	DD Total £m
Drainage	**0.7**	0.2	0.1	0.1	0.1	0.1	**0.7**
Other Unplanned Costs	**0.9**	0.2	0.2	0.2	0.2	0.2	**0.9**
Total	**1.7**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**1.7**

Figures may not sum due to rounding

4.24 We do not propose any reductions to the submission amount for unplanned maintenance in the draft determination.

Table 12: MEL – Draft determination for system operation

Cost Category	BP Request - £m	2017-18 £m	2018-19 £m	2019-20 £m	2020-21 £m	2021-22 £m	DD Total £m
Contracts & Licences	**0.7**	0.1	0.1	0.1	0.1	0.1	**0.7**
Grid Control	**3.3**	0.7	0.7	0.4	0.4	0.4	**2.4**
Network Code Development	**0.1**	0.1	0.0	0.0	0.0	0.0	**0.1**
SCADA & Communications	**2.0**	0.2	0.2	0.3	0.2	0.3	**1.2**
Total	**6.1**	**1.1**	**1.0**	**0.8**	**0.7**	**0.7**	**4.3**

Figures may not sum due to rounding

4.25 MEL has tendered for control room services. The costs submitted for 2017-18 and 2018-19 reflect the result of this tender. We previously indicated our view that efficiencies can be gained when the licence holders take a joined up approach. We believe that the arrangements being made for the CJV could be built upon. It is therefore our view that efficiencies can be gained should grid control be jointly tendered.

4.26 For clarity, the grid control *allowance* is £353k p.a. from 2019-20 onward for MEL (compared to the request of £670k). This is equal to GNI (UK) average annual spend in GT17. It is our view that these savings could be recognised if the TSOs procured jointly.

4.27 We recognise that there could be some initial implementation costs of re-tendering but evidence of any such costs would need to be provided before an allowance can be made. Our determination, as shown above, is based on the most efficient arrangements going forward.

4.28 SCADA (Supervisory Control and Data Acquisition) and communications included costs for a system refresh in 2019-20. MEL has not provided sufficient evidence as to why this refresh is needed, particularly since an upgrade was undertaken in 2012-13. £800k has been removed from the determination as a consequence.

4.29 In summary, for non-CJV system operation costs, we propose allowing 71% of the submitted amount as shown in Table 12.

Uncontrollable Expenditure

Table 13: MEL – Draft determination for uncontrollable costs

Cost Category	BP Request - £m	2017-18 £m	2018-19 £m	2019-20 £m	2020-21 £m	2021-22 £m	DD Total £m
Business Rates	**10.4**	1.9	2.1	2.1	2.1	2.1	**10.4**
Licence Fees	**6.3**	1.3	1.3	1.3	1.3	1.3	**6.3**
Compressor Fuel	**4.9**	0.8	0.8	0.8	0.8	0.8	**4.2**
Scottish Costs	**27.5**	7.7	5.0	5.0	5.0	5.0	**27.5**
Stranraer Income	**-3.3**	-0.6	-0.7	-0.7	-0.7	-0.7	**-3.3**
Total	**45.7**	**11.0**	**8.5**	**8.5**	**8.5**	**8.5**	**45.0**

Figures may not sum due to rounding

4.30 The only reductions we propose in uncontrollable costs are to the compressor fuel costs. A formula error in the submission spreadsheet inflated these costs slightly. The allowance for compressor fuel in Table 13 reflects the amended amount.

Summary

4.31 Overall, our determination proposes an allowance of 94%[15] against the submitted amount. The reductions being proposed are mostly due to comparisons with actual costs in the GT12 period, with additional allowances being made for WTL where appropriate.

4.32 Where reductions were made on the basis of being considered too high in comparison to GT12 actuals, we took the view that these costs were also proportionally over inflated for WTL. The total pre-efficiency allowance of £78.5m for MEL is made up of £59.0m for PTL, £10.9m for BGTL and £8.7m for WTL.

[15] See Chapter 6 for more detail on allowances as a proportion of submission.

GNI (UK) – UR Proposals

Overview

4.33 The bottom-up approach as described above has been the approach used to arrive at the draft determination for GNI (UK). The tables below show:

- The total requested from the licence holder for the full 5 years;
- The proposed determination for each year of the price control; and
- The total determination for the full 5 years.

4.34 Where reductions to the submitted amount are being proposed, a reason for this is given. No comments have been made on costs lines that we do not propose making reductions to in this draft determination.

Bottom-up Assessment

Overview

Table 14: GNI (UK) – Draft determination for pre-efficiency opex

Cost Category	BP Request - £m	2017-18 £m	2018-19 £m	2019-20 £m	2020-21 £m	2021-22 £m	DD Total £m
Controllable Opex non-CJV							
Administration	**2.9**	0.4	0.4	0.4	0.4	0.4	**1.9**
Staff Costs (excluding CJV)	**4.7**	0.7	0.7	0.7	0.7	0.7	**3.7**
Planned Maintenance	**9.9**	1.8	2.1	1.8	1.8	1.8	**9.3**
Unplanned Maintenance	**2.5**	0.4	0.4	0.4	0.4	0.4	**2.0**
System Operation	**2.0**	0.4	0.4	0.4	0.4	0.4	**2.0**
CJV							
CJV Costs (for GNI [UK])	**3.7**	0.5	0.5	0.5	0.5	0.5	**2.6**
Uncontrollable Opex							
Uncontrollable Costs	**9.1**	1.8	1.8	1.8	1.9	1.9	**9.1**
Total	**34.8**	**6.0**	**6.3**	**6.0**	**6.1**	**6.1**	**30.6**

Figures may not sum due to rounding

4.35 The draft determination proposes allowing £30.6m for the GT17 period for total opex (prior to efficiency challenge). This represents 88% of the submission of £34.8m. The CJV line refers purely to the GNI (UK) element of the single system allowance. Total CJV costs are reported separately in this chapter.

4.36 In the draft determination, reductions have been made in all of the areas shown in Table 14 above except uncontrollable costs. The reasons for the reductions in the non-CJV opex are discussed below.

Controllable Non-CJV Expenditure

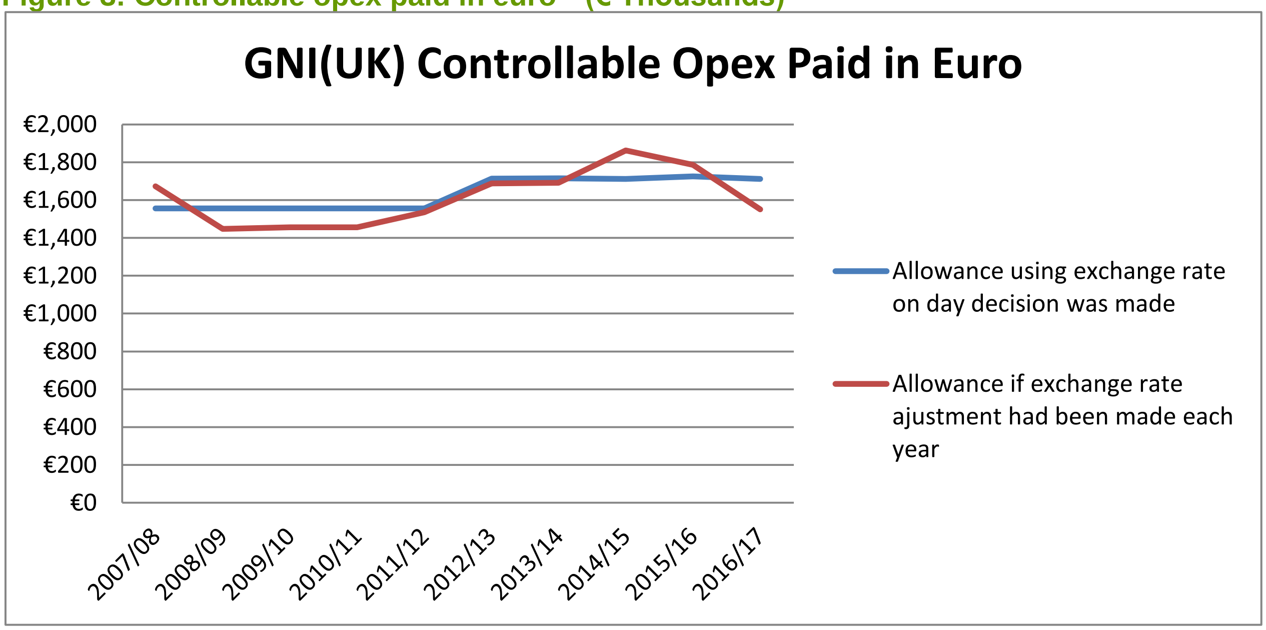
Table 15: GNI (UK) – Draft determination for staff costs

Cost Category	BP Request - £m	2017-18 £m	2018-19 £m	2019-20 £m	2020-21 £m	2021-22 £m	DD Total £m
Support Staff	**2.9**	0.4	0.4	0.4	0.4	0.4	**2.1**
Engineering Staff	**1.8**	0.3	0.3	0.3	0.3	0.3	**1.6**
Total	**4.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**3.7**

Figures may not sum due to rounding

4.37 GNI (UK) submitted staff costs which show an increase in the cost per FTE, largely due to exchange rate fluctuations. We accept that the pound is currently weak and therefore more *sterling* is required to cover staff costs paid in *euros*. However, we have carried out analysis which shows that over time, the cost/benefit of exchange rate fluctuations is largely negligible. See figure below for historic analysis.

Figure 3: Controllable opex paid in euro[16] (€ Thousands)

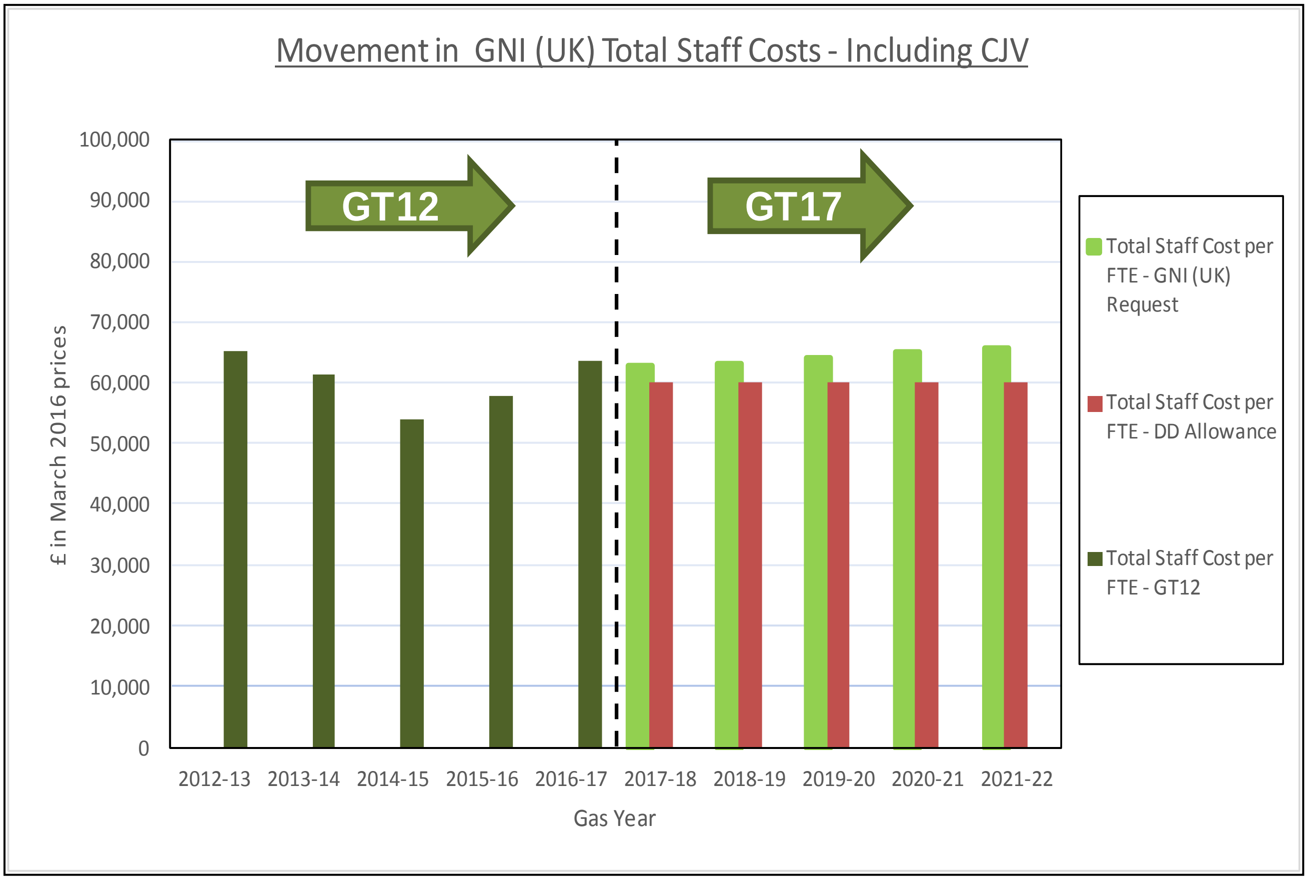


4.38 In this determination, we do not propose making an allowance for exchange rates. Accordingly staff cost requests from the business plan have been reduced as shown in

[16] Assumes that 85% of controllable opex is paid in euros.

Figure 4. We would reconsider this if exchange rate changes caused a significant impact in the longer term.

Figure 4: Total staff cost per FTE – request versus allowance[17]



4.39 Staff cost allowance has also been impacted by a proposed reduction in FTEs. This is illustrated in Table 16.

[17] The staff costs allowance for GNI (UK) is much less than for MEL. This is to be expected to some extent as the MEL figures include executive pay spread across a small number of employees. The issue is much less pronounced for GNI (UK) as their parent company incurs most of these executive costs. Removing this element results in much closer unit cost comparisons.

Table 16: GNI (UK) allowed FTEs

Staff Category	GT12 – Average Number of FTEs	GT17 – Average Requested FTEs	GT17 – Average Allowed FTEs
Non-CJV Staff	13.5	14.5	12.5
CJV Staff	0.0	4.0	3.0
Total Staff	**13.5**	**18.5**	**15.5**

4.40 We have made allowances for GNI (UK) based on 15.5 FTEs. GNI (UK) requested 4 additional staff for the CJV and an additional FTE in engineering. We propose allowing 3 CJV staff with 2 coming from the current compliment of support staff.

4.41 We also propose to allow the requested additional FTE for engineering given the aging network. The result is an allowance for 15.5 FTEs. This is an increase of 2 staff with recognition of additional members for both the CJV and engineering requirements.

Table 17: GNI (UK) – Draft determination for administration

Cost Category	BP Request - £m	2017-18 £m	2018-19 £m	2019-20 £m	2020-21 £m	2021-22 £m	DD Total £m
Pipeline Insurance	**1.2**	0.2	0.2	0.2	0.2	0.2	**0.9**
Intra-company Recharge	**1.1**	0.1	0.1	0.1	0.1	0.1	**0.5**
Other Overheads	**0.5**	0.1	0.1	0.1	0.1	0.1	**0.5**
Total	**2.9**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**1.9**

Figures may not sum due to rounding

4.42 The pipeline insurance costs submitted by GNI (UK) were high compared to actual spending in the GT12 period. We recognise that GNI (UK) provided information from insurance brokers that insurance cost is forecast to increase. Given that both PTL and BGTL pipeline insurance costs are not predicted to increase in real terms in the GT17 period, we reduced GNI (UK)'s allowance to be in line with their GT12 actuals. We then allowed an additional 4% to take account of the increase in insurance premium tax.

4.43 Intra-company recharge, other overheads (Table 17 above) and asset management and compliance (Table 18 below) were categorised as shared services in the GT12 reporting structure. These three areas have been given a total allowance of £300k per annum (£100k per annum each) in line with GT12 levels for shared services. Overall, we propose allowing 65% of the total amount requested for administration as shown in Table 17.

Table 18: GNI (UK) – Draft determination for planned maintenance

Cost Category	BP Request - £m	2017-18 £m	2018-19 £m	2019-20 £m	2020-21 £m	2021-22 £m	DD Total £m
Asset Management	**0.6**	0.1	0.1	0.1	0.1	0.1	**0.5**
Emergency Response	**1.4**	0.3	0.3	0.3	0.3	0.3	**1.4**
Pipeline Inspection	**1.2**	0.2	0.5	0.2	0.2	0.2	**1.2**
Routine Maintenance	**6.8**	1.2	1.2	1.2	1.3	1.2	**6.2**
Total	**9.9**	**1.8**	**2.1**	**1.8**	**1.8**	**1.8**	**9.3**

Figures may not sum due to rounding

4.44 For pipeline inspections, the cost of on land inspection was reduced to be in line with actual spending in the GT12 period. In the area of routine maintenance, our external consultants advised than allowance of £1m per annum for AGI maintenance was appropriate. Overall, we propose allowing 94% of the total submitted for planned maintenance as show in Table 18 above.

Table 19: GNI (UK) – Draft determination for unplanned maintenance

Cost Category	BP Request - £m	2017-18 £m	2018-19 £m	2019-20 £m	2020-21 £m	2021-22 £m	DD Total £m
Drainage	**1.4**	0.2	0.2	0.2	0.2	0.2	**1.0**
Other Unplanned Costs	**1.2**	0.2	0.2	0.2	0.2	0.2	**1.0**
Total	**2.5**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**2.0**

Figures may not sum due to rounding

4.45 The submitted costs for drainage were based on actual spending for particularly wet years. This amount has been reduced to reflect a ‘normal’ year.

4.46 Within other unplanned costs, our external consultants have advised that £200k per year for fault repairs is an appropriate allowance.

4.47 Our proposed allowance for unplanned maintenance is 79% of the amount submitted as shown in Table 19.

Table 20: GNI (UK) – Draft determination for system operation

Cost Category	BP Request - £m	2017-18 £m	2018-19 £m	2019-20 £m	2020-21 £m	2021-22 £m	DD Total £m
Grid Control	**1.8**	0.3	0.3	0.4	0.4	0.4	**1.8**
SCADA & Communications	**0.3**	0.0	0.0	0.1	0.1	0.1	**0.3**
European Compliance	**0.0**	0.0	0.0	0.0	0.0	0.0	**0.0**
Total	**2.0**	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	**2.0**

Figures may not sum due to rounding

4.48 With regard to the grid control costs there would appear to be a significant difference in the level of costs between MEL and GNI (UK). Given that the two networks are of broadly similar size and complexity this differential appears difficult to justify.

4.49 As outlined in the MEL section, we would see value for consumers if control room services for both licence holders were awarded by means of a joint tender. The cost information revealed in the business plans would appear to support this position. The amounts shown for grid control represent full allowance for GNI (UK).

4.50 £25k was submitted as a cost of European compliance in 2017-18. This has not been allowed since funding was given in the previous price control period. We propose allowing 99% of the total submission amount for GNI (UK) systems operations as shown in Table 20.

Uncontrollable Expenditure

Table 21: GNI (UK) – Draft determination for uncontrollable expenditure

Cost Category	BP Request - £m	2017-18 £m	2018-19 £m	2019-20 £m	2020-21 £m	2021-22 £m	DD Total £m
Business Rates	**3.2**	0.6	0.6	0.6	0.7	0.7	**3.2**
Licence Fees	**5.9**	1.2	1.2	1.2	1.2	1.2	**5.9**
Total	**9.1**	**1.8**	**1.8**	**1.8**	**1.9**	**1.9**	**9.1**

Figures may not sum due to rounding

4.51 For the draft determination, we propose to make no adjustments to the submitted uncontrollable costs. This is shown in Table 21 above.

CJV – UR Proposals

Overview

4.52 The UR intention is to have a single system operator for Northern Ireland in place for 1 October 2017. This will be delivered by means of a Contractual Joint Venture (CJV) between MEL and GNI (UK). This is not a legal entity and cannot be granted a licence. The funding of the CJV will therefore be via the existing licences.

4.53 Licence holders were required to submit an agreed business plan together with their allowance requests for CJV activity. When setting an overall allowance, the UR has determined the efficient level of costs on the basis of dealing with a single entity. The global allowance has then been allocated to the individual licence holders based on responsibility for the various activities funded.

4.54 It is accepted that there will be initial start up costs in addition to business as usual expense. However, a key objective is that the CJV will result in a downward movement in the overall costs of system operation. The mobilisation and system development cost required to establish the CJV will occur during the 2016-17 gas year. It does not form part of this price control determination. We note that the assessment of CJV development cost will be ongoing during this consultation period. Finalisation of these figures may impact on the final determination.

4.55 The CJV costs allocated to each licence holder are shown in Appendix 1. Table 22 below represents the cost allocation to the CJV as a whole.

Table 22: Draft determination for CJV for pre-efficiency opex

Cost Category	BP Request - £m	2017-18 £m	2018-19 £m	2019-20 £m	2020-21 £m	2021-22 £m	Totals £m
CJV Staff Costs	**2.5**	0.4	0.4	0.4	0.4	0.4	**1.8**
Administration	**0.6**	0.1	0.1	0.2	0.1	0.1	**0.6**
Contracts & Licences	**2.9**	0.4	0.4	0.4	0.4	0.4	**2.2**
Network Code Development	**1.0**	0.1	0.2	0.1	0.1	0.1	**0.7**
European Compliance	**0.3**	0.0	0.0	0.0	0.0	0.0	**0.1**
Total CJV Costs (Industry)	**7.3**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**	**5.4**

Figures may not sum due to rounding

4.56 MEL and GNI (UK) requested an allowance of 8 staff in total for the CJV. The submitted cost of these 8 staff was £502k per annum. For the purposes of this determination we have assumed that the resources are split evenly. This may not be the case when staff are finally in place, in which case the cost allocation will be adjusted accordingly.

4.57 Overall, we propose allowing 6 FTEs for the CJV. It is our opinion that the detailed TSO staff allocations include too much resource for market operation and market development. Maintaining a single code should significantly reduce work requirements in this area. Consequently, we think these roles should be amalgamated.

4.58 For both MEL and GNI (UK) this allowance means 3 FTEs each (2 from the current pool and one additional). At £60k per FTE, this gives a total CJV staff cost allowance of £360k per annum. We consider that the £60k per FTE is largely in line with what was requested.

4.59 Within the submission for contracts and licences, a request of £200k p.a. was made for upgrades to the GTMS system. We have allowed £50k in the draft determination. Our external advisors are currently considering if this amount is appropriate and we will advise of this in the final determination.

4.60 The network code development cost line includes a request for expenditure on a 'time to fail' model. This model calculates failure scenarios under different operating conditions. Little evidence has been provided for the need for this model. This element of expenditure has been removed for our determination but we will reconsider if provided with sufficient justification.

4.61 European compliance costs have been reduced because it included an amount for travel to Europe which we considered excessive. It also included costs for REMIT reporting which is currently carried out by in house staff so a separate allowance would not be appropriate.

4.62 Overall, the TSOs requested £7.3m for CJV against the UR allowance of £5.4m (74%).

CJV – Cost Benefit Analysis

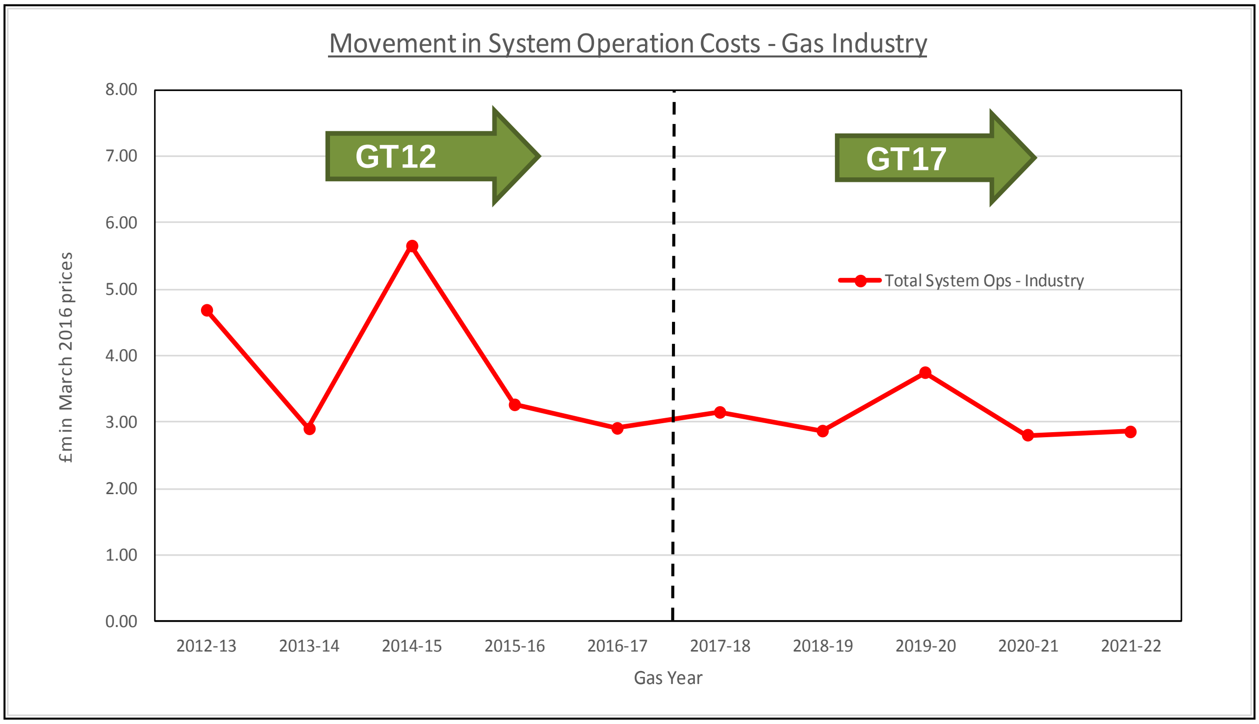
4.63 The aim of the CJV is to promote the ongoing development of the gas industry. It is intended to delivery a range of benefits to both TSOs and network users alike.

4.64 A key objective of the CJV is to deliver efficiency. This can be estimated using cost benefit analysis (CBA). We have undertaken such a study looking at forecast cost against historic spends. TSOs estimate of start-up costs have also been used, though these are yet to be determined upon.

4.65 For the purposes of the CBA, we have had to look at *total system operations (including grid control and CJV operations) in its entirety*. This is due to the fact that CJV market operations were not separately accounted for in the GT12 period.

4.66 The CBA also reflects expenditure at the industry level. This is necessary as functions are now being shared or are no longer required i.e. one IT system will become obsolete. On an overall industry basis the cost change proposed by TSOs is shown as follows:

Figure 5: Gas industry total (CJV and non-CJV) system operation cost movement

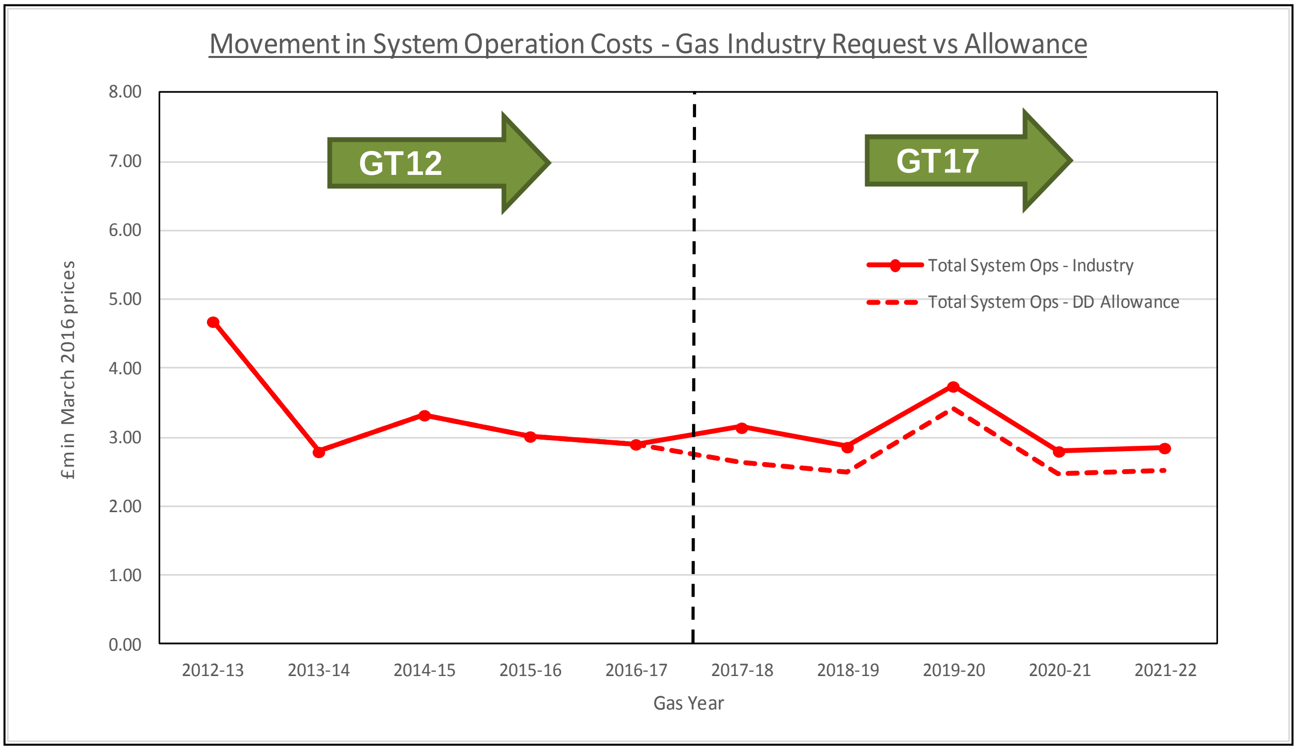


4.67 From the graph it can be seen that system costs are falling. On an annual basis (GT12 versus GT17 average) the saving is around £0.8m. Allowing for start-up costs of £2.3m,[18] the net present benefit (NPB) of the proposal is £1.3m by the end of GT17.

4.68 However, the GT12 period includes some years with significant 'atypical' expenditure. These largely relate to the MEL IT system development for entry/exit. Assuming the majority (80%) of these costs would not normally be required, the industry spend now looks as follows:

[18] This figure has yet to be determined. This will be done via a separate process from GT17.

Figure 6: Gas industry total system operation request and UR allowance



4.69 In the 'normalised' scenario the TSO proposed annual saving is much lower at £0.3m p.a. This results in a net present cost (NPC) of £1.1m by period end. Such a result would not be in line with the efficiency objective of the CJV.

4.70 Assuming all non-CJV system costs are allowed in full,[19] but applying the UR determination for CJV, annual saving is now £0.6m. Across the GT17 period this results in a total NPB of £0.6m. This figure may further increase depending on the allowance for mobilisation costs and the extension of the IT asset life beyond GT17.

4.71 Results of the cost benefit analysis for the UR allowance is provided below.

[19] This is done in order to separate out the impact of the CJV. Applying changes to the TSO system operation allowance would obscure this impact.

Table 22: Cost benefit analysis results – UR allowance scenario

Cost Category	Start Up Cost - £m	2017-18 £m	2018-19 £m	2019-20 £m	2020-21 £m	2021-22 £m	Totals £m
Discount Factor (3.5%)[20]	**1.000**	**0.966**	**0.934**	**0.902**	**0.871**	**0.842**	
Mobilisation cost	-2.3	0.0	0.0	0.0	0.0	0.0	**-2.3**
Annual Benefit	0.0	0.6	0.6	0.6	0.6	0.6	**3.2**
Net (Cost) / Benefit	-2.3	0.6	0.6	0.6	0.6	0.6	**0.9**
Discounted (Cost) / Benefit	**-2.3**	**0.6**	**0.6**	**0.6**	**0.6**	**0.5**	**0.6**

CJV – Cost Transfer Mechanism

4.72 Whilst the CJV will operate as a separate team, revenue will be recovered by individual TSOs. The companies have estimated the cost split, upon which CJV allowances have been made.

4.73 However, there may be occasions during the price control where resource for activity 'shifts' between TSOs. In such a circumstance a mechanism is required to ensure that the cost can be recovered by the appropriate licence holder.

4.74 This change is not easily undertaken in the GNI (UK) licence. Condition 2.2.1.1(f) requires that forecast required revenue (FRR) equals their allowed revenue (ARR) for tariff setting purposes. To transfer revenue between TSOs would require the price control to be re-opened.

4.75 In order to provide flexibility we have considered the possibility of treating such transferred opex as uncontrollable. This would resolve the issue as the FRR would still equal the allowed controllable revenue. However, a positive or negative value could be recorded in the uncontrollable opex line (depending on the direction of the transfer).

4.76 To facilitate such a transfer we would require certain information before such an approval would be given. We foresee this as being a joint proposal from the CJV detailing the following:

- Item for which responsibility is changing;
- Rationale for the change;
- Initial allowance for the activity;
- Amount spent to date and amount to be transferred etc.

4.77 The UR would then decide if this request is reasonable. The amount of detail in the proposal should be commensurate with the value of the budget being transferred. This particular cost element would remain as an uncontrollable item until the next price review where it would be reclassified.

[20] Discounting is used to compare costs / benefits that occur in different time periods. Values are discounted to reflect individuals preference to receive goods and services now rather than later. The 3.5% rate reflects the discount factor advised by HM Treasury in *The Green Book*.

4.78 This mechanism reflects a new regulatory approach. As such we would welcome views on this as part of the draft determination consultation.

5 Replacement Expenditure (Repex)

Detailed Approach – UR Proposals

Overview

5.1 Capital expenditure allowances are only provided for in the GNI (UK) and WTL licences. These are set outside the scope of the price control review process. Much of what might be described as capital expenditure in terms of accounting rules we consider as being maintenance/repex. It does not add to the capacity of the existing pipeline network but rather replaces or upgrades existing equipment. We propose to treat such expenditure in the same way as *controllable operating expenditure*.

5.2 As part of their business plans, TSOs submitted a list of repex projects for which they sought an allowance. In considering each project we followed a two stage approach. In the first stage we determined whether or not the project should be carried out during the price control period. For those projects that pass this first stage we then, in the second stage, considered what the appropriate allowance would be.

5.3 In making an assessment of the efficient level of allowances required to deliver individual projects our consultants benchmarked costs against other companies who have carried out similar work. We also aim to take account of, amongst other things, available cost data from Ofgem and the CER in the final determination.

MEL – UR Proposals

5.4 Both the PTL and BGTL pipeline networks will be 25 years old by the end of the price control period. It might be expected that, in particular the AGI assets, will be beginning to be replaced over the period.

5.5 Table 23 sets out for each of the major projects, the request included in the business plan and our draft determination for MEL.

Table 23: MEL repex allowance (pre-efficiency)

Project	MEL Request (£m)	UR Allowance (£m)
Boiler house Replacement - Larne - Torytown - Knocknagoney	0.9	0.9
Replacement Ballylumford Water bath Heaters	0.8	0.0
C&I Panel PLC Replacement	0.6	0.5
Fire Detection System - Kiosks	0.2	0.0
Transformer Rectifier Replacement	0.2	0.0
Lagging Replacement	0.2	0.0
Replacement / Overhaul of Valves / Actuators	0.2	0.0
UPS & UPS Battery Replacement	0.1	0.1
Other	1.8	0.4
Total	**5.0**	**1.9**

Figures may not sum due to rounding

5.6 The evidence provided by MEL is less robust than might be expected and there was a lack of detail with regard to specific projects. For these projects, we propose not to provide allowances.

5.7 The business plan gave the impression of there being a robust system including an Asset Replacement Model and Asset Risk Register. On further inspection it would appear that these have only been developed for a few key assets. In many instances this contains little more than manufacturers' guidance on average design life.

5.8 Many utilities now operate sophisticated Asset Management Systems certified, by for instance, the International Standards Organisation. We do, however, recognise that a certified process may impose excessive costs on a TSO of MEL's scale.

5.9 An uncertified process based on the same principles might be more appropriate. We would expect MEL to continue developing their approach to asset management on this basis.

5.10 While the submission included a number of substantive projects, it also included a large number of minor projects. In many cases the average spend per site and/or per year is under £25k.

5.11 Many of these projects might be regarded as similar in nature to maintenance rather than asset replacement. Instead of setting an allowance for each individual project we are considering setting a consolidated allowance for such activities.

5.12 MEL has sought an allowance of approximately £0.8m for the replacement of a water bath heater at Ballylumford in 2020 to support the continued operation of the B Station. We have discussed this matter internally in the UR.

5.13 The B Station has a Local Reserves Service Agreement with SONI that lasts from 2016 to 2018 inclusive, with an option to extend for a further two years. Given the likelihood that the B Station will be closing in the near future, we do not propose to provide an allowance for this project.

5.14 Should the Local Reserves Services Agreement be further extended this project might become a requirement. Given the customer specific nature of the project and the potentially short duration of it being required, it might be questioned whether the generality of gas consumers should be asked to fund it.

5.15 We have reduced the allowance for 'boiler house replacement' and 'C&I / PLC replacement' based on cost information provided by external advisors for similar projects.

GNI (UK) – UR Proposals

5.16 At the time of the previous price control review, GNI (UK) submitted a business plan requesting £6.8m[21] of allowances for repex over the five year period. Based on the evidence provided, we made an allowance of £61k for only one such project, cathodic protection.

5.17 In our determination for GT12 we stated that, should some of the projects for which no allowance had been made become necessary during the price control period, we would be prepared to reconsider. This was on the proviso that GNI (UK) provides the necessary evidence in advance of the project proceeding. In October 2013 GNI (UK) sought additional allowances of £2.3m during the price control period for a number of repex projects. In May 2014 we determined that we would provide an additional allowance of £25,000 for some project management in the 2016-17 gas year. As part of that determination we also stated that we would not consider any further requests for similar expenditure during the 2012-17 price control period.

5.18 We also note that during the first three years of the current price control period, that is, those years for which final cost reporting data has been provided, GNI (UK) has spent £24k on one project.

5.19 By the end of the price control period the oldest part of the GNI (UK) network, the NWP, will be 18 years old. The average age of the network will be just over 16 years. During the period when the BGTL and PTL networks were a similar age (between October 2008 and September 2013) expenditure on such projects averaged £0.15m p.a. The equivalent figure in the GNI (UK) business plan is £1.2m.

5.20 Table 24 below sets out for each of the major projects, the request included in the business plan and our draft determination for GNI (UK) in £ sterling.

[21] April 2011 prices, excluding pipeline inspection.

Table 24: GNI (UK) Repex

Project	GNI (UK) Request (£m)	UR Allowance (£m)
Cathodic Protection	0.2	0.2
Boiler Refurbishment	2.0	0.0
Control System Upgrade	0.1	0.0
Instrumentation Refurbishment	0.3	0.0
Metering Recalibration	0.5	0.0
Gormanston P2 Metering	0.9	0.0
AGI Security	1.1	0.0
Cyber Security Upgrade	0.2	0.2
Emergency Escapes	0.6	0.0
Remote Line Valve Actuation	0.0	0.0
Total	**5.9**	**0.4**

Figures may not sum due to rounding

5.21 Little specific evidence has been presented to date in support of these projects. The justification for expenditure tends to be based on manufacturers' guidance on average design life; any analysis of actual asset health and fault data has been limited. We will accept further representation on these projects as part of the draft determination consultation process.

5.22 It is clear that further design work of specific projects would be required to establish more reliable cost estimates. Given the quality of the evidence provided, we would find it difficult at this stage to justify the inclusion of allowances for all but a few of these projects in the draft determination. We have reduced the allowance for cathodic protection based on cost data for similar projects provided by external advisors.

5.23 In their submission, GNI (UK) stated that its parent company (Gas Networks Ireland) has developed an ISO55000 accredited Asset Management System.

5.24 During the price control period we may be willing to fund additional projects to those agreed in the final determination should GNI (UK) be able to provide convincing evidence in advance that such projects are necessary. Having an appropriate Asset Management System in place is likely to assist in providing us with the robust evidence we would need to make such decisions. This approach is in line with that set out in our previous determination, GT12.

6 Efficiency Analysis

Catch-Up Efficiencies

6.1 A catch-up efficiency challenge to the TSO allowance has not been applied. To do so would require top-down benchmarking that indicates a gap in the level of performance between NI TSOs and the frontier performer. Such an analysis does not exist due to the absence of comparable detail.

6.2 Absence of this challenge does not mean that the scope for efficiency does not exist. Indeed it is normal for most companies to experience some 'lag' from the frontier performer. Rather, the lack of challenge simply demonstrates that the size of this lag has not been determined.

6.3 Whilst no catch-up percentage challenge is applied, we have made use of comparisons. By contrasting between different TSOs and over time, the UR has disallowed forecast cost increases which it does not consider reasonable or justified. It is intended to expand on these assessments if comparable TSO data becomes available from the CER and Ofgem.

Frontier Shift

6.4 Frontier shift is calculated by applying the average annual productivity figure to the real price effects (RPEs) result. The real price effect is computed from discounting RPI from the weighted impact of nominal input prices.

6.5 In a simplified calculation, frontier shift can be determined as follows:

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

6.6 Real Price Effects – The UR has split controllable opex (including repex) spend into a number of categories. Input prices for these categories have then been forecast using various indices and OBR[22] analysis. Discounting RPI from the input price gives a figure for the real price effect on gas TSOs. Generally speaking industry costs are forecast to rise faster than inflation.

6.7 Productivity – In addition to real price effects, it is necessary to apply a productivity assumption. This takes account of continuing efficiencies which industry can achieve over the price control period (for example with new technologies, new working practices or other means).

6.8 An assessment of productivity has been undertaken. This is based on both recent regulatory precedent and the achievement of similar industries. From this analysis we have applied a 1% per annum productivity challenge to all controllable opex.

[22] Office of Budget Responsibility.

6.9 The respective net impact of frontier shift for controllable opex is shown in Table 25 below. Full details concerning the calculations around frontier shift can be found in Annex 1.

Table 25: Frontier shift efficiency targets

	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22
Input Price Inflation	**3.2%**	**3.3%**	**3.5%**	**3.4%**	**3.5%**	**3.6%**
RPI	**2.5%**	**3.5%**	**3.4%**	**3.1%**	**3.2%**	**3.3%**
Real Price Effect	**0.7%**	**-0.1%**	**0.0%**	**0.3%**	**0.3%**	**0.3%**
Productivity	**1.0%**	**1.0%**	**1.0%**	**1.0%**	**1.0%**	**1.0%**
Frontier Shift (p.a.)	**-0.3%**	**-1.1%**	**-1.0%**	**-0.7%**	**-0.7%**	**-0.7%**
Cumulative Challenge	**-0.3%**	**-1.4%**	**-2.4%**	**-3.1%**	**-3.8%**	**-4.5%**

A negative value for frontier shift represents a challenge to the company in terms of reduced cost allowance by the cumulative percentage stated.

6.10 For the GT17 draft determination we are assuming a cumulative frontier shift of 4.5% for controllable opex by the end of the period assessed. This challenge is also applied to repex. No challenge is applied to uncontrollable costs.

Summary

6.11 Figures presented earlier in this paper all refer to allowances pre-efficiency. Applying the cumulative frontier shift challenge to MEL results in the following determination:[23]

[23] See *Appendix* 3: Proposed Post-Efficiency Allowances for breakdown by TSO.

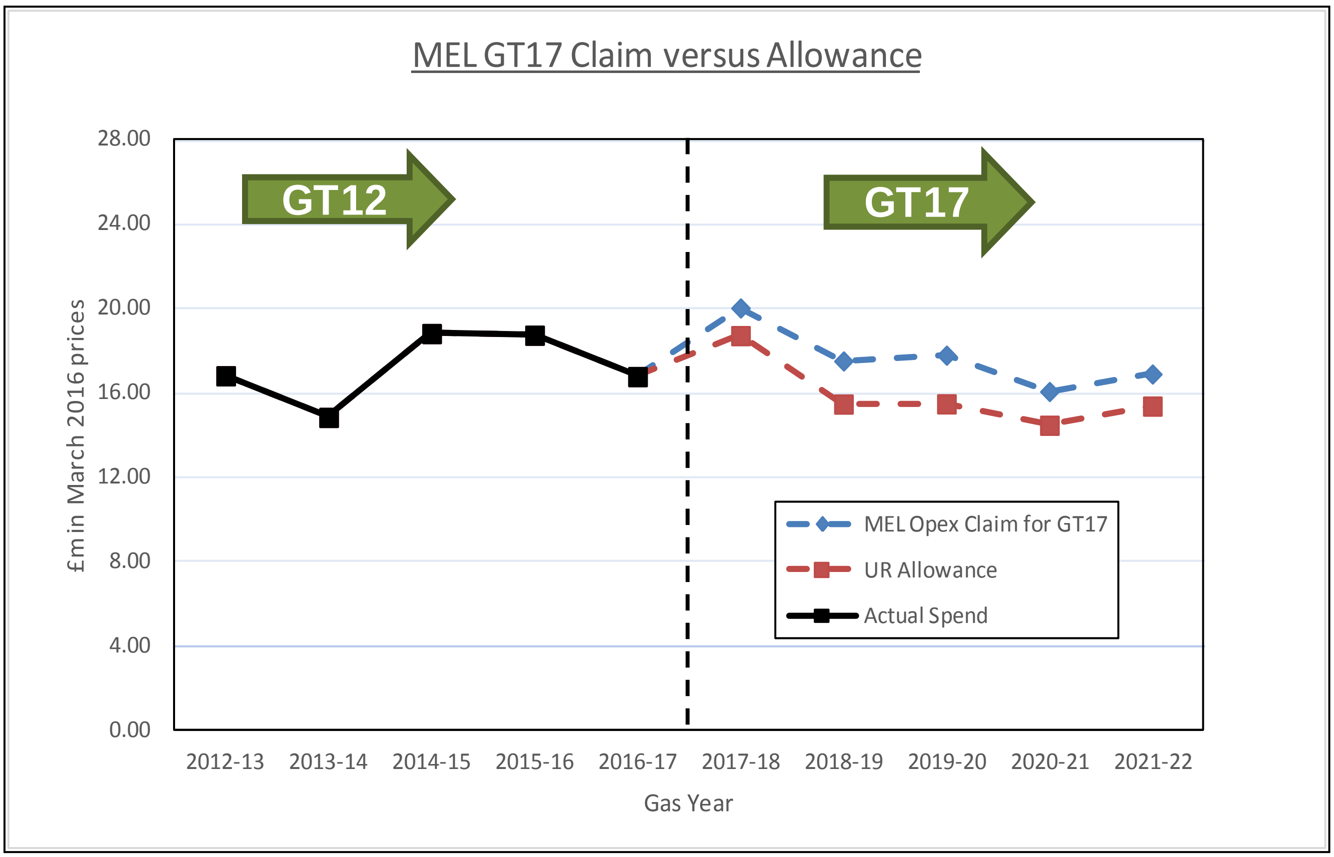
Table 26: Total allowance for MEL (post efficiency) – March 2016 prices

Cost Category	BP Request - £m	2017-18 £m	2018-19 £m	2019-20 £m	2020-21 £m	2021-22 £m	Totals £m
Controllable Opex non-CJV	**33.9**	6.8	5.7	6.1	4.9	6.2	**29.7**
Controllable Opex CJV	**3.7**	0.6	0.6	0.6	0.5	0.5	**2.8**
Asset Replacement - Repex	**4.9**	0.3	0.7	0.3	0.5	0.1	**1.9**
Uncontrollable Costs	**45.7**	11.0	8.5	8.5	8.5	8.5	**45.0**
Total	**88.2**	**18.7**	**15.5**	**15.5**	**14.4**	**15.4**	**79.4**

Figures may not sum due to rounding

6.12 Graphically this can be presented as follows:

Figure 7: Total allowance for MEL (post efficiency) – March 2016 prices



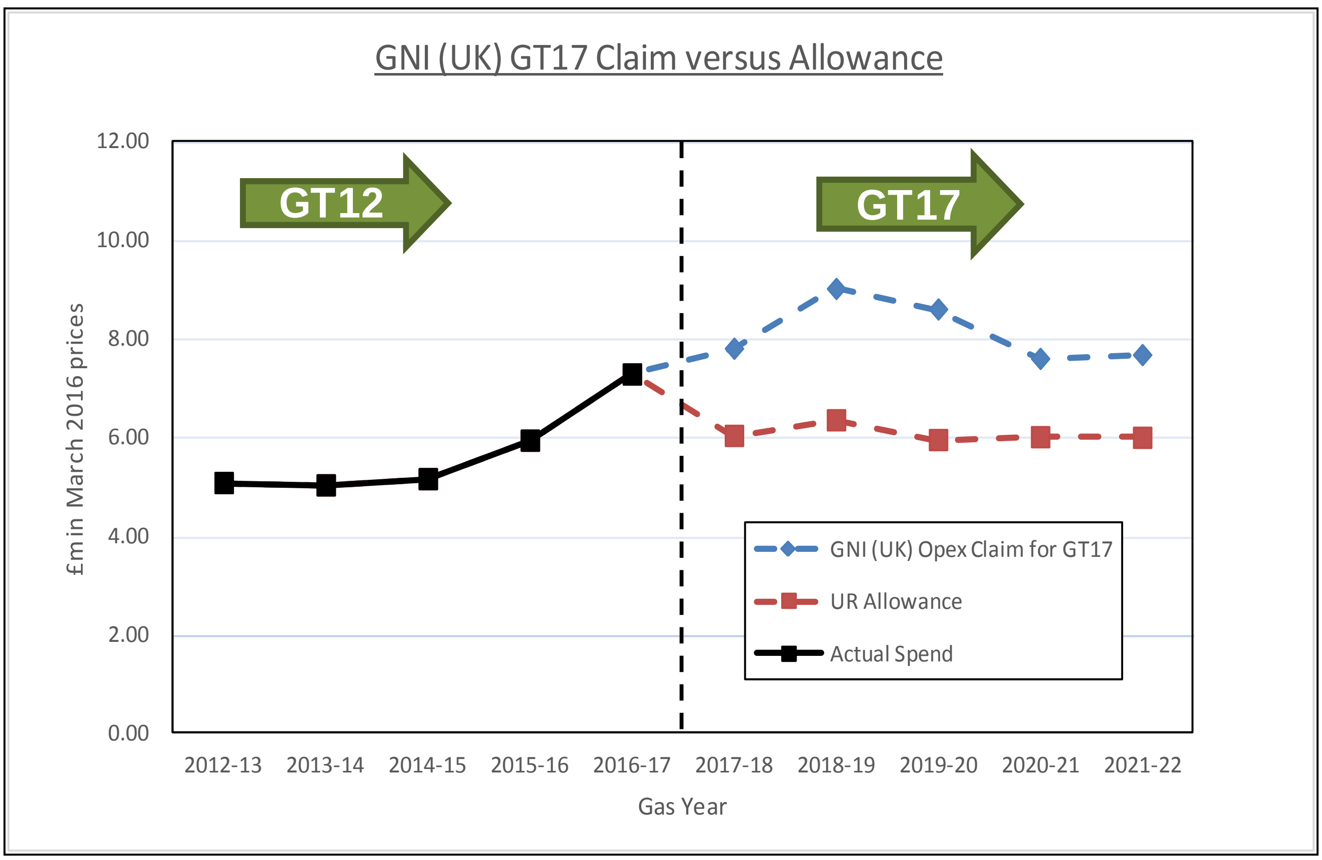
6.13 For GNI (UK) the results are:

Table 27: Total allowance for GNI (UK) (post efficiency) – March 2016 prices

Cost Category	BP Request - £m	2017-18 £m	2018-19 £m	2019-20 £m	2020-21 £m	2021-22 £m	Totals £m
Controllable Opex non-CJV	**22.1**	3.7	3.9	3.6	3.6	3.6	**18.4**
Controllable Opex CJV	**3.7**	0.5	0.5	0.5	0.5	0.5	**2.5**
Asset Replacement - Repex	**5.9**	0.1	0.2	0.0	0.0	0.0	**0.4**
Uncontrollable Costs	**9.1**	1.8	1.8	1.8	1.9	1.9	**9.1**
Total	**40.7**	**6.0**	**6.3**	**5.9**	**6.0**	**6.0**	**30.3**

Figures may not sum due to rounding

Figure 8: Total allowance for GNI (UK) (post efficiency) – March 2016 prices



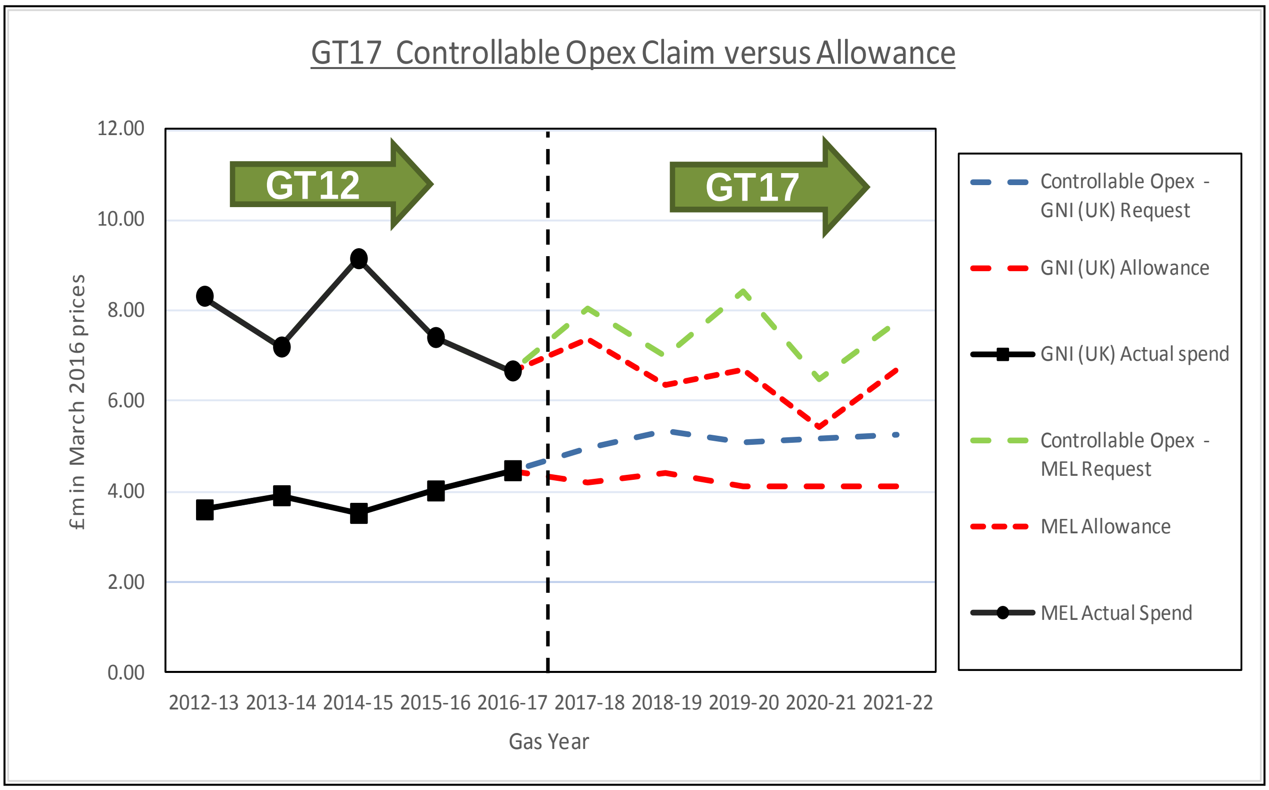
6.14 Allowance for all opex and repex represents 90% and 75% respectively of the business plan request for MEL and GNI (UK). Taken at face value, it would appear that the price control represents a more robust challenge for GNI (UK).

6.15 However, three factors may be somewhat confusing this comparison. In the first case, Figure 8 illustrates that GNI (UK) have requested substantial cost increases above GT12 levels. MEL figures do not reflect this, though there are reasons behind this outcome.[24]

6.16 Secondly, the graphs and tables include uncontrollable costs which are a pass through item. MEL has a much larger proportion of these costs, which helps explain the higher overall allowance percentages.

6.17 Finally, the allowances incorporate repex figures which are bespoke projects that do not lend themselves easily to comparisons. If both repex and uncontrollable costs are excluded, the results are as follows:

Figure 9: Total allowance for TSOs controllable opex (post efficiency)



6.18 Allowance for controllable opex (excluding repex) now represents 86% of that requested for MEL. This compares to a figure of 81% for GNI (UK).

[24] Within the CJV, GNI (UK) will have responsibility for bearing the cost of the IT system. MEL no longer need to provide such services separately so will benefit from cost reductions.

7 Incentives and Innovation

Detailed Approach – UR Proposals

Overview

7.1 In our approach paper we set the various incentive mechanisms that each TSO is exposed to. We have reviewed each of these mechanisms under two broad criteria;

- The ability to deliver efficient outcomes for consumers; and
- The clarity with which the incentive operates.

7.2 In addition we have given some consideration to our approach to innovation on the part of licence holders.

Innovation Projects

7.3 Our approach to innovation is in line with that set out in our final determination on GD17 published in September 2016.

7.4 It is our view that successful innovation is best driven by the licence holders 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.

7.5 The licence holders will then be rewarded through the price control framework for resulting outperformance to the end of the price control period. Consumers will benefit in the long run from improved services and lower prices[25].

7.6 We consider that this approach should remain the principal mechanism for delivering innovation. It provides maximum flexibility to the licence holders to make innovative decisions. It further aligns the benefits for consumers and licence holders and avoids the risk of the UR being asked to pick winners from a list of potential innovation projects.

7.7 Generally, the purpose of innovation is to reduce cost. 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.

7.8 That said, we are conscious that in some cases funding of innovations through increased prices could be appropriate. For instance, this may be the case for 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.

7.9 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 licence holder requesting such funding:

[25] It is recognised that this is true for licence holders with a revenue cap but may not be the case for those with a cost pass through mechanism.

- 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 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 licence holder has arrived at its bid for innovation and how this interacts with other investments planned under the normal price control;
- 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 regulatory action to progress, and the consequences of the innovation not happening;
- Details on what deliverables / benefits may be expected for local consumers from the research / development / trials;
- Detailed risk assessment as well as details on and justification of proposed treatment of risk and reward;
- Description of how the innovation, if successful, could be efficiently rolled out across the industry; and
- Justification of how the proposed innovation is different to anything that has occurred previously, within the wider industry.

7.10 We note that we may consider additional, project-specific assessment criteria, where relevant and appropriate.

7.11 Where licence holders 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 licence holder at the onset of a price control. However, we recognise that in certain circumstances this may present difficulties or not be possible.

MEL – UR Proposals

7.12 The last review of the relevant governance arrangements was carried out in 2008. As a matter of good regulatory practice it would be appropriate to review the existing arrangements. We therefore intend to carry out this review during the price control period.

7.13 As noted in our approach we consider that the value of the Social Enhancement Fund (SEF) in providing appropriate incentives to managers is not clear. Having taken note of the response received from MEL, however, we consider the future of this mechanism and the funds already retained by it should form part of our proposed governance review.

7.14 In the meantime we propose that no further monies are allocated to the fund and that all future operating cost savings are returned directly to consumers at the end of the gas year. This will be achieved by setting the 'z' factor to zero each year. We intend to give this proposal effect immediately, commencing with the 2016-17 gas year reconciliation process.

GNI (UK) – UR Proposals

7.15 This licence holder operates under a 'revenue cap' regime that provides a strong incentive to manage costs. As we noted in our BGE (NI) 2012 Determination[26] we consider the licence holder receives sufficient return on capital to accept the level of risk associated with being required to fund a very limited level of operating expenditure risk. In addition, the current licence provides real protection in relation to operating expenditure.

- Condition 2.2.4(i) allows GNI (UK) to request a special operating expenditure review if actual operating expenditure in any gas year differs from the most recently agreed forecast by more than 15%. The UR may substitute an amended figure following such a review.
- Condition 2.2.4(j) allows GNI (UK) to seek the UR approval to recover unforeseen operating expenditure. We may approve this in our absolute discretion although any expenditure must be genuinely unforeseen.

7.16 We consider that these mechanisms are sufficient to provide GNI (UK) with adequate protection against risks. In particular this includes unforeseen IT development costs related to the CJV, and/or repex projects for which no allowance is made at the time of the price control determination but which we subsequently allow during the price control period due to new information provided by GNI (UK).

7.17 We expect GNI (UK) to submit forecast cost estimates for each project once the project requirements have been agreed. We will then make an assessment of what is considered to be an efficient level of expenditure for project delivery. An appropriate allowance can then be included in the annual Forecast and Actual Revenue Requirement process.

7.18 This process is in line with our 2012 determination and will follow the following steps:

- **Step 1:** - Project deliverables to be agreed with the UR;
- **Step 2:** - Estimated cost requirement to deliver agreed project submitted to the UR for consideration;
- **Step 3:** - UR determines the allowance to be recovered through the postalised transmission tariff; and
- **Step 4:** - Monthly cost reporting, as necessary, to the UR during project delivery phase.

7.19 We note that the current arrangements have proven sufficiently flexible over the previous price control periods. GNI (UK) has been provided with additional allowances over and above the previous determination to deliver significant EU compliance projects.

7.20 However, the licence is unclear as to the definition of actual expenditure in condition 2.2.4 (l). We propose to modify the licence such that the assessment is made with regard to controllable operating costs only. By explicitly excluding uncontrollable costs

[26] BGE (NI) Price Control Determination 2012-17 paragraph 3.4 – 3.6.

from the calculation a smaller variation in costs will be required to trigger the mechanism.

7.21 Based on our draft determination, with controllable opex equal to an average of £4.3m per annum, a £0.6m deviation would be required to trigger the mechanism. The inclusion of £1.8m uncontrollable opex would increase this figure to £0.9m.

8 Financial Aspects

Detailed Approach – UR Proposals

Overview

8.1 We set out our approach for WACC in our approach document. There were no responses in relation to this and it remains unchanged.

8.2 This section is structured as follows:

- UR proposals with respect to WACC for GNI (UK) and WTL as well as consideration of related issues;
- Capital Repayments; and
- Financeability.

GNI (UK) – UR Proposals

8.3 In June 2016 we approved a modification to the GNI (UK) licence which brought the setting of WACC in line with what had been set out in the original licence granted in February 2002. That licence envisaged the possibility that the UR might set the rate of return for the licence holder based on a funding model with 100% debt.

8.4 Experience in NI has demonstrated that the financial markets are willing to fund gas transmission assets on this basis. Most recently the competitive process to award the high pressure gas conveyance licence that formed part of the GttW project was secured by WTL based on a 100% debt model.

8.5 The original licence was modified at the request of the licence holder such that the gearing ratio was fixed at 72.5%. In combination with a fixed return on equity of 15% (nominal), this has meant that the licence holder received a premium on the rate of return when compared to an investor in a regulated utility with an equivalent risk profile. Based on this understanding it was determined by us that the licence should be modified in advance of this price control process.

8.6 As we noted in our consultation on the recent licence modification, one useful comparator when considering an appropriate rate of return for GNI (UK) is the output from the competitive process to award the GttW high pressure conveyance licence. Both are on land high pressure networks that once operational are not expected to require further investment in new capacity. The financial model set out in both licences to recover this investment is almost identical.[27]

8.7 This clearly demonstrates that the financial markets are prepared to accept 100% debt funding of such assets at very low interest rates. The successful applicant indicated that based on market conditions as at April 2014 they would require a WACC of 1.98% to fund the purchase of the pipeline assets.

[27] The Monthly Capital Revenue Requirement is inflated by RPI in the WTL licence and CPI (Consumer Price Index) in the GNI (UK) licence respectively.

8.8 Since then there has been a significant change in market conditions. Applying the 2014 analysis to current debt figures indicates an equivalent WACC of 0.3%. This figure includes the costs of bond issuance and providing a liquidity reserve, which together amount to 0.4%. This suggests negative real bond yields.

8.9 Ten year nominal gilt futures suggest that, out to the end of the price control period, yields will increase by on average 0.5%. This would indicate an appropriate forward looking cost of debt might be 0.8%.

8.10 During the GttW project we calculated an adjustment factor to equalise the bids of those applicants seeking a 'revenue cap' and a 'cost pass through' treatment of controllable opex.[28] At that time we calculated an adjustment to the WACC of 0.22% was required to compensate for the increased risk. Including this adjustment would result in an estimate of a plausible GNI (UK) WACC of 1.0% real.

8.11 Economic theory suggests that for any given level of systematic risk the WACC required to attract capital to the company will remain unchanged irrespective of the gearing ratio. Our view is that the level of systematic risk which GNI (UK) and WTL will be exposed to is similar.

8.12 Once the pipeline network is in place no further capital expenditure will be required. The ratio between ongoing controllable opex and the regulatory asset value is low. We therefore repeated the analysis but using a more typical gearing ratio of 65% to determine if the above estimate was reasonable. The gearing ratio in the GNI (UK) licence had previously been fixed at 72.5%.

Cost of Debt

8.13 It is not possible to directly observe GNI (UK) debt cost from market traded bonds, as it is funded by internal loans from the parent. As in previous price control periods, we have relied on market data for 10+ year maturity bonds with A and BBB ratings. Prevailing market conditions would indicate a real cost of debt of 0.6%, assuming RPI over the price control period of 3.3%.

8.14 In addition we have sought information from the GNI (UK) parent with regard to the cost of their embedded debt. The parent fully funds the GNI (UK) licenced assets in NI by means of an inter company loan. As at 31 December 2015[29] the parent had a total of €374m of floating rate debt and €788m of fixed rate debt of which €500m is in the form of a five year bond with a maturity date of December 2017.

8.15 The average interest rate of the fixed portfolio is 3.3% (nominal) while the rate on the bond is 3.6% (nominal). This data on the embedded debt of the parent does not contradict our view on the cost of debt GNI (UK) would face under prevailing market conditions.

8.16 We also note that in December 2016 Gas Networks Ireland reported that it had raised €625m of capital through the issue of two bonds. The funding was in the form of:

- A €500m 10-year bond at a rate of 1.375%; and
- A €125m 20-year bond at a rate of 2.25%.

[28] Published 24 April 2014.
[29] Data provided by Ervia.

8.17 The company said there was strong demand from high-calibre investors for both the 10 and 20-year bond issuances.

8.18 GNI (UK) has proposed a cost of debt of 2.5% made up of a risk free rate of 1.25% and a debt premium of 1.25%. This approach mirrors that set out in the licence prior to the June 2016 modification. The modified licence, however, states that the cost of debt should be estimated using amongst other things prevailing market rates. This approach is in line with the approach that other economic regulators have adopted in recent years.

8.19 The risk free rate is estimated at 1.25%. However, returns to UK gilts in recent years have been negative in real terms. One key piece of evidence presented by GNI (UK) is the one percent spread between UK gilts and 'Irish' utility bonds.

8.20 Given that UK gilts in the period considered had a negative real return, this suggests a real cost of debt for these utilities of between zero and one percent. To add this spread to a risk free rate estimate of 1.25% therefore results in an erroneous impression of the true position faced by GNI (UK).

Asset beta

8.21 A firm's equity beta is a measure of the riskiness of a firm – or more specifically, a measure of the systematic risk that a firm presents – relative to the market portfolio. Firms that exhibit a beta of more than 1 can be considered more risky than the average firm in the portfolio and need to pay their investors a higher-than-average return.

8.22 Firms with a beta of less than 1 are less risky and warrant lower returns. Firms with a beta of exactly 1 are seen by investors as being of equal risk to the market portfolio and are expected to generate a return in line with market returns.

8.23 Empirical estimates of beta are usually obtained by measuring the covariance between movements in a company's share price and movements in the value of the stock market as a whole. However, in this instance we are interested in obtaining beta estimates for an unlisted business and cannot use market data directly.

8.24 The next best alternative that we have is to collect beta estimates for companies that look to be in some sense similar and to make a judgment about the value of GNI (UK)'s beta on the basis of this comparator evidence. This is an approach that has been deployed in an increasing number of periodic reviews, including several CC/CMA inquiries.

8.25 As the number of regulated companies with a stock market listing has declined, it is regarded as a robust and reliable way of assessing beta in the absence of direct stock market data.

8.26 When comparing the betas of different firms, one has to be careful to take account of the different gearing levels that firms choose since, all other things being equal, a firm with higher gearing will exhibit a higher equity beta. Unless one controls for this effect, there is a danger of confusing the risk that comes from high leverage with the underlying business risk that a firm faces by virtue of the nature of the activities it is carrying out.

8.27 This is where the concept of an asset beta proves useful. An asset beta is a hypothetical measure of the beta that a firm would have if it had no debt and were financed entirely by equity. By comparing different firms' asset betas it becomes possible to isolate the underlying systematic risk that a company has and carry out an assessment of the relative riskiness of different businesses.

8.28 Evidence from market observations and precedent from other economic regulators indicates that the value of this variable should lie between 0.30 and 0.40.

8.29 Table 28 below sets out the beta values that other regulators have used when calculating WACC for regulated network utilities in the United Kingdom. We consider that the comparative exposure of GNI (UK) to systematic risk would mean that an appropriate beta value should be 0.30.

Table 28: Beta estimates used in recent periodic reviews

Regulator / Decision	Year	Estimates of Asset Beta
Ofgem, gas distribution networks	2012	0.38
Ofwat, water and sewerage networks	2014	0.30
Ofgem, electricity distribution networks	2014	0.38
Competition Commission, NIE	2014	0.40
Competition Commission, GB regulated networks	2014	0.31 to 0.40
Utility Regulator, gas distribution networks	2016	0.40

8.30 GNI (UK) has proposed an asset beta of 0.44. We consider that a beta of this magnitude does not reflect the exposure to systematic risk of the licenced activity.

8.31 We also consider evidence from other regulatory decisions including those of the CMA would indicate that such a beta was outside the range of plausible beta estimates for GNI (UK).

Cost of Equity

8.32 In calculating the cost of equity we have set the *market returns to equity* figure at 6.5% and the *risk free rate* at 1.25%. This is in line with recent decisions by the Competition and Markets Authority, other economic regulators and the figures proposed by GNI (UK).

Gearing Ratio

8.33 In line with other regulators, we have set the gearing ratio consistent with the licence holder maintaining a credit rating in the range A to BBB/Baa. Depending on the particular circumstances of the regulated utility, gearing ratio figures of between 45% and 65% have been used.

8.34 We consider that given the low level of cash flow risk to which GNI (UK) is exposed, controllable opex is less than 5% of the Regulated Asset Base (RAB), a gearing ratio of 65% is appropriate. Our analysis of financeability confirms that this gearing ratio is reasonable to maintain the desired credit rating.

Summary

8.35 Table 29 below sets out the WACC as proposed by GNI (UK) against an assessment based on a beta of 0.30 and our view on the prevailing cost of debt.

Table 29: WACC – GNI (UK)

WACC Component	GNI (UK) Request	UR Draft Determination
Gearing Ratio	55.0%	65.0%
Cost of Equity	6.1%	4.8%
Cost of Debt	2.5%	0.6%
WACC (real)	**4.1%**	**2.0%**

8.36 The analysis above indicates that the WACC required to fund the GNI (UK) licence could lie somewhere between 1.0% and 2.0%. This spread may be due to a number of reasons. Firstly, the adjustment factor used in the GttW licence award process might be higher if calculated specifically for GNI (UK). Secondly, the *market returns to equity* figure used by economic regulators in the CAPM model may be an over estimate.

8.37 We have, however, taken a conservative approach in our determination of the appropriate WACC. Our proposal is that the WACC should be set at a rate of 2.0% for this draft determination.

WTL – UR Proposals

8.38 The WACC for WTL (1.98%) was established by the competitive process to award the GttW high pressure licence. This figure was based on prevailing market conditions in April 2014. At the time we made it clear that we would revise this figure if there was a significant shift in market conditions.

8.39 In their business plan WTL noted the significant reduction in the cost of debt since then. Applying the 2014 analysis to current debt figures indicates an equivalent WACC of 0.3%. We therefore propose for this draft determination that the rate of return figure for WTL should be 0.3%.

Other Issues

8.40 We recognise that in reaching our estimate of an appropriate rate of return for GNI (UK), we have converted from nominal to real market data by applying the Retail Prices Index measure of inflation. This is in line with the practice of other economic regulators and facilitates comparison with other relevant regulatory decisions.

8.41 The financial model set out in the GNI (UK) licence, however, uses the Consumer Prices Index measure. It is recognised that due to methodological approach and scope there is a wedge between the annual estimates of inflation these two indices generate.

8.42 An adjustment will therefore need to be applied to the various components of WACC before being input into the GNI (UK) financial model. In the absence of such an adjustment GNI (UK) would be disadvantaged in comparison to other regulated utilities whose costs are inflated using the Retail Prices Index.

8.43 We propose that this adjustment will equal the spread between the Office of Budget Responsibility forecast of inflation using both measures which for the price control period is 1.08%.[30] Making this adjustment results in a WACC of 3.1%. This adjusted figure has been used to calculate the capital repayments for GNI (UK) reported in Table 30 below.

8.44 For the purpose of this draft determination it is also necessary to estimate the RAB for WTL to which the WACC figure will be applied. In August 2015 WTL estimated a cost for the GttW project of £137m. Added to this will be the value of assets in East Down to be funded from the postalised transmission tariff, which we estimate as being £28.7m, September 2014 prices.[31]

8.45 The value of a maximum £32.5m subvention from the NI Executive is then netted off. Uplifting these costs to March 2016 prices gives a final estimate of £134.5m. It is assumed that bond issuance costs are rolled into the cost of debt.

8.46 The capital allowances for the GNI (UK) assets are determined by means of specific methodology set out in the conveyance licence. The ex post part of this process is still ongoing even though the network was entirely operational by October 2011. Between now and our final determination we will work with GNI (UK) and endeavour to finalise the RAB to which the WACC is applied.

Capital Repayments

8.47 Table 30 below sets out the capital repayments that will need to be funded over the price control period based on the proposed WACC figures. All figures are in £m March 2016 prices.

Table 30: Capital Repayments – March 2016 prices[32]

Gas Year	GNI (UK) - (£m)	PTL - (£m)	BGTL - (£m)	WTL - (£m)	Industry Total - (£m)
2017-18	10.9	8.4	4.6		**23.8**
2018-19	10.9	8.6	4.6	3.6	**27.7**
2019-20	10.9	8.8	4.7	3.6	**27.9**
2020-21	10.9	8.9	4.8	3.6	**28.2**
2021-22	10.9	9.1	4.9	3.6	**28.4**

Figures may not sum due to rounding

[30] Office of Budget Responsibility Report 23 November 2016.
[31] GD17 Final Determination paragraph 11.119.
[32] Capital repayments for BGTL and PTL do not form part of this price control but where agreed by the Utility Regulator at the time of bond issuance and set out in the Direction.

Financeability

8.48 Article 14 of the Energy (Northern Ireland) Order 2003 requires us to carry out our functions in the manner we consider best calculated to further our principal objective, having regard to the need to secure that licence holders are able to finance their obligations (amongst other things).

8.49 This duty is framed similarly to the financing duties of other UK regulators. It can broadly be taken in practice to mean that the price control ought to be set at a level which would allow an efficient network company to finance its licensed activities.

8.50 In assessing whether our proposals will allow licence holders to finance their activities during the GT17 period, we need to consider their ability to utilise both equity and debt finance.

8.51 Both PTL and BGTL are entirely financed by means of two bonds that were issued to fund the purchase of existing transmission assets. It is not envisaged that either licence holder will be required to invest further capital in these networks. At the time of issue the UR agreed, by means of the Direction,[33] to fully fund the repayments on these bonds through the postalised transmission tariff.

8.52 Both licences include an operating cost pass through mechanism. This means that allowed revenues will always match actual costs. In effect, neither PTL nor BGTL face any cash flow risk and so financeability is not a relevant issue for either of these licence holders.

8.53 WTL intends to fund the relevant assets on the same basis and operate under the same regulatory framework. The WTL licence already includes the same operating cost pass through mechanism. Financeability is therefore not a relevant issue.

8.54 GNI (UK) is financed entirely by a loan from the parent. However, we set WACC as if it was an independent company having to raise its own finance through a combination of debt and equity finance.

8.55 The key determinant of the ability to access equity finance is the allowed return on equity. 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 GNI (UK) logically against these alternative investments. Accordingly, we are satisfied that GNI (UK) ought to be capable of securing equity finance on an ongoing basis.

8.56 As far as borrowing is concerned the key objective is to retain credit worthiness in the eyes of lenders. This will be impacted by two factors, the level of cash flows that GNI (UK) can generate under our price control and the amount of borrowing. While we influence the former, the later is at the discretion of GNI (UK).

8.57 In order to analyse the impact of our draft determination on the ability of GNI (UK) to borrow we have employed the post maintenance interest cover ratio metric[34], the key metric used for a similar analysis in GD17. It is normally taken that a ratio above 1.4 indicates a firm that is in a position to service a given level of borrowing.

8.58 The table below sets out the calculation of this metric price control period. All figures are in £m at March 2016 prices

[33] As defined in Condition 3.1.7.1 of the PTL and BGTL licences.
[34] PMICR = EBITDA adjusted cash taxes less regulatory depreciation all divided by cash interest.

Table 31: PMICR – GNI (UK)

Cost Category	2017-18	2018-19	2019-20	2020-21	2021-22
Allowed Revenue - (£m)	**16.9**	**17.2**	**16.8**	**16.9**	**16.9**
Controllable Opex[35] - (£m)	4.3	4.6	4.1	4.1	4.1
Uncontrollable Opex - (£m)	1.8	1.8	1.8	1.9	1.9
Depreciation[36] - (£m)	3.3	3.3	3.3	3.3	3.3
Tax - (£m)	0.0	0.0	0.0	0.0	0.5
Post Maintenance FFO - (£m)	**7.5**	**7.5**	**7.6**	**7.6**	**7.1**
Interest Payment - (£m)	**3.0**	**2.9**	**2.7**	**2.6**	**2.4**
PMICR (FFO / Interest)	**2.5**	**2.6**	**2.8**	**2.9**	**3.0**

Figures may not sum due to rounding

8.59 Based on this analysis of both equity and debt we are content that our draft proposals are such that GNI (UK) is capable of financing the licenced activity.

[35] Includes repex, CJV and non-CJV opex.
[36] Straight line depreciation over 40 years.

9 Outputs and Allowances

Detailed Approach – UR Proposals

Overview

9.1 The principle legal duty of the UR in relation to gas is:

> *"to promote the development and maintenance of an efficient, economic and co-ordinated gas industry in Northern Ireland."*[37]

9.2 This must be done having regard to the interests of gas consumers and ensuring that licence holders are able to finance their activities.

9.3 Chapter 8 details how GT17 has tried to achieve the objective. This is demonstrated by setting out the allowances for each company as well as the associated outputs, targets and outcomes. Such an approach provides transparency for the licence holders, network users, consumers and the UR.

9.4 The chapter is structured as follows:

- GT17 outputs and allowance for the CJV;
- Cost reporting outputs for TSOs;
- Allowance for MEL;
- Allowance for GNI (UK); and
- Consumer impact.

Price Control Output Summary – CJV

9.5 At an industry level, the key project for TSOs in the future development of gas in Northern Ireland is the single system. The CJV is expected to deliver a number of benefits including:

a) Cost efficiency – as detailed in the CJV chapter;

b) A single IT system interface for shippers;

c) One set of transportation rules (single code);

d) Co-ordinated connection policies; and

e) Distinct set of invoices and credit arrangements.

9.6 These benefits will be visible during ongoing operations and can be viewed as specific outcomes of the project. In order to deliver these outcomes, the following allowance has been provided for the CJV.

[37] The Energy (NI) Order 2003, Article 14 (1) http://www.legislation.gov.uk/nisi/2003/419/contents/made.

Table 32: Allowance for single system operator (post efficiency)

Cost Category	2017-18 £m	2018-19 £m	2019-20 £m	2020-21 £m	2021-22 £m	Totals £m
CJV Staff Cost	**0.4**	0.4	0.4	0.4	0.4	**1.8**
Administration	**0.1**	0.1	0.2	0.1	0.1	**0.6**
Contracts & Licences	**0.4**	0.4	0.4	0.4	0.4	**2.2**
Network Code	**0.1**	0.2	0.1	0.1	0.1	**0.7**
European Compliance	**0.0**	0.0	0.0	0.0	0.0	**0.1**
Total (pre-efficiency)	**1.1**	1.1	1.1	1.1	1.1	**5.4**
Frontier Shift	**1.4%**	**2.4%**	**3.1%**	**3.8%**	**4.5%**	
Total (post efficiency)	**1.1**	**1.1**	**1.1**	**1.0**	**1.0**	**5.3**

Figures may not sum due to rounding

9.7 At a cost of approximately £1m per annum, the CJV will be responsible for market operations of transmission system users. Unlike a number of other utilities, gas TSOs typically have not had many regulatory KPI targets to meet. This is expected to change in the GT17 period.

9.8 A key outcome of the price control is the development of performance indicators for the single system. TSOs have already highlighted in their CJV business plan a number of potential areas which these may focus on. Proposed KPI's include:

a) Amount of IT system downtime;

b) Accuracy and timeliness of invoices;

c) Debtors adherence to payment terms;

d) Metrics on response to shipper queries;

e) Shipper satisfaction levels; and

f) Budgeting and cost control targets.

9.9 The draft determination does not require specific targets at this stage. More engagement in this area is required. We expect to take a view on these issues for the final determination.

9.10 The single system should, however, provide a more efficient and co-ordinated industry, evidenced by KPI's and regular reporting.

Price Control Output Summary – Cost Reporting

9.11 Another key output of the price control is cost reporting. As part of the business plan process, the UR and TSOs developed a common reporting template. TSOs have submitted plans on the basis of this template and associated guidance.

9.12 Going forward, we see value in continuing this reporting on a regular basis. Annual reporting provides a number of benefits such as:

a) Monitoring against price control targets;

b) Developing historic trends;

c) Benchmarking network operators; and

d) Providing transparency to network users.

9.13 It is our intention to develop and publish a report on TSO performance at annual intervals. The basis of this report will be the data provided by companies as part of their common reporting requirements. Reporting should be proportional and targeted.

9.14 We anticipate that their will be 3 elements to common reporting in GT17:

a) ***TSO cost reporting* –** Financial data should be provided in line with that requested for Table 1 of the business plan. Commentary should be included focusing on areas of spend where costs have risen/fallen or are substantially different from the GT17 allowance.

b) ***TSO output monitoring* –** On the basis of the final determination, it is the UR intention that an output table be developed. This table will focus on the delivery of major repex and maintenance projects (such as sub-sea surveys). It will also record spend associated with such schemes.

c) ***CJV Monitoring* –** A report from the CJV on its' performance, governance, costs, KPI's etc will be established. Details of this report are yet to be determined. Licence changes are being proposed to facilitate CJV operation.

9.15 Besides the 3 strands, we may also consider the issue of network serviceability measures and asset management reporting. Further engagement is required on this post determination.

9.16 We do not see this as a regulatory burden as reasonable and prudent network operators should be collecting similar data for their own purposes. This process merely formalises and aligns reporting between the TSOs. Consequently, we do not propose to grant any specific allowances for such activity.

9.17 It does, however, represent a new output of the price control process. We are of the opinion that such an activity will add value and transparency for network users and TSOs alike.

MEL – UR Proposals

Price Control Output Summary

9.18 For MEL the price control allowance is advisory. The company has an opex pass though mechanism, whilst the capital repayments are largely fixed at a low rate of interest.

9.19 However, we expect MEL to operate in a responsible and efficient manner. The draft determination represents the UR estimate of what forecast spend is anticipated for just such a network operator in GT17.

9.20 Total allowance post efficiency, including capital repayments for PTL, BGTL and WTL are set out in Table 33.

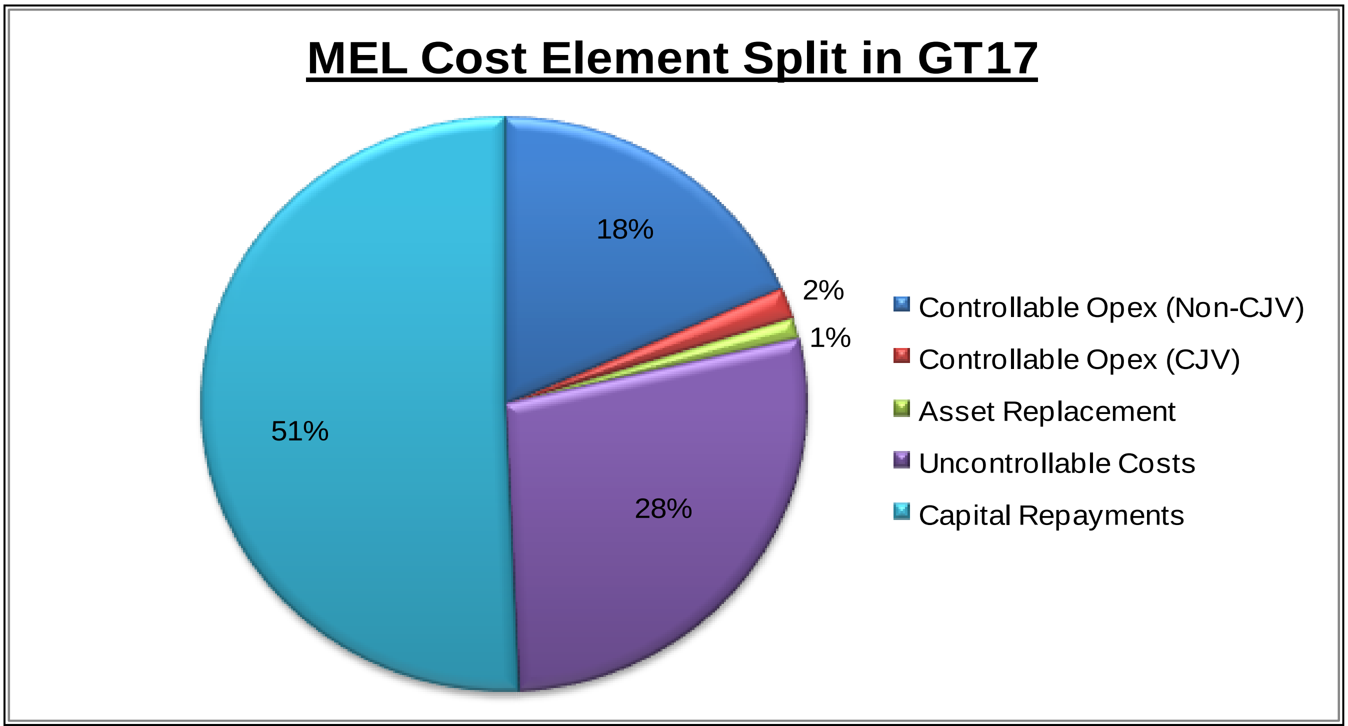
Table 33: Total allowance for MEL (post efficiency) – March 2016 prices

Cost Category	BP Request - £m	2017-18 £m	2018-19 £m	2019-20 £m	2020-21 £m	2021-22 £m	Totals £m
Controllable Opex non-CJV	**33.9**	6.8	5.7	6.1	4.9	6.2	**29.7**
Controllable Opex CJV	**3.7**	0.6	0.6	0.6	0.5	0.5	**2.8**
Asset Replacement - Repex	**4.9**	0.3	0.7	0.3	0.5	0.1	**1.9**
Uncontrollable Costs	**45.7**	11.0	8.5	8.5	8.5	8.5	**45.0**
Capital Repayments	**81.7**	13.0	16.8	17.1	17.3	17.6	**81.7**
Total	**169.9**	**31.7**	**32.2**	**32.5**	**31.8**	**32.9**	**161.1**

Figures may not sum due to rounding

9.21 The price control represents an allowance of 94.8% of what the company requested. Proportionally this can be viewed as follows:

Figure 10: Proportional split of MEL GT17 allowance



9.22 The final determination will set out more definitively what will be expected of MEL in the GT17 period for this allowance. The UR intends to report annually against these costs.

Environmental Impact and Carbon Budget

9.23 Work is ongoing with MEL to establish the carbon impact and budget. This will be detailed fully in the final determination.

GNI (UK) – UR Proposals

Price Control Output Summary

9.24 The draft determination total allowance for GNI (UK) is detailed below.

Table 34: Total allowance for GNI (UK) (post efficiency) – March 2016 prices

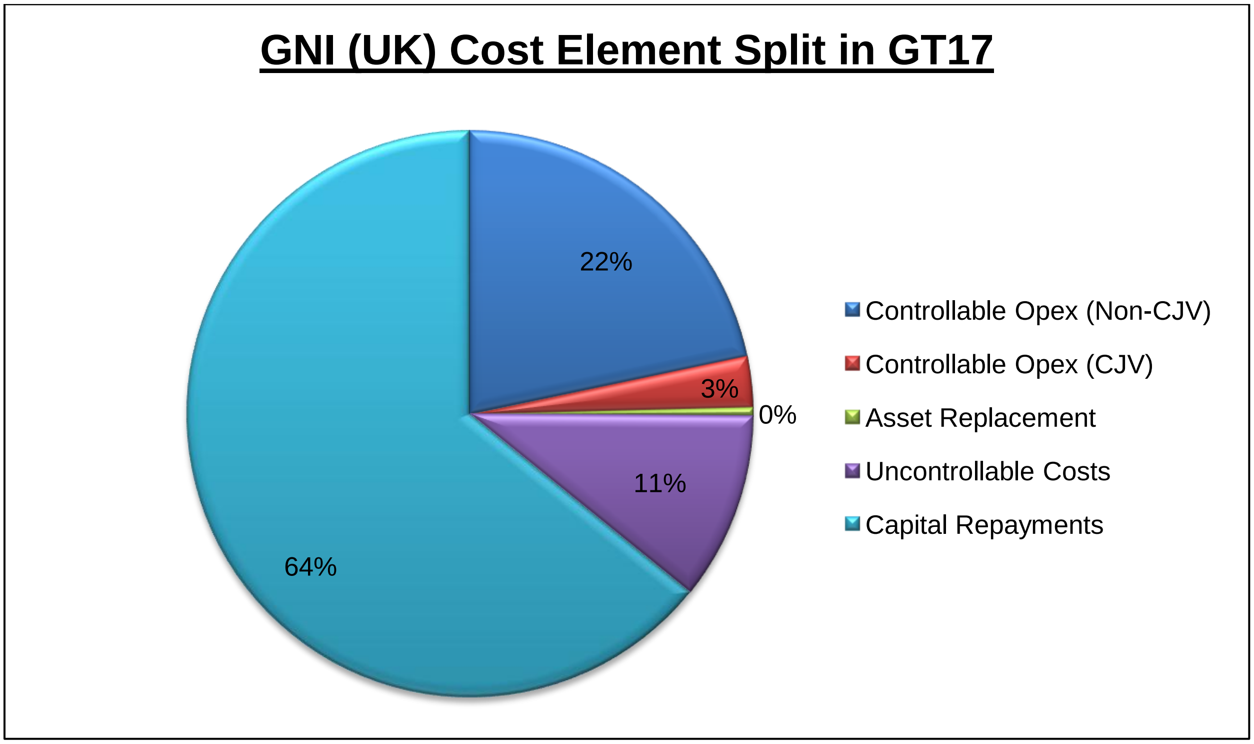
Cost Category	BP Request - £m	2017-18 £m	2018-19 £m	2019-20 £m	2020-21 £m	2021-22 £m	Totals £m
Controllable Opex non-CJV	**22.1**	3.7	3.9	3.6	3.6	3.6	**18.4**
Controllable Opex CJV	**3.7**	0.5	0.5	0.5	0.5	0.5	**2.5**
Asset Replacement - Repex	**5.9**	0.1	0.2	0.0	0.0	0.0	**0.4**
Uncontrollable Costs	**9.1**	1.8	1.8	1.8	1.9	1.9	**9.1**
Capital Repayments	**56.2**	10.9	10.9	10.9	10.9	10.9	**54.3**
Total	**96.9**	**16.9**	**17.2**	**16.8**	**16.9**	**16.9**	**84.6**

Figures may not sum due to rounding

9.25 UR views represent 87.4% of the amount asked for. There are notable reductions in areas of controllable opex and in particular repex. These categories will be subject to further scrutiny and review from our consultants as part of the final determination.

9.26 On a proportional basis, the allowance is split as follows:

Figure 11: Proportional split of GNI (UK) GT17 allowance



9.27 Outputs and targets associated with this allowance will be provided in detail for the final determinations. The UR expects to report against these commitments on an ongoing basis.

Environmental Impact and Carbon Budget

9.28 Work is continuing with GNI (UK) to establish the carbon impact and budget. This will be detailed fully in the final determination.

Consumer Impact

Impact on Consumer Bills

9.29 On an industry basis the overall allowance is approximately £49.2m p.a. in real terms against a request of £53.4m, as shown in Table 35. The figures forecast that the postalised tariff revenues should remain fairly constant in real terms throughout the period.

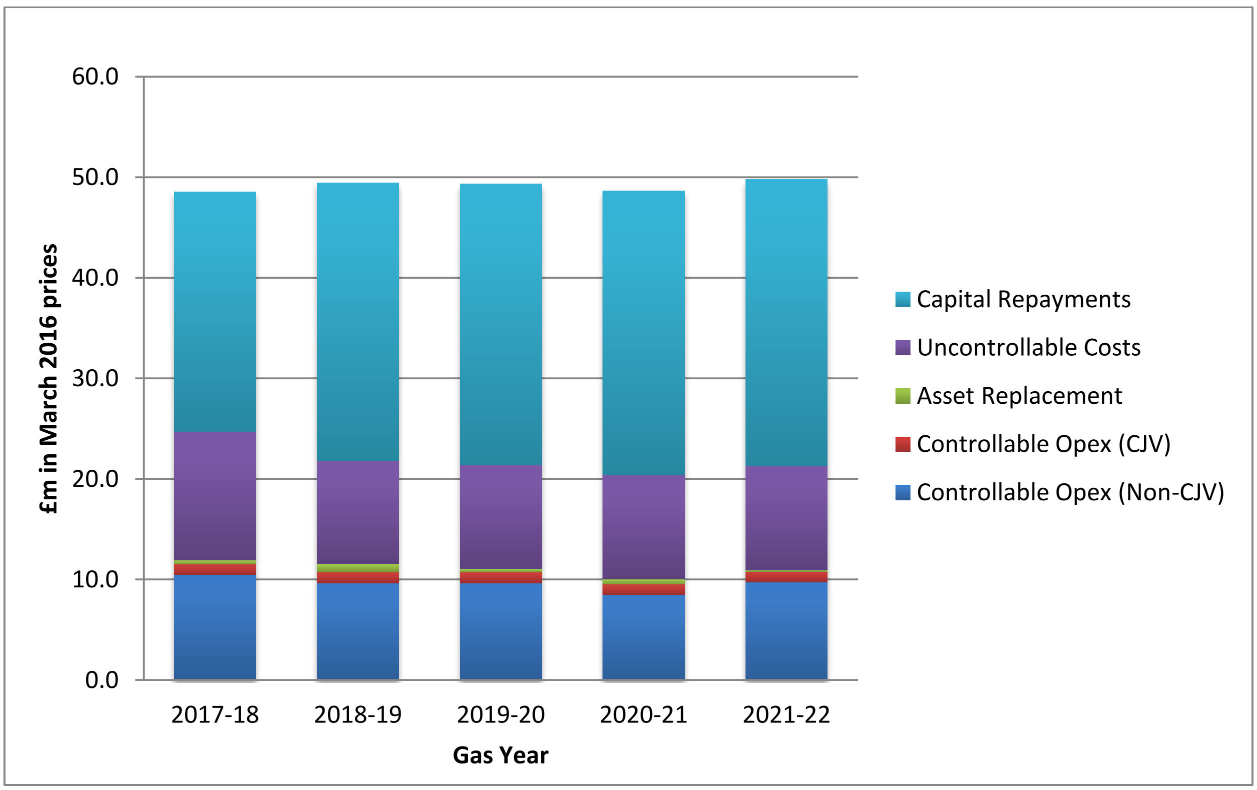
Table 35: Total allowance for gas industry (post efficiency) – March 2016 prices

Cost Category	BP Request - £m	2017-18 £m	2018-19 £m	2019-20 £m	2020-21 £m	2021-22 £m	Totals £m
Controllable Opex non-CJV	**56.0**	10.5	9.7	9.7	8.5	9.8	**48.1**
Controllable Opex CJV	**7.3**	1.1	1.1	1.1	1.0	1.0	**5.3**
Asset Replacement - Repex	**10.8**	0.4	0.8	0.3	0.5	0.2	**2.3**
Uncontrollable Costs	**54.8**	12.8	10.2	10.3	10.4	10.4	**54.1**
Capital Repayments	**137.9**	23.8	27.7	27.9	28.2	28.4	**136.0**
Total	**266.8**	**48.6**	**49.5**	**49.3**	**48.6**	**49.8**	**245.8**

Figures may not sum due to rounding

9.30 Split by year and category, the same revenue pot detail looks as follows:

Figure 12: Revenue allowance for gas industry by cost category – March 2016 prices



9.31 The figure indicates increasing capital repayments. This is due in large part to the WTL pipeline. Uncontrollable costs also show some fluctuation due to capital cost movements in Scotland. Controllable cost does shift, but this is largely a reflection of large maintenance project timings e.g. sub-sea surveys.

9.32 For domestic gas tariffs in Northern Ireland, the consumer bill is made up of the following distinct cost elements:

Table 36: Supply price split by cost element – April 2016

Cost Category	Greater Belfast	Ten Towns
Transmission network costs	11.8%	9.7%
Distribution network costs	38.9%	48.3%
Wholesale gas costs	38.8%	32.7%
Supply retail costs	10.5%	9.4%
Total	**100%**	**100%**

Figures may not sum due to rounding

9.33 Assuming domestic usage of 12,500 kWh, the average gas bill is currently around £500 per annum. From the table above it can be seen that approximately 10% (+£50) of this is related to the transmission network.

9.34 Using 2016-17 volumes, the UR has calculated the entry/exit transmission tariff employing both the business plan and draft determination figures.[38]

9.35 The analysis indicates that the current tariff[39] is forecast to increase by over 9% in real terms based on TSO forecasts. The draft determination allowance results in a 1% real term increase.

9.36 Assuming these increases apply equally to domestic bills, the impact of implementing the business plans would be an approximate £5 real terms uplift in the annual bill. This compares to a £0.50 increase proposed in the draft determination. The UR allowance therefore results in a £4.50 saving compared to the company submissions.

[38] A 5-year average of the total GT17 forecast has been used to calculate business plan tariffs. A 5-year average of the total GT17 draft determination allowance has also been used to calculate UR tariffs.

[39] http://www.mutual-energy.com/wp-content/uploads/downloads/2016/08/NI-Forecast-Postalised-System-Transmission-Tariffs.pdf

10 Next Steps and Further Issues

Submission of Consultation Responses

10.1 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 12 noon on 17 February 2017 and should be addressed to:

Veronika Gallagher

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 veronika.gallagher@uregni.gov.uk

10.2 Our preference would be for responses to be submitted by e-mail.

10.3 We note that we may make public any responses to this consultation on the GT17 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.

10.4 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.

10.5 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.

10.6 This document is available in accessible formats. Please contact Veronika Gallagher on 028 9031 1575 or email: Gas_networks_responses@uregni.gov.uk with cc to veronika.gallagher@uregni.gov.uk to request this.

Next Steps

10.7 Table 37 below provides an overview of the next steps and associated timelines of the GT17 process.

Table 37: GT17 Next Steps

Key Milestones	Proposed Date
Closure of consultation on draft determination	17 February 2017
Publication of final determination and consultation on licence modifications	April 2017
Closure of consultation on GT17 licence modifications	May 2017
Publication of decision on GT17 licence modifications	June 2017
Lessons learnt review	July 2017
Effective date of licence modifications and start of GT17 price control period	1 October 2017

Consequential Changes

10.8 We are currently drafting licence modifications and will discuss these with TSOs in the near future. The 28 day statutory consultation will begin when the consultation on these modifications is published together with the final determination of this GT17 price control. The purpose of these licence modifications are to:

- Align price control review dates for all licence holders included in this price control;
- Formally introduce Regulatory Instructions and Guidance into the licence. This new condition will match that included in the conveyance licence of distribution companies;
- Include licence conditions within the GNI (UK) licence to facilitate appeals to the Competition and Markets Authority; and
- Clarify the conditions under which GNI (UK) can request a determination to be reopened.

10.9 We note that this list is not necessarily exhaustive and that the need for further consequential changes may arise as the GT17 determination is being finalised.

Further Issues

MEL Governance Review

10.10 In our approach document we stated that as part of the price control we would make a decision as to whether or not there needed to be a review of the governance of the MEL, with the review to take place in the next price control period.

10.11 The last review of the relevant governance arrangements was carried out in 2008. As a matter of best regulatory practice we intend to carry out a review of existing arrangements during the price control period.

10.12 As noted in our approach we consider that the value of the Social Enhancement Fund in providing appropriate incentives to managers is not clear. Having taken note of the response received from MEL, we consider the future of this mechanism and the funds already retained by it should form part of our proposed governance review.

10.13 In the meantime we propose that no further monies are allocated to the fund and that all future operating cost savings are returned directly to consumers at the end of the gas year. This will be achieved by setting the 'z' factor to zero each year. We intend to give this proposal effect immediately, commencing with the 2016-17 gas year reconciliation process.

Cost Reporting

10.14 It is our intention to develop the annual cost reporting process further providing information on company performance during the price control period including publication of key cost and output metrics.

10.15 We anticipate that there will be 3 elements to common reporting in GT17; *TSO cost reporting*, *TSO output monitoring and CJV Monitoring.* More detail on this can be found in Chapter 8 – Price Control Output Summary.

Capital Allowances

10.16 We aim to progress the capital allowance decisions for both GNI (UK) and WTL before the final determination. Whilst these allowances are set outside the price control, the value determined will impact on GT17 revenue.

10.17 This work includes decisions around the AFCE (actual final capital expenditure) for the GNI (UK) pipelines and spurs.

10.18 It further includes approval of the WTL Compliance Plan as required under Condition 4.1.4 (c) of their licence. This provides assurance around cost apportionment and ensures that no capital expenditure is treated as pass-through opex.

Appendices

Appendix 1: Proposed Pre-efficiency Opex Allowances

Table 38: MEL Pre-efficiency Determination - £m in March 2016 prices

	MEL											
	Submission						Determination					
	2017-18	2018-19	2019-20	2020-21	2021-22	Total Submission	2017-18	2018-19	2019-20	2020-21	2021-22	Total Allowance
Administration												
Pipeline Insurance	0.546	0.626	0.626	0.626	0.626	3.051	0.515	0.545	0.545	0.545	0.545	2.695
Intra-company Recharge	0.349	0.377	0.392	0.379	0.372	1.870	0.279	0.302	0.317	0.304	0.298	1.500
Other Overheads	0.058	0.058	0.149	0.058	0.058	0.382	0.058	0.058	0.149	0.058	0.058	0.382
Support Staff Costs (excluding CJV)	0.211	0.209	0.209	0.209	0.210	1.048	0.204	0.185	0.185	0.185	0.186	0.945
Mutualisation Costs	0.472	0.414	0.483	0.476	0.476	2.320	0.472	0.414	0.483	0.476	0.476	2.320
Total Administration	1.636	1.684	1.860	1.749	1.743	8.671	1.528	1.503	1.679	1.568	1.563	7.841
Asset Replacement (Repex)												
Asset Replacement	0.819	1.910	0.712	0.920	0.510	4.870	0.323	0.671	0.287	0.519	0.148	1.947
Planned Maintenance												
Asset Management & Compliance	0.170	0.219	0.172	0.278	0.149	0.988	0.122	0.122	0.122	0.122	0.122	0.608
Emergency Response	0.312	0.360	0.350	0.330	0.356	1.708	0.285	0.360	0.350	0.330	0.356	1.681
Pipeline Inspection	2.059	0.771	1.207	0.232	1.561	5.831	2.059	0.771	1.207	0.232	1.561	5.831
Routine Maintenance	0.886	1.194	1.190	1.193	1.200	5.663	0.861	1.194	1.190	1.193	1.200	5.638
Engineering Staff Costs (excluding CJV)	0.651	0.673	0.673	0.674	0.674	3.345	0.589	0.605	0.605	0.606	0.606	3.011
Total Planned Maintenance	4.077	3.217	3.593	2.707	3.941	17.535	3.917	3.052	3.474	2.483	3.844	16.769
Unplanned Maintenance												
Drainage	0.174	0.130	0.145	0.145	0.145	0.737	0.174	0.130	0.145	0.145	0.145	0.737
Other Unplanned Costs	0.160	0.213	0.188	0.204	0.183	0.947	0.160	0.213	0.188	0.204	0.183	0.947
Total unplanned maintenance	0.334	0.342	0.332	0.349	0.327	1.685	0.334	0.342	0.332	0.349	0.327	1.685
System Operation												
Contracts and Licences	0.140	0.132	0.149	0.132	0.101	0.652	0.140	0.132	0.149	0.132	0.101	0.652
Grid Control	0.656	0.670	0.670	0.670	0.670	3.338	0.656	0.670	0.353	0.353	0.353	2.386
Major IT System Development	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Network Code Development	0.106	0.000	0.000	0.000	0.000	0.106	0.106	0.000	0.000	0.000	0.000	0.106
SCADA & Comms	0.237	0.186	1.076	0.186	0.271	1.957	0.237	0.186	0.276	0.186	0.271	1.157
European Compliance	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total System Operation	1.139	0.988	1.896	0.988	1.042	6.053	1.139	0.988	0.778	0.671	0.725	4.301
CJV Costs												
CJV Staff Costs	0.251	0.251	0.251	0.251	0.251	1.256	0.180	0.180	0.180	0.180	0.180	0.900
CJV Administration	0.112	0.131	0.156	0.131	0.120	0.649	0.112	0.131	0.156	0.131	0.120	0.649
Contracts and Licences	0.104	0.103	0.102	0.101	0.101	0.511	0.104	0.103	0.102	0.101	0.101	0.511
Grid Control	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Major IT System Development	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Network Code Development	0.341	0.213	0.155	0.139	0.139	0.988	0.141	0.163	0.145	0.129	0.129	0.708
SCADA & Comms	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
European Compliance	0.052	0.052	0.052	0.052	0.052	0.260	0.026	0.026	0.026	0.026	0.026	0.130
Total CJV	0.861	0.750	0.715	0.674	0.664	3.663	0.563	0.603	0.608	0.567	0.556	2.898
Uncontrollable Costs												
Business Rates	1.901	2.123	2.123	2.123	2.123	10.393	1.901	2.123	2.123	2.123	2.123	10.393
Licence Fees	1.263	1.263	1.263	1.263	1.263	6.317	1.263	1.263	1.263	1.263	1.263	6.317
Compressor Fuel	0.959	0.966	0.977	0.982	0.972	4.855	0.820	0.827	0.838	0.843	0.833	4.161
Scottish Costs	7.660	4.960	4.960	4.960	4.960	27.498	7.660	4.960	4.960	4.960	4.960	27.498
Stranraer/Dundalk Income	-0.635	-0.705	-0.659	-0.665	-0.665	-3.329	-0.635	-0.705	-0.659	-0.665	-0.665	-3.329
Total	11.148	8.607	8.664	8.662	8.652	45.732	11.009	8.468	8.525	8.523	8.513	45.039
Grand total	20.013	17.498	17.772	16.049	16.878	88.210	18.813	15.626	15.685	14.680	15.676	80.479

Table 39: PTL Pre-efficiency Determination- £m in March 2016 prices

PTL	Submission						Determination					
	2017-18	2018-19	2019-20	2020-21	2021-22	Total Submission	2017-18	2018-19	2019-20	2020-21	2021-22	Total Allowance
Administration												
Pipeline Insurance	0.366	0.366	0.366	0.366	0.366	1.830	0.366	0.366	0.366	0.366	0.366	1.830
Intra-company Recharge	0.237	0.147	0.160	0.145	0.137	0.826	0.190	0.118	0.129	0.116	0.109	0.662
Other Overheads	0.026	0.024	0.115	0.024	0.024	0.211	0.026	0.024	0.115	0.024	0.024	0.211
Support Staff Costs (Excluding CJV)	0.148	0.069	0.068	0.066	0.065	0.415	0.143	0.061	0.060	0.059	0.057	0.380
Mutualisation Costs	0.292	0.228	0.230	0.227	0.225	1.202	0.292	0.228	0.230	0.227	0.225	1.202
Total Administration	1.069	0.834	0.938	0.827	0.817	4.484	1.016	0.797	0.899	0.791	0.782	4.285
Asset Replacement (Repex)												
Asset Replacement	0.421	1.263	0.268	0.281	0.202	2.435	0.164	0.196	0.045	0.051	0.025	0.481
Planned Maintenance												
Asset Management & Compliance	0.093	0.087	0.102	0.115	0.084	0.480	0.066	0.048	0.072	0.050	0.068	0.305
Emergency Response	0.176	0.201	0.176	0.176	0.201	0.929	0.161	0.201	0.176	0.176	0.201	0.914
Pipeline Inspection	1.236	0.087	0.663	0.072	0.941	2.999	1.236	0.087	0.663	0.072	0.941	2.999
Routine Maintenance	0.428	0.439	0.430	0.420	0.433	2.149	0.416	0.439	0.430	0.420	0.433	2.137
Engineering Staff Costs (excluding CJV)	0.424	0.297	0.294	0.292	0.290	1.597	0.384	0.267	0.265	0.263	0.260	1.438
Total Planned Maintenance	2.356	1.111	1.665	1.074	1.948	8.154	2.263	1.042	1.605	0.980	1.903	7.793
Unplanned Maintenance												
Drainage	0.174	0.100	0.100	0.100	0.100	0.572	0.174	0.100	0.100	0.100	0.100	0.572
Other Unplanned Costs	0.047	0.047	0.047	0.047	0.047	0.233	0.047	0.047	0.047	0.047	0.047	0.233
Total unplanned maintenance	0.221	0.146	0.146	0.146	0.146	0.805	0.221	0.146	0.146	0.146	0.146	0.805
System Operation												
Contracts and Licences	0.109	0.111	0.128	0.111	0.080	0.540	0.109	0.111	0.128	0.111	0.080	0.540
Grid Control	0.552	0.481	0.481	0.481	0.481	2.475	0.552	0.481	0.253	0.253	0.253	1.792
Major IT System Development	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Network Code Development	0.106	0.000	0.000	0.000	0.000	0.106	0.106	0.000	0.000	0.000	0.000	0.106
SCADA & Comms	0.233	0.149	1.039	0.149	0.234	1.804	0.233	0.149	0.267	0.149	0.234	1.032
European Compliance	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total System Operation	1.001	0.741	1.648	0.741	0.795	4.925	1.001	0.741	0.648	0.513	0.567	3.470
CJV Costs												
CJV Staff Costs	0.251	0.251	0.251	0.251	0.251	1.256	0.180	0.180	0.180	0.180	0.180	0.900
CJV Administration	0.112	0.131	0.156	0.131	0.120	0.649	0.112	0.131	0.156	0.131	0.120	0.649
Contracts and Licences	0.104	0.103	0.102	0.101	0.101	0.511	0.104	0.103	0.102	0.101	0.101	0.511
Grid Control	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
Major IT System Development	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Network Code Development	0.341	0.213	0.155	0.139	0.139	0.988	0.141	0.163	0.145	0.129	0.129	0.708
SCADA & Comms	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
European Compliance	0.052	0.052	0.052	0.052	0.052	0.260	0.026	0.026	0.026	0.026	0.026	0.130
Total CJV	0.861	0.750	0.715	0.674	0.664	3.663	0.563	0.603	0.608	0.567	0.556	2.898
Uncontrollable Costs												
Business Rates	1.566	1.566	1.566	1.566	1.566	7.831	1.566	1.566	1.566	1.566	1.566	7.831
Licence Fees	0.709	0.709	0.709	0.709	0.709	3.547	0.709	0.709	0.709	0.709	0.709	3.547
Compressor Fuel	0.959	0.966	0.977	0.982	0.972	4.855	0.820	0.827	0.838	0.843	0.833	4.161
Scottish Costs	7.660	4.960	4.960	4.960	4.960	27.498	7.660	4.960	4.960	4.960	4.960	27.498
Stranraer/Dundalk Income	-0.635	-0.705	-0.659	-0.665	-0.665	-3.329	-0.635	-0.705	-0.659	-0.665	-0.665	-3.329
Total Uncontrollable	10.259	7.496	7.553	7.551	7.542	40.401	10.120	7.357	7.414	7.413	7.403	39.707
Grand total	16.187	12.339	12.933	11.295	12.112	64.866	15.348	10.881	11.365	10.460	11.382	59.438

Table 40: BGTL Pre-efficiency Determination- £m in March 2016 prices

BGTL												
	Submission						Determination					
	2017-18	2018-19	2019-20	2020-21	2021-22	Total Submission	2017-18	2018-19	2019-20	2020-21	2021-22	Total Allowance
Administration												
Pipeline Insurance	0.130	0.130	0.130	0.130	0.130	0.651	0.130	0.130	0.130	0.130	0.130	0.651
Intra-company Recharge	0.087	0.050	0.050	0.049	0.048	0.285	0.070	0.040	0.040	0.039	0.039	0.228
Other Overheads	0.017	0.016	0.016	0.016	0.016	0.081	0.017	0.016	0.016	0.016	0.016	0.081
Support Staff Costs (Excluding CJV)	0.055	0.030	0.029	0.029	0.028	0.171	0.053	0.026	0.026	0.025	0.025	0.156
Mutualisation Costs	0.124	0.099	0.099	0.098	0.098	0.518	0.124	0.099	0.099	0.098	0.098	0.518
Total Administration	0.413	0.325	0.325	0.322	0.320	1.705	0.394	0.311	0.312	0.309	0.307	1.633
Asset Replacement (Repex)												
Asset Replacement	0.397	0.648	0.444	0.639	0.308	2.435	0.159	0.474	0.243	0.468	0.123	1.466
Planned Maintenance												
Asset Management & Compliance	0.054	0.105	0.044	0.136	0.035	0.375	0.039	0.058	0.031	0.060	0.029	0.216
Emergency Response	0.074	0.074	0.074	0.074	0.074	0.372	0.068	0.074	0.074	0.074	0.074	0.365
Pipeline Inspection	0.823	0.040	0.424	0.040	0.500	1.828	0.823	0.040	0.424	0.040	0.500	1.828
Routine Maintenance	0.326	0.301	0.306	0.319	0.313	1.564	0.317	0.301	0.306	0.319	0.313	1.555
Engineering Staff Costs (excluding CJV)	0.159	0.109	0.109	0.108	0.107	0.592	0.144	0.098	0.098	0.097	0.096	0.533
Total Planned Maintenance	1.437	0.630	0.957	0.677	1.029	4.730	1.391	0.572	0.933	0.590	1.012	4.497
Unplanned Maintenance												
Drainage	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Other Unplanned Costs	0.100	0.084	0.084	0.106	0.084	0.458	0.100	0.084	0.084	0.106	0.084	0.458
Total unplanned maintenance	0.100	0.084	0.084	0.106	0.084	0.458	0.100	0.084	0.084	0.106	0.084	0.458
System Operation												
Contracts and Licences	0.021	0.021	0.021	0.021	0.021	0.103	0.021	0.021	0.021	0.021	0.021	0.103
Grid Control	0.088	0.051	0.051	0.051	0.051	0.291	0.088	0.051	0.027	0.027	0.027	0.219
Major IT System Development	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Network Code Development	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
SCADA & Comms	0.003	0.003	0.003	0.003	0.003	0.016	0.003	0.003	0.001	0.003	0.003	0.013
European Compliance	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total System Operation	0.111	0.074	0.074	0.074	0.074	0.409	0.111	0.074	0.048	0.050	0.050	0.335
CJV Costs												
CJV Staff Costs	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
CJV Administration	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Contracts and Licences	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Grid Control	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Major IT System Development	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Network Code Development	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
SCADA & Comms	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
European Compliance	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total CJV	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Uncontrollable Costs												
Business Rates	0.299	0.299	0.299	0.299	0.299	1.497	0.299	0.299	0.299	0.299	0.299	1.497
Licence Fees	0.498	0.498	0.498	0.498	0.498	2.488	0.498	0.498	0.498	0.498	0.498	2.488
Compressor Fuel	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Scottish Costs	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Stranraer/Dundalk Income	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Uncontrollable	0.797	0.797	0.797	0.797	0.797	3.985	0.797	0.797	0.797	0.797	0.797	3.985
Grand total	3.255	2.558	2.681	2.615	2.613	13.722	2.952	2.313	2.417	2.320	2.373	12.374

Table 41: WTL Pre-efficiency Determination- £m in March 2016 prices

WTL												
	Submission						Determination					
	2017-18	2018-19	2019-20	2020-21	2021-22	Total Submission	2017-18	2018-19	2019-20	2020-21	2021-22	Total Allowance
Administration												
Pipeline Insurance	0.050	0.130	0.130	0.130	0.130	0.571	0.019	0.049	0.049	0.049	0.049	0.214
Intra-company Recharge	0.024	0.179	0.183	0.186	0.187	0.759	0.019	0.143	0.148	0.149	0.150	0.609
Other Overheads	0.015	0.019	0.019	0.019	0.019	0.090	0.015	0.019	0.019	0.019	0.019	0.090
Support Staff Costs (Excluding CJV)	0.008	0.111	0.112	0.114	0.117	0.462	0.008	0.098	0.100	0.101	0.103	0.409
Mutualisation Costs	0.056	0.087	0.154	0.151	0.153	0.600	0.056	0.087	0.154	0.151	0.153	0.600
Total Administration	0.154	0.525	0.598	0.600	0.606	2.483	0.117	0.396	0.468	0.469	0.473	1.924
Asset Replacement (Repex)												
Asset Replacement	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Planned Maintenance												
Asset Management & Compliance	0.023	0.027	0.026	0.026	0.030	0.133	0.017	0.015	0.019	0.012	0.025	0.086
Emergency Response	0.062	0.084	0.100	0.080	0.080	0.407	0.057	0.084	0.100	0.080	0.080	0.402
Pipeline Inspection	0.001	0.644	0.120	0.120	0.120	1.004	0.001	0.644	0.120	0.120	0.120	1.004
Routine Maintenance	0.132	0.455	0.455	0.455	0.455	1.950	0.128	0.455	0.455	0.455	0.455	1.947
Engineering Staff Costs (excluding CJV)	0.068	0.267	0.270	0.274	0.278	1.157	0.061	0.240	0.243	0.246	0.250	1.040
Total Planned Maintenance	0.285	1.477	0.971	0.955	0.963	4.652	0.263	1.438	0.936	0.913	0.929	4.479
Unplanned Maintenance												
Drainage	0.000	0.030	0.045	0.045	0.045	0.165	0.000	0.030	0.045	0.045	0.045	0.165
Other Unplanned Costs	0.013	0.082	0.057	0.052	0.052	0.257	0.013	0.082	0.057	0.052	0.052	0.257
Total unplanned maintenance	0.013	0.112	0.102	0.097	0.097	0.422	0.013	0.112	0.102	0.097	0.097	0.422
System Operation												
Contracts and Licences	0.010	0.000	0.000	0.000	0.000	0.010	0.010	0.000	0.000	0.000	0.000	0.010
Grid Control	0.017	0.139	0.139	0.139	0.139	0.572	0.017	0.139	0.073	0.073	0.073	0.375
Major IT System Development	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Network Code Development	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
SCADA & Comms	0.000	0.034	0.034	0.034	0.034	0.137	0.000	0.034	0.009	0.034	0.034	0.112
European Compliance	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total System Operation	0.027	0.173	0.173	0.173	0.173	0.719	0.027	0.173	0.082	0.107	0.107	0.497
CJV Costs												
CJV Staff Costs	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
CJV Administration	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Contracts and Licences	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Grid Control	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Major IT System Development	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Network Code Development	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
SCADA & Comms	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
European Compliance	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total CJV	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Uncontrollable Costs												
Business Rates	0.035	0.257	0.257	0.257	0.257	1.065	0.035	0.257	0.257	0.257	0.257	1.065
Licence Fees	0.056	0.056	0.056	0.056	0.056	0.281	0.056	0.056	0.056	0.056	0.056	0.281
Compressor Fuel	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Scottish Costs	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Stranraer/Dundalk Income	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Uncontrollable	0.092	0.314	0.314	0.314	0.314	1.346	0.092	0.314	0.314	0.314	0.314	1.346
Grand total	0.571	2.601	2.158	2.139	2.153	9.622	0.513	2.432	1.902	1.900	1.921	8.668

Table 42: GNI (UK) Pre-efficiency Determination - £m in March 2016 prices

GNI(UK)												
	Submission						Determination					
	2017-18	2018-19	2019-20	2020-21	2021-22	Total Submission	2017-18	2018-19	2019-20	2020-21	2021-22	Total Allowance
Administration	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m	£m
Pipeline Insurance	0.224	0.231	0.249	0.257	0.276	1.237	0.176	0.176	0.176	0.176	0.176	0.879
Intra-company Recharge	0.210	0.211	0.219	0.228	0.232	1.100	0.100	0.100	0.100	0.100	0.100	0.500
Other Overheads	0.093	0.097	0.121	0.112	0.109	0.532	0.100	0.100	0.100	0.100	0.100	0.500
Support Staff Costs (Excluding CJV)	0.562	0.558	0.572	0.587	0.593	2.872	0.422	0.422	0.422	0.422	0.422	2.108
Mutualisation Costs	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Administration	1.089	1.097	1.161	1.184	1.210	5.741	0.797	0.797	0.797	0.797	0.797	3.987
Asset Replacement (Repex)												
Asset Replacement	1.081	1.952	1.727	0.568	0.568	5.896	0.095	0.181	0.042	0.042	0.042	0.402
Planned Maintenance												
Asset Management & Compliance	0.109	0.109	0.109	0.112	0.112	0.551	0.100	0.100	0.100	0.100	0.100	0.500
Emergency Response	0.288	0.288	0.288	0.288	0.288	1.440	0.288	0.288	0.288	0.288	0.288	1.440
Pipeline Inspection	0.170	0.466	0.177	0.177	0.195	1.185	0.170	0.454	0.177	0.177	0.195	1.173
Routine Maintenance	1.317	1.332	1.316	1.391	1.396	6.752	1.243	1.228	1.222	1.262	1.243	6.198
Engineering Staff Costs (excluding C	0.350	0.357	0.362	0.367	0.372	1.808	0.327	0.327	0.327	0.327	0.327	1.635
Total Planned Maintenance	2.234	2.552	2.252	2.335	2.363	11.736	2.128	2.397	2.114	2.154	2.153	10.946
Unplanned Maintenance												
Drainage	0.273	0.273	0.273	0.273	0.273	1.365	0.195	0.195	0.195	0.195	0.195	0.976
Other Unplanned Costs	0.210	0.255	0.235	0.235	0.240	1.175	0.210	0.225	0.200	0.200	0.200	1.035
Total unplanned maintenance	0.483	0.528	0.508	0.508	0.513	2.540	0.405	0.420	0.395	0.395	0.395	2.011
System Operation												
Contracts and Licences	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Grid Control	0.346	0.349	0.353	0.356	0.359	1.763	0.346	0.349	0.353	0.356	0.359	1.763
Major IT System Development	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Network Code Development	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
SCADA & Comms	0.046	0.049	0.052	0.055	0.058	0.260	0.046	0.049	0.052	0.055	0.058	0.260
European Compliance	0.025	0.000	0.000	0.000	0.000	0.025	0.000	0.000	0.000	0.000	0.000	0.000
Total System Operation	0.417	0.398	0.405	0.411	0.417	2.048	0.392	0.398	0.405	0.411	0.417	2.023
CJV Costs												
CJV Staff Costs	0.251	0.251	0.251	0.251	0.251	1.256	0.180	0.180	0.180	0.180	0.180	0.900
CJV Administration	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Contracts and Licences	0.480	0.480	0.480	0.480	0.480	2.401	0.330	0.330	0.330	0.330	0.330	1.651
Grid Control	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Major IT System Development	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Network Code Development	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
SCADA & Comms	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
European Compliance	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total CJV	0.731	0.731	0.731	0.731	0.731	3.657	0.510	0.510	0.510	0.510	0.510	2.551
Uncontrollable Costs												
Business Rates	0.594	0.585	0.642	0.685	0.698	3.204	0.594	0.585	0.642	0.685	0.698	3.204
Licence Fees	1.171	1.171	1.171	1.171	1.171	5.856	1.171	1.171	1.171	1.171	1.171	5.856
Compressor Fuel	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Scottish Costs	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Stranraer/Dundalk Income	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Uncontrollable	1.765	1.756	1.813	1.856	1.869	9.060	1.765	1.756	1.813	1.856	1.869	9.060
Grand total	**7.800**	**9.015**	**8.598**	**7.593**	**7.671**	**40.677**	**6.092**	**6.460**	**6.077**	**6.166**	**6.184**	**30.979**

Appendix 2: Proposed Pre-efficiency Repex Allowances

Table 43: MEL Total Pre-efficiency repex allowance - in March 2016 prices

Project	BP Request £m	2017-18 £m	2018-19 £m	2019-20 £m	2020-21 £m	2021-22 £m	Totals £m
Boiler house Replacement	**0.942**	0.050	0.448	0.076	0.299	0.000	**0.872**
Ballylumford Water Bath Heaters	**0.806**	0.000	0.000	0.000	0.000	0.000	**0.000**
C&I Panel PLC Replacement	**0.575**	0.105	0.105	0.134	0.134	0.047	**0.526**
Fire Detection System - Kiosks	**0.215**	0.000	0.000	0.000	0.000	0.000	**0.000**
Transformer Replacement	**0.169**	0.000	0.000	0.000	0.000	0.000	**0.000**
Lagging Replacement	**0.161**	0.000	0.000	0.000	0.000	0.000	**0.000**
Replacement / Overhaul of Valves	**0.161**	0.000	0.000	0.000	0.000	0.000	**0.000**
UPS & UPS Battery Replacement	**0.149**	0.047	0.045	0.000	0.014	0.043	**0.149**
Other	**1.804**	0.121	0.072	0.078	0.072	0.058	**0.400**
Total	**4.983**	**0.323**	**0.671**	**0.287**	**0.519**	**0.148**	**1.947**

Table 44: PTL Pre-efficiency repex allowance - in March 2016 prices

Project	BP Request £m	2017-18 £m	2018-19 £m	2019-20 £m	2020-21 £m	2021-22 £m	Totals £m
Boiler house Replacement	**0.000**	0.000	0.000	0.000	0.000	0.000	**0.000**
Ballylumford Water Bath Heaters	**0.806**	0.000	0.000	0.000	0.000	0.000	**0.000**
C&I Panel PLC Replacement	**0.230**	0.105	0.105	0.000	0.000	0.000	**0.210**
Fire Detection System - Kiosks	**0.108**	0.000	0.000	0.000	0.000	0.000	**0.000**
Transformer Replacement	**0.094**	0.000	0.000	0.000	0.000	0.000	**0.000**
Lagging Replacement	**0.097**	0.000	0.000	0.000	0.000	0.000	**0.000**
Replacement / Overhaul of Valves	**0.108**	0.000	0.000	0.000	0.000	0.000	**0.000**
UPS & UPS Battery Replacement	**0.049**	0.000	0.045	0.000	0.004	0.000	**0.049**
Other	**0.997**	0.059	0.046	0.045	0.046	0.025	**0.221**
Total	**2.489**	**0.164**	**0.196**	**0.045**	**0.051**	**0.025**	**0.481**

Table 45: BGTL Pre-efficiency repex allowance - in March 2016 prices

Project	BP Request £m	2017-18 £m	2018-19 £m	2019-20 £m	2020-21 £m	2021-22 £m	Totals £m
Boiler house Replacement	**0.942**	0.050	0.448	0.076	0.299	0.000	**0.872**
Ballylumford Water Bath Heaters	**0.000**	0.000	0.000	0.000	0.000	0.000	**0.000**
C&I Panel PLC Replacement	**0.345**	0.000	0.000	0.134	0.134	0.047	**0.316**
Fire Detection System - Kiosks	**0.108**	0.000	0.000	0.000	0.000	0.000	**0.000**
Transformer Replacement	**0.075**	0.000	0.000	0.000	0.000	0.000	**0.000**
Lagging Replacement	**0.065**	0.000	0.000	0.000	0.000	0.000	**0.000**
Replacement / Overhaul of Valves	**0.054**	0.000	0.000	0.000	0.000	0.000	**0.000**
UPS & UPS Battery Replacement	**0.100**	0.047	0.000	0.000	0.010	0.043	**0.100**
Other	**0.807**	0.062	0.026	0.033	0.025	0.033	**0.179**
Total	**2.495**	**0.159**	**0.474**	**0.243**	**0.468**	**0.123**	**1.466**

Table 46: GNI (UK) pre-efficiency repex allowance - in March 2016 prices

Project	BP Request £m	2017-18 £m	2018-19 £m	2019-20 £m	2020-21 £m	2021-22 £m	Totals £m
Cathodic Protection	**0.247**	0.079	0.042	0.042	0.042	0.042	**0.247**
Boiler Refurbishment	**1.982**	0.000	0.000	0.000	0.000	0.000	**0.000**
Control System Upgrade	**0.114**	0.000	0.000	0.000	0.000	0.000	**0.000**
Instrumentation	**0.303**	0.000	0.000	0.000	0.000	0.000	**0.000**
Metering Recalibration	**0.518**	0.000	0.000	0.000	0.000	0.000	**0.000**
Gormanston P2 Metering	**0.852**	0.000	0.000	0.000	0.000	0.000	**0.000**
AGI Security	**1.056**	0.000	0.000	0.000	0.000	0.000	**0.000**
Cyber Security Upgrade	**0.155**	0.015	0.139	0.000	0.000	0.000	**0.155**
Emergency Escapes	**0.641**	0.000	0.000	0.000	0.000	0.000	**0.000**
Remote Line Valve Actuation	**0.027**	0.000	0.000	0.000	0.000	0.000	**0.000**
Total	**5.896**	**0.095**	**0.181**	**0.042**	**0.042**	**0.042**	**0.402**

Appendix 3: Proposed Post-Efficiency Allowances

Table 47: MEL post-efficiency determination - in March 2016 prices

Cost Category	BP Request £m	2017-18 £m	2018-19 £m	2019-20 £m	2020-21 £m	2021-22 £m	DD Total £m
Administration	**8.671**	1.505	1.467	1.627	1.509	1.493	**7.602**
Asset Replacement	**4.870**	0.318	0.654	0.279	0.499	0.141	**1.891**
Planned Maintenance	**17.535**	3.860	2.978	3.367	2.389	3.672	**16.266**
Unplanned Maintenance	**1.685**	0.329	0.334	0.322	0.336	0.313	**1.633**
System Operation	**6.053**	1.123	0.964	0.754	0.645	0.692	**4.179**
CJV Costs	**3.663**	0.555	0.588	0.589	0.546	0.532	**2.810**
Uncontrollable Costs	**45.732**	11.009	8.468	8.525	8.523	8.513	**45.039**
Total	**88.210**	**18.700**	**15.453**	**15.463**	**14.448**	**15.356**	**79.420**

Table 48: PTL post-efficiency determination - in March 2016 prices

Cost Category	BP Request £m	2017-18 £m	2018-19 £m	2019-20 £m	2020-21 £m	2021-22 £m	DD Total £m
Administration	**4.484**	1.002	0.777	0.871	0.761	0.747	**4.158**
Asset Replacement	**2.435**	0.162	0.192	0.043	0.049	0.024	**0.469**
Planned Maintenance	**8.154**	2.230	1.017	1.555	0.943	1.818	**7.563**
Unplanned Maintenance	**0.805**	0.217	0.143	0.142	0.141	0.139	**0.782**
System Operation	**4.925**	0.986	0.723	0.628	0.494	0.542	**3.373**
CJV Costs	**3.663**	0.555	0.588	0.589	0.546	0.532	**2.810**
Uncontrollable Costs	**40.401**	10.120	7.357	7.414	7.413	7.403	**39.707**
Total	**64.866**	**15.273**	**10.796**	**11.243**	**10.346**	**11.204**	**58.862**

Table 49: BGTL post-efficiency determination - in March 2016 prices

Cost Category	BP Request £m	2017-18 £m	2018-19 £m	2019-20 £m	2020-21 £m	2021-22 £m	DD Total £m
Administration	**1.705**	0.388	0.304	0.302	0.297	0.294	**1.585**
Asset Replacement	**2.435**	0.156	0.463	0.235	0.450	0.117	**1.422**
Planned Maintenance	**4.730**	1.371	0.558	0.904	0.568	0.966	**4.367**
Unplanned Maintenance	**0.458**	0.099	0.082	0.081	0.102	0.080	**0.444**
System Operation	**0.409**	0.110	0.073	0.047	0.049	0.048	**0.326**
CJV Costs	**0.000**	0.000	0.000	0.000	0.000	0.000	**0.000**
Uncontrollable Costs	**3.985**	0.797	0.797	0.797	0.797	0.797	**3.985**
Total	**13.722**	**2.920**	**2.276**	**2.367**	**2.262**	**2.303**	**12.128**

Table 50: WTL post-efficiency determination - in March 2016 prices

Cost Category	BP Request £m	2017-18 £m	2018-19 £m	2019-20 £m	2020-21 £m	2021-22 £m	DD Total £m
Administration	**2.483**	0.116	0.386	0.454	0.451	0.452	**1.859**
Asset Replacement	**0.000**	0.000	0.000	0.000	0.000	0.000	**0.000**
Planned Maintenance	**4.652**	0.259	1.403	0.907	0.878	0.888	**4.336**
Unplanned Maintenance	**0.422**	0.013	0.109	0.099	0.093	0.093	**0.408**
System Operation	**0.719**	0.027	0.169	0.079	0.103	0.102	**0.481**
CJV Costs	**0.000**	0.000	0.000	0.000	0.000	0.000	**0.000**
Uncontrollable Costs	**1.346**	0.092	0.314	0.314	0.314	0.314	**1.346**
Total	**9.622**	**0.507**	**2.381**	**1.853**	**1.840**	**1.849**	**8.430**

Table 51: GNI (UK) post-efficiency determination - in March 2016 prices

Cost Category	BP Request £m	2017-18 £m	2018-19 £m	2019-20 £m	2020-21 £m	2021-22 £m	DD Total £m
Administration	**5.741**	0.786	0.778	0.773	0.767	0.762	**3.866**
Asset Replacement	**5.896**	0.093	0.177	0.041	0.040	0.040	**0.391**
Planned Maintenance	**11.736**	2.097	2.339	2.048	2.073	2.057	**10.614**
Unplanned Maintenance	**2.540**	0.399	0.410	0.383	0.380	0.377	**1.950**
System Operation	**2.048**	0.386	0.388	0.392	0.396	0.398	**1.961**
CJV Costs	**3.657**	0.503	0.498	0.494	0.491	0.487	**2.473**
Uncontrollable Costs	**9.060**	1.765	1.756	1.813	1.856	1.869	**9.060**
Total	**40.677**	**6.030**	**6.347**	**5.945**	**6.004**	**5.991**	**30.315**

Annexes

Overview

Table 52 provides an overview over the annexes to this GT17 draft determination.

Table 52: Annexes

Annex Number	Annex Name
Annex 1	Real Price Effects and Frontier Shift